Short-Term Assessment of Reliability: 2025 Quarter 3

A Report by the
New York Independent System Operator

October 13, 2025

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Executive Summary

This report sets forth the 2025 Quarter 3 Short-Term Assessment of Reliability ("STAR") findings for the five-year study period of July 15, 2025, through July 15, 2030, considering forecasts of peak power demand, planned upgrades to the transmission system, and changes to the generation mix over the next five years. The deactivations of the following Initiating Generators[1] are evaluated in this STAR: Hyland LFGE, Pinelawn Power 1, Far Rockaway Gas Turbine 1 and 2, Gowanus Gas Turbine 2-1 through 2-8, Gowanus Gas Turbine 3-1 through 3-8, Narrows Gas Turbine 1-1 through 1-8 and Narrows Gas Turbine 2-1 through 2-8.

The NYISO performed an assessment of the Bulk Power Transmission Facilities ("BPTF") and identified several Short-Term Reliability Process Needs across the study period, as further explained below. Con Edison, PSEG-LI,[2] and NYSEG also performed deactivation assessments to evaluate the reliability of their non-BPTF systems. In addition to the needs on the bulk transmission system identified by the NYISO, PSEG-LI identified Generator Deactivation Reliability Needs on the non-BPTF associated with the deactivation of the Far Rockaway generators. No needs were identified associated with Hyland LFGE.

The risk of deficiencies beyond the needs identified in this STAR is even greater when considering a range of plausible futures with combined risks, such as the statistical likelihood of further generator retirements or failures. New York's generation fleet is among the oldest in the country, and as these generators age, they are experiencing more frequent and longer outages. The 2025-2034 Comprehensive Reliability Plan, to be issued by the end of 2025, will provide further information regarding reliability risks over the next ten years.

New York City Generator Deactivation Reliability Need

In the 2023 Quarter 2 STAR, the NYISO identified a short-term reliability need beginning in summer 2025 within New York City primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by the New York State Department of Environmental Conservation regulation to limit emissions of nitrogen oxides, known as the "DEC Peaker Rule."[3] On November 20, 2023, following a solicitation

[1] Per OATT 38.1, an "Initiating Generator" is "a Generator with a nameplate rating that exceeds 1 MW that submits a Generator Deactivation Notice for purposes of becoming Retired or entering into a Mothball Outage or that has entered into an ICAP Ineligible Forced Outage pursuant to Section 5.18.2.1 of the ISO Services Tariff, which action is being evaluated by the ISO in accordance with its Short-Term Reliability Process requirements in this Section 38 of the ISO OATT."

[2] PSEG-LI serves as the agent for the Long Island Power Authority ("LIPA"), which is the Transmission Owner.

[3] In 2019, the New York State Department of Environmental Conservation adopted a regulation to limit nitrogen oxides (NO_x) emissions from simple-cycle combustion turbines, referred to as the "Peaker Rule." 6 N.Y.C.R.R. Part 227-3 (available here).

for solutions, the NYISO issued a Short-Term Reliability Process Report[4] identifying the temporary and permanent solutions to the 2025 New York City need. The NYISO determined that temporarily retaining the Gowanus 2 & 3 and Narrows 1 & 2 generators is necessary to address the need,[5] and that the permanent solution is the Champlain Hudson Power Express ("CHPE") connection from Quebec, Canada to New York City.

The NYISO's designation of the Gowanus 2 & 3 and Narrows 1 & 2 generators under the DEC Peaker Rule in 2023 has allowed their continued operation beyond May 1, 2025 until permanent solutions are in place, for an initial period of up to two years (May 1, 2027). The 2023 report further noted that the DEC Peaker Rule provides that there is a potential for an additional two-year extension (until May 1, 2029) if reliability needs still exist.

In this 2025 Quarter 3 STAR, the Gowanus Gas Turbine 2-1 through 2-8, Gowanus Gas Turbine 3-1 through 3-8, Narrows Gas Turbine 1-1 through 1-8 and Narrows Gas Turbine 2-1 through 2-8 units (collectively "Gowanus and Narrows") have completed their generator deactivation notices and are now all Initiating Generators, requiring the NYISO and Con Edison to evaluate in this STAR if there are any Generator Deactivation Reliability Needs. Prior to the completion of their generator deactivation notices, all prior STARs evaluated the unavailability of these units consistent with the assumptions for compliance with the Peaker Rule.

Consistent with the findings in 2023, this STAR continues to find that the New York City locality (Zone J) would be deficient in the summer through the entire five-year horizon without the completion and energization of future planned projects. This includes deficiencies on the BPTF and non-BPTF within Zone J. The future planned projects include:

- Gowanus-Greenwood 345/138 kV feeder – May 2026
- CHPE, 1,250 MW HVDC – May 2026
- Empire Wind, 816 MW offshore wind – July 2027
- Propel NY Public Policy Transmission Project – May 2030

Until these system plans are completed and demonstrate their planned power capabilities to address the identified reliability needs, the previously identified BPTF and non-BPTF deficiencies would persist without Gowanus and Narrows. The following table provides the magnitude and duration of the BPTF deficiency through the five-year study period if system plans are not

[4] https://www.nyiso.com/documents/20142/39103148/2023-Q2-Short-Term-Reliability-Process-Report.pdf

[5] Such retention was accomplished by the NYISO designating Gowanus 2 & 3 and Narrows 1 & 2 generators as reliability resources under the DEC Peaker Rule to allow their continued operation beyond May 2025.

completed.

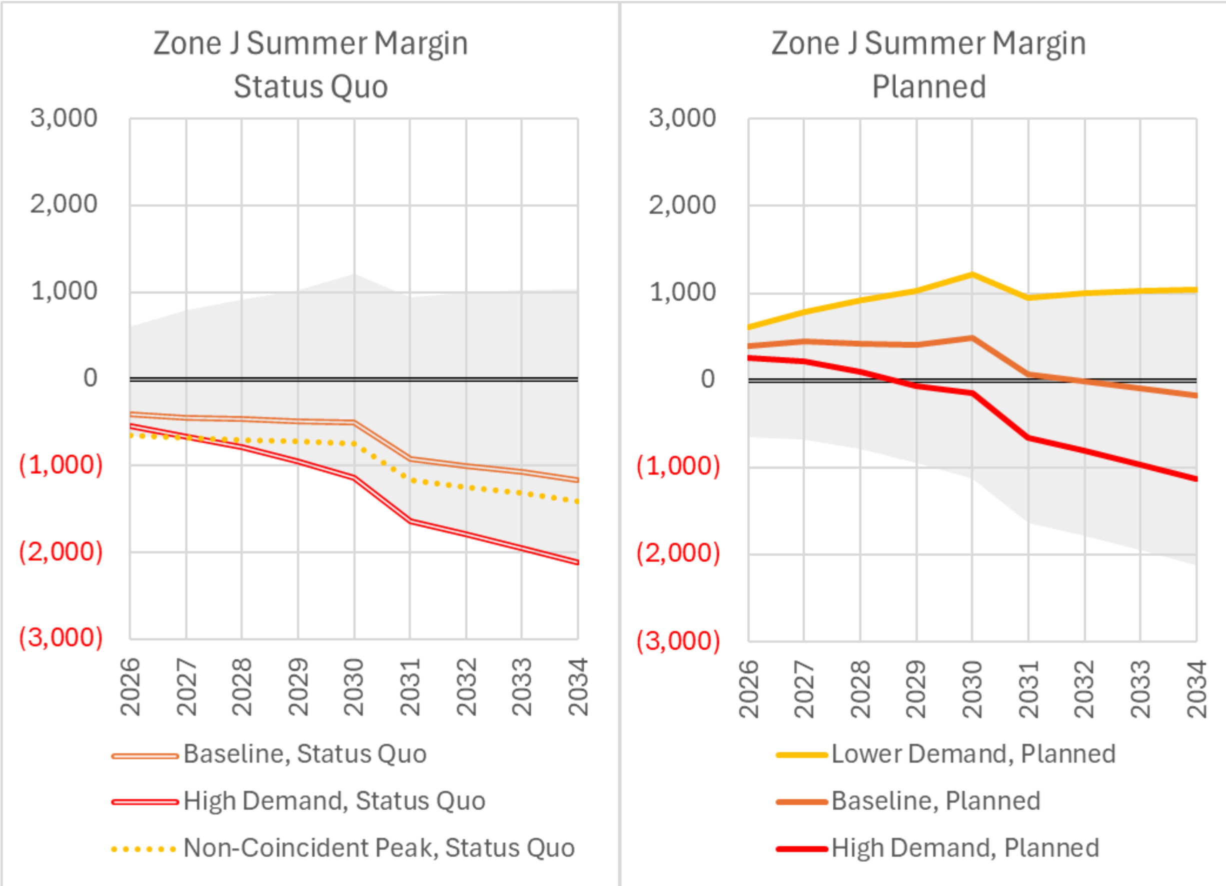
New York City BPTF Deficiencies:

Summer Peak	**2026**	**2027**	**2028**	**2029**	**2030**
MW Deficiency	410-650	440-680	460-790	480-950	500-1,130
Duration (hours)	6-8	6-9	8-11	8-13	8-13
MWh	1,709-3,569	1,753-3,782	3,014-6,658	3,227-8,794	3,211-10,922

Additionally, the Lower Hudson Valley locality (Zones G-J) would be deficient by 260 MW over three hours (924 MWh) in 2030 without the completion and energization of future planned projects. This deficiency is further exacerbated through time without any additional capabilities added within the Lower Hudson Valley locality, which includes New York City.

Once CHPE, Empire Wind, and the Propel NY Public Policy Transmission Project enter service and demonstrate their planned power capabilities, the margins improve substantially assuming all existing generators remain available, but gradually erode as forecasted demand for electricity grows. Even with the future planned projects delivering power according to schedule, there remains a risk of a Zone J deficiency in summer 2029, following the deactivation of Gowanus and Narrows, assuming all other generators in Zone J are available. Specifically, Zone J may be deficient by 68 MW over 5 hours (871 MWh) in 2029, which grows to 148 MW over 6 hours (1,249 MWh) in 2030. Beyond 2030, these deficiencies are further exacerbated with increasing demand for electricity and the planned deactivation of the NYPA small plants. Con Edison does not observe non-BPTF reliability needs within the study period with the future planned projects in service. Figure 1 depicts the reliability margins for Zone J without any future planned projects ("status quo") and assuming all projects enter service as planned ("planned"). Figure 2 provides a summary of the factors affecting the New York City bulk power transmission security margin.

Figure 1: Zone J Summer Transmission Security Margin



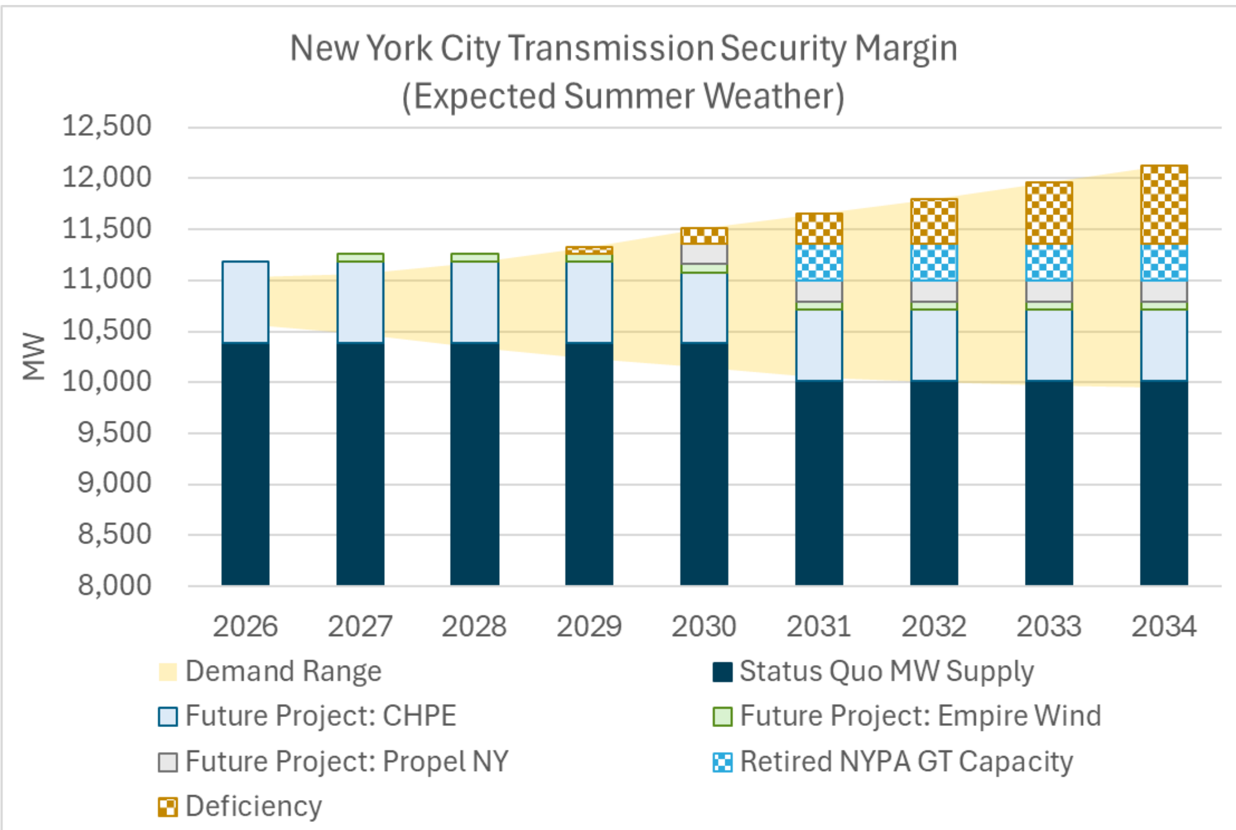
The range in the demand forecast for expected weather is driven by key assumptions, such as population and economic growth, energy efficiency, the installation of behind-the-meter renewable energy resources, and electric vehicle adoption and charging patterns. The summer peak demand forecast uncertainty for Zone J has a range of 460 MW in 2026 growing to 1,360 MW in 2030, primarily driven by assumptions in electrification of transportation and buildings as described in the 2025 Load and Capacity Data Report ("Gold Book"). The assumed available supply has also been adjusted to account for expected reductions of 110 MW in generators' dependable maximum net capability (DMNC)[6] and a 175 MW reduction in expected capacity sales from PJM.

The New York City and Lower Hudson Valley deficiencies are driven by the deactivation of the Gowanus and Narrows generators (672 MW nameplate total) in combination with demand forecasts based on expected weather, expected generator availability, transmission limitations, and risks associated with the availability of key future planned projects. As the Zone J need is observed

[6] See discussion of Correlated Derates below.

within the first three years of the short-term planning horizon and resolved in whole or part by Gowanus and Narrows, that need is a Near-Term Reliability Need and a Generator Deactivation Reliability Need. As the need in the Lower Hudson Valley is an exacerbation of the need observed in Zone J, it is also a Generator Deactivation Reliability Need, but it is not a Near-Term Reliability Need. In accordance with the DEC Peaker Rule, the Gowanus and Narrows generators may extend operation for up to an additional two years (until May 1, 2029) if the NYISO or Con Edison determine that the reliability need still exists and a permanent solution has been identified and is in the process of construction but not yet online. The DEC Peaker Rule, however, does not provide for peaker generators to continue operating after this date without meeting the emissions requirements.

Figure 2: Factors Affecting New York City Transmission Security Margin



Long Island Generator Deactivation Reliability Need

In this 2025 Quarter 3 STAR the Pinelawn Power 1 ("Pinelawn") and Far Rockaway Gas Turbine 1 and 2 ("Far Rockaway GTs") completed their generator deactivation notices requiring the NYISO and LIPA determine if there are any generator deactivation reliability needs. None of these Initiating Generators in the Long Island service territory are impacted by the DEC Peaker Rule.

This STAR finds that the BPTF in the Long Island locality (Zone K) is deficient beginning in summer 2027 and continuing through the remaining five-year horizon, primarily driven by the deactivation of Pinelawn (82 MW nameplate) and the Far Rockaway GTs (121 MW nameplate total). In addition to the BPTF deficiency, LIPA also identified non-BPTF system deficiencies on the 69 kV system through the entire five-year horizon.

On the BPTF, the Zone K need is based on a deficient transmission security margin that accounts for demand forecasts based on expected weather, expected generator availability, transmission limitations, and risks associated with the availability of key future planned projects.

Figure 3 shows the Long Island summer transmission security margin for a range of demand forecasts under expected weather. Figure 4 provides a summary of the factors affecting the Long Island bulk power transmission security margin. The following table provides the magnitude and duration of the BPTF deficiency through the five-year study period if system plans are not completed.

Long Island BPTF Deficiencies

Summer Peak	**2026**	**2027**	**2028**	**2029**	**2030**
MW Deficiency	None	39-116	61-138	107-185	175-254
Duration	None	1-3	3	3	3-4
MWh	None	39-176	213-444	320-554	515-819

Once Sunrise Wind is delivering power as planned, the margins improve in summer 2028, followed by dramatic improvement in 2030 with the planned energization of the Propel NY project such that margins remain positive throughout the remainder of the planning horizon. However, even if these future planned projects are available according to current schedules, deficiencies under summer peak conditions are still observed from 2027 through 2029. Specifically, with the planned projects available, the BPTF deficiency is 39-116 MW over 1-3 hours (39-176 MWh) in 2027 and by summer 2029 the deficiency is 14-92 MW over 2-3 hours (90-277 MWh).

LIPA, in its review of the impact of the deactivation of the Far Rockaway GTs and Pinelawn, has also identified generator deactivation reliability needs on the non-BPTF transmission system. Within the Far Rockaway load pocket LIPA identified local 69 kV thermal and voltage issues, resulting in a 61 MW deficiency over 13 hours (505 MWh) in 2026, and grows to 72-80 MW over 14-15 hours (649-813 MWh) by 2030.

The bulk system deficiencies are driven by the deactivation of Far Rockaway and Pinelawn generators (203 MW nameplate total) in combination with demand forecasts based on expected weather, expected generator availability, transmission limitations, and risks associated with the availability of key future planned projects. The non-BPTF Generator Deactivation Reliability Need on the LIPA 69 kV system is driven by the deactivation of the Far Rockaway GTs. As these needs are observed within the first three years of the short-term horizon and resolved in whole or part by Far Rockaway and/or Pinelawn, the needs are Near-Term Reliability Needs and Generator Deactivation Reliability Needs. For the reasons stated, the NYISO has determined that the Far Rockaway GTs and the Pinelawn Generator must remain in service until the conclusion of the 365-day notice period. The generators will be Interim Service Providers that are compensated under an Interim Service Provider rate commencing December 25, 2025.

The summer peak demand forecast uncertainty for Zone K has a range of 92 MW in 2026 growing to 302 MW in 2030, primarily driven by assumptions in electrification of transportation and buildings as described in the 2025 Gold Book. The assumed available supply has also been adjusted to account for expected reductions of 200 MW in generators' DMNC.

In accordance with filed compliance plans for the DEC Peaker Rule, the Glenwood GT 3 and Shoreham 1 generators are assumed available until May 1, 2027 and unavailable thereafter. Additionally, the assumed capacity purchases from ISO New England into Zone K have been adjusted to account for a LIPA import of 288 MW from ISO-NE until April 2027, with zero flow scheduled thereafter. If these additional resources are available through the five-year horizon, the observed reliability need on the BTPF would be eliminated.

Figure 3: Zone K Summer Transmission Security Margin

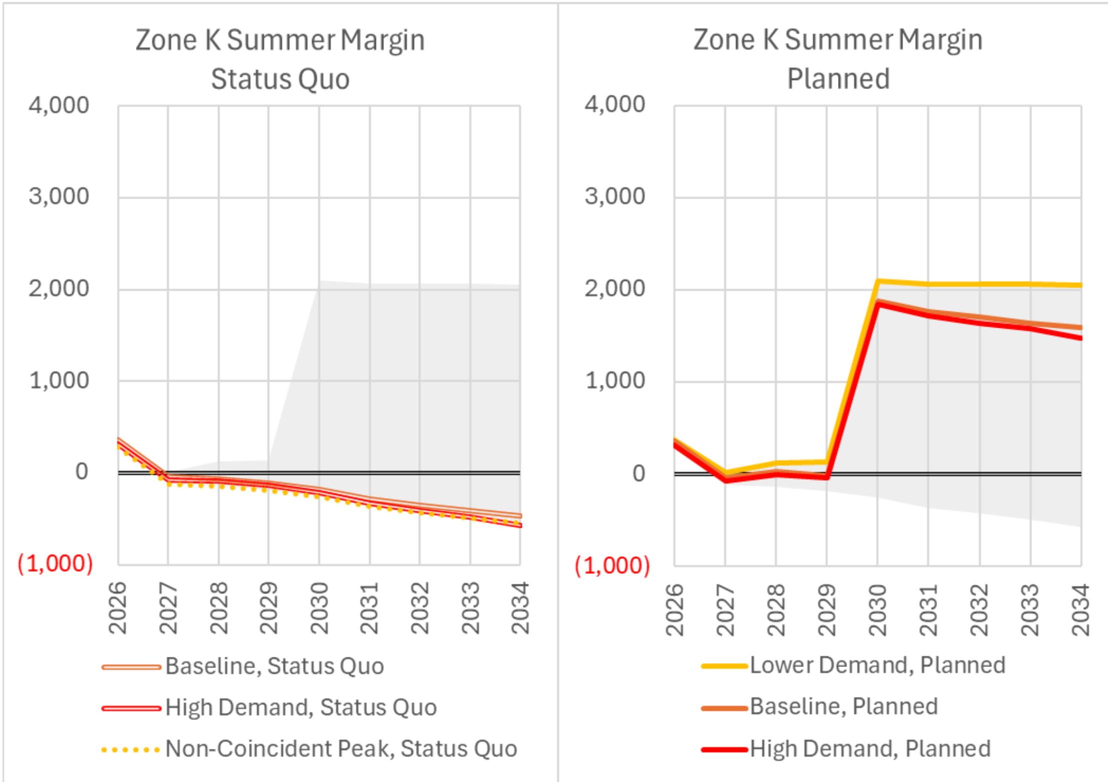
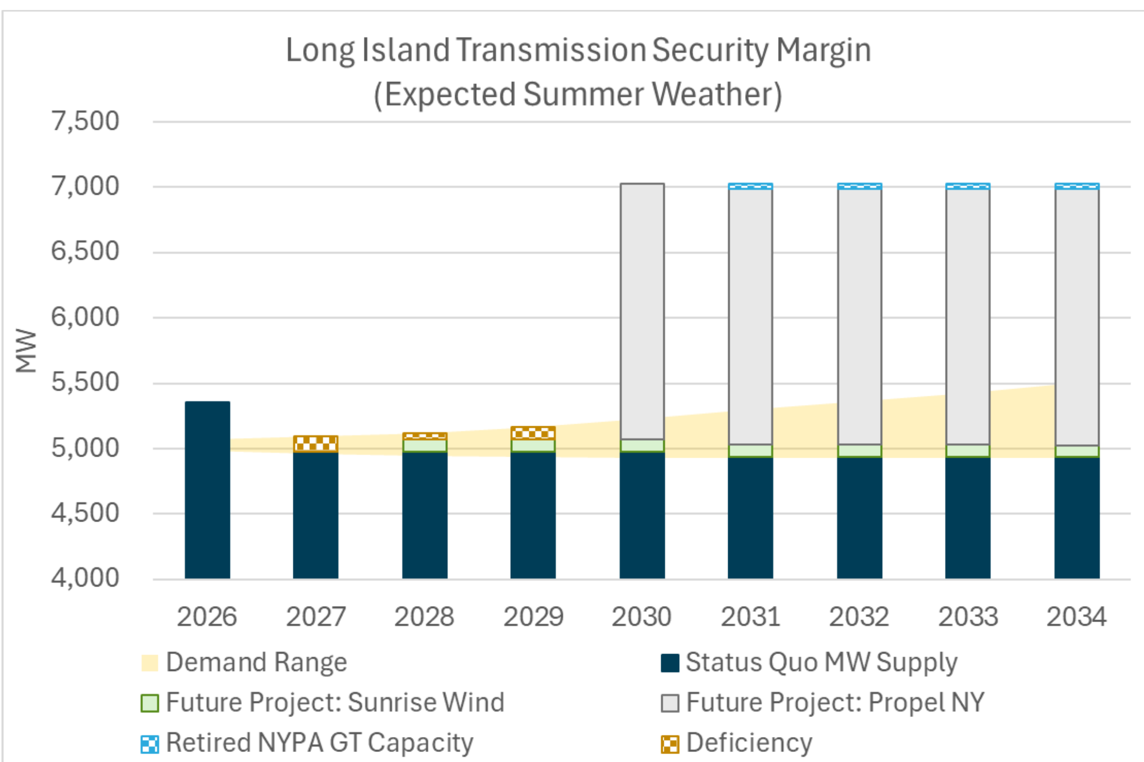


Figure 4 : Factors Affecting Long Island Transmission Security Margin



Next Steps

The Short-Term Reliability Process Needs observed are Near-Term Reliability Needs and/or Generator Deactivation Reliability Needs. As a result, solutions will be solicited, evaluated, and addressed in accordance with the NYISO's Short-Term Reliability Process. These needs may be addressed with generation solutions, demand-side solutions, and/or transmission solutions. The New York City/Lower Hudson Valley need arises within the Con Edison Transmission District; therefore, Con Edison is the Responsible Transmission Owner for developing a regulated solution. The Long Island need arises within the Long Island Power Authority Transmission District; therefore, the Long Island Power Authority is the Responsible Transmission Owner for developing a regulated solution through its service provider, PSEG-LI.

Following the issuance of a 60-day solicitation for solutions, the NYISO will evaluate the proposed solutions that it receives and issue a Short-Term Reliability Process Report indicating NYISO's selection of a solution or combination of solutions, along with a reasoned explanation regarding why particular generation and/or transmission solutions were selected. If proposed solutions are not viable or sufficient to meet the identified reliability needs, interim solutions must be in place to keep the grid reliable. The NYISO's solution selection process is designed to ensure that executing a Reliability Must Run (RMR) Agreement with generators is a last resort to addressing a reliability need.

The wholesale electricity markets administered by the NYISO are an important tool to help mitigate reliability risks. The markets are designed, and continue to evolve and adapt, to send appropriate price signals for new market entry and the retention of resources that assist in maintaining reliability. The potential risks and resource needs identified in the NYISO's analyses may be resolved by new capacity resources coming into service, construction of additional transmission facilities, and/or increased energy efficiency and integration of demand-side resources. The NYISO is tracking the progression of many projects that may contribute to grid reliability that have not yet met the inclusion rules for reliability assessments. The NYISO will continue to monitor these resources and other developments to determine whether changing system resources and conditions could impact the reliability of the New York bulk electric grid. Specifically, through the quarterly STAR reports, the NYISO will continue to reassess if the identified reliability needs persist as planned projects are energized and demonstrate their capabilities.

Purpose

The NYISO's Short-Term Reliability Process ("STRP") with its requirements prescribed in Attachments Y and FF of the NYISO's Open Access Transmission Tariff ("OATT") evaluates the first five years of the planning horizon, with a focus on needs arising in the first three years of the study period. With this process in place, the biennial Reliability Planning Process focuses on identifying and resolving longer-term needs through the Reliability Needs Assessment ("RNA") and the Comprehensive Reliability Plan ("CRP").

The first step in the STRP is the Short-Term Assessment of Reliability ("STAR"). STARs are performed quarterly to proactively address reliability needs that may arise within five years ("Short-Term Reliability Process Needs")[7] due to various changes to the grid, such as generator deactivations, revised generator/transmission plans, and updated demand forecasts. Transmission Owners also assess the impact of generator deactivations on their non-BPTF systems. A Short-Term Reliability Process Need that is observed within the first three years of the study period constitutes a "Near-Term Reliability Need."[8] Should a Near-Term Reliability Need be identified in a STAR, the NYISO solicits and selects the solution to address the need. If a need arises beyond the first three years of the study period, the NYISO may choose to address the need within the STRP or, if time permits, through the long-term Reliability Planning Process.

This STAR report sets forth the 2025 Quarter 3 findings for the study period from the STAR Start Date (July 15, 2025) through July 15, 2030. The NYISO assessed the potential reliability impacts to the BPTF considering system changes, including the availability of resources and the status of generator/transmission plans in accordance with the NYISO Reliability Planning Process Manual.[9]

Assumptions

The NYISO evaluated the study period using the most recent Reliability Planning Process assumptions and data available as of July 14, 2025 (*i.e.,* the day before the July 15, 2025 Q2 STAR start date). In accordance with the Reliability Planning Process inclusion rules,[10] generation and transmission projects are included if they have met significant milestones such that there is a

[7] OATT Section 38.1 contains the tariff definition of a "Short-Term Reliability Process Need."

[8] OATT Section 38.1 contains the tariff definition of a "Near-Term Reliability Need." *See also*, OATT Section 38.3.6.

[9] NYISO Reliability Planning Process Manual, July 11, 2022. *See:* https://www.nyiso.com/documents/20142/2924447/rpp_mnl.pdf

[10] *See* NYISO Reliability Planning Process Manual Section 3.

reasonable expectation of timely completion of the project. A summary of key projects is provided in Appendix C.

This assessment used the major assumptions included in the 2024 RNA, along with several updates to key study assumptions that are provided below. Consistent with the obligations under its tariffs, the NYISO provided information to stakeholders on the modeling assumptions employed in this assessment. Details regarding the study assumptions were reviewed with stakeholders at the joint Electric System Planning Working Group ("ESPWG")/Transmission Planning Advisory Subcommittee ("TPAS") meeting on July 23, 2025. The meeting materials are posted on the NYISO's website.[11]

Generation Assumptions

Study assumptions of generators for this STAR are derived from the 2024 RNA, except for the changes to generation assumptions specified below.

Generator Deactivation Notices

For this STAR, the deactivating generators included in this assessment are listed in Figure 5. A list of all generator deactivations, including those evaluated in prior STARs, is provided in Appendix C. Generator deactivation notices for retirement, mothball outage, or ICAP ineligible forced outage are available on the NYISO's website under the Short-Term Reliability Process.[12]

Figure 5: 2025 Quarter 3 STAR Generator Deactivations

Owner/ Operator	Plant Name	PTID	Zone	Nameplate (MW)	Status	Proposed Deactivation/IIFO Date
Casella Waste Systems, Inc	Hyland LFGE	323620	B	4.8	IIFO	6/1/2025
MPH Cross Island Power, LLC	Pinelawn Power 1	323563	K	82	R	11/1/2025
MPH Rockaway Peakers, LLC	Far Rockaway GT1	24212	K	60.5	R	11/1/2025
MPH Rockaway Peakers, LLC	Far Rockaway GT2	23815	K	60.5	R	11/1/2025
Astoria Generating Company, L.P.	Gowanus 2-1 through 2-8	24114-24121	J	160	R	7/14/2026
Astoria Generating Company, L.P.	Gowanus 3-1 through 3-8 (1)	24122-24129	J	160	R	7/14/2026
Astoria Generating Company, L.P.	Narrows 1-1 through 2-8 (2)	24228-24243	J	352	R	7/14/2026

Notes:
(1) Includes Gowanus GT 3-6. Gowanus GT 3-6 IIFO was studied as part of the 2025 Q2 STAR.
(2) Includes Narrows GT 2-1 and 2-7. Narrows GT 2-1 and 2-7 IIFOs were studied as part of the 2025 Q2 STAR.

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[11] Short-Term Assessment of Reliability: 2025 Q3 Key Study Assumptions, ESPWG/TPAS, July 23, 2025 (here).

[12] *See* https://www.nyiso.com/short-term-reliability-process then Generator Deactivation Notices/Planned Retirement Notices or Generator Deactivation Notices/IIFO Notifications.

Peaker Rule: Ozone Season Oxides of Nitrogen (NOx) Emission Limits for Simple Cycle and Regenerative Combustion Turbines

In 2019, the New York State Department of Environmental Conservation ("DEC") adopted a regulation to limit nitrogen oxides (NOx) emissions from simple-cycle combustion turbines (referred to as the "Peaker Rule").[13] Since May 2023, over 1,600 MW of peaker units have deactivated or limited their operations. A list of peaker generators that were expected to be unavailable in the summer ozone season by May 1, 2025 is provided in Figure 6.

The DEC regulations include a provision to allow an affected generator to continue to operate for up to two years, with a possible further two-year extension, after the compliance deadline if the generator is designated by the NYISO or by the local transmission owner as needed to resolve a reliability need until a permanent solution is in place. Consistent with the DEC's regulations and detailed in the Short-Term Reliability Process report it issued on November 20, 2023, the NYISO has designated the Gowanus 2 & 3 and Narrows 1 & 2 generators (32 units total) to temporarily continue operation beyond May 2025 until permanent solutions are in place, for an initial period of up to two years (until May 1, 2027).

[13] DEC Peaker Rule, 6 N.Y.C.R.R. Part 227-3 (available here).

Figure 6: Status Changes Due to DEC Peaker Rule

Owner/Operator	Station	Zone	Nameplate (MW)	CRIS (MW) (1)		Capability (MW) (1)		Status Change Date (2)	STAR Evaluation
				Summer	Winter	Summer	Winter		
National Grid	West Babylon 4 (6)(7)	K	52.4	49.0	64.0	41.2	63.4	12/12/2020 (R)	Other
National Grid	Glenwood GT 01 (4)(7)	K	16.0	14.6	19.1	13.0	15.3	02/28/2021 (R)	2020 Q3
Helix Ravenswood, LLC	Ravenswood 11 (12)	J	25.0	20.2	25.7	16.1	22.4	12/1/2021 (IIFO)	2022 Q1/2023 Q3
Helix Ravenswood, LLC	Ravenswood 01 (12)	J	18.6	8.8	11.5	7.7	11.1	1/1/2022 (IIFO)	2022 Q1/2023 Q3
Astoria Generating Company L.P.	Gowanus 1-1 through 1-8	J	160.0	138.7	181.1	133.1	182.2	11/1/2022 (R)	2022 Q2
Astoria Generating Company L.P.	Gowanus 4-1 through 4-8	J	160.0	140.1	182.9	138.8	183.4	11/1/2022 (R)	2022 Q2
Consolidated Edison Co. of NY, Inc.	Hudson Ave 3	J	16.3	16.0	20.9	12.3	15.6	11/1/2022 (R)	2022 Q2
Consolidated Edison Co. of NY, Inc.	Hudson Ave 5	J	16.3	15.1	19.7	15.3	18.6	11/1/2022 (R)	2022 Q2
Central Hudson Gas & Elec. Corp.	Coxsackie GT (8)	G	21.6	21.6	26.0	19.7	25.2	05/01/2023	2024 Q1
Central Hudson Gas & Elec. Corp.	South Cairo	G	21.6	19.8	25.9	18.7	23.1	5/1/2023 (R)	2023 Q4
Consolidated Edison Co. of NY, Inc.	74 St. GT 1 & 2 (10)	J	37.0	39.1	49.2	37.8	43.6	05/01/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 2-1, 2-2, 2-3, 2-4	J	186.0	165.8	204.1	138.0	184.2	5/1/2023 (R)	2022 Q2
NRG Power Marketing LLC	Astoria GT 3-1, 3-2, 3-3, 3-4	J	186.0	170.7	210.0	139.1	180.4	5/1/2023 (R)	2022 Q2
NRG Power Marketing LLC	Astoria GT 4-1, 4-2, 4-3, 4-4	J	186.0	167.9	206.7	138.5	178.6	5/1/2023 (R)	2022 Q2
Helix Ravenswood, LLC	Ravenswood 10	J	25.0	21.2	27.0	16.1	20.3	5/1/2023 (R)	2022 Q3
National Grid	Glenwood GT 03 (3)(16)	K	55.0	54.7	71.5	54.1	66.6	05/01/2023	
National Grid	Northport GT (9)	K	16.0	13.8	18.0	8.3	12.7	05/01/2023	
National Grid	Port Jefferson GT 01 (9)	K	16.0	14.1	18.4	13.0	15.3	05/01/2023	
National Grid	Shoreham 1 (3)(16)	K	52.9	48.9	63.9	46.0	50.7	5/1/2023 (3)	
National Grid	Shoreham 2 (3)(4)	K	18.6	18.5	23.5	16.7	21.3	5/1/2023 (3)	2025 Q1
Astoria Generating Company, L.P.	Astoria GT 01 (11)	J	16.0	15.7	20.5	13.8	18.0	05/01/2025	2022 Q4
Consolidated Edison Co. of NY, Inc.	59 St. GT 1 (10)	J	17.1	15.4	20.1	13.9	17.4	05/01/2025	
NRG Power Marketing, LLC	Arthur Kill GT 1 (10)	J	20.0	16.5	21.6	12.4	16.1	05/01/2025	
Astoria Generating Company, L.P.	Gowanus 2-1 through 2-8 (5)(13)	J	160.0	152.8	199.6	142.2	182.5	05/01/2025	
Astoria Generating Company, L.P.	Gowanus 3-1 through 3-8 (5)(13)(14)	J	140.0	129.2	168.7	123.8	159.7	05/01/2025	
Astoria Generating Company, L.P.	Gowanus 3-6 (5)(13)	J	20.0	17.6	23.0	16.4	20.4	4/1/2025 (IIFO)	2025 Q2
Astoria Generating Company, L.P.	Narrows 1-1 through 2-8 (5)(13)(15)	J	308.0	269.0	351.3	250.4	323.7	05/01/2025	
Astoria Generating Company, L.P.	Narrows 2-1 and 2-7 (5)(13)	J	44.0	40.1	52.3	37.9	48.8	4/1/2025 (IIFO)	2025 Q2
	Prior to Summer 2022		112.0	92.6	120.3	78.0	112.2		
	Prior to Summer 2023		1174.3	1066.0	1348.8	945.5	1221.8		
	Prior to Summer 2025		725.1	656.3	857.1	610.8	786.6		
	Total		2011.4	1,814.9	2,326.2	1,634.3	2,120.6		

Notes
1. MW values are from the 2025 Load and Capacity Data Report except where the 2025 Load and Capacity Data Report lists 0 MW for CRIS and/or Capability. For those instances, previous Load and Capacity Data Report MW values are used.
2. Dates identified by generators in their DEC Peaker Rule compliance plan submittals for transitioning the facility to Retired, Blackstart, or will be out-of-service in the summer ozone season or the date in which the generator entered (or proposed to enter) Retired (R) or Mothball Outage (MO) or the date on which the generator entered ICAP Ineligible Forced Outage (IIFO).
3. Generator changed DEC peaker rule compliance plan as compare to the 2020 RNA and all STARs prior to 2021 Q3.
4. Long Island Power Authority (LIPA) has submitted notfications to the DEC per part 227-3 of the peaker rule stating that these units are needed for reliability allowing these units to operate untill at least May 1, 2025. Due to the future nature of these units being operated only as designated by the operator as an emergency operating procedure the NYISO will continue to plan for these units be unavailable starting May 2023.
5. These units have indicated they will be out-of-service during the ozone season (May through September) in their compliance plans in response to the DEC peaker rule.
6. This unit was evaluated in a stand-alone generator deactivation assessment prior to the creation of the STAR process.
7. Unit operating as a load modifier.
8. In March 2024, Central Hudson submitted an update to its DEC peaker compliance plan to extend the retirement date of Coxsackie GT until December 31, 2025 until a permanent Transmission and Distribution solution to local non-BPTF transmission security issues is completed. At the April 7, 2025 TPAS/ESPWG, Central Hudson presented an LTP update including a delay of the retirement of the Coxsackie GT until May 2026.
9. On May 24, 2023 National Grid notified the New York State Public Service Commission that these units have been clasified as black-start only units and are no longer subject to NYISO dispatch.
10. Unit no longer subject to NYISO dispatch and is used for local reliability only.
11. The initial proposed retirement was on or after May 1, 2023, and was studied in the 2022 Q4 STAR. However, the unit modified its Peaker Rule compliance plan to be available for operation through May 1, 2025. The unit has submitted a new generator deactivation notice with a new proposed retirement date by May 1, 2025.
12. The retirement for this unit was evaluated in the 2023 Q3 STAR.
13. To address the Need identified in the 2023 Q2 STAR, the NYISO designated the generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges to temporarily remain in operation after the DEC Peaker Rule compliance date (May 1, 2025) until permanent solutions to the Need are in place, for an initial period of up to two years (May 1, 2027).
14. Does not include Gowanus 3-6.
15. Does not include Narrows 2-1 and 2-7.
16. Long Island Power Authority (LIPA) has submitted notfications to the DEC per part 227-3 of the peaker rule stating that these units are needed for reliability allowing these units to operate untill at least May 1, 2027.

Generator Return-to-Service

There are no generators that have returned to service beyond those included in the 2024 RNA.

Generator Additions

There are generation additions beyond those included in the 2024 RNA. A list of generator additions, including updates to planned commercial operation dates compared to the 2024 RNA is provided in Appendix C.

Additional Generation Updates

At the March 27, 2024 meeting of the Management Committee, several changes were approved that impact the level of Installed Capacity resources are eligible to provide starting with the Summer 2026 Capability Period. These changes were made as part of the Modeling Improvements for Capacity Accreditation project – Correlated Derates. The Correlated Derates project addresses issues identified in Potomac Economics' Q3 2022 State of the Market Report as "functionally unavailable capacity." Specifically, (1) ambient water-related deratings for steam units, (2) humidity-adjustments for combined and simple cycle combustion turbines, and (3) emergency-only capacity that may not be reliably available in real-time (CLR's). These updated requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5. Overall, these changes reduce the expected DMNC for several generators. Due to the deactivations evaluated in this STAR within New York City and Long Island, the NYISO has proactively accounted for the reduction in summer capability of 110 MW in New York City and 200 MW in Long Island rather than waiting for the publication of the updates in the 2026 Gold Book. These MW reductions reflect the expected impacts to DMNC on resources impacted by the rule changes.

Demand Assumptions

This assessment recognizes that there is a range of possibilities for demand driven by uncertainties in key assumptions, such as population and economic growth, energy efficiency, installation of behind-the-meter renewable energy resources, and electric vehicle adoption and charging patterns that are captured in the 2025 Gold Book. The 2025 Gold Book includes three demand forecasts: Lower Demand, Baseline, and Higher Demand. Each of these forecasts contains differing inputs on economic, electrification, and large load assumptions, but the weather conditions are the same across each of these forecast which are summarized in Appendix C (Figure 47 and Figure 48). The behind-the-meter (BTM) solar, BTM distributed generation, and energy storage forecasts are consistent across all forecasts. 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 7 through Figure 10 provide visual depictions of the three forecasts for the summer peak for Lower Hudson Valley, New York City, Long Island and Statewide. Specific to this STAR, the NYISO is also including consideration of the Lower Hudson Valley, New York City, and Long Island localities non-coincident peak in the identification of bulk system generator deactivation reliability needs.

One key assumption in this STAR is that cryptocurrency mining and hydrogen production large loads will be flexible during system peak demand conditions. This assumption, based on communications with load developers and recent operating experience, results in up to approximately 685 MW of large load reduction during the summer and winter peak periods by 2026. The trend of large load development, and their operating characteristics, requires continuous monitoring as they enter service. The NYISO will continue to coordinate with load developers and Transmission Owners.

Additional details of the demand forecasts are provided in Appendix C.

Figure 7: Lower Hudson Valley Demand Forecasts (2025 Gold Book)

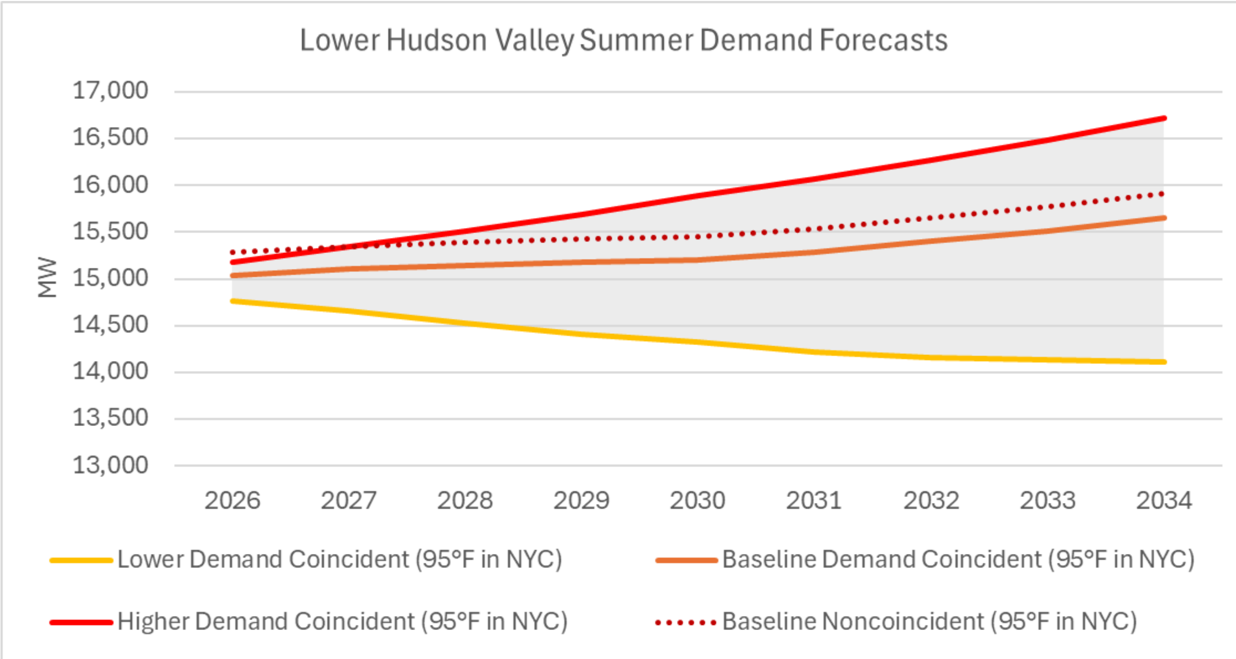


Figure 8: New York City Demand Forecasts (2025 Gold Book)

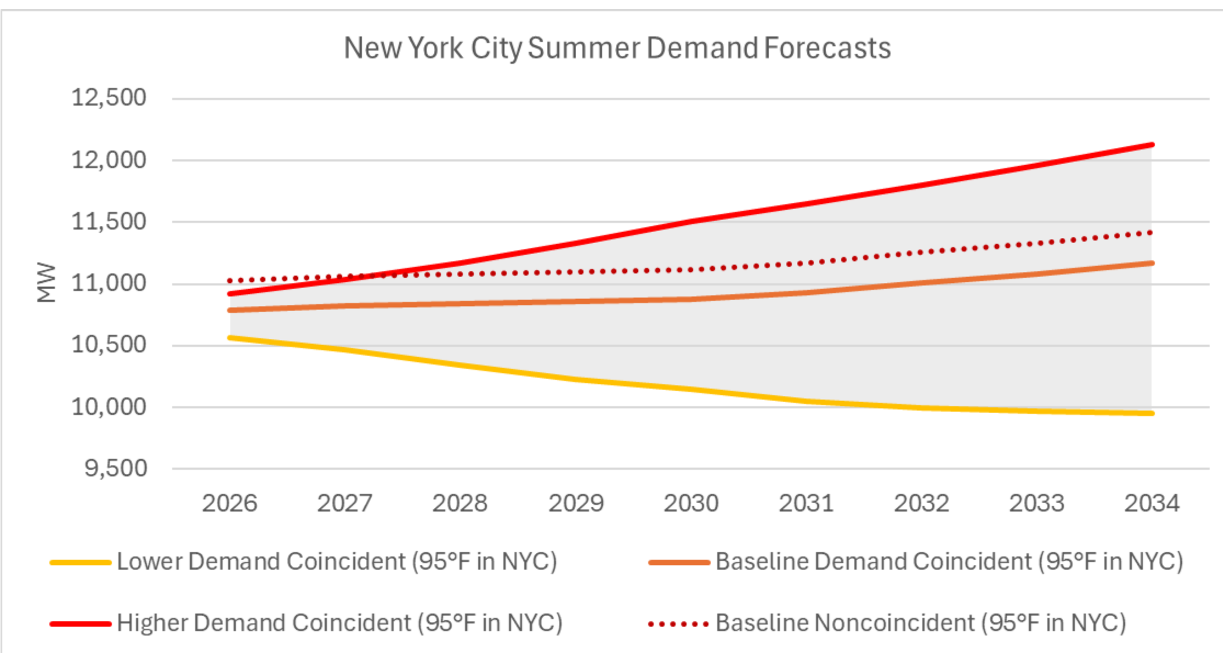


Figure 9: Long Island Demand Forecasts (2025 Gold Book)

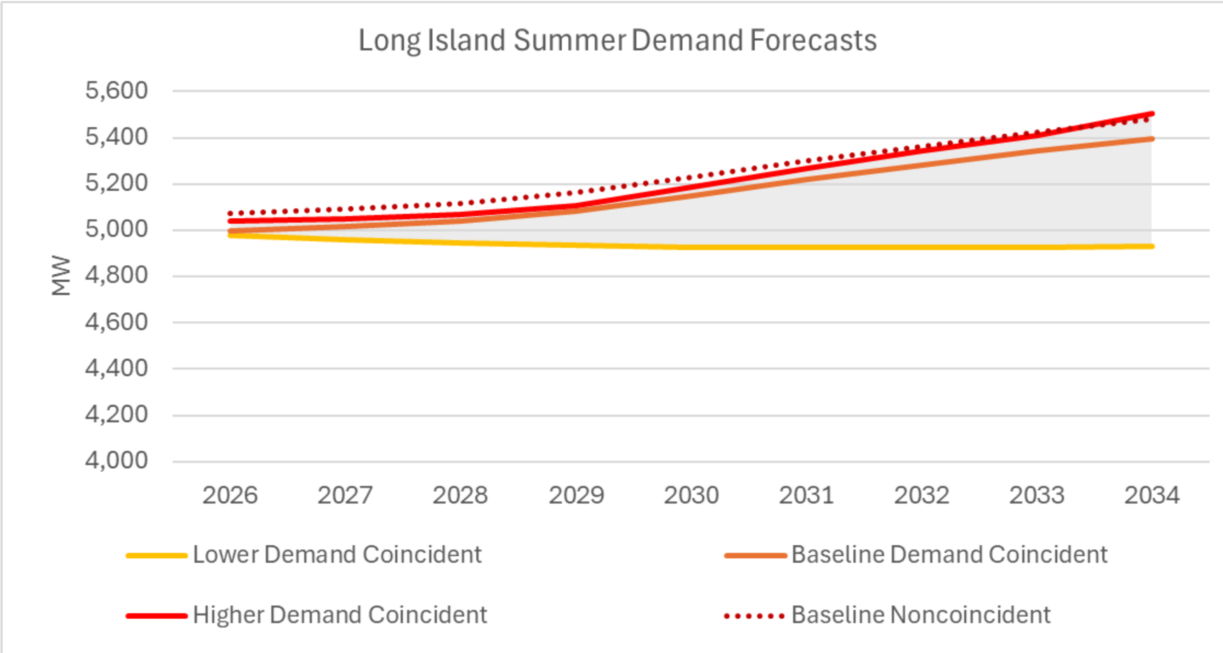
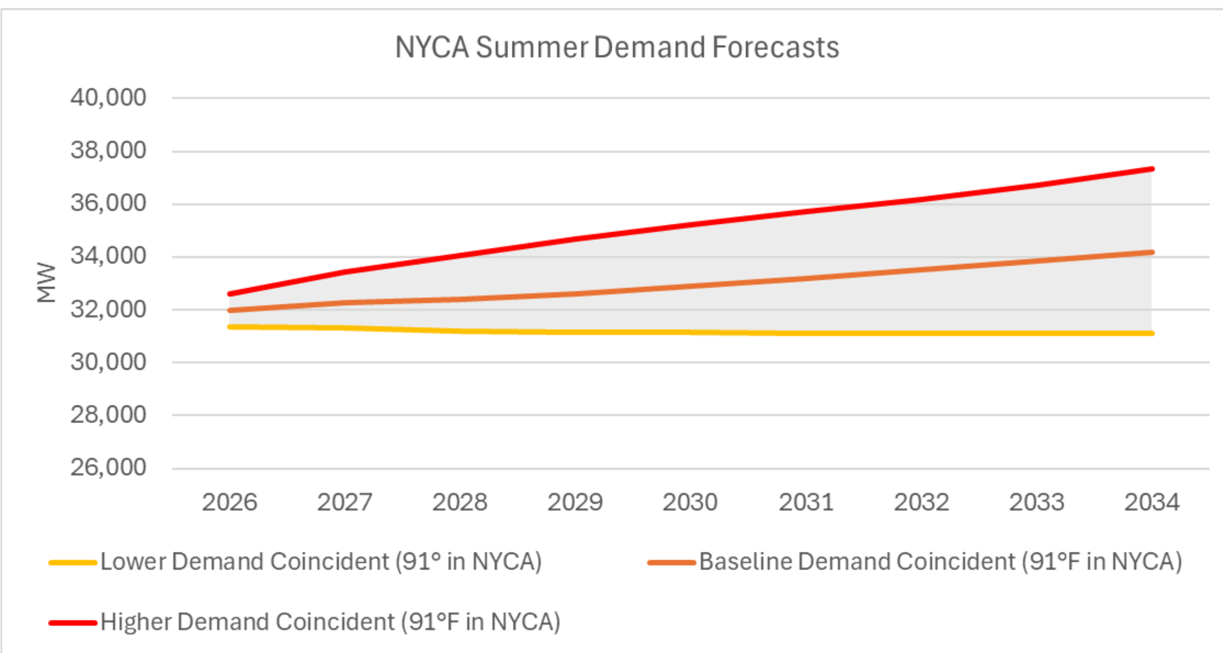


Figure 10: NYCA Demand Forecasts (2025 Gold Book)



Transmission Assumptions

Existing Transmission

The transmission assumptions utilized in this assessment are similar to those used for the 2024 RNA. Figure 11 lists the existing transmission outage assumptions.

Figure 11: Transmission Assumptions

From	To	kV	ID	Out-of-Service Through	
				Prior STAR	Current STAR
Marion	Farragut	345	B3402	Long-Term	
Marion	Farragut	345	C3403	Long-Term	
Plattsburgh (1)	Plattsburgh	230/115	AT1	9/2025	9/2026
Stolle Rd	Stolle Rd	115	T11-52	6/2025	Dec-25
Station 23	Station 42	115	920	12/2025	
Farragut		345	8E	11/2025	In-service
Farragut		345	9E	11/2025	In-service

Notes
(1) A spare transformer is placed in-service during the outage

Proposed Transmission

Changes to firm projects in the Transmission Owners' Local Transmission Owner Plans ("LTPs") are captured in Section VII of the 2025 Gold Book.

Compared to the 2024 RNA, there are no changes to assumed firm transmission facilities, as captured in Section 7 of the 2025 Gold Book. Details of the proposed transmission assumptions included in the 2024 RNA are provided in Appendix C. Except for the projects listed in Figure 56 in Appendix C , all firm transmission plans captured in the 2025 Gold Book are included.

Findings

Grid reliability is determined by assessing transmission security and resource adequacy. Transmission security is the ability of the electric system to withstand disturbances, such as electric short circuits or unanticipated loss of system elements, without involuntarily disconnecting firm load. Resource adequacy is the ability of electric systems to supply the aggregate electrical demand and energy requirements of customers, accounting for scheduled and reasonably expected unscheduled outages of system elements.

As explained below, this assessment finds that reliability criteria would not be met for the BPTF in the Lower Hudson Valley, New York City, and Long Island localities throughout the five-year study period under the study assumptions and forecasted demand under expected weather as described in this report. The observed needs include Generator Deactivation Reliability Needs in the near-term horizon with the deactivation of the Gowanus 2 & 3 and Narrows 1 & 2 generators, the Pinelawn generator, and the Far Rockaway GTs. No generator deactivation reliability needs were observed with the IIFO of the Hyland LFGE. LIPA has also identified non-BPTF Generator Deactivation Reliability Needs with the deactivation of the Far Rockaway GTs.

Resource Adequacy Assessments

Resource adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the firm load at all times, considering scheduled and reasonably expected unscheduled outages of system elements. The NYISO performs resource adequacy assessments on a probabilistic basis to capture the random nature of system element outages. If a system has sufficient transmission and generation, the probability of an unplanned disconnection of firm load is equal to or less than the system's standard, which is expressed as a loss of load expectation ("LOLE"). Consistent with the NPCC and NYSRC criterion, the New York State bulk power system is planned to meet an LOLE that, at any given point in time, is less than or equal to an involuntary firm load disconnection that is not more frequent than once in every 10 years, or 0.1 event days per year.

This assessment finds that the planned system through the study period meets the resource adequacy criterion. Details about the resource adequacy study assumptions are provided in Appendix D.

Transmission Security Assessments

Transmission security is 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. The analysis for the transmission security assessment is conducted in accordance with NERC Reliability Standards, NPCC Transmission Design Criteria, and the NYSRC Reliability Rules. Transmission security is assessed deterministically with potential disturbances being applied without concern for the likelihood of the disturbance in the assessment. These disturbances (single-element and multiple-element contingencies) are categorized as the design criteria contingencies, which are explicitly defined in the reliability criteria. The impacts resulting from applying these design criteria contingencies are assessed to determine whether thermal loading, voltage or stability violations will occur. In addition, the NYISO performs a short circuit analysis to determine if the system can clear faulted facilities reliably under short circuit conditions. The NYISO's "Guideline for Fault Current Assessment"[14] describes the methodology for that analysis.

Transmission security analysis includes the assessment of various combinations of credible system conditions intended to stress the system. As transmission security analysis is deterministic, these various credible combinations of system conditions are evaluated throughout the study period to identify reliability needs. Intermittent generation is represented based on expected output during the modeled system conditions.[15]

Transmission security margins are included in this assessment to identify plausible changes in conditions or assumptions that might adversely impact the reliability of the system. The transmission security margin is the ability to meet load plus losses and system reserve (*i.e.*, total capacity requirement) using NYCA generation, interchange, and including temperature-based generation derates (total resources). This assessment is performed using a deterministic approach through powerflow simulations combined with post-processing spreadsheet-based calculations.[16] For the transmission security margin assessment, margins are evaluated for the statewide system margin, as well as Lower Hudson Valley, New York City, and Long Island localities. This evaluation will identify a BPTF reliability when the margin is less than zero under expected weather, normal transfer criteria conditions for the Lower Hudson Valley, New York City, and Long Island localities. Additional details regarding the impact of heatwaves, cold snaps, and other system conditions are

[14]Attachment I of Transmission, Expansion, and Interconnection Manual.

[15]The RNA assumptions matrix is posted with the April 18, 2024 TPAS/ESPWG meeting materials, which are available here,

[16] At its June 23, 2022, meeting, the NYISO Operating Committee approved revisions to the Reliability Planning Process Manual that reflect the use of transmission security margins and other enhancements.

provided in Appendix E.

For the purposes of identifying reliability needs on the BPTF using transmission security margin calculations, thermal generation MW capability is considered available based on NERC five-year class averages for the relevant type of unit.[17] Derates for thermal generation are included due to the aging fleet without expected replacement, while the share of intermittent, weather dependent, generation is growing.

Steady State Assessment

In the NYISO's evaluation of the BPTF, one voltage violation and two thermal overloads are observed. The identified issues do not result in a Short-Term Reliability Process Need, as they are addressed by modifications to planned system changes or consideration of known operational behavior. No other steady-state transmission security related needs were observed under other system conditions.

The first steady-state transmission security issue identified for the study period under expected summer peak conditions is a thermal violation on the Oakdale 345/115/34.5 kV transformer and Oakdale – North Endicott 115 kV transmission line. The violation occurs under N-1-1 conditions, for contingency combinations that result in the loss of the Oakdale – Westover 115 kV and Oakdale – Northside 115 kV transmission lines. This overload is observed as early as summer 2026 and is addressed by the reconfiguration of the Oakdale 345 and 115 kV system along with a second Oakdale 345/115 kV transformer which are planned to be completed by winter 2030. Prior to completion of this project, NYSEG will utilize an interim operating procedure to address this overload. With the proposed interim load shed operating procedure and the local transmission plans, the NYISO will not solicit for solutions to address these issues but will continue to track the development of the local plans in the quarterly tracking process.

The second steady-state transmission security issue identified for the study period under expected summer peak conditions is a voltage violation at the Oakdale 115 kV station in expected summer peak conditions. The violation occurs under N-1-1 conditions, for contingency combinations that result in loss of 345/115 kV transformers along with one of the two 345 kV lines from Oakdale to Fraser or Watercure. NYSEG has two local transmission plans that help to address these issues. The first plan is a reconfiguration at the Frasier 115 kV station that provides stronger voltage support of the transmission system in the local area which is planned to be in-service in

[17] The NERC five-year class average EFORd data is available here. NERC class average derating factors used in the STAR do not have a mechanism for excluding 9300 events (generator outages due to transmission system problems). *See* further discussion in Oct. 7, 2024 ICAP/MIWG/PRLWG presentation.

summer 2027. The second local plan is a reconfiguration of the Oakdale 345 and 115 kV system and a second Oakdale 345/115 kV transformer, which are planned to be completed by winter 2030. Due to the observations in this STAR at Oakdale, NYSEG has proposed interim operating procedures including possible load shedding should the critical contingencies occur. With the proposed interim load shed operating procedure and the local transmission plans, the NYISO will not solicit for solutions to address these issues but will continue to track the development of the local plans in the quarterly tracking process.

The third steady-state transmission security issue identified for the study period under expected summer peak conditions is a thermal violation on the Moses AT3 230/115 kV transformer. This violation was first observed in the 2024 Quarter 3 STAR winter peak conditions and is impacted by the inclusion of Q1213- St Lawrence Data and Agricultural Center in the2025 Q1 STAR. The violation occurs under N-1-1 conditions, for contingency combinations that result in the loss of the other three Moses 230/115 kV transformers. This overload is observed as early as summer 2026 and is driven by the growth of the North Country Data Center ("NCDC") load and the addition of St Lawrence Data and Agricultural Center. This issue is addressed by the expected operational behavior of flexible large loads, which would reduce their electrical demand under peak conditions. In consideration of this expected flexibility, the thermal violation on the Moses AT3 230/115 kV transformer would not be observed. As such, there are no thermal criteria violations and the NYISO will not solicit for solutions to address these issues. However, a reliability risk to note is that more than 2,000 MW of additional load has requested to interconnect in Zone D downstream of the Moses 230/115 kV transformers. The NYISO will continue to monitor the status of these large loads and their anticipated operational behavior in future STARs.

Dynamics Assessment

No BPTF dynamic criteria violations were observed for this assessment. Additionally, no dynamic stability related non-BPTF generator deactivation reliability needs were observed for this assessment.

Short Circuit Assessment

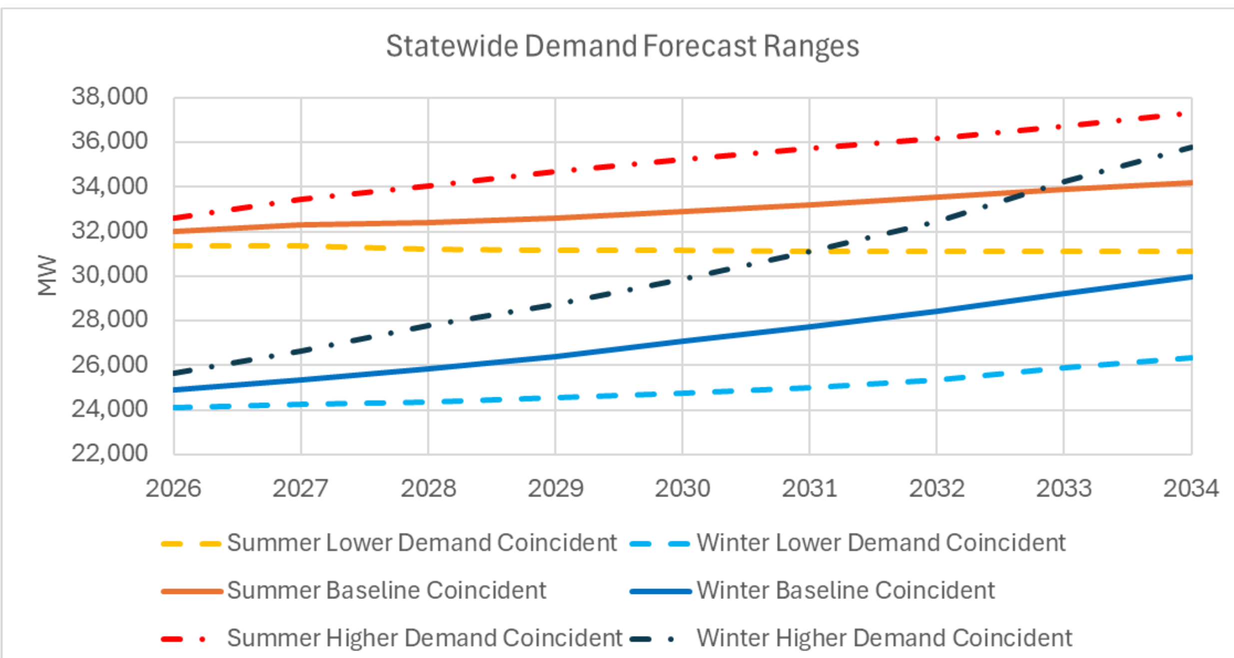
No BPTF short-circuit criteria violations were observed in this assessment. Additionally, no short-circuit non-BPTF generator deactivation reliability needs were observed in this assessment.

Statewide System Margins

The statewide system margin is a measure of the amount of generation and net imports available to supply firm load with the bulk power transmission system within applicable normal ratings and limits (i.e., normal transfer criteria) while maintaining 10-minute operating reserves. Statewide system margin is a useful metric that respects multiple reliability criteria, but there is currently not a specific reliability criterion about statewide system margin. A negative statewide system margin, on its own, is not a criteria violation, but it is a leading indicator of the system's inability to securely serve demand under normal operations. Violations in steady state assessment may occur prior to the statewide system margin becoming negative. This leading indication is explored further in the 2025-2034 Comprehensive Reliability Plan.[18]

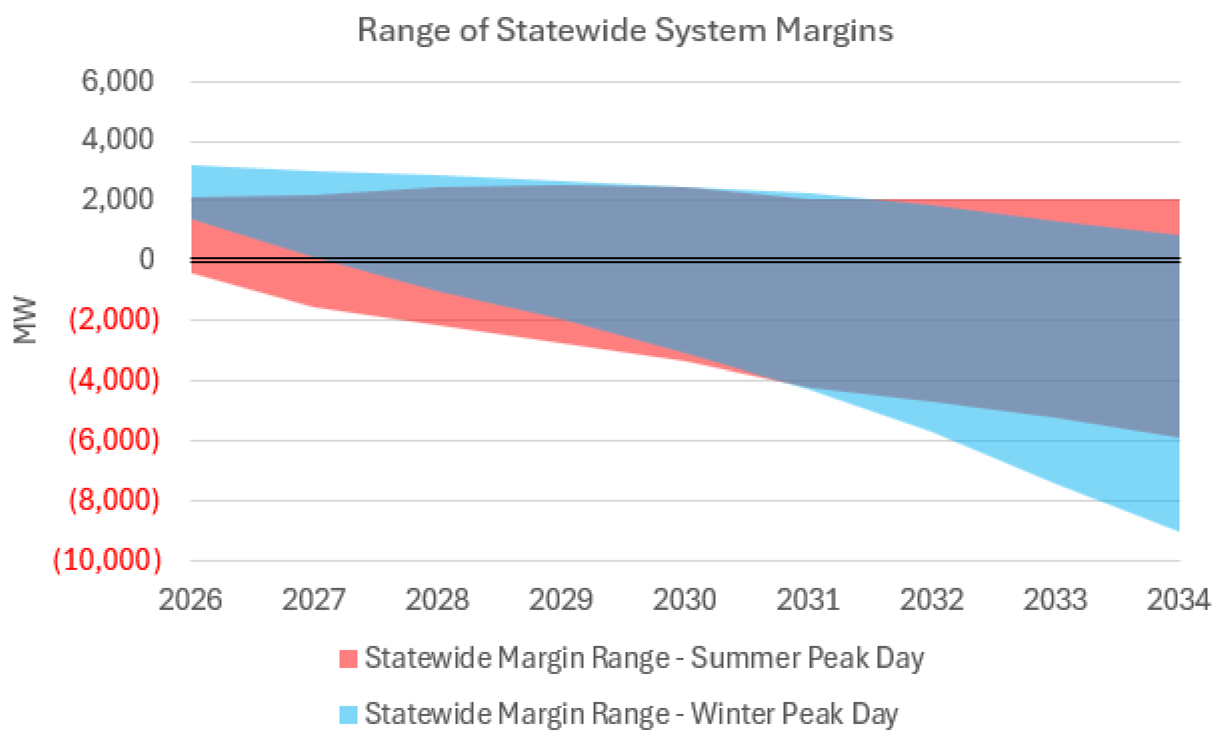
The statewide range of demand forecasts in the planning horizon is shown in Figure 12 under expected weather conditions. Figure 13 shows the range of statewide system margins. The decreasing statewide system margin in both summer and winter can be attributed to increasing demand that is not matched by sufficient planned resources. Additionally, the unavailability of non-firm gas is a key driver of deficient statewide margins in the winter peak condition.

Figure 12: 2026-2034 Demand Forecasts



[18] The most recent draft of the NYISO's 2025-2034 Comprehensive Reliability Plan at the time of the releasing of this STAR is found with the October, 16, 2025 Operating Committee Materials (here).

Figure 13: Range of Statewide System Margins



Further risks to the statewide system margin and transmission security margins in the Lower Hudson Valley, New York City, and Long Island localities include: (1) additional power plants become unavailable, and (2) demand significantly exceeds current forecasts, and (3) extreme weather (heatwaves, cold snaps). These risks are included in this assessment for informational purposes. Further details are provided later in this report, as well as Appendix E contains additional details of the margin calculations.

Transmission Security Margin Assessment

For the transmission security margin assessment, "tipping points" are evaluated for the Lower Hudson Valley, New York City, and Long Island localities as applicable to the identification of needs as the analysis is based on established Reliability Criteria. In the Lower Hudson Valley and Long Island localities, the BPTF system is designed to remain reliable in the event of two non-simultaneous outages (N-1-1). In the Con Edison service territory, the 345 kV transmission system and specific portions of the 138 kV transmission system are designed to remain reliable and return to normal ratings after the occurrence of two non-simultaneous outages (N-1-1-0).

Consistent with the findings of the 2023 Quarter 2 STAR, this STAR continues to find that the

New York City locality (Zone J) would be deficient in the summer through the entire five-year horizon without the completion and energization of future planned projects. This includes deficiencies on the BPTF and non-BPTF within Zone J. The future planned projects associated with New York City include:

- Gowanus-Greenwood 345/138 kV feeder – May 2026
- CHPE, 1,250 MW HVDC – May 2026
- Empire Wind, 816 MW offshore wind – July 2027
- Propel NY Public Policy Transmission Project – May 2030

Until these system plans within New York City are completed and demonstrate their planned power capabilities to address the identified reliability needs, the previously identified BPTF and non-BPTF deficiencies would persist without Gowanus and Narrows.

This STAR finds that the BPTF in the Long Island locality (Zone K) is deficient beginning in summer 2027 and continuing through the remaining five-year horizon, primarily driven by the deactivation of Pinelawn (82 MW nameplate) and the Far Rockaway GTs (121 MW nameplate total), but is also impacted by the completion and energization of future planned projects including the Sunrise Wind (July 2027) along with the Propel NY Public Policy Transmission Project. In addition to the BPTF deficiency, LIPA also identified non-BPTF system deficiencies on the 69 kV system through the entire five-year horizon.

The NYISO performed "status quo" evaluations the prior to these system plans and other additional resources state-wide demonstrating their planned capabilities (approximately 4,400 MW of generation projects, as described in Figure 45 and Figure 46) during the planning horizon, while maintaining the assumption that demand grows as forecasted for expected weather, including large load development.

This STAR finds that the Lower Hudson Valley, New York City, and Long Island localities are deficient in the summer. Details are provided below.

New York City Transmission Security Margin

In this 2025 Quarter 3 STAR, the Gowanus Gas Turbine 2-1 through 2-8, Gowanus Gas Turbine 3-1 through 3-8, Narrows Gas Turbine 1-1 through 1-8 and Narrows Gas Turbine 2-1 through 2-8 units (672 MW nameplate total) completed their generator deactivation notice requiring the NYISO and Con Edison to complete evaluations to determine if there are any generator deactivation reliability needs. Prior to the completion of this generator deactivation notice, all prior STARs evaluated the unavailability of these units consistent with the Reliability Planning Process inclusion rules for generation deactivations in considering the requirements of the DEC Peaker Rule.

With the deactivation of these units, this STAR continues to find that the New York City locality (Zone J) would be deficient through the entire five-year horizon until system plans are completed (CHPE, Empire Wind, Propel NY project) and demonstrate their planned power capabilities. While these planned projects are advancing in their development, the completion is subject to inherent risks commonly observed among large infrastructure projects that may impact timely completion and energization. Key challenges include permitting at federal, state, and local levels, material availability, construction complexities, and other unexpected factors. Moreover, offshore wind generating projects face additional permitting uncertainty following the issuance of the Presidential Memorandum in January 2025 directing federal agencies to halt certain activities related to the development of offshore wind generation sources.[19]

The following table provides the magnitude and duration of the BPTF deficiency through the five-year study period under summer peak if system plans are not completed. Winter transmission security margins in Zone J remain positive throughout the five-year horizon.

New York City BPTF Deficiencies:

Summer Peak	**2026**	**2027**	**2028**	**2029**	**2030**
MW Deficiency	410-650	440-680	460-790	480-950	500-1,130
Duration (hours)	6-8	6-9	8-11	8-13	8-13
MWh	1,709-3,569	1,753-3,782	3,014-6,658	3,227-8,794	3,211-10,922

In addition to being Generator Deactivation Reliability Needs, as these needs are observed within three years following the conclusion of the 365 days that follow the STAR start date, they are also Near-Term Reliability Needs. In accordance with the DEC Peaker Rule, the Gowanus and Narrows generators may extend operation for up to an additional two years (until May 1, 2029) if the NYISO or Con Edison determine that the reliability need still exists and a permanent solution has been identified and is in the process of construction but not yet online. The DEC Peaker Rule, however, does not provide for the Peaker generators to continue operating after this date without meeting the emissions requirement.

Additionally, the Lower Hudson Valley locality (Zones G-J) would be deficient by 260 MW over

[19] Temporary Withdrawal of All Areas of the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects (January 20, 2025), available at: https://www.whitehouse.gov/presidential-actions/2025/01/temporary-withdrawal-of-all-areas-on-the-outer-continental-shelf-from-offshore-wind-leasing-and-review-of-the-federal-governments-leasing-and-permitting-practices-for-wind-projects/.

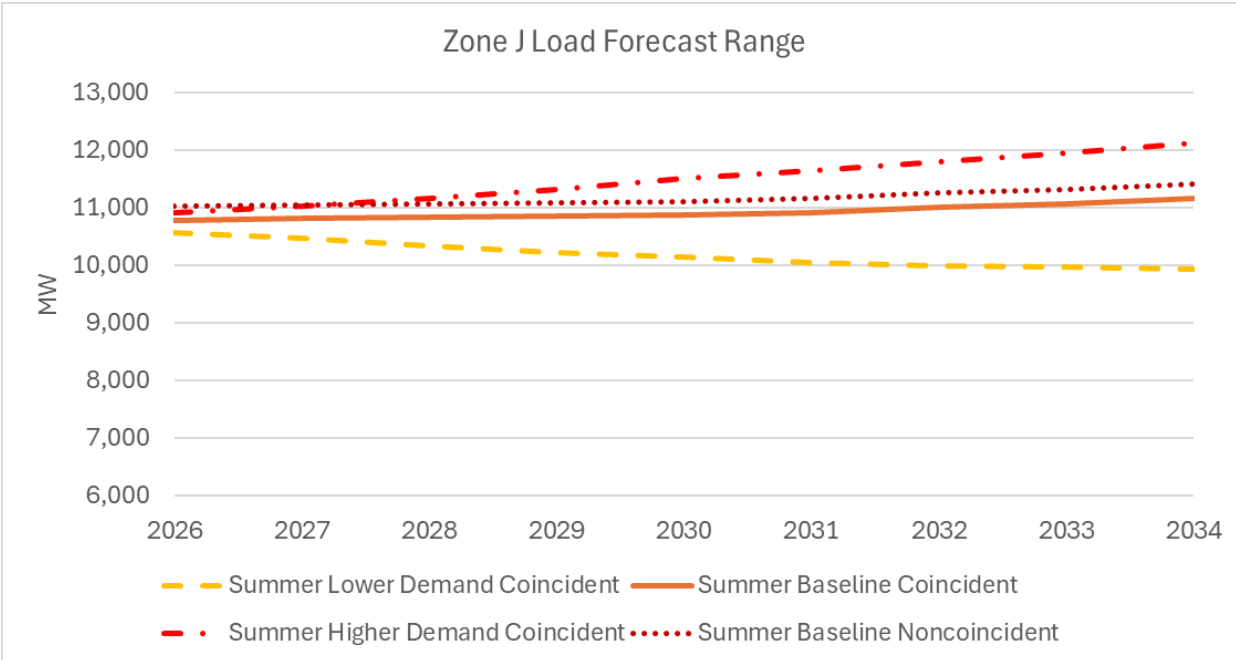
three hours (924 MWh) in 2030 without the completion and demonstration of the planned capabilities of the future planned projects associated with New York City. As the need in the Lower Hudson Valley is an exacerbation of the need observed in New York City, it is also a Generator Deactivation Reliability Need, but it is not a Near-Term Reliability Need. This deficiency is further exacerbated through time without any additional capabilities added within the Lower Hudson Valley locality, which includes New York City.

These deficiencies are driven by the deactivation of Gowanus 2 & 3 and Narrows 1 & 2 generators (672 MW nameplate total) in combination with other factors such as: the range in the demand forecasts based on expected weather, expected generator availability, transmission limitations, and risks associated with the availability of key future planned projects.

Once CHPE, Empire Wind, Propel NY project enter service and demonstrate their planned power capabilities, the margins within Zone J would improve substantially and the Lower Hudson Valley deficiency would be fully addressed, but the margin gradually erodes thereafter as expected demand for electricity grows. Even with the planned inclusion of these future planned projects entering service according to schedule and demonstrate their planned power capabilities, and assuming no other generators are unavailable, in 2029 Zone J could still remain deficient by 68 MW over 5 hours (871 MWh), which grows to 148 MW over 6 hours (1,249 MWh) in 2030. Beyond 2030, these deficiencies would be further exacerbated with increasing demand for electricity. Figure 15 and Figure 16 depict the reliability margins for Zone J without any planned projects ("status quo") and as planned. The New York City summer peak margin is shown in Figure 17 showing the reliability impact of the status quo as well as future planned generation and transmission projects that have met the Reliability Planning Process inclusion rules. Hourly margin details for this locality are provided in Figure 18 for summer 2026 and for summer 2030.

The range 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 as described in the 2025 Gold Book. The forecasted summer peak demand in New York City has a range of 460 MW in 2026 growing to 1,360 MW in 2030, primarily driven by assumptions in electrification of transportation and buildings. Details of the different load forecasts used in this STAR are shown below in Figure 14. The forecasted peak demand in New York City has a range of 460 MW in 2026 growing to 1,360 MW in 2030, primarily driven by assumptions in electrification of transportation and buildings. The assumed available supply has also been adjusted to account for expected reductions of 110 MW in generators' dependable maximum net capability (DMNC) and 175 MW reduction in capacity sales from PJM.

Figure 14: Zone J Load Forecast



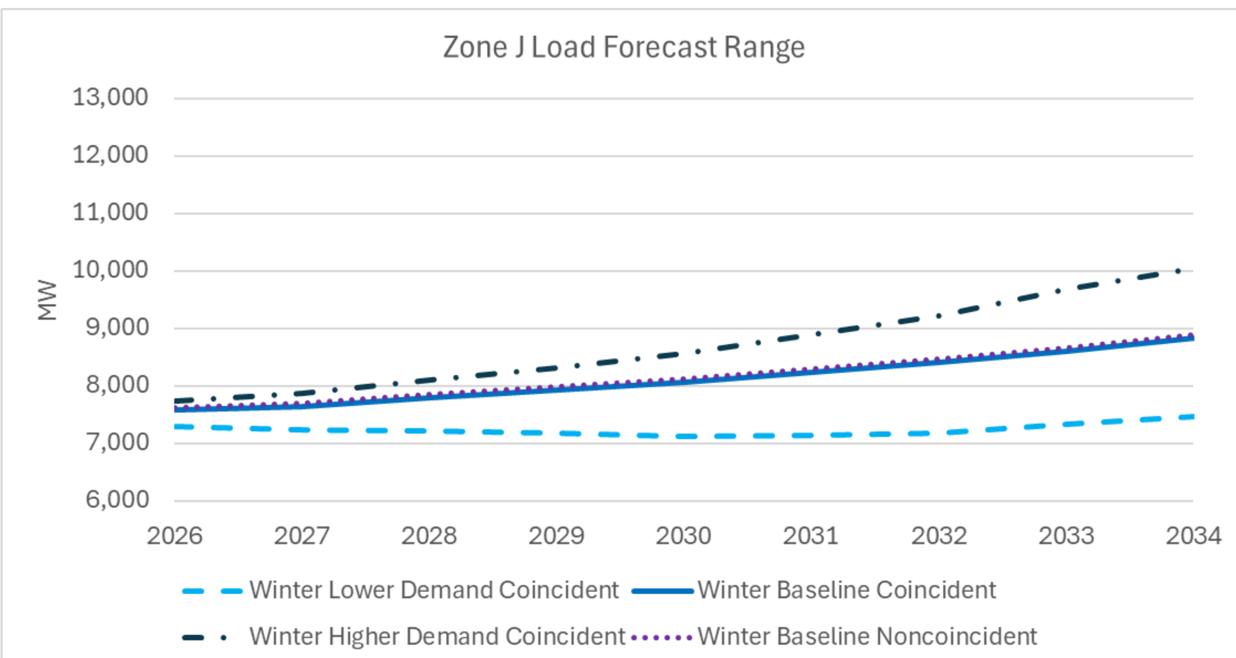


Figure 15: Zone J Summer Transmission Security Margin

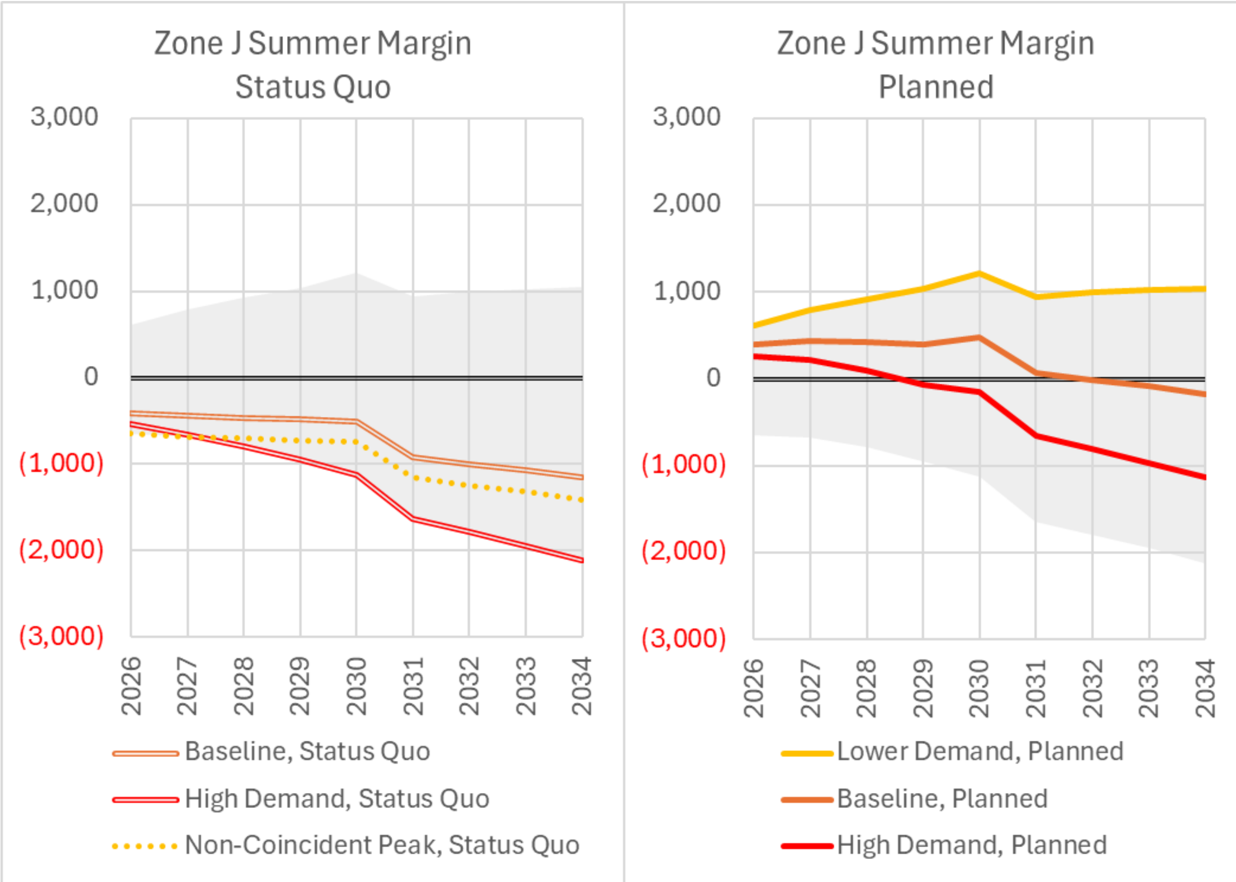


Figure 16: Zone J Winter Transmission Security Margin

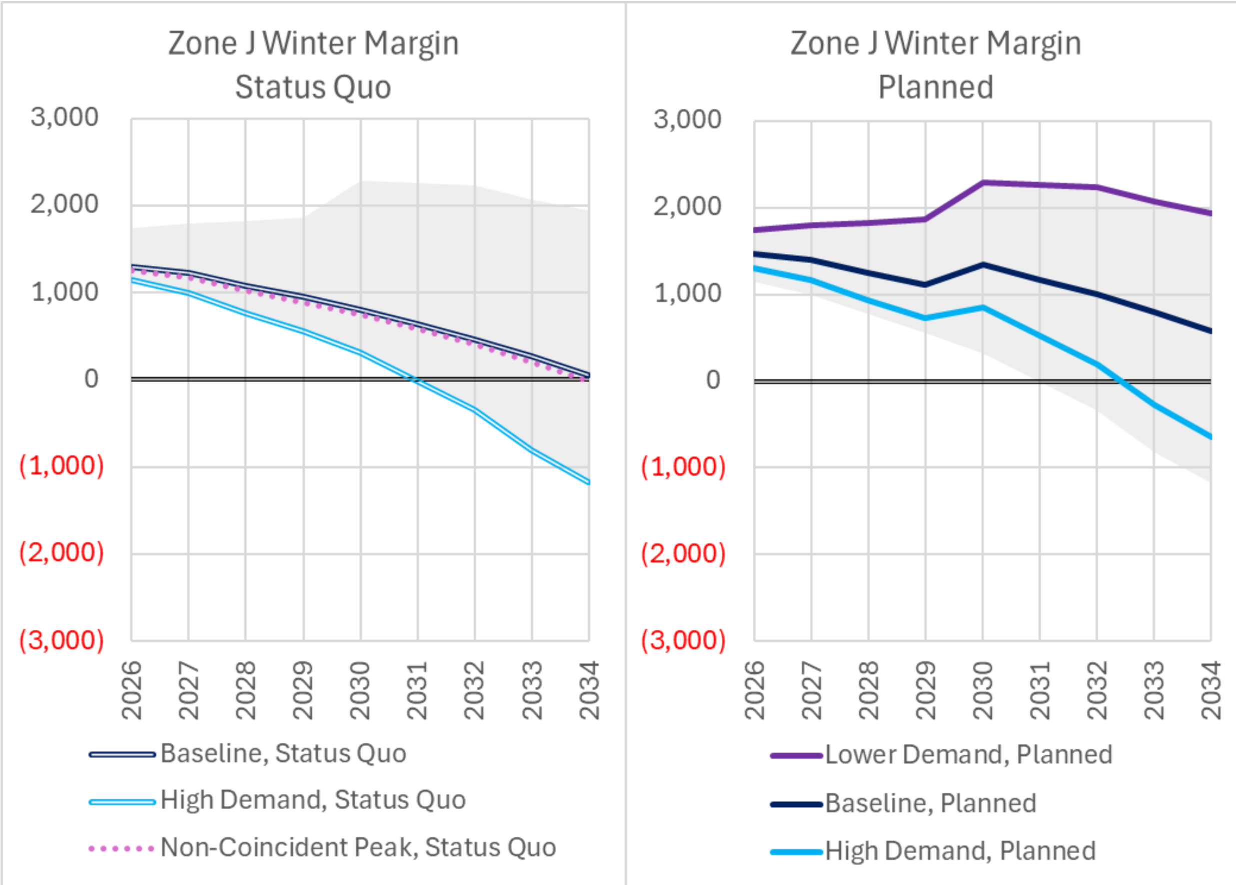


Figure 17: Factors Affecting New York City Transmission Security Margin

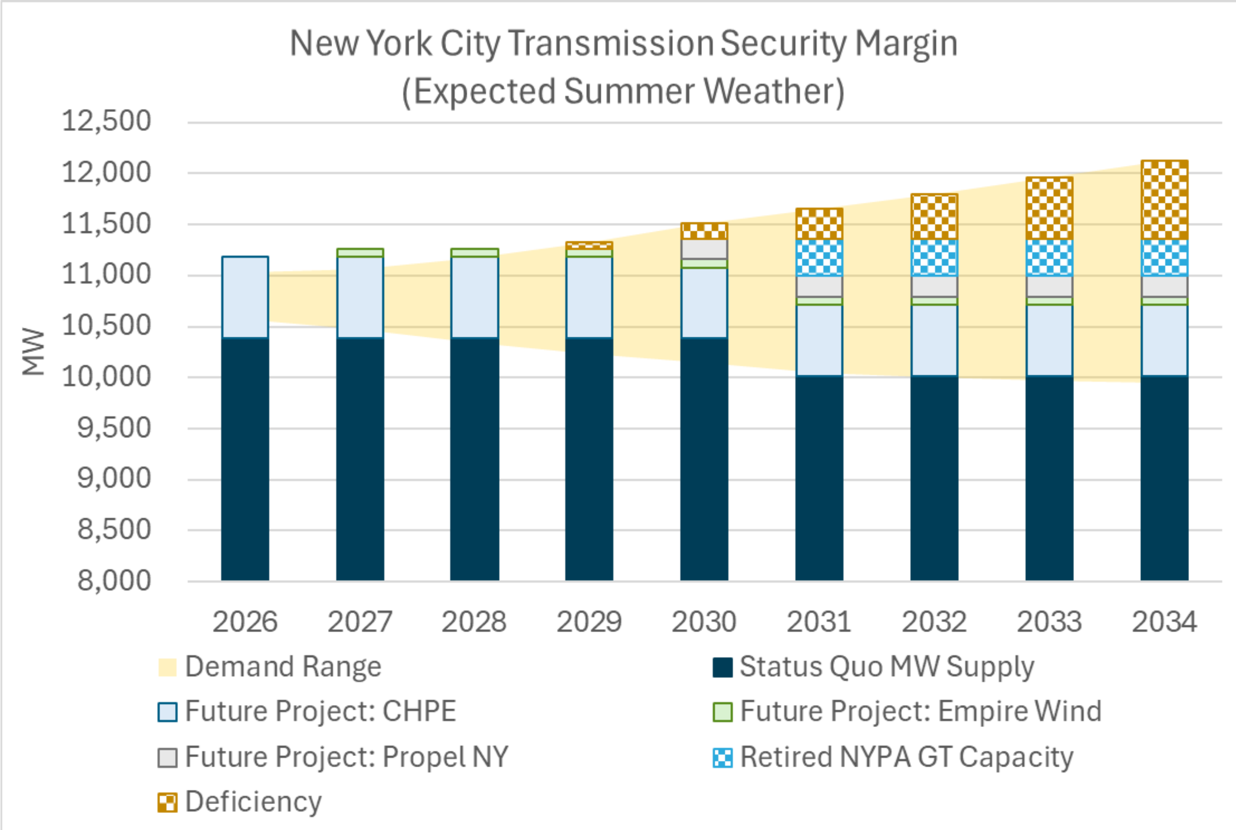
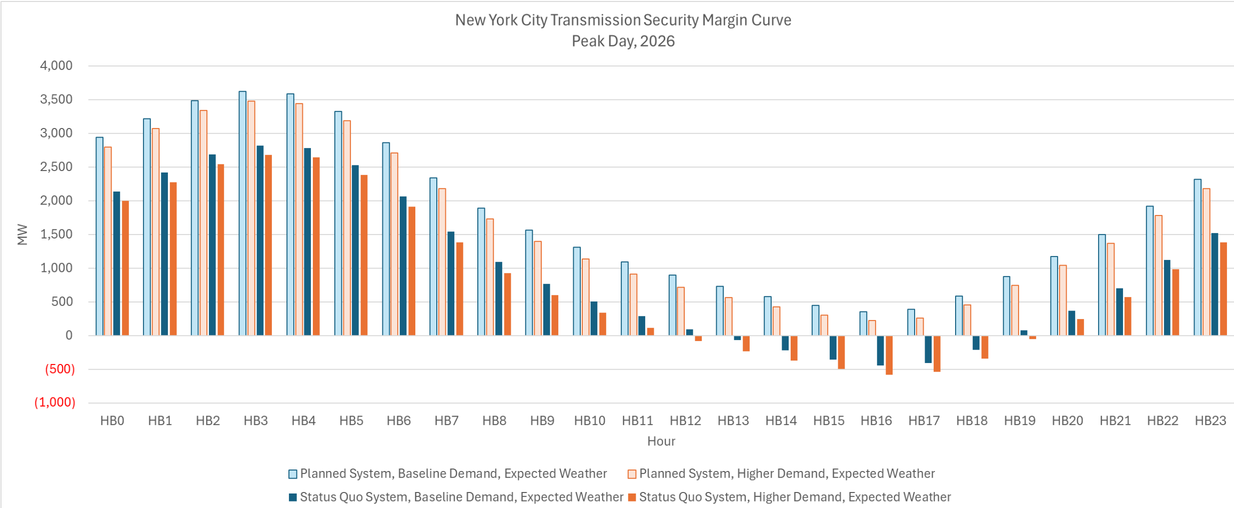
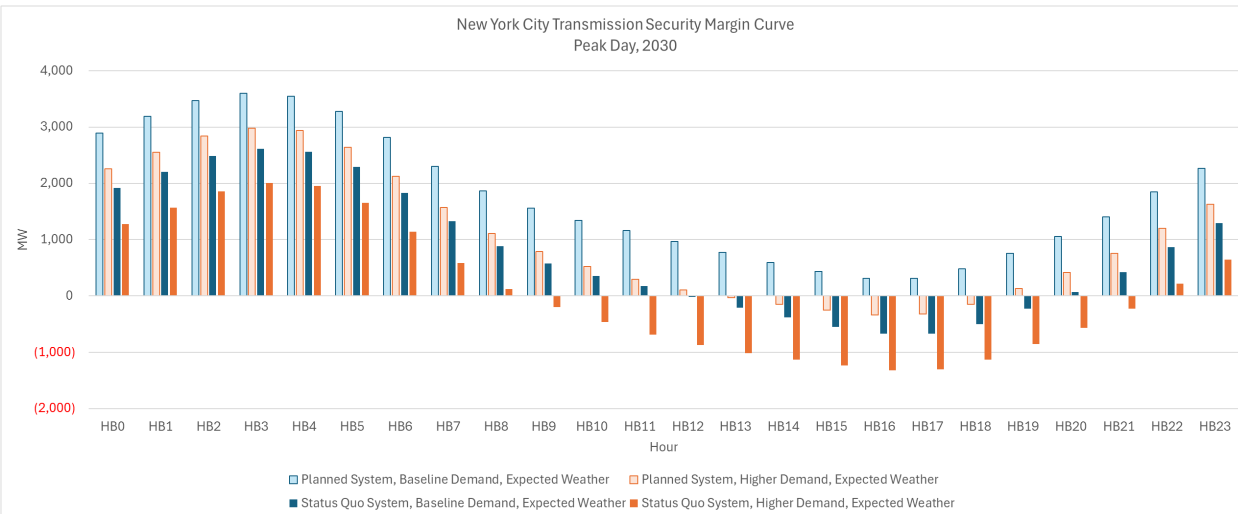


Figure 18: New York City Hourly Transmission Security Margin – Summer Peak





Con Edison's non-BPTF system analysis found no Generator Deactivation Reliability Needs following the retirement of the Narrows and Gowanus generators. Details regarding the Con Edison non-BPTF reliability system analysis are provided later in this report under non-BPTF reliability assessments.

Con Edison projects a potential 250 MW deficiency starting in 2030 within the 345/138 kV BPTF New York City Transmission Load Area (TLA) assuming CHPE, Empire Wind, Propel NY project entering service and demonstrating their planned power capabilities. Further information on the local reliability needs for the next decade will be provided in Con Edison's 2025 Local Transmission Plan (LTP), scheduled for release by the end of 2025.

Long Island Transmission Security Margin

In this 2025 Quarter 3 STAR the Pinelawn Power 1 (“Pinelawn”) (82 MW nameplate) and Far Rockaway Gas Turbine 1 and 2 (“Far Rockaway GTs”) (121 MW nameplate total) completed their generator deactivation notice requiring the NYISO and LIPA determine if there are any generator deactivation reliability needs. Neither of these units in the Long Island service territory are impacted by the DEC Peaker Rule.

This STAR finds that Zone K is projected to be deficient without the completion and demonstration of planned capabilities of future projects. The following table provides the magnitude and duration of the BPTF deficiency through the five-year study period under summer peak if system plans are not completed. Winter transmission security margins in Zone K remain positive throughout the five-year horizon.

Long Island BPTF Deficiencies

Summer Peak	**2026**	**2027**	**2028**	**2029**	**2030**
MW Deficiency	None	39-116	61-138	107-185	175-254
Duration	None	1-3	3	3	3-4
MWh	None	39-176	213-444	320-554	515-819

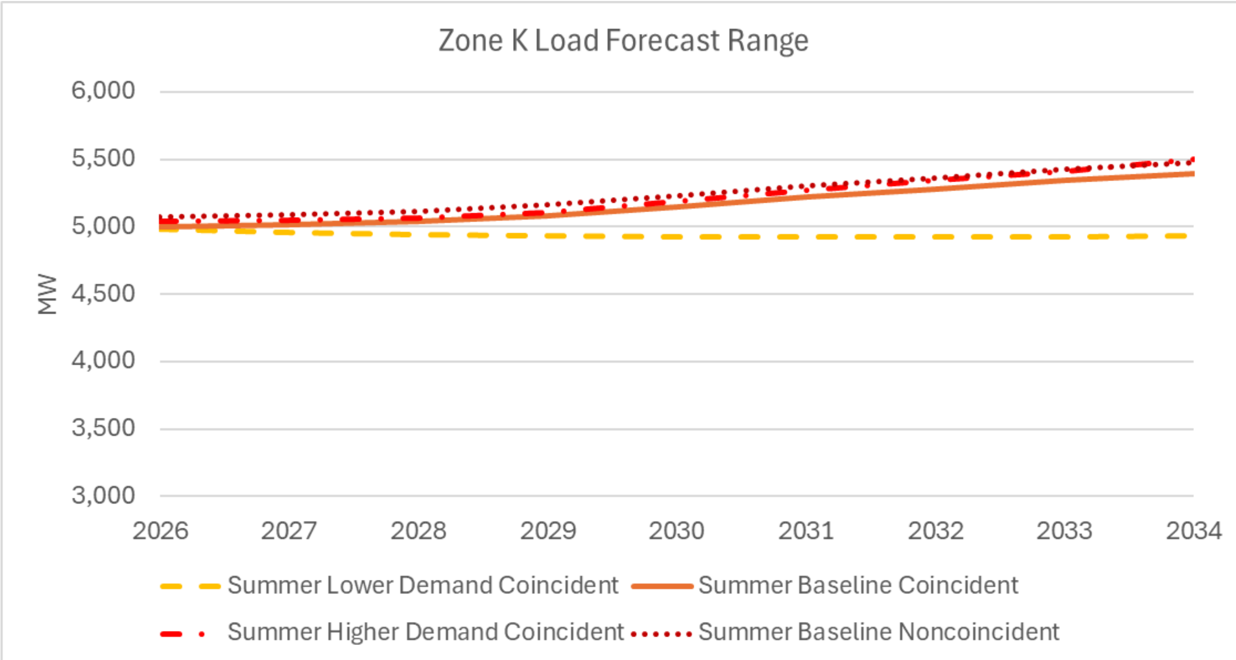
Once Sunrise Wind is delivering power as planned, the margins improve in summer 2028, followed by dramatic improvement in 2030 with the planned energization of the Propel NY project such that margins remain positive throughout the remainder of the planning horizon. However, even if these future planned projects are available according to current schedules, deficiencies under summer peak conditions are still observed from 2027 through 2029. Specifically, with the planned projects available, the BPTF deficiency is 39-116 MW over 1-3 hours (39-176 MWh) in 2027 and by summer 2029 the deficiency is 14-92 MW over 3 hours (277 MWh). The Long Island summer peak margin is shown in Figure 22, which illustrates the reliability impact of the status quo as well as future planned generation and transmission projects that have met the Reliability Planning Process inclusion rules. Hourly margin details for this locality are provided in Figure 23 for summer 2027 and for summer 2030.

These deficiencies are driven by the deactivation of the Pinelawn and Far Rockaway generators in combination with other factors such as: the range in the demand forecasts based on expected weather, expected generator availability, transmission limitations, and risks associated with the availability of key future planned projects. Key inputs into these findings includes planned assumptions from the start of the STAR for external imports from the Cross-Sound Cable at in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW. The Glenwood GT 3 and Shoreham 1 generators are also assumed unavailable beyond May 2027 due to their current Peaker Rule compliance plans. In addition to being generator deactivation reliability needs, as these needs are observed within three years following the conclusion of the 365 days that follow the STAR Start date they are also near-term reliability needs. Winter margins in Zone K remain positive throughout the five-year horizon.

The range 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 as described in the 2025 Gold Book. The forecasted summer peak demand in Long Island has a range of 92 MW in 2026 growing to 302 MW in 2030, primarily driven by assumptions in the demand forecast. Details of the demand forecasts for expected weather used in the determination of the need in this STAR are shown below in Figure 19. The assumed available supply has also been adjusted to account for expected reductions of 200 MW in generators' DMNC based on the Correlated Derates explained above.

In accordance with filed compliance plans for the DEC Peaker Rule, the Glenwood GT 3 and Shoreham 1 generators are assumed available until May 1, 2027 and unavailable thereafter. Additionally, the assumed capacity purchases from ISO New England into Zone K have been adjusted to account for a LIPA import of 288 MW from ISO-NE until April 2027, with zero flow scheduled thereafter. If these additional resources are available through the five-year horizon, the observed reliability need on the BTPF would be eliminated.

Figure 19: Zone K Load Forecast Uncertainty



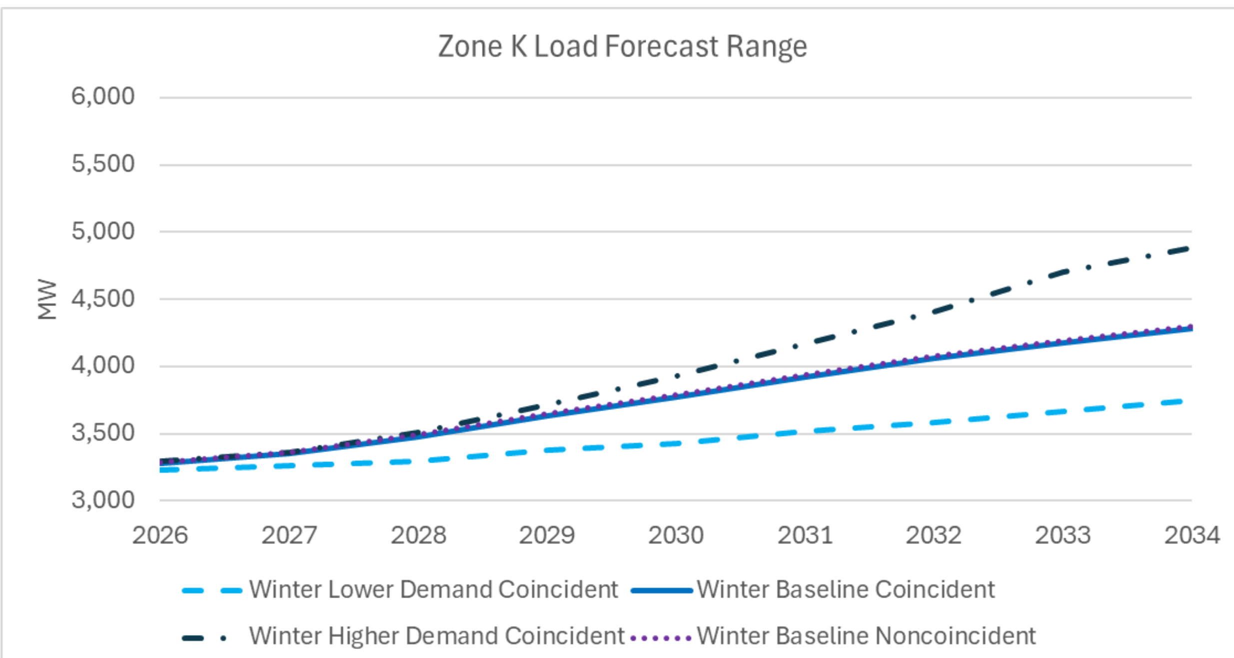


Figure 20: Zone K Summer Transmission Security Margin

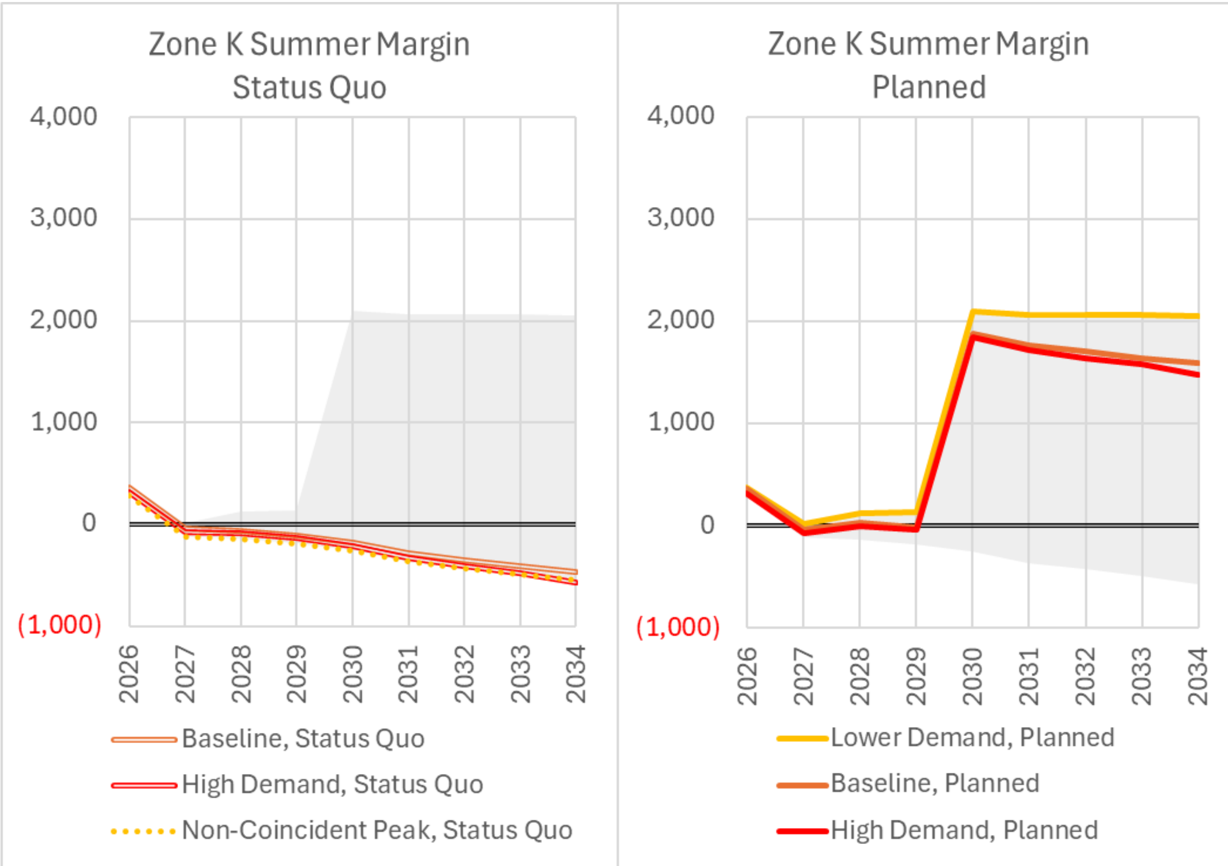


Figure 21: Zone K Winter Transmission Security Margin

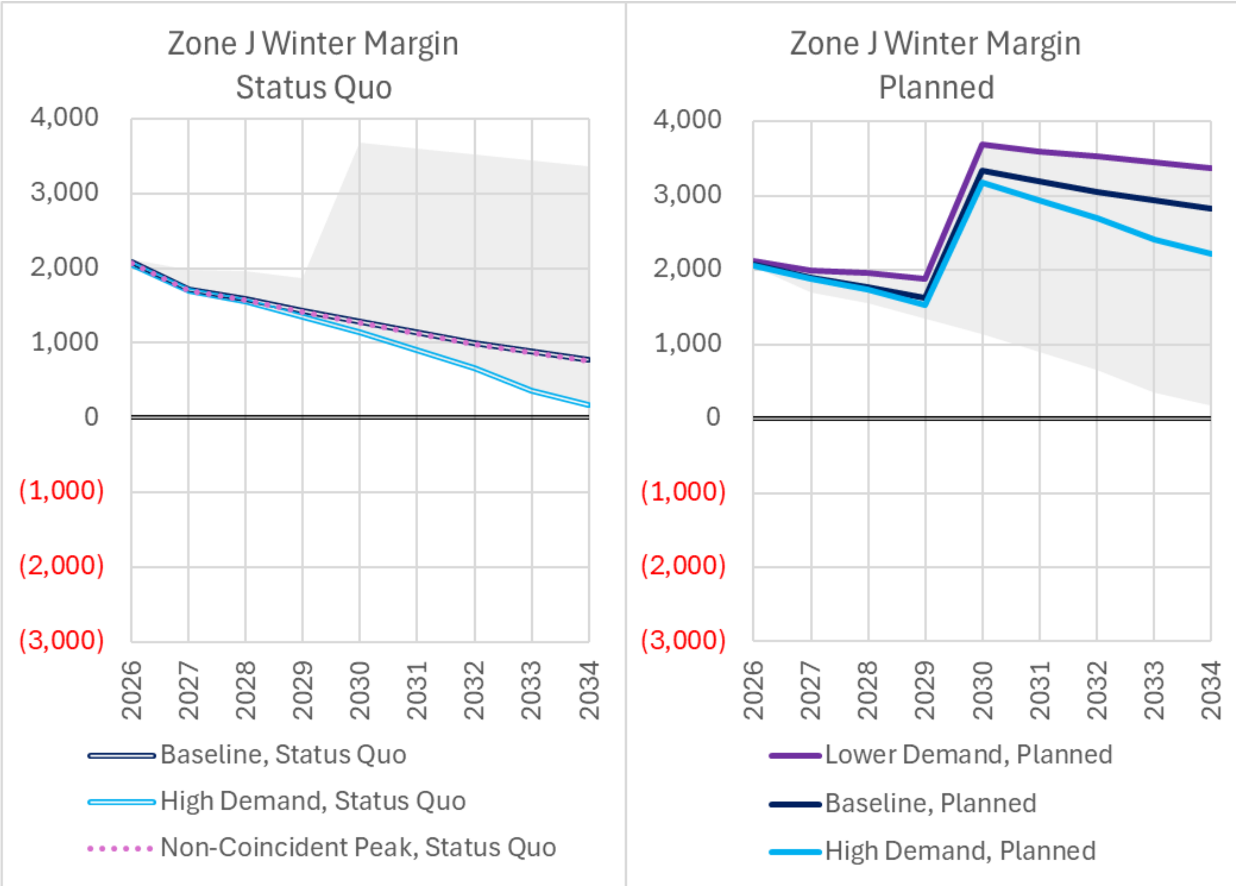


Figure 22: Factors Affecting Long Island Transmission Security Margin

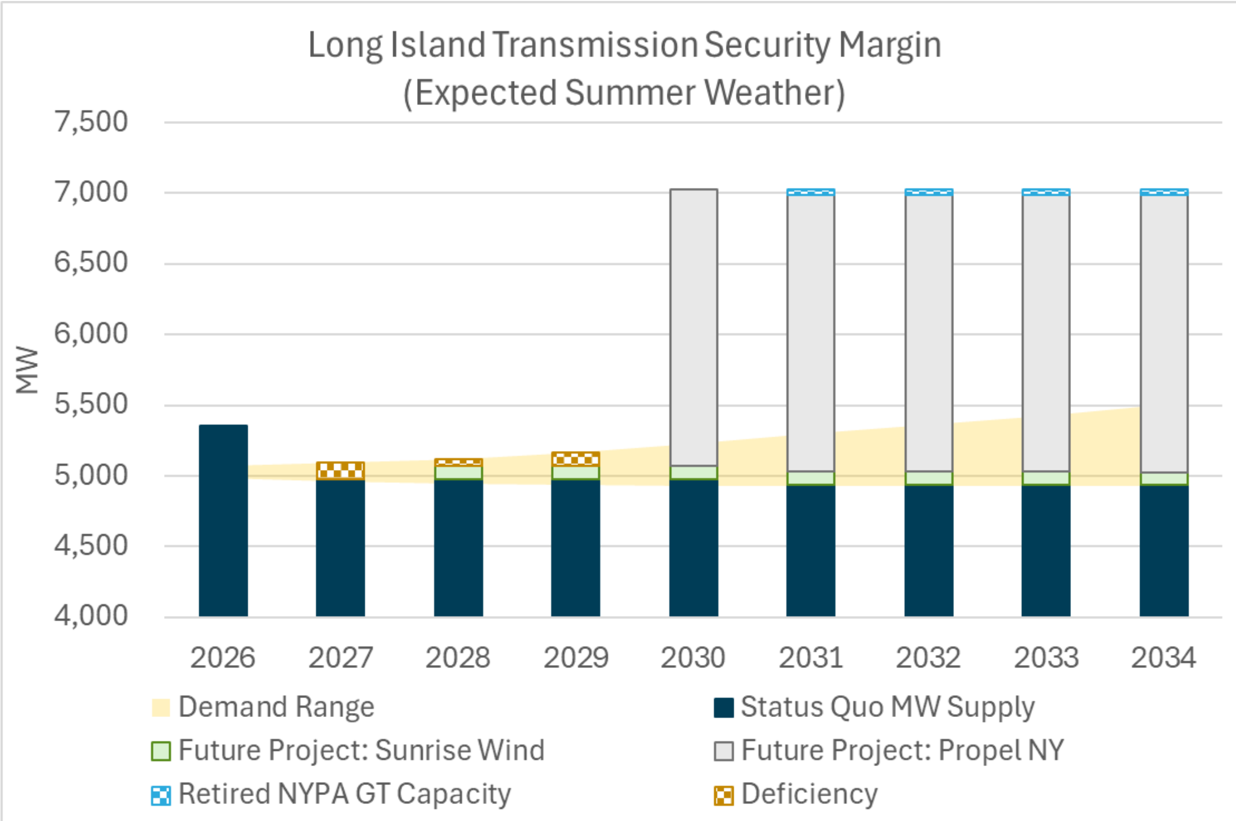
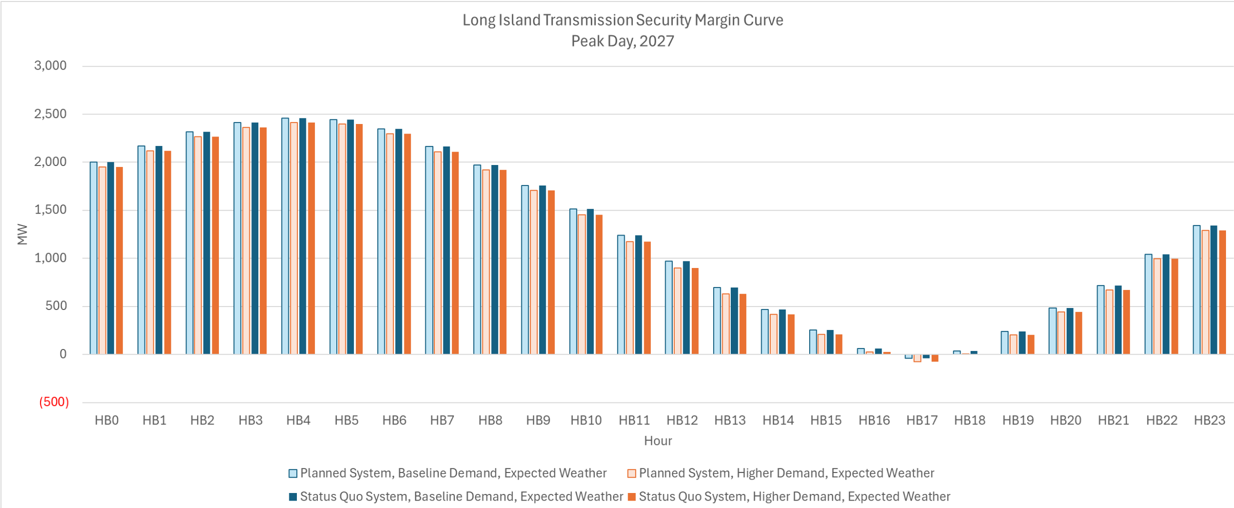
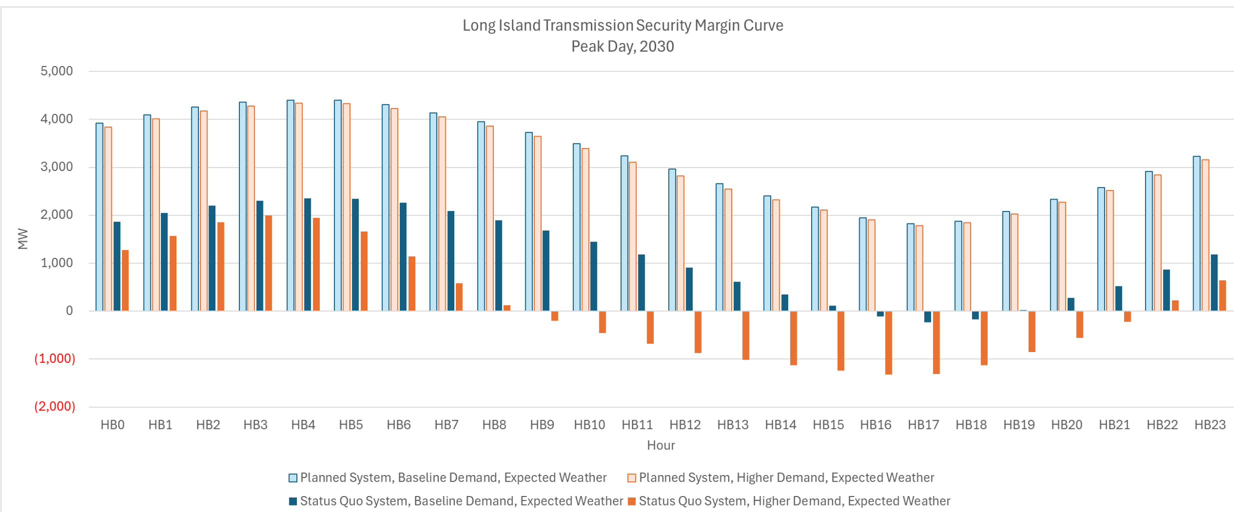


Figure 23: Long Island Hourly Transmission Security Margin – Summer Peak





Solutions to Previously Identified Short-Term Reliability Needs

On October 3, 2023, the NYISO received proposed solutions to the 2023 Quarter 2 STAR need within New York City. On November 20, 2023 the NYISO issued its Short-Term Reliability Process Report identifying the solution selected to address the 2025 New York City need.[20] The results of this determination were reviewed with stakeholders at the November 29, 2023 Management Committee meeting.[21] There were no viable and sufficient solutions submitted to the NYISO in response to its solicitation that met the need in 2025. The NYISO determined that temporarily retaining the peaker generators on the Gowanus 2 & 3 and Narrows 1 & 2 generators is necessary to address the need until a permanent solution is in place. The NYISO's designation of the Gowanus 2 & 3 and Narrows 1 & 2 generators as needed to maintain reliability allows their continued operation beyond May 2025 until the earlier of May 1, 2027, or the date a permanent solution is in place and a reliability need does not exist, consistent with the DEC Peaker Rule. The Gowanus 2 & 3 and Narrows 1 & 2 plant owner, Astoria Generating Company L.P., informed the NYISO that its generators are available to continue operation for so long as they are determined to be needed for reliability and are allowed to continue operating consistent with the Peaker Rule. With the continued operation of these peakers until the earlier of the date (a) the date a permanent solution (*i.e.,* CHPE) is in place and demonstrates dependable capacity supply during summer peak conditions or (b) May 2027, the need for the currently forecasted demand is addressed if CHPE is not delayed beyond 2026, as shown in Figure 24. The deactivation of Gowanus 2 & 3 and Narrows 1 & 2 units is assessed in this STAR report and the resulting impact to reliability criteria is discussed earlier in the report.

[20] Short-Term Reliability Process Report: 2025 Near-Term Reliability Need, November 20, 2023 (here).

[21] Short-Term Reliability Process Report, Management Committee Meeting, November 29, 2023 (here).

Figure 24: New York City Margin with Designated Peakers

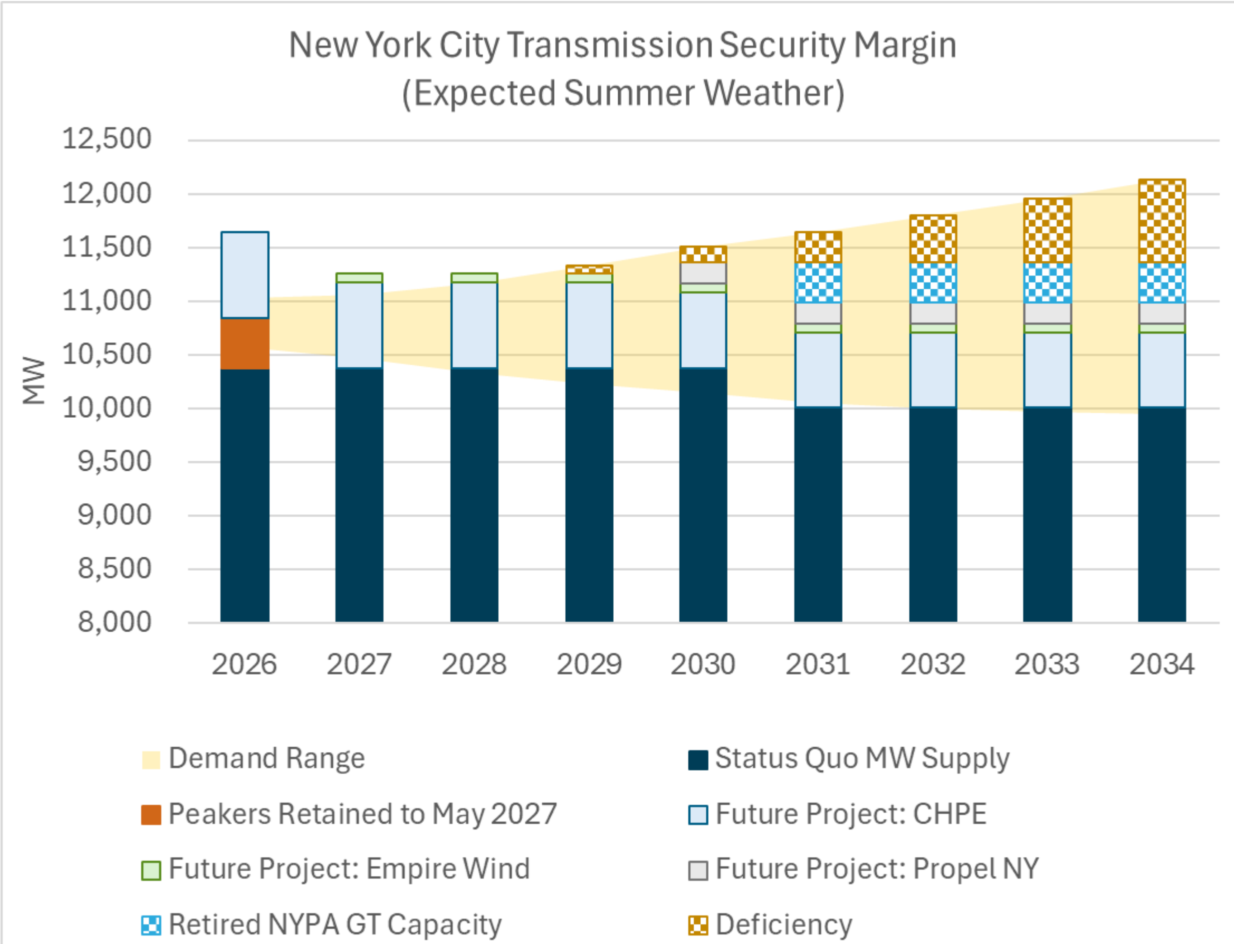
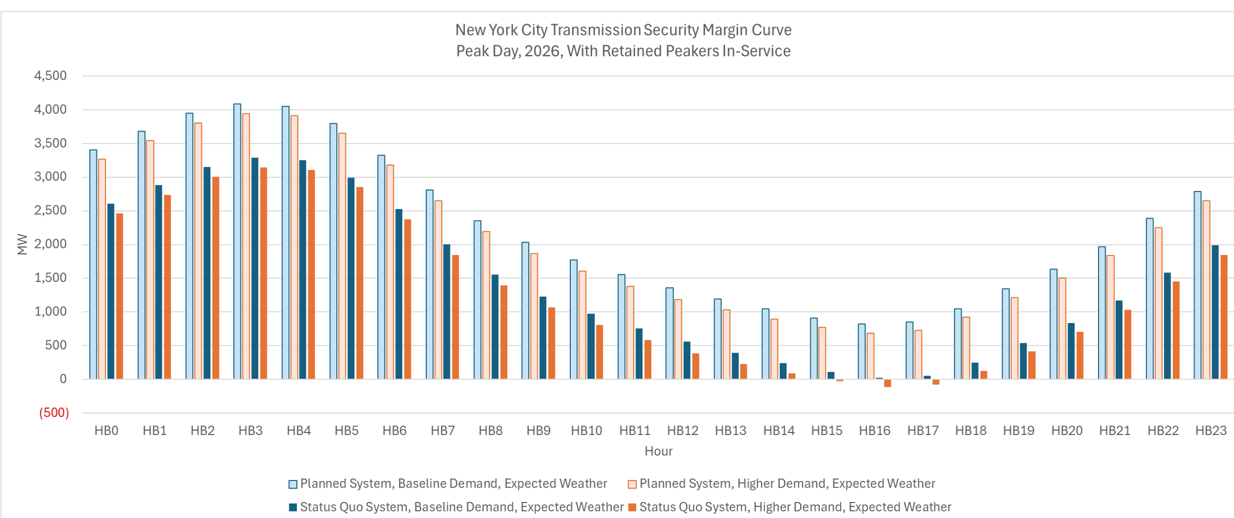


Figure 25: New York City Hourly Margin with Designated Peakers



Local Non-BPTF Reliability Assessment

The Transmission Owners that evaluated the impact of the generator deactivations on their non-BPTF are NYSEG, Con Edison, and LIPA. The NYISO reviewed and verified the analysis performed by the Transmission Owners.

NYSEG Non-BPTF Generator Deactivation Assessment

For this STAR, NYSEG performed a deactivation assessment to evaluate the reliability of the local non-BPTF system for the IIFO of Hyland LFGE. NYSEG did not identify Generator Deactivation Reliability Needs with the IIFO of Hyland LFGE.

Con Edison Non-BPTF Generator Deactivation Assessment

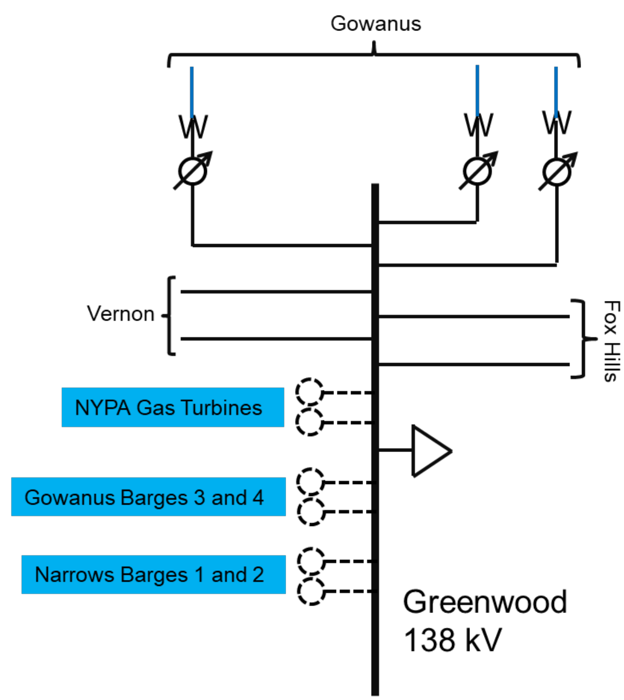
As discussed in the 2025 Quarter 2 STAR (along with other prior STAR reports), Con Edison previously conducted a non-BPTF reliability assessment for its non-bulk Greenwood 138 kV transmission load area ("TLA") and observed transmission security violations due to deficiencies. These assessments assumed the Gowanus 2 & 3 and Narrows 1 & 2 generators to be available in summer 2025 due to the overall (Zone J) reliability need as established by the NYISO and unavailable starting in summer 2026. Con Edison's firm[22] solution that it plans to have in service by summer 2026 is a fourth Gowanus – Greenwood 345/138 kV PAR controlled feeder, which is currently in an engineering / procurement / construction phase(s), with an in-service date of May 2026. The addition of a fourth PAR controlled feeder is an interim solution (i.e., bridge the gap) to be supplemented by future system expansion projects in the local area that are not yet firm projects. Until the fourth Gowanus – Greenwood 345/138 kV PAR controlled feeder is placed into service, Con Edison found that the Narrows and Gowanus generators are required to remain in service. If the Greenwood TLA deficiency is not addressed, neighboring TLAs, including the Vernon 138 kV TLA, would also have deficiencies.

For this STAR, Con Edison performed a deactivation assessment to evaluate the reliability of the non-BPTF system for the deactivations of Gowanus Gas Turbine 2-1 through 2-8, Gowanus Gas Turbine 3-1 through 3-8, Narrows Gas Turbine 1-1 through 1-8 and Narrows Gas Turbine 2-1 through 2-8 units. Con Edison determined there are no Generator Deactivation Reliability Needs on the non-BPTF. This conclusion is based on the timely completion of the fourth Gowanus – Greenwood 345/138 kV PAR controlled feeder. Con Edison remains on schedule to establish the 4th

[22] Con Edison made the fourth Gowanus – Greenwood feeder a firm project on January 21, 2025, ESPWG: https://www.nyiso.com/documents/20142/49295323/CECONY's_LTP_Update_1_21_2025.pdf/abf6cfb4-10e6-eee4-3988-0a434f5a1dcb

Gowanus-Greenwood 345/138 kV PAR controlled feeder. However, if this connection is not established by summer 2026, Con Edison concludes that it will require the continued operation of the Gowanus 2 & 3 and Narrows 1 & 2 generators.

Figure 26: Greenwood 138 kV TLA



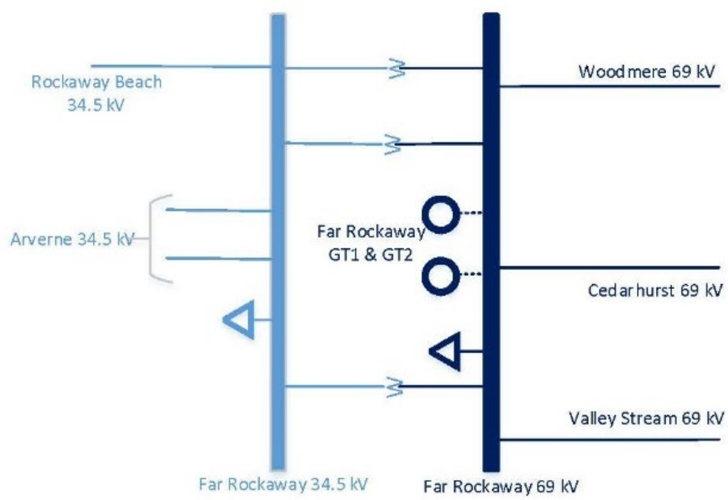
The unavailability of Gowanus 2 & 3 and Narrows 1 & 2 units neither results in any identified thermal or voltage violations nor degrades Con Edison's System Restoration Plans. Prior analyses confirmed the absence of fault duty and stability issues under both full unavailability and temporary retention scenarios for the Narrows and Gowanus generators.

In summary, with the planned local transmission upgrades within the Con Edison service territory, the deactivations of Gowanus 2 & 3 and Narrows 1 & 2 do not pose a reliability concern for the assessed non-BPTF and system restoration capabilities, unless the 4th 345/138 kV PAR controlled feeder does not enter service consistent with Con Edison's current expectations.

LIPA Non-BPTF Generator Deactivation Assessment

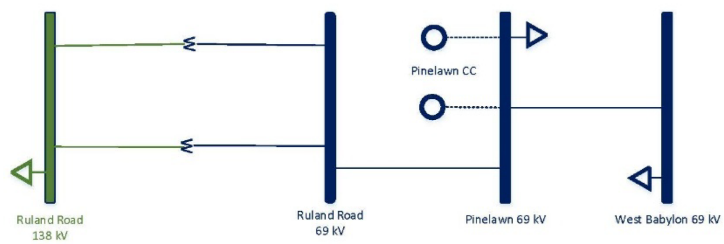
For this STAR, LIPA performed a deactivation assessment to evaluate the reliability of the local non-BPTF system for the deactivation of Pinelawn Power 1 and Far Rockaway Gas Turbine 1 and 2. The key areas evaluated by LIPA for their assessment include the Far Rockaway load pocket and the Babylon load pocket.

Figure 27: Far Rockaway Load Pocket



Far Rockaway GT 1 and GT2 are located in the Far Rockaway load pocket which is in the west region of Nassau County. Figure 27 provides a high-level visual of this pocket. The deactivation of Far Rockaway GTs results in multiple N-1 thermal and voltage violations on LIPA's 69 kV transmission system feeding the Far Rockaway load pocket. In 2026, LIPA observes that the Far Rockaway load pocket is deficient 61 MW for up to 13 hours. This deficiency grows by 2029 to 80 MW for up to 15 hours. The deficiency shows a reduction in 2030 to 72 MW over 14 hours (649 MWh) due to the inclusion of the Propel NY project. As these needs are observed within the first three years of the study period and can be resolved, in whole or in part, by the retention of the Far Rockaway GTs, they are Generator Deactivation Reliability Needs, which are also Near-Term Reliability Needs.

Figure 28: Babylon Load Pocket



Pinelawn Power 1 is located in the Babylon load pocket which is in the western region of Suffolk County. Figure 28 provides a high-level visual of this pocket. The deactivation of Pinelawn Power 1 does not result in Generator Deactivation Reliability Need on the non-BPTF.

Informational Reliability Assessment

As identified in the NYISO's 2025-2034 Comprehensive Reliability Plan, there are several key risk factors to the reliability of the grid, including generation unavailability and extreme weather.

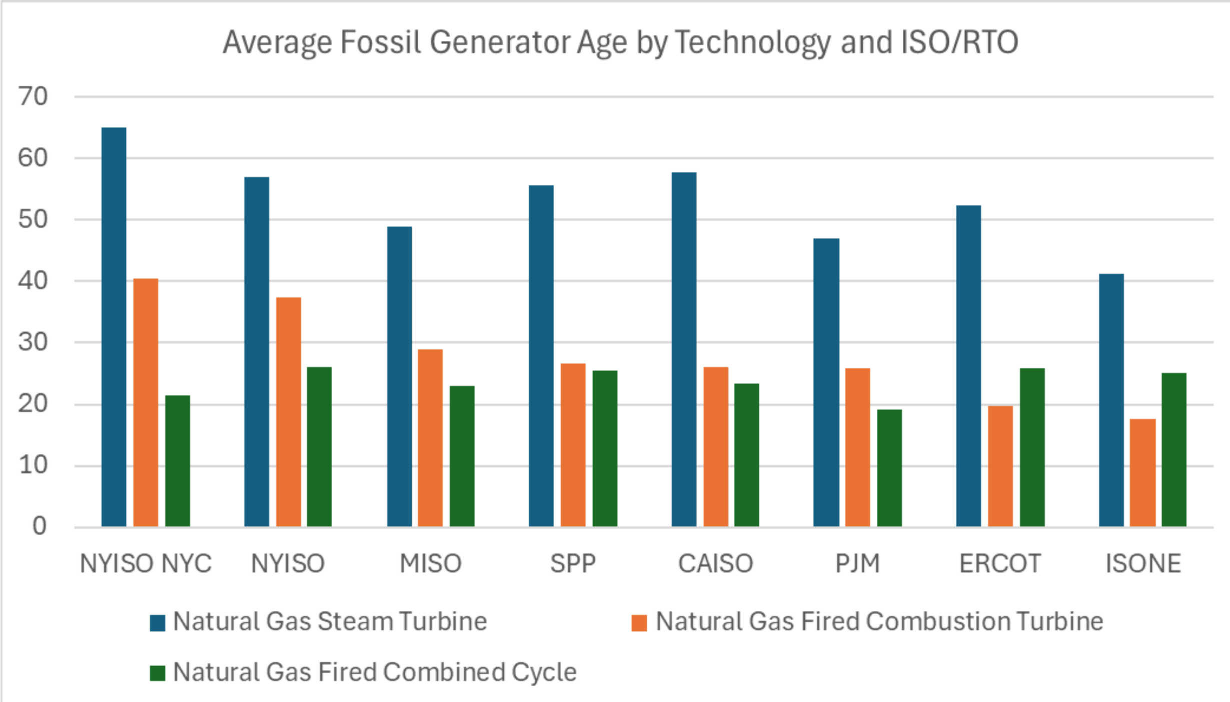
In addition to meeting the identified Near-Term Reliability Needs on the BPTF and satisfying the mandatory Reliability Criteria, the retention of the Gowanus 2 & 3 and Narrows 1 & 2 generators in the Lower Hudson Valley and New York City or the Pinelawn and Far Rockaway GTs in Long Island helps to increase BTPF resilience during unexpected facility outages or under extreme weather conditions, such as heatwaves (98 degrees Fahrenheit) and extreme heatwaves (102 degrees Fahrenheit).

Aging Generation

New York's generation fleet is among the oldest in the country. Compared to generation in other Independent System Operator (ISO)/Regional Transmission Operator (RTO) regions in the United States,[23] 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.

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

Figure 29: National Average Fossil 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 faced with these maintenance difficulties while also considering the impact of policies to restrict or eliminate emissions. These factors may drive aging generators to deactivate or to 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.[24]

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 model, described in detail in Appendix C of the 2025-2034 CRP[25], uses a data-driven approach to represent the risk of retirement or end-of-life failures for generating units as they advance in age. The model begins with retirement information for existing and retired generating units from the U.S. Energy Information Administration's EIA-860 data form.[26] Observed retirement behavior is transformed into survival

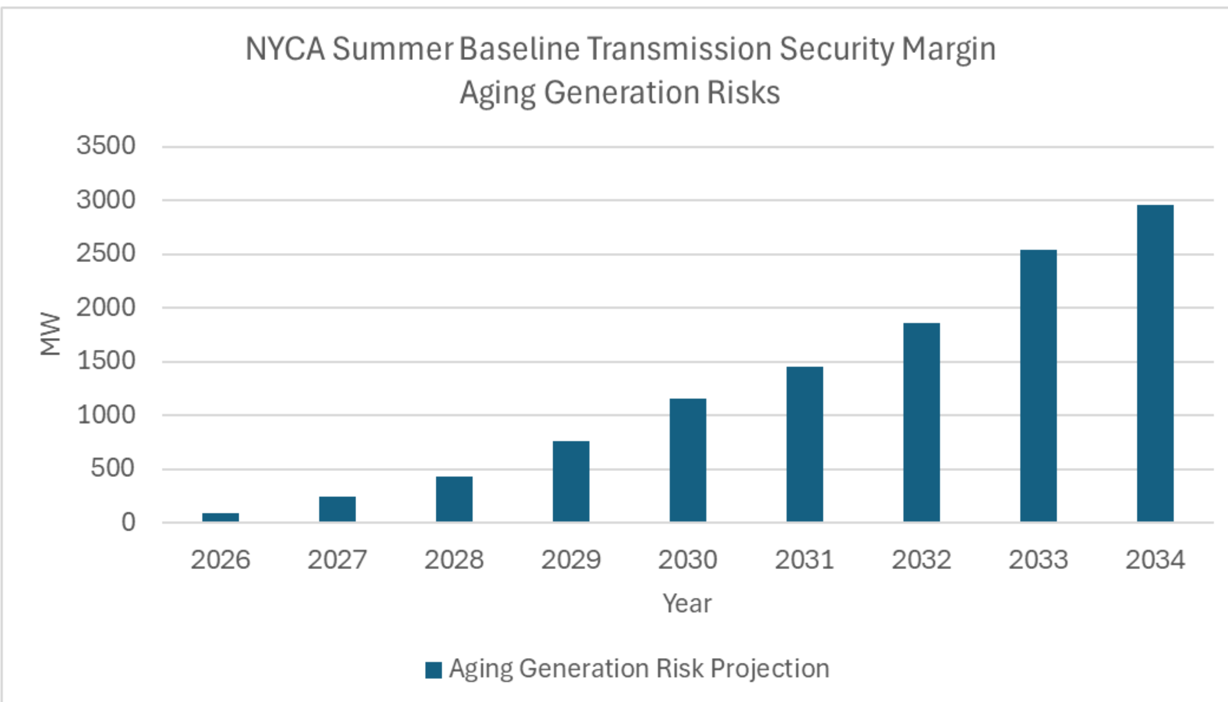
[24] Generator Status Updates, https://www.nyiso.com/ny-power-system-information-outlook.

[25] The most recent draft appendix of the NYISO's 2025-2034 Comprehensive Reliability Plan is found with the October, 16, 2025 Operating Committee Materials (here)

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

(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 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. This model does not have a separate component to explicitly model the potential for increased forced outage rates as a generator approaches end of life. Forced outage rates of aging generation could also be compounded if these units experience increased run cycles and extreme weather operations as they are relied on more in the future due to decreasing reliability margins. Figure 30 shows how the risk, calculated in unavailable MW, grows over time as the fleet ages during the course of the planning horizon.

Figure 30: Aging Generation Risk Projection



Reliance on an aging fossil-fuel generation fleet presents a growing risk to maintaining reliability of the New York grid. The following results quantify the impact of the retirement or failure of aging fossil-fuel generators on statewide system margins as well as the New York City and Long Island localities (*see* Figure 31 through Figure 33) under the expected demand range.

Overall, as seen in each of the localities as well as statewide, the aging generation advances the year of potential reliability issues forward by several years, if not already indicating a potential deficiency throughout the planning horizon.

Figure 31: Impact of Aging Generation on the Statewide System Margin

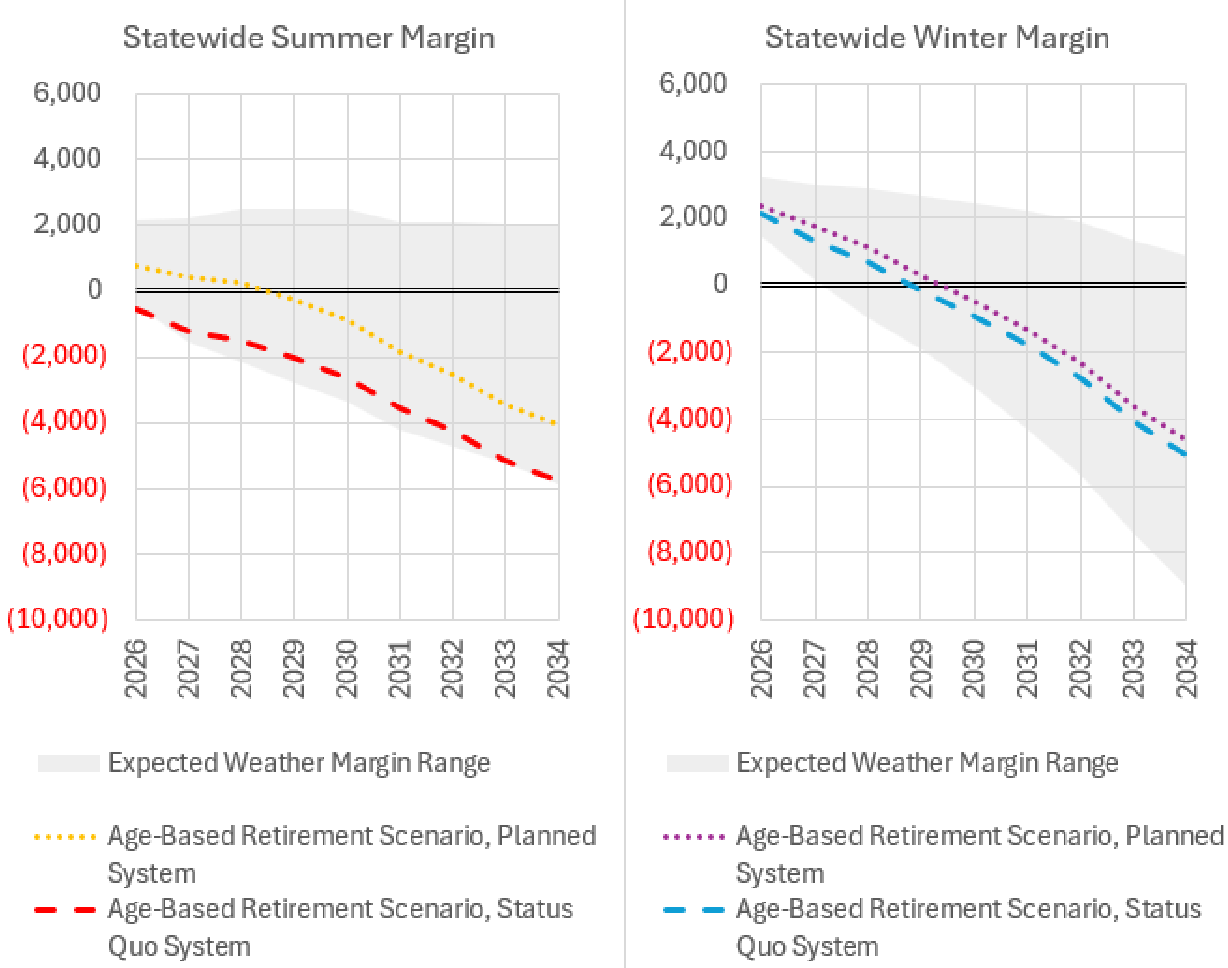


Figure 32: Impact of Aging Generation on the New York City Transmission Security Margin

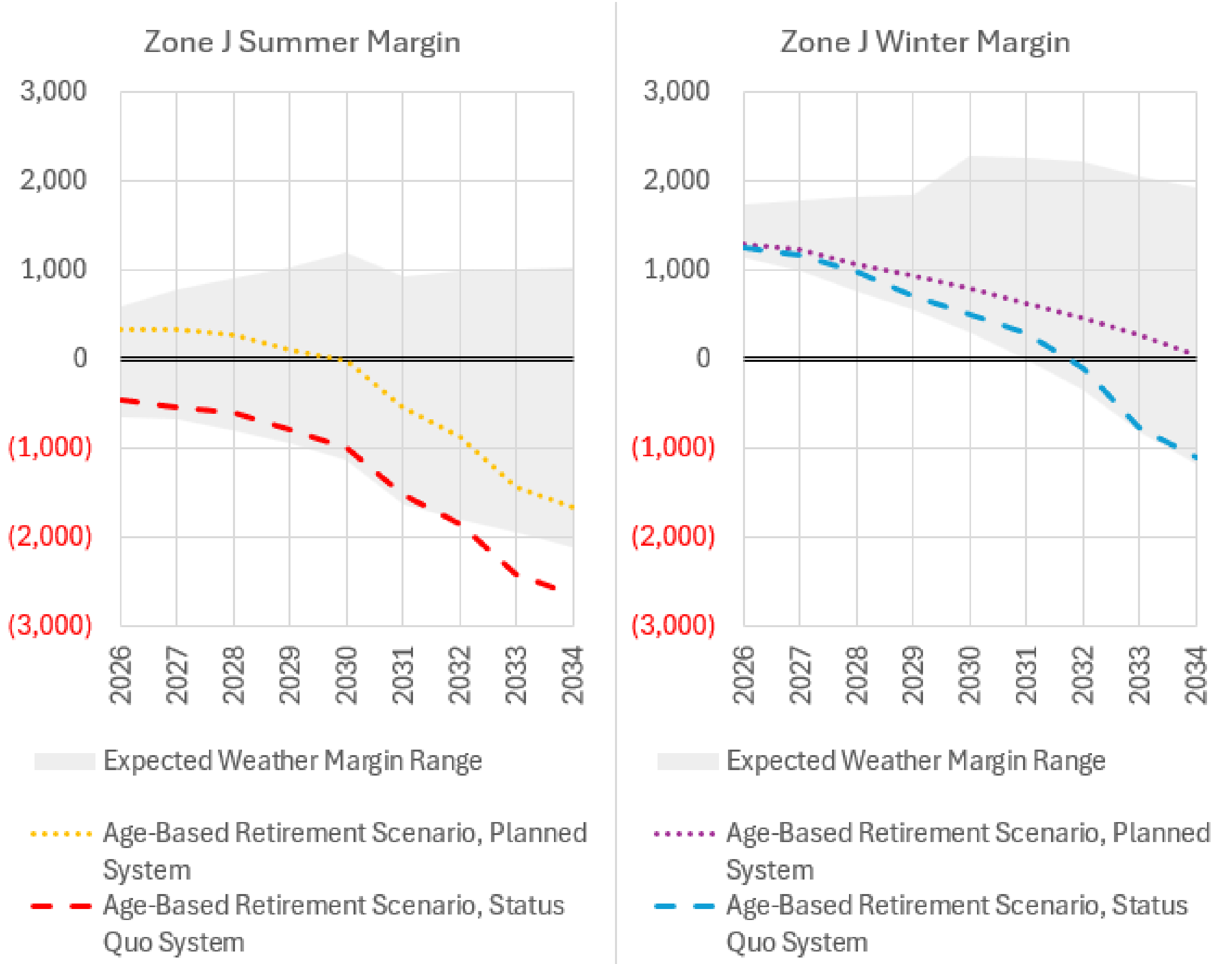
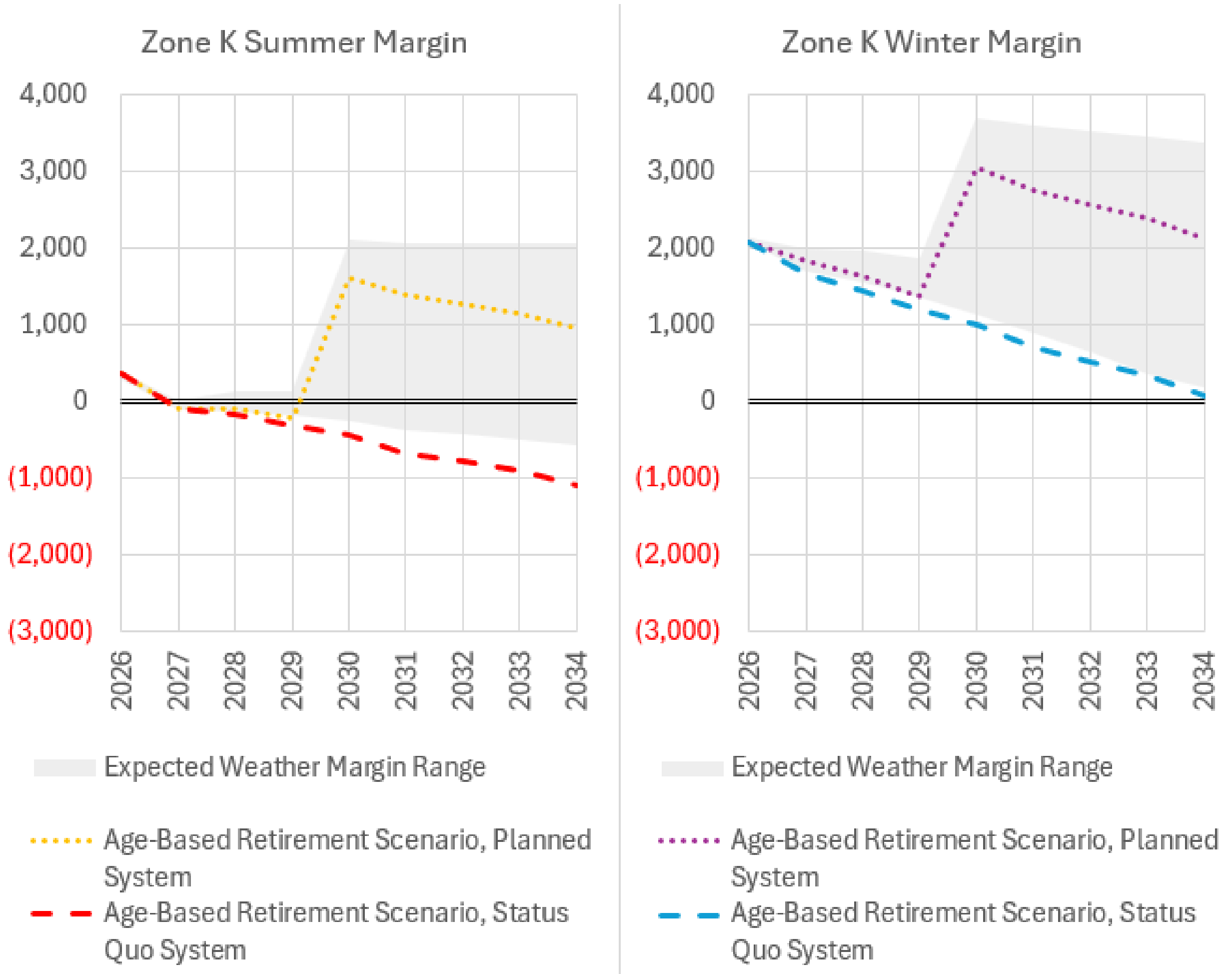


Figure 33: Impact of Aging Generation on the Long Island Transmission Security Margin



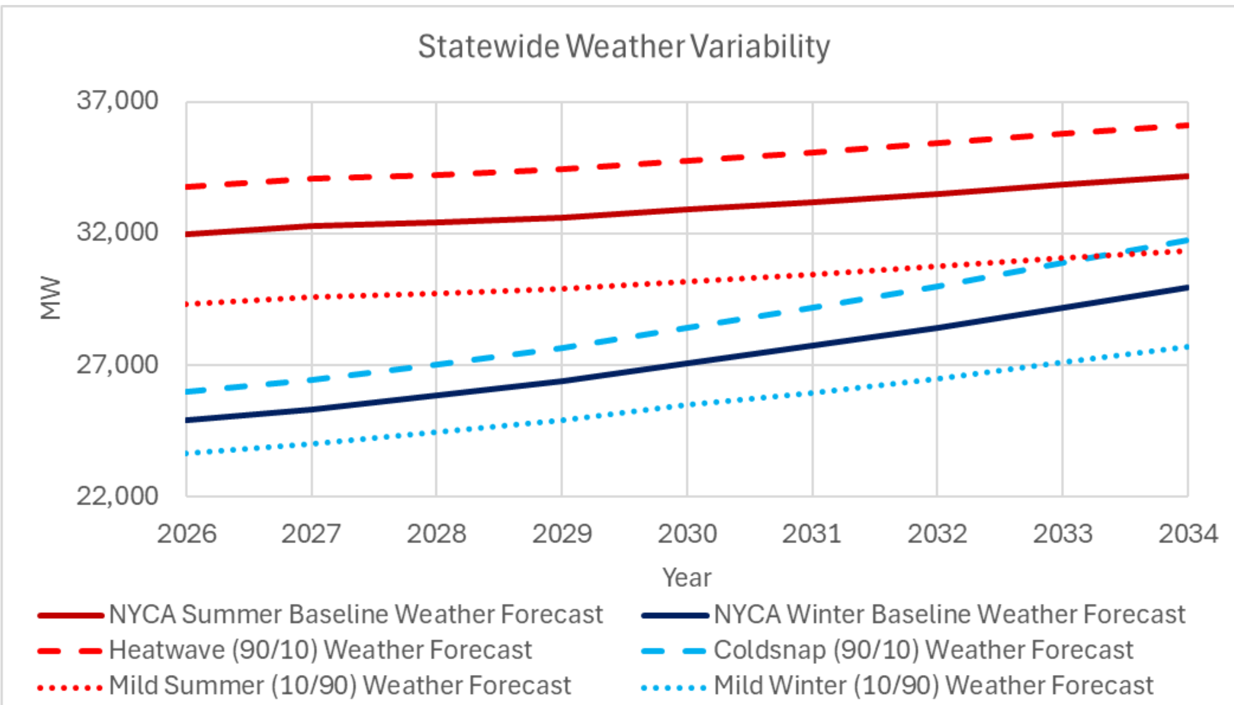
Weather Variability

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 current demand forecasts indicate that for the statewide coincident peak the baseline summer peak day daily maximum temperature is 92 degrees, and the statewide baseline winter daily minimum temperature is 8 degrees. The peak day temperature weather distributions, at the statewide level as well as zonally, is provided in Table I-20 of the 2025 Gold Book.

The expected weather design condition serves as a balanced benchmark used in planning studies. However, the NYISO needs to operate the system reliably when actual conditions differ from the expected weather forecasts 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 34, below, summarizes the variability of the forecasts based on the variability of the temperature compared to the summer and winter baseline expected weather forecast for the NYCA.

Figure 34: Weather Variability



Weather extremes can cause significant deviations in the results when compared to the expected weather forecasts used in the planning process. Figure 35 shows the impact of deviation in temperature as seen by heatwaves and, cold snaps on the statewide system margins. Additional details are also provided for the New York City and Long Island localities (Figure 36 and Figure 37). Other aspects of extreme weather such as wind speed and solar irradiance may also impact these margin results, but are not explored for this assessment.

Figure 35: Statewide System Margin Impact of Weather Variability

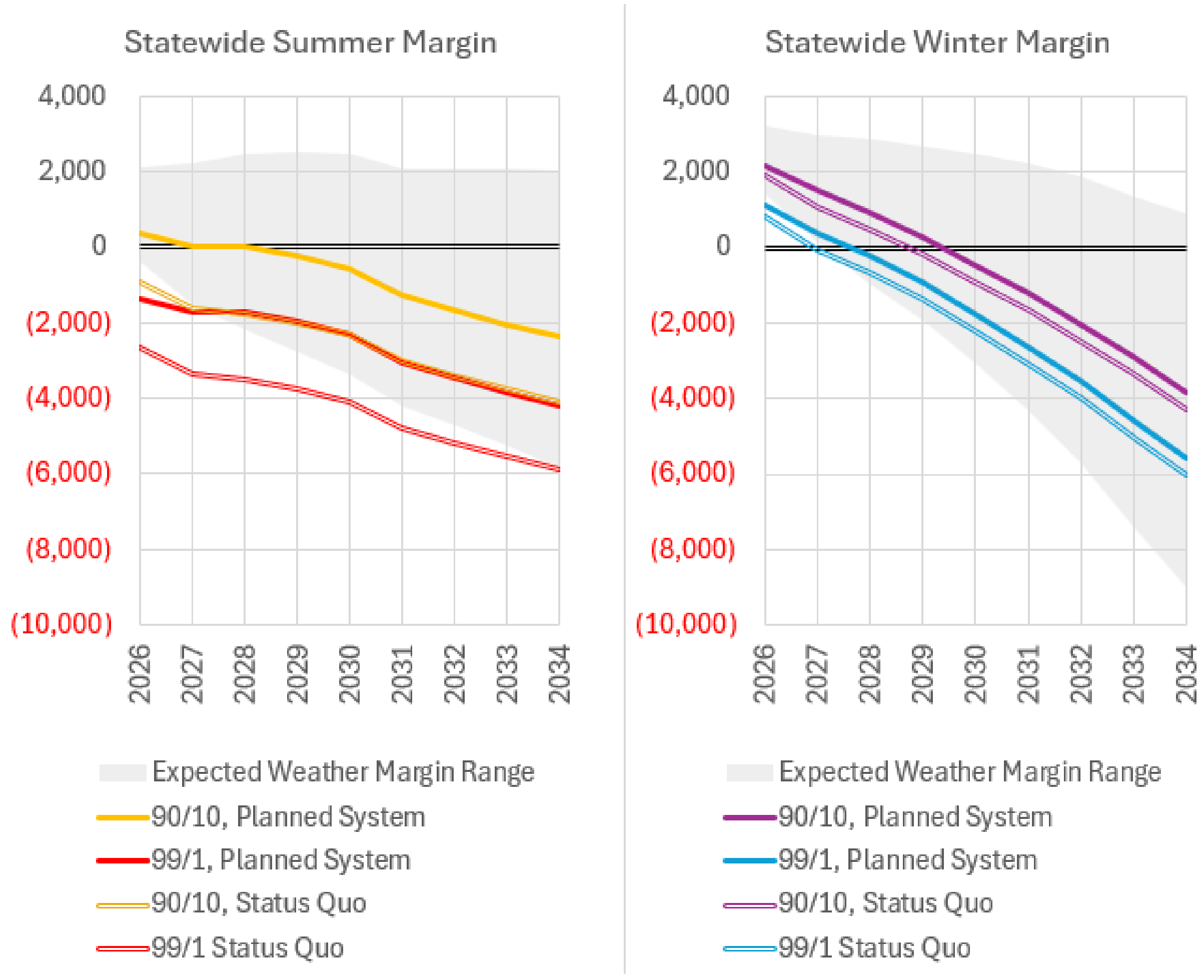


Figure 36: Weather Variability Impact on New York City Transmission Security Margin

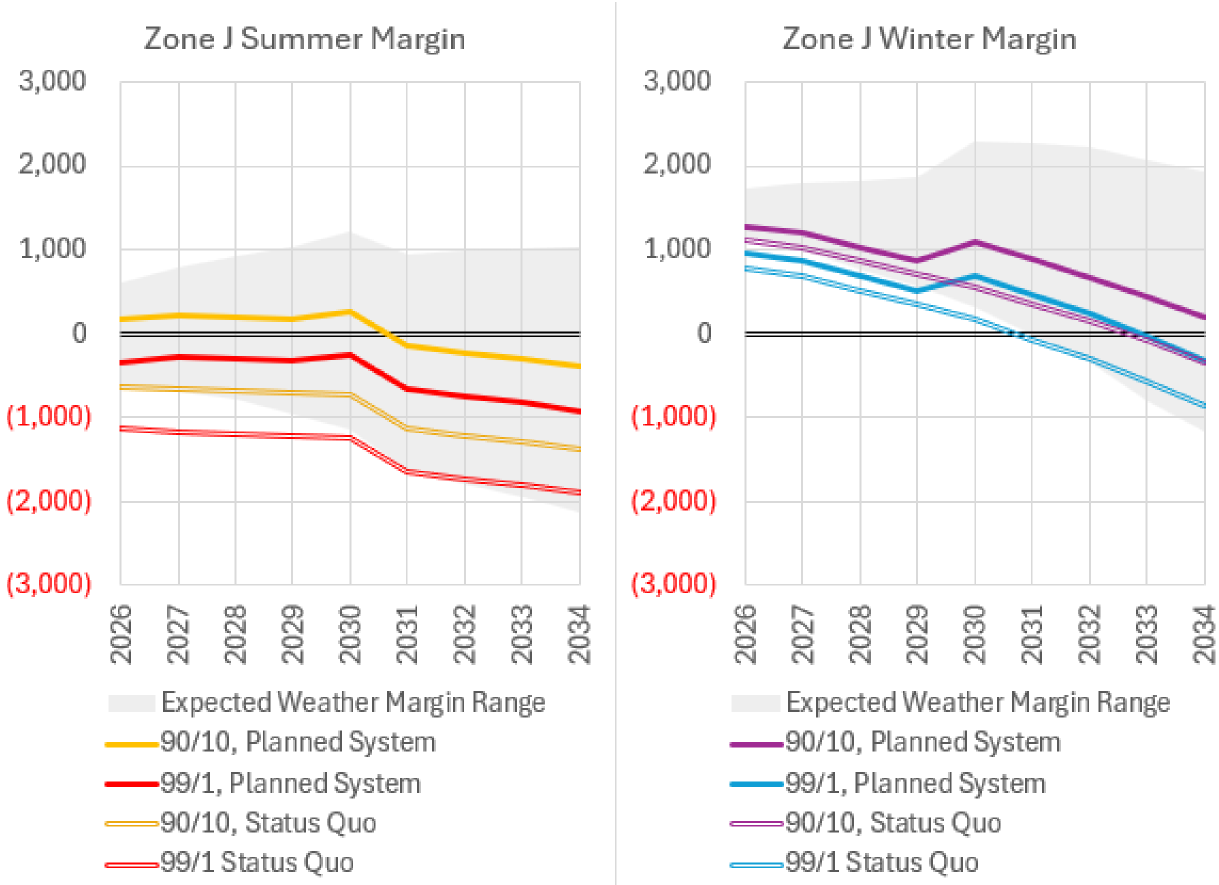
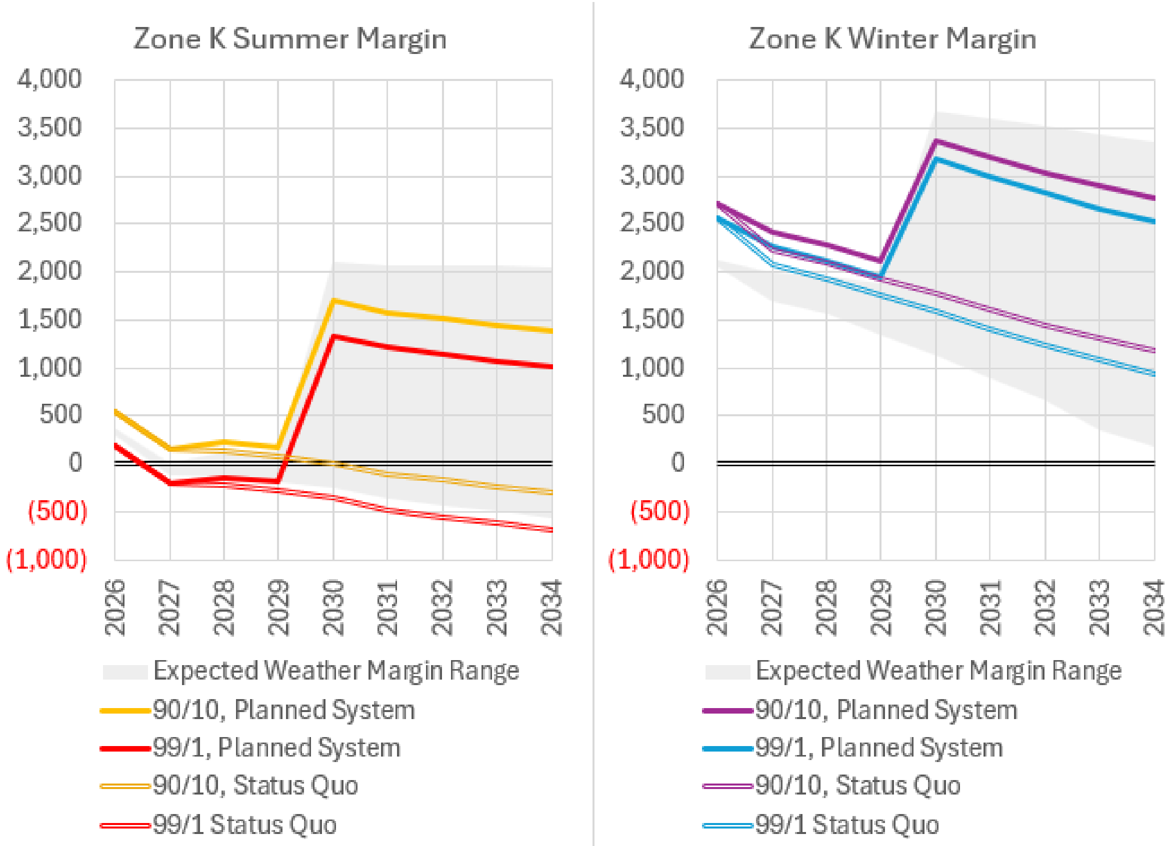


Figure 37: Weather Variability Impact on Long Island Transmission Security Margin



Additional Resources

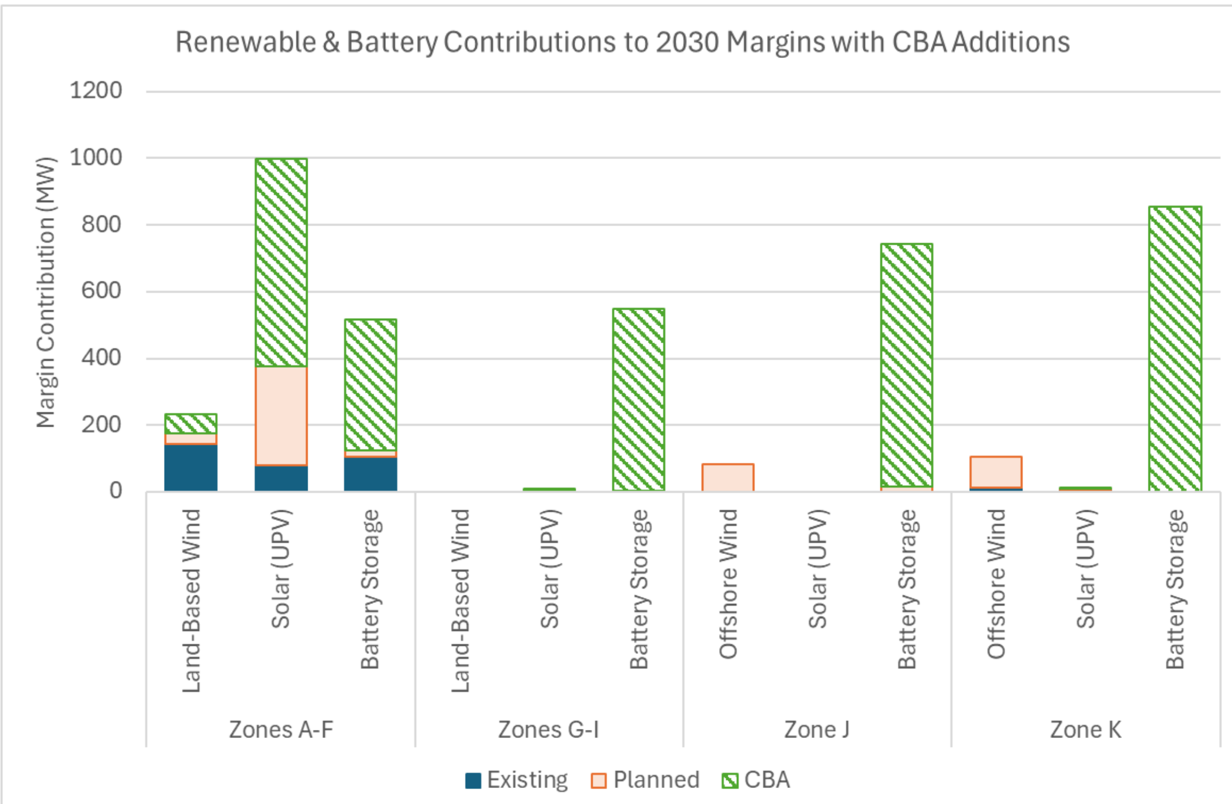
Narrowing statewide reliability margins as well as deficient transmission security margins are observed in this assessment. The future planned resources only include a subset of the total resources in the NYISO's interconnection queue. The narrowing reliability margins could be positively impacted by 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 38 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 38: Additional Resources from CBA Case

Additional Resources	Land-Based Wind	Off-Shore Wind	Solar	Energy Storage
A-F	1,158	0	4,143	392
G-I	0	0	40	546
J	0	0	0	728
K	0	0	36	854
NYCA	1,158	0	4,219	2,519

Figure 39: Breakdown of Renewable and Battery Generation by Location and Status



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 assessment looks at the impact if the 517 MW plants are either retained or replaced by functionally equivalent generation.

Many of the uncertainties highlighted in earlier sections pose significant reliability risks. Figure

40 shows how new resource entry and retaining existing generation can help offset those risks statewide as well as in each of the localities (Figure 41 and Figure 42). With the CBA resources included in the margin evaluations, each locality remains positive throughout the planning horizon. However, the statewide system margin continues to show the potential for system risks in the early 2030s.

Figure 40: Statewide System Margin Impact of Additional Resources

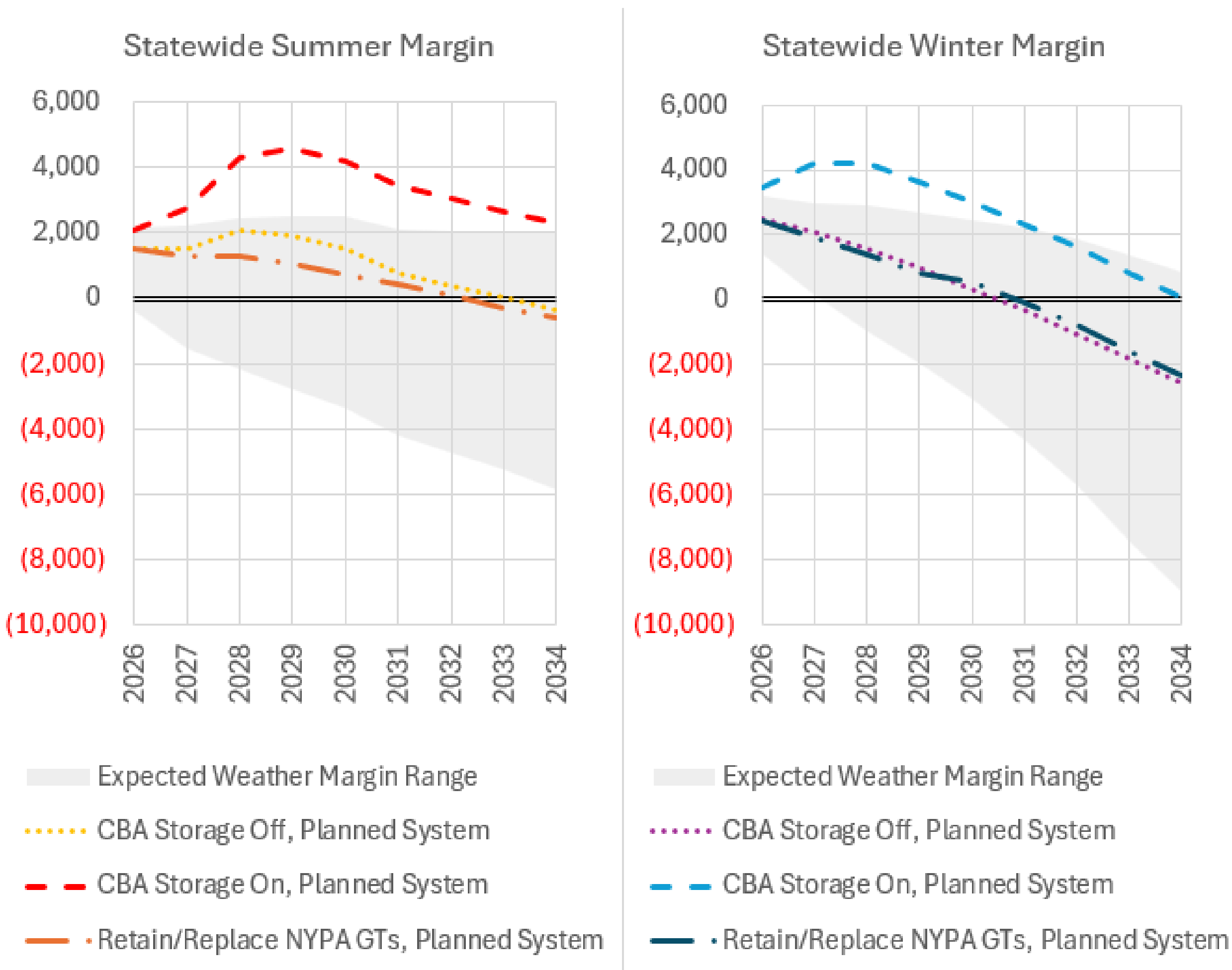


Figure 41: New York City Transmission Security Margin with Impact of Additional Resources

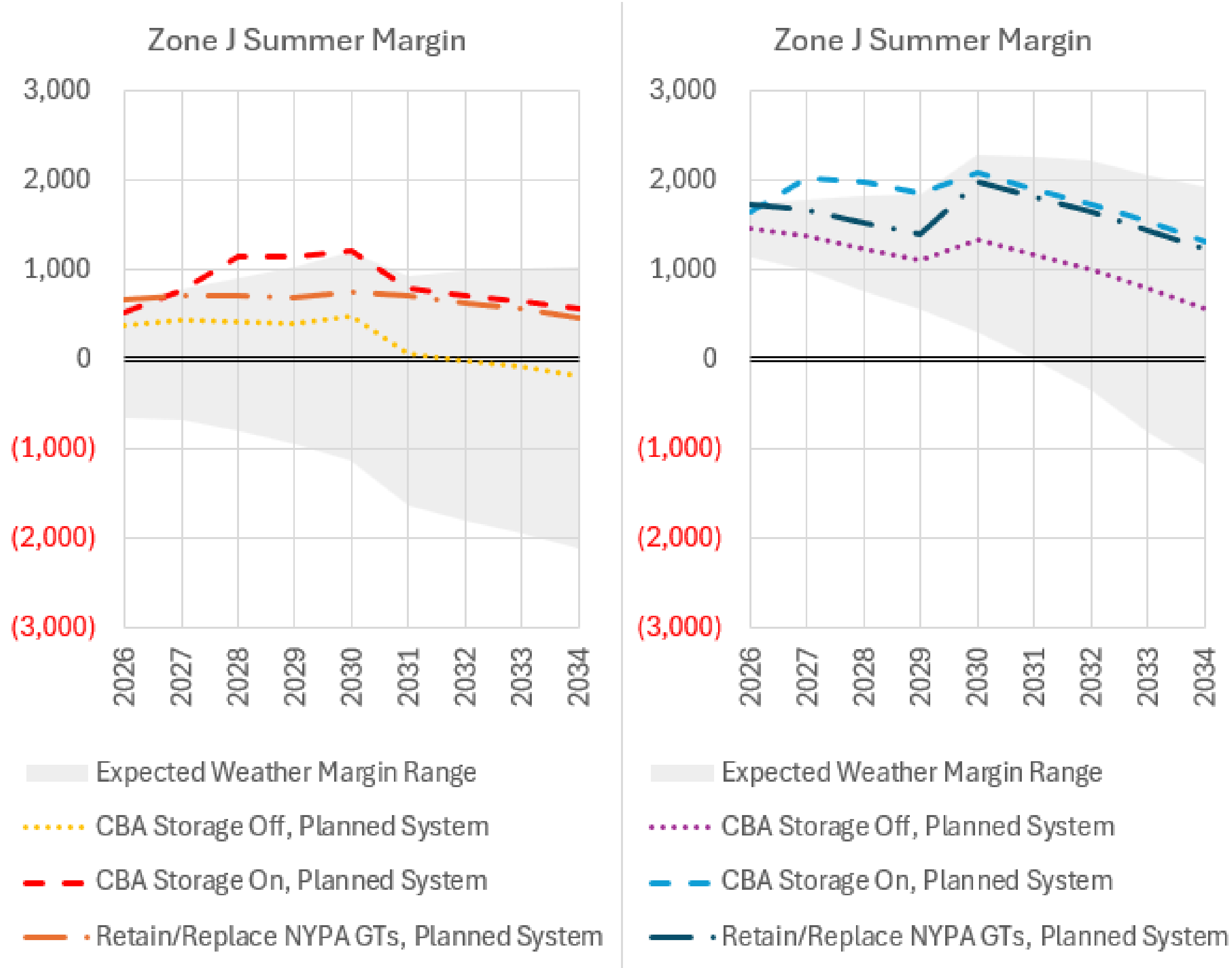
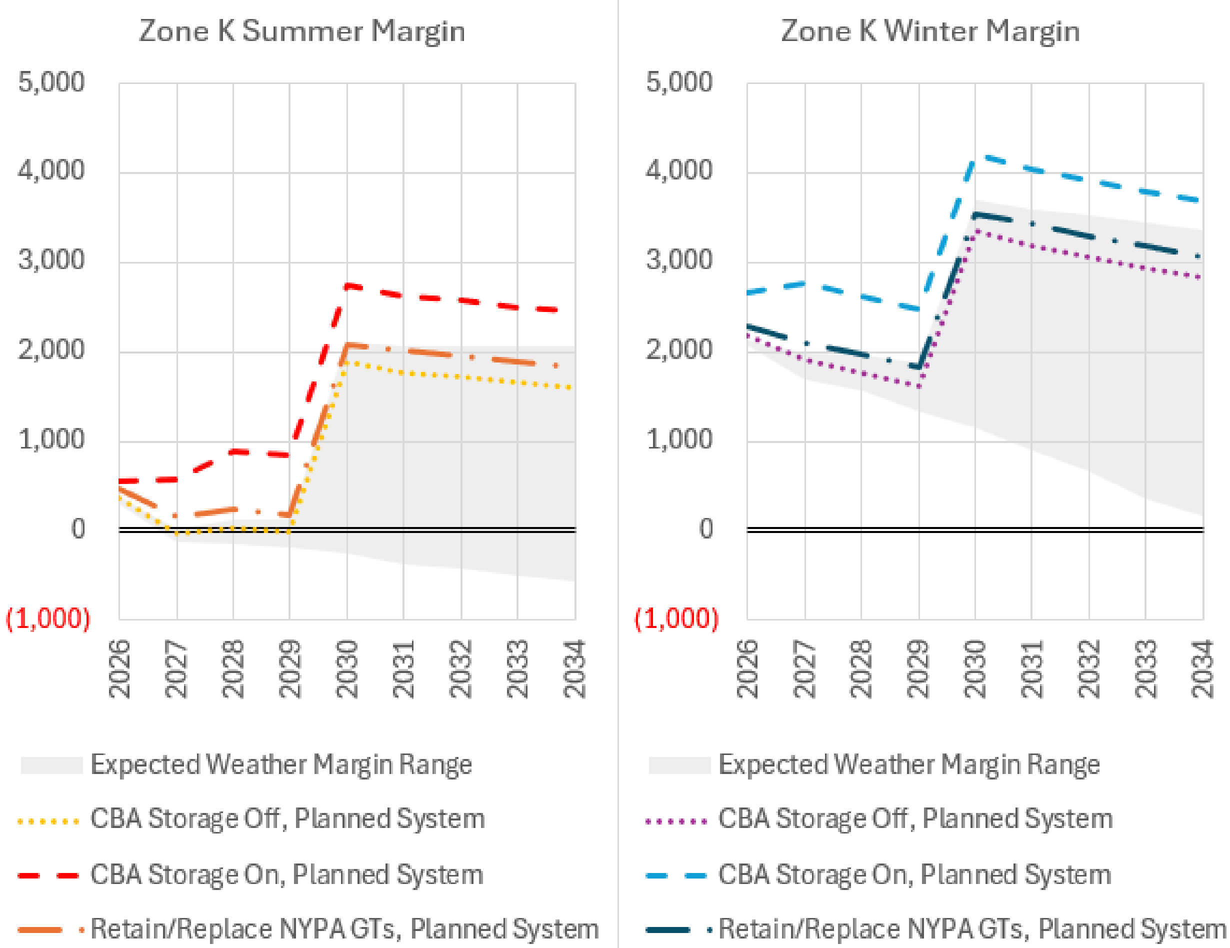


Figure 42: Long Island Transmission Security Margin with Impact of Additional Resources



Conclusions

This STAR continues to find, as observed in prior STAR reports, that the New York City locality would be deficient following the deactivation of the Gowanus 2 & 3 and Narrows 1 & 2 generators through the entire five-year horizon without the completion and energization of planned projects. Until the CHPE, Empire Wind and Propel NY projects enter service and demonstrate their planned power capabilities, the Zone J BPTF is projected to be deficient by 410-650 MW over 6-8 hours (1,709-3,569 MWh) during summer peak conditions in 2026, which could grow to as high as 500-1,130 MW over 8-13 hours (3,211-10,922 MWh) in 2030. Similarly, the local need previously identified by Con Edison persists until the fourth Gowanus-Greenwood 345/138 kV PAR controlled feeder enters service, currently scheduled for summer 2026.

This STAR also finds that the Long Island locality is deficient beginning in summer 2027 and continuing through the remaining five-year horizon, primarily driven by the deactivation of Pinelawn (82 MW nameplate) and the Far Rockaway GTs (121 MW nameplate). Specifically, Zone K BPTF is projected to be deficient by 39-116 MW over 1-3 hours (39-176 MWh) in 2027. The deficiency would grow to 175-254 MW over 3-4 hours (515-819 MWh) in 2030.

In addition to the BTPF transmission security margin deficiency, PSEG-LI also identified non-BPTF system deficiencies on the 69 kV system through the entire five-year horizon for the Far Rockaway load pocket. These deficiencies in the Far Rockaway load pocket show a 61 MW deficiency over 13 hours (505 MWh) in 2026, and grow to 80 MW over 15 hours (813 MWh) in 2029. The Far Rockaway load pocket is also 72 MW deficient over 14 hours (649 MWh) in 2030 with the improvement from 2029 primarily due to the inclusion of the Propel NY Project.

As the New York City and Long Island needs are observed within the first three years of the short-term horizon and resolved in whole or part by Gowanus 2 & 3 and Narrows 1 & 2 or Pinelawn and Far Rockaway GTs, these needs are Near-Term Reliability Needs and also Generator Deactivation Reliability Needs. All needs observed in this STAR will be addressed through the Short-Term Reliability Process, as the needs observed in 2030 cannot be timely addressed through the NYISO's Reliability Planning Process.

As this STAR finds generator deactivation reliability needs that all the initiating generators located in New York City and on Long Island could help resolve, in whole or in part, they may not deactivate prior to the expiration of the 365-day notice period (*i.e.,* before July 15, 2026).[27] The Far Rockaway GTs and the Pinelawn Generator will be Interim Service Providers that are compensated under an Interim Service Provider rate commencing December 25, 2025 and concluding at the end of the 365-day Generator Deactivation Notice Period.

Next Steps

The Short-Term Reliability Process Needs observed are Near-Term Reliability Needs and Generator Deactivation Reliability Needs. As a result, solutions will be solicited, evaluated, and addressed in accordance with the NYISO Short-Term Reliability Process. The needs may be addressed with generation solutions, demand-side solutions, and/or transmission solutions. The New York City/Lower Hudson Valley need arises within the Con Edison Transmission District; therefore, Con Edison is the Responsible Transmission Owner for developing a regulated solution. The Long Island need arises within the LIPA Transmission District; therefore, LIPA is the Responsible Transmission Owner for developing a regulated solution.

Following the 60-day solicitation for solutions, the NYISO will evaluate the proposed solutions and issue a Short-Term Reliability Process Report, which shall indicate NYISO's selection of a solution or combination of solutions, along with a reasoned explanation regarding why particular generation and/or transmission solutions were selected. If proposed solutions are not viable or sufficient to meet the identified reliability needs, interim solutions must be in place to keep the grid reliable. This solution selection process is designed to ensure that executing a Reliability Must Run (RMR) Agreement with generators is a last resort to addressing a reliability need.

The wholesale electricity markets administered by the NYISO are an important tool to help mitigate reliability risks. The markets are designed, and continue to evolve and adapt, to send appropriate price signals for new market entry and the retention of resources that assist in maintaining reliability. The potential risks and resource needs identified in the NYISO's analyses may be resolved by new capacity resources coming into service, construction of additional

[27] Consistent with Section 38.3.7 of the OATT, the earliest possible retirement date for Alpha Generator Services, LLC generators (Gowanus 2 & 3 and Narrows 1 & 2 generators) and Hull Street Energy, LLC generators (Pinelawn Power 1 and the Far Rockaway GTs) is July 15, 2026. Alpha Generator Services, LLC and Hull Street Energy, LLC must complete all required NYISO administrative process and procedures prior to retirement of their generating units. See NYISO Technical Bulletin 185. The NYISO's determination in this Short-Term Reliability Process does not relieve Alpha Generator Services, LLC or Hull Street Energy, LLC of any obligations they have with respect to their Generators participation in the NYISO markets. If Alpha Generator Services, LLC or Hull Street Energy, LLC rescinds their Generator Deactivation Notices or do not retire their units within 730 days of July 15, 2025, then they will be required to submit a new Generator Deactivation Notice in order to deactivate the affected Generator(s) and will be required to repay study cost in accordance with Section 38.14 of the OATT.

transmission facilities, and/or increased energy efficiency and integration of demand-side resources. The NYISO is tracking the progression of many projects that may contribute to grid reliability that have not yet met the inclusion rules for reliability assessments. The NYISO will continue to monitor these resources and other developments to determine whether changing system resources and conditions could impact the reliability of the New York bulk electric grid. Specifically, through the quarterly STAR reports, the NYISO will continue to reassess if the identified reliability needs persist as planned projects are energized and demonstrate their capabilities.

Appendix A: List of Short-Term Reliability Needs

New York City Generator Deactivation Reliability Needs

Listed below are the Generator Deactivation Reliability Needs in the New York City locality in this STAR. The needs observed through summer 2029 are also Near-Term Reliability Needs.

BPTF Deficiencies:

Summer Peak	**2026**	**2027**	**2028**	**2029**	**2030**
MW Deficiency	410-650	440-680	460-790	480-950	500-1,130
Duration (hours)	6-8	6-9	8-11	8-13	8-13
MWh	1,709-3,569	1,753-3,782	3,014-6,658	3,227-8,794	3,211-10,922

Additionally, the Lower Hudson Valley locality (Zones G-J) would be deficient by 260 MW over three hours (924 MWh) in 2030 without the completion and energization of future planned projects. This deficiency is further exacerbated through time without any additional capabilities added within the Lower Hudson Valley locality, which includes New York City.

Local Transmission System Needs

As of this STAR, Con Edison is on track to establish the 4th Gowanus-Greenwood 345/138 kV PAR controlled feeder by summer 2026. However, if the 4th connection is not established by summer 2026, Con Edison has noted that it would require the continued operation of the Gowanus 2 & 3 and Narrows 1 & 2 generators.

Long Island Generator Deactivation Reliability Needs

Listed below are the Generator Deactivation Reliability Needs in the Long Island locality in this STAR. The needs observed through summer 2029 are also Near-Term Reliability Needs.

BPTF Deficiencies:

Summer Peak	2026	2027	2028	2029	2030
MW Deficiency	None	39-116	61-138	107-185	175-254
Duration	None	1-3	3	3	3-4
MWh	None	39-176	213-444	320-554	515-819

Non-BPTF Deficiencies (Far Rockaway Load Pocket)

Summer Peak	2026	2027	2028	2029	2030
MW Deficiency	61	68	74	80	72
Duration	13	14	15	15	14
MWh	505	658	736	813	649

Appendix B: Short-Term Reliability Process Solution List

The Short-Term Reliability Process solution list and the status of these solutions is posted on the NYISO website at the following location:

https://www.nyiso.com/documents/20142/19556596/SolutionStatus-03092021.pdf/

Appendix C: Summary of Study Assumptions

This assessment used the major assumptions included in the 2024 RNA, with the key updates noted below. Consistent with the NYISO's obligations under its tariffs, the NYISO provided information to stakeholders on the modeling assumptions employed in this assessment. Details regarding the 2024 RNA study assumptions were reviewed with stakeholders at the April 18, 2024, joint Electric System Planning Working Group ("ESPWG")/Transmission Planning Advisory Subcommittee ("TPAS") meeting. Details regarding the 2025 Q3 STAR study assumptions were reviewed with stakeholders at the July 23, 2025, joint ESPWG/ TPAS meeting. The meeting materials are posted on the NYISO's website.[28] The figures below (Figure 43, Figure 44, Figure 45, and Figure 46) summarize the changes to generation, load, and transmission.

Generation Assumptions

[28] Short-Term Assessment of Reliability: 2025 Q3 Key Study Assumptions, ESPWG/TPAS, July 23, 2025 (https://www.nyiso.com/documents/20142/52668370/05_2025%20Q3%20STAR%20Key%20Study%20Assumptions_final.pdf/938f771c-d9ae-b673-e075-52851cdb608c). 2024 RNA Key Study Assumptions, ESPWG/TPAS, April 18, 2024 (here),

Figure 43: Completed Generator Deactivations

Owner/ Operator	Plant Name	Zone	Nameplate	CRIS (MW)		Capability (MW)		Status	Deactivation Date (2)	STAR Evaluation (3)
			(MW)	Summer	Winter	Summer	Winter			
International Paper Company	Ticonderoga (1)	F	9.0	7.6	7.5	9.5	9.8	I	5/1/2017	-
Helix Ravenswood, LLC	Ravenswood 2-4	J	42.9	39.8	50.6	30.7	41.6	I	4/1/2018	-
	Ravenswood 3-1	J	42.9	40.5	51.5	31.9	40.8	I	4/1/2018	-
	Ravenswood 3-2	J	42.9	38.1	48.5	29.4	40.3	I	4/1/2018	-
	Ravenswood 3-4	J	42.9	35.8	45.5	31.2	40.8	I	4/1/2018	-
Rockville Centre, Village of	Charles P Keller 07	K	2.0	2.0	2.0	1.9	1.9	R	3/1/2019	-
Exelon Generation Company LLC	Monroe Livingston	B	2.4	2.4	2.4	2.4	2.4	R	9/1/2019	-
Innovative Energy Systems, Inc.	Steuben County LF	C	3.2	3.2	3.2	3.2	3.2	R	9/1/2019	-
Consolidated Edison Co. of NY, Inc	Hudson Ave 4	J	16.3	13.9	18.2	14.0	16.3	R	9/10/2019	-
New York State Elec. & Gas Corp.	Auburn - State St	C	7.4	5.8	6.2	4.1	7.3	R	10/1/2019	-
Somerset Operating Company, LLC	Somerset	A	655.1	686.5	686.5	676.4	684.4	R	3/12/2020	-
Entergy Nuclear Power Marketing, LLC	Indian Point 2	H	1,299.0	1,026.5	1,026.5	1,011.5	1,029.4	R	4/30/2020	-
Cayuga Operating Company, LLC	Cayuga 1	C	155.3	154.1	154.1	151.0	152.0	R	6/4/2020	-
Entergy Nuclear Power Marketing, LLC	Indian Point 3	H	1,012.0	1,040.4	1,040.4	1,036.3	1,038.3	R	4/30/2021	-
Helix Ravenswood, LLC	Ravenswood GT 11	J	25.0	20.2	25.7	16.1	22.4	I	12/1/2021	2022 Q1
Helix Ravenswood, LLC	Ravenswood GT 1	J	18.6	8.8	11.5	7.7	11.1	I	1/1/2022	2022 Q1
Freeport Electric	Freeport 1-4	K	6.0	4.4	4.4	4.5	5.0	R	5/1/2022	-
Exelon Generation Company LLC	Madison County LF	E	1.6	1.6	1.6	1.6	1.6	I	4/1/2022	2022 Q2
Nassau Energy, LLC	Trigen CC	K	55.0	51.6	60.1	38.5	51.0	R	7/15/2022	2022 Q2
Consolidated Edison Co. of NY, Inc.	Hudson Ave 3	J	16.3	16.0	20.9	12.3	15.6	R	11/1/2022	2022 Q2
Consolidated Edison Co. of NY, Inc.	Hudson Ave 5	J	16.3	15.1	19.7	15.3	18.6	R	11/1/2022	2022 Q2
Astoria Generating Company, L.P.	Gowanus 1-1 through 1-8	J	160.0	138.7	181.1	133.1	182.2	R	11/1/2022	2022 Q2
Astoria Generating Company, L.P.	Gowanus 4-1 through 4-8	J	160.0	140.1	182.9	138.8	183.4	R	11/1/2022	2022 Q2
NRG Power Marketing LLC	Astoria GT 2-1	J	46.5	41.2	50.7	34.9	46.5	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 2-2	J	46.5	42.4	52.2	34.3	45.6	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 2-3	J	46.5	41.2	50.7	36.3	46.7	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 2-4	J	46.5	41.0	50.5	32.5	45.4	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 3-1	J	46.5	41.2	50.7	34.6	45.0	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 3-2	J	46.5	43.5	53.5	35.7	45.3	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 3-3	J	46.5	43.0	52.9	33.9	44.6	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 3-4	J	46.5	43.0	52.9	34.9	45.5	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 4-1	J	46.5	42.6	52.4	33.6	43.8	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 4-2	J	46.5	41.4	51.0	34.3	44.3	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 4-3	J	46.5	41.1	50.6	35.4	46.4	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 4-4	J	46.5	42.8	52.7	35.2	44.1	R	5/1/2023	2022 Q2
Helix Ravenswood, LLC	Ravenswood 10	J	25.0	21.2	27.0	16.1	20.3	R	5/1/2023	2022 Q3
Helix Ravenswood, LLC	Ravenswood 01	J	18.6	8.8	11.5	7.7	11.1	R	10/14/2023	2023 Q3
Helix Ravenswood, LLC	Ravenswood 11	J	25.0	20.2	25.7	16.1	22.4	R	10/14/2023	2023 Q3
Astoria Generating Company, L.P.	Gowanus 3-6	J	20.0	17.6	23.0	16.4	20.4	I	7/14/2026	2025 Q3
Astoria Generating Company, L.P.	Narrows 2-1 and 2-7	J	44.0	40.1	52.3	37.9	48.8	I	7/14/2026	2025 Q3
Consolidated Edison Co. of NY, Inc.	59 St. GT 1 (4)	J	17.1	15.4	20.1	13.9	17.4	R	5/1/2025	-
Western New York Wind Corp	Western NY Wind Power	B	6.6	0.0	0.0	0.0	0.0	R	10/15/2023	2023 Q3
Central Hudson Gas & Electric Corp.	South Cairo GT	G	21.6	19.8	25.9	18.7	23.1	R	3/31/2024	2023 Q4
Cubit Power One Inc.	Arthur Kill Cogen	J	11.1	11.1	11.1	11.1	10.2	I	3/2/2024	2024 Q2
NRG Power Marketing, LLC	Arthur Kill GT 1 (4)	J	20	16.5	21.6	12.4	16.1	R	5/1/2025	-
Eastern Generation, LLC	Astoria GT 01	J	16	15.7	20.5	13.8	17.6	R	5/1/2025	2024 Q3
Madison Windpower, LLC	Madison Windpower	E	11.6	11.5	11.5	11.6	11.6	R	5/1/2025	2025 Q1
Astoria Generating Company, L.P.	Gowanus 3-6	J	20.0	17.6	23.0	16.4	20.4	I	7/14/2026	2025 Q3
Astoria Generating Company, L.P.	Narrows 2-1 and 2-7	J	44.0	40.1	52.3	37.9	48.8	I	7/14/2026	2025 Q3
Casella Waste Systems, Inc	Hyland LFGE	B	4.8	4.8	4.8	4.8	4.8	I	6/1/2025	2025 Q3
		Total	4,655.5	4,257.9	4,602.1	4,051.8	4,435.6			

Notes

(1) Part of SCR program

(2) This table only includes units that have entered into IIFO (I) or have completed the generator deactivation process (R).

(3) "-" denotes that the generator deactivation was assessed prior to the creation of the Short-Term Reliability Process

(4) Unit no longer subject to NYISO dispatch and is used for local reliability only.

Figure 44: Proposed Generator Deactivations

Owner/ Operator	Plant Name (1)	Zone	Nameplate (MW)	CRIS (MW)		Capability (MW)		Status	Deactivation date (2)	STAR Evaluation
				Summer	Winter	Summer	Winter			
Consolidated Edison Co. of NY, Inc.	74 St. GT 1 & 2	J	37	39.1	49.2	0.0	0.0	R	5/1/2023	2022 Q2
Central Hudson Gas & Electric Corp.	Coxsackie GT	G	21.6	21.6	26.0	19.7	22.7	R	12/31/2025 (3)	2024 Q1
National Grid	Shoreham 2	K	18.6	18.5	23.5	17.4	21.5	R	5/1/2025 (4)	2025 Q1
MPH Cross Island Power, LLC	Pinelawn Power 1	K	82	78.0	78.0	73.6	76.5	R	11/1/2025	2025 Q3
MPH Rockaway Peakers, LLC	Far Rockaway GT1	K	60.5	53.5	73.1	48.9	52.6	R	11/1/2025	2025 Q3
MPH Rockaway Peakers, LLC	Far Rockaway GT2	K	60.5	55.4	75.7	55.7	59.0	R	11/1/2025	2025 Q3
Astoria Generating Company, L.P.	Gowanus 2-1 through 2-8	J	160	152.8	199.6	142.2	182.5	R	7/14/2026	2025 Q3
Astoria Generating Company, L.P.	Gowanus 3-1 through 3-8 (5)	J	140	129.2	168.7	123.8	159.7	R	7/14/2026	2025 Q3
Astoria Generating Company, L.P.	Narrows 1-1 through 2-8 (6)	J	308	269.0	351.3	250.4	323.7	R	7/14/2026	2025 Q3
		Total	888.2	817.1	1045.1	731.7	898.2			

Notes:

(1) This table includes units that have proposed to Retire or enter Mothball Outage and have a completed generator deactivation notice but have yet to complete the generator deactivation process.

(2) Date in which the generator proposed Retire (R) or enter Mothball Outage (MO)

(3) In March 2024, Central Hudson submitted an update to its DEC peaker compliance plan to extend the retirement date of Coxsackie GT until December 31, 2025 until a permanent transmission and distrubition solution to local non-BPTF transmission security issues is completed. At the April 7, 2025 TPAS/ESPWG, Central Hudson presented an LTP update including a delay of the retirement of the Coxsakie GT until May 2026.

(4) The initial proposed retirement was on or after May 1, 2023, and was studied in the 2022 Q4 STAR. However, the unit modified its Peaker Rule compliance plan to be available for operation through May 1, 2025. The unit has submitted a new generator deactivation notice with a new proposed retirement date by May 1, 2025.

(5) Does not include Gowanus GT 3-6.

(6) Does not include Narrows GT 2-1 and 2-7.

Figure 45: Large Generation Additions

Proposed Project Inclusion: Large Generation						
Queue	**Project Name**	**MW**	**Type**	**Zone**	**Proposed Date**	**Included in Prior STAR**
396	Baron Winds Phase II	117	W	C	Dec-25	**No**
571	Heritage Wind, LLC	200.1	W	B	Sep-26	**No**
596	Alle Catt II Wind	339.1	W	A	Dec-26	**No**
704	Bear Ridge Solar	100	S	A	Apr-27	**No**
720	Trelinia Solar Energy Center	80	S	C	Apr-28	**No**
721	Excelsior Energy Center	280	S	A	Nov-26	**No**
737	Empire Wind 1	816	W	J	**Jul-27**	Yes
811	Hecate Energy Cider Solar LLC	500	S	B	Dec-26	**No**
880	Brookside Solar	100	S	D	May-28	**No**
883	Garnet Energy Center, LLC	200	S	B	Apr-28	**No**
950	Hemlock Ridge Solar	200	S	B	May-27	**No**
1079	Somerset Solar	125	S	A	Mar-27	**No**
766/987	Sunrise Wind LLC	924	W	K	**Jul-27**	Yes

Figure 46: Small Generation Additions

Proposed Project Inclusion: Small Generation						
Queue	**Project Name**	**MW**	**Type**	**Zone**	**Proposed Date**	**Included in Prior STAR**
545	Sky High Solar	20	S	C	Jun-25	Yes
564	Rock District Solar	20	S	F	Feb-27	Yes
572	Greene County 1	20	S	G	May-25	Yes
573	Greene County 2	10	S	G	May-25	Yes
581	Hills Solar	20	S	E	Dec-26	Yes
584	Dog Corners Solar	20	S	C	Apr-26	Yes
586	Watkins Rd Solar	20	S	E	Jul-26	Yes
590	Scipio Solar	18	S	C	Dec-26	Yes
591	Highview Solar	20	S	C	Feb-25	Yes
592	Niagara Solar	20	S	A	Dec-26	Yes
734	Ticonderoga Solar	20	S	F	Dec-26	Yes
804	KCE NY 10	20	ES	A	Oct-26	Yes
827	Arthur Kill Energy Storage 1	15	ES	J	Sep-25	**No**
828	Valley Solar	20	S	C	Nov-24	Yes
832	CS Hawthorn Solar	20	S	F	Dec-26	Yes
833	Dolan Solar	20	S	F	Dec-26	Yes
848	Fairway Solar	20	S	E	Mar-25	Yes
855	NY13 Solar	20	S	F	Jun-25	Yes
865	Flat Hill Solar	20	S	E	Dec-25	Yes
885	Grassy Knoll Solar	20	S	E	Dec-25	Yes
1003	Clear View Solar	20	S	C	Dec-25	Yes
1015	Somers Solar, LLC	20	S	F	Dec-26	**No**
1047	Millers Grove Solar	20	S	E	Dec-26	**No**

*All projects have CRIS.

Demand Assumptions

The 2025 Quarter 3 STAR uses the demand forecasts for the study years consistent with the 2025 Gold Book for expected weather conditions. Details on the demand forecasts utilized for determining reliability needs from the 2025 Gold Book are provided below.

Figure 47: Summer Coincident Peak Demand Forecasts

Summer Coincident Peak Demand Forecast (MW)													
Year		A	B	C	D	E	F	G	H	I	J	K	NYCA
2026	Low Demand	2,840	1,842	2,559	839	1,287	2,240	2,262	615	1,316	10,570	4,980	31,350
	Baseline	2,943	1,854	2,568	1,042	1,298	2,255	2,304	620	1,320	10,790	4,996	31,990
	High Demand	3,120	1,995	2,633	1,045	1,308	2,274	2,307	625	1,324	10,920	5,039	32,590
2027	Low Demand	2,820	1,837	2,613	934	1,271	2,243	2,261	613	1,317	10,470	4,961	31,340
	Baseline	2,936	1,846	2,639	1,171	1,293	2,275	2,331	625	1,327	10,820	5,017	32,280
	High Demand	3,214	2,124	2,831	1,287	1,305	2,299	2,339	627	1,333	11,040	5,051	33,450
2028	Low Demand	2,802	1,827	2,716	931	1,256	2,206	2,258	610	1,318	10,340	4,946	31,210
	Baseline	2,925	1,834	2,737	1,173	1,293	2,265	2,344	625	1,336	10,840	5,038	32,410
	High Demand	3,423	2,135	3,034	1,297	1,312	2,284	2,366	628	1,343	11,170	5,068	34,060
2029	Low Demand	2,785	1,816	2,846	928	1,246	2,195	2,254	606	1,319	10,230	4,935	31,160
	Baseline	2,920	1,826	2,876	1,179	1,296	2,264	2,346	627	1,343	10,860	5,083	32,620
	High Demand	3,567	2,137	3,256	1,297	1,316	2,305	2,372	631	1,352	11,330	5,107	34,670
2030	Low Demand	2,768	1,804	2,966	927	1,238	2,186	2,250	603	1,320	10,150	4,928	31,140
	Baseline	2,917	1,821	3,062	1,180	1,307	2,267	2,347	627	1,351	10,880	5,151	32,910
	High Demand	3,596	2,140	3,469	1,298	1,332	2,329	2,387	632	1,360	11,510	5,187	35,240

Figure 48: Winter Coincident Peak Demand Forecasts

Winter Coincident Peak Demand Forecast (MW)													
Year		A	B	C	D	E	F	G	H	I	J	K	NYCA
2026-27	Low Demand	2,208	1,503	2,555	1,055	1,309	1,900	1,599	519	933	7,300	3,229	24,110
	Baseline	2,323	1,525	2,583	1,249	1,333	1,917	1,662	525	947	7,580	3,276	24,920
	High Demand	2,530	1,744	2,656	1,253	1,339	1,934	1,668	529	951	7,740	3,296	25,640
2027-28	Low Demand	2,202	1,499	2,655	1,094	1,300	1,900	1,612	519	937	7,250	3,262	24,230
	Baseline	2,329	1,531	2,688	1,316	1,343	1,939	1,701	528	956	7,650	3,349	25,330
	High Demand	2,668	1,827	2,898	1,469	1,347	1,965	1,719	530	963	7,880	3,364	26,630
2028-29	Low Demand	2,201	1,496	2,763	1,095	1,298	1,875	1,631	519	941	7,220	3,291	24,330
	Baseline	2,346	1,537	2,812	1,321	1,351	1,961	1,738	533	973	7,800	3,478	25,850
	High Demand	2,962	1,843	3,182	1,477	1,363	1,997	1,787	538	994	8,110	3,507	27,760
2029-30	Low Demand	2,200	1,494	2,911	1,094	1,296	1,884	1,638	515	944	7,180	3,374	24,530
	Baseline	2,361	1,540	2,966	1,322	1,374	1,988	1,771	539	989	7,930	3,630	26,410
	High Demand	3,085	1,864	3,406	1,479	1,409	2,069	1,811	550	1,009	8,320	3,718	28,720
2030-31	Low Demand	2,205	1,497	3,123	1,092	1,295	1,894	1,656	517	946	7,120	3,425	24,770
	Baseline	2,386	1,556	3,189	1,324	1,398	2,020	1,814	546	1,007	8,070	3,770	27,080
	High Demand	3,156	1,913	3,679	1,485	1,469	2,158	1,886	568	1,041	8,560	3,925	29,840

Figure 49: Annual Energy Forecasts

Annual Energy Forecast (GWh)													
Year		A	B	C	D	E	F	G	H	I	J	K	NYCA
2026	Low Demand	15,430	9,150	14,710	6,890	7,010	10,980	9,260	2,770	5,810	48,160	19,890	150,060
	Baseline	16,170	9,280	14,790	8,310	7,190	11,240	9,640	2,790	5,910	50,100	20,040	155,460
	High Demand	17,240	10,040	15,260	8,350	7,240	11,350	9,790	2,820	5,940	51,010	20,270	159,310
2027	Low Demand	15,330	8,970	15,040	7,640	6,850	10,910	9,300	2,770	5,830	47,170	19,700	149,510
	Baseline	16,160	9,150	15,200	9,280	7,130	11,410	9,830	2,800	5,950	50,260	20,050	157,220
	High Demand	18,350	10,970	16,550	10,080	7,150	11,420	10,000	2,840	5,990	51,790	20,400	165,540
2028	Low Demand	15,240	8,850	15,640	7,630	6,780	10,820	9,370	2,770	5,870	46,830	19,630	149,430
	Baseline	16,150	9,080	15,860	9,300	7,150	11,380	10,000	2,810	6,030	50,530	20,410	158,700
	High Demand	19,780	11,300	18,110	10,490	7,210	11,520	10,210	2,870	6,080	52,520	20,850	170,940
2029	Low Demand	15,110	8,730	16,450	7,590	6,700	10,720	9,330	2,770	5,890	46,270	19,790	149,350
	Baseline	16,120	9,000	16,750	9,270	7,160	11,360	10,060	2,820	6,080	50,730	21,020	160,370
	High Demand	21,220	11,330	20,020	10,520	7,420	11,710	10,320	2,890	6,160	53,250	21,570	176,410
2030	Low Demand	15,050	8,650	17,750	7,560	6,660	10,690	9,340	2,770	5,930	46,140	20,090	150,630
	Baseline	16,150	8,980	18,140	9,260	7,250	11,410	10,150	2,840	6,150	51,110	21,760	163,200
	High Demand	21,910	11,490	22,060	10,580	7,740	12,040	10,590	2,930	6,260	54,120	22,470	182,190

Figure 50: Summer Non-Coincident Peak Demand Forecast

Baseline Summer Non-Coincident Peak Demand Forecast (MW)					
Zone	2026	2027	2028	2029	2030
G-J	15,280	15,349	15,392	15,423	15,452
J	11,030	11,060	11,080	11,100	11,120
K	5,072	5,094	5,115	5,161	5,230

Figure 51: Winter Non-Coincident Peak Demand Forecast

Baseline Winter Non-Coincident Peak Demand Forecast (MW)					
Zone	2026-27	2027-28	2028-29	2029-30	2030-31
G-J	10,748	10,870	11,080	11,266	11,474
J	7,630	7,700	7,850	7,990	8,130
K	3,289	3,362	3,492	3,645	3,785

Figure 52: Large Load Demand Forecast

Large Loads Summer Peak Forecasts (MW)

Zone	A	B	C	D	E	F	G	K	NYCA Total	Flexible Total
2025	250	5	0	166	13	0	32	0	466	416
2026	335	11	72	518	15	0	72	0	1,023	685
2027	335	11	168	647	30	40	93	5	1,329	685
2028	335	11	288	647	41	40	104	34	1,500	685
2029	335	11	442	651	54	40	107	78	1,718	685
2030	335	11	653	651	70	40	110	135	2,005	685

Large Loads Winter Peak Forecasts (MW)

Zone	A	B	C	D	E	F	G	K	NYCA Total	Flexible Total
2024-25	250	5	0	177	14	0	32	0	478	416
2025-26	335	11	72	582	23	0	72	0	1,095	685
2026-27	335	11	168	647	36	40	93	17	1,347	685
2027-28	335	11	288	651	48	40	104	90	1,567	685
2028-29	335	11	442	651	62	40	107	174	1,822	685
2029-30	335	11	653	651	70	40	110	236	2,106	685

Note: These projections are included in the baseline zonal forecasts, and should not be added as additional load.

Transmission Assumptions

The study assumptions for existing transmission facilities that are modeled as out-of-service are listed in Figure 53. Figure 54 shows the Con Edison series reactor status utilized in this STAR. There is one change in Con Edison series reactor assumptions in this STAR compared to the 2024 RNA. Figure 55 and Figure 56 provide a summary of the transmission projects included in the 2024 RNA as listed in the 2025 Gold Book.

Figure 53: Existing Transmission Facilities Modeled Out-of-Service

From	To	kV	ID	Out-of-Service Through	
				Prior STAR	Current STAR
Marion	Farragut	345	B3402	Long-Term	
Marion	Farragut	345	C3403	Long-Term	
Plattsburgh (1)	Plattsburgh	230/115	AT1	9/2025	9/2026
Stolle Rd	Stolle Rd	115	T11-52	6/2025	Dec-25
Station 23	Station 42	115	920	12/2025	
Farragut		345	8E	11/2025	In-service
Farragut		345	9E	11/2025	In-service

Notes
(1) A spare transformer is placed in-service during the outage

Figure 54: Con Edison Proposed Series Reactor Status

Terminals		ID	kV	Summer	Winter
Dunwoodie	Mott Haven	71	345	In-Service	By-Passed
Dunwoodie	Mott Haven	72	345	In-Service	By-Passed
Sprainbrook	W. 49th Street	M51	345	In-Service	By-Passed
Sprainbrook	W. 49th Street	M52	345	In-Service	By-Passed
Farragut	Gowanus	41	345	By-Passed	In-Service
Farragut	Gowanus	42	345	By-Passed	In-Service
Sprainbrook	Uninondale Hub	Y49	345	By-Passed	By-Passed

Figure 55: Major Transmission Projects Included in 2024 RNA

Queue	Project Name	MW	POI	Zone	Proposed Date
631/887	TDI Champlain Hudson Power Express (CHPE)	1250	Astoria Annex 345kV	J	May-26
1125	Northern New York Priority Transmission Project (NNYPTP)	N/A	Moses/Adirondack/Porter path	D&E	Dec-25
1289/1667	Propel NY Energy - Alternate Sol 5	N/A	Sprain Brook, Tremont, East Garden City, Shore Road, additional Long Island Substations	I,J,K	May-30
-	Brooklyn Clean Energy Hub	N/A	Between Farragut 345 kV and Rainey 345 kV	J	Jun-28
-	Gowanus/Greenwood PAR Regulated Feeder	N/A	Gowanus 345 kV/Greenwood 138 kV TLA	J	May-25
-	Goethals/Foxhills PAR Regulated Feeder	N/A	Goethals 345 kV/Greenwood 138 kV TLA	J	May-25
-	Eastern Queens Clean Energy Hub	N/A	Between Jamaica 138 kV and Valley Stream/Lake Success 138 kV	J	Jun-28
-	Gowanus/Greenwood PAR Regulated Feeder	N/A	Gowanus 345 kV/Greenwood 138 kV TLA	J	May-26

Figure 56: Transmission Project Inclusion Rules Application for 2024 RNA

Transmission Project Inclusion Rules Application: Class Year Transmission, TIP, and Firm LTP Projects Not Included in the 2025 RPP Base Cases											
Transmission Owner	Terminals		Line Length (Miles)	Proposed In-Service Date		Nominal Voltage (kV)		# of CKTs	Thermal Ratings		Project Description / Conductor Size
				Prior to	Year	Operating	Design		Summer	Winter	
NYSEG	New Gardenville	New Gardenville	xfmr	W	2030	115/34.5	115/34.5	1	50	60	NYSEG Transformer #7 and Station Reconfiguration
NYSEG	New Gardenville	New Gardenville	xfmr	W	2030	115/34.5	115/34.5	2	50	60	NYSEG Transformer #8 and Station Reconfiguration
NYSEG	New Gardenville	New Gardenville	xfmr	W	2030	230/115	230/115	1	316 MVA	370 MVA	NYSEG Transformer #6 and Station Reconfiguration
Clean Path New York LLC	Fraser 345kV	Rainey 345kV	HVDC	S	2028	492	492	1	1300 MW	1300 MW	-/+ 400kV Bipolar HVDC cable

Appendix D: Resource Adequacy Assumptions

2025 Q3 STAR MARS Assumptions Matrix

	Parameter	2024 RNA Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q3 STAR Key Assumptions (2025 GB)
Load Parameters			
1	**Peak** Load Forecast	Adjusted 2024 Gold Book NYCA baseline peak load forecast. It includes large loads from the NYISO interconnection queue, with forecasted impacts. Baseline load represents coincident summer peak demand and includes the reductions due to projected energy efficiency programs, building codes and standards, BtM storage impacts at peak, distributed energy resources and BtM solar photovoltaic resources; it also reflects expected impacts (increases) from projected electric vehicle usage and electrification. The 2024 GB baseline peak load forecast includes the impact (reduction) of behind-the-meter (BtM) solar at the time of NYCA peak. For the BtM Solar adjustment, gross load forecasts that include the impact of the BtM generation are used for the 2024 RNA, which then allows for a discrete modeling of the BtM solar resources using 5 years of inverter data.	Adjusted 2025 Gold Book NYCA baseline peak load forecast. It includes large loads from the NYISO interconnection queue, with forecasted impacts. Baseline load represents coincident summer peak demand and includes the reductions due to projected energy efficiency programs, building codes and standards, BtM storage impacts at peak, distributed energy resources and BtM solar photovoltaic resources; it also reflects expected impacts (increases) from projected electric vehicle usage and electrification. The 2025 GB baseline peak load forecast includes the impact (reduction) of behind-the-meter (BtM) solar at the time of NYCA peak. For the BtM Solar adjustment, gross load forecasts that include the impact of the BtM generation are used for the 2025 RPP, which then allows for a discrete modeling of the BtM solar resources using 5 years of inverter data.
1a	Proposed large loads	As included in the Baseline Peak Load Forecast from the Gold Book. Certain large loads that are assumed flexible (e.g., crypto, hydrogen) are modeled as EOP step.	As included in the Baseline Peak Load Forecast from the Gold Book. Certain large loads that are assumed flexible (e.g., crypto, hydrogen) are modeled as EOP step.
2	Load **Shapes** (Multiple Load Shapes)	Used Multiple Load Shape MARS Feature *(see March 24, 2022 LFTF/ESPWG).* 8,760-hour historical gross load shapes were used as base shapes for LFU bins: Load Bins 1 and 2: 2013 Load Bins 3 and 4: 2018 Load Bins 5 to 7: 2017 Historical load shapes are adjusted to meet zonal (as well as G-J) coincident and non-coincident peak forecasts (summer and winter), while maintaining the energy targets. For the BtM Solar discrete modeling, gross load forecasts that include the impact of the BtM generation are used (additional details under the BtM Solar category below).	Used Multiple Load Shape MARS Feature *(see March 24, 2022 LFTF/ESPWG).* 8,760-hour historical gross load shapes were used as base shapes for LFU bins: Load Bins 1 and 2: 2013 Load Bins 3 and 4: 2018 Load Bins 5 to 7: 2017 Historical load shapes are adjusted to meet zonal (as well as G-J) coincident and non-coincident peak forecasts (summer and winter), while maintaining the energy targets. For the BtM Solar discrete modeling, gross load forecasts that include the impact of the BtM generation are used (additional details under the BtM Solar category below).
3	Load Forecast Uncertainty (LFU) The LFU model captures the impacts of weather conditions on future loads.	Same summer LFU values as the ones presented in 2023 *(as presented at the May 26, 2023 LFTF [link] and also presented at the April 18, 2024 LFTF [link])* **New Additional Method for Winter:** **Winter Dynamic Load Forecast Uncertainty (LFU)**: In order to reflect uncertainty stemming from electrification, electric vehicles (EVs), and large loads, the 2024 RNA will use a winter LFU multipliers model. Over the study period year 2 through year 10, dynamic winter LFU multipliers	Same summer LFU values as the ones presented in 2023 *(as presented at the May 26, 2023 LFTF [link] and also presented at the April 18, 2024 LFTF [link])* **Starting 2024 RNA, winter Dynamic Load Forecast Uncertainty (LFU)**: In order to reflect uncertainty stemming from electrification, electric vehicles (EVs), and large loads, starting with the 2024 RNA used a winter LFU multipliers model. Over the study period year 2 through year 10, dynamic winter LFU multipliers were calculated, reflecting the

	Parameter	2024 RNA Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q3 STAR Key Assumptions (2025 GB)
		were calculated, reflecting the increasing share and load behavior of EV charging load, heating electrification, and large load projects. The dynamic winter LFU multipliers increase over the study horizon, reflecting the increasing winter weather sensitivity due to additional EV charging and electric heating load. Note: the first winter of the study period (winter 2024-25) match those calculated using recent winter load and weather data. Additional details are available in the April 18 TPAS/ESPWG/LFTF presentation [link]	increasing share and load behavior of EV charging load, heating electrification, and large load projects. The dynamic winter LFU multipliers increase over the study horizon, reflecting the increasing winter weather sensitivity due to additional EV charging and electric heating load. Note: the first winter of the study period (winter 2024-25) match those calculated using recent winter load and weather data. Additional details are available in the May 29 TPAS/ESPWG/LFTF presentation [link]
Generation Parameters			
1	**Existing** Generating Unit Capacities (*e.g., thermal units, large hydro)*	2024 Gold Book values: Summer is min of (DMNC, CRIS). Winter is min of (DMNC, CRIS). Adjusted for RNA inclusion rules application	2025 Gold Book values: Summer is min of (DMNC, CRIS). Winter is min of (DMNC, CRIS). Adjusted for RNA inclusion rules application
2	**Proposed New Units Inclusion** Determination	2024 Gold Book with RNA inclusion rules applied	2025 Gold Book with RNA inclusion rules applied
3	Retirement, Mothballed Units, IIFO	2024 Gold Book with RNA inclusion rules applied	2025 Gold Book with RNA inclusion rules applied
4	Forced and Partial Outage Rates (*e.g., thermal units)*	Five-year (2019-2023) GADS data for each unit represented. Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period. For new units or units that are in service for less than three years, NERC 5-year class average EFORd data are used.	Five-year (2020-2024) GADS data for each unit represented. Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period. For new units or units that are in service for less than three years, NERC 5-year class average EFORd data are used.
5	Modeling of Non-firm Gas Unavailability During Winter Peak Conditions	**New:** In order to simulate anticipated risks from cold snaps on the gas availability, gas plants available MWs in NYCA are further derated, *i.e.,* all gas-only units with non-firm gas within the NYCA are assumed unavailable**.** Also, certain dual-fuel units with duct-burn capability are derated. The forecasted winter coincident peak is used to determine when the gas derates are applied in the RNA and for each load bin and Study Year.	**Starting 2024 RNA:** In order to simulate anticipated risks from cold snaps on the gas availability, gas plants available MWs in NYCA are further derated, *i.e.,* all gas-only units with non-firm gas within the NYCA are assumed unavailable**.** Also, certain dual-fuel units with duct-burn capability are derated. The forecasted winter coincident peak is used to determine when the gas derates are applied in the RNA and for each load bin and Study Year.
6	Daily Maintenance	Fixed maintenance based on schedules received by the NYISO.	Fixed maintenance based on schedules received by the NYISO.
7	Weekly Planned Maintenance	MARS is automatically scheduling maintenance based on NYCA capacity and demand. Data: 5y (2019-2023) of historical scheduled maintenance data from Operations and GADS system to determine the number of weeks on maintenance for each thermal unit.	MARS is automatically scheduling maintenance based on NYCA capacity and demand. Data: 5y (2020-2024) of historical scheduled maintenance data from Operations and GADS system to determine the number of weeks on maintenance for each thermal unit.

	Parameter	2024 RNA Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q3 STAR Key Assumptions (2025 GB)
8	Summer Maintenance	None	None
9	Combustion Turbine Derates	Derate based on temperature correction curves. Thermal derates are based on a ratio of peak load before LFU is applied and LFU applied load. For new units: used data for a unit of same type in same zone, or neighboring zone data.	Derate based on temperature correction curves. Thermal derates are based on a ratio of peak load before LFU is applied and LFU applied load. For new units: used data for a unit of same type in same zone, or neighboring zone data.
10	Existing Landfill Gas (LFG) Plants	Actual hourly plant output over the last 5 years. Program randomly selects an LFG shape of hourly production over the last 5 years for each model replication. Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected in the Monte Carlo process.	Actual hourly plant output over the last 5 years. Program randomly selects an LFG shape of hourly production over the last 5 years for each model replication. Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected in the Monte Carlo process.
11	Existing and Proposed **Wind** Units	**New data source:** Model-based hourly data over the available past 5 years (2017-2021 developed by DNV-GL). For any unit that was included in the DNV data the data "as is" was used. For any unit not included a weighted zonal average was modeled. Probabilistic model is incorporated based on five years of input shapes with one shape per replication being randomly selected in Monte Carlo process.	**Starting 2024 RNA, new data source:** Model-based hourly data over the available past 5 years (2020-2024 developed by DNV-GL). For any unit that was included in the DNV data the data "as is" was used. For any unit not included a weighted zonal average was modeled. Probabilistic model is incorporated based on five years of input shapes with one shape per replication being randomly selected in Monte Carlo process.
12	Proposed **Offshore Wind** Units	RNA inclusion rules Applied to determine the generator status. **New data source:** 5 years of hourly model-based data as developed by DNV-GL (2017-2021)	RNA inclusion rules Applied to determine the generator status. 5 years of hourly model-based data as developed by DNV-GL (2020-2024)
13	Existing and Proposed **Utility-scale Solar Resources**	**New data source:** Probabilistic model chooses from the model-based data shapes covering past available 5 years (2017-2021), as developed by DNV-GL. One shape per replication is randomly selected in Monte Carlo process.	Probabilistic model chooses from the model-based data shapes covering past available 5 years (2020-2024), as developed by DNV-GL. One shape per replication is randomly selected in Monte Carlo process.
14	**BtM Solar Resources**	**Supply side:** Past five years (2017-2021) of 8,760 hourly MW profiles based on sampled inverter data. The MARS random shape mechanism randomly picks one 8,760 hourly shape (of five) for each replication year; similar with the past planning modeling and aligns with the method used for wind, utility solar, landfill gas, and run-of-river facilities. **Load side:** Gross load forecasts	**Supply side:** Past five years (2020-2024) of 8,760 hourly MW profiles based on sampled inverter data. The MARS random shape mechanism randomly picks one 8,760 hourly shape (of five) for each replication year; similar with the past planning modeling and aligns with the method used for wind, utility solar, landfill gas, and run-of-river facilities. **Load side:** Gross load forecasts
15	Existing **BTM-NG Program**	These units are former load modifiers that sell capacity into the ICAP market. Modeled as cogen type 1 (or type 2 as applicable) unit in MARS. Unit capacity set to CRIS value, load modeled with weekly pattern that can change monthly.	These units are former load modifiers that sell capacity into the ICAP market. Modeled as cogen type 1 (or type 2 as applicable) unit in MARS. Unit capacity set to CRIS value, load modeled with weekly pattern that can change monthly.

	Parameter	2024 RNA Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q3 STAR Key Assumptions (2025 GB)
16	Existing **Small Hydro** Resources (*e.g.*, run of river)	Actual hourly plant output over the past 5 years period. Program randomly selects a hydro shape of hourly production over the 5-year window for each model replication. The randomly selected shape is multiplied by their current nameplate rating.	Actual hourly plant output over the past 5 years period. Program randomly selects a hydro shape of hourly production over the 5-year window for each model replication. The randomly selected shape is multiplied by their current nameplate rating.
17	Existing **Large Hydro**	Probabilistic Model based on 5 years of GADS data. Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period. Methodology consistent with thermal unit transition rates.	Probabilistic Model based on 5 years of GADS data. Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period. Methodology consistent with thermal unit transition rates.
18	Proposed front-of-meter **Battery Storage**	GE MARS 'ES' model is used. Units are given a maximum capacity, maximum stored energy, and a dispatch window.	GE MARS 'ES' model is used. Units are given a maximum capacity, maximum stored energy, and a dispatch window.
19	Existing Energy Limited Resources (**ELRs)**	GE developed MARS functionality to be used for ELRs. Resource output is aligned with the NYISO's peak load window when most loss-of-load events are expected to occur.	GE developed MARS functionality to be used for ELRs. Resource output is aligned with the NYISO's peak load window when most loss-of-load events are expected to occur.
Transaction – Imports/ Exports			
1	Capacity Purchases	Grandfathered Rights and other awarded long-term rights Modeled using MARS explicit contracts feature.	Grandfathered Rights and other awarded long-term rights Modeled using MARS explicit contracts feature.
2	Capacity Sales	These are long-term contracts filed with FERC. Modeled using MARS explicit contracts feature. Contracts sold from ROS (Zones: A-F). ROS ties to external pool are derated by sales MW amount	These are long-term contracts filed with FERC. Modeled using MARS explicit contracts feature. Contracts sold from ROS (Zones: A-F). ROS ties to external pool are derated by sales MW amount
3	FCM Sales	Model sales for known years Modeled using MARS explicit contracts feature. Contracts sold from ROS (Zones: A-F). ROS ties to external pool are derated by sales MW amount	Model sales for known years Modeled using MARS explicit contracts feature. Contracts sold from ROS (Zones: A-F). ROS ties to external pool are derated by sales MW amount
4	UDRs	Updated with most recent elections/awards information (VFT, HTP, Neptune, CSC) Added CHPE HVDC (from Hydro Quebec into Zone J) at 1250 MW (summer only) starting 2026.	Updated with most recent elections/awards information (VFT, HTP, Neptune, CSC) Added CHPE HVDC (from Hydro Quebec into Zone J) at 1250 MW (summer only) starting 2026.
5	External Deliverability Rights (EDRs)	Cedars Uprate 80 MW. Modeled reflecting External CRIS rights.	Cedars Uprate 80 MW. Modeled reflecting External CRIS rights.
6	Wheel-Through Contract	300 MW HQ through NYISO to ISO-NE. Modeled as firm contract; reduced the transfer limit from HQ to NYISO by 300 MW and increased the transfer limit from NYISO to ISO-NE by 300 MW.	300 MW HQ through NYISO to ISO-NE. Modeled as firm contract; reduced the transfer limit from HQ to NYISO by 300 MW and increased the transfer limit from NYISO to ISO-NE by 300 MW.

<table>
<tr><th></th><th>Parameter</th><th>2024 RNA

Key Assumptions

(2024 Gold Book)</th><th>2025 RPP, 2025 Q3 STAR

Key Assumptions

(2025 GB)</th></tr>
<tr><td colspan="3">MARS Topology: a simplified bubble-and-pipe representation of the transmission system</td><td></td></tr>
<tr><td>1</td><td>Interface Limits</td><td>Developed by review of previous studies and specific analysis prior and during the RNA study process.</td><td>Developed by review of previous studies and specific analysis prior and during the RNA study process. Starting with the 2025 models, Chateaugay to NY limit set to zero for winter.</td></tr>
<tr><td>2</td><td>New Transmission</td><td>Based on TO-provided firm plans via Gold Book/LTP 2024 processes) and proposed merchant transmission and public policy facilities meeting the RNA inclusion rules.</td><td>Based on TO-provided firm plans (via Gold Book/LTP 2025 processes) and proposed merchant transmission and public policy facilities meeting the inclusion rules.</td></tr>
<tr><td>3</td><td>AC Cable Forced Outage Rates</td><td>All existing cable transition rates updated with data received from ConEd and PSEG-LIPA to reflect most recent five-year history.</td><td>All existing cable transition rates updated with data received from ConEd and PSEG-LIPA to reflect most recent ten-year history.</td></tr>
<tr><td>4</td><td>UDR unavailability</td><td>Five-year history of forced outages.</td><td>Ten-year history of forced outages.</td></tr>
<tr><td colspan="3">Emergency Operating Procedures (EOPs)</td><td></td></tr>
<tr><td>1</td><td>EOP Steps Order</td><td>New order, and new flexible large loads at step 2:
1. No EOP Support
2. Flexible Large Loads (400-900 MW)
3. Special Case Resources (SCRs) (Load and Generator)
4. 5% Manual Voltage Reduction
5. 30-Minute Operating Reserve to Zero (655 MW)
6. Voluntary Load Curtailment
7. Public Appeals
8. 5% Remote Controlled Voltage Reduction
9. Emergency Assistance from External Areas
10. Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero</td><td>Starting 2024 RNA, new EOP order and flexible large loads:
1. No EOP Support
2. Flexible Large Loads (about 485 MW at max)
3. Special Case Resources (SCRs) (Load and Generator)
4. 5% Manual Voltage Reduction
5. 30-Minute Operating Reserve to Zero (655MW)
6. Voluntary Load Curtailment
7. Public Appeals
8. 5% Remote Controlled Voltage Reduction
9. Emergency Assistance from External Areas
10. Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero</td></tr>
<tr><td>2</td><td>Special Case Resources (SCR)</td><td>SCRs sold for the program discounted to historic availability (“effective capacity”). Monthly variation based on historical experience.

Summer values calculated from the latest available July registrations (July 2023 SCR enrollment) held constant for all years of study.

New Method:

SCRs are modeled as duration-limited resources. The duration limited units are constrained to be called once in a day when a loss of load event occurs, and are invoked between 5 and 7 hours (defined by zone), which is determined based on historical SCR performance in the applicable zone. Hourly response rates are used. The contribution by the SCRs vary monthly by applicable zone. These monthly values are also derived from historical performance of the SCRs. Additional details in the January 3, 2024 ICS/ICAP presentation [link] and May 1, 2024 ICS [link].</td><td>SCRs sold for the program discounted to historic availability (“effective capacity”). Monthly variation based on historical experience.

Summer values calculated from the latest available July registrations (July 2024 SCR enrollment) held constant for all years of study.

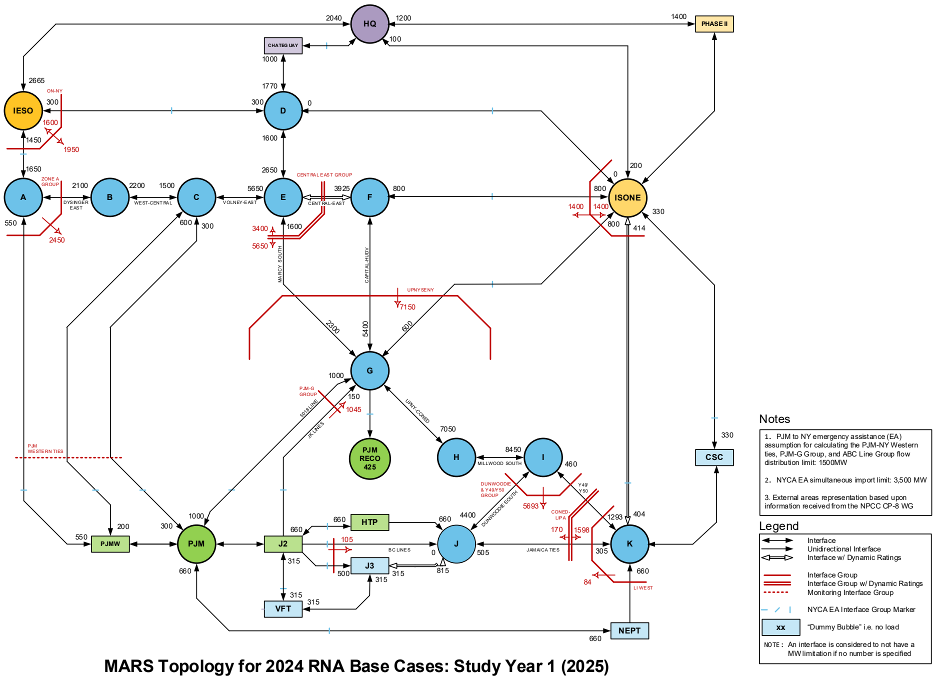
Starting 2024 RNA, new method:

SCRs are modeled as duration-limited resources. The duration limited units are constrained to be called once in a day when a loss of load event occurs, and are invoked between 5 and 7 hours (defined by zone), which is determined based on historical SCR performance in the applicable zone. Hourly response rates are used. The contribution by the SCRs vary monthly by applicable zone. These monthly values are also derived from historical performance of the SCRs. Additional details in the January 3, 2024 ICS/ICAP presentation [link] and May 1, 2024 ICS [link].</td></tr>
<tr><td>3</td><td>EDRP Resources</td><td>Not modeled if the values are less than 2 MW.</td><td>Not modeled if the values are less than 2 MW.</td></tr>
</table>

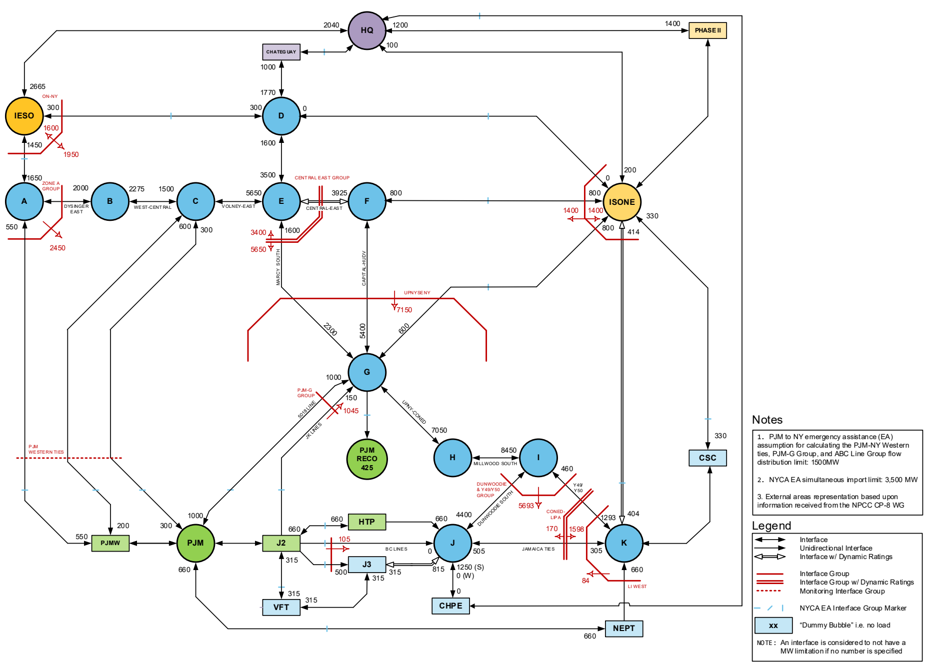
	Parameter	2024 RNA Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q3 STAR Key Assumptions (2025 GB)
4	Operating Reserves	655 MW 30-min reserve to zero 910 MW (of 1310 MW) 10-min reserve to zero Note: the 10-min reserve modeling method is updated per NYISO's recommendation (approved at the Oct. 3, 2023 NYSRC ICS [link]) to maintain (or no longer deplete/use) 400 MW of the 1,310 MW 10-min operating reserve at the applicable EOP step. Therefore, the 10-min operating reserve MARS EOP step will use, as needed each MARS replication: 910 MW (=1,310 MW–400 MW).	655 MW 30-min reserve to zero 910 MW (of 1310 MW) 10-min reserve to zero Note: the 10-min reserve modeling method is updated per NYISO's recommendation (approved at the Oct. 3, 2023 NYSRC ICS [link]) to maintain (or no longer deplete/use) 400 MW of the 1,310 MW 10-min operating reserve at the applicable EOP step. Therefore, the 10-min operating reserve MARS EOP step will use, as needed each MARS replication: 910 MW (=1,310 MW–400 MW).
5	Other EOPs *(e.g., manual voltage reduction, voltage curtailments, public appeals, external assistance, as listed above)*	Based on TO information, measured data, and NYISO forecasts. Will use 2024 elections, as available.	Based on TO information, measured data, and NYISO forecasts. Will use 2024 elections, as available.
External Control Areas Modeling Assumptions • External models (NE, HQ, Ontario, PJM) received via the NPCC CP-8 WG process. • Starting 2024 RNA, the top 5 (instead of 3) summer and winter peak load days of an external Control Area modeled as coincident with the NYCA top 5 peak load days. • Load and capacity fixed through the study years. • The renewable and energy limited shapes are removed. • EOPs are not represented for the external Control Area capacity models. • External Areas adjusted to be between 0.1 and 0.15 event-days/year LOLE by adjusting capacity pro-rata in all areas. • Implemented a statewide emergency assistance (from the neighboring systems) limit of 3500 MW. • LFU is applied to neighboring systems. • Same load historical years are used as NY.			
1	PJM	Simplified model: The 5 PJM MARS areas (bubbles) were consolidated into one starting 2020 RNA. As per RNA procedure.	Simplified model: The 5 PJM MARS areas (bubbles) were consolidated into one starting 2020 RNA. As per RNA procedure.
2	ISONE	Simplified model: The 8 ISO-NE MARS areas (bubbles) were consolidated into one starting 2020 RNA	Simplified model: The 8 ISO-NE MARS areas (bubbles) were consolidated into one starting 2020 RNA
3	HQ	Per RNA Procedure.	Per RNA Procedure.
4	IESO	Per RNA procedure.	Per RNA procedure.
5	Reserve Sharing	All NPCC Control Areas indicate that they will share reserves equally among all members before sharing with PJM.	All NPCC Control Areas indicate that they will share reserves equally among all members before sharing with PJM.
6	NYCA Emergency Assistance Limit	Implemented a statewide limit of 3,500 MW, additional to the "pipe" limits.	Implemented a statewide limit of 3,500 MW, additional to the "pipe" limits.
Miscellaneous			

	Parameter	2024 RNA Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q3 STAR Key Assumptions (2025 GB)
1	MARS Model Version	4.14.2179	5.7.3765

2024 RNA MARS Topology[29]



MARS Topology for 2024 RNA Base Cases: Study Year 1 (2025)



MARS Topology for 2024 RNA Base Cases: Study Years 2 through 5 (2026-2029) (with CHPE)

29 This is the MARS topology used for 2024 Reliability Needs Assessment studies and is not fully re-evaluated for each quarterly STAR.

Appendix E: Transmission Security Margin Assessment

Introduction

The purpose of this assessment is to identify plausible changes in conditions or assumptions that might adversely impact the reliability of the BPTF or "tip" the system into a violation of a transmission security criterion. This assessment is performed using a deterministic approach through a spreadsheet-based method using input from the 2025 Gold Book and the projects that meet the reliability planning inclusion rules for the 2025 Q3 STAR. For this assessment, the statewide system margin is calculated and transmission security margins for the Lower Hudson Valley, New York City, and Long Island localities are calculated.

A BPTF reliability need is identified when the transmission security margin in the Lower Hudson Valley, New York City, or Long Island localities is less than zero. Additional details beyond the system design conditions regarding the statewide system margin, impact of extreme weather, or conditions are provided to more fully understand the impact of various changes to the system such as demand forecast or other parameters in the assessment.

For the evaluation of winter peak conditions, all gas-only units within the NYCA are assumed unavailable with consideration of firm gas fuel contracts. Dual-fuel units with gas-only duct-burn capability are assumed to be available at a lower capacity, accounting for the unavailability of duct-burn. This assessment assumes the remaining units have available fuel for the peak period. This shortage impacts approximately 6,325 MW of gas generation throughout the NYCA.

Transmission security analysis represents discrete snapshots in time of various credible combinations of system conditions. Therefore, the identification of reliability needs only indicates the magnitude of the need (*e.g.*, a thermal overload expressed in terms of percentage of the applicable rating) under those specific system conditions. Additional details are required to fully describe the nature of the need. To describe the nature of the transmission security and statewide system margins more fully, the NYISO uses load shapes to reflect the expected behavior of the load over 24 hours on the summer peak day for the 10-year study horizon. Details of the load shapes are provided in the body of this report in Figure 18 and Figure 23.

Further details on the assumptions utilized in this assessment are provided in Appendix C. Under expected weather conditions this assessment recognizes that there is a range of possibilities for the expected weather demand forecast driven by key assumptions, such as population and economic growth, energy efficiency, installation of behind-the-meter renewable energy resources, and electric vehicle adoption and charging patterns that are captured in the 2025 Gold Book. These additional factors are not explored further under extreme weather. For the extreme weather conditions this assessment only utilizes the 90th or 99th percentile forecast of baseline summer or winter coincident peak demand due to weather. Extreme weather conditions are informational and are not used to identify reliability needs in this assessment.

Key to the determination of generator deactivation reliability needs is the availability of future planned projects such as CHPE, Empire Wind, Sunrise Wind, and the Propel NY project. These evaluations are labeled with “status quo.” The status quo evaluation 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.

Statewide System Margin

The statewide system margin for New York is evaluated under expected weather for summer and winter conditions with normal transfer criteria. The statewide system margin is the ability to meet the forecasted load and largest loss-of-source contingency (*i.e.,* total capacity requirement) against the NYCA generation (including derates) and external area interchanges. The NYCA generation (from line-item A in the following figures) is comprised of the existing generation plus additions of future generation resources, as well as the removal of deactivating generation, that meet the reliability planning process inclusion rules. The dispatch of renewable generation is aligned with current transmission planning practices for transmission security. Derates for thermal resources based on their NERC five-year class average EFORd are also included.[30] Additionally, for the statewide system margin, the NYCA generation includes the Oswego export limit with all lines in service.

The decreasing statewide system margin in both summer and winter can be attributed to increasing demand that is not matched by incoming proposed generation that meets inclusion rules. Additionally, the unavailability of non-firm gas is a key driver of deficient statewide margins in the winter peak condition. A negative statewide system margin is not, on its own, a violation of the Reliability Criteria. It is, however, a leading indicator of the system’s inability to securely serve

[30] The NERC five-year class average EFORd data is available here. NERC class average derating factors used in the STAR do not have a mechanism for excluding 9300 events (generator outages due to transmission system problems), see further discussion in Oct. 7, 2024 ICAP/MIWG/PRLWG presentation.

demand under normal operations. This metric is further explored in the 2025-2034 Comprehensive Reliability Plan.[31]

[31] The most recent draft of the NYISO's 2025-2034 Comprehensive Reliability Plan is found with the October, 16, 2025 Operating Committee Materials (here)

Figure 57: Summer Peak Statewide System Margin Calculation - Planned System, Flexible Large Loads Offline

Line	Item	Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW)									
		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
A	NYCA Generation (1)	37,705	40,383	41,687	41,687	41,687	41,233	41,233	41,233	41,233	41,233
B	NYCA Generation Unavailability (2)	(6,700)	(9,123)	(10,292)	(10,318)	(10,343)	(10,322)	(10,347)	(10,347)	(10,373)	(10,373)
C	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
D	External Area Interchanges (3)	3,208	2,919	2,919	2,919	2,919	2,919	2,919	2,919	2,919	2,919
E	**Total Resources (A+B+C+D)**	34,212	34,179	34,314	34,289	34,263	33,830	33,804	33,804	33,779	33,779
F	Demand Forecast (5)	(31,305)	(31,595)	(31,725)	(31,935)	(32,225)	(32,505)	(32,835)	(33,185)	(33,485)	(33,815)
G	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
H	**Total Capability Requirement (F+G)**	(32,615)	(32,905)	(33,035)	(33,245)	(33,535)	(33,815)	(34,145)	(34,495)	(34,795)	(35,125)
I	**Statewide System Margin (E+H)**	1,597	1,274	1,279	1,044	728	15	(341)	(691)	(1,016)	(1,346)
J	Higher Demand Impact	(600)	(1,170)	(1,650)	(2,050)	(2,330)	(2,520)	(2,660)	(2,830)	(3,160)	(3,610)
K	**Higher Demand Statewide System Margin (I+J)**	997	104	(371)	(1,006)	(1,602)	(2,505)	(3,001)	(3,521)	(4,176)	(4,956)
L	SCRs (6), (7)	804	804	804	804	804	804	804	804	804	804
M	**Statewide System Margin with SCR (K+L)**	1,801	908	433	(203)	(798)	(1,701)	(2,197)	(2,717)	(3,373)	(4,153)
N	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
O	**Statewide System Margin with Full Operating Reserve (M+N) (4)**	491	(402)	(877)	(1,513)	(2,108)	(3,011)	(3,507)	(4,027)	(4,683)	(5,463)

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 15% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included as well as the Oswego Export limit for all lines in-service. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 310 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.
4. For informational purposes.
5. Reflects the 2025 Gold Book Forecast.
6. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
7. Includes a derate of 401 MW for SCRs

Figure 58: Summer Peak Statewide System Margin Calculation – Planned System, 1-in-10 Year Heatwave

Line	Item	Summer Peak - 1-in-10-Year Heatwave, Emergency Transfer Criteria (MW)									
		2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
A	NYCA Generation (1)	37,705	40,383	41,687	41,687	41,687	41,233	41,233	41,233	41,233	41,233
B	NYCA Generation Unavailability (2)	(6,700)	(9,123)	(10,292)	(10,318)	(10,343)	(10,322)	(10,347)	(10,347)	(10,373)	(10,373)
C	Temperature Based Generation Derates	(250)	(246)	(246)	(246)	(246)	(234)	(234)	(234)	(234)	(234)
D	External Area Interchanges (3)	3,208	2,919	2,919	2,919	2,919	2,919	2,919	2,919	2,919	2,919
E	SCRs (4), (5)	804	804	804	804	804	804	804	804	804	804
F	**Total Resources (A+B+C+D+E)**	34,766	34,737	34,872	34,847	34,821	34,399	34,374	34,374	34,348	34,348
G	Demand Forecast	(33,099)	(33,409)	(33,547)	(33,773)	(34,083)	(34,379)	(34,729)	(35,101)	(35,419)	(35,768)
H	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
I	**Total Capability Requirement (G+H)**	(34,409)	(34,719)	(34,857)	(35,083)	(35,393)	(35,689)	(36,039)	(36,411)	(36,729)	(37,078)
J	**Statewide System Margin (F+I)**	357	18	15	(236)	(572)	(1,290)	(1,665)	(2,037)	(2,381)	(2,730)
K	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
L	**Statewide System Margin with Full Operating Reserve (J+K)**	(953)	(1,292)	(1,295)	(1,546)	(1,882)	(2,600)	(2,975)	(3,347)	(3,691)	(4,040)

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included as well as the Oswego Export limit for all lines in-service. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 310 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.
4. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
5. Includes a derate of 401 MW for SCRs.

Figure 59: Summer Peak Statewide System Margin – Planned System, 1-in-100 Year Heatwave

Line	Item	Summer Peak - 1-in-100-Year Extreme Heatwave, Emergency Transfer Criteria (MW)									
		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
A	NYCA Generation (1)	37,705	40,383	41,687	41,687	41,687	41,233	41,233	41,233	41,233	41,233
B	NYCA Generation Unavailability (2)	(6,700)	(9,123)	(10,292)	(10,318)	(10,343)	(10,322)	(10,347)	(10,347)	(10,373)	(10,373)
C	Temperature Based Generation Derates	(443)	(437)	(437)	(437)	(437)	(425)	(425)	(425)	(425)	(425)
D	External Area Interchanges (3)	3,208	2,919	2,919	2,919	2,919	2,919	2,919	2,919	2,919	2,919
E	SCRs (4), (5)	804	804	804	804	804	804	804	804	804	804
F	**Total Resources (A+B+C+D+E)**	34,573	34,546	34,681	34,656	34,630	34,208	34,183	34,183	34,157	34,157
G	Demand Forecast	(34,613)	(34,934)	(35,079)	(35,315)	(35,639)	(35,952)	(36,318)	(36,708)	(37,037)	(37,404)
H	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
I	**Total Capability Requirement (G+H)**	(35,923)	(36,244)	(36,389)	(36,625)	(36,949)	(37,262)	(37,628)	(38,018)	(38,347)	(38,714)
J	**Statewide System Margin (F+I)**	(1,350)	(1,698)	(1,708)	(1,969)	(2,319)	(3,054)	(3,445)	(3,835)	(4,190)	(4,557)
K	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
L	**Statewide System Margin with Full Operating Reserve (J+K)**	(2,660)	(3,008)	(3,018)	(3,279)	(3,629)	(4,364)	(4,755)	(5,145)	(5,500)	(5,867)

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included as well as the Oswego Export limit for all lines in-service. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 310 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.
4. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
5. Includes a derate of 401 MW for SCRs.

Figure 60: Winter Peak Statewide System Margin – Planned System, Flexible Large Loads Offline

Line	Item	Winter Peak - Baseline Expected Winter Weather, Normal Transfer Criteria (MW)									
		2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
A	NYCA Generation (1)	42,115	43,367	43,747	43,747	43,289	43,289	43,289	43,289	43,289	43,289
B	NYCA Generation Unavailability (2)	(8,575)	(9,747)	(10,127)	(10,127)	(10,127)	(10,127)	(10,127)	(10,127)	(10,127)	(10,127)
C	Unavailability of Non-Firm Gas (6)	(6,328)	(6,328)	(6,328)	(6,328)	(5,870)	(5,870)	(5,870)	(5,870)	(5,870)	(5,870)
D	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
E	External Area Interchanges (3)	849	560	560	560	560	560	560	560	560	560
F	**Total Resources (A+B+C+D+E)**	28,061	27,852	27,852	27,852	27,853	27,853	27,853	27,853	27,853	27,853
G	Demand Forecast (5)	(24,920)	(25,330)	(25,850)	(26,410)	(27,080)	(27,730)	(28,440)	(29,210)	(29,970)	(30,850)
H	Large Load Flexibility	685	685	685	685	685	685	685	685	685	685
I	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
J	**Total Capability Requirement (G+H+I)**	(25,545)	(25,955)	(26,475)	(27,035)	(27,705)	(28,355)	(29,065)	(29,835)	(30,595)	(31,475)
K	**Statewide System Margin (F+J)**	2,516	1,897	1,377	817	148	(502)	(1,212)	(1,982)	(2,742)	(3,622)
L	SCRs (7), (8)	721	721	721	721	721	721	721	721	721	721
M	**Statewide System Margin with SCR (K+L)**	3,237	2,618	2,098	1,538	868	218	(492)	(1,262)	(2,022)	(2,902)
N	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
O	**Statewide System Margin with Full Operating Reserve (M+N) (4)**	1,927	1,308	788	228	(442)	(1,092)	(1,802)	(2,572)	(3,332)	(4,212)

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 310 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.
4. For informational purposes.
5. Reflects the 2025 Gold Book Forecast.
6. Includes all gas only units that do not have a firm gas contract. Also includes reductions in units with duct burner capabilities.
7. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
8. Includes a derate of 305 MW for SCRs.

Figure 61: Winter Peak Statewide System Margin – Planned System, 1-in-10-Year Cold Snap

Line	Item	Winter Peak - 1-in-10-Year Cold Snap, Gas Fuel Shortage, Emergency Transfer Criteria (MW)									
		2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
A	NYCA Generation (1)	42,115	43,367	43,747	43,747	43,289	43,289	43,289	43,289	43,289	43,289
B	Shortage of Gas Fuel Supply (6)	(8,575)	(9,747)	(10,127)	(10,127)	(10,127)	(10,127)	(10,127)	(10,127)	(10,127)	(10,127)
C	NYCA Generation Unavailability (2)	(6,328)	(6,328)	(6,328)	(6,328)	(5,870)	(5,870)	(5,870)	(5,870)	(5,870)	(5,870)
D	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
E	External Area Interchanges (3)	849	560	560	560	560	560	560	560	560	560
F	SCRs (4), (5)	721	721	721	721	721	721	721	721	721	721
G	**Total Resources (A+B+C+D+E+F)**	28,782	28,573	28,573	28,573	28,573	28,573	28,573	28,573	28,573	28,573
H	Demand Forecast	(25,992)	(26,443)	(27,014)	(27,650)	(28,407)	(29,172)	(30,005)	(30,873)	(31,770)	(32,793)
I	Large Load Flexibility	685	685	685	685	685	685	685	685	685	685
J	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
K	**Total Capability Requirement (H+I+J)**	(26,617)	(27,068)	(27,639)	(28,275)	(29,032)	(29,797)	(30,630)	(31,498)	(32,395)	(33,418)
L	**Statewide System Margin (G+K)**	2,165	1,505	934	298	(459)	(1,224)	(2,057)	(2,925)	(3,822)	(4,845)
M	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
N	**Statewide System Margin with Full Operating Reserve (L+M)**	855	195	(376)	(1,012)	(1,769)	(2,534)	(3,367)	(4,235)	(5,132)	(6,155)

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 310 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.
4. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
5. Includes a derate of 305 MW for SCRs.
6. Includes all gas only units that do not have a firm gas contract. Also includes reductions in units with duct burner capabilities.

Figure 62: Winter Peak Statewide System Margin – Planned System, 1-in-100-Year Cold Snap

Line	Item	Winter Peak - 1-in-100-Year Extreme Cold Snap, Gas Fuel Shortage, Emergency Transfer Criteria (MW)									
		2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
A	NYCA Generation (1)	42,115	43,367	43,747	43,747	43,289	43,289	43,289	43,289	43,289	43,289
B	Shortage of Gas Fuel Supply (6)	(8,575)	(9,747)	(10,127)	(10,127)	(10,127)	(10,127)	(10,127)	(10,127)	(10,127)	(10,127)
C	NYCA Generation Unavailability (2)	(6,328)	(6,328)	(6,328)	(6,328)	(5,870)	(5,870)	(5,870)	(5,870)	(5,870)	(5,870)
D	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
E	External Area Interchanges (3)	849	560	560	560	560	560	560	560	560	560
F	SCRs (4), (5)	721	721	721	721	721	721	721	721	721	721
G	**Total Resources (A+B+C+D+E+F)**	28,782	28,573	28,573	28,573	28,573	28,573	28,573	28,573	28,573	28,573
H	Demand Forecast	(27,063)	(27,560)	(28,176)	(28,867)	(29,707)	(30,586)	(31,511)	(32,511)	(33,506)	(34,645)
I	Large Load Flexibility	685	685	685	685	685	685	685	685	685	685
J	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
K	**Total Capability Requirement (H+I+J)**	(27,688)	(28,185)	(28,801)	(29,492)	(30,332)	(31,211)	(32,136)	(33,136)	(34,131)	(35,270)
L	**Statewide System Margin (G+K)**	1,094	388	(228)	(919)	(1,759)	(2,638)	(3,563)	(4,563)	(5,558)	(6,697)
M	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
N	**Statewide System Margin with Full Operating Reserve (L+M)**	(216)	(922)	(1,538)	(2,229)	(3,069)	(3,948)	(4,873)	(5,873)	(6,868)	(8,007)

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 310 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.
4. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
5. Includes a derate of 305 MW for SCRs.
6. Includes all gas only units that do not have a firm gas contract. Also includes reductions in units with duct burner capabilities.

Figure 63: Summer Peak Statewide System Margin Calculation – Planned System, Flexible Large Loads Online

Line	Item	Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW)									
		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
A	NYCA Generation (1)	37,705	40,383	41,687	41,687	41,687	41,233	41,233	41,233	41,233	41,233
B	NYCA Generation Unavailability (2)	(6,700)	(9,123)	(10,292)	(10,318)	(10,343)	(10,322)	(10,347)	(10,347)	(10,373)	(10,373)
C	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
D	External Area Interchanges (3)	3,208	2,919	2,919	2,919	2,919	2,919	2,919	2,919	2,919	2,919
E	**Total Resources (A+B+C+D)**	34,212	34,179	34,314	34,289	34,263	33,830	33,804	33,804	33,779	33,779
F	Demand Forecast (5)	(31,990)	(32,280)	(32,410)	(32,620)	(32,910)	(33,190)	(33,520)	(33,870)	(34,170)	(34,500)
G	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
H	**Total Capability Requirement (F+G)**	(33,300)	(33,590)	(33,720)	(33,930)	(34,220)	(34,500)	(34,830)	(35,180)	(35,480)	(35,810)
I	**Statewide System Margin (E+H)**	912	589	594	359	43	(670)	(1,026)	(1,376)	(1,701)	(2,031)
J	Higher Demand Impact	(600)	(1,170)	(1,650)	(2,050)	(2,330)	(2,520)	(2,660)	(2,830)	(3,160)	(3,610)
K	**Higher Demand Statewide System Margin (I+J)**	312	(581)	(1,056)	(1,691)	(2,287)	(3,190)	(3,686)	(4,206)	(4,861)	(5,641)
L	SCRs (6), (7)	804	804	804	804	804	804	804	804	804	804
M	**Statewide System Margin with SCR (K+L)**	1,116	223	(252)	(888)	(1,483)	(2,386)	(2,882)	(3,402)	(4,058)	(4,838)
N	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
O	**Statewide System Margin with Full Operating Reserve (M+N) (4)**	(194)	(1,087)	(1,562)	(2,198)	(2,793)	(3,696)	(4,192)	(4,712)	(5,368)	(6,148)

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 15% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included as well as the Oswego Export limit for all lines in-service. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 310 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.
4. For informational purposes.
5. Reflects the 2025 Gold Book Forecast.
6. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
7. Includes a derate of 401 MW for SCRs

Figure 64: Winter Statewide System Margin Calculation – Planned System Flexible Large Loads Online

Line	Item	Winter Peak - Baseline Expected Winter Weather, Normal Transfer Criteria (MW)									
		2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
A	NYCA Generation (1)	42,115	43,367	43,747	43,747	43,289	43,289	43,289	43,289	43,289	43,289
B	NYCA Generation Unavailability (2)	(8,575)	(9,747)	(10,127)	(10,127)	(10,127)	(10,127)	(10,127)	(10,127)	(10,127)	(10,127)
C	Unavailability of Non-Firm Gas (6)	(6,328)	(6,328)	(6,328)	(6,328)	(5,870)	(5,870)	(5,870)	(5,870)	(5,870)	(5,870)
D	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
E	External Area Interchanges (3)	849	560	560	560	560	560	560	560	560	560
F	**Total Resources (A+B+C+D+E)**	28,061	27,852	27,852	27,852	27,853	27,853	27,853	27,853	27,853	27,853
G	Demand Forecast (5)	(24,920)	(25,330)	(25,850)	(26,410)	(27,080)	(27,730)	(28,440)	(29,210)	(29,970)	(30,850)
H	Large Load Flexibility	0	0	0	0	0	0	0	0	0	0
I	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
J	**Total Capability Requirement (G+H+I)**	(26,230)	(26,640)	(27,160)	(27,720)	(28,390)	(29,040)	(29,750)	(30,520)	(31,280)	(32,160)
K	**Statewide System Margin (F+J)**	1,831	1,212	692	132	(537)	(1,187)	(1,897)	(2,667)	(3,427)	(4,307)
L	SCRs (7), (8)	721	721	721	721	721	721	721	721	721	721
M	**Statewide System Margin with SCR (K+L)**	2,552	1,933	1,413	853	183	(467)	(1,177)	(1,947)	(2,707)	(3,587)
N	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
O	**Statewide System Margin with Full Operating Reserve (M+N) (4)**	1,242	623	103	(457)	(1,127)	(1,777)	(2,487)	(3,257)	(4,017)	(4,897)

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 310 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.

3. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.
4. For informational purposes.
5. Reflects the 2025 Gold Book Forecast.
6. Includes all gas only units that do not have a firm gas contract. Also includes reductions in units with duct burner capabilities.
7. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
8. Includes a derate of 305 MW for SCRs.

Figure 65: Summer Statewide System Margin Calculation – Status Quo System

Line	Item	Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW)									
		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
A	NYCA Generation (1)	37,363	37,263	37,263	37,263	37,263	36,809	36,809	36,809	36,809	36,809
B	NYCA Generation Unavailability (2)	(6,406)	(6,408)	(6,413)	(6,419)	(6,425)	(6,383)	(6,389)	(6,389)	(6,395)	(6,395)
C	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
D	External Area Interchanges (3)	1,958	1,669	1,669	1,669	1,669	1,669	1,669	1,669	1,669	1,669
E	**Total Resources (A+B+C+D)**	32,915	32,525	32,519	32,513	32,507	32,094	32,088	32,088	32,083	32,083
F	Demand Forecast (5)	(31,305)	(31,595)	(31,725)	(31,935)	(32,225)	(32,505)	(32,835)	(33,185)	(33,485)	(33,815)
G	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
H	**Total Capability Requirement (F+G)**	(32,615)	(32,905)	(33,035)	(33,245)	(33,535)	(33,815)	(34,145)	(34,495)	(34,795)	(35,125)
I	**Statewide System Margin (E+H)**	300	(380)	(516)	(732)	(1,028)	(1,721)	(2,057)	(2,407)	(2,712)	(3,042)
J	Higher Demand Impact	(600)	(1,170)	(1,650)	(2,050)	(2,330)	(2,520)	(2,660)	(2,830)	(3,160)	(3,610)
K	**Higher Demand Statewide System Margin (I+J)**	(300)	(1,550)	(2,166)	(2,782)	(3,358)	(4,241)	(4,717)	(5,237)	(5,872)	(6,652)
L	SCRs (6), (7)	804	804	804	804	804	804	804	804	804	804
M	**Statewide System Margin with SCR (K+L)**	503	(747)	(1,363)	(1,978)	(2,554)	(3,437)	(3,913)	(4,433)	(5,069)	(5,849)
N	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
O	**Statewide System Margin with Full Operating Reserve (M+N) (4)**	(807)	(2,057)	(2,673)	(3,288)	(3,864)	(4,747)	(5,223)	(5,743)	(6,379)	(7,159)

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 15% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included as well as the Oswego Export limit for all lines in-service. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 310 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.
4. For informational purposes.
5. Reflects the 2025 Gold Book Forecast.
6. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
7. Includes a derate of 401 MW for SCRs

Figure 66: Winter Statewide System Margin Calculation – Status Quo System

Line	Item	Winter Peak - Baseline Expected Winter Weather, Normal Transfer Criteria (MW)									
		2026-27	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**	**2035-36**
A	NYCA Generation (1)	39,440	39,323	39,323	39,323	38,865	38,865	38,865	38,865	38,865	38,865
B	NYCA Generation Unavailability (2)	(6,162)	(6,150)	(6,150)	(6,150)	(6,149)	(6,149)	(6,149)	(6,149)	(6,149)	(6,149)
C	Unavailability of Non-Firm Gas (6)	(6,328)	(6,328)	(6,328)	(6,328)	(5,870)	(5,870)	(5,870)	(5,870)	(5,870)	(5,870)
D	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
E	External Area Interchanges (3)	849	560	560	560	560	560	560	560	560	560
F	**Total Resources (A+B+C+D+E)**	27,799	27,406	27,406	27,406	27,406	27,406	27,406	27,406	27,406	27,406
G	Demand Forecast (5)	(24,920)	(25,330)	(25,850)	(26,410)	(27,080)	(27,730)	(28,440)	(29,210)	(29,970)	(30,850)
H	Large Load Flexibility	685	685	685	685	685	685	685	685	685	685
I	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
J	**Total Capability Requirement (G+H+I)**	(25,545)	(25,955)	(26,475)	(27,035)	(27,705)	(28,355)	(29,065)	(29,835)	(30,595)	(31,475)
K	**Statewide System Margin (F+J)**	2,254	1,451	931	371	(299)	(949)	(1,659)	(2,429)	(3,189)	(4,069)
L	SCRs (7), (8)	721	721	721	721	721	721	721	721	721	721
M	**Statewide System Margin with SCR (K+L)**	2,975	2,171	1,651	1,091	422	(228)	(938)	(1,708)	(2,468)	(3,348)
N	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
O	**Statewide System Margin with Full Operating Reserve (M+N) (4)**	1,665	861	341	(219)	(888)	(1,538)	(2,248)	(3,018)	(3,778)	(4,658)

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 310 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.

3. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.
4. For informational purposes.
5. Reflects the 2025 Gold Book Forecast.
6. Includes all gas only units that do not have a firm gas contract. Also includes reductions in units with duct burner capabilities.
7. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
8. Includes a derate of 305 MW for SCRs.

Lower Hudson Valley (Zones G-J)

The Lower Hudson Valley or southeastern New York (SENY) locality comprises Zones G-J and includes the electrical connections to the RECO load in PJM. To determine the transmission security margin for this area, the NYISO determines the most limiting combination of two non-simultaneous contingency events (N-1-1) to the transmission security margin. As the system changes, the limiting contingency combination may also change.

In summer throughout the study period, the limiting contingency combination is the loss of Knickerbocker – Pleasant Valley 345 kV followed by the loss of Athens-Van Wagner 345 kV (91). The limiting contingency combination for winter throughout the study period is the loss of Ravenswood 3 followed by the loss of Pleasant Valley-Wood St. 345 kV (F30/F31).

Figure 68 and Figure 72 show the calculation of the summer and winter Lower Hudson Valley transmission security margin for baseline expected weather, expected load conditions for the statewide coincident peak hour with normal transfer criteria. This STAR finds that the Lower Hudson Valley is deficient beginning in summer 2030. Under the demand range for expected weather the Lower Hudson Valley deficiency in 2030 is 260 MW over 3 hours (924 MWh). This deficiency is further exacerbated through time without any additional capabilities added to this locality.

Figure 67: Summer Peak Lower Hudson Valley Margin Calculation – Status Quo System

Summer Peak - Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
A	G-J Demand Forecast	(15,034)	(15,103)	(15,145)	(15,176)	(15,205)	(15,280)	(15,401)	(15,515)	(15,652)	(15,788)
B	RECO Demand	(407)	(407)	(407)	(404)	(404)	(404)	(404)	(404)	(417)	(417)
C	**Total Demand (A+B)**	(15,441)	(15,510)	(15,552)	(15,580)	(15,609)	(15,684)	(15,805)	(15,919)	(16,069)	(16,205)
D	UPNY-SENY Limit (3)	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	47	(279)	(301)	(347)	(415)	(527)	(586)	(649)	(702)	(771)
G	**Total SENY AC Import (D+E+F)**	4,736	4,410	4,388	4,342	4,274	4,162	4,103	4,040	3,987	3,918
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(10,705)	(11,100)	(11,164)	(11,238)	(11,335)	(11,522)	(11,702)	(11,879)	(12,082)	(12,287)
J	G-J Generation (1)	12,849	12,849	12,849	12,849	12,849	12,439	12,439	12,439	12,439	12,439
K	G-J Generation Unavailability (2)	(1,230)	(1,230)	(1,230)	(1,230)	(1,230)	(1,188)	(1,188)	(1,188)	(1,188)	(1,188)
L	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (4)	140	140	140	140	140	140	140	140	140	140
N	**Total Resources Available (J+K+L+M)**	11,759	11,759	11,759	11,759	11,759	11,392	11,392	11,392	11,392	11,392
O	**Transmission Security Margin (I+N)**	1,054	659	595	521	424	(130)	(311)	(488)	(690)	(895)
P	Higher Demand Impact	(142)	(236)	(362)	(509)	(684)	(791)	(865)	(971)	(1,067)	(1,190)
Q	**Higher Demand Transmission Security Margin (O+P)**	912	423	233	12	(260)	(921)	(1,176)	(1,459)	(1,757)	(2,085)

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 15% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Limits for 2026 through 2029 are based on summer peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on summer peak 2034 representations evaluated in the 2024 RNA.
4. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

Figure 68: Summer Peak Lower Hudson Valley Margin Calculation – Planned System

Summer Peak - Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
A	G-J Demand Forecast	(15,034)	(15,103)	(15,145)	(15,176)	(15,205)	(15,280)	(15,401)	(15,515)	(15,652)	(15,788)
B	RECO Demand	(407)	(407)	(407)	(404)	(404)	(404)	(404)	(404)	(417)	(417)
C	**Total Demand (A+B)**	(15,441)	(15,510)	(15,552)	(15,580)	(15,609)	(15,684)	(15,805)	(15,919)	(16,069)	(16,205)
D	UPNY-SENY Limit (3)	4,700	4,700	4,700	4,700	4,500	4,500	4,500	4,500	4,500	4,500
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	47	(279)	(209)	(254)	(323)	(434)	(494)	(557)	(609)	(678)
G	**Total SENY AC Import (D+E+F)**	4,736	4,410	4,480	4,435	4,166	4,055	3,995	3,932	3,880	3,811
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(10,705)	(11,100)	(11,072)	(11,145)	(11,443)	(11,629)	(11,810)	(11,987)	(12,189)	(12,394)
J	G-J Generation (1)	12,894	13,710	13,710	13,710	13,710	13,300	13,300	13,300	13,300	13,300
K	G-J Generation Unavailability (2)	(1,269)	(2,004)	(2,005)	(2,005)	(2,005)	(1,963)	(1,963)	(1,964)	(1,964)	(1,964)
L	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (4)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
N	**Total Resources Available (J+K+L+M)**	13,014	13,096	13,095	13,095	13,095	12,727	12,727	12,726	12,726	12,726
O	**Transmission Security Margin (I+N)**	2,309	1,995	2,024	1,950	1,652	1,098	917	740	537	332
P	Higher Demand Impact	(142)	(236)	(362)	(509)	(684)	(791)	(865)	(971)	(1,067)	(1,190)
Q	**Higher Demand Transmission Security Margin (O+P)**	2,167	1,759	1,662	1,441	968	307	52	(231)	(530)	(858)
R	Noncoincident Peak Demand Impact	(246)	(246)	(247)	(247)	(247)	(248)	(250)	(252)	(256)	(258)
S	**Noncoincident Peak Transmission Security Margin (O+R)**	2,063	1,749	1,777	1,703	1,405	850	667	488	281	74

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 15% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Limits for 2026 through 2029 are based on summer peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on summer peak 2034 representations evaluated in the 2024 RNA.
4. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

Figure 69: Summer Peak Lower Hudson Valley Margin Calculation – Planned System, 1-in-10-Year Heatwave

Summer Peak - 1-in-10-Year Heatwave, Emergency Transfer Criteria (MW)											
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
A	G-J Demand Forecast	(15,626)	(15,699)	(15,743)	(15,775)	(15,805)	(15,881)	(16,008)	(16,127)	(16,270)	(16,412)
B	RECO Demand	(431)	(431)	(431)	(427)	(427)	(427)	(427)	(427)	(441)	(441)
C	**Total Demand (A+B)**	(16,057)	(16,130)	(16,174)	(16,202)	(16,232)	(16,308)	(16,435)	(16,554)	(16,711)	(16,853)
D	UPNY-SENY Limit (5)	5,300	5,300	5,300	5,300	5,500	5,500	5,500	5,500	5,500	5,500
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	(348)	(747)	(677)	(726)	(800)	(917)	(982)	(1,050)	(1,107)	(1,181)
G	**Total SENY AC Import (D+E+F)**	4,941	4,542	4,612	4,563	4,689	4,572	4,507	4,439	4,382	4,308
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(11,116)	(11,587)	(11,561)	(11,640)	(11,543)	(11,737)	(11,928)	(12,115)	(12,329)	(12,545)
J	G-J Generation (1)	12,894	13,710	13,710	13,710	13,710	13,300	13,300	13,300	13,300	13,300
K	G-J Generation Unavailability (2)	(1,269)	(2,004)	(2,005)	(2,005)	(2,005)	(1,963)	(1,963)	(1,964)	(1,964)	(1,964)
L	Temperature Based Generation Derates	(118)	(118)	(118)	(118)	(118)	(107)	(107)	(107)	(107)	(107)
M	Net ICAP External Imports (6)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
N	SCRs (3), (4)	274	274	274	274	274	274	274	274	274	274
O	**Total Resources Available (J+K+L+M+N)**	13,170	13,251	13,250	13,250	13,250	12,894	12,893	12,893	12,893	12,893
P	**Transmission Security Margin (I+O)**	2,054	1,664	1,689	1,610	1,706	1,157	965	778	564	348

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 15% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for “Capacity Accreditation project – Correlated Derates” requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a derate of 253 MW for SCRs.
5. Limits for 2026 through 2029 are based on summer peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on summer peak 2034 representations evaluated in the 2024 RNA.
6. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

Figure 70: Summer Peak Lower Hudson Valley Margin Calculation – Planned System, 1-in-100-Year Heatwave

Summer Peak - 1-in-100-Year Extreme Heatwave, Emergency Transfer Criteria (MW)											
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
A	G-J Demand Forecast	(16,238)	(16,312)	(16,357)	(16,391)	(16,422)	(16,504)	(16,634)	(16,758)	(16,906)	(17,053)
B	RECO Demand	(446)	(446)	(446)	(443)	(443)	(443)	(443)	(443)	(457)	(457)
C	**Total Demand (A+B)**	(16,684)	(16,758)	(16,803)	(16,834)	(16,865)	(16,947)	(17,077)	(17,201)	(17,363)	(17,510)
D	UPNY-SENY Limit (5)	5,300	5,300	5,300	5,300	5,500	5,500	5,500	5,500	5,500	5,500
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	(708)	(1,105)	(1,038)	(1,089)	(1,168)	(1,289)	(1,358)	(1,430)	(1,489)	(1,568)
G	**Total SENY AC Import (D+E+F)**	4,581	4,184	4,251	4,200	4,321	4,200	4,131	4,059	4,000	3,921
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(12,103)	(12,575)	(12,552)	(12,634)	(12,544)	(12,747)	(12,946)	(13,142)	(13,363)	(13,589)
J	G-J Generation (1)	12,894	13,710	13,710	13,710	13,710	13,300	13,300	13,300	13,300	13,300
K	G-J Generation Unavailability (2)	(1,269)	(2,004)	(2,005)	(2,005)	(2,005)	(1,963)	(1,963)	(1,964)	(1,964)	(1,964)
L	Temperature Based Generation Derates	(198)	(198)	(198)	(198)	(198)	(186)	(186)	(186)	(186)	(186)
M	Net ICAP External Imports (6)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
N	SCRs (3), (4)	274	274	274	274	274	274	274	274	274	274
O	**Total Resources Available (J+K+L+M+N)**	13,090	13,172	13,171	13,171	13,170	12,814	12,814	12,814	12,814	12,814
P	**Transmission Security Margin (I+O)**	987	597	619	537	627	67	(131)	(328)	(550)	(776)

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 15% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for “Capacity Accreditation project – Correlated Derates” requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a derate of 253 MW for SCRs.
5. Limits for 2026 through 2029 are based on summer peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on summer peak 2034 representations evaluated in the 2024 RNA.
6. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

Figure 71: Winter Peak Lower Hudson Valley Margin Calculation – Status Quo System

Winter Peak - Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**	**2035-36**
A	G-J Demand Forecast	(10,714)	(10,835)	(11,044)	(11,229)	(11,437)	(11,682)	(11,944)	(12,248)	(12,588)	(13,007)
B	RECO Demand	(246)	(246)	(246)	(236)	(236)	(236)	(236)	(236)	(313)	(313)
C	**Total Demand (A+B)**	(10,960)	(11,081)	(11,290)	(11,465)	(11,673)	(11,918)	(12,180)	(12,484)	(12,901)	(13,320)
D	UPNY-SENY Limit (3)	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	47	47	47	47	1,013	1,013	1,013	905	797	675
G	**Total SENY AC Import (D+E+F)**	5,336	5,336	5,336	5,336	6,302	6,302	6,302	6,194	6,086	5,964
H	Loss of Source Contingency	(973)	(973)	(973)	(973)	(973)	(973)	(973)	(973)	(973)	(973)
I	**Resource Need (C+G+H)**	(6,597)	(6,718)	(6,927)	(7,102)	(6,344)	(6,589)	(6,851)	(7,263)	(7,788)	(8,329)
J	G-J Generation (1)	13,580	13,580	13,580	13,580	13,169	13,169	13,169	13,169	13,169	13,169
K	G-J Generation Unavailability (2)	(1,118)	(1,118)	(1,118)	(1,118)	(1,117)	(1,117)	(1,117)	(1,117)	(1,117)	(1,117)
L	Shortage of Gas Fuel Supply (4)	(2,719)	(2,719)	(2,719)	(2,719)	(2,308)	(2,308)	(2,308)	(2,308)	(2,308)	(2,308)
M	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
N	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
O	**Total Resources Available (J+K+L+M+N)**	9,883	9,883	9,883	9,883	9,883	9,883	9,883	9,883	9,883	9,883
P	**Transmission Security Margin (I+O)**	3,286	3,165	2,956	2,781	3,540	3,295	3,033	2,621	2,096	1,555

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Limits for 2026 through 2029 are based on summer peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on summer peak 2034 representations evaluated in the 2024 RNA.
4. Includes all gas only units that do not have a firm gas contract.
5. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

Figure 72: Winter Peak Lower Hudson Valley Margin Calculation – Planned System

Winter Peak - Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**	**2035-36**
A	G-J Demand Forecast	(10,714)	(10,835)	(11,044)	(11,229)	(11,437)	(11,682)	(11,944)	(12,248)	(12,588)	(13,007)
B	RECO Demand	(246)	(246)	(246)	(236)	(236)	(236)	(236)	(236)	(313)	(313)
C	**Total Demand (A+B)**	(10,960)	(11,081)	(11,290)	(11,465)	(11,673)	(11,918)	(12,180)	(12,484)	(12,901)	(13,320)
D	UPNY-SENY Limit (3)	5,300	5,300	5,300	5,300	5,700	5,700	5,700	5,700	5,700	5,700
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	47	47	47	47	1,013	1,013	1,013	1,013	982	860
G	**Total SENY AC Import (D+E+F)**	5,336	5,336	5,336	5,336	6,702	6,702	6,702	6,702	6,671	6,549
H	Loss of Source Contingency	(973)	(973)	(973)	(973)	(973)	(973)	(973)	(973)	(973)	(973)
I	**Resource Need (C+G+H)**	(6,597)	(6,718)	(6,927)	(7,102)	(5,944)	(6,189)	(6,451)	(6,755)	(7,203)	(7,744)
J	G-J Generation (1)	14,441	14,441	14,441	14,441	14,030	14,030	14,030	14,030	14,030	14,030
K	G-J Generation Unavailability (2)	(1,816)	(1,816)	(1,816)	(1,816)	(1,815)	(1,815)	(1,815)	(1,815)	(1,815)	(1,815)
L	Shortage of Gas Fuel Supply (4)	(2,719)	(2,719)	(2,719)	(2,719)	(2,308)	(2,308)	(2,308)	(2,308)	(2,308)	(2,308)
M	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
N	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
O	**Total Resources Available (J+K+L+M+N)**	10,046	10,046	10,046	10,046	10,047	10,047	10,047	10,047	10,047	10,047
P	**Transmission Security Margin (I+O)**	3,449	3,328	3,119	2,944	4,103	3,858	3,596	3,292	2,844	2,303

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Limits for 2026 through 2029 are based on summer peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on summer peak 2034 representations evaluated in the 2024 RNA.
4. Includes all gas only units that do not have a firm gas contract.
5. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

Figure 73: Winter Peak Lower Hudson Valley Margin Calculation – Planned System, 1-in-10-Year Cold Snap

Winter Peak - 1-in-10-Year Cold Snap, Emergency Transfer Criteria (MW)											
Line	Item	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
A	G-J Demand Forecast	(11,175)	(11,312)	(11,541)	(11,756)	(11,997)	(12,289)	(12,602)	(12,946)	(13,344)	(13,827)
B	RECO Demand	(260)	(260)	(260)	(250)	(250)	(250)	(250)	(250)	(331)	(331)
C	**Total Demand (A+B)**	(11,435)	(11,572)	(11,801)	(12,006)	(12,247)	(12,539)	(12,852)	(13,196)	(13,675)	(14,158)
D	UPNY-SENY Limit (5)	5,700	5,700	5,700	5,700	5,900	5,900	5,900	5,900	5,900	5,900
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	141	141	141	141	1,200	1,151	994	858	731	588
G	**Total SENY AC Import (D+E+F)**	5,830	5,830	5,830	5,830	7,089	7,040	6,883	6,747	6,620	6,477
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(5,605)	(5,742)	(5,971)	(6,176)	(5,158)	(5,499)	(5,969)	(6,449)	(7,055)	(7,681)
J	G-J Generation (1)	14,441	14,441	14,441	14,441	14,030	14,030	14,030	14,030	14,030	14,030
K	G-J Generation Unavailability (2)	(1,816)	(1,816)	(1,816)	(1,816)	(1,815)	(1,815)	(1,815)	(1,815)	(1,815)	(1,815)
L	Shortage of Gas Fuel Supply (6)	(2,719)	(2,719)	(2,719)	(2,719)	(2,308)	(2,308)	(2,308)	(2,308)	(2,308)	(2,308)
M	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
N	Net ICAP External Imports (7)	140	140	140	140	140	140	140	140	140	140
O	SCRs (3), (4)	171	171	171	171	171	171	171	171	171	171
P	**Total Resources Available (J+K+L+M+N+O)**	10,217	10,217	10,217	10,217	10,218	10,218	10,218	10,218	10,218	10,218
Q	**Transmission Security Margin (I+P)**	4,612	4,475	4,246	4,042	5,060	4,719	4,249	3,769	3,163	2,537

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a derate of 158 MW for SCRs.

5. Limits for 2026 through 2029 are based on winter peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on winter peak 2034 representations evaluated in the 2024 RNA.
6. Includes all gas only units that do not have a firm gas contract.
7. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

Figure 74: Winter Peak Lower Hudson Valley Margin Calculation – Planned System, 1-in-100-Year Cold Snap

Winter Peak - 1-in-100-Year Extreme Cold Snap, Emergency Transfer Criteria (MW)											
Line	**Item**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**	**2035-36**
A	G-J Demand Forecast	(11,635)	(11,788)	(12,038)	(12,273)	(12,547)	(12,886)	(13,233)	(13,633)	(14,073)	(14,607)
B	RECO Demand	(270)	(270)	(270)	(259)	(259)	(259)	(259)	(259)	(343)	(343)
C	**Total Demand (A+B)**	(11,905)	(12,058)	(12,308)	(12,532)	(12,806)	(13,145)	(13,492)	(13,892)	(14,416)	(14,950)
D	UPNY-SENY Limit (5)	5,700	5,700	5,700	5,700	5,900	5,900	5,900	5,900	5,900	5,900
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	141	141	141	141	1,138	951	779	624	482	324
G	**Total SENY AC Import (D+E+F)**	5,830	5,830	5,830	5,830	7,027	6,840	6,668	6,513	6,371	6,213
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(6,075)	(6,228)	(6,478)	(6,702)	(5,779)	(6,305)	(6,824)	(7,379)	(8,045)	(8,737)
J	G-J Generation (1)	14,441	14,441	14,441	14,441	14,030	14,030	14,030	14,030	14,030	14,030
K	G-J Generation Unavailability (2)	(1,816)	(1,816)	(1,816)	(1,816)	(1,815)	(1,815)	(1,815)	(1,815)	(1,815)	(1,815)
	Shortage of Gas Fuel Supply (6)	(2,719)	(2,719)	(2,719)	(2,719)	(2,308)	(2,308)	(2,308)	(2,308)	(2,308)	(2,308)
L	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (7)	140	140	140	140	140	140	140	140	140	140
N	SCRs (3), (4)	171	171	171	171	171	171	171	171	171	171
O	**Total Resources Available (J+K+L+M+N)**	10,217	10,217	10,217	10,217	10,218	10,218	10,218	10,218	10,218	10,218
P	**Transmission Security Margin (I+O)**	4,143	3,990	3,740	3,516	4,439	3,913	3,394	2,839	2,173	1,481

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a derate of 158 MW for SCRs.
5. Limits for 2026 through 2029 are based on winter peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on winter peak 2034 representations evaluated in the 2024 RNA.
6. Includes all gas only units that do not have a firm gas contract.
7. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

New York City (Zone J)

The New York City locality comprises Zone J. Within the Con Edison service territory, the 345 kV transmission system, along with specific portions of the 138 kV transmission system, is designed for the occurrence of two non-simultaneous contingencies and a return to normal (N-1-1-0).[32] Therefore, unlike the Lower Hudson Valley and Long Island localities, the New York City transmission security margin is calculated based on the most limiting N-1-1-0 contingency combination. As the system changes, the limiting contingency combination may also change.

Starting in summer 2026 and continuing throughout the study period, the limiting contingency combination is the loss of the CHPE HVDC cable followed by the loss of Ravenswood 3. In winter 2026-2027 through winter 2029-2030, the limiting contingency combination is the loss of Ravenswood 3 followed by the loss of Mott Haven – Rainey 345 kV (Q12). Starting in winter 2030-2031 and continuing throughout the remainder of the study period, the limiting contingency combination changes to the loss of Ravenswood 3 followed by the loss of Bayonne. The CHPE cable is not included in limiting contingencies in winter due to the assumption that following the in-service status of CHPE, it is scheduled at 0 MW for the winter seasons.

This assessment recognizes that there is a range 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. The forecasted summer peak demand in New York City has a range of 460 MW in 2026 growing to 1,360 MW in 2030, primarily driven by assumptions in electrification of transportation and buildings. Baseline demand lies approximately in the middle of the range and is used for the baseline margin (line-item L) in Figure 76. The upper range of this forecast band is used for the higher demand margin (line-item N). The assumed available supply has also been adjusted to account for expected reductions of 110 MW in generators' dependable maximum net capability (DMNC) and 175 MW reduction in capacity sales from PJM. Heatwave conditions, shown in Figure 77 and Figure 78 are separate single forecasts.

32 https://www.coned.com/-/media/files/coned/documents/business-partners/transmission-planning/transmission-planning-criteria.pdf

Figure 75: Summer Peak New York City Transmission Security Margin Calculation – Status Quo System

Summer Peak - Baseline Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
A	**Zone J Demand Forecast**	(10,790)	(10,820)	(10,840)	(10,860)	(10,880)	(10,930)	(11,010)	(11,080)	(11,170)	(11,250)
B	I+K to J (3)	3,900	3,900	3,900	3,900	3,900	3,900	3,900	3,900	3,900	3,900
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	3,889	3,889	3,889	3,889	3,889	3,889	3,889	3,889	3,889	3,889
E	Loss of Source Contingency	(985)	(985)	(985)	(985)	(985)	(985)	(985)	(985)	(985)	(985)
F	**Resource Need (A+D+E)**	(7,886)	(7,916)	(7,936)	(7,956)	(7,976)	(8,026)	(8,106)	(8,176)	(8,266)	(8,346)
G	J Generation (1)	8,108	8,108	8,108	8,108	8,108	7,698	7,698	7,698	7,698	7,698
H	J Generation Unavailability (2)	(772)	(772)	(772)	(772)	(772)	(730)	(730)	(730)	(730)	(730)
I	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
J	Net ICAP External Imports (4)	140	140	140	140	140	140	140	140	140	140
K	**Total Resources Available (G+H+I+J)**	7,476	7,476	7,476	7,476	7,476	7,109	7,109	7,109	7,109	7,109
L	**Baseline Transmission Security Margin (F+K)**	(410)	(440)	(460)	(480)	(500)	(917)	(997)	(1,067)	(1,157)	(1,237)
M	Higher Demand Impact	(130)	(220)	(330)	(470)	(630)	(720)	(790)	(880)	(960)	(1,050)
N	**Higher Demand Transmission Security Margin (L+M)**	(540)	(660)	(790)	(950)	(1,130)	(1,637)	(1,787)	(1,947)	(2,117)	(2,287)

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx)**.** Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.

3. Limits for 2026 through 2029 are based on the summer peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on the summer peak 2034 representations evaluated in the 2024 RNA.
4. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

Figure 76: Summer Peak New York City Transmission Security Margin Calculation – Planned System

Summer Peak - Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
A	**Zone J Demand Forecast**	(10,790)	(10,820)	(10,840)	(10,860)	(10,880)	(10,930)	(11,010)	(11,080)	(11,170)	(11,250)
B	I+K to J (3)	4,700	4,700	4,700	4,700	4,800	4,800	4,800	4,800	4,800	4,800
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	4,689	4,689	4,689	4,689	4,789	4,789	4,789	4,789	4,789	4,789
E	Loss of Source Contingency	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)
F	**Resource Need (A+D+E)**	(8,336)	(8,366)	(8,386)	(8,406)	(8,326)	(8,376)	(8,456)	(8,526)	(8,616)	(8,696)
G	J Generation (1)	8,123	8,939	8,939	8,939	8,939	8,529	8,529	8,529	8,529	8,529
H	J Generation Unavailability (2)	(787)	(1,521)	(1,521)	(1,521)	(1,521)	(1,479)	(1,479)	(1,479)	(1,479)	(1,479)
I	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
J	Net ICAP External Imports (4)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
K	**Total Resources Available (G+H+I+J)**	8,726	8,808	8,808	8,808	8,808	8,440	8,440	8,440	8,440	8,440
L	**Baseline Transmission Security Margin (F+K)**	390	442	422	402	482	64	(16)	(86)	(176)	(256)
M	Higher Demand Impact	(130)	(220)	(330)	(470)	(630)	(720)	(790)	(880)	(960)	(1,050)
N	**Higher Demand Transmission Security Margin (L+M)**	260	222	92	(68)	(148)	(656)	(806)	(966)	(1,136)	(1,306)
O	Noncoincident Peak Demand Impact	(240)	(240)	(240)	(240)	(240)	(240)	(250)	(250)	(250)	(250)
P	**Noncoincident Peak Transmission Security Margin (L+O)**	150	202	182	162	242	(176)	(266)	(336)	(426)	(506)

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.

3. Limits for 2026 through 2029 are based on the summer peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on the summer peak 2034 representations evaluated in the 2024 RNA.
4. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

Figure 77: Summer Peak New York City Transmission Security Margin Calculation – Planned System, 1-in-10-Year Heatwave

Summer Peak - 1-in-10-Year Heatwave, Emergency Transfer Criteria (MW)											
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
A	**Zone J Demand Forecast**	(11,149)	(11,180)	(11,201)	(11,221)	(11,242)	(11,293)	(11,376)	(11,448)	(11,541)	(11,624)
B	I+K to J (5)	4,700	4,700	4,700	4,700	4,800	4,800	4,800	4,800	4,800	4,800
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J Import (B+C)**	4,689	4,689	4,689	4,689	4,789	4,789	4,789	4,789	4,789	4,789
E	Loss of Source Contingency	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)
F	**Resource Need (A+D+E)**	(8,695)	(8,726)	(8,747)	(8,767)	(8,688)	(8,739)	(8,822)	(8,894)	(8,987)	(9,070)
G	J Generation (1)	8,123	8,939	8,939	8,939	8,939	8,529	8,529	8,529	8,529	8,529
H	J Generation Unavailability (2)	(787)	(1,521)	(1,521)	(1,521)	(1,521)	(1,479)	(1,479)	(1,479)	(1,479)	(1,479)
I	Temperature Based Generation Derates	(86)	(86)	(86)	(86)	(86)	(74)	(74)	(74)	(74)	(74)
J	Net ICAP External Imports (6)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
K	SCRs (3), (4)	228	228	228	228	228	228	228	228	228	228
L	**Total Resources Available (G+H+I+J+K)**	8,868	8,950	8,950	8,950	8,950	8,594	8,594	8,594	8,594	8,594
M	**Transmission Security Margin (F+L)**	173	224	203	183	262	(145)	(228)	(300)	(393)	(476)

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a derate of 225 MW for SCRs.
5. Limits for 2026 through 2029 are based on the summer peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on the summer peak 2024 representations evaluated in the 2024 RNA.
6. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

Figure 78: Summer Peak New York City Transmission Security Margin Calculation – Planned System, 1-in-100-Year Heatwave

Summer Peak - 1-in-100-Year Extreme Heatwave, Emergency Transfer Criteria (MW)											
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
A	**Zone J Demand Forecast**	(11,594)	(11,626)	(11,647)	(11,669)	(11,690)	(11,744)	(11,830)	(11,905)	(12,002)	(12,088)
B	I+K to J (5)	4,700	4,700	4,700	4,700	4,800	4,800	4,800	4,800	4,800	4,800
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J Import (B+C)**	4,689	4,689	4,689	4,689	4,789	4,789	4,789	4,789	4,789	4,789
E	Loss of Source Contingency	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)
F	**Resource Need (A+D+E)**	(9,140)	(9,172)	(9,193)	(9,215)	(9,136)	(9,190)	(9,276)	(9,351)	(9,448)	(9,534)
G	J Generation (1)	8,123	8,939	8,939	8,939	8,939	8,529	8,529	8,529	8,529	8,529
H	J Generation Unavailability (2)	(787)	(1,521)	(1,521)	(1,521)	(1,521)	(1,479)	(1,479)	(1,479)	(1,479)	(1,479)
I	Temperature Based Generation Derates	(147)	(147)	(147)	(147)	(147)	(136)	(136)	(136)	(136)	(136)
J	Net ICAP External Imports (6)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
K	SCRs (3), (4)	228	228	228	228	228	228	228	228	228	228
L	**Total Resources Available (G+H+I+J+K)**	8,807	8,889	8,889	8,889	8,889	8,533	8,533	8,533	8,533	8,533
M	**Transmission Security Margin (F+L)**	(333)	(284)	(305)	(327)	(248)	(658)	(744)	(819)	(916)	(1,002)

Notes:

1. Reflects the 2023 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for “Capacity Accreditation project – Correlated Derates” requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a derate of 225 MW for SCRs.
5. Limits for 2026 through 2029 are based on the summer peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on the summer peak 2024 representations evaluated in the 2024 RNA.
6. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

Figure 79: Winter Peak New York City Transmission Security Margin Calculation – Status Quo System

Winter Peak - Baseline Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**	**2035-36**
A	**Zone J Demand Forecast**	(7,580)	(7,650)	(7,800)	(7,930)	(8,070)	(8,240)	(8,410)	(8,610)	(8,830)	(9,120)
B	I+K to J (3)	3,900	3,900	3,900	3,900	3,900	3,900	3,900	3,900	3,900	3,900
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	3,889	3,889	3,889	3,889	3,889	3,889	3,889	3,889	3,889	3,889
E	Loss of Source Contingency	(973)	(973)	(973)	(973)	(973)	(973)	(973)	(973)	(973)	(973)
F	**Resource Need (A+D+E)**	(4,664)	(4,734)	(4,884)	(5,014)	(5,154)	(5,324)	(5,494)	(5,694)	(5,914)	(6,204)
G	J Generation (1)	8,602	8,602	8,602	8,602	8,190	8,190	8,190	8,190	8,190	8,190
H	J Generation Unavailability (2)	(721)	(721)	(721)	(721)	(721)	(721)	(721)	(721)	(721)	(721)
I	Unavailability of Non-Firm Gas (4)	(2,057)	(2,057)	(2,057)	(2,057)	(1,646)	(1,646)	(1,646)	(1,646)	(1,646)	(1,646)
J	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
K	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
L	**Total Resources Available (G+H+I+J+K)**	5,963	5,963	5,963	5,963	5,964	5,964	5,964	5,964	5,964	5,964
M	**Transmission Security Margin (F+L)**	1,300	1,230	1,080	950	810	640	470	270	50	(240)

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Limits for 2026 through 2029 are based on the winter peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on the winter peak 2034 representations evaluated in the 2024 RNA.
4. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule 154a which became effective May 2024. Includes all gas only units that do not have a firm gas contract.
5. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

Figure 80: Winter Peak New York City Transmission Security Margin Calculation – Planned System

Winter Peak - Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**	**2035-36**
A	**Zone J Demand Forecast**	(7,580)	(7,650)	(7,800)	(7,930)	(8,070)	(8,240)	(8,410)	(8,610)	(8,830)	(9,120)
B	I+K to J (3)	3,900	3,900	3,900	3,900	4,900	4,900	4,900	4,900	4,900	4,900
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	3,889	3,889	3,889	3,889	4,889	4,889	4,889	4,889	4,889	4,889
E	Loss of Source Contingency	(973)	(973)	(973)	(973)	(1,606)	(1,606)	(1,606)	(1,606)	(1,606)	(1,606)
F	**Resource Need (A+D+E)**	(4,664)	(4,734)	(4,884)	(5,014)	(4,787)	(4,957)	(5,127)	(5,327)	(5,547)	(5,837)
G	J Generation (1)	9,433	9,433	9,433	9,433	9,021	9,021	9,021	9,021	9,021	9,021
H	J Generation Unavailability (2)	(1,389)	(1,389)	(1,389)	(1,389)	(1,388)	(1,388)	(1,388)	(1,388)	(1,388)	(1,388)
I	Unavailability of Non-Firm Gas (4)	(2,057)	(2,057)	(2,057)	(2,057)	(1,646)	(1,646)	(1,646)	(1,646)	(1,646)	(1,646)
J	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
K	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
L	**Total Resources Available (G+H+I+J+K)**	6,127	6,127	6,127	6,127	6,127	6,127	6,127	6,127	6,127	6,127
M	**Transmission Security Margin (F+L)**	1,463	1,393	1,243	1,113	1,340	1,170	1,000	800	580	290

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Limits for 2026 through 2029 are based on the winter peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on the winter peak 2034 representations evaluated in the 2024 RNA.
4. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule 154a which became effective May 2024. Includes all gas only units that do not have a firm gas contract.
5. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

Figure 81: Winter Peak New York City Transmission Security Margin – Planned System, 1-in-10-Year Cold Snap

Winter Peak - 1-in-10-Year Cold Snap, Emergency Transfer Criteria (MW)											
Line	**Item**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**	**2035-36**
A	**Zone J Demand Forecast**	(7,906)	(7,987)	(8,151)	(8,303)	(8,465)	(8,668)	(8,873)	(9,101)	(9,360)	(9,695)
B	I+K to J (5)	3,900	3,900	3,900	3,900	4,900	4,900	4,900	4,900	4,900	4,900
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J Import (B+C)**	3,889	3,889	3,889	3,889	4,889	4,889	4,889	4,889	4,889	4,889
E	Loss of Source Contingency	(973)	(973)	(973)	(973)	(1,606)	(1,606)	(1,606)	(1,606)	(1,606)	(1,606)
F	**Resource Need (A+D+E)**	(4,990)	(5,071)	(5,235)	(5,387)	(5,182)	(5,385)	(5,590)	(5,818)	(6,077)	(6,412)
G	J Generation (1)	9,433	9,433	9,433	9,433	9,021	9,021	9,021	9,021	9,021	9,021
H	J Generation Unavailability (2)	(1,389)	(1,389)	(1,389)	(1,389)	(1,388)	(1,388)	(1,388)	(1,388)	(1,388)	(1,388)
I	Shortage of Gas Fuel Supply (6)	(2,057)	(2,057)	(2,057)	(2,057)	(1,646)	(1,646)	(1,646)	(1,646)	(1,646)	(1,646)
J	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
K	Net ICAP External Imports (7)	140	140	140	140	140	140	140	140	140	140
L	SCRs (3), (4)	140	140	140	140	140	140	140	140	140	140
M	**Total Resources Available (G+H+I+J+K)**	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267
N	**Transmission Security Margin (F+L)**	1,277	1,196	1,032	880	1,086	883	678	450	191	(144)

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a derate of 138 MW for SCRs.
5. Limits for 2026 through 2029 are based on the winter peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on the winter peak 2034 representations evaluated in the 2024 RNA.
6. Includes all gas only units that do not have a firm gas contract.
7. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

Figure 82: Winter Peak New York City Transmission Security Margin – Planned System, 1-in-100-Year Cold Snap

Winter Peak - 1-in-100-Year Extreme Cold Snap, Emergency Transfer Criteria (MW)											
Line	**Item**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**	**2035-36**
A	**Zone J Demand Forecast**	(8,232)	(8,323)	(8,502)	(8,667)	(8,853)	(9,089)	(9,318)	(9,583)	(9,872)	(10,242)
B	I+K to J (5)	3,900	3,900	3,900	3,900	4,900	4,900	4,900	4,900	4,900	4,900
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J Import (B+C)**	3,889	3,889	3,889	3,889	4,889	4,889	4,889	4,889	4,889	4,889
E	Loss of Source Contingency	(973)	(973)	(973)	(973)	(1,606)	(1,606)	(1,606)	(1,606)	(1,606)	(1,606)
F	**Resource Need (A+D+E)**	(5,316)	(5,407)	(5,586)	(5,751)	(5,570)	(5,806)	(6,035)	(6,300)	(6,589)	(6,959)
G	J Generation (1)	9,433	9,433	9,433	9,433	9,021	9,021	9,021	9,021	9,021	9,021
H	J Generation Unavailability (2)	(1,389)	(1,389)	(1,389)	(1,389)	(1,388)	(1,388)	(1,388)	(1,388)	(1,388)	(1,388)
I	Shortage of Gas Fuel Supply (6)	(2,057)	(2,057)	(2,057)	(2,057)	(1,646)	(1,646)	(1,646)	(1,646)	(1,646)	(1,646)
I	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
J	Net ICAP External Imports (7)	140	140	140	140	140	140	140	140	140	140
K	SCRs (3), (4)	140	140	140	140	140	140	140	140	140	140
L	**Total Resources Available (G+H+I+J+K)**	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267	6,267
M	**Transmission Security Margin (F+L)**	951	860	681	516	698	462	233	(32)	(321)	(691)

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a derate of 138 MW for SCRs.
5. Limits for 2026 through 2029 are based on the winter peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on the winter peak 2034 representations evaluated in the 2024 RNA.
6. Includes all gas only units that do not have a firm gas contract.
7. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

Long Island (Zone K)

The Long Island locality comprises Zone K. Within the Long Island Power Authority (LIPA) service territory, the BPTF system (primarily comprised of 138 kV transmission) is designed for N-1-1. To determine the transmission security margin for this area, the most limiting combination of two non-simultaneous contingency events (N-1-1) to the transmission security margin is determined.

For summer 2026 through summer 2029, the most limiting contingency combination is the loss of the Neptune HVDC cable followed by a stuck breaker event at Sprain Brook leading to loss of the Y49 cable. From summer 2030 onward, after the Propel NY project is in service, the limiting contingency combination changes to the loss of the Y50 cable followed by a stuck breaker event at Uniondale. For winter 2026-2027 through winter 2029-2030, the most limiting contingency combination is the loss of the Neptune HVDC cable followed by a stuck breaker event at Sprain Brook. From winter 2030-2031 onward, after the Propel NY project is in service, the limiting contingency combination changes to the loss of the Northport 1 unit followed by loss of a Shore Road-Lake Success 138 kV line (367).

Figures below show the calculation of the summer and winter Long Island transmission security margin. Significant increases in transmission security margins are seen after the Long Island Public Policy transmission project is placed in service.

Figure 83: Summer Peak Long Island Margin Calculation – Status Quo System

Summer Peak - Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
A	**Zone K Demand Forecast**	(4,996)	(5,017)	(5,038)	(5,083)	(5,151)	(5,222)	(5,281)	(5,344)	(5,396)	(5,465)
B	I+J to K (3)	900	900	900	900	900	900	900	900	900	900
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	900	900	900	900	900	900	900	900	900	900
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	**Resource Need (A+D+E)**	(4,756)	(4,777)	(4,798)	(4,843)	(4,911)	(4,982)	(5,041)	(5,104)	(5,156)	(5,225)
G	K Generation (1)	5,001	4,901	4,901	4,901	4,901	4,856	4,856	4,856	4,856	4,856
H	K Generation Unavailability (2)	(832)	(823)	(823)	(824)	(825)	(820)	(821)	(821)	(821)	(821)
I	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
J	Net ICAP External Imports (4)	949	660	660	660	660	660	660	660	660	660
K	**Total Resources Available (G+H+I+J)**	5,117	4,738	4,737	4,736	4,736	4,695	4,695	4,695	4,694	4,694
L	**Transmission Security Margin (F+K)**	361	(39)	(61)	(107)	(175)	(287)	(346)	(409)	(462)	(531)
M	Higher Demand Impact	(43)	(34)	(30)	(24)	(36)	(47)	(63)	(65)	(110)	(165)
N	**Higher Demand Transmission Security Margin (L+M)**	318	(73)	(91)	(131)	(211)	(334)	(409)	(474)	(572)	(696)

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2023 https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 200 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for “Capacity Accreditation project – Correlated Derates” requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.

3. Limits for 2026 through 2029 are based on the 2024 LIPA Summer Operating Study. Limits for 2030 through 2034 are based on the 2034-2035W winter peak representations evaluated in the 2024RNA.
4. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.

Figure 84: Summer Peak Long Island Margin Calculation – Planned System

Summer Peak - Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
A	**Zone K Demand Forecast**	(4,996)	(5,017)	(5,038)	(5,083)	(5,151)	(5,222)	(5,281)	(5,344)	(5,396)	(5,465)
B	I+J to K (3)	900	900	900	900	2,200	2,200	2,200	2,200	2,200	2,200
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	900	900	900	900	2,200	2,200	2,200	2,200	2,200	2,200
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	0	0	0	0	0	0
F	**Resource Need (A+D+E)**	(4,756)	(4,777)	(4,798)	(4,843)	(2,951)	(3,022)	(3,081)	(3,144)	(3,196)	(3,265)
G	K Generation (1)	5,001	4,901	5,825	5,825	5,825	5,780	5,780	5,780	5,780	5,780
H	K Generation Unavailability (2)	(832)	(823)	(1,655)	(1,656)	(1,656)	(1,652)	(1,652)	(1,652)	(1,653)	(1,653)
I	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
J	Net ICAP External Imports (4)	949	660	660	660	660	660	660	660	660	660
K	**Total Resources Available (G+H+I+J)**	5,117	4,738	4,829	4,829	4,828	4,788	4,787	4,787	4,787	4,787
L	**Transmission Security Margin (F+K)**	361	(39)	31	(14)	1,877	1,766	1,706	1,643	1,591	1,522
M	Higher Demand Impact	(43)	(34)	(30)	(24)	(36)	(47)	(63)	(65)	(110)	(165)
N	**Higher Demand Transmission Security Margin (L+M)**	318	(73)	1	(38)	1,841	1,719	1,643	1,578	1,481	1,357
O	Noncoincident Peak Demand Impact	(76)	(77)	(77)	(78)	(79)	(80)	(81)	(82)	(83)	(84)
P	**Noncoincident Peak Transmission Security Margin (L+O)**	285	(116)	(46)	(92)	1,798	1,686	1,625	1,561	1,508	1,438

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2023 https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 200 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for “Capacity Accreditation project – Correlated Derates” requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.

3. Limits for 2026 through 2029 are based on the 2024 LIPA Summer Operating Study. Limits for 2030 through 2034 are based on the 2034-2035W winter peak representations evaluated in the 2024RNA.
4. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.

Figure 85: Summer Peak Long Island Margin Calculation – Planned System, 1-in-10-Year Heatwave

Summer Peak - 1-in-10-Year Heatwave, Emergency Transfer Criteria (MW)											
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
A	**Zone K Demand Forecast**	(5,394)	(5,417)	(5,439)	(5,488)	(5,561)	(5,638)	(5,702)	(5,770)	(5,826)	(5,900)
B	I+J to K	900	900	900	900	2,500	2,500	2,500	2,500	2,500	2,500
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	900	900	900	900	2,500	2,500	2,500	2,500	2,500	2,500
E	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
F	**Resource Need (A+D+E)**	(4,494)	(4,517)	(4,539)	(4,588)	(3,061)	(3,138)	(3,202)	(3,270)	(3,326)	(3,400)
G	K Generation (1)	5,001	4,901	5,825	5,825	5,825	5,780	5,780	5,780	5,780	5,780
H	K Generation Unavailability (2)	(832)	(823)	(1,655)	(1,656)	(1,656)	(1,652)	(1,652)	(1,652)	(1,653)	(1,653)
I	Temperature Based Generation Derates	(82)	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(78)
J	Net ICAP External Imports (5)	949	660	660	660	660	660	660	660	660	660
K	SCRs (3), (4)	11	11	11	11	11	11	11	11	11	11
L	**Total Resources Available (G+H+I+J+K)**	5,046	4,670	4,762	4,762	4,761	4,721	4,720	4,720	4,719	4,719
M	**Transmission Security Margin (F+L)**	552	153	223	174	1,700	1,583	1,518	1,450	1,393	1,319

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2023 https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 200 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for “Capacity Accreditation project – Correlated Derates” requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a derate of 12 MW for SCRs.
5. Interchanges are based on ERAG MMWG values and firm transactions. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.

Figure 86: Summer Peak Long Island Margin Calculation – Planned System, 1-in-100-Year Heatwave

Summer Peak - 1-in-100-Year Extreme Heatwave, Emergency Transfer Criteria (MW)											
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
A	**Zone K Demand Forecast**	(5,709)	(5,733)	(5,757)	(5,808)	(5,886)	(5,967)	(6,035)	(6,107)	(6,166)	(6,245)
B	I+J to K	900	900	900	900	2,500	2,500	2,500	2,500	2,500	2,500
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	900	900	900	900	2,500	2,500	2,500	2,500	2,500	2,500
E	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
F	**Resource Need (A+D+E)**	(4,809)	(4,833)	(4,857)	(4,908)	(3,386)	(3,467)	(3,535)	(3,607)	(3,666)	(3,745)
G	K Generation (1)	5,001	4,901	5,825	5,825	5,825	5,780	5,780	5,780	5,780	5,780
H	K Generation Unavailability (2)	(832)	(823)	(1,655)	(1,656)	(1,656)	(1,652)	(1,652)	(1,652)	(1,653)	(1,653)
I	Temperature Based Generation Derates	(127)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)
J	Net ICAP External Imports (5)	949	660	660	660	660	660	660	660	660	660
K	SCRs (3), (4)	11	11	11	11	11	11	11	11	11	11
L	**Total Resources Available (G+H+I+J+K)**	5,001	4,628	4,719	4,719	4,718	4,678	4,677	4,677	4,677	4,677
M	**Transmission Security Margin (F+L)**	192	(205)	(138)	(189)	1,332	1,211	1,142	1,070	1,011	932

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2023 https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 200 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for “Capacity Accreditation project – Correlated Derates” requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a derate of 12 MW for SCRs.
5. Interchanges are based on ERAG MMWG values and firm transactions. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.

Figure 87: Winter Peak Long Island Margin Calculation – Status Quo System

Winter Peak - Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**	**2035-36**
A	**Zone K Demand Forecast**	(3,276)	(3,349)	(3,478)	(3,630)	(3,770)	(3,919)	(4,057)	(4,178)	(4,286)	(4,408)
B	I+J to K (3), (4)	900	900	900	900	900	900	900	900	900	900
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	900	900	900	900	900	900	900	900	900	900
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	**Resource Need (A+D+E)**	(3,036)	(3,109)	(3,238)	(3,390)	(3,530)	(3,679)	(3,817)	(3,938)	(4,046)	(4,168)
G	K Generation (1)	5,437	5,320	5,320	5,320	5,274	5,274	5,274	5,274	5,274	5,274
H	K Generation Unavailability (2)	(852)	(840)	(840)	(840)	(839)	(839)	(839)	(839)	(839)	(839)
I	Shortage of Gas Fuel Supply (5)	(318)	(318)	(318)	(318)	(272)	(272)	(272)	(272)	(272)	(272)
J	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
K	Net ICAP External Imports (6)	949	660	660	660	660	660	660	660	660	660
L	**Total Resources Available (G+H+I+J+K)**	5,216	4,822	4,822	4,822	4,823	4,823	4,823	4,823	4,823	4,823
M	**Transmission Security Margin (F+L)**	2,180	1,713	1,584	1,432	1,293	1,144	1,006	885	777	655

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. For winter the expected solar PV output at peak is 0 MW. Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 200 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Limits for 2026 through 2029 are based on the 2024 LIPA Summer Operating Study. Limits for 2030 through 2034 are based on the 2034-2035W winter peak representations evaluated in the 2024RNA.
4. As a conservative winter peak assumption these limits utilize the summer values through 2029-2030W.
5. Includes all gas only units that do not have a firm gas contract.
6. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.

Figure 88: Winter Peak Long Island Margin Calculation – Planned System

Winter Peak - Baseline Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**	**2035-36**
A	**Zone K Demand Forecast**	(3,276)	(3,349)	(3,478)	(3,630)	(3,770)	(3,919)	(4,057)	(4,178)	(4,286)	(4,408)
B	I+J to K (3), (4)	900	900	900	900	2,500	2,500	2,500	2,500	2,500	2,500
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	900	900	900	900	2,500	2,500	2,500	2,500	2,500	2,500
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(399)	(399)	(399)	(399)	(399)	(399)
F	**Resource Need (A+D+E)**	(3,036)	(3,109)	(3,238)	(3,390)	(1,669)	(1,818)	(1,956)	(2,077)	(2,185)	(2,307)
G	K Generation (1)	5,437	6,244	6,244	6,244	6,198	6,198	6,198	6,198	6,198	6,198
H	K Generation Unavailability (2)	(852)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)
I	Shortage of Gas Fuel Supply (5)	(318)	(318)	(318)	(318)	(272)	(272)	(272)	(272)	(272)	(272)
J	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
K	Net ICAP External Imports (6)	949	660	660	660	660	660	660	660	660	660
L	**Total Resources Available (G+H+I+J+K)**	5,216	5,007	5,007	5,007	5,007	5,007	5,007	5,007	5,007	5,007
M	**Transmission Security Margin (F+L)**	2,180	1,898	1,769	1,617	3,339	3,190	3,052	2,931	2,823	2,701

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. For winter the expected solar PV output at peak is 0 MW. Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 200 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Limits for 2026 through 2029 are based on the 2024 LIPA Summer Operating Study. Limits for 2030 through 2034 are based on the 2034-2035W winter peak representations evaluated in the 2024RNA.
4. As a conservative winter peak assumption these limits utilize the summer values through 2029-2030W.
5. Includes all gas only units that do not have a firm gas contract.
6. Interchanges are based on ERAG MMWG values and firm transactions. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.

Figure 89: Winter Peak Long Island Margin Calculation - Planned System, 1-in-10-Year Cold Snap

Winter Peak - 1-in-10-Year Cold Snap, Emergency Transfer Criteria (MW)											
Line	**Item**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**	**2035-36**
A	**Zone K Demand Forecast**	(3,417)	(3,496)	(3,635)	(3,801)	(3,955)	(4,123)	(4,280)	(4,416)	(4,543)	(4,686)
B	I+J to K (5), (6)	900	900	900	900	2,700	2,700	2,700	2,700	2,700	2,700
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	900	900	900	900	2,700	2,700	2,700	2,700	2,700	2,700
E	Loss of Source Contingency	0	0	0	0	(399)	(399)	(399)	(399)	(399)	(399)
F	**Resource Need (A+D+E)**	(2,517)	(2,596)	(2,735)	(2,901)	(1,654)	(1,822)	(1,979)	(2,115)	(2,242)	(2,385)
G	K Generation (1)	5,437	6,244	6,244	6,244	6,198	6,198	6,198	6,198	6,198	6,198
H	K Generation Unavailability (2)	(852)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)
I	Shortage of Gas Fuel Supply (7)	(318)	(318)	(318)	(318)	(272)	(272)	(272)	(272)	(272)	(272)
J	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
K	Net ICAP External Imports (8)	949	660	660	660	660	660	660	660	660	660
L	SCRs (3), (4)	6	6	6	6	6	6	6	6	6	6
M	**Total Resources Available (G+H+I+J+K+L)**	5,222	5,013	5,013	5,013	5,014	5,014	5,014	5,014	5,014	5,014
N	**Transmission Security Margin (F+M)**	2,705	2,417	2,278	2,112	3,360	3,192	3,035	2,899	2,772	2,629

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. For winter the expected solar PV output at peak is 0 MW. Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 200 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for “Capacity Accreditation project – Correlated Derates” requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a derate of 7 MW for SCRs.
5. Limits for 2026 through 2029 are based on the 2024 LIPA Summer Operating Study. Limits for 2030 through 2034 are based on the 2034-2035W winter peak representations evaluated in the 2024RNA.
6. As a conservative winter peak assumption these limits utilize the summer values through 2029-2030W.
7. Includes all gas only units that do not have a firm gas contract.
8. Interchanges are based on ERAG MMWG values and firm transactions. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.

Figure 90: Winter Peak Long Island Margin Calculation – Planned System, 1-in-100-Year Cold Snap

Winter Peak - 1-in-100-Year Extreme Cold Snap, Emergency Transfer Criteria (MW)											
Line	**Item**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**	**2035-36**
A	**Zone K Demand Forecast**	(3,558)	(3,644)	(3,791)	(3,968)	(4,136)	(4,323)	(4,495)	(4,650)	(4,792)	(4,950)
B	I+J to K (5), (6)	900	900	900	900	2,700	2,700	2,700	2,700	2,700	2,700
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	900	900	900	900	2,700	2,700	2,700	2,700	2,700	2,700
E	Loss of Source Contingency	0	0	0	0	(399)	(399)	(399)	(399)	(399)	(399)
F	**Resource Need (A+D+E)**	(2,658)	(2,744)	(2,891)	(3,068)	(1,835)	(2,022)	(2,194)	(2,349)	(2,491)	(2,649)
G	K Generation (1)	5,437	6,244	6,244	6,244	6,198	6,198	6,198	6,198	6,198	6,198
H	K Generation Unavailability (2)	(852)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)	(1,579)
I	Shortage of Gas Fuel Supply (7)	(318)	(318)	(318)	(318)	(272)	(272)	(272)	(272)	(272)	(272)
J	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
K	Net ICAP External Imports (8)	949	660	660	660	660	660	660	660	660	660
L	SCRs (3), (4)	6	6	6	6	6	6	6	6	6	6
M	**Total Resources Available (G+H+I+J+K+L)**	5,222	5,013	5,013	5,013	5,014	5,014	5,014	5,014	5,014	5,014
N	**Transmission Security Margin (F+M)**	2,564	2,269	2,122	1,945	3,179	2,992	2,820	2,665	2,523	2,365

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. For winter the expected solar PV output at peak is 0 MW. Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 200 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
4. Includes a derate of 7 MW for SCRs.
5. Limits for 2026 through 2029 are based on the 2024 LIPA Summer Operating Study. Limits for 2030 through 2034 are based on the 2034-2035W winter peak representations evaluated in the 2024RNA.
6. As a conservative winter peak assumption these limits utilize the summer values through 2029-2030W.
7. Includes all gas only units that do not have a firm gas contract.
8. Interchanges are based on ERAG MMWG values and firm transactions. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.

Appendix F – Additional Outage Impacts to Margins

The figures in this section show the impact of additional generator and plant outages, or Additional Outage Impacts (AOI), on the statewide system margin and transmission security margins for each locality. The impact of the outages is shown relative to the base margins considering the higher demand forecast with flexible large loads modeled offline.

- Figure 91: AOI - Statewide System Margin
- Figure 92: AOI - Lower Hudson Valley Transmission Security Margin
- Figure 93: AOI - New York City Transmission Security Margin
- Figure 94: AOI - Long Island Transmission Security Margin

Figure 91: AOI - Statewide System Margin

Statewide System Margin												
Year				2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				624	589	594	359	43	(670)	(1,026)	(1,376)	(1,701)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Jamestown 5, 6 & 7	74.7	(7.90)	66.80	557	523	528	292	(24)	(737)	(1,092)	(1,442)	(1,768)
Jamestown 5	19.0	(2.06)	16.94	607	572	578	342	26	(687)	(1,043)	(1,393)	(1,718)
Jamestown 6	16.5	(1.79)	14.71	609	575	580	344	28	(685)	(1,040)	(1,390)	(1,716)
Jamestown 7	39.2	(4.05)	35.15	589	554	559	324	8	(705)	(1,061)	(1,411)	(1,737)
Indeck-Yerkes	43.1	(2.03)	41.07	583	548	553	318	2	(711)	(1,067)	(1,417)	(1,742)
Indeck-Olean	79.0	(3.72)	75.28	549	514	519	284	(32)	(745)	(1,101)	(1,451)	(1,777)
American Ref-Fuel 1 & 2	37.6	(4.08)	33.52	590	556	561	325	10	(704)	(1,059)	(1,409)	(1,735)
American Ref-Fuel 1	18.8	(2.04)	16.76	607	573	578	342	26	(687)	(1,042)	(1,392)	(1,718)
American Ref-Fuel 2	18.8	(2.04)	16.76	607	573	578	342	26	(687)	(1,042)	(1,392)	(1,718)
Fortistar - N.Tonawanda (BTM:NG)	46.5	(2.19)	44.31	580	545	550	314	(1)	(714)	(1,070)	(1,420)	(1,746)
Model City Energy	5.6	(0.74)	4.86	619	584	590	354	38	(675)	(1,031)	(1,381)	(1,706)
Modern LF	6.4	(0.84)	5.56	618	584	589	353	38	(676)	(1,031)	(1,381)	(1,707)
Chaffee	6.4	(0.84)	5.56	618	584	589	353	38	(676)	(1,031)	(1,381)	(1,707)
Chautauqua LFGE	0.0	0.00	0.00	624	589	594	359	43	(670)	(1,026)	(1,376)	(1,701)
Lockport CC1, CC2, and CC3	210.0	(9.89)	200.11	424	389	394	159	(157)	(870)	(1,226)	(1,576)	(1,901)
Lockport CC1	70.0	(3.30)	66.70	557	523	528	292	(24)	(737)	(1,092)	(1,442)	(1,768)
Lockport CC2	70.0	(3.30)	66.70	557	523	528	292	(24)	(737)	(1,092)	(1,442)	(1,768)
Lockport CC3	70.0	(3.30)	66.70	557	523	528	292	(24)	(737)	(1,092)	(1,442)	(1,768)
Allegany	62.7	(2.95)	59.75	564	530	535	299	(17)	(730)	(1,085)	(1,435)	(1,761)
R. E. Ginna	578.8	(11.98)	566.82	57	23	28	(208)	(524)	(1,237)	(1,593)	(1,943)	(2,268)
Batavia	47.5	(2.24)	45.26	579	544	549	314	(2)	(715)	(1,071)	(1,421)	(1,747)
Nine Mile Point 2[2]	1,283.4	(23.10)	1,260.30	(348)	(383)	(377)	(613)	(929)	(1,642)	(1,998)	(2,348)	(2,673)
Mill Seat	6.4	(0.84)	5.56	618	584	589	353	38	(676)	(1,031)	(1,381)	(1,707)
Hyland LFGE	4.8	(0.63)	4.17	620	585	590	355	39	(674)	(1,030)	(1,380)	(1,706)
Synergy Biogas	0.0	0.00	0.00	624	589	594	359	43	(670)	(1,026)	(1,376)	(1,701)
Red Rochester (BTM:NG)	16.5	(1.79)	14.71	609	575	580	344	28	(685)	(1,040)	(1,390)	(1,716)
James A. FitzPatrick	844.0	(15.19)	828.81	(205)	(239)	(234)	(470)	(786)	(1,499)	(1,855)	(2,205)	(2,530)
Oswego 6	791.7	(85.90)	705.80	(82)	(116)	(111)	(347)	(663)	(1,376)	(1,731)	(2,081)	(2,407)
Oswego 5	820.5	(89.02)	731.48	(107)	(142)	(137)	(373)	(688)	(1,402)	(1,757)	(2,107)	(2,433)
Nine Mile Point 1	619.7	(11.15)	608.55	15	(19)	(14)	(250)	(565)	(1,279)	(1,634)	(1,984)	(2,310)

Statewide System Margin												
Year				2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				624	589	594	359	43	(670)	(1,026)	(1,376)	(1,701)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Independence GS1, GS2, GS3, & GS4	996.4	(46.93)	949.47	(325)	(360)	(355)	(591)	(906)	(1,619)	(1,975)	(2,325)	(2,651)
Independence GS1	249.1	(11.73)	237.37	387	352	357	121	(194)	(907)	(1,263)	(1,613)	(1,939)
Independence GS2	249.1	(11.73)	237.37	387	352	357	121	(194)	(907)	(1,263)	(1,613)	(1,939)
Independence GS3	249.1	(11.73)	237.37	387	352	357	121	(194)	(907)	(1,263)	(1,613)	(1,939)
Independence GS4	249.1	(11.73)	237.37	387	352	357	121	(194)	(907)	(1,263)	(1,613)	(1,939)
Syracuse	86.2	(4.06)	82.14	542	507	512	277	(39)	(752)	(1,108)	(1,458)	(1,783)
Carr St.-E. Syr	89.6	(4.22)	85.38	539	504	509	273	(42)	(755)	(1,111)	(1,461)	(1,787)
Indeck-Oswego	51.9	(2.44)	49.46	575	540	545	309	(6)	(719)	(1,075)	(1,425)	(1,751)
Indeck-Silver Springs	52.7	(2.48)	50.22	574	539	544	309	(7)	(720)	(1,076)	(1,426)	(1,752)
Greenidge 4 (BTM:NG)	29.8	(3.23)	26.57	597	(1,047)	169	(36)	(240)	(494)	(834)	(1,328)	(1,823)
Ontario LFGE	11.2	(1.48)	9.72	614	580	585	349	33	(680)	(1,035)	(1,385)	(1,711)
High Acres	9.6	(1.27)	8.33	616	581	586	350	35	(678)	(1,034)	(1,384)	(1,710)
Seneca Energy 1 & 2	17.6	(2.32)	15.28	609	574	579	344	28	(685)	(1,041)	(1,391)	(1,717)
Seneca Energy 1	8.8	(1.16)	7.64	616	582	587	351	35	(678)	(1,033)	(1,383)	(1,709)
Seneca Energy 2	8.8	(1.16)	7.64	616	582	587	351	35	(678)	(1,033)	(1,383)	(1,709)
Broome LFGE	2.4	(0.32)	2.08	622	587	592	357	41	(672)	(1,028)	(1,378)	(1,703)
Massena	79.5	(3.74)	75.76	548	514	519	283	(33)	(746)	(1,101)	(1,451)	(1,777)
Clinton LFGE	6.4	(0.84)	5.56	618	584	589	353	38	(676)	(1,031)	(1,381)	(1,707)
Saranac Energy CC1 & CC2	239.4	(11.28)	228.12	396	361	366	131	(185)	(898)	(1,254)	(1,604)	(1,929)
Saranac Energy CC1	122.1	(5.75)	116.35	508	473	478	242	(73)	(786)	(1,142)	(1,492)	(1,818)
Saranac Energy CC2	117.3	(5.52)	111.78	512	478	483	247	(69)	(782)	(1,137)	(1,487)	(1,813)
Sterling	48.4	(2.28)	46.12	578	543	548	313	(3)	(716)	(1,072)	(1,422)	(1,747)
Carthage Energy	52.8	(2.49)	50.31	574	539	544	308	(7)	(720)	(1,076)	(1,426)	(1,752)
Beaver Falls	79.7	(3.75)	75.95	548	513	519	283	(33)	(746)	(1,102)	(1,452)	(1,777)
Broome 2 LFGE	2.1	(0.28)	1.82	622	588	593	357	41	(672)	(1,028)	(1,378)	(1,703)
DANC LFGE	6.4	(0.84)	5.56	618	584	589	353	38	(676)	(1,031)	(1,381)	(1,707)
Oneida-Herkimer LFGE	3.2	(0.42)	2.78	621	587	592	356	40	(673)	(1,028)	(1,378)	(1,704)
Athens 1, 2, and 3	947.7	(44.64)	903.06	(279)	(314)	(309)	(544)	(860)	(1,573)	(1,929)	(2,279)	(2,604)
Athens 1	329.4	(15.51)	313.89	310	275	281	45	(271)	(984)	(1,340)	(1,690)	(2,015)
Athens 2	333.3	(15.70)	317.60	306	272	277	41	(274)	(988)	(1,343)	(1,693)	(2,019)
Athens 3	285.0	(13.42)	271.58	352	318	323	87	(228)	(942)	(1,297)	(1,647)	(1,973)
Rensselaer	76.8	(3.62)	73.18	551	516	521	286	(30)	(743)	(1,099)	(1,449)	(1,775)
Wheelabrator Hudson Falls	10.4	(1.13)	9.27	615	580	585	350	34	(679)	(1,035)	(1,385)	(1,711)

Statewide System Margin												
Year				2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				624	589	594	359	43	(670)	(1,026)	(1,376)	(1,701)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Selkirk I & II	353.0	(16.63)	336.37	288	253	258	22	(293)	(1,006)	(1,362)	(1,712)	(2,038)
Selkirk-I	76.4	(3.60)	72.80	551	517	522	286	(30)	(743)	(1,098)	(1,448)	(1,774)
Selkirk-II	276.6	(13.03)	263.57	360	326	331	95	(220)	(934)	(1,289)	(1,639)	(1,965)
Indeck-Corinth	128.5	(6.05)	122.45	502	467	472	236	(79)	(792)	(1,148)	(1,498)	(1,824)
Castleton Energy Center	67.0	(3.16)	63.84	560	525	531	295	(21)	(734)	(1,090)	(1,440)	(1,765)
Bethlehem GS1, GS2, GS3	817.2	(38.49)	778.71	(155)	(189)	(184)	(420)	(736)	(1,449)	(1,804)	(2,154)	(2,480)
Bethlehem GS1	272.4	(12.83)	259.57	364	330	335	99	(216)	(930)	(1,285)	(1,635)	(1,961)
Bethlehem GS2	272.4	(12.83)	259.57	364	330	335	99	(216)	(930)	(1,285)	(1,635)	(1,961)
Bethlehem GS3	272.4	(12.83)	259.57	364	330	335	99	(216)	(930)	(1,285)	(1,635)	(1,961)
Colonie LFGTE	6.4	(0.84)	5.56	618	584	589	353	38	(676)	(1,031)	(1,381)	(1,707)
Albany LFGE	5.6	(0.74)	4.86	619	584	590	354	38	(675)	(1,031)	(1,381)	(1,706)
Fulton LFGE	3.2	(0.42)	2.78	621	587	592	356	40	(673)	(1,028)	(1,378)	(1,704)
Empire CC1 & CC2	591.6	(27.86)	563.74	60	26	31	(205)	(521)	(1,234)	(1,589)	(1,939)	(2,265)
Empire CC1	295.8	(13.93)	281.87	342	307	313	77	(239)	(952)	(1,308)	(1,658)	(1,983)
Empire CC2	295.8	(13.93)	281.87	342	307	313	77	(239)	(952)	(1,308)	(1,658)	(1,983)
Bowline 1 & 2	1,136.3	(123.29)	1,013.01	(389)	(424)	(419)	(654)	(970)	(1,683)	(2,039)	(2,389)	(2,714)
Bowline 1	565.1	(61.31)	503.79	120	86	91	(145)	(461)	(1,174)	(1,529)	(1,879)	(2,205)
Bowline 2	571.2	(61.98)	509.22	115	80	85	(150)	(466)	(1,179)	(1,535)	(1,885)	(2,211)
Danskammer 1, 2, 3, & 4	498.2	(54.05)	444.15	180	145	150	(85)	(401)	(1,114)	(1,470)	(1,820)	(2,146)
Danskammer 1	68.8	(7.46)	61.34	563	528	533	297	(18)	(731)	(1,087)	(1,437)	(1,763)
Danskammer 2	64.9	(7.04)	57.86	566	531	537	301	(15)	(728)	(1,084)	(1,434)	(1,759)
Danskammer 3	140.2	(15.21)	124.99	499	464	469	234	(82)	(795)	(1,151)	(1,501)	(1,826)
Danskammer 4	224.3	(24.34)	199.96	424	389	394	159	(157)	(870)	(1,226)	(1,576)	(1,901)
Roseton 1 & 2	1,224.1	(132.81)	1,091.29	(467)	(502)	(497)	(732)	(1,048)	(1,761)	(2,117)	(2,467)	(2,793)
Roseton 1	616.8	(66.92)	549.88	74	39	45	(191)	(507)	(1,220)	(1,576)	(1,926)	(2,251)
Roseton 2	607.3	(65.89)	541.41	83	48	53	(183)	(498)	(1,211)	(1,567)	(1,917)	(2,243)
Hillburn GT	34.7	(3.14)	31.56	592	558	563	327	12	(702)	(1,057)	(1,407)	(1,733)
Shoemaker GT	32.3	(2.92)	29.38	595	560	565	329	14	(699)	(1,055)	(1,405)	(1,731)
DCRRA	6.3	(0.68)	5.62	618	584	589	353	38	(676)	(1,031)	(1,381)	(1,707)
CPV Valley CC1 & CC2	649.8	(30.61)	619.19	5	(30)	(25)	(260)	(576)	(1,289)	(1,645)	(1,995)	(2,321)
CPV Valley CC1	320.4	(15.09)	305.31	319	284	289	53	(262)	(975)	(1,331)	(1,681)	(2,007)
CPV Valley CC2	329.4	(15.51)	313.89	310	275	281	45	(271)	(984)	(1,340)	(1,690)	(2,015)
Cricket Valley CC1, CC2, & CC3	1,021.6	(48.12)	973.48	(349)	(384)	(379)	(615)	(930)	(1,644)	(1,999)	(2,349)	(2,675)
Cricket Valley CC1	349.7	(16.47)	333.23	291	256	261	26	(290)	(1,003)	(1,359)	(1,709)	(2,035)

Statewide System Margin												
Year				2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				624	589	594	359	43	(670)	(1,026)	(1,376)	(1,701)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Cricket Valley CC2	345.5	(16.27)	329.23	295	260	265	30	(286)	(999)	(1,355)	(1,705)	(2,031)
Cricket Valley CC3	326.4	(15.37)	311.03	313	278	283	48	(268)	(981)	(1,337)	(1,687)	(2,012)
Wheelabrator Westchester	53.5	(5.80)	47.70	576	542	547	311	(5)	(718)	(1,073)	(1,423)	(1,749)
Arthur Kill ST 2 & 3	883.6	(95.87)	787.73	(164)	(198)	(193)	(429)	(745)	(1,458)	(1,813)	(2,163)	(2,489)
Arthur Kill ST 2	363.2	(39.41)	323.79	300	266	271	35	(281)	(994)	(1,349)	(1,699)	(2,025)
Arthur Kill ST 3	520.4	(56.46)	463.94	160	125	131	(105)	(421)	(1,134)	(1,490)	(1,840)	(2,165)
Brooklyn Navy Yard	249.2	(11.74)	237.46	387	352	357	121	(194)	(907)	(1,263)	(1,613)	(1,939)
Astoria 2, 3, & 5	902.3	(97.90)	804.40	(180)	(215)	(210)	(446)	(761)	(1,474)	(1,830)	(2,180)	(2,506)
Astoria 2	158.0	(17.14)	140.86	483	448	454	218	(98)	(811)	(1,167)	(1,517)	(1,842)
Astoria 3	371.1	(40.26)	330.84	293	258	264	28	(288)	(1,001)	(1,357)	(1,707)	(2,032)
Astoria 5	373.2	(40.49)	332.71	291	257	262	26	(290)	(1,003)	(1,358)	(1,708)	(2,034)
Ravenswood ST 01, 02, & 03	1,724.8	(187.14)	1,537.66	(914)	(948)	(943)	(1,179)	(1,495)	(2,208)	(2,563)	(2,913)	(3,239)
Ravenswood ST 01	364.5	(39.55)	324.95	299	264	270	34	(282)	(995)	(1,351)	(1,701)	(2,026)
Ravenswood ST 02	375.2	(40.71)	334.49	290	255	260	24	(291)	(1,005)	(1,360)	(1,710)	(2,036)
Ravenswood ST 03	985.1	(106.88)	878.22	(254)	(289)	(284)	(519)	(835)	(1,548)	(1,904)	(2,254)	(2,580)
Ravenswood CC 04	222.2	(10.47)	211.73	412	378	383	147	(169)	(882)	(1,237)	(1,587)	(1,913)
East River 1, 2, 6, & 7	630.7	(49.54)	581.16	43	8	13	(222)	(538)	(1,251)	(1,607)	(1,957)	(2,283)
East River 1	153.2	(7.22)	145.98	478	443	448	213	(103)	(816)	(1,172)	(1,522)	(1,847)
East River 2	154.5	(7.28)	147.22	477	442	447	212	(104)	(817)	(1,173)	(1,523)	(1,849)
East River 6	141.5	(15.35)	126.15	498	463	468	233	(83)	(796)	(1,152)	(1,502)	(1,828)
East River 7	181.5	(19.69)	161.81	462	428	433	197	(119)	(832)	(1,188)	(1,538)	(1,863)
Linden Cogen	748.2	(35.24)	712.96	(89)	(124)	(118)	(354)	(670)	(1,383)	(1,739)	(2,089)	(2,414)
KIAC_JFK (BTM:NG)	105.4	(4.96)	100.44	524	489	494	258	(57)	(770)	(1,126)	(1,476)	(1,802)
Gowanus 5 & 6[4]	79.9	(8.25)	71.65	552	518	523	287	(29)	-	-	-	-
Gowanus 5[4]	40.0	(4.13)	35.87	588	553	559	323	7	-	-	-	-
Gowanus 6[4]	39.9	(4.12)	35.78	588	554	559	323	7	-	-	-	-
Kent[4]	46.0	(4.75)	41.25	583	548	553	318	2	-	-	-	-
Pouch[4]	44.7	(4.61)	40.09	584	549	554	319	3	-	-	-	-
Hellgate 1 & 2[4]	79.5	(8.20)	71.30	553	518	523	288	(28)	-	-	-	-
Hellgate 1[4]	39.9	(4.12)	35.78	588	554	559	323	7	-	-	-	-
Hellgate 2[4]	39.6	(4.09)	35.51	588	554	559	323	8	-	-	-	-
Harlem River 1 & 2[4]	79.5	(8.20)	71.30	553	518	523	288	(28)	-	-	-	-
Harlem River 1[4]	39.9	(4.12)	35.78	588	554	559	323	7	-	-	-	-
Harlem River 2[4]	39.6	(4.09)	35.51	588	554	559	323	8	-	-	-	-

Statewide System Margin												
Year				2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				624	589	594	359	43	(670)	(1,026)	(1,376)	(1,701)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Vernon Blvd 2 & 3[4]	79.9	(8.25)	71.65	552	518	523	287	(29)	-	-	-	-
Vernon Blvd 2[4]	40.0	(4.13)	35.87	588	553	559	323	7	-	-	-	-
Vernon Blvd 3[4]	39.9	(4.12)	35.78	588	554	559	323	7	-	-	-	-
Astoria CC 1 & 2	474.0	(22.33)	451.67	172	138	143	(93)	(409)	(1,122)	(1,477)	(1,827)	(2,153)
Astoria CC 1	237.0	(11.16)	225.84	398	363	369	133	(183)	(896)	(1,252)	(1,602)	(1,927)
Astoria CC 2	237.0	(11.16)	225.84	398	363	369	133	(183)	(896)	(1,252)	(1,602)	(1,927)
Astoria East Energy CC1 & CC2	582.8	(27.45)	555.35	69	34	39	(197)	(512)	(1,225)	(1,581)	(1,931)	(2,257)
Astoria East Energy - CC1	291.4	(13.72)	277.68	346	312	317	81	(235)	(948)	(1,303)	(1,653)	(1,979)
Astoria East Energy - CC2	291.4	(13.72)	277.68	346	312	317	81	(235)	(948)	(1,303)	(1,653)	(1,979)
Astoria Energy 2 - CC3 & CC4	570.3	(26.86)	543.44	81	46	51	(185)	(500)	(1,213)	(1,569)	(1,919)	(2,245)
Astoria Energy 2 - CC3	285.0	(13.42)	271.58	352	318	323	87	(228)	(942)	(1,297)	(1,647)	(1,973)
Astoria Energy 2 - CC4	285.3	(13.44)	271.86	352	317	323	87	(229)	(942)	(1,298)	(1,648)	(1,973)
Bayonne EC CT G1 through G10	604.8	(54.67)	550.13	74	39	44	(191)	(507)	(1,220)	(1,576)	(1,926)	(2,251)
Bayonne EC CTG1	62.0	(5.60)	56.40	568	533	538	302	(13)	(726)	(1,082)	(1,432)	(1,758)
Bayonne EC CTG2	58.0	(5.24)	52.76	571	537	542	306	(10)	(723)	(1,078)	(1,428)	(1,754)
Bayonne EC CTG3	58.1	(5.25)	52.85	571	536	542	306	(10)	(723)	(1,079)	(1,429)	(1,754)
Bayonne EC CTG4	61.1	(5.52)	55.58	568	534	539	303	(12)	(726)	(1,081)	(1,431)	(1,757)
Bayonne EC CTG5	61.8	(5.59)	56.21	568	533	538	303	(13)	(726)	(1,082)	(1,432)	(1,758)
Bayonne EC CTG6	61.4	(5.55)	55.85	568	533	539	303	(13)	(726)	(1,082)	(1,432)	(1,757)
Bayonne EC CTG7	59.7	(5.40)	54.30	570	535	540	304	(11)	(724)	(1,080)	(1,430)	(1,756)
Bayonne EC CTG8	60.0	(5.42)	54.58	569	535	540	304	(11)	(725)	(1,080)	(1,430)	(1,756)
Bayonne EC CTG9	61.3	(5.54)	55.76	568	534	539	303	(13)	(726)	(1,081)	(1,431)	(1,757)
Bayonne EC CTG10	61.4	(5.55)	55.85	568	533	539	303	(13)	(726)	(1,082)	(1,432)	(1,757)
Greenport IC 4, 5, & 6	5.6	(0.83)	4.77	619	585	590	354	38	(675)	(1,030)	(1,380)	(1,706)
Greenport IC 4	1.0	(0.15)	0.85	623	588	594	358	42	(671)	(1,027)	(1,377)	(1,702)
Greenport IC 5	1.5	(0.22)	1.28	623	588	593	358	42	(671)	(1,027)	(1,377)	(1,703)
Greenport IC 6	3.1	(0.46)	2.64	621	587	592	356	40	(673)	(1,028)	(1,378)	(1,704)
Freeport 1-2, 1-3, & 2-3	19.2	(2.21)	16.99	607	572	577	342	26	(687)	(1,043)	(1,393)	(1,718)
Freeport 1-2	2.3	(0.34)	1.96	622	587	593	357	41	(672)	(1,028)	(1,378)	(1,703)
Freeport 1-3	2.7	(0.40)	2.30	622	587	592	357	41	(672)	(1,028)	(1,378)	(1,704)
Freeport 2-3	14.2	(1.47)	12.73	611	577	582	346	30	(683)	(1,038)	(1,388)	(1,714)
Charles P Killer 09 through 14	13.5	(1.78)	11.72	612	578	583	347	31	(682)	(1,037)	(1,387)	(1,713)
Charles P Keller 09	1.6	(0.21)	1.39	623	588	593	357	42	(671)	(1,027)	(1,377)	(1,703)
Charles P Keller 10	1.6	(0.21)	1.39	623	588	593	357	42	(671)	(1,027)	(1,377)	(1,703)

Statewide System Margin												
Year				2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				624	589	594	359	43	(670)	(1,026)	(1,376)	(1,701)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Charles P Keller 11	2.4	(0.32)	2.08	622	587	592	357	41	(672)	(1,028)	(1,378)	(1,703)
Charles P Keller 12	2.5	(0.33)	2.17	622	587	592	357	41	(672)	(1,028)	(1,378)	(1,704)
Charles P Keller 13	2.5	(0.33)	2.17	622	587	592	357	41	(672)	(1,028)	(1,378)	(1,704)
Charles P Keller 14	2.9	(0.38)	2.52	621	587	592	356	41	(673)	(1,028)	(1,378)	(1,704)
Wading River 1, 2, & 3	214.8	(22.17)	192.63	431	397	402	166	(149)	(863)	(1,218)	(1,568)	(1,894)
Wading River 1	77.6	(8.01)	69.59	554	520	525	289	(26)	(740)	(1,095)	(1,445)	(1,771)
Wading River 2	64.3	(6.64)	57.66	566	532	537	301	(15)	(728)	(1,083)	(1,433)	(1,759)
Wading River 3	72.9	(7.52)	65.38	559	524	529	293	(22)	(735)	(1,091)	(1,441)	(1,767)
Barrett ST 01 & 02	380.5	(41.28)	339.22	285	250	255	20	(296)	(1,009)	(1,365)	(1,715)	(2,041)
Barrett ST 01	192.0	(20.83)	171.17	453	418	423	188	(128)	(841)	(1,197)	(1,547)	(1,873)
Barrett ST 02	188.5	(20.45)	168.05	456	421	426	191	(125)	(838)	(1,194)	(1,544)	(1,869)
Barrett GT 01 through 12	246.6	(23.47)	223.13	401	366	371	136	(180)	(893)	(1,249)	(1,599)	(1,924)
Barrett GT 01	13.7	(1.41)	12.29	612	577	582	347	31	(682)	(1,038)	(1,388)	(1,714)
Barrett GT 02	13.6	(1.40)	12.20	612	577	582	347	31	(682)	(1,038)	(1,388)	(1,714)
Barrett 03	12.2	(1.26)	10.94	613	578	584	348	32	(681)	(1,037)	(1,387)	(1,712)
Barrett 04	14.5	(1.50)	13.00	611	576	581	346	30	(683)	(1,039)	(1,389)	(1,714)
Barrett 05	12.0	(1.24)	10.76	613	579	584	348	32	(681)	(1,036)	(1,386)	(1,712)
Barrett 06	12.9	(1.33)	11.57	612	578	583	347	32	(682)	(1,037)	(1,387)	(1,713)
Barrett 08	12.8	(1.32)	11.48	613	578	583	347	32	(682)	(1,037)	(1,387)	(1,713)
Barrett 09	38.6	(3.49)	35.11	589	554	559	324	8	(705)	(1,061)	(1,411)	(1,736)
Barrett 10	39.2	(3.54)	35.66	588	554	559	323	7	(706)	(1,061)	(1,411)	(1,737)
Barrett 11	38.2	(3.45)	34.75	589	555	560	324	8	(705)	(1,060)	(1,410)	(1,736)
Barrett 12	38.9	(3.52)	35.38	589	554	559	323	8	(705)	(1,061)	(1,411)	(1,737)
Northport 1, 2, 3, and 4	1,582.2	(171.67)	1,410.53	(787)	(821)	(816)	(1,052)	(1,367)	(2,081)	(2,436)	(2,786)	(3,112)
Northport 1	399.0	(43.29)	355.71	268	234	239	3	(313)	(1,026)	(1,381)	(1,731)	(2,057)
Northport 2	399.0	(43.29)	355.71	268	234	239	3	(313)	(1,026)	(1,381)	(1,731)	(2,057)
Northport 3	386.2	(41.90)	344.30	280	245	250	15	(301)	(1,014)	(1,370)	(1,720)	(2,046)
Northport 4	398.0	(43.18)	354.82	269	235	240	4	(312)	(1,025)	(1,381)	(1,731)	(2,056)
Port Jefferson GT 02 & 03	79.3	(8.18)	71.12	553	518	523	288	(28)	(741)	(1,097)	(1,447)	(1,772)
Port Jefferson GT 02	39.1	(4.04)	35.06	589	554	559	324	8	(705)	(1,061)	(1,411)	(1,736)
Port Jefferson GT 03	40.2	(4.15)	36.05	588	553	558	323	7	(706)	(1,062)	(1,412)	(1,737)
Port Jefferson 3 & 4	380.0	(41.23)	338.77	285	251	256	20	(296)	(1,009)	(1,364)	(1,714)	(2,040)
Port Jefferson 3	191.0	(20.72)	170.28	454	419	424	189	(127)	(840)	(1,196)	(1,546)	(1,872)
Port Jefferson 4	189.0	(20.51)	168.49	456	421	426	190	(125)	(839)	(1,194)	(1,544)	(1,870)

Statewide System Margin												
Year				2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				624	589	594	359	43	(670)	(1,026)	(1,376)	(1,701)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Hempstead (RR)	74.2	(8.05)	66.15	558	523	528	293	(23)	(736)	(1,092)	(1,442)	(1,768)
Glenwood GT 02, 04, & 05	123.9	(12.79)	111.11	513	478	483	248	(68)	(781)	(1,137)	(1,487)	(1,812)
Glenwood GT 02	40.3	(4.16)	36.14	588	553	558	323	7	(706)	(1,062)	(1,412)	(1,737)
Glenwood GT 04	41.9	(4.32)	37.58	586	552	557	321	6	(708)	(1,063)	(1,413)	(1,739)
Glenwood GT 05	41.7	(4.30)	37.40	587	552	557	321	6	(707)	(1,063)	(1,413)	(1,739)
Holtsville 01 through 10	527.9	(47.72)	480.18	144	109	114	(121)	(437)	(1,150)	(1,506)	(1,856)	(2,182)
Holtsville 01	54.2	(4.90)	49.30	575	540	545	309	(6)	(719)	(1,075)	(1,425)	(1,751)
Holtsville 02	56.8	(5.13)	51.67	572	538	543	307	(9)	(722)	(1,077)	(1,427)	(1,753)
Holtsville 03	51.2	(4.63)	46.57	577	543	548	312	(3)	(717)	(1,072)	(1,422)	(1,748)
Holtsville 04	53.0	(4.79)	48.21	576	541	546	311	(5)	(718)	(1,074)	(1,424)	(1,750)
Holtsville 05	52.6	(4.76)	47.84	576	541	547	311	(5)	(718)	(1,074)	(1,424)	(1,749)
Holtsville 06	49.4	(4.47)	44.93	579	544	550	314	(2)	(715)	(1,071)	(1,421)	(1,746)
Holtsville 07	54.0	(4.88)	49.12	575	540	545	310	(6)	(719)	(1,075)	(1,425)	(1,750)
Holtsville 08	49.9	(4.51)	45.39	579	544	549	313	(2)	(715)	(1,071)	(1,421)	(1,747)
Holtsville 09	55.4	(5.01)	50.39	574	539	544	308	(7)	(720)	(1,076)	(1,426)	(1,752)
Holtsville 10	51.4	(4.65)	46.75	577	543	548	312	(4)	(717)	(1,072)	(1,422)	(1,748)
Shoreham GT 3 & 4	84.7	(8.74)	75.96	548	513	519	283	(33)	(746)	(1,102)	(1,452)	(1,777)
Shoreham GT3	42.9	(4.43)	38.47	586	551	556	320	5	(709)	(1,064)	(1,414)	(1,740)
Shoreham GT4	41.8	(4.31)	37.49	587	552	557	321	6	(708)	(1,063)	(1,413)	(1,739)
East Hampton GT 01, 2, 3, & 4	23.8	(2.47)	21.33	603	568	573	337	22	(691)	(1,047)	(1,397)	(1,723)
East Hampton GT 01	18.4	(1.66)	16.74	607	573	578	342	26	(687)	(1,042)	(1,392)	(1,718)
East Hampton 2	1.8	(0.27)	1.53	622	588	593	357	42	(672)	(1,027)	(1,377)	(1,703)
East Hampton 3	1.8	(0.27)	1.53	622	588	593	357	42	(672)	(1,027)	(1,377)	(1,703)
East Hampton 4	1.8	(0.27)	1.53	622	588	593	357	42	(672)	(1,027)	(1,377)	(1,703)
Southold 1	9.5	(0.98)	8.52	615	581	586	350	35	(679)	(1,034)	(1,384)	(1,710)
S Hampton 1	8.1	(0.84)	7.26	617	582	587	352	36	(677)	(1,033)	(1,383)	(1,709)
Freeport CT 1 & 2	88.8	(9.16)	79.64	544	510	515	279	(37)	(750)	(1,105)	(1,455)	(1,781)
Freeport CT 1	45.8	(4.73)	41.07	583	548	553	318	2	(711)	(1,067)	(1,417)	(1,742)
Freeport CT 2	43.0	(4.44)	38.56	585	551	556	320	5	(709)	(1,064)	(1,414)	(1,740)
Flynn	139.5	(6.57)	132.93	491	456	462	226	(90)	(803)	(1,159)	(1,509)	(1,834)
Greenport GT1	51.0	(4.61)	46.39	578	543	548	312	(3)	(716)	(1,072)	(1,422)	(1,748)
Far Rockaway GT1 & GT2[3]	-	-	-	-	-	-	-	-	-	-	-	-
Far Rockaway GT1[3]	-	-	-	-	-	-	-	-	-	-	-	-
Far Rockaway GT2[3]	-	-	-	-	-	-	-	-	-	-	-	-

Statewide System Margin												
Year				2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				624	589	594	359	43	(670)	(1,026)	(1,376)	(1,701)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Bethpage	51.0	(2.40)	48.60	575	541	546	310	(5)	(719)	(1,074)	(1,424)	(1,750)
Bethpage 3	75.7	(3.57)	72.13	552	517	522	287	(29)	(742)	(1,098)	(1,448)	(1,773)
Bethpage GT4	43.7	(4.51)	39.19	585	550	555	320	4	(709)	(1,065)	(1,415)	(1,741)
Stony Brook (BTM:NG)	0.0	0.00	0.00	624	589	594	359	43	(670)	(1,026)	(1,376)	(1,701)
Brentwood	45.0	(4.64)	40.36	584	549	554	318	3	(710)	(1,066)	(1,416)	(1,742)
Pilgrim GT1 & GT2	83.6	(8.63)	74.97	549	514	519	284	(32)	(745)	(1,101)	(1,451)	(1,776)
Pilgrim GT1	41.3	(4.26)	37.04	587	552	557	322	6	(707)	(1,063)	(1,413)	(1,738)
Pilgrim GT2	42.3	(4.37)	37.93	586	551	557	321	5	(708)	(1,064)	(1,414)	(1,739)
Pinelawn Power 1[3]	-	-	-	-	-	-	-	-	-	-	-	-
Caithness_CC_1	313.5	(14.77)	298.73	325	291	296	60	(256)	(969)	(1,324)	(1,674)	(2,000)
Islip (RR)	8.0	(0.87)	7.13	617	582	587	352	36	(677)	(1,033)	(1,383)	(1,708)
Babylon (RR)	15.7	(1.70)	14.00	610	575	580	345	29	(684)	(1,040)	(1,390)	(1,715)
Huntington (RR)	24.8	(2.69)	22.11	602	567	572	337	21	(692)	(1,048)	(1,398)	(1,723)

Notes

1. Utilizes the Higher Demand System Margin for Summer Peak with Expected Weather.
2. Utilizes the next largest generation contingency outage which is the loss of the Cricket Valley CC1, CC2, & CC3.
3. Unit is modeled out of service beginning in 2026 in the baseline margin calculation.
4. Unit is modeled out of service beginning in 2031 in the baseline margin calculation.

Figure 92: AOI - Lower Hudson Valley Transmission Security Margin

Lower Hudson Valley												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Lower Hudson Valley Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,953	1,759	1,570	1,441	968	307	52	(231)	(530)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Bowline 1 & 2	1,136.3	(123.29)	1,013.01	940	746	557	428	(45)	(706)	(961)	(1,244)	(1,543)
Bowline 1	565.1	(61.31)	503.79	1,449	1,255	1,066	937	464	(197)	(452)	(735)	(1,034)
Bowline 2	571.2	(61.98)	509.22	1,444	1,250	1,061	931	459	(202)	(457)	(741)	(1,039)
Danskammer 1, 2, 3, & 4	498.2	(54.05)	444.15	1,509	1,315	1,126	997	524	(137)	(392)	(676)	(974)
Danskammer 1	68.8	(7.46)	61.34	1,892	1,698	1,509	1,379	906	245	(9)	(293)	(591)
Danskammer 2	64.9	(7.04)	57.86	1,895	1,701	1,512	1,383	910	249	(6)	(289)	(588)
Danskammer 3	140.2	(15.21)	124.99	1,828	1,634	1,445	1,316	843	182	(73)	(356)	(655)
Danskammer 4	224.3	(24.34)	199.96	1,753	1,559	1,370	1,241	768	107	(148)	(431)	(730)
Roseton 1 & 2	1,224.1	(132.81)	1,091.29	862	668	479	349	(123)	(785)	(1,039)	(1,323)	(1,621)
Roseton 1	616.8	(66.92)	549.88	1,403	1,209	1,020	891	418	(243)	(498)	(781)	(1,080)
Roseton 2	607.3	(65.89)	541.41	1,412	1,218	1,029	899	426	(235)	(489)	(773)	(1,071)
Hillburn GT	34.7	(3.14)	31.56	1,922	1,728	1,539	1,409	936	275	20	(263)	(561)
Shoemaker GT	32.3	(2.92)	29.38	1,924	1,730	1,541	1,411	938	277	23	(261)	(559)
DCRRA	6.3	(0.68)	5.62	1,948	1,754	1,564	1,435	962	301	46	(237)	(536)
CPV Valley CC1 & CC2	649.8	(30.61)	619.19	1,334	1,140	951	821	349	(312)	(567)	(851)	(1,149)
CPV Valley CC1	320.4	(15.09)	305.31	1,648	1,454	1,265	1,135	663	1	(253)	(537)	(835)
CPV Valley CC2	329.4	(15.51)	313.89	1,639	1,445	1,256	1,127	654	(7)	(262)	(545)	(844)
Cricket Valley CC1, CC2, & CC3	1,021.6	(48.12)	973.48	980	786	597	467	(6)	(667)	(922)	(1,205)	(1,503)
Cricket Valley CC1	349.7	(16.47)	333.23	1,620	1,426	1,237	1,107	635	(26)	(281)	(565)	(863)
Cricket Valley CC2	345.5	(16.27)	329.23	1,624	1,430	1,241	1,111	639	(22)	(277)	(561)	(859)
Cricket Valley CC3	326.4	(15.37)	311.03	1,642	1,448	1,259	1,130	657	(4)	(259)	(542)	(841)
Wheelabrator Westchester	53.5	(5.80)	47.70	1,905	1,712	1,522	1,393	920	259	4	(279)	(578)
Arthur Kill ST 2 & 3	883.6	(95.87)	787.73	1,165	972	782	653	180	(481)	(736)	(1,019)	(1,318)
Arthur Kill ST 2	363.2	(39.41)	323.79	1,629	1,435	1,246	1,117	644	(17)	(272)	(555)	(854)
Arthur Kill ST 3	520.4	(56.46)	463.94	1,489	1,295	1,106	977	504	(157)	(412)	(695)	(994)
Brooklyn Navy Yard	249.2	(11.74)	237.46	1,716	1,522	1,333	1,203	730	69	(186)	(469)	(767)
Astoria 2, 3, & 5	902.3	(97.90)	804.40	1,149	955	766	636	163	(498)	(752)	(1,036)	(1,334)
Astoria 2	158.0	(17.14)	140.86	1,812	1,618	1,429	1,300	827	166	(89)	(372)	(671)
Astoria 3	371.1	(40.26)	330.84	1,622	1,428	1,239	1,110	637	(24)	(279)	(562)	(861)
Astoria 5	373.2	(40.49)	332.71	1,620	1,427	1,237	1,108	635	(26)	(281)	(564)	(863)
Ravenswood ST 01, 02, & 03	1,724.8	(187.14)	1,537.66	415	222	32	(97)	(570)	(1,231)	(1,486)	(1,769)	(2,068)
Ravenswood ST 01	364.5	(39.55)	324.95	1,628	1,434	1,245	1,116	643	(18)	(273)	(556)	(855)
Ravenswood ST 02	375.2	(40.71)	334.49	1,619	1,425	1,236	1,106	633	(28)	(283)	(566)	(864)

Lower Hudson Valley												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Lower Hudson Valley Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,953	1,759	1,570	1,441	968	307	52	(231)	(530)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Ravenswood ST 03	985.1	(106.88)	878.22	1,075	881	692	562	90	(571)	(826)	(1,110)	(1,408)
Ravenswood CC 04	222.2	(10.47)	211.73	1,741	1,548	1,358	1,229	756	95	(160)	(443)	(742)
East River 1, 2, 6, & 7	630.7	(49.54)	581.16	1,372	1,178	989	859	387	(274)	(529)	(813)	(1,111)
East River 1	153.2	(7.22)	145.98	1,807	1,613	1,424	1,295	822	161	(94)	(377)	(676)
East River 2	154.5	(7.28)	147.22	1,806	1,612	1,423	1,293	821	160	(95)	(379)	(677)
East River 6	141.5	(15.35)	126.15	1,827	1,633	1,444	1,315	842	181	(74)	(358)	(656)
East River 7	181.5	(19.69)	161.81	1,791	1,597	1,408	1,279	806	145	(110)	(393)	(692)
Linden Cogen	748.2	(35.24)	712.96	1,240	1,046	857	728	255	(406)	(661)	(944)	(1,243)
KIAC_JFK (BTM:NG)	105.4	(4.96)	100.44	1,853	1,659	1,470	1,340	867	206	(49)	(332)	(630)
Gowanus 5 & 6[2]	79.9	(8.25)	71.65	1,881	1,688	1,498	1,369	896	-	-	-	-
Gowanus 5[2]	40.0	(4.13)	35.87	1,917	1,723	1,534	1,405	932	-	-	-	-
Gowanus 6[2]	39.9	(4.12)	35.78	1,917	1,723	1,534	1,405	932	-	-	-	-
Kent[2]	46.0	(4.75)	41.25	1,912	1,718	1,529	1,399	927	-	-	-	-
Pouch[2]	44.7	(4.61)	40.09	1,913	1,719	1,530	1,401	928	-	-	-	-
Hellgate 1 & 2[2]	79.5	(8.20)	71.30	1,882	1,688	1,499	1,369	897	-	-	-	-
Hellgate 1[2]	39.9	(4.12)	35.78	1,917	1,723	1,534	1,405	932	-	-	-	-
Hellgate 2[2]	39.6	(4.09)	35.51	1,918	1,724	1,535	1,405	932	-	-	-	-
Harlem River 1 & 2[2]	79.5	(8.20)	71.30	1,882	1,688	1,499	1,369	897	-	-	-	-
Harlem River 1[2]	39.9	(4.12)	35.78	1,917	1,723	1,534	1,405	932	-	-	-	-
Harlem River 2[2]	39.6	(4.09)	35.51	1,918	1,724	1,535	1,405	932	-	-	-	-
Vernon Blvd 2 & 3[2]	79.9	(8.25)	71.65	1,881	1,688	1,498	1,369	896	-	-	-	-
Vernon Blvd 2[2]	40.0	(4.13)	35.87	1,917	1,723	1,534	1,405	932	-	-	-	-
Vernon Blvd 3[2]	39.9	(4.12)	35.78	1,917	1,723	1,534	1,405	932	-	-	-	-
Astoria CC 1 & 2	474.0	(22.33)	451.67	1,501	1,308	1,118	989	516	(145)	(400)	(683)	(982)
Astoria CC 1	237.0	(11.16)	225.84	1,727	1,533	1,344	1,215	742	81	(174)	(457)	(756)
Astoria CC 2	237.0	(11.16)	225.84	1,727	1,533	1,344	1,215	742	81	(174)	(457)	(756)
Astoria East Energy CC1 & CC2	582.8	(27.45)	555.35	1,398	1,204	1,015	885	412	(249)	(503)	(787)	(1,085)
Astoria East Energy - CC1	291.4	(13.72)	277.68	1,675	1,482	1,292	1,163	690	29	(226)	(509)	(808)
Astoria East Energy - CC2	291.4	(13.72)	277.68	1,675	1,482	1,292	1,163	690	29	(226)	(509)	(808)
Astoria Energy 2 - CC3 & CC4	570.3	(26.86)	543.44	1,410	1,216	1,027	897	424	(237)	(492)	(775)	(1,073)
Astoria Energy 2 - CC3	285.0	(13.42)	271.58	1,682	1,488	1,299	1,169	696	35	(220)	(503)	(801)
Astoria Energy 2 - CC4	285.3	(13.44)	271.86	1,681	1,487	1,298	1,169	696	35	(220)	(503)	(802)
Bayonne EC CT G1 through G10	604.8	(54.67)	550.13	1,403	1,209	1,020	891	418	(243)	(498)	(781)	(1,080)
Bayonne EC CTG1	62.0	(5.60)	56.40	1,897	1,703	1,514	1,384	911	250	(4)	(288)	(586)
Bayonne EC CTG2	58.0	(5.24)	52.76	1,900	1,706	1,517	1,388	915	254	(1)	(284)	(583)

Lower Hudson Valley												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Lower Hudson Valley Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,953	1,759	1,570	1,441	968	307	52	(231)	(530)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Bayonne EC CTG3	58.1	(5.25)	52.85	1,900	1,706	1,517	1,388	915	254	(1)	(284)	(583)
Bayonne EC CTG4	61.1	(5.52)	55.58	1,898	1,704	1,515	1,385	912	251	(4)	(287)	(585)
Bayonne EC CTG5	61.8	(5.59)	56.21	1,897	1,703	1,514	1,384	912	251	(4)	(288)	(586)
Bayonne EC CTG6	61.4	(5.55)	55.85	1,897	1,703	1,514	1,385	912	251	(4)	(287)	(586)
Bayonne EC CTG7	59.7	(5.40)	54.30	1,899	1,705	1,516	1,386	914	252	(2)	(286)	(584)
Bayonne EC CTG8	60.0	(5.42)	54.58	1,899	1,705	1,516	1,386	913	252	(3)	(286)	(584)
Bayonne EC CTG9	61.3	(5.54)	55.76	1,897	1,703	1,514	1,385	912	251	(4)	(287)	(586)
Bayonne EC CTG10	61.4	(5.55)	55.85	1,897	1,703	1,514	1,385	912	251	(4)	(287)	(586)

Notes
1. Utilizes the Higher Demand Transmission Security Margin for Summer Peak with Expected Weather.
2. Unit is modeled out of service beginning in 2031 in the baseline margin calculation.

Figure 93: AOI - New York City Transmission Security Margin

New York City												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
New York City Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				260	222	92	(68)	(148)	(656)	(806)	(966)	(1,136)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Arthur Kill ST 2 & 3	883.6	(95.87)	787.73	(528)	(566)	(696)	(856)	(936)	(1,444)	(1,594)	(1,754)	(1,924)
Arthur Kill ST 2	363.2	(39.41)	323.79	(64)	(102)	(232)	(392)	(472)	(980)	(1,130)	(1,290)	(1,460)
Arthur Kill ST 3	520.4	(56.46)	463.94	(204)	(242)	(372)	(532)	(612)	(1,120)	(1,270)	(1,430)	(1,600)
Brooklyn Navy Yard	249.2	(11.74)	237.46	23	(16)	(146)	(306)	(386)	(893)	(1,043)	(1,203)	(1,373)
Astoria 2, 3, & 5	902.3	(97.90)	804.40	(544)	(583)	(713)	(873)	(953)	(1,460)	(1,610)	(1,770)	(1,940)
Astoria 2	158.0	(17.14)	140.86	119	81	(49)	(209)	(289)	(797)	(947)	(1,107)	(1,277)
Astoria 3	371.1	(40.26)	330.84	(71)	(109)	(239)	(399)	(479)	(987)	(1,137)	(1,297)	(1,467)
Astoria 5	373.2	(40.49)	332.71	(73)	(111)	(241)	(401)	(481)	(989)	(1,139)	(1,299)	(1,469)
Ravenswood ST 01, 02, & 03[2]	1,724.8	(187.14)	1,537.66	(542)	(1,131)	(1,261)	(1,421)	(1,501)	(2,008)	(2,158)	(2,318)	(2,488)
Ravenswood ST 01	364.5	(39.55)	324.95	(65)	(103)	(233)	(393)	(473)	(981)	(1,131)	(1,291)	(1,461)
Ravenswood ST 02	375.2	(40.71)	334.49	(74)	(113)	(243)	(403)	(483)	(990)	(1,140)	(1,300)	(1,470)
Ravenswood ST 03[2]	985.1	(106.88)	878.22	117	(471)	(271)	(761)	(841)	(1,349)	(1,499)	(1,659)	(1,829)
Ravenswood CC 04	222.2	(10.47)	211.73	48	10	(120)	(280)	(360)	(868)	(1,018)	(1,178)	(1,348)
East River 1, 2, 6, & 7	630.7	(49.54)	581.16	(321)	(359)	(489)	(649)	(729)	(1,237)	(1,387)	(1,547)	(1,717)
East River 1	153.2	(7.22)	145.98	114	76	(54)	(214)	(294)	(802)	(952)	(1,112)	(1,282)
East River 2	154.5	(7.28)	147.22	113	74	(56)	(216)	(296)	(803)	(953)	(1,113)	(1,283)
East River 6	141.5	(15.35)	126.15	134	96	(34)	(194)	(274)	(782)	(932)	(1,092)	(1,262)
East River 7	181.5	(19.69)	161.81	98	60	(70)	(230)	(310)	(818)	(968)	(1,128)	(1,298)
Linden Cogen	748.2	(35.24)	712.96	(453)	(491)	(621)	(781)	(861)	(1,369)	(1,519)	(1,679)	(1,849)
KIAC_JFK (BTM:NG)	105.4	(4.96)	100.44	160	121	(9)	(169)	(249)	(756)	(906)	(1,066)	(1,236)
Gowanus 5 & 6[3]	79.9	(8.25)	71.65	188	150	20	(140)	(220)	-	-	-	-
Gowanus 5[3]	40.0	(4.13)	35.87	224	186	56	(104)	(184)	-	-	-	-
Gowanus 6[3]	39.9	(4.12)	35.78	224	186	56	(104)	(184)	-	-	-	-
Kent[3]	46.0	(4.75)	41.25	219	180	50	(110)	(190)	-	-	-	-
Pouch[3]	44.7	(4.61)	40.09	220	182	52	(108)	(188)	-	-	-	-
Hellgate 1 & 2[3]	79.5	(8.20)	71.30	189	150	20	(140)	(220)	-	-	-	-
Hellgate 1[3]	39.9	(4.12)	35.78	224	186	56	(104)	(184)	-	-	-	-
Hellgate 2[3]	39.6	(4.09)	35.51	225	186	56	(104)	(184)	-	-	-	-
Harlem River 1 & 2[3]	79.5	(8.20)	71.30	189	150	20	(140)	(220)	-	-	-	-
Harlem River 1[3]	39.9	(4.12)	35.78	224	186	56	(104)	(184)	-	-	-	-
Harlem River 2[3]	39.6	(4.09)	35.51	225	186	56	(104)	(184)	-	-	-	-
Vernon Blvd 2 & 3[3]	79.9	(8.25)	71.65	188	150	20	(140)	(220)	-	-	-	-

New York City												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
New York City Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				260	222	92	(68)	(148)	(656)	(806)	(966)	(1,136)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Vernon Blvd 2[3]	40.0	(4.13)	35.87	224	186	56	(104)	(184)	-	-	-	-
Vernon Blvd 3[3]	39.9	(4.12)	35.78	224	186	56	(104)	(184)	-	-	-	-
Astoria CC 1 & 2	474.0	(22.33)	451.67	(192)	(230)	(360)	(520)	(600)	(1,107)	(1,257)	(1,417)	(1,587)
Astoria CC 1	237.0	(11.16)	225.84	34	(4)	(134)	(294)	(374)	(882)	(1,032)	(1,192)	(1,362)
Astoria CC 2	237.0	(11.16)	225.84	34	(4)	(134)	(294)	(374)	(882)	(1,032)	(1,192)	(1,362)
Astoria East Energy CC1 & CC2	582.8	(27.45)	555.35	(295)	(334)	(464)	(624)	(704)	(1,211)	(1,361)	(1,521)	(1,691)
Astoria East Energy - CC1	291.4	(13.72)	277.68	(18)	(56)	(186)	(346)	(426)	(933)	(1,083)	(1,243)	(1,413)
Astoria East Energy - CC2	291.4	(13.72)	277.68	(18)	(56)	(186)	(346)	(426)	(933)	(1,083)	(1,243)	(1,413)
Astoria Energy 2 - CC3 & CC4	570.3	(26.86)	543.44	(283)	(322)	(452)	(612)	(692)	(1,199)	(1,349)	(1,509)	(1,679)
Astoria Energy 2 - CC3	285.0	(13.42)	271.58	(11)	(50)	(180)	(340)	(420)	(927)	(1,077)	(1,237)	(1,407)
Astoria Energy 2 - CC4	285.3	(13.44)	271.86	(12)	(50)	(180)	(340)	(420)	(928)	(1,078)	(1,238)	(1,408)
Bayonne EC CT G1 through G10	604.8	(54.67)	550.13	(290)	(328)	(458)	(618)	(698)	(1,206)	(1,356)	(1,516)	(1,686)
Bayonne EC CTG1	62.0	(5.60)	56.40	204	165	35	(125)	(205)	(712)	(862)	(1,022)	(1,192)
Bayonne EC CTG2	58.0	(5.24)	52.76	207	169	39	(121)	(201)	(709)	(859)	(1,019)	(1,189)
Bayonne EC CTG3	58.1	(5.25)	52.85	207	169	39	(121)	(201)	(709)	(859)	(1,019)	(1,189)
Bayonne EC CTG4	61.1	(5.52)	55.58	205	166	36	(124)	(204)	(711)	(861)	(1,021)	(1,191)
Bayonne EC CTG5	61.8	(5.59)	56.21	204	165	35	(125)	(205)	(712)	(862)	(1,022)	(1,192)
Bayonne EC CTG6	61.4	(5.55)	55.85	204	166	36	(124)	(204)	(712)	(862)	(1,022)	(1,192)
Bayonne EC CTG7	59.7	(5.40)	54.30	206	167	37	(123)	(203)	(710)	(860)	(1,020)	(1,190)
Bayonne EC CTG8	60.0	(5.42)	54.58	206	167	37	(123)	(203)	(710)	(860)	(1,020)	(1,190)
Bayonne EC CTG9	61.3	(5.54)	55.76	204	166	36	(124)	(204)	(712)	(862)	(1,022)	(1,192)
Bayonne EC CTG10	61.4	(5.55)	55.85	204	166	36	(124)	(204)	(712)	(862)	(1,022)	(1,192)

Notes
1. Utilizes the Higher Demand Transmission Security Margin for Summer Peak with Expected Weather.
2. In all years, the most limiting contingency includes the loss of Ravenswood . For this calculation, the margin based on the loss of two transmission elements is utilized. Other combinations with loss of generation may be more limiting.
3. Unit is modeled out of service beginning in 2031 in the baseline margin calculation.

Figure 94: AOI - Long Island Transmission Security Margin

Long Island												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Long Island Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				30	(73)	1	(38)	1,841	1,719	1,643	1,578	1,481
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Greenport IC 4, 5, & 6	5.6	(0.83)	4.77	25	(78)	(3)	(43)	1,837	1,714	1,638	1,573	1,476
Greenport IC 4	1.0	(0.15)	0.85	29	(74)	1	(39)	1,840	1,718	1,642	1,577	1,480
Greenport IC 5	1.5	(0.22)	1.28	28	(75)	0	(39)	1,840	1,717	1,642	1,577	1,479
Greenport IC 6	3.1	(0.46)	2.64	27	(76)	(1)	(41)	1,839	1,716	1,641	1,576	1,478
Freeport 1-2, 1-3, & 2-3	19.2	(2.21)	16.99	13	(90)	(16)	(55)	1,824	1,702	1,626	1,561	1,464
Freeport 1-2	2.3	(0.34)	1.96	28	(75)	(1)	(40)	1,839	1,717	1,641	1,576	1,479
Freeport 1-3	2.7	(0.40)	2.30	27	(76)	(1)	(40)	1,839	1,716	1,641	1,576	1,478
Freeport 2-3	14.2	(1.47)	12.73	17	(86)	(11)	(51)	1,829	1,706	1,630	1,565	1,468
Charles P Killer 09 through 14	13.5	(1.78)	11.72	18	(85)	(10)	(50)	1,830	1,707	1,632	1,567	1,469
Charles P Keller 09	1.6	(0.21)	1.39	28	(75)	0	(40)	1,840	1,717	1,642	1,577	1,479
Charles P Keller 10	1.6	(0.21)	1.39	28	(75)	0	(40)	1,840	1,717	1,642	1,577	1,479
Charles P Keller 11	2.4	(0.32)	2.08	28	(76)	(1)	(40)	1,839	1,717	1,641	1,576	1,479
Charles P Keller 12	2.5	(0.33)	2.17	28	(76)	(1)	(40)	1,839	1,717	1,641	1,576	1,479
Charles P Keller 13	2.5	(0.33)	2.17	28	(76)	(1)	(40)	1,839	1,717	1,641	1,576	1,479
Charles P Keller 14	2.9	(0.38)	2.52	27	(76)	(1)	(41)	1,839	1,716	1,641	1,576	1,478
Wading River 1, 2, & 3	214.8	(22.17)	192.63	(163)	(266)	(191)	(231)	1,649	1,526	1,451	1,386	1,288
Wading River 1	77.6	(8.01)	69.59	(40)	(143)	(68)	(108)	1,772	1,649	1,574	1,509	1,411
Wading River 2	64.3	(6.64)	57.66	(28)	(131)	(56)	(96)	1,784	1,661	1,586	1,521	1,423
Wading River 3	72.9	(7.52)	65.38	(36)	(139)	(64)	(104)	1,776	1,653	1,578	1,513	1,415
Barrett ST 01 & 02	380.5	(41.28)	339.22	(309)	(413)	(338)	(377)	1,502	1,380	1,304	1,239	1,141
Barrett ST 01	192.0	(20.83)	171.17	(141)	(245)	(170)	(209)	1,670	1,548	1,472	1,407	1,310
Barrett ST 02	188.5	(20.45)	168.05	(138)	(241)	(167)	(206)	1,673	1,551	1,475	1,410	1,313
Barrett GT 01 through 12	246.6	(23.47)	223.13	(193)	(297)	(222)	(261)	1,618	1,496	1,420	1,355	1,258
Barrett GT 01	13.7	(1.41)	12.29	17	(86)	(11)	(50)	1,829	1,706	1,631	1,566	1,468
Barrett GT 02	13.6	(1.40)	12.20	18	(86)	(11)	(50)	1,829	1,707	1,631	1,566	1,468
Barrett 03	12.2	(1.26)	10.94	19	(84)	(10)	(49)	1,830	1,708	1,632	1,567	1,470
Barrett 04	14.5	(1.50)	13.00	17	(86)	(12)	(51)	1,828	1,706	1,630	1,565	1,468
Barrett 05	12.0	(1.24)	10.76	19	(84)	(9)	(49)	1,831	1,708	1,632	1,567	1,470
Barrett 06	12.9	(1.33)	11.57	18	(85)	(10)	(50)	1,830	1,707	1,632	1,567	1,469
Barrett 08	12.8	(1.32)	11.48	18	(85)	(10)	(50)	1,830	1,707	1,632	1,567	1,469
Barrett 09	38.6	(3.49)	35.11	(5)	(109)	(34)	(73)	1,806	1,684	1,608	1,543	1,446
Barrett 10	39.2	(3.54)	35.66	(6)	(109)	(34)	(74)	1,806	1,683	1,608	1,543	1,445

Long Island												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Long Island Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				30	(73)	1	(38)	1,841	1,719	1,643	1,578	1,481
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Barrett 11	38.2	(3.45)	34.75	(5)	(108)	(33)	(73)	1,807	1,684	1,608	1,543	1,446
Barrett 12	38.9	(3.52)	35.38	(6)	(109)	(34)	(74)	1,806	1,683	1,608	1,543	1,445
Northport 1, 2, 3, and 4	1,582.2	(171.67)	1,410.53	(1,381)	(1,484)	(1,409)	(1,449)	431	308	233	168	70
Northport 1	399.0	(43.29)	355.71	(326)	(429)	(354)	(394)	1,486	1,363	1,288	1,223	1,125
Northport 2	399.0	(43.29)	355.71	(326)	(429)	(354)	(394)	1,486	1,363	1,288	1,223	1,125
Northport 3	386.2	(41.90)	344.30	(315)	(418)	(343)	(382)	1,497	1,374	1,299	1,234	1,136
Northport 4	398.0	(43.18)	354.82	(325)	(428)	(353)	(393)	1,486	1,364	1,288	1,223	1,126
Port Jefferson GT 02 & 03	79.3	(8.18)	71.12	(41)	(145)	(70)	(109)	1,770	1,648	1,572	1,507	1,410
Port Jefferson GT 02	39.1	(4.04)	35.06	(5)	(109)	(34)	(73)	1,806	1,684	1,608	1,543	1,446
Port Jefferson GT 03	40.2	(4.15)	36.05	(6)	(110)	(35)	(74)	1,805	1,683	1,607	1,542	1,445
Port Jefferson 3 & 4	380.0	(41.23)	338.77	(309)	(412)	(337)	(377)	1,503	1,380	1,304	1,239	1,142
Port Jefferson 3	191.0	(20.72)	170.28	(141)	(244)	(169)	(208)	1,671	1,548	1,473	1,408	1,310
Port Jefferson 4	189.0	(20.51)	168.49	(139)	(242)	(167)	(207)	1,673	1,550	1,475	1,410	1,312
Hempstead (RR)	74.2	(8.05)	66.15	(36)	(140)	(65)	(104)	1,775	1,653	1,577	1,512	1,415
Glenwood GT 02, 04, & 05	123.9	(12.79)	111.11	(81)	(185)	(110)	(149)	1,730	1,608	1,532	1,467	1,370
Glenwood GT 02	40.3	(4.16)	36.14	(6)	(110)	(35)	(74)	1,805	1,683	1,607	1,542	1,445
Glenwood GT 04	41.9	(4.32)	37.58	(8)	(111)	(36)	(76)	1,804	1,681	1,606	1,541	1,443
Glenwood GT 05	41.7	(4.30)	37.40	(8)	(111)	(36)	(76)	1,804	1,681	1,606	1,541	1,443
Holtsville 01 through 10	527.9	(47.72)	480.18	(450)	(554)	(479)	(518)	1,361	1,239	1,163	1,098	1,001
Holtsville 01	54.2	(4.90)	49.30	(20)	(123)	(48)	(87)	1,792	1,669	1,594	1,529	1,431
Holtsville 02	56.8	(5.13)	51.67	(22)	(125)	(50)	(90)	1,790	1,667	1,592	1,527	1,429
Holtsville 03	51.2	(4.63)	46.57	(17)	(120)	(45)	(85)	1,795	1,672	1,597	1,532	1,434
Holtsville 04	53.0	(4.79)	48.21	(18)	(122)	(47)	(86)	1,793	1,671	1,595	1,530	1,432
Holtsville 05	52.6	(4.76)	47.84	(18)	(121)	(46)	(86)	1,793	1,671	1,595	1,530	1,433
Holtsville 06	49.4	(4.47)	44.93	(15)	(118)	(44)	(83)	1,796	1,674	1,598	1,533	1,436
Holtsville 07	54.0	(4.88)	49.12	(19)	(123)	(48)	(87)	1,792	1,670	1,594	1,529	1,432
Holtsville 08	49.9	(4.51)	45.39	(16)	(119)	(44)	(84)	1,796	1,673	1,598	1,533	1,435
Holtsville 09	55.4	(5.01)	50.39	(21)	(124)	(49)	(89)	1,791	1,668	1,593	1,528	1,430
Holtsville 10	51.4	(4.65)	46.75	(17)	(120)	(45)	(85)	1,795	1,672	1,596	1,531	1,434
Shoreham GT 3 & 4	84.7	(8.74)	75.96	(46)	(149)	(75)	(114)	1,765	1,643	1,567	1,502	1,405
Shoreham GT3	42.9	(4.43)	38.47	(9)	(112)	(37)	(77)	1,803	1,680	1,605	1,540	1,442
Shoreham GT4	41.8	(4.31)	37.49	(8)	(111)	(36)	(76)	1,804	1,681	1,606	1,541	1,443
East Hampton GT 01, 2, 3, & 4	23.8	(2.47)	21.33	8	(95)	(20)	(59)	1,820	1,697	1,622	1,557	1,459

Long Island												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Long Island Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				30	(73)	1	(38)	1,841	1,719	1,643	1,578	1,481
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
East Hampton GT 01	18.4	(1.66)	16.74	13	(90)	(15)	(55)	1,825	1,702	1,626	1,561	1,464
East Hampton 2	1.8	(0.27)	1.53	28	(75)	(0)	(40)	1,840	1,717	1,642	1,577	1,479
East Hampton 3	1.8	(0.27)	1.53	28	(75)	(0)	(40)	1,840	1,717	1,642	1,577	1,479
East Hampton 4	1.8	(0.27)	1.53	28	(75)	(0)	(40)	1,840	1,717	1,642	1,577	1,479
Southold 1	9.5	(0.98)	8.52	21	(82)	(7)	(47)	1,833	1,710	1,635	1,570	1,472
S Hampton 1	8.1	(0.84)	7.26	22	(81)	(6)	(45)	1,834	1,712	1,636	1,571	1,473
Freeport CT 1 & 2	88.8	(9.16)	79.64	(50)	(153)	(78)	(118)	1,762	1,639	1,564	1,499	1,401
Freeport CT 1	45.8	(4.73)	41.07	(11)	(115)	(40)	(79)	1,800	1,678	1,602	1,537	1,440
Freeport CT 2	43.0	(4.44)	38.56	(9)	(112)	(37)	(77)	1,803	1,680	1,605	1,540	1,442
Flynn	139.5	(6.57)	132.93	(103)	(206)	(132)	(171)	1,708	1,586	1,510	1,445	1,348
Greenport GT1	51.0	(4.61)	46.39	(17)	(120)	(45)	(85)	1,795	1,672	1,597	1,532	1,434
Far Rockaway GT1 & GT2[2]	-	-	-	-	-	-	-	-	-	-	-	-
Far Rockaway GT1[2]	-	-	-	-	-	-	-	-	-	-	-	-
Far Rockaway GT2[2]	-	-	-	-	-	-	-	-	-	-	-	-
Bethpage	51.0	(2.40)	48.60	(19)	(122)	(47)	(87)	1,793	1,670	1,595	1,530	1,432
Bethpage 3	75.7	(3.57)	72.13	(42)	(146)	(71)	(110)	1,769	1,647	1,571	1,506	1,409
Bethpage GT4	43.7	(4.51)	39.19	(9)	(113)	(38)	(77)	1,802	1,680	1,604	1,539	1,441
Stony Brook (BTM:NG)	0.0	0.00	0.00	30	(73)	1	(38)	1,841	1,719	1,643	1,578	1,481
Brentwood	45.0	(4.64)	40.36	(11)	(114)	(39)	(78)	1,801	1,678	1,603	1,538	1,440
Pilgrim GT1 & GT2	83.6	(8.63)	74.97	(45)	(148)	(74)	(113)	1,766	1,644	1,568	1,503	1,406
Pilgrim GT1	41.3	(4.26)	37.04	(7)	(110)	(36)	(75)	1,804	1,682	1,606	1,541	1,444
Pilgrim GT2	42.3	(4.37)	37.93	(8)	(111)	(37)	(76)	1,803	1,681	1,605	1,540	1,443
Pinelawn Power 1[2]	-	-	-	-	-	-	-	-	-	-	-	-
Caithness_CC_1	313.5	(14.77)	298.73	(269)	(372)	(297)	(337)	1,543	1,420	1,344	1,279	1,182
Islip (RR)	8.0	(0.87)	7.13	23	(81)	(6)	(45)	1,834	1,712	1,636	1,571	1,474
Babylon (RR)	15.7	(1.70)	14.00	16	(87)	(13)	(52)	1,827	1,705	1,629	1,564	1,467
Huntington (RR)	24.8	(2.69)	22.11	8	(96)	(21)	(60)	1,819	1,697	1,621	1,556	1,459

Notes

1. Utilizes the Higher Demand Transmission Security Margin for Summer Peak with Expected Weather.
2. Unit is modeled out of service beginning in 2026 in the baseline margin calculation.