Appendices

2024 Reliability Needs Assessment (RNA)

A Report from the New York Independent System Operator

November 19, 2024

Table of Contents

List of Figures

Appendix A - 2024 Reliability Needs Assessment Glossary

The following glossary offers definitions and explanations of terms used in the Reliability Needs Assessment it appends, as well as references to additional source information published by the NYISO and other energy industry entities.

Annual Transmission Reliability Assessment (ATRA): An assessment, conducted by the NYISO staff in cooperation with Market Participants, to determine the System Upgrade Facilities required for each generation project and Class Year Transmission Project to interconnect to the New York State Transmission System in compliance with Applicable Reliability Standards and the NYISO Minimum Interconnection Standard. See NYISO OATT

Area Transmission Review (ATR): An annual report provided to the Northeast Power Coordinating Council Compliance Committee by the NYISO, in its role as Planning Coordinator, in regard to its Area Transmission Review. See NPCC.org

Baseline Forecast: Prepared for the NYISO Gold Book, baseline forecasts report the expected New York Control Area load and includes the projected impacts of energy efficiency programs, building codes and standards, distributed energy resources, behind-the-meter energy storage, behind-the-meter solar photovoltaic power, electric vehicle usage, and electrification of heating and other end uses. The baseline forecasts are used in the Reliability Needs Assessment Base Cases for determining Bulk Power Transmission Facilities Reliability Needs for the Reliability Needs Assessment Study Period.

Best Technology Available (BTA): Performance goal established by the New York State Department of Environmental Conservation for cooling water intake structures at proposed and existing electric generating plants with intake capacity greater than 20 million gallons per day. See DEC.NY.gov

New York State Bulk Power Transmission Facility (BPTF): Facilities identified as the New York State Bulk Power Transmission Facilities in the annual Area Transmission Review submitted to the Northeast Power Coordinating Council by the NYISO. See NYISO OATT

Clean Energy Standard (CES): New York State initiative requiring 70% of electricity consumed in the State to be produced from renewable sources by 2030. See NYSERDA.NY.gov

Climate Leadership and Community Protection Act (CLCPA): New York State statute enacted in 2019 to address and mitigate the effects of climate change. Among other requirements, the law mandates that; (1) 70% of energy consumed in New York State be sourced from renewable resources by 2030, (2) greenhouse gas emissions must be reduced by 40% by 2030, (3) the electric generation sector must be zero greenhouse gas emissions by 2040, and (4) greenhouse gas emissions across all sectors of the economy must be reduced by 85% by 2050. See CLIMATE.NY.gov

Contingencies: Actual or potential unexpected failure or outage of a system component such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages. See NYSRC.org

Dependable Maximum Net Capability (DMNC): Sustained maximum net output of a Generator, as demonstrated by the performance of a test or through actual operation, averaged over a continuous time period. See NYISO OATT

Disturbance: Severe oscillations or severe step changes of current, voltage and/or frequency usually caused by faults. See NYSRC.org

Electric System Planning Work Group (ESPWG): The stakeholder forum that provides Market Participant input on the NYISO's comprehensive system planning processes. See Committees at NYISO.com

Emergency Transfer Criteria: In the event that adequate facilities are not available to supply firm load within Normal Transfer Criteria, emergency transfer criteria may be invoked. Under emergency transfer criteria, transfers may be increased up to, but not exceed, emergency ratings and limits, as follows:

> a. Pre-contingency line and equipment loadings may be operated up to LTE ratings for up to four (4) hours, provided the STE ratings are set appropriately. Otherwise, pre-contingency line and equipment loadings must be within normal ratings. Pre-contingency voltages and transmission interface flows must be within applicable pre-contingency voltage and stability limits.
>
> b. Post-contingency line and equipment loadings within STE ratings. Post-contingency voltages and transmission interface flows within applicable post-contingency voltage and stability limits. See NYSRC.org

Fault: An electrical short circuit. See NYSRC.org

Federal Energy Regulatory Commission (FERC): The United States federal agency that regulates the transmission and wholesale sale of electricity and natural gas in interstate commerce.

FERC Form No. 715: Annual report by transmitting utilities on transmission planning, constraints, and available transmission capacity. See FERC.gov

Forced Outage: Unscheduled inability of a Market Participant's Generator to produce energy that does not meet the notification criteria to be classified as a scheduled outage or de-rate as established in NYISO Procedures. See NYISO.com

Gold Book: Annual NYISO publication, also known as the Load and Capacity Data Report. See Library/Reports at NYISO.com

Installed Capacity (ICAP): External or Internal Capacity that is made available pursuant to Tariff requirements and NYISO Procedures. See NYISO Services Tariff

Installed Capacity Requirement (ICR): The annual statewide requirement established by the New York State Reliability Council in order to provide resource adequacy in the New York Control Area. See NYSRC.org

Installed Reserve Margin (IRM): The amount of installed electric generation capacity above 100% of the forecasted peak electric demand that is required to meet New York State Reliability Council resource adequacy criteria.

Local Transmission Plan (LTP): The Local Transmission Owner Plan, developed by each Transmission Owner, which describes its respective plans that may be under consideration or finalized for its own Transmission District. See NYISO OATT

Local Transmission Planning Process (LTPP): The Local Planning Process conducted by each Transmission Owner for its own Transmission District. See NYISO OATT

Loss of Load Expectation (LOLE): A New York State Reliability Council resource adequacy criterion requiring that the probability (or risk) of the unplanned disconnecting of any firm load due to resource deficiencies shall be, on average, not more than once in ten years, expressed mathematically as 0.1 days per year. See NYSRC.org

- LOLE is generally defined as the expected (weighted average) number of days in a given period (e.g., one study year) when for at least one hour from that day the hourly demand is projected to exceed the zonal resources (event day). Within a day, if the zonal demand exceeds the resources in at least one hour of that day, this will be counted as one event day. The criterion is that the LOLE not exceed one day in 10 years, or LOLE < 0.1 days/year.
- LOLH is generally defined[1] as the expected number of hours per period (e.g., one study year) when a system's hourly demand is projected to exceed the zonal resources (event hour). Within an hour, if the zonal demand exceeds the resources, this will be counted as one event hour.
- EUE, also referred to as loss of energy expectation (LOEE), is generally defined[2] as the expected energy (MWh) per period (e.g., one study year) when the summation of the system's hourly demand is projected to exceed the zonal resources. Within an hour, if the zonal demand exceeds the resources, this deficit will be counted toward the system's EUE.

Market Monitoring Unit: The consulting or professional services firm, or other similar entity, responsible for carrying out the Core Market Monitoring Functions and other functions assigned to it in the NYISO's tariffs. See NYISO OATT Attachment O

Market Participant: An entity, excluding the NYISO, that produces, transmits, sells, and/or purchases for resale unforced capacity, energy, or ancillary services in the wholesale market, including entities that buy or sell Transmission Congestion Contracts. See NYISO Services Tariff

Market Administration and Control Area Services Tariff (NYISO Services Tariff): The document addressing the Market Services, and the Control Area Services provided by the NYISO, and the terms and conditions, regulated by the FERC, under which those services are provided.

New York Control Area (NYCA): The area under the electrical control of the NYISO, including the entire state of New York, divided into eleven load zones. See NYISO.com

New York State Department of Environmental Conservation (NYSDEC): The agency that implements the New York State Environmental Conservation Law, with some programs also governed by federal law.

New York Independent System Operator (NYISO): A not-for-profit organization that operates New York's bulk electricity grid, wholesale electricity markets and conducts interconnection and transmission planning.

NYISO Procedures (Manuals, Guides, Technical Bulletins): NYISO Manuals specify and explain the procedures and policies used to operate the bulk power system of the New York Control Area and to conduct wholesale electricity markets, consistent with the NYISO Tariffs and Agreements. NYISO Guides serve to assist users with information needed to participate in NYISO Administered Markets. NYISO Technical Bulletins explain changes to, and provide instruction for, NYISO processes and procedures. See NYISO.com

[1] NYSRC's "Resource Adequacy Metrics and their Application": https://www.nysrc.org/PDF/Reports/Resource%20Adequacy%20Metric%20Report%20Final%204-20-2020[6431].pdf

[2] NYSRC's "Resource Adequacy Metrics and their Application": https://www.nysrc.org/PDF/Reports/Resource%20Adequacy%20Metric%20Report%20Final%204-20-2020[6431].pdf

New York State Department of Public Service (NYDPS): The New York State agency that supports the New York State Public Service Commission. See DPS.NY.gov

New York State Energy Research and Development Authority (NYSERDA): The New York State public authority charged with conducting a multifaceted energy and environmental research and development program to meet New York State's diverse economic needs, including administering the state System Benefits Charge, Renewable Portfolio Standard, energy efficiency programs, the Clean Energy Fund, and the NY-Sun Initiative. See NYSERDA.NY.gov

New York State Public Service Commission (NYPSC): The decision-making body of the New York State Department of Public Service, which regulates the state's electric, gas, steam, telecommunications, and water utilities, oversees the cable industry, has the responsibility for setting rates and overseeing that safe and adequate service is provided by New York's utilities, and exercises jurisdiction over the siting of major gas and electric transmission facilities.

NY-Sun Initiative: A program run by NYSERDA for the purpose of obtaining more than 6,000 MW-DC of behind-the-meter solar photovoltaic systems by the end of 2023. See NYSERDA.NY.gov

New York State Reliability Council (NYSRC): A not-for-profit entity the mission of which is to annually establish the Installed Reserve Margin, and to promote and preserve the reliability of electric service on the New York State Power System by developing, maintaining, and updating the Reliability Rules with which the NYISO and all entities engaging in electric transmission, ancillary services, energy, and power transactions on the New York State Power System must comply. See NYSRC.org

Normal Transfer Criteria: Measures established, in accordance with the North American Electric Reliability Corporation, Northeast Power Coordinating Council, and the New York State Reliability Council's Reliability Rules, to determine that adequate facilities are available to supply firm load in the bulk power transmission system within applicable normal ratings and limits. See NYSRC.org

Normal Transfer Limit: The lowest limit based on the most restrictive of three maximum allowable transfers, calculated based on thermal, voltage, and stability testing, considering contingencies, ratings, and limits specified for normal conditions. See NYSRC.org

North American Electric Reliability Corporation (NERC): A not-for-profit international regulatory authority the mission of which is to assure the effective and efficient reduction of risks to the reliability and security of the grid. See NERC.com

Northeast Power Coordinating Council (NPCC): The entity to whom the North American Electric Reliability Corporation has delegated Electric Reliability Organization functions in the New York Control Area. See NYISO OATT

Open Access Transmission Tariff (OATT): The document setting forth the rates, terms, and conditions, accepted or approved by the FERC, under which the NYISO provides transmission service and conducts interconnection and transmission system planning.

Order No. 890: Order issued by the FERC in 2007 that amended the regulations and the *pro forma* open access transmission tariff to provide that transmission services and planning are provided on a basis that is just, reasonable and not unduly discriminatory or preferential. See FERC.gov

Order No. 1000: Order issued by the FERC in 2011 that amended the transmission planning and cost allocation requirements established in Order No. 890 to provide that Commission-jurisdictional services, including transmission planning, are provided at just and reasonable rates and on a basis that is just and reasonable and not unduly discriminatory or preferential. See FERC.gov

Order No. 1920: Order issued by FERC in 2024 that amended the *pro forma* open access transmission tariff to provide for Long-Term Regional Transmission Planning and cost allocation. See FERC.gov

Outage: The forced or scheduled removal of generating capacity or a transmission line from service.

Peak Demand: The maximum instantaneous power demand, measured in megawatts (MW), and known as peak load, is usually measured, and averaged over an hourly interval. The peak hour is the hour during which the coincident usage was the highest across the entire New York Control Area in a given time period.

Queue Position: The order, in the NYISO's Interconnection Queue, of a valid Interconnection Request, Study Request, or Transmission Interconnection Application relative to all other pending Requests.
See NYISO OATT

Rating: The operational limits of an electric system, facility, or element under a set of specified conditions. Rating categories include Normal Rating, Long-Term Emergency (LTE) Rating, and Short-Term Emergency (STE) Rating, as follows:

1. **Normal Rating:** The capacity rating of a transmission facility that may be carried through consecutive twenty- four (24) hour load cycles.
2. **Long-Time Emergency (LTE) Rating:** The capacity rating of a transmission facility that can be carried through infrequent, non- consecutive four (4) hour periods.
3. **Short-Time Emergency (STE) Rating:** The capacity rating of a transmission facility that may be carried during very infrequent contingencies of fifteen (15) minutes or less duration.
(Source: NYSRC Reliability Rules). See NYSRC.org

Reasonably Available Control Technology for Major Facilities of Oxides of Nitrogen (NOx RACT): New York State Department of Environmental Conservation regulations for the control of emissions of nitrogen oxides (NOx) from fossil fuel-fired power plants. See DEC.ny.gov

Reactive Power: The portion of electric power that establishes and sustains the electric and magnetic fields of alternating-current equipment.

Reactive Power Resources: Facilities such as generators, high voltage transmission lines, synchronous condensers, capacitor banks, and static var compensators that provide reactive power.

Regional Greenhouse Gas Initiative (RGGI): A cooperative effort by a group of Northeast and Mid-Atlantic states to limit power sector greenhouse gas emissions using a market-based cap-and-trade approach. See RGGI.org

Reliability: The degree of performance of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired, which can be addressed by considering the adequacy and security of the electric system:

1. **Adequacy:** The ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected

unscheduled outages of system elements. Note: Adequacy encompasses both generation and transmission.

2. **Security:** The ability of the electric system to withstand disturbances such as electric short circuits or unanticipated loss of system elements. The ability of the power system to withstand the loss of one or more elements without involuntarily disconnecting firm load. See NYSRC.org

Reliability Criteria: The electric power system planning and operating policies, standards, criteria, guidelines, procedures, and rules promulgated by the North American Electric Reliability Corporation, Northeast Power Coordinating Council, and the New York State Reliability Council. See NYISO OATT Attachment Y

Reliability Need: A condition identified by the NYISO as a violation or potential violation of one or more Reliability Criteria. See NYISO OATT Attachment Y

Reliability Needs Assessment (RNA): A report that evaluates resource adequacy and transmission system security over years four through ten of a 10-year planning horizon and identifies future needs of the New York electricity grid. It is the first step in the NYISO's reliability planning process.
See NYISO OATT Attachment Y

Reliability Needs Assessment (RNA) Study Period: The seven-year time period encompassing years four through ten following the year in which the RNA is conducted, which is used in the RNA and the Comprehensive Reliability Plan. See NYISO OATT Attachment Y

Reliability Planning Process (RPP): The process by which the NYISO determines, in the Reliability Needs Assessment, whether any Reliability Need(s) on the New York State Bulk Power Transmission Facilities will arise in the Study Period and addresses any identified Reliability Need(s) in the Comprehensive Reliability Plan. See NYISO OATT Attachment Y

Reliability Solutions: Potential solutions to reliability needs include the following:

1. **Alternative Regulated Solutions (ARS):** Regulated solutions submitted by a Transmission Owner or other developer in response to a solicitation for solutions to a Reliability Need identified in a Reliability Needs Assessment.

2. **Gap Solution:** A solution to a Reliability Need that is designed to be temporary and to strive to be compatible with permanent market-based proposals. The NYISO may call for a Gap Solution to an imminent threat to reliability of the Bulk Power Transmission Facilities if no market-based solutions, regulated backstop solutions, or alternative regulated solutions can meet the Reliability Needs in a timely manner.

3. **Market-Based Solution:** Investor-proposed project driven by market needs to meet future reliability requirements of the bulk electricity grid as outlined in the Reliability Needs Assessment. These can include generation, transmission, and demand response Programs.

4. **Regulated Backstop Solution:** Proposals are required of certain Transmission Owners to meet Reliability Needs as outlined in the Reliability Needs Assessment.

Those solutions can include generation, transmission, or demand response. Non-Transmission Owner developers may also submit regulated solutions. See NYISO OATT Attachment Y

Resource Adequacy: The ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Note: Adequacy encompasses both generation and transmission. See definition of Reliability.

Responsible Transmission Owner (Responsible TO): The Transmission Owner(s) designated by the NYISO to prepare a proposal for a regulated backstop solution to a Reliability Need or to proceed with a regulated solution to a Reliability Need. The Responsible Transmission Owner will normally be the Transmission Owner in whose Transmission District the ISO identifies a Reliability Need and/or that owns a transmission facility on which a Reliability Need arises. See NYISO OATT Attachment Y

Short-Term Assessment of Reliability (STAR): The NYISO's quarterly assessment, in coordination with the Responsible Transmission Owner(s), of whether a Short-Term Reliability Process Need will result from a Generator becoming Retired, entering into a Mothball Outage, or being unavailable due to an Installed Capacity Ineligible Forced Outage, or from other changes to the availability of Resources or to the New York State Transmission System. See NYISO OATT Attachment FF

Short-Term Reliability Process: The process by which the NYISO evaluates and addresses the reliability impacts resulting from both: (1) Generator Deactivation Reliability Need(s), and/or (2) other Reliability Needs on or affecting the Bulk Power Transmission Facilities that are identified in a Short-Term Assessment of Reliability. The Short-Term Reliability Process evaluates reliability needs in years one through five of the ten-year Study Period, with a focus on needs in years one through three. See NYISO OATT Attachment FF

Short-Term Reliability Process Need: A Generator Deactivation Reliability Need or a condition identified by the NYISO in a Short-Term Assessment of Reliability as a violation or potential violation of one or more Reliability Criteria on the Bulk Power Transmission Facilities. See NYISO OATT Attachment FF

Short-Term Reliability Process Solution: A solution to address a Short-Term Reliability Process Need, which may include (1) an Initiating Generator, (2) a solution proposed pursuant to the NYISO Services Tariff, or (3) a Generator identified by the NYISO pursuant to the NYISO Services Tariff. See NYISO OATT and NYISO Services Tariff

Short-Term Assessment of Reliability (STAR) Start Date: The date on which the NYISO next commences a STAR after issuing a written notice to a Market Participant indicating that the Generator Deactivation Notice for its Generator is complete. See NYISO OATT Attachment FF

Special Case Resource ("SCR"): Demand Side Resources the Load of which is capable of being interrupted upon demand at the direction of the NYISO, and/or Demand Side Resources that have a Local Generator, which is not visible to the NYISO's Market Information System and is rated 100 kW or higher, that can be operated to reduce Load from the New York State Transmission System or the distribution system at the direction of the NYISO. See NYISO Services Tariff

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances. See NYSRC.org

System & Resource Outlook (The Outlook): This biennial report, formerly known as Caris, produced by the NYISO, through which it summarizes the current assessments, evaluations, and plans in the biennial Comprehensive System Planning Process, produces a twenty-year projection of congestion on the New York State Transmission System, identifies, ranks, and groups congested elements, and assesses the potential benefits of addressing the identified congestion.

System Benefits Charge (SBC): An amount of money, charged to ratepayers on their electric bills, which is administered and allocated by the New York State Energy Research and Development Authority towards energy-efficiency programs, research and development initiatives, low-income energy programs, and environmental disclosure activities.

Transfer Capability: The measure of the ability of interconnected electrical systems to reliably move or transfer power from one area to another over all transmission facilities (or paths) between those areas under specified system conditions.

Transmission Constraints: Limitations on the ability of a transmission system to transfer electricity during normal or emergency system conditions.

Transmission Owner (TO): A public utility or authority that owns transmission facilities and provides Transmission Service under the NYISO Tariffs.

Transmission Security: The ability of the electric system to withstand disturbances such as electric short circuits or unanticipated loss of system elements. The ability of the power system to withstand the loss of one or more elements without involuntarily disconnecting firm load. See definition of Reliability.

Unforced Capacity: The measure by which Installed Capacity Suppliers will be rated to quantify the extent of their contribution to satisfy the New York Control Area Installed Capacity Requirement.
See NYISO Services Tariff

Unforced Capacity Deliverability Rights (UDRs): Rights, as measured in MWs, associated with (1) new incremental controllable transmission projects, and (2) new projects to increase the capability of existing controllable transmission projects that have UDRs, that provide a transmission interface to a Locality. which, under certain conditions, allow such Unforced Capacity to be treated as if it were located in the Locality, thereby contributing to an LSE's Locational Minimum Installed Capacity Requirement. When combined with Unforced Capacity which is located in an External Control Area or non-constrained NYCA region either by contract or ownership, and which is deliverable to the NYCA interface in the Locality in which the UDR transmission facility is electrically located, UDRs allow such Unforced Capacity to be treated as if it were located in the Locality, thereby contributing to an LSE's Locational Minimum Installed Capacity Requirement. To the extent the NYCA interface is with an External Control Area the Unforced Capacity associated with UDRs must be deliverable to the Interconnection Point. See NYISO Services Tariff

Weather Normalized: Adjustments made to normalize the impact of weather when making energy and peak demand forecasts. Using historical weather data, energy analysts can account for the influence of extreme weather conditions and adjust actual energy use and peak demand to estimate what would have happened if the hottest day or the coldest day had been the typical, or “normal,” weather conditions. “Normal” is usually calculated by taking the average of the previous 20 years of weather data.

Zone: One of the eleven regions in the New York Control Area connected to each other by identified transmission interfaces and designated as Load Zones A-K.

Appendix B - The Reliability Planning Process

This appendix presents an overview of the NYISO's Reliability Planning Process (RPP).

A detailed discussion of the Reliability Planning Process, including applicable Reliability Criteria, is contained in NYISO Manual entitled: Reliability Planning Process Manual, which is posted on the NYISO's website.[3]

The NYISO Reliability Planning Process is an integral part of the NYISO's overall Comprehensive System Planning Process (CSPP).

The CSPP is comprised of four components:

1. Local Transmission Planning Process (LTPP),
2. Reliability Planning Process (RPP), along with the Short-Term Reliability Process (STRP),
3. Economic Planning Process, and
4. Public Policy Transmission Planning Process.

Under the LTPP, the local Transmission Owners (TOs) perform transmission studies for their transmission areas according to all applicable criteria. This process produces the Local Transmission Owner Plan (LTP), which feeds into the NYISO's determination of system needs through the CSPP. Links to LTPs can be found on the NYISO's website.[4]

The second component in the CSPP cycle is the RPP, covering year 4 through year 10 following the year of starting the study, in conjunction with the STRP, covering year 1 through year 5 following the STAR Start Date of the study. The RPP and STRP requirements are described in detail in the Reliability Planning Process Manual and Attachments Y and FF to the OATT. Under the biennial process for conducting the RPP, the reliability of the New York State Bulk Power Transmission Facilities (BPTF) is assessed, any Reliability Needs are identified, solutions to identified needs are proposed and evaluated for their viability and sufficiency to satisfy the identified needs, and the more efficient or cost-effective transmission solution to the identified needs is selected by the NYISO.

During the RPP, the NYISO conducts the Reliability Needs Assessment (RNA) and Comprehensive Reliability Plan (CRP). The RNA evaluates the adequacy and security of the BPTFs over the RNA Study Period (*i.e.*, years 4 through 10 following the year in which the RNA is conducted). In identifying resource

[3] Link to RPP Manual: https://www.nyiso.com/documents/20142/2924447/rpp_mnl.pdf.

[4] Link to LTPP: https://www.nyiso.com/documents/20142/3632262/Local-Transmission-Owner-Planning-Process-LTPP.pdf.

adequacy needs, the NYISO identifies the amount of resources in megawatts (MW), which is known as "compensatory MW," and the locations in which they are needed to meet those needs.

Following approval of the RNA by its Board of Directors and before NYISO issues a solicitation for market-based, regulated backstop, and alternative regulated solutions, the NYISO will request updated LTPs, NYPA transmission plans, and other status updates relevant to reducing, or eliminating, the Reliability Needs, as timely received from Market Participants, Developers, TOs, and other parties. Any such update must meet, in NYISO's determination, the RNA Base Case inclusion rules, as defined in Section 3 of the RPP Manual. If there are remaining Reliability Needs after these updates, the NYISO will request solutions for the remaining Reliability Needs. These solutions will be then undergoing the Viability and Sufficiency Assessments under the CRP, and if needed and as applicable, Transmission Evaluation and Selection. The CRP documents the solutions determined to be viable and sufficient to meet the identified Reliability Needs. The NYISO ranks any regulated transmission solutions submitted for the Board to consider for selection of the more efficient or cost-effective transmission solution. If built, the selected transmission project would be eligible for cost allocation and recovery under the NYISO's tariff.

There RNA analyzes the reliability of the BPTF for adequacy and security. Adequacy is a planning and probabilistic concept. A system is adequate if the probability of having sufficient transmission and generation to meet expected demand is equal to or less than the system's standard, which is expressed as a loss of load expectation (LOLE). The New York State bulk power system is planned[5] to meet an LOLE that, at any given point in time, is less than or equal to an involuntary load disconnection that is not more frequent than once in every 10 years, or 0.1 days per year. This requirement also forms the basis of New York's installed reserve margin (IRM) resource adequacy requirement.

Security is an operating and deterministic concept. This means that possible events are identified as having significant adverse reliability consequences. The system is planned and operated so that the system can continue to serve load even if these events occur. Security requirements are sometimes referred to as N-1 or N-1-1. The analysis for the transmission security assessment is conducted in accordance with the NERC Reliability Standards, NPCC Transmission Design Criteria, and the NYSRC Reliability Rules. Contingency analysis is performed to assess the BPTF response to design criteria contingencies.

For the RNA, over 1,000 design criteria contingencies are evaluated under N-1, N-1-0, and N-1-1

[5] NYSRC Reliability Rules: "The loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. LOLE evaluations shall make do allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring control areas, NYS Transmission System emergency transfer capability, and capacity and/or load relief from available operating procedures."

normal transfer criteria conditions to provide that the system is planned to meet all Reliability Criteria. To evaluate the impact of a single event from the normal system condition (N-1), all design criteria contingences are evaluated including single element, common structure, stuck breaker, generator, bus, high voltage direct current (HVDC) contingencies, etc. An N-1 requirement means that the system can withstand single disturbance events (*e.g.*, generator, bus section, transmission circuit, breaker failure, double-circuit tower) without violating thermal, voltage and stability limits or before resulting in unplanned loss of service to consumers. An N-1 violation occurs when the system response following the contingency event does not meet the applicable criteria. For example, an N-1 thermal violation occurs when the power flow on branch or transformer is higher than the applicable post-contingency rating. N-1-0 and N-1-1 analysis evaluate the ability of the system to meet design criteria after a critical element has already been lost. For N-1-0 and N-1-1 analysis, single-element contingencies are evaluated as the first-level outage. An N-1-1 requirement means that the Reliability Criteria apply after any critical element, such as a generator, a transmission circuit, a transformer, series or shunt compensating device, or a HVDC pole, has already been lost. For N-1-0 and N-1-1 analysis, generation and power flows can be adjusted between contingencies by the use of 10-minute operating reserve, phase angle regulator control, and HVDC control. Following such adjustments, a second single disturbance is analyzed. An N-1-0 violation occurs when the system cannot meet applicable Reliability Criteria after the first element is lost following system adjustments but prior to the occurrence of another event. An N-1-1 violation occurs when the system cannot meet applicable Reliability Criteria after the first element is lost following system adjustments and securing for all applicable second-level contingencies. Within the Con Edison service territory, the 345 kV transmission system and specific portions of the 138 kV transmission system are designed for the occurrence of two non-simultaneous outages and a return to normal ratings (N-1-1-0). For N-1-1-0 analysis, after the second contingency occurs, system adjustments are allowed to secure the system back to normal ratings. The requirement to plan for the occurrence of a second contingency in the Con Edison transmission system is contained in the NYSRC Reliability Rules, Rule G.1.

The RNA's security analysis also includes transmission security margin analysis. Transmission security margins are also included in 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 violation of a transmission security criterion. The transmission security margin is the ability to meet load plus losses and system reserve (*i.e.,* total capacity requirement) against the NYCA generation, interchanges, and temperature-based generation derates (*i.e.*, total resources). This assessment is performed using a deterministic approach through a spreadsheet-based method based on the RNA study assumptions. For this assessment, "tipping points" are evaluated for the statewide system margin, as well as Lower Hudson Valley, New York

City, and Long Island localities. For this evaluation, a Reliability Need related to the BPTF is identified when the transmission security margin is less than zero for the Lower Hudson Valley, New York City, and Long Island localities.

The RPP is anchored in the market-based philosophy of the NYISO and its Market Participants, which posits that market solutions should be the preferred choice to meet the identified needs related to reliability. In the RNA, the reliability of the BPTFs is assessed and Reliability Needs identified in accordance with existing NERC, NPCC, and NYSRC criteria, as they may change from time to time. Solutions to Reliability Needs are evaluated in the CRP. These criteria and a description of the nature of long-term bulk power system planning are described in detail in the Reliability Planning Process Manual, and are briefly summarized below.

In the event that market-based solutions do not materialize to meet a Reliability Need in a timely manner, the NYISO notifies the Responsible Transmission Owner(s) or Other Developer of an alternative regulated solution to proceed with a regulated solution in order to maintain system reliability. Under the RPP, the NYISO also has an affirmative obligation to report historic congestion across the transmission system. In addition, the draft RNA is provided to the Market Monitoring Unit (MMU) for review and consideration of whether market rules changes are necessary to address an identified failure, if any, in one of the NYISO's competitive markets. If a market failure is identified as the reason for the lack of market-based solutions to a Reliability Need, the NYISO will explore appropriate changes in its market rules with its stakeholders and the MMU. The Reliability Planning Process does not substitute for the planning that each TO conducts to maintain the reliability of its own bulk and non-bulk power systems.

The NYISO does not permit or construct projects to respond to identified Reliability Needs reported in the RNA. The ultimate approval of those projects lies with regulatory agencies, such as the Federal Energy Regulatory Commission (FERC), the New York State Public Service Commission (NYPSC), environmental permitting agencies, and local governments. The NYISO monitors the progress and continued viability of proposed market and regulated projects to meet identified Reliability Needs and reports its findings to the Board.

The Short-Term Reliability Process (STRP) uses quarterly Short-Term Assessment of Reliability (STAR) studies to assess the reliability impacts of generator deactivations on both the BPTF and non-BPTF transmission facilities, in coordination with the Responsible Transmission Owner(s). The STAR is also used by the NYISO, in coordination with the Responsible Transmission Owner(s), to assess the reliability impacts on the BPTF of system changes that are not related to a Generator deactivation. These changes may include adjustments to load forecasts, delays in completion of planned upgrades, long duration transmission facility outages and other system topology changes. Section 38 of the NYISO OATT describes the process by which the NYISO, Transmission Owners, Market Participants, Generator Owners, Developers, and other interested parties follow to plan to meet Generator Deactivation Reliability Needs affecting the New York State Transmission System and other Reliability Needs affecting the BPTF (collectively, Short-Term Reliability Needs).

Each STAR will assess a five-year period, with a particular focus on Short-Term Reliability Process Needs ("needs") that are expected to arise in the first three years of the study period. The STRP is the sole venue for addressing Generator Deactivation Reliability Needs on the non-BPTF, and for BPTF needs that arise in the first three years of the assessment period. With one exception,[6] needs that arise in years four or five of the assessment period may be addressed in either the STRP or longer-term Reliability Planning Process (RPP).

Each STAR looks out five years from its STAR Start Date. The STRP concludes if a STAR does not identify a need or if the NYISO determines that all identified needs will be addressed in the RPP. Should a STAR identify a need to be addressed in the STRP, the NYISO would request the submission of market-based solutions to satisfy the need along with a Responsible Transmission Owner STRP solution. The NYISO evaluates the viability and sufficiency of the proposed solutions to satisfy the identified needs and selects a solution to address the need. The NYISO reviews the results of the solution or combination of solutions (including an explanation regarding the solution that is selected) with stakeholders and posts a Short-Term Reliability Process Report detailing the determination with stakeholders.

The third component of the CSPP is the Economic Planning Process, which is the process by which the NYISO: (1) develops the System & Resource Outlook and identifies current and future congestion on the New York State Transmission System; (2) evaluates in an Economic Transmission Project Evaluation any Regulated Economic Transmission Project proposals to address any constraint(s) on the BPTFs identified in the Economic Planning Process, which transmission projects are eligible for cost allocation and cost recovery under the ISO OATT if approved by a vote of the project's Load Serving Entity beneficiaries; and (3) conducts any Requested Economic Planning Studies. In conducting the process, the ISO will analyze a base case and scenarios that are developed in consultation with stakeholders.

The fourth component of the CSPP is the Public Policy Transmission Planning Process. Under this process interested entities propose, and the New York State Public Service Commission (NYPSC) identifies, transmission needs related to the BPTF driven by Public Policy Requirements. The NYISO then requests

[6] Generator Deactivation Reliability Needs that arise on local facilities, not on the BPTF, must always be addressed in the STRP.

that interested entities submit proposed solutions to the identified Public Policy Transmission Need. The NYISO evaluates the viability and sufficiency of the proposed solutions to satisfy the identified Public Policy Transmission Need. The NYISO then evaluates and may select the more efficient or cost-effective transmission solution to the identified need. The NYISO develops the Public Policy Transmission Planning Report that sets forth its findings regarding the proposed solutions. This report is reviewed by NYISO stakeholders and approved by the Board of Directors.

In concert with these four components, interregional planning is conducted with the NYISO's neighboring control areas in the United States and Canada under the Northeastern ISO/RTO Planning Coordination Protocol. The NYISO participates in interregional planning and may consider Interregional Transmission Projects in its regional planning processes.

Figure 1 summarizes the CSPP and Figure 2 summarizes the RPP process.

Figure 1: NYISO's Comprehensive System Planning Process (CSPP)

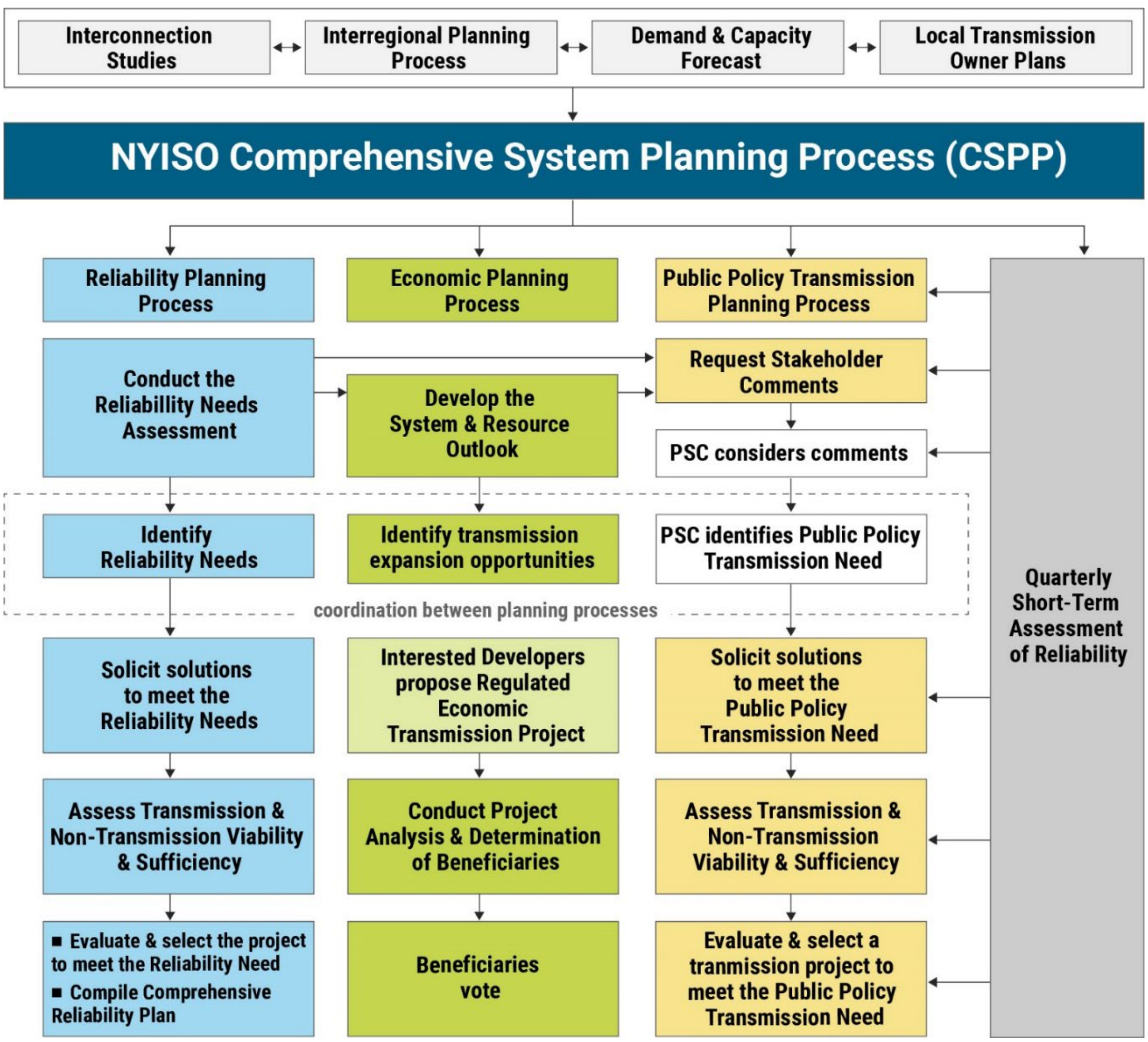
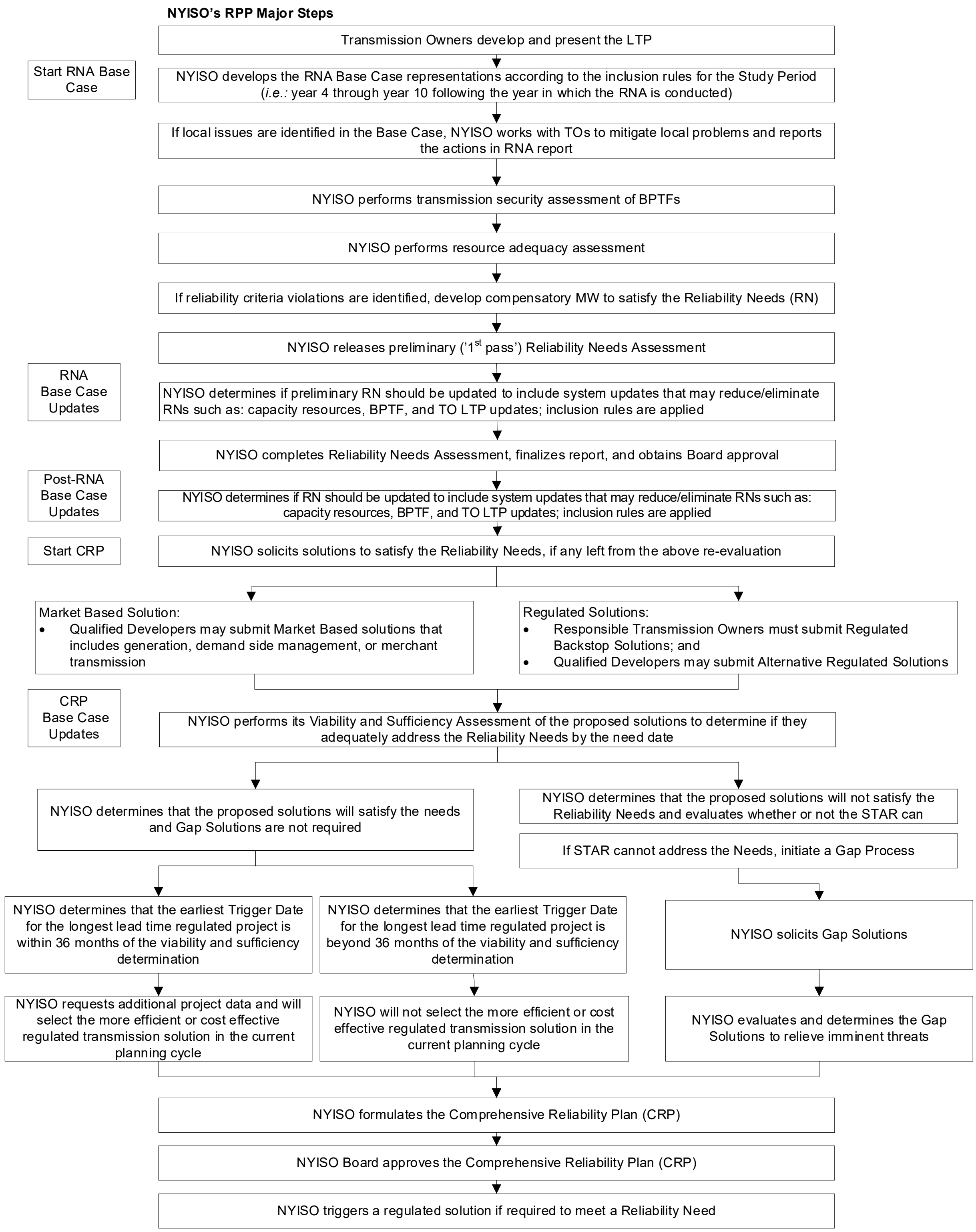


Figure 2: NYISO Reliability Planning Process



Notes:
* If an immediate threat to the reliability of the power system is identified, a Gap Solution outside of the normal RPP cycle may be requested by the NYISO Board.

Appendix C - Load and Energy Forecast 2024-2034

Overview

The NYCA is comprised of 11 geographical zones from western New York (Zone A) through Long Island (Zone K). A map of the NYISO load zones is shown below for reference.

Figure 3: NYISO Load Zone Map

Significant changes in the NYCA electric demand are expected over the next ten years, and through 2050. Over the next ten years, total energy is projected to increase by 10% to 35%, and winter peak load is projected to increase by 20% to 50%. New York is projected to become a winter-peaking system in the late 2030s. These drastic changes are largely driven by the electrification of building heating and electric vehicle charging in response to state policies and the addition of significant large load projects. The demand pattern is expected to evolve with the continuing load impacts of behind-the-meter solar and future impacts of electric heating and electric vehicle (EV) charging.

Beyond the CLCPA's mandate for a zero-emissions grid by 2040, demand will continue to increase through 2050 as multi-sectoral electrification continues in order to meet the CLCPA's mandate to achieve 85% greenhouse gas emission reductions below 1990 levels by 2050.

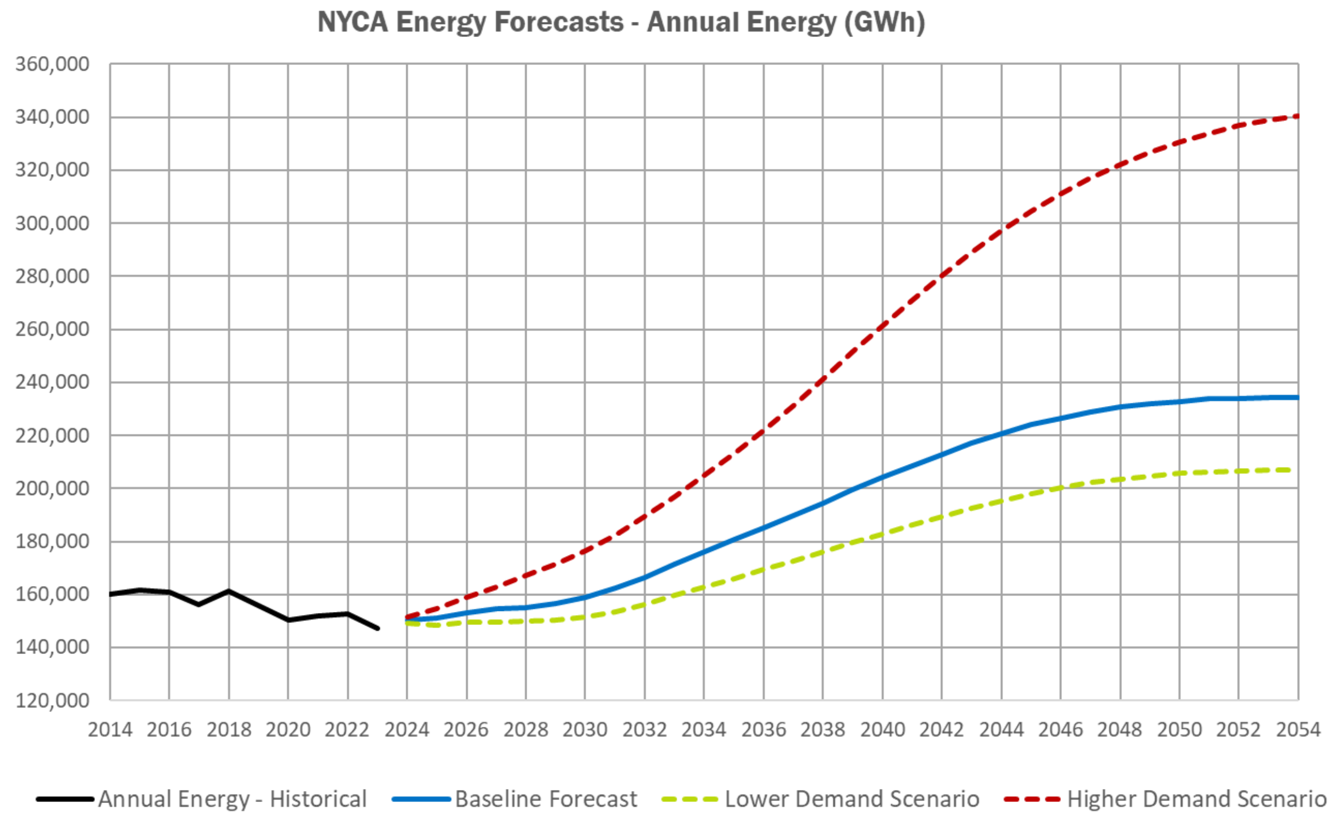
The timing of the switch to a winter-peaking system is mainly influenced by the timing and composition of heating electrification. The changing demand patterns, as well as the scale of demand increase, will impact the future generation capacity mix and resulting power flows across the system. While peak demand is not projected to occur during the winter until the late 2030s, loss of load risk will become concentrated during the winter months in the early 2030s within the ten-year study period. This is due to the more constrained system conditions during extremely cold winter days, and the modeling of gas unavailability via the gas constraints framework.

Energy and Peak Demand Forecasts

The RNA utilizes forecasts from the 2024 Gold Book, which contains multiple forecast scenarios, including the baseline forecast, for energy and peak demand forecasts. All forecasts account for drivers, such as economic growth, energy efficiency, behind-the-meter load-reducing resources, large loads, and electrification. The lower demand scenario represents a lower bound on forecast growth, including slower economic growth and rate of electrification. The higher demand scenario represents a higher bound on forecast growth, including faster economic growth and electrification sufficient to meet state policy targets, and includes additional large load growth not included in the baseline forecast.

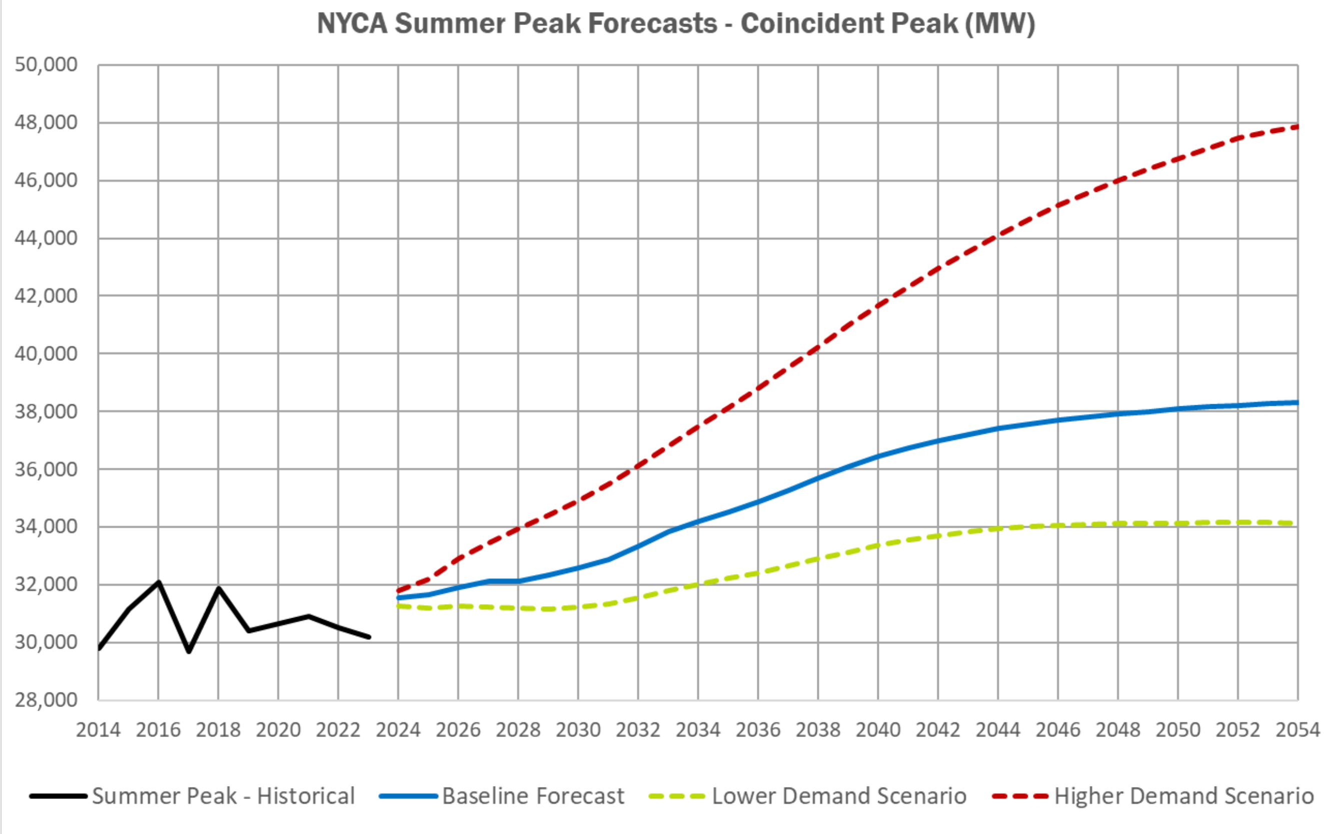
Of the forecast scenarios presented in the 2024 Gold Book, the baseline forecast, and higher demand forecast are used for the 2024 RNA analysis. The figures below show the annual energy forecast and summer and winter peak demand forecasts for the RNA study horizon (2025-2034).

Figure 4: Annual Energy by Zone - Actual and 2024 Gold Book Forecast (MW)



Baseline Annual Energy Forecast (GWh)												
Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2025	15,960	10,000	14,590	5,850	7,010	11,030	9,230	2,740	5,530	49,210	19,870	151,020
2026	16,100	10,330	14,810	7,380	6,740	10,780	9,280	2,740	5,560	49,290	19,980	152,990
2027	15,950	10,310	14,890	8,640	6,530	10,730	9,380	2,760	5,610	49,560	20,170	154,530
2028	15,750	10,100	15,260	8,650	6,390	10,770	9,510	2,780	5,670	49,830	20,390	155,100
2029	15,670	9,990	16,160	8,680	6,320	10,730	9,690	2,830	5,750	50,170	20,670	156,660
2030	15,710	9,970	17,260	8,680	6,330	10,810	9,920	2,890	5,850	50,640	20,990	159,050
2031	15,950	10,110	18,160	8,690	6,450	11,040	10,220	2,970	5,990	51,360	21,420	162,360
2032	16,320	10,340	19,290	8,710	6,650	11,370	10,550	3,070	6,150	52,200	21,880	166,530
2033	16,810	10,670	20,520	8,740	6,910	11,810	10,920	3,180	6,320	53,090	22,410	171,380
2034	17,350	11,030	21,230	8,770	7,220	12,290	11,320	3,300	6,510	54,050	22,970	176,040
Higher Demand Annual Energy Forecast (GWh)												
Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2025	16,630	10,140	15,290	6,210	7,020	11,140	9,390	2,780	5,610	50,390	20,190	154,790
2026	17,090	10,370	15,500	8,760	6,880	11,220	9,480	2,790	5,660	50,920	20,380	159,050
2027	17,530	10,530	15,920	10,130	6,750	11,500	9,640	2,820	5,740	51,720	20,680	162,960
2028	17,780	10,570	16,670	10,960	6,730	12,030	9,870	2,870	5,840	52,650	21,040	167,010
2029	18,010	10,630	17,790	11,290	6,870	12,510	10,180	2,930	5,960	53,690	21,480	171,340
2030	18,370	10,800	19,210	11,430	7,150	12,960	10,570	3,020	6,110	54,850	22,000	176,470
2031	18,930	11,110	20,780	11,580	7,560	13,380	11,030	3,120	6,290	56,130	22,610	182,520
2032	19,630	11,530	22,380	11,740	8,050	13,930	11,560	3,240	6,500	57,530	23,320	189,410
2033	20,450	12,040	23,910	11,910	8,620	14,580	12,140	3,380	6,740	59,040	24,110	196,920
2034	21,360	12,600	25,320	12,090	9,240	15,290	12,770	3,530	7,000	60,650	24,990	204,840

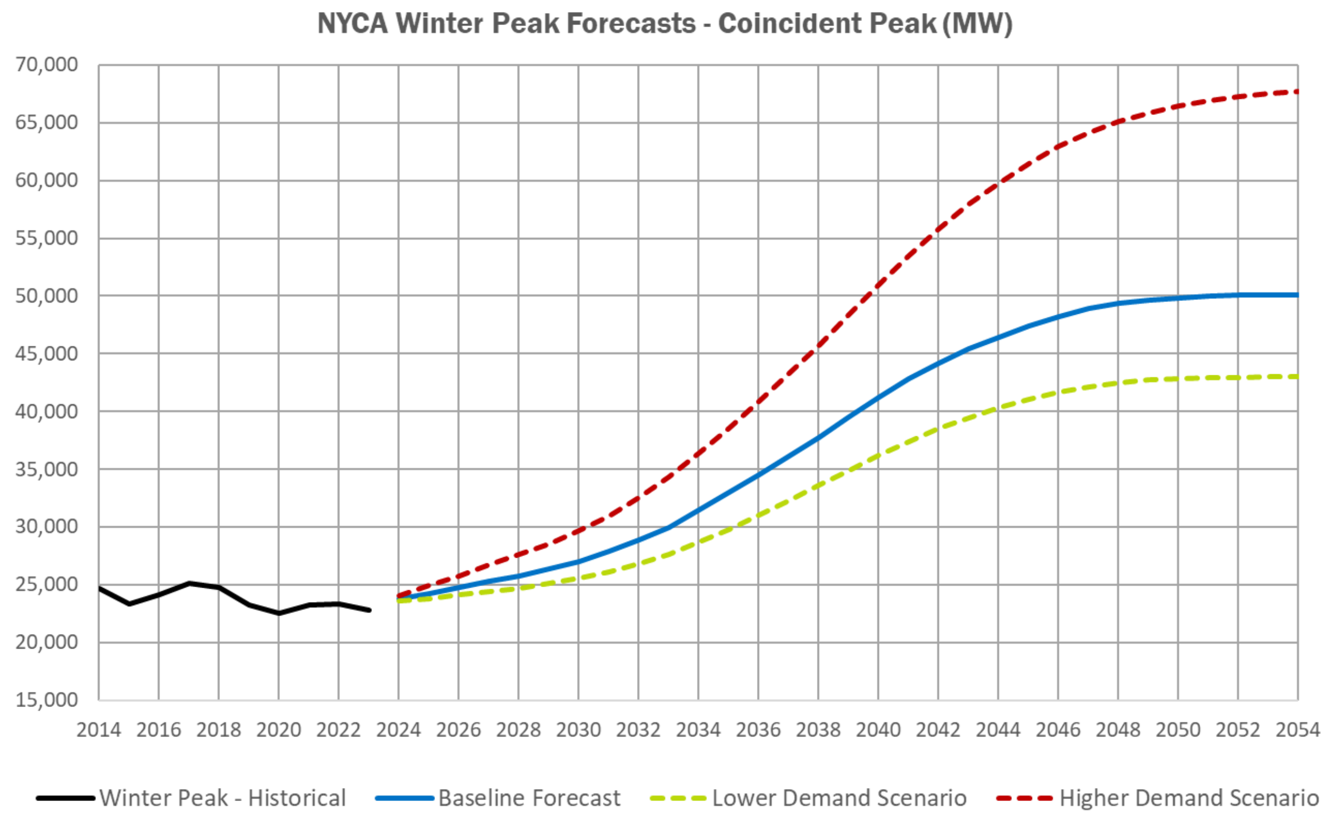
Figure 5: Summer Coincident Peak Demand by Zone - Actual and 2024 Gold Book Forecast (MW)



Baseline Summer Coincident Peak Demand Forecast (MW)												
Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2025	2,821	1,969	2,559	689	1,317	2,273	2,157	615	1,334	10,960	4,956	31,650
2026	2,853	2,000	2,598	871	1,276	2,229	2,167	620	1,341	10,990	4,955	31,900
2027	2,835	1,993	2,612	1,050	1,238	2,235	2,183	625	1,351	11,020	4,968	32,110
2028	2,799	1,968	2,639	1,051	1,222	2,225	2,209	632	1,363	11,040	4,982	32,130
2029	2,770	1,951	2,790	1,054	1,218	2,225	2,251	642	1,380	11,050	5,009	32,340
2030	2,752	1,942	2,940	1,054	1,216	2,232	2,287	652	1,395	11,080	5,030	32,580
2031	2,763	1,944	3,044	1,055	1,220	2,245	2,329	663	1,413	11,130	5,074	32,880
2032	2,789	1,955	3,189	1,057	1,230	2,270	2,375	676	1,430	11,220	5,129	33,320
2033	2,826	1,977	3,310	1,060	1,253	2,308	2,438	691	1,452	11,310	5,205	33,830
2034	2,858	1,989	3,361	1,064	1,275	2,339	2,488	706	1,472	11,390	5,268	34,210

Higher Demand Summer Coincident Peak Demand Forecast (MW)												
Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2025	2,894	2,003	2,645	754	1,331	2,293	2,175	621	1,345	11,140	4,999	32,200
2026	3,002	2,019	2,693	1,125	1,296	2,302	2,197	627	1,358	11,270	5,021	32,910
2027	3,049	2,041	2,754	1,315	1,274	2,336	2,225	635	1,373	11,400	5,048	33,450
2028	3,057	2,039	2,844	1,428	1,261	2,400	2,262	645	1,390	11,530	5,084	33,940
2029	3,048	2,034	2,977	1,465	1,259	2,453	2,308	656	1,410	11,660	5,130	34,400
2030	3,052	2,036	3,137	1,474	1,267	2,494	2,361	670	1,432	11,800	5,187	34,910
2031	3,077	2,050	3,299	1,483	1,283	2,525	2,421	685	1,457	11,940	5,260	35,480
2032	3,118	2,073	3,453	1,493	1,306	2,566	2,487	702	1,483	12,100	5,349	36,130
2033	3,171	2,101	3,585	1,503	1,337	2,614	2,558	720	1,512	12,260	5,449	36,810
2034	3,230	2,131	3,685	1,514	1,370	2,665	2,627	738	1,539	12,430	5,551	37,480

Figure 6: Winter Coincident Peak Demand by Zone - Actual and 2024 Gold Book Forecast (MW)



Baseline Winter Coincident Peak Demand Forecast (MW)												
Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2025-26	2,283	1,584	2,481	1,022	1,292	1,922	1,524	508	885	7,410	3,299	24,210
2026-27	2,348	1,626	2,587	1,169	1,289	1,931	1,548	512	896	7,490	3,334	24,730
2027-28	2,402	1,647	2,675	1,258	1,304	2,001	1,591	522	914	7,560	3,396	25,270
2028-29	2,444	1,670	2,797	1,259	1,323	2,037	1,640	532	933	7,660	3,465	25,760
2029-30	2,499	1,700	2,941	1,263	1,349	2,083	1,700	537	955	7,770	3,553	26,350
2030-31	2,574	1,738	3,121	1,263	1,376	2,124	1,760	542	973	7,910	3,639	27,020
2031-32	2,669	1,789	3,232	1,264	1,414	2,179	1,832	543	998	8,230	3,750	27,900
2032-33	2,755	1,833	3,389	1,267	1,457	2,240	1,910	552	1,027	8,540	3,880	28,850
2033-34	2,882	1,908	3,570	1,271	1,523	2,340	2,020	576	1,072	8,730	4,058	29,950
2034-35	3,029	1,995	3,728	1,276	1,601	2,458	2,148	604	1,125	9,250	4,266	31,480
Higher Demand Winter Coincident Peak Demand Forecast (MW)												
Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2025-26	2,426	1,617	2,560	1,137	1,306	1,959	1,556	517	901	7,620	3,361	24,960
2026-27	2,528	1,658	2,691	1,396	1,318	2,009	1,588	523	916	7,750	3,413	25,790
2027-28	2,634	1,704	2,817	1,559	1,339	2,100	1,641	533	938	7,930	3,495	26,690
2028-29	2,723	1,745	2,967	1,642	1,367	2,218	1,705	544	964	8,140	3,595	27,610
2029-30	2,806	1,791	3,137	1,669	1,404	2,322	1,781	554	993	8,390	3,713	28,560
2030-31	2,909	1,848	3,321	1,679	1,452	2,414	1,870	565	1,027	8,710	3,855	29,650
2031-32	3,040	1,922	3,518	1,690	1,514	2,506	1,978	579	1,068	9,110	4,035	30,960
2032-33	3,197	2,011	3,739	1,703	1,594	2,622	2,109	600	1,120	9,590	4,255	32,540
2033-34	3,384	2,121	3,954	1,715	1,692	2,766	2,264	630	1,185	10,120	4,519	34,350
2034-35	3,594	2,247	4,177	1,730	1,803	2,931	2,438	666	1,258	10,710	4,816	36,370

Resource Adequacy Load Forecast Considerations

In addition to projected load at expected weather conditions, the RNA considers the impacts of extreme weather on peak load conditions, known as Load Forecast Uncertainty (LFU).[7]. In both summer and winter, potential peak load levels are much higher than baseline during potential periods of extreme heat and cold. In the winter, this uncertainty will become exacerbated as electric heating and EV charging load is added to the system. This increase in winter peak load uncertainty is modeled via the dynamic winter LFU multipliers.

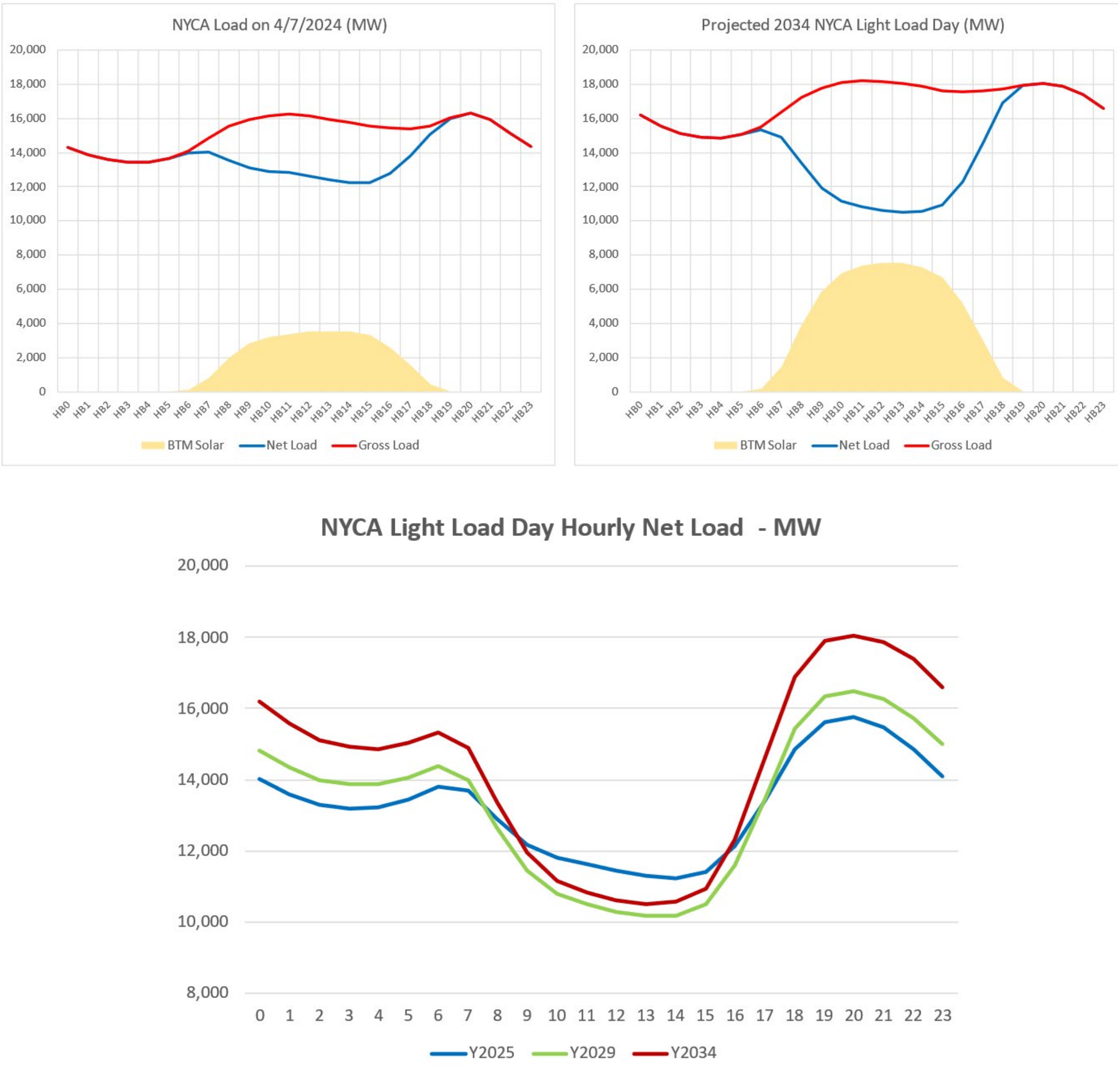
The NYISO uses Behind-the Meter (BtM) solar PV production data in the RNA resource adequacy assessments. For General Electric's Multi Area Reliability Simulations (GE-MARS) modeling, the BtM solar component is added back in the baseline forecast in order to explicitly model BtM solar as a generation resource. The 2013, 2017, and 2018 load shapes used in the study were adjusted to meet the forecasted zonal peaks, NYCA peak, Zones G through J Locality peak, and NYCA energy forecast. Projected load reductions from BtM solar are added back to the forecasted load levels and shapes. The resource adequacy model captures load uncertainty due to solar variability by randomly selecting from five historical solar shapes during each replication.

Transmission Security Load Forecast Considerations

A light load forecast is developed for the RNA for use in transmission security analyses. The forecast reflects a low midday net load hour with high BtM solar generation, approaching or equal to the overall NYCA annual minimum load hour. The forecast is set on a spring weekend day during the noon hour, when load levels are lower and solar generation is at its maximum. As BtM solar capacity and generation increases over time, minimum net loads during midday hours decrease significantly in later forecast years. These effects are most drastic in some upstate zones, since the relative concentration of BtM solar (relative to load) is generally greatest in these areas during the later study years. These impacts are somewhat mitigated by additional large load, economic growth, and electrification. The following figures show the evolving system daily load pattern during the light load day due primarily to increase in BtM solar generation.

[7] Dynamic LFU April 18, 2024, presentation: https://www.nyiso.com/documents/20142/44204719/03_DynamicLFU_April18LFTF-ESPWG-TPAS.pdf.

Figure 7: NYCA Light Load Day Shapes



Appendix D – Inclusion Rules Application

The analysis performed during the Reliability Needs Assessment (RNA) requires the development of a base case for transmission security analysis and for resource adequacy analysis. Through this analysis and the assumptions contained in the RNA base case, the NYISO identifies violations of Reliability Criteria,[8] which are termed "Reliability Needs" and are actionable for the NYISO to solicit solutions through the development of the CRP.

The assumptions making up the RNA base case depict a future system, such as the probable generation, transmission and large loads, over the Study Period. Section 3 of the Reliability Planning Process Manual[9] describes the inclusion rules for the reliability planning base cases, and its application is summarized below.

Summary of Proposed Generation Assumptions

The NYISO develops a 2024 RNA Base Case that consists of cases that are used for both transmission security and resource adequacy. The RNA Base Case used to analyze the performance of the transmission system stem from the 2023 and 2024 FERC 715 filing power flow case library. The load representation in the power flow model is the expected summer peak load forecast reported in the baseline forecast of coincident peak demand in Table 1-3a of the 2024 Gold Book.[10] The system representation external to the New York Control Area is the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) 2023 power flow model library.

For the resource adequacy evaluations, the models are developed starting with prior resource adequacy models and are updated with information from the 2024 Gold Book and historical data, with the application of the inclusion rules. Information on modeling of neighboring systems is based on the input received from the NPCC CP-8 working group.

For the 2024 Base Case, the NYISO applied the inclusion rules to screen the projects and plans for inclusion or exclusion. As a result of applying the inclusion results set forth in Section 3 of the Reliability Planning Manual, the 2024 RNA Base Case does not include all projects currently listed on the NYISO's interconnection queue or those shown in the 2024 Gold Book. Rather, it includes only those which met the screening requirements, as shown in the of the main report. .

[8] As defined by the Reliability Councils: NERC (https://www.nerc.com/Pages/default.aspx), NPCC (https://www.npcc.org/), and NYSRC (https://www.nysrc.org/).

[9] RPP Manual: https://www.nyiso.com/documents/20142/2924447/rpp_mnl.pdf.

[10] 2024 Gold Book: https://www.nyiso.com/documents/20142/2226333/2024-Gold-Book-Public.pdf.

The figures below summarize the Base Case generator addition and removals.

Figure 8: Large Generation Additions

Proposed Project Inclusion: Large Generation					
Queue	**Project Name**	**MW**	**Type**	**Zone**	**Proposed Date**
619	East Point Solar	50	Solar	F	Feb-24
618	High River Solar	90	Solar	F	Jun-24
717	Morris Ridge Solar Energy Center	177	Solar	C	Sep-24
637	Flint Mine Solar	100	Solar	G	Oct-24
766/987	Sunrise Wind II	924	Offshore Wind	K	Mar-26
737	Empire Wind 1	816	Offshore Wind	J	Dec-26

Figure 9:Small Generation Additions

Proposed Project Inclusion: Small Generation					
	Name	**MW**	**Type**	**Zone**	**Proposed Date**
572	Greene County 1	20	Solar	G	Jan-23
573	Greene County 2	10	Solar	G	Mar-23
545	Sky High Solar	20	Solar	C	Jun-23
744	Magruder BESS	20	Energy Storage	G	Sep-23
581	Hills Solar	20	Solar	E	Feb-24
586	Watkins Rd Solar	20	Solar	E	Feb-24
584	Dog Corners Solar	20	Solar	C	Apr-24
833	Dolan Solar	20	Solar	F	Apr-24
565	Tayandenega Solar	20	Solar	F	Jun-24
1003	Clear View Solar	20	Solar	C	Jun-24
564	Rock District Solar	20	Solar	F	Jul-24
807	Hilltop Solar	20	Solar	F	Jul-24
670	SunEast Skyline Solar LLC	20	Solar	E	Aug-24
734	Ticonderoga Solar	20	Solar	F	Aug-24
832	CS Hawthorn Solar	20	Solar	F	Aug-24
804	KCE NY 10*	20	Energy Storage	A	Nov-24
828	Valley Solar	20	Solar	C	Nov-24
590	Scipio Solar	18	Solar	C	Dec-24
591	Highview Solar	20	Solar	C	Dec-24
575	Little Pond Solar	20	Solar	G	Jan-25
848	Fairway Solar	20	Solar	E	Mar-25
592	Niagara Solar	20	Solar	B	Jun-25
855	NY13 Solar	20	Solar	F	Jun-25
865	Flat Hill Solar	20	Solar	E	Dec-25
885	Grassy Knoll Solar	20	Solar	E	Dec-25

Notes:
*Project does not have CRIS.

Figure 10: Generation Additions by Year

Running Total of MW Additions by Type (2)			
Year (1)	Solar	Off-shore Wind	Energy Storage
2024	180	0	20
2025	785	0	40
2026	865	924	40
2027	865	1740	40
2028	865	1740	40
2029	865	1740	40
2030	865	1740	40
2031	865	1740	40
2032	865	1740	40
2033	865	1740	40
2034	865	1740	40

Notes:

1. First summer peak period following the addtion.
2. MW based on the Nameplate Rating.

Figure 11: Generation Removals by Year

MW Removals			
Generator Name	Zone	MW Removals (1)	Year (2)
Coxsackie GT	G	19.7	2024
South Cairo	G	14.6	2024
Glenwood GT 03	K	52	2024
Shoreham 1	K	42	2024
Shoreham 2	K	17.4	2024
Arthur Kill Cogen	J	11.1	2024
Astoria GT 01	J	13.8	2025
59 St. GT 1	J	13.9	2025
Arthur Kill GT 1	J	12.3	2025
Gowanus 2-1 - 2-8	J	140.9	2025
Gowanus 3-1 - 3-8	J	138.5	2025
Narrows 1-1 - 1-8	J	140	2025
Narrows 2-1 - 2-8	J	144.3	2025
Gowanus 5	J	40	2031
Gowanus 6	J	39.9	2031
Kent	J	46	2031
Pouch	J	45.4	2031
Hellgate 1	J	39.9	2031
Hellgate 2	J	39.6	2031
Harlem River 1	J	39.9	2031
Harlem River 2	J	39.6	2031
Vernon Blvd 2	J	40	2031
Vernon Blvd 3	J	39.9	2031
Brentwood	K	45	2031
Total Removed before Summer 2025		760.5	
Total Removed before Summer 2031		1215.7	

Notes:

1. MW based on the Summer Capability (DMNC.)
2. First summer peak period following removal.

Additionally, the NYISO's interconnection queue has seen an unprecedented increase in the number of projects seeking interconnection service. The projects that are at a more advanced stage in the interconnection process are listed in Table IV from the 2024 Gold Book. Many of these projects did not satisfy the inclusion rules and, therefore, are not in the 2024 RNA Base Case. However, the NYISO performs scenario analysis to understand changes on the system for information purposes only. Figure 12 below shows proposed projects that were included in a scenario performed under this RNA for information. The projects that are included in the 2024 RNA Base Cases are highlighted in green.

Figure 12: Additional Proposed Generation Projects from the 2024 Gold Book

2024 RNA Status	Queue #	OWNER / OPERATOR	STATION UNIT	ZONE	Proposed Date[6] (M-YY)	Nameplate Rating (MW)	Min (CRIS,DMNC)	Requested CRIS (MW)	CRIS (MW)	SUMMER (MW)	WINTER (MW)	Unit Type	Class Year Facilities Study
			Completed Class Year Facilities Study										
Scenario	596	Alle-Catt Wind Energy LLC	Alle Catt II Wind	A	Feb-25	339.1	339.1	339.1	339.1	339.1	339.1	Wind Turbines	2019
Scenario	704	Bear Ridge Solar, LLC	Bear Ridge Solar	A	Oct-24	100.0	100.0	100.0	100.0	100.0	100.0	Solar	2019
Scenario	783	ConnectGen Chautauqua County LLC	South Ripley Solar and BESS	A	Jun-24	270.0	270.0	270.0	270.0	270.0	270.0	Solar+Energy Storage	2021
Scenario	787	Levy Grid, LLC	Levy Grid, LLC	A	Aug-25	150.0	150.0	150.0	150.0	150.0	150.0	Energy Storage	2021
Scenario	571	Heritage Wind, LLC	Heritage Wind	B	Sep-26	200.1	200.1	200.1	200.1	200.1	200.1	Wind Turbines	2021
Scenario	710	Horseshoe Solar Energy LLC	Horseshoe Solar	B	Oct-25	180.0	180.0	180.0	180.0	180.0	180.0	Solar	2021
Scenario	721	Excelsior Energy Center, LLC	Excelsior Energy Center	B	Feb-25	280.0	280.0	280.0	280.0	280.0	280.0	Solar	2019
Scenario	811	Hecate Energy Cider Solar LLC	Cider Solar	B	Nov-24	500.0	500.0	500.0	500.0	500.0	500.0	Solar	2021
Scenario	883	Garnet Energy Center, LLC	Garnet Energy Center	B	Nov-25	200.0	200.0	200.0	200.0	200.0	200.0	Solar	2021
Scenario	276	Homer Solar Energy Center LLC	Homer Solar Energy Center	C	Apr-26	90.0	90.0	90.0	90.0	90.0	90.0	Solar	2019
Scenario	396	Baron Winds, LLC	Baron Winds	C	Dec-24	238.8	117.0	300.0	300.0	117.0	117.0	Wind Turbines	2017
Scenario	519	Canisteo Wind Energy LLC	Canisteo Wind	C	Feb-25	289.8	289.8	290.7	290.7	289.8	289.8	Wind Turbines	2019
Scenario	617	Watkins Glen Solar Energy Center, LLC	Watkins Glen Solar	C	Nov-24	54.0	50.0	50.0	50.0	50.0	50.0	Solar	2019
Base Case	717	Morri Ridge Solar Energy Center, LLC	Morris Ridge Solar Energy Center	C	Sep-24	177.0	177.0	177.0	177.0	177.0	177.0	Solar	2021
Scenario	720	Trelina Solar Energy Center, LLC	Trelina Solar Energy Center	C	Dec-24	86.8	79.8	80.0	80.0	79.8	79.8	Solar	2019
Scenario	801	Prattsburgh Wind, LLC	Prattsburgh Wind Farm	C	Dec-25	147.0	147.0	147.0	147.0	147.0	147.0	Wind Turbines	2021
Scenario	805	Osbow Hill Solar, LLC	Owbox Hill Solar	C	Dec-24	140.0	140.0	140.0	140.0	140.0	140.0	Solar	2021
Scenario	521	Bull Run Energy LLC	Bull Run II Wind	D	Dec-26	449.0	449.0	449.0	449.0	449.0	449.0	Wind Turbines	2021
Scenario	620	North Side Energy Center, LLC	North Side Solar	D	Dec-24	180.0	180.0	180.0	180.0	180.0	180.0	Solar	2019
Scenario	706	High Bridge Wind, LLC	High Bridge Wind	E	Dec-24	100.8	100.8	100.8	100.8	100.8	100.8	Wind Turbines	2019
Scenario	864	Greens Corners Solar LLC	NY38 Solar	E	Dec-24	120.0	120.0	120.0	120.0	120.0	120.0	Solar	2021
Scenario	495	Mohawk Solar LLC	Mohawk Solar	F	Nov-24	90.5	90.5	90.5	90.5	90.5	90.5	Solar	2019
Base Case	618	High River Energy Center, LLC	High River Solar	F	Jun-24	90.0	90.0	90.0	90.0	90.0	90.0	Solar	2019
Base Case	619	East Point Energy Center, LLC	East Point Solar	F	Feb-24	50.0	50.0	50.0	50.0	50.0	50.0	Solar	2019
Scenario	644	Hecate Energy Columbia County 1, LLC	Columbia County 1	F	Dec-24	60.0	60.0	60.0	60.0	60.0	60.0	Solar	2019
Base Case	637	Flint Mine Solar LLC	Flint Mine Solar	G	Oct-24	100.0	100.0	100.0	100.0	100.0	100.0	Solar	2019
Scenario	683	KCE NY 2, LLC	KCE NY 2	G	Dec-24	200.0	200.0	200.0	200.0	200.0	200.0	Energy Storage	2019
Base Case	737	Empire Offshore Wind LLC	Empire Wind 1	J	Dec-26	816.0	816.0	816.0	816.0	816.0	816.0	Wind Turbines	2019
Scenario	815	Bayonne Energy Center	Bayonne Energy Center III	J	Oct-25	49.8	49.8	49.8	49.8	49.8	49.8	Energy Storage	2021
Scenario	835	Astoria Generating Company, LP	Luyster Creek Energy Storage 1	J	May-26	59.1	56.3	56.3	56.3	56.3	57.3	Energy Storage	2021
Scenario	840	Hecate Grid Swiftsure LLC	Swiftsure Energy Storage	J	Nov-26	650.0	121.0	650.0	121.0	650.0	650.0	Energy Storage	2021
Scenario	907	Harlem River ESS, LLC	Harlem River Yard	J	Dec-26	100.0	100.0	100.0	100.0	100.0	100.0	Energy Storage	2021
Scenario	931	East River ESS, LLC	Astoria Energy Storage	J	Dec-24	106.7	100.0	100.0	100.0	100.0	100.0	Energy Storage	2021
Scenario	535	Riverhead Solar 2, LLC	Riverhead Solar 2	K	Feb-25	36.0	36.0	36.0	36.0	36.0	36.0	Solar	2019
Base Case	612	South Fork Wind, LLC	South Fork Wind Farm	K	Feb-24	96.0	96.0	96.0	96.0	96.0	96.0	Wind Turbines	2019
Base Case	695	South Fork Wind, LLC	South Fork Wind Farm II	K	Feb-24	40.0	40.0	40.0	40.0	40.0	40.0	Wind Turbines	2019
Base Case	766	Sunrise Wind LLC	Sunrise Wind	K	Mar-26	1,085.7	880.0	880.0	880.0	880.0	880.0	Wind Turbines	2021
Scenario	956	Holtsville Energy Storage, LLC	Holtsville 138kV Energy Storage	K	Oct-26	300.9	110.0	110.0	110.0	110.0	110.0	Energy Storage	2021
Scenario	965	Yaphank Energy Storage, LLC	Yaphank Energy Storage	K	Sep-26	79.6	76.8	76.8	76.8	76.8	77.6	Energy Storage	2021
Base Case	987	Sunrise Wind LLC	Sunrise Wind II	K	Mar-26	1,085.7	44.0	44.0	44.0	44.0	44.0	Wind Turbines	2021
			Non Class Year Generators (Small Generators) Interconnection Agreement Complete										
Base Case	545	Sky High Solar LLC	Sky High Solar	C	Jun-23	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	564	Rock District Solar, LLC	Rock District Solar	F	Jul-24	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	565	Tayandenega Solar, LLC	Tayandenega Solar	F	Jun-24	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	572	Hecate Energy Greene 1 LLC	Greene County 1	G	Jan-23	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	573	Hecate Energy Greene 2 LLC	Greene County 2	G	Mar-23	10.0	10.0	10.0	10.0	10.0	10.0	Solar	
Base Case	581	SunEast Hills Solar LLC	Hills Solar	E	Feb-24	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	584	SunEast Dog Corners Solar LLC	Dog Corners Solar	C	Apr-24	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	586	SunEast Watkins Road Solar LLC	Watkins Rd Solar	E	Feb-24	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	590	SunEast Scipio Solar LLC.	Scipio Solar	C	Dec-24	18.0	18.0	18.0	18.0	18.0	18.0	Solar	
Base Case	591	SunEast Highview Solar LLC	Highview Solar	C	Dec-24	20.0	20.0	20.0	20.0	20.0	20.0	Solar	2019
Base Case	592	SunEast Niagara Solar LLC	Niagara Solar	B	Jun-25	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	670	SunEast Skyline Solar LLC	SunEast Skyline Solar LLC	E	Aug-24	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	734	ELP Ticonderoga Solar, LLC	Ticonderoga Solar	F	Aug-24	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	744	Mitchell Energy Facility, LLC	Magruder BESS	G	Jan-24	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	807	SunEast Hilltop Solar LLC	Hilltop Solar	F	Jul-24	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	828	SunEast Valley Solar LLC	Valley Solar	C	Nov-24	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	832	Granada Solar, LLC	CS Hawthorn Solar	F	Aug-24	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	833	Dolan Solar, LLC	Dolan Solar	F	Apr-24	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	848	SunEast Fairway Solar LLC	Fairway Solar	E	Mar-25	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	855	Bald Mountain Solar LLC	NY 13 Solar	F	Jun-25	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	865	SunEast Flat Hill Solar LLC	Flat Hill Solar	E	Dec-25	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	885	SunEast Grassy Knoll Solar LLC	Grassy Knoll Solar	E	Dec-25	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	1003	Clear View LLC	Clear View Solar	C	Jun-24	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	575	Little Pond Solar, LLC	Little Pond Solar	G	Jan-25	20.0	20.0	20.0	20.0	20.0	20.0	Solar	
Base Case	804	KCE NY 10, LLC	KCE NY 10	A	Nov-24	20.0	20.0	20.0	20.0	20.0	20.0	Energy Storage	

Summary of Transmission Assumptions

Figure 13 summarizes NYCA import assumptions for summer and winter peak load conditions.

Major transmission projects included in the 2024 RNA Base Cases are highlighted in Figure 14.

All firm transmission plans and transmission interconnection projects included in Table VII of the 2024 Gold Book are included in the 2024 RNA Base Cases, except those listed in Figure 15 below.

Figure 13: Net NYCA Import Assumptions

Net Imports			
Summer (MW)		Winter (MW)	
2025	1844	2025-26	735
2026	3094	2026-27	735
2027	3094	2027-28	735
2028	3094	2028-29	735
2029	3094	2029-30	735
2030	3094	2030-31	735
2031	3094	2031-32	735
2032	3094	2032-33	735
2033	3094	2033-34	735
2034	3094	2034-35	735

Figure 14: Major Transmission Projects Included in Base Cases

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	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

Figure 15: Transmission Project Inclusion Rules Application for 2024 RNA Base Case

Transmission Project Includion Rules Application: Class Year Transmission, TIP, and Firm LTP Projects Not Included in the RNA Base Cases											
Transmission Owner	Terminals		Line Length (Miles)	Proposed In-Service Date		Nominal Voltage (kV)		# of CKTs	Thermal Ratings (4)		Project Description / Conductor Size
				Prior to (2)	Year	Operating	Design		Summer	Winter	
Clean Path New York LLC	Fraser 345kV	Rainey 345kV	173	S	2027	492	492	1	1300 MW	1300 MW	'-/+ 400kV Bipolar HVDC cable
NYSEG	Canandaigua	Stoney Ridge	24	W	2030	230	230	1	795 MVA	853 MVA	Rebuild the existing 24 mile 230 kV line #68 with mile 230 kV line with bundled 1192 Bunting ACSR ACSR conductor.
NYSEG	Hillside	Watercure	1	W	2030	230	230	1	819 MVA	972 MVA	Rebuild the existing 1 mile 230 kV line #69 with 2156 Bluebird ACSR conductor.
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
NYSEG	Stolle Rd	High Sheldon	11	W	2030	230	230	1	795 MVA	853 MVA	Rebuild the existing 11-mile 230 kV line #67 with bundled 1192 Bunting ACSR conductor on an offset with steel monopole structures.
NYSEG	Stoney Ridge	Hillside	27	W	2030	230	230	1	795 MVA	886 MVA	Rebuild the existing 27 mile 230 kV line #72 with 2156 Bluebird ACSR conductor.

Summary of Proposed Large Load Assumptions

The 2024 RNA Base Case uses the baseline forecasts from the 2024 Gold Book. Large loads are included in the baseline zonal forecasts. One key assumption in the RNA is that cryptocurrency mining and hydrogen production large loads will be flexible during system peak demand conditions. This assumption is based on recent operating experience and outreach to load developers.

Figure 16 and Figure 17 present the large load peak baseline forecast values for summer and winter peak, respectively. The final column shows the total load assumed to be flexible during system peak demand conditions.

Figure 16: Large Load Summer Peak Forecast

Large Loads Summer Peak Forecasts (MW)

Reflects Cumulative Existing and Future Load Impacts of Large Load Projects

Zone	A	B	C	D	E	F	NYCA Total	Flexible Total
2024	188	0	0	169	11	0	368	357
2025	288	150	0	173	19	0	630	611
2026	348	248	122	352	21	0	1,091	998
2027	348	248	218	534	21	40	1,409	1,180
2028	348	248	338	534	21	40	1,529	1,180
2029	348	248	492	534	21	40	1,683	1,180
2030	348	248	703	534	21	40	1,894	1,180
2031	348	248	818	534	21	40	2,009	1,180
2032	348	248	933	534	21	40	2,124	1,180
2033	348	248	1,048	534	21	40	2,239	1,180
2034	348	248	1,077	534	21	40	2,268	1,180

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

Figure 17: Large Load Winter Peak Forecast

Large Loads Winter Peak Forecasts (MW) Reflects Cumulative Existing and Future Load Impacts of Large Load Projects								
Zone	A	B	C	D	E	F	NYCA Total	Flexible Total
2024-25	188	0	0	173	11	0	372	361
2025-26	288	150	0	324	21	0	783	762
2026-27	348	248	122	462	21	0	1,201	1,108
2027-28	348	248	218	534	21	40	1,409	1,180
2028-29	348	248	338	534	21	40	1,529	1,180
2029-30	348	248	492	534	21	40	1,683	1,180
2030-31	348	248	703	534	21	40	1,894	1,180
2031-32	348	248	818	534	21	40	2,009	1,180
2032-33	348	248	933	534	21	40	2,124	1,180
2033-34	348	248	1,048	534	21	40	2,239	1,180
2034-35	348	248	1,077	534	21	40	2,268	1,180

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

Appendix E - Resource Adequacy Models and Assessments

The NYISO uses GE-MARS models and performs probabilistic simulations to determine whether adequate resources would be available to meet the NPCC and NYSRC reliability criteria of Loss of Load Expectation (LOLE) of one day in ten years (0.1 event-days/year). The results identify whether or not there are LOLE violations. The MARS models were also used to evaluate variations to the Base Case assumptions to identify, through the development of appropriate scenarios, factors and issues that might adversely impact the reliability of the BPTFs.

The NYISO conducts its resource adequacy analysis using the GE-MARS software package, which performs probabilistic simulations of outages of capacity and select transmission resources. The program employs a sequential Monte Carlo simulation method and calculates expected values of reliability indices such as LOLE (event-days/year) and includes load, generation, and transmission representation. Additional modeling details and links to various stakeholders' presentations are in the assumption's matrix, which is included in this appendix. In determining the reliability of a system, there are several types of randomly occurring events that are taken into consideration. Among these are the forced outages of generation and transmission, and deviations from the forecasted loads.

The planning models reflected several changes highlighted below (additional details in the assumptions matrix):

- To account for winter uncertainties:
  - Dynamic LFU: on the demand side, increasing winter peak load forecast uncertainty (throughout the study years) was modeled to account for the impacts of heating electrification, EV charging, and large loads.
  - Winter gas unavailability: on the resources side, risk of gas unavailability mainly related with gas-only plants was implemented.
- New data sources: using 5 years (2017-2021) of hourly MW model-based data developed by DNV-GL for land-based and offshore wind, and front of the meter solar.
- Further limiting external reliance: the top 5 (changed from 3 starting 2024 RNA as an additional method to further limit reliance) summer and winter peak load days of an external Control Area are modeled as coincident with the NYCA top five peak load days.
- SCR model: modeled as duration-limited resources with units being constrained to be called once in a day when a loss of load event occurs.
- Large loads: a total of about 1,200 MW was assumed flexible and will decrease demand on peak days. This was modeled in MARS as an EOP step before the SCR step.

Modeling Assumptions

Generation Model

The NYISO models the generation system in GE-MARS using several types of units. Thermal unit considerations include random forced outages, scheduled and unplanned maintenance, and thermal derates (minimum between CRIS and DMNC MW from the 2024 Gold Book is used for both summer and winter). Renewable resource units (*i.e.,* both utility and behind the meter solar PV, wind, run-of-river hydro, and landfill gas) are modeled using five years of historical production data. Co-generation units are also modeled using a capacity and load profile for each unit. The 2024 RNA resource adequacy assessments make the following assumptions about 6,400 MW of gas plants (about 5,600 MW located in F through K) during winter to account for cold weather risks:[11] (1) assumes all gas-only units with non-firm gas within the NYCA are unavailable and (2) certain dual-fuel units modeled at their alternate fuel capability. Both assumptions are triggered at the forecasted baseline winter coincident peak. This is a static value applied to all load levels. Therefore, the gas constraint triggers more often at the higher MARS load levels (*i.e.*, bins 1-3).

Load Model

The NYISO's load model for the GE-MARS model consists of historical load shapes and load forecast uncertainty (LFU). The NYISO uses three historical load shapes (8,760 hourly MW) in the GE-MARS model in seven different load levels using a normal distribution. The load shapes are adjusted on a seasonal (summer and winter) basis to meet peak forecasts while maintaining the energy target from the Gold Book. The load forecast includes large loads from the NYISO interconnection queue with forecasted impacts in the 2024 baseline demand. The 2024 Gold Book baseline peak load forecast also includes the impact (reduction) of behind-the-meter (BtM) solar at the time of the NYCA peak. For the BtM solar adjustment, gross load forecasts that include the impact of the BtM generation are used for the RNA, which then allows for a discrete modeling of the BtM solar resources using 5 years of inverter data. LFU is applied to every hour of these historical shapes and each hour of the seven load levels is run through the GE-MARS model for each replication for resources availability evaluations.

Historical shapes used in the past (2002 for bin 2, 2006 for bin 1, and 2007 for bin 3 through 7) were replaced by 2013, 2017, 2018 starting with the 2022 RNA and based on detailed analysis performed by the

[11] Winter gas derates April 30, 2024 presentation: https://www.nyiso.com/documents/20142/44393357/03_2024RNA_WinterGasDerates_ESPWG_043024.pdf.

NYISO.[12] The load bin distribution in MARS is below:

- Load Bins 1 and 2: 2013
  - 2013 had a hot summer peak day and a steep load shape and was selected to represent LFU Bins 1 and 2. Years with significantly hot peak-producing weather (analogous to Bin 1 and Bin 2 LFU temperatures) have fairly steep load duration curves.
- Load Bins 3 and 4: 2018
  - 2018 had fairly average peak-producing weather and a relatively flat load shape, nd was selected to represent Bins 3 and 4. Bin 4 represents the expected (average) weather and load level.
- Load Bins 5 to 7: 2017
  - 2017 had a cool summer peak day and a relatively flat load shape. 2017 is selected to represent Bins 5 through 7, which represent summers with milder than expected peak weather conditions.

Additionally, starting with the 2024 RNA, and to account for forecast uncertainty during winter due to electrification and large loads, a winter dynamic load forecast uncertainty[13] has been implemented in the MARS model for the 2024 RNA.

External Areas Model

The NYISO models the four external Control Areas interconnected to the NYCA (ISO-New England, PJM, Ontario, and Quebec). The transfer limits between the NYCA and the external areas are set in collaboration with the NPCC CP-8 Working Group. Additionally, the probabilistic model used in the RNA to assess resource adequacy employs a number of methods aimed at preventing the NYISO's overreliance on support from the external Control Areas. These include imposing a limit of 3,500 MW to the total emergency assistance from all neighbors, modeling simultaneous five peak days (changed from 3 days to further limit reliance), and modeling the long-term purchases and sales with neighboring control areas. Furthermore, the external Control Areas are kept within a Loss of Load Expectation (LOLE) range of 0.10 to 0.15 event-days/year throughout Study Period.

Additionally, various grandfathered or firm contracts and Unforced Deliverability Rights (UDRs) links

[12] The changes to the historical shapes were presented at the March 24, 2022 LFTF/TPAS/ESPWG and available at: https://www.nyiso.com/documents/20142/29418084/07%20LFU%20Phase%202_Recommendation.pdf and https://www.nyiso.com/documents/20142/29418084/08%20MARS_PlanningModel-NewLoadShapes.pdf.

[13] Dynamic LFU April 18, 2024 presentation: https://www.nyiso.com/documents/20142/44204719/03_DynamicLFU_April18LFTF-ESPWG-TPAS.pdf.

with the neighboring systems are generally modeled using the "contracts" feature in the GE-MARS model.

Emergency Operating Procedures (EOPs)

The New York model evaluates the need to implement in sequential order a number of emergency operating procedures, such as operating reserves, Special Case Resources (SCRs), manual voltage reduction, public appeals, 10-minute reserve, 30-minute reserve, and emergency assistance from external areas.

A change was implemented for this RNA to maintained (*i.e.,* no longer deplete) 350 MW of the 1,310 MW 10-min operating reserves as part of the MARS EOPs and as presented at the May 5, 2022, ESPWG/TPAS.[14] The updated value for the 2024 RNA is maintaining 400 MW, as discussed at the ICS.[15] Additionally, the SCR model (a demand response program) was changed for the 2024 RNA[16] (additional details in the assumption matrix in Appendix E).

MARS Topology

The NYISO models the amount of power that could be transferred during emergency conditions across the system in GE-MARS using interface transfer limits applied to the connections between the NYCA 11 Areas ("bubble-and-pipe" model), and with the four neighboring systems (Ontario, Quebec, New England, and PJM). No generation pockets within Zone J and Zone K are modeled in detail in MARS.

The internal transfer limits modeled are the summer emergency ratings derived from the RNA power flow cases discussed above.

The emergency transfer criteria limits used for the MARS topology model are developed from an assessment of analysis of 2023 and 2024 power flow base cases and review of analysis performed for other planning and operations studies.

Key observations, as comparing with the 2023-2033 Comprehensive Reliability Plan (CRP) base cases, are below.

- The NYISO modeled a decrease in the thermal transfer limit for Dysinger East of 100 MW starting with the study year 2 (2026). This is mainly due to the Western New York large loads forecasted in the 2024 Gold Book.
- Limits changes (increases) around Long Island (Zone K) due to the inclusion of the

[14] Details were presented at the May 5, 2022 ESPWG/TPAS and available at: https://www.nyiso.com/documents/20142/30451285/08_Reliability_Practices_TPAS-ESPWG_2022-05-05.pdf.

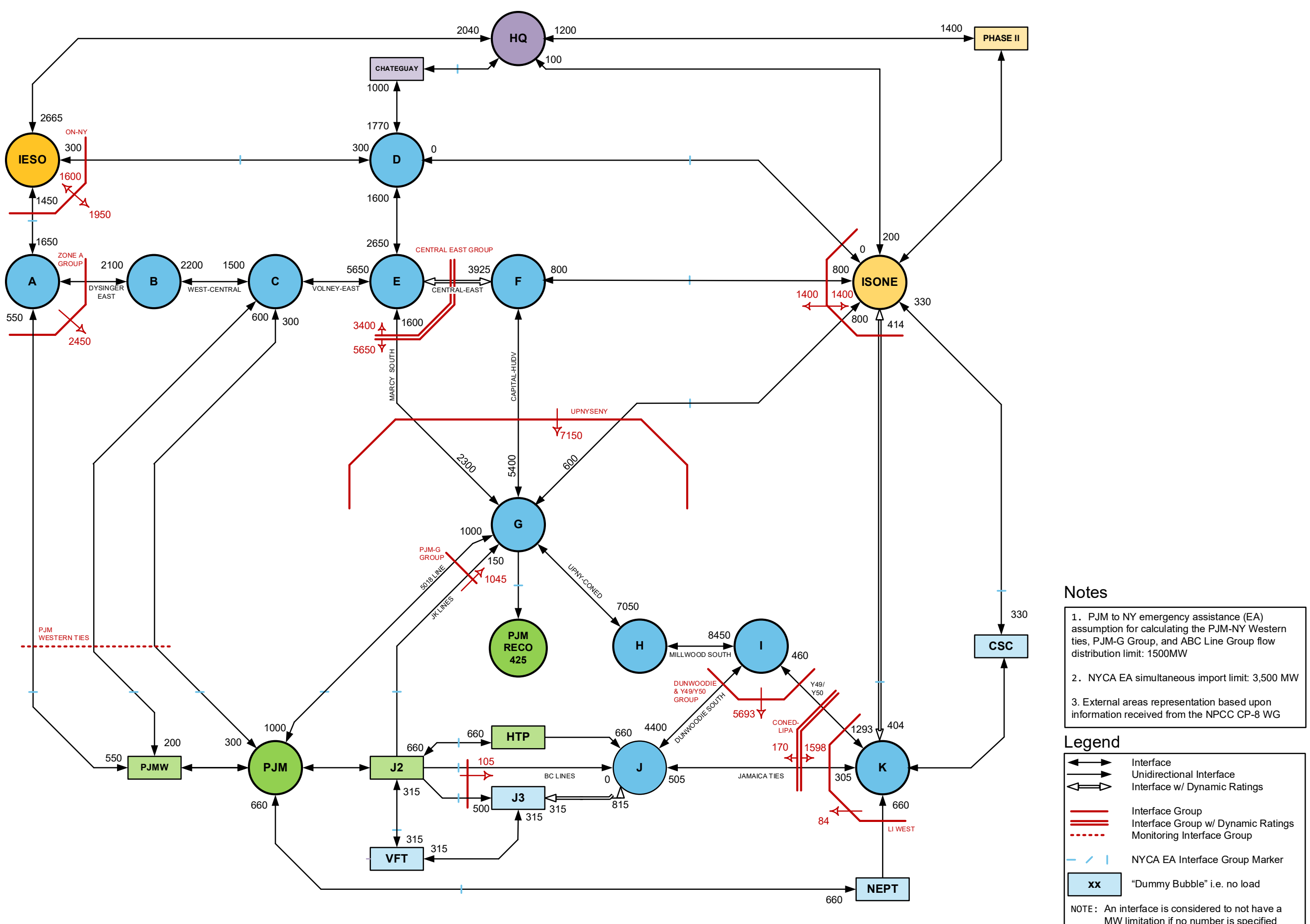
[15] Maintaining Operating Reserves during Load Shedding – *2024-2025 IRM* presented at the May 5, 2023 NYSRC ICS available at: https://www.nysrc.org/wp-content/uploads/2024/10/6.1_WithholdingOperatingReserveAssumptionReview_2023.05.03_Revised-1.pdf.

transmission selected by the NYISO's Board of Directors in 2023 to address the Long Island Offshore Wind Export Public Policy Transmission Public Policy, assumed in service 2030.

- Starting from year 2030, the Zone I to Zone K forward limit is increased by about 1,400 MW and the reverse limit increased by about 1,600 MW. The Zone J to Zone K forward limit is increased by about 500 MW and the reverse limit is increased by about 650 MW. Con Edison-LIPA forward limit is increased by about 1,650 MW and the reverse limit is increased by about 1,700 MW. Zone I to Zones J and K limit is increased by about 1,400 MW and finally LI West is increased by about 1,100 MW.

Visual depictions of the MARS topologies used for the 2024 RNA Base Case are below.

Figure 18: 2024 Planning Topology Year 1 (2025)



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

Figure 19: 2024 Planning Topology Years 2-5 (2026 -2029)

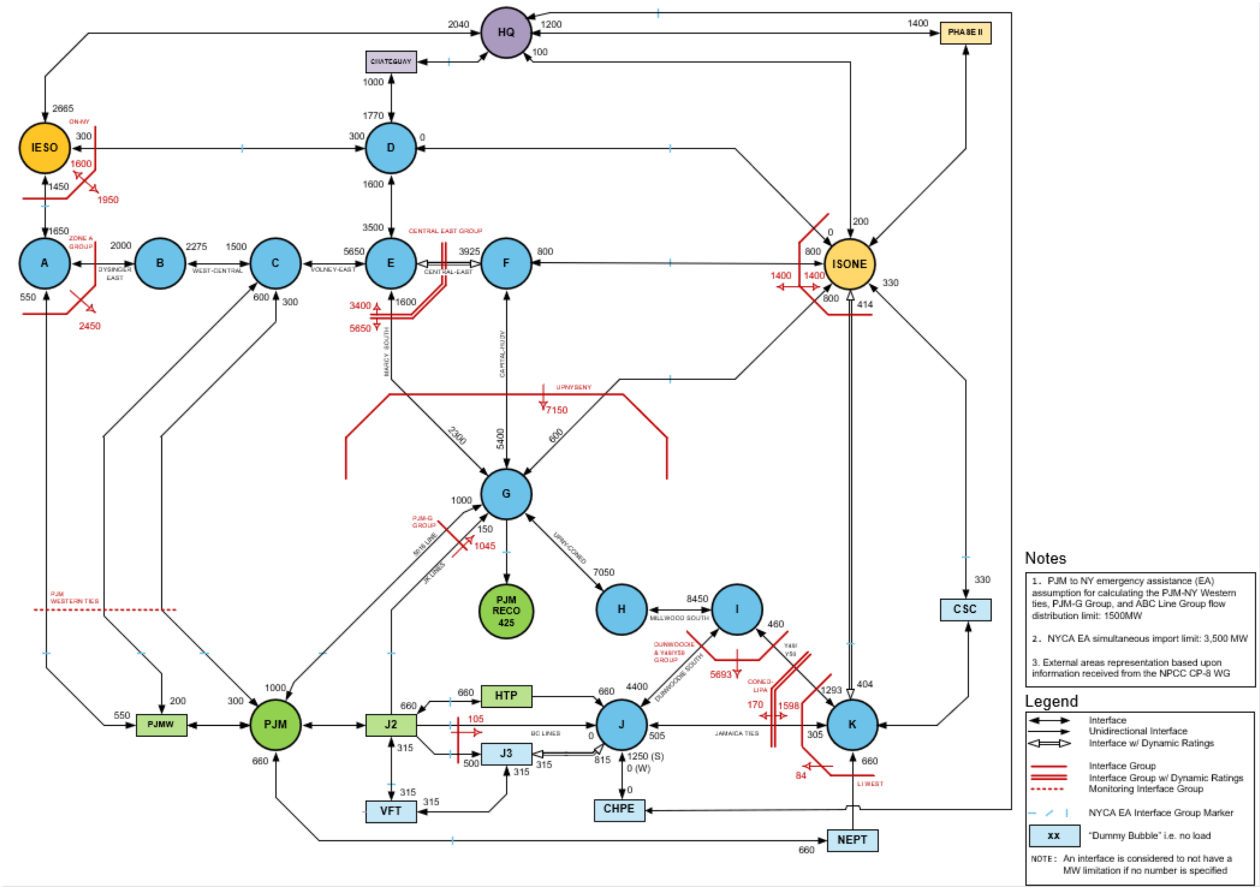
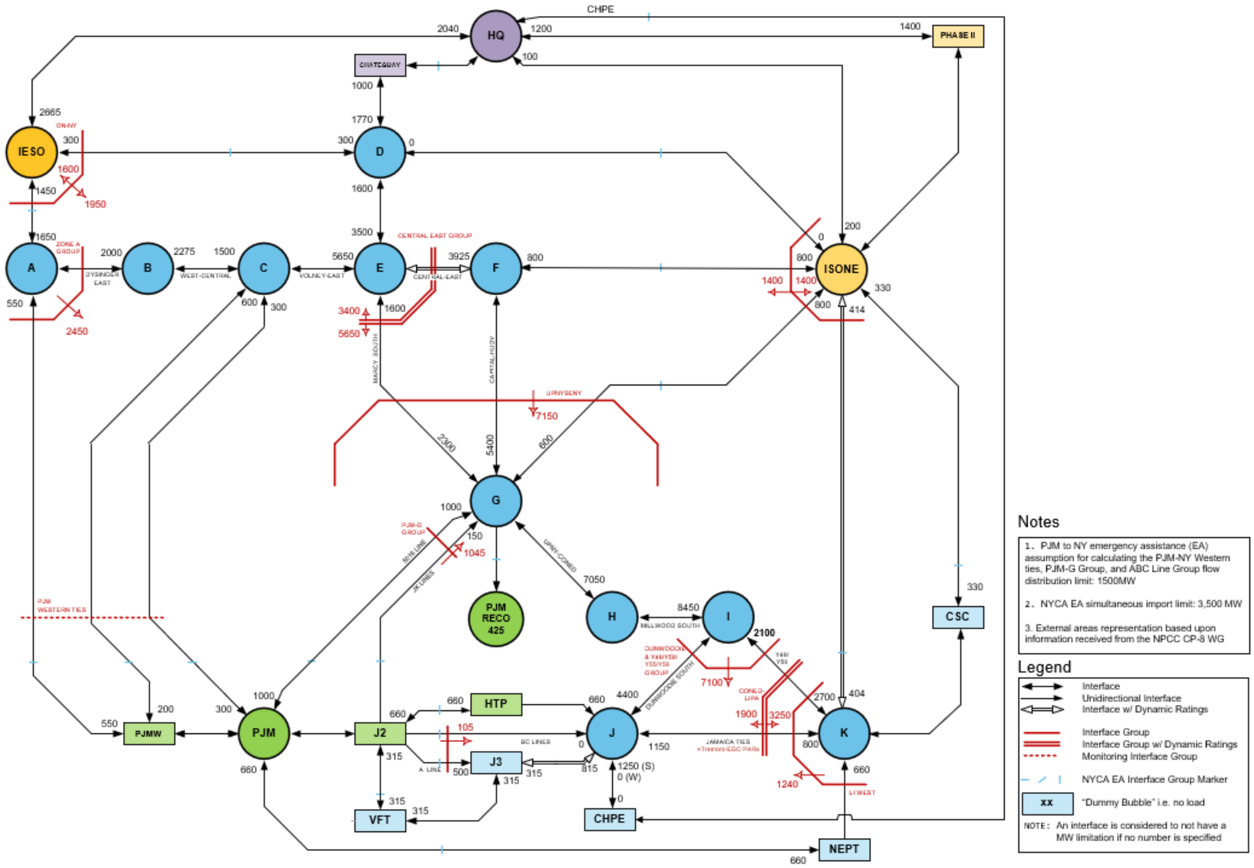


Figure 20: 2024 RNA Topology Years 6-10 (2030 -2034)



Topology for 2024 Base Case: RNA Study Years 6 through 10 (2030-2034)
Dynamic Limits and Groupings Information

Interface Group	Limit	Flow Equation
LI_WEST	1240	(K to I&J) - 0.13*(PJM to K i.e., Neptune)

Central East Voltage Limits, Oswego Complex Units

Depends On:	9MILP1, 9MILP2, FPNUC1, STHIND, OS05, OS06			
Units	E_to_F		E_to_FG	
Available	Fwd	Rev	Fwd	Rev
6	3925	1999	5650	3400
5	3875	1999	5575	3400
4	3815	1999	5490	3400
3	3710	1999	5335	3400
2	3595	1999	5160	3400
Otherwise	3470	1999	4960	3400

Staten Island Import Limits, AK and Linden CoGen Units

Unit Availability				J_to_J3	
AK02	AK03	LINCOG1	LINCOG2	Fwd	Rev
A	A	A	A	315	425
U	A	A	A	315	700
A	A	U	A	315	750
A	A	A	U	315	750
Otherwise				315	815

Depends On:	NPRTS1-4	
	LI_NE	
Units Available	Norwalk to K	K to Norwalk
4	260	414
Otherwise	404	414

Depends On:	Barrett1 and 2	
	SY2030-34 ConEd-LIPA	
Units Available	IJ to K	K to IJ
2	3250	1900
1	3250	1700
0	3250	1500

With LIPA Public Policy project starting 2030

PJM-NY JOA Flow Distribution (Jan 31, 2017 filing)	RECO Load Deliveries	PJM-NY Emergency Assistance
PJM-NY Western Ties	20%	46%
5018 Line	80%	32%
JK Lines	0%	15%
A Line	0%	7%
BC Lines	0%	0%

Resource Adequacy Assumptions Matrix

#	Parameter	2022 RNA (2022 Gold Book) Study Period: y4 (2026)-y10 (2032)	2024 RNA (2024 Gold Book) Study Period: y4 (2028)-y10 (2034)
Key Assumptions and Reports			
1	**Links to Key Assumptions Presentations and Final Reports**	**Nov 15, 2022:** NYISO Board approval and final 2022 RNA posting. 2022 RNA Report link 2022 RNA Appendix link	**March 1 ESPWG/TPAS:** Draft Schedule [link] **April 18 ESPWG/TPAS/LFTF [link]**: Schedule, Scenarios, Assumptions Matrices for resource adequacy and transmission security **April 30 ESPWG/TPAS** [link]: Winter Gas Derates **July 25 ESPWG/TPAS** [link]: preliminary RNA results presentation **September 3, 2024 ESPWG/TPAS** [link]: Updated results **September 27, 2024 ESPWG/TPAS** [link]: Updated results October 17, 2024 OC: Vote on Draft Report October 31, 2024 MC: Vote on Draft Report, and MMU's review November 2024: NYISO's Board of Directors approval
Load Parameters			
1	**Peak** Load Forecast	Adjusted 2022 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 GB 2022 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 will be used for the 2022 RNA, as provided by the Demand Forecasting Team which then allows for a discrete modeling of the BtM solar resources using 5 years of inverter data.	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 GB 2024 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 will be used for the 2024 RNA, as provided by the Demand Forecasting Team which then allows for a discrete modeling of the BtM solar resources using 5 years of inverter data.
2	Load **Shapes** (Multiple Load Shapes)	**New Load Shapes** *(see March 24, 2022 LFTF/ESPWG):* Used Multiple Load Shape MARS Feature 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	Used Multiple Load Shape MARS Feature *(see March 24, 2022LFTF/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.

#	Parameter	2022 RNA (2022 Gold Book) Study Period: y4 (2026)-y10 (2032)	2024 RNA (2024 Gold Book) Study Period: y4 (2028)-y10 (2034)
		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).	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.	2022 LFU Updated via Load Forecast Task Force (LFTF) process. Updated LFU values *(as presented at the April 21, 2022 LFTF [link])*	2024 LFU Updated via Load Forecast Task Force process. 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 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 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]
Generation Parameters			
1	**Existing** Generating Unit Capacities *(e.g., thermal units, large hydro)*	2022 Gold Book values: Summer is min of (DMNC, CRIS). Winter is min of (DMNC, CRIS). Adjusted for RNA Base Case inclusion rules application.	2024 Gold Book values: Summer is min of (DMNC, CRIS). Winter is min of (DMNC, CRIS). Adjusted for RNA Base Case inclusion rules application
2	**Proposed New Units Inclusion** Determination	2022 Gold Book with RNA Base Case inclusion rules applied *See April 26, 2022 TPAS/ESPWG*	2024 Gold Book with RNA Base Case inclusion rules applied *See April 18, 2024 TPAS/ESPWG*
3	Retirement, Mothballed Units, IIFO	2022 Gold Book with RNA Base Case inclusion rules applied *See April 26, 2022 TPAS/ESPWG*	2024 Gold Book with RNA Base Case inclusion rules applied *See April 18, 2024 TPAS/ESPWG*
4	Forced and Partial Outage Rates *(e.g., thermal units)*	Five-year (2017-2021) 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.	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.

#	Parameter	2022 RNA (2022 Gold Book) Study Period: y4 (2026)-y10 (2032)	2024 RNA (2024 Gold Book) Study Period: y4 (2028)-y10 (2034)
		For new units or units that are in service for less than three years, NERC 5-year class average EFORd data are used.	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	N/A	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 Base Cases and for each load bin and Study Year.
6	Daily Maintenance	Fixed maintenance based on schedules received by the NYISO.	Based on schedules received by the NYISO.
7	Weekly Planned Maintenance	MARS is automatically scheduling maintenance based on NYCA capacity and demand. Data: 5y (2017-2021) 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 (2019-2023) of historical scheduled maintenance data from Operations and GADS system to determine the number of weeks on maintenance for each thermal unit.
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	Actual hourly plant output over the last 5 years (2017-2021). Probabilistic model is incorporated based on five years of input shapes with one shape per replication being randomly selected in Monte Carlo process.	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

#	Parameter	2022 RNA (2022 Gold Book) Study Period: y4 (2026)-y10 (2032)	2024 RNA (2024 Gold Book) Study Period: y4 (2028)-y10 (2034)
			five years of input shapes with one shape per replication being randomly selected in Monte Carlo process.
12	Proposed **Offshore Wind** Units	RNA Base Case inclusion rules Applied to determine the generator status. Power curves based on 2008-2012 NREL from 3 different sites: NY Harbor, LI Shore, LI East, and GE updates of the NREL curves reflecting derates.	RNA Base Case 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)
13	Existing and Proposed **Utility-scale Solar Resources**	Probabilistic model chooses from the production data output shapes covering the last 5 years. One shape per replication is randomly selected in Monte Carlo process.	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.
14	**BtM Solar Resources**	**Supply side:** Five years (2017-20217) of 8,760 hourly MW profiles based on sampled inverter data. The MARS random shape mechanism randomly picks ne 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 for the 2022 RNA, as developed by the NYISO forecasting team.	**Supply side:** 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 for the 2024 RNA, as developed by the NYISO forecasting team.
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.
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 most recent 5 years of GADS data (2019-2023). 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.

#	Parameter	2022 RNA (2022 Gold Book) Study Period: y4 (2026)-y10 (2032)	2024 RNA (2024 Gold Book) Study Period: y4 (2028)-y10 (2034)
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. Limited to one charge/discharge cycle per day.
19	Existing Energy Limited Resources (**ELRs**)	**New method:** 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. Limited to one charge/discharge cycle per day.
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 HTP (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.** Increased the HQ to D by 80 MW. Note: The Cedar bubble has been removed and its corresponding MW was reflected in HQ to D limit.	**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.
MARS Topology: a simplified bubble-and-pipe representation of the transmission system			
1	Interface Limits	Developed by review of previous studies and specific analysis during the RNA study process.	Developed by review of previous studies and specific analysis during the RNA study process.

#	Parameter	2022 RNA (2022 Gold Book) Study Period: y4 (2026)-y10 (2032)	2024 RNA (2024 Gold Book) Study Period: y4 (2028)-y10 (2034)
2	New Transmission	Based on TO-provided firm plans (via Gold Book/LTP 2021-2020 process) and proposed merchant transmission facilities meeting the RNA Base Case inclusion rules.	Based on TO-provided firm plans (via Gold Book/LTP 2023-2024 processes) and proposed merchant transmission facilities meeting the RNA Base Case inclusion rules.
3	AC Cable Forced Outage Rates	All existing cable transition rates updated with data received from ConEd and PSEG-LIPA to reflect most recent five-year history.	All existing cable transition rates updated with data received from ConEd and PSEG-LIPA to reflect most recent five-year history.
4	UDR unavailability	Five-year history of forced outages.	Five-year history of forced outages.
Emergency Operating Procedures (EOPs)			
1	EOP Steps Order	1. Removing Operating Reserve 2. Special Case Resources (SCRs) (Load and Generator) 3. 5% Manual Voltage Reduction 4. 30-Minute Operating Reserve to Zero 5. 5% Remote Controlled Voltage Reduction 6. Voluntary Load Curtailment 7. Public Appeals 8. Emergency Assistance from External Areas 9. Part of the 10-Minute Operating Reserve to Zero (960 MW of 1310 MW) to Zero	New order: Implementing NYSRC ICS/EC November 9, 2023 decision for the new EOP order recommendation: 1. Removing Operating Reserve 2. Special Case Resources (SCRs) (Load and Generator) 3. 5% Manual Voltage Reduction 4. 30-Minute Operating Reserve to Zero 5. Voluntary Load Curtailment 6. Public Appeals 7. 5% Remote Controlled Voltage Reduction 8. Emergency Assistance from External Areas 9. Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero
2	Special Case Resources (SCR)	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 2022 SCR enrollment) held constant for all years of study. Modeling 15 calls/year. Generation and load zonal MW are combined into one step.	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].**
3	EDRP Resources	Not modeled if the values are less than 2 MW.	Not modeled if the values are less than 2 MW.

#	Parameter	2022 RNA (2022 Gold Book) Study Period: y4 (2026)-y10 (2032)	2024 RNA (2024 Gold Book) Study Period: y4 (2028)-y10 (2034)
4	Operating Reserves	655 MW 30-min reserve to zero 960 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 May 4, 2022 NYSRC ICS [link]) to maintain (or no longer deplete/use) 350 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: 960 MW (=1,310 MW–350 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 May 5, 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. Used 2022 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. • The top 5 (changed from 3 starting 2024 RNA as an additional method to further limit reliance) summer and winter peak load days of an external Control Area is modeled as coincident with the NYCA top three 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	As per RNA Procedure.	Per RNA Procedure.
4	IESO	As 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.

#	Parameter	2022 RNA (2022 Gold Book) Study Period: y4 (2026)-y10 (2032)	2024 RNA (2024 Gold Book) Study Period: y4 (2028)-y10 (2034)
Miscellaneous			
1	MARS Model Version	4.10.2035	4.14.2179

Resource Adequacy Base Case Results

The 2024 RNA Base Case resource adequacy studies show that the annual NYCA LOLE is below the 0.1 event-days/year criterion throughout the Study Period, except study year 10 (2034). As reflected in the summer and winter LOLE results, the annual NYCA LOLE increases through the study period are more driven by the winter events.

The planning models reflected several changes to account for winter uncertainties:

- On the demand side, a load forecast growing (through study years) uncertainty was modeled for winter to account for electrification and large loads, and
- On the resources side, risk of gas unavailability mainly related with gas-only plants was implemented.

Over 2,000 MW of proposed large loads, such as industrial loads and data centers, were included in the baseline load forecast used for the 2024 RNA Base Case. A total of about 1,200 MW was assumed flexible. This assumption was modeled in MARS as an EOP step before the SCR step. The Base Case results show the LOLE for both with and without flexibility of certain large loads.

The NYCA LOLE results are presented in Figure 21 and Figure 22 below. The 2024 RNA Study Years are year 4 (2028) through year 10 (2034), and year 1 through year 3 are for information.

The resource adequacy studies show that the annual NYCA LOLE would be below the 0.1 event-days/year criterion for each study year. There is a sharp increase in LOLE in the outer years with the LOLE just below criterion for 2034. For information, the LOLE results are also shown without large load flexibility, which would result in an LOLE above the criterion in 2034. The increase in LOLE is mainly due to the winter risks reflected in the Base Case, such as the non-firm gas unavailability and growth in winter demand forecast.

Figure 21: NYCA Resource Adequacy LOLE Results

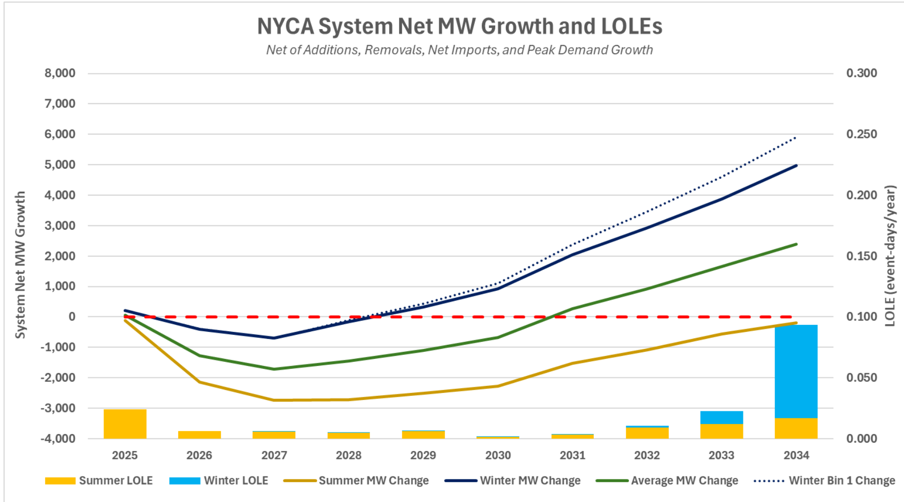
	NYCA Annual LOLE (event-days/year)	
Study Year	Base Case without Large Loads Flexibility	Base Case with Large Loads Flexibility
2025	0.031	**0.024**
2026	0.010	**0.006**
2027	0.009	**0.006**
2028	0.007	**0.005**
2029	0.009	**0.006**
2030	0.004	**0.001**
2031	0.011	**0.004**
2032	0.030	**0.010**
2033	0.080	**0.022**
2034	0.289	**0.094**

Figure 22: NYCA Resource Adequacy Annual, Summer, Winter LOLE Results

	Base Case with Large Loads Flexibility NYCA LOLE (event-days/year)			
Study Year Summer	Annual	Summer	Winter	Study Year Winter
2025	**0.024**	0.024	0.000	2024-25
2026	**0.006**	0.006	0.000	2025-26
2027	**0.006**	0.006	0.000	2026-27
2028	**0.005**	0.005	0.000	2027-28
2029	**0.006**	0.006	0.000	2028-29
2030	**0.001**	0.001	0.000	2029-30
2031	**0.004**	0.003	0.000	2030-31
2032	**0.010**	0.009	0.001	2031-32
2033	**0.022**	0.012	0.010	2032-33
2034	**0.094**	0.017	0.076	2033-34

Figure 23 shows how the **net** resource balance in the NYCA trends similar to the LOLE. For each forecast year, summer and winter peak demand growth is calculated relative to 2024, as drivers for increasing LOLE. Resource removals also contribute to the increases in the LOLE. Resource additions and the change in net imports relative to 2024 are subtracted, as this additional supply acts to reduce LOLE. The solid yellow and blue lines represent the baseline net demand minus supply growth for summer and winter, respectively. The green line shows the average of the summer and winter lines. Finally, the dotted winter blue line adds the impacts of the dynamic winter LFU fanning on the Bin 1 MW balance.

Figure 23: NYCA Net MW Resources Growth



The LOLE is generally defined as the expected (weighted average) number of days in a given period (*e.g.,* one study year) when for at least one hour from that day the hourly demand is projected to exceed the zonal resources (event day). Within a day, if the zonal demand exceeds the resources in at least one hour of that day, this will be counted as one event-day. The criterion is that the LOLE shall not exceed one day in 10 years, or LOLE < 0.1 days/year. The LOLE calculation accounts for events but does not account for the magnitude (MW) or duration (hours) of a deficit. Therefore, the NYISO calculates two additional reliability indices for informational purposes— loss of load hours (LOLH in event-hours/year) and expected unserved energy (EUE in MWh/year).[17]

LOLH is generally defined as the expected number of hours per period (*e.g.,* one study year) when a system's hourly demand is projected to exceed the zonal resources (event-hour). If the zonal demand exceeds the resources within an hour, this will be counted as one event-hour.

EUE, also referred to as loss of energy expectation (LOEE), is generally defined as the expected energy (MWh) per period (*e.g.,* one study year) when the summation of the system's hourly demand is projected to exceed the zonal resources. If the zonal demand exceeds the resources in an hour, this deficit will be counted toward the system's EUE.

While the resource adequacy reliability criterion of 0.1 days/year established by the NYSRC and the NPCC is compared with the loss of load expectation (LOLE in event-days/year) calculation, currently there is no criterion for determining a reliable system based on the LOLH and EUE reliability indices. However,

[17] NYSRC's "Resource Adequacy Metrics and their Application" is available at: https://www.nysrc.org/PDF/Reports/Resource%20Adequacy%20Metric%20Report%20Final%204-20-2020[6431].pdf.

consideration of LOLH and EUE reliability indices is helpful to better understand the adequacy of resources in terms of duration and magnitude of events, which is additional to the LOLE.

Figure 24: NYCA Resource Adequacy Results with Additional Reliability Indices

Study Year	LOLE (event-days/year)	LOLH (event-hrs/year)	EUE *(MWh/year)*
2025	**0.024**	0.064	21.9
2026	**0.006**	0.017	3.5
2027	**0.006**	0.017	3.3
2028	**0.005**	0.012	1.7
2029	**0.006**	0.016	2.6
2030	**0.001**	0.002	0.5
2031	**0.004**	0.007	2.3
2032	**0.010**	0.025	9.4
2033	**0.022**	0.053	22.8
2034	**0.094**	0.251	148.1

RNA Base Case MARS Event Analysis

LOLE is generally defined as the expected (weighted average) number of days in a given time period (*e.g.,* one study year) when at least one hour from that day, the hourly demand (for each of the seven load bins and per replication) is projected to exceed the zonal resources capacity (event day) in any of the seven load bins. Within a day, if the zonal demand exceeds the resources in at least one hour of that day (anywhere from hour 1 to 24, consecutive or not), this will be counted as one event day for the respective load bin and replication. The NYISO currently simulates 2,000 replications per study year and load level (seven load bins) for a total of 14,000 replications per study year. Weighted average is based on load bin probability, total bin event days, and total number of replications.

For each study year and in a single GE-MARS replication, the zonal MW hourly margins (MW surplus or deficit) are calculated for each bin using LFU-applied load, forced outage calculations, hourly shape values (*i.e.,* wind, solar, run-of-river hydro, landfill gas), contracts, and interface flows. In instances where there is a deficit in any area, emergency operating procedure (EOP) steps are completed until either the deficits are gone or there are no more EOP steps to call. Once all of this is completed GE-MARS calculates the reliability indices (LOLE, LOLH, LOEE) for the replication. This occurs concurrently across all load levels simultaneously, and GE-MARS lumps them all together in a weighted sum to get a single value for each replication.

$$\text{NYCA LOLE (days/ year)} = \frac{1}{N}\sum_{i=1}^{7} D_i\, P_i$$

NYCA LOLH (hour/ year) $=\frac{1}{N}\sum_{i=1}^{7} H_i\, P_i$

NYCA EUE (MWh) $= \frac{1}{N}\sum_{i=1}^{7} E_i\, P_i$

where, $\boldsymbol{D_i}$ is the **event days** for bin i for the study year
$\mathbf{H_i}$ is the **event hours** for bin i
$\mathbf{E_i}$ is the MW deficit for bin i
$\mathbf{P_i}$ is the **probability of occurring of bin i** which is the LFU probability data
N is the total number of **replications** e.g., 2000

The below figures provide additional insight into how the LOLE bin and month distribution for the RNA Base Case, study year 10 (2034) for the RNA Base Cases with large loads assumed flexible.

Figure 25: 2024 RNA Base Case Study Year 10 Bin and Month LOLE Distributions

LOLE (dy/yr)

Month	1	2	3	4	5	6	7	Total
Jan	0.0185	0.0298	0.0015					0.0498
Feb	0.0078	0.0043						0.0121
Mar								
Apr								
May								
Jun								
Jul	0.0117	0.0037	0.0002					0.0157
Aug	0.0012		0.0001					0.0013
Sep								
Oct	0.0000	0.0000						0.0000
Nov	0.0001							0.0001
Dec	0.0089	0.0056						0.0145
Annual	0.0482	0.0435	0.0018					0.0936

Load Level

Figure 26: 2024 RNA Base Case Study Year 10 Event Summary Hour of Day and Month Distribution

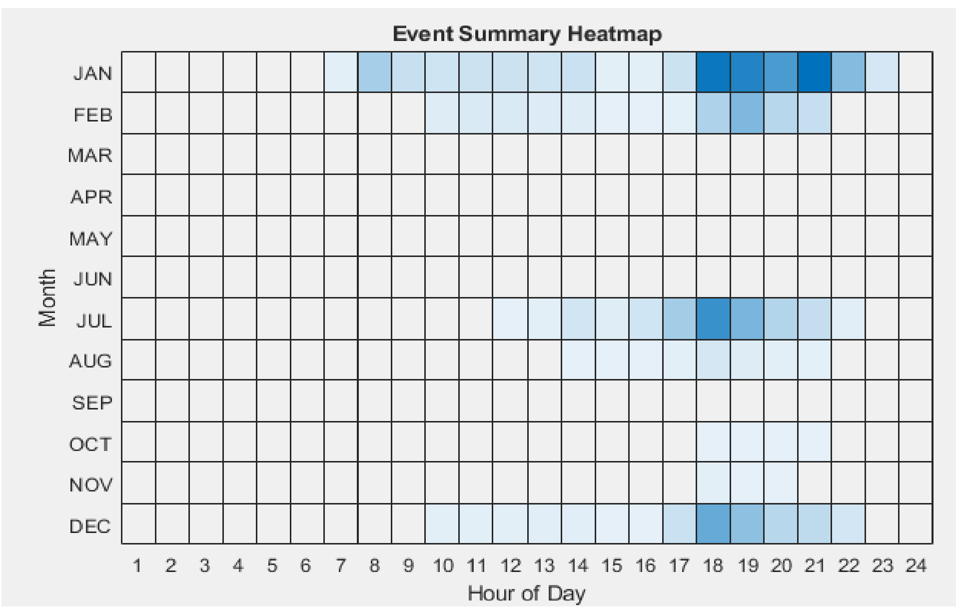
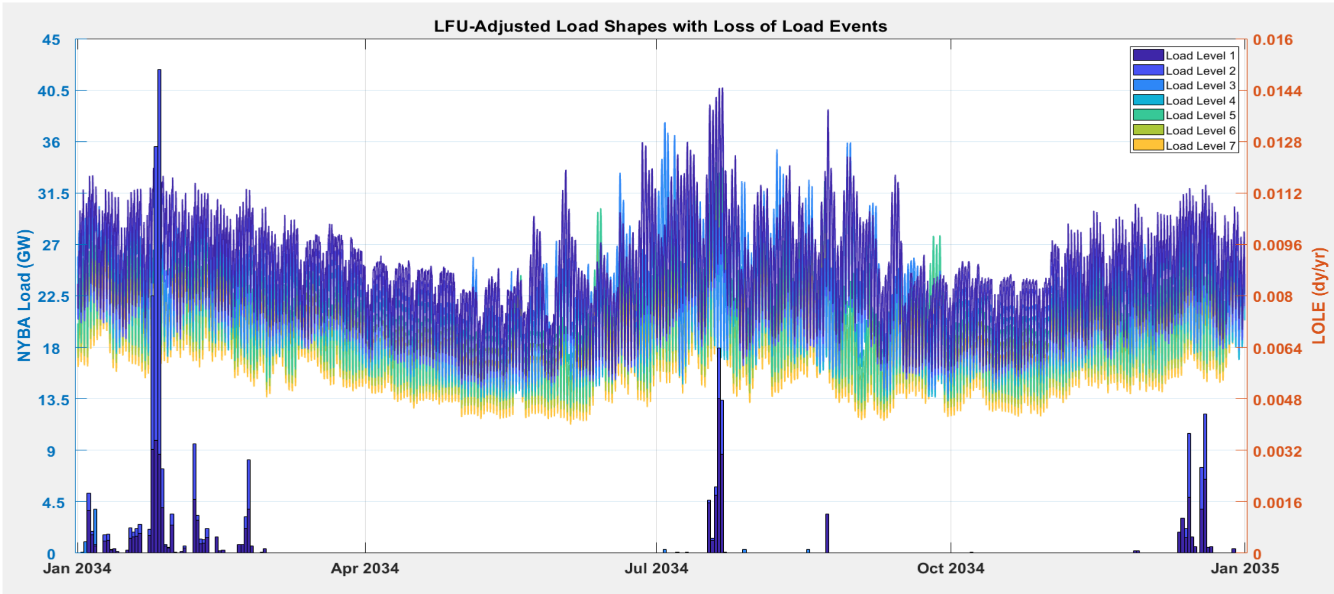


Figure 27: 2024 RNA Base Case Load Shapes and Events



Impact of Emergency Operating Procedures

The LOLE results after each EOP step are shown in Figure 28. GE-MARS evaluates the need for using EOP MW by calculating after each EOP step the expected number of days per year that the system is at a positive (surplus) and a negative (deficiency) MW margin. Each EOP's MW is used as needed and in sequential order.

The EOP step 8 shows the impact of emergency assistance from external areas. As an example, study year 10 (2034) results show that after EOP steps 1 through 7 have been applied and before the emergency assistance is available, the NYCA LOLE is 3.16 event-days/year, which is significantly above the 0.1 event-days/year criterion. After the external area emergency assistance from EOP step 8 becomes available, the LOLE decreases to 0.67 event-days/year. While still above the criterion, the decrease in LOLE is significant. Without emergency assistance from neighboring regions, there would not be sufficient resources to serve demand within New York for each of the study years evaluated.

Figure 28: LOLE Results by Emergency Operating Procedure Step for Study Year 10 (2034)

	NYCA LOLE (days/year) by EOP Step											
	Step	EOP	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	1	Removing Operating Reserve (1965 MW)	3.47	2.09	2.23	2.14	2.98	1.63	2.61	3.72	5.89	7.64
	2	Flexible Large Loads (407-976 MW)	2.95	1.53	1.46	1.45	2.22	0.82	1.53	2.37	4.02	5.45
	3	Require SCRs (Load and Generator)	2.16	1.10	1.08	1.09	1.71	0.46	0.92	1.58	2.87	4.18
	4	5% Manual Voltage Reduction	2.11	1.08	1.05	1.07	1.68	0.43	0.88	1.51	2.77	4.08
	5	655 MW 30-Minute Reserve to Zero	0.95	0.46	0.46	0.41	0.66	0.20	0.45	0.92	1.88	3.03
	6	Voluntary Load Curtailment	0.76	0.37	0.37	0.33	0.53	0.16	0.35	0.76	1.61	2.72
	7	Public Appeals	0.69	0.34	0.34	0.29	0.47	0.14	0.33	0.72	1.55	2.63
	8	5% Remote Controlled Voltage Reduction	0.51	0.25	0.25	0.21	0.37	0.09	0.22	0.53	1.22	2.19
	9	Emergency Assistance	0.09	0.03	0.02	0.02	0.02	0.01	0.03	0.06	0.11	0.30
NYCA LOLE	10	Part of 10-Minute Reserve (910 of 1310 MW) to Zero	0.02	0.01	0.01	0.00	0.01	0.00	0.00	0.01	0.02	0.09

Notes:

- The results at **step 9** in grey highlight represent the NYCA LOLE and are compared against the 0.1 event-days/year criterion. Blue font value indicates number is above 0.1 days/year, however the criterion does not apply until step 10.

To avoid overly relying on external areas, the NYISO uses several modeling methods to limit New York's reliance on external areas in the analysis. For instance, the NYISO applies a 3,500 MW statewide limitation on emergency assistance, as well as aligning New York's five peak days with external areas, and setting the LOLE for external areas between 0.1 and 0.15 event-days/year. This assumes that the external areas are self-sufficient before providing assistance to New York.

The RNA Base Case resource adequacy results show:

- The New York Control Area (NYCA) loss of load expectation through the study period is below the NYSRC's and NPCC's criterion of one day in 10 years (or 0.1 event-days per year) when certain large loads are assumed flexible.
- The increase in LOLE through the study years, culminating in the highest LOLE in year 10, is mainly due to the winter risks reflected in the 2024 RNA Base Case, such as the winter non-firm gas unavailability, the winter demand forecast uncertainties modeled in the 2024 RNA Base Case, and growth in demand forecast.
- The MARS events are distributed in both winter and summer months (December, January, February, July, and August) and in the late afternoon hours (as shown in the event analysis graphs above).
- In addition to internal EOPs, New York relies on support from external areas during emergency conditions.
- There are positive reliability impacts (*i.e.*, NYCA LOLE decrease) as result of including the following proposed projects in the RNA Base Case:
    a. The Champlain Hudson Transmission Partners (CHPE) 1,250 MW HVDC (summer only) project from Hydro Quebec to Astoria Annex 345 kV in Zone J.
    b. The NYPA/National Grid Northern New York Priority Transmission Project starting 2026. This increases the Moses South interface limits.

c. New for this RNA:

   i. The Long Island Public Policy Propel NY Energy project was selected by the NYISO Board of Directors in 2023 and increases the MARS topology limits (both imports and exports) starting 2030.

- Two additional offshore wind projects: Sunrise Wind (starting in 2026) and Empire 1 (starting in 2027)
- The assumption that approximately 450 MW of NYPA's simple cycle GTs based on state legislation will be out of service starting January 2031 led to an increase in the reliability indices (system less reliable) starting 2031. Most of the affected generators are located in New York City Zone J and one generator located in Long Island Zone K.

  a. Note: Narrows 1 and 2 and Gowanus 2 and 3 barges in New York City, the temporary solutions for the 2023 Q2 STAR Short Term Needs, were assumed as out-of-service in the MARS model, starting 2025.

Resource Adequacy Scenarios

Scenarios are variations on the RNA Base Case to assess the impact of possible changes in key study assumptions which, if they occurred, could change the timing, location, or degree of violations of reliability criteria on the NYCA system during the study period. RNA scenarios are provided for information only and do not lead to the identification of Reliability Needs. The following resource adequacy scenarios were performed as part of this RNA, with an identification of the type of assessment performed:

1. **Zonal Resource Adequacy Margins (ZRAM) Scenario**
   - Identification of the maximum level of zonal MW capacity that can be removed without either causing a NYCA LOLE violation or exceeding the zonal capacity.
2. **Free Flow Scenario**
   - This analysis removes the limit on various transmission interfaces in resource adequacy models—either one at the time or in various combinations (*i.e.,* "free flow").
3. **High Demand Forecast Scenario**
   - The 2024 Gold Book High Demand forecast was used for the resource adequacy analysis.

4. **CHPE Unavailable Scenario**

    - Removal of the proposed 1,250 MW HVDC transmission line from Quebec to New York City.

5. **Additional Proposed Projects Scenarios.** Two scenarios were performed, one at a time, on the RNA Base Case:

    a) One scenario added approximately 5,000 MW of resource projects that are in an advanced stage of development but has not yet met the reliability planning inclusion rules to be included in the 2024 RNA Base Case. This amounted to approximately 2,500 MW solar, 1,500 MW land-based wind, and 1,000 MW battery storage.

    b) One scenario added approximately 7,000 of additional proposed offshore wind (5,000 MW in Zone J and 2,000 MW in Zone K) for a total of about 9,000 MW interconnected to the NYCA.

Zonal Resource Adequacy Margins (ZRAM)

Resource adequacy simulations were performed on the RNA Base Case to determine the amount of "perfect capacity" in each zone (one zone at the time) that could be removed before the NYCA LOLE reaches 0.1 event-days/year (one-event-day-in-ten-years). These simulations offer another relative measure of how close the system is from not having adequate resources to reliably serve load.

In performing this analysis, and if the LOLE is below criterion, resource capacity is reduced one zone at a time to determine when a violation occurs. This analysis is performed in the same manner as the compensatory "perfect MW" (compensatory MW) are added to mitigate resource adequacy violations but with the opposite impact.

"Perfect capacity" is capacity that is not derated (*e.g.,* due to ambient temperature or unit unavailability), not subject to energy durations limitations (*i.e.*, available at maximum capacity every hour of the study year), and not tested for transmission security or interface impacts. A map of NYISO zones is shown in Figure 29, and the zonal resource margin analysis (ZRAM) is summarized in Figure 30.

Figure 29: NYISO Load Zone Map

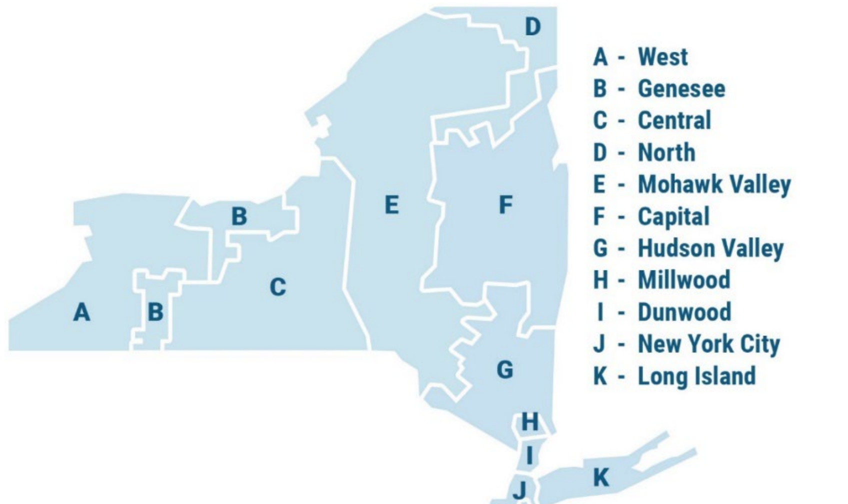


Figure 30: Zonal Resource Adequacy Margins/Compensatory MW

Study Year	Base Case LOLE event-days/year	Zone A MW	Zone B MW	Zone C MW	Zone D MW	Zone E MW	Zone F MW	Zone G MW	Zone H MW	Zone I MW	Zone J MW	Zone K MW
2025	0.024	-1500	-1500	-2200	-1500	-2200	-2200	-2200	-1600	-1600	-1300	-500
2026	0.006	-1600	-1600	-3400	-1600	-3400	-3400	-3400	-2700	-2700	-2200	-700
2027	0.006	-1700	-1700	-3600	-1900	-3600	-3600	-3600	-2900	-2900	-2400	-700
2028	0.005	-1600	-1700	-3700	-1900	-3700	-3700	-3700	-2900	-2900	-2500	-700
2029	0.006	-1700	-1700	-3200	-2000	-3200	-3200	-3200	-2800	-2800	-2300	-600
2030	0.001	-1800	-1800	-3600	-1900	-3600	-3600	-3600	-3100	-3100	-2900	-1300
2031	0.004	-1700	-1700	-2800	-1900	-2800	-2800	-2800	-2500	-2500	-2400	-1200
2032	0.010	-1600	-1600	-2000	-1700	-2000	-2000	-2000	-1800	-1800	-1800	-1000
2033	0.022	-1000	-1000	-1100	-1000	-1100	-1100	-1100	-1000	-1000	-1100	-800
2034	0.094	-50	-50	-50	-50	-50	-50	-50	-50	-50	-50	-50

The ZRAM/Compensatory MW assessment identifies a maximum level of "perfect capacity" that can be removed/added from/to each zone without causing a violation of the NYCA LOLE criterion. However, the impacts of removing (or adding) capacity on the reliability of the transmission system and on transfer capability are highly dependent on location. Thus, removal of lower amounts of capacity are likely to result in reliability issues at specific transmission locations. These simulations did not attempt to assess a comprehensive set of potential scenarios that might arise from specific unit retirements. Therefore, actual proposed capacity removals from any of these zones will need to be further studied in light of the specific capacity locations in the transmission network to determine whether any additional violations of reliability criteria would result. Additional transmission security analysis, such as N-1-1 steady-state analysis, transient stability, and short circuit, will be necessary under the applicable process for any contemplated plant retirement in any zone.

Free Flow Scenario

To determine whether a specific transmission interface impacts system resource adequacy, the NYISO performed "free flow" simulations. This analysis removes the limit on various transmission interfaces in the resource adequacy models—either one at the time or in various combinations (*i.e.,* "free flow"). A decrease in the NYCA LOLE resulting from removal of an interface limit is an indication that the flow of power across the interface is "binding" due to transmission constraints.

The results of removing all the internal New York topology limits are shown in Figure 31. The results show that increasing transmission system limits does not decrease LOLE significantly.

Figure 31: Free Flow LOLE Results (event-days/year)

Year	Base Case	Free flow	*Delta*
2025	**0.024**	0.017	*-0.007*
2026	**0.006**	0.003	*-0.004*
2027	**0.006**	0.001	*-0.005*
2028	**0.005**	0.001	*-0.004*
2029	**0.006**	0.001	*-0.005*
2030	**0.001**	0.001	*0.000*
2031	**0.004**	0.003	*0.000*
2032	**0.010**	0.009	*-0.001*
2033	**0.022**	0.020	*-0.002*
2034	**0.094**	0.093	*-0.001*

High Demand Scenario

The RNA Base Case uses the baseline forecasts developed for the 2024 Gold Book. The 2024 Gold Book also contains other demand forecasts—one of which is a higher demand scenario. The high demand forecast represents a higher bound on forecast growth, including faster economic growth and electrification sufficient to meet state policy targets, and includes additional large load growth not included in the baseline forecast.

Figure 32 below shows a comparison between the baseline forecast and the higher demand forecast.

Figure 32: Baseline Demand Forecasts vs the High Demand Forecasts (MW)

Summer				Winter			
Year	Baseline	High Demand	*Delta*	Year	Baseline	High Demand	*Delta*
2025	31,650	32,200	*550*	2024-25	23,800	24,050	*250*
2026	31,900	32,910	*1,010*	2025-26	24,210	24,960	*750*
2027	32,110	33,450	*1,340*	2026-27	24,730	25,790	*1,060*
2028	32,130	33,940	*1,810*	2027-28	25,270	26,690	*1,420*
2029	32,340	34,400	*2,060*	2028-29	25,760	27,610	*1,850*
2030	32,580	34,910	*2,330*	2029-30	26,350	28,560	*2,210*
2031	32,880	35,480	*2,600*	2030-31	27,020	29,650	*2,630*
2032	33,320	36,130	*2,810*	2031-32	27,900	30,960	*3,060*
2033	33,830	36,810	*2,980*	2032-33	28,850	32,540	*3,690*
2034	34,210	37,480	*3,270*	2033-34	29,950	34,350	*4,400*

The NYCA LOLE results are in the figure below and show that the higher demand would result in an LOLE violation by 2032.

Figure 33: High Demand Scenario NYCA LOLE Results

Sudy Year	Base Case	High Demand Scenario
2025	0.024	0.036
2026	0.006	0.013
2027	0.006	0.015
2028	0.005	0.016
2029	0.006	0.028
2030	0.001	0.026
2031	0.004	0.081
2032	0.010	0.298
2033	0.022	1.328
2034	0.094	2.744

CHPE Unavailable Scenario

The proposed 1,250 MW CHPE project was included in the 2024 RNA Base Case starting summer 2026. The CHPE project is assumed to inject 1,250 MW into New York City from Hydro Quebec in the summer and zero MW in the winter. This scenario removes the CHPE project to gauge the impacts of potential delays in the project's development. The results are in Figure 34 below.

The scenario shows that the impact of CHPE's delay or failure to enter service on NYCA LOLE is significant.

Figure 34: Scenario with CHPE Removed NYCA LOLE Results (event-days/year)

Study Year	Base Case	Without CHPE Scenario
2025	**0.024**	0.024
2026	**0.006**	0.014
2027	**0.006**	0.010
2028	**0.005**	0.008
2029	**0.006**	0.010
2030	**0.001**	0.005
2031	**0.004**	0.014
2032	**0.010**	0.029
2033	**0.022**	0.044
2034	**0.094**	0.119

Addition of Other Proposed Projects Scenarios

The RNA Base Case included certain proposed projects that met the reliability inclusion rules and are in advanced development stages. These projects only represent a fraction of the proposed projects that have interconnection requests undergoing study in the NYISO's interconnection processes.

The 2024 RNA performed two scenarios, one at a time, on the RNA Base Case:

1. One scenario added approximately 5,000 MW of resource projects that are in an advanced stage of development but has not yet met the reliability planning inclusion rules to be included in the 2024 RNA Base Case. This amounted to approximately 2,500 MW solar, 1,500 MW land-based wind, and 1,000 MW battery storage.

One scenario added approximately 7,000 of additional proposed offshore wind (5,000 MW in Zone J and 2,000 MW in Zone K) for a total of about 9,000 MW interconnected to the NYCA. The results of these scenarios are below and show that LOLE falls well below criterion for each of the scenarios for study year 10 (2023).

Figure 35: Additional Proposed Projects Scenarios NYCA LOLE Results

	Base Case	Scenario	Scenario
Stduy Year	With Large Load Flexibility	Additional Proposed Projects *(5,000 MW)*	Additional Offshore Wind *(7,000 MW)*
2034	0.094	0.030	0.031

Conclusion

As with any planning study, there is a level of uncertainty in the key assumptions used in the 2024 RNA given the 10-year planning horizon. Through the Reliability Planning Process and Short-Term Reliability Process, the NYISO will monitor system developments and update assumptions as new information becomes available. Additional action includes:

- Monitoring the impact of projects that did not satisfy the reliability planning inclusion rules but have completed an interconnection facilities study, including projects in Class Year 2023, and projects selected in the upcoming NYSERDA large-scale renewable, offshore wind, and storage procurement efforts.
- Considering market rules and behaviors of various existing and future markets programs, such as demand response, DER, capacity accreditation, and winter fuel risks in planning assumptions.
- Continuing to monitor the development of the existing and proposed large loads.

Appendix F - Transmission Security Assessment

The transmission security assessment is conducted in accordance with NERC Reliability Standards, NPCC Transmission Design Criteria, and the NYSRC Reliability Rules. Analysis is performed on the BPTF to evaluate performance using the Siemens PTI PSS®E, PowerGEM TARA, and ASPEN Oneliner programs.

Modelling Assumptions

The NYISO developed the 2024 RNA Base Case, which is used to analyze the performance of the transmission system, from the 2024 FERC 715 filing power flow case library. Load representation in each summer peak power flow model is the summer peak load forecast reported in the 2024 Gold Book Table 1-3a baseline forecast of coincident peak demand. Load representation in each winter peak power flow model is the winter peak load forecast reported in the 2024 Gold Book Table 1-3b baseline forecast of coincident peak demand. The system representation for the NPCC Areas in the base cases is from the 2023 Base Case Development libraries compiled by the NPCC SS-37 Base Case Development working group. The NYISO derived the PJM system representation from the PJM Regional Transmission Expansion Plan (RTEP) planning process models. The remaining models are from the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) 2023 power flow model library. Generation is dispatched to match load plus system losses, while respecting transmission security according to the dispatch assumptions. Scheduled inter-area transfers modeled in the base case between the NYCA and neighboring systems are held constant consistent with ERAG MMWG[18] interchange schedule to the extent possible.

Transmission security analysis evaluates expected summer peak, winter peak, and light load conditions under normal transfer criteria. The following power flow cases were evaluated.

- 2029 baseline coincident summer peak
- 2029 daytime light load
- 2029-2030 baseline coincident winter peak
- 2034 baseline coincident summer peak
- 2034 daytime light load
- 2034-2035 baseline coincident winter peak

18 Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) procedural manual: https://www.rfirst.org/wp-content/uploads/2023/07/MMWG_Procedural_Manual_v35.pdf.

Assumptions Matrix for Transmission Security Assessment

Parameter	2024 RNA Transmission Security Studies Modeling Assumptions	2024 Source
Criteria	The criteria for transmission security determination are based on a deterministic approach, which must meet the reliability requirements defined by NERC, NPCC, and NYSRC. The applicable design criteria can be found in the NYSRC Reliability Rules, the NPCC Directory 1, the NERC TPL-001 and other relevant standards. Including NYSRC Reliability Rules 153a and 154a, which became effective during the RNA.	NYISO RPP Manual
Load Forecast	The 2024 Gold Book publishes the baseline coincident peak load forecasts (summer and winter) including the impact (reduction) of behind-the-meter (BtM) generation (solar, non-solar, and storage adjustments) at the time of NYCA peak, as well as energy efficiency and codes & standards. The midday light load forecast utilizes the BtM solar generation from the 2024 Gold Book Table 1-9d and includes expected load during the midday light load hour.	2024 Gold Book
Load Model	Con Edison: voltage varying Rest of NYCA: constant power	2024 FERC 715 filing
System Representation	Per updates received through the annual database update process (subject to RNA Base Case inclusion rules).	NYISO RAD Manual, 2024 FERC 715 filing
Inter-area Interchange Schedules	Consistent with ERAG MMWG interchange schedule to the extent possible. However, Hydro Quebec to New York interchange for the winter period will be 0 MW.	2024 FERC 715 filing, MMWG
Inter-area Controllable Tie Schedules	Consistent with applicable tariffs and known firm contracts or rights.	2024 FERC 715 filing
NYC Series Reactors	Consistent with Con Edison series reactor status in their 2021 Local Transmission Plan update presented at the November 19, 2021 ESPWG/TPAS [here]. 2021-2023 Series Reactor Status • 71, 72, M51, M52 are bypassed • 41, 42, Y49 are in-service Post-2023 Series Reactor Status • 71, 72, M51, M52 are in service • 41, 42, Y49 are bypassed	2024 FERC 715 filing, Con Edison protocol
SVCs, FACTS	Set near zero pre-contingency; allowed to adjust post-contingency	NYISO T&D Manual
Transformer & PAR taps	Taps allowed to adjust pre-contingency; fixed post-contingency	2024 FERC 715 filing

Parameter	2024 RNA Transmission Security Studies Modeling Assumptions	2024 Source
Switched Shunts	Allowed to adjust pre-contingency; fixed post-contingency	2024 FERC 715 filing
Fault Current analysis settings	Per Fault Current Assessment Guideline	NYISO Fault Current Assessment Guideline
Thermal Generation (includes fossil and nuclear) Unavailability	The impact of thermal generation unavailability is captured in the transmission security margin calculations (aka "tipping points") and incorporates the NERC five-year class-average forced outage rate values (EFORd). Consideration is given to NYSRC Proposed Reliability Rules 153a and 154a, which became effective during the RNA.	NERC Generating Unit Statistical Brochures, most recently available Brochure 4 [here]. Reference May 5, 2022 TPAS/ESPWG meeting materials [here] and May 23, 2022 ESPWG meeting materials [here]. Reference January 23, 2024 ESPWG meeting materials [here] and March 1, 2024 ESPWG/TPAS meeting materials [here].
Wind Generation	Dispatch land-based wind (LBW) generation and off-shore wind (OSW) generation to the following percentage of nameplate capacity: LBW • Summer 5% • Winter 15% • Light load 10% OSW • Summer 10% • Winter 20% • Light load 15%	Reference May 5, 2022 TPAS/ESPWG meeting materials [here] and May 23, 2022 ESPWG meeting materials [here].
Solar Generation	BtM solar reductions in load forecast are included in the Gold Book (Table I-9d) along with nameplate capacity (Table I-9a). Utility-scale solar resources are dispatched at the same factor as the BtM solar resources for a given transmission security case.	Reference May 5, 2022 TPAS/ESPWG meeting materials [here] and May 23, 2022 ESPWG meeting materials [here].
Hydro Generation	Large hydro and pumped storage are dispatchable up to the stated seasonal capabilities published in the Gold Book. Run-of-river hydro units are fixed at their 5-year average based on GADS data for production during specific peak or light load hours. Dispatches are roughly the following percentage of the capability stated in the Gold Book: • Summer 40% • Winter 60% • Light load 55%	Reference May 5, 2022 TPAS/ESPWG meeting materials [here] and May 23, 2022 ESPWG meeting materials [here].
Battery Storage	As the starting point in transmission security analysis utility-scale battery storage resources are modeled at 0 MW output. If a potential transmission security violation is observed, post-	2024 Gold Book

Parameter	2024 RNA Transmission Security Studies Modeling Assumptions	2024 Source
	processing analysis is performed to understand the nature of the need and how the characteristics of the battery storage resources may address the need. BtM storage resources are netted with load consistent with the forecasts published in the Gold Book.	Reference May 5, 2022 TPAS/ESPWG meeting materials [here] and May 23, 2022 ESPWG meeting materials [here].

Difficulty Modeling Sufficient Reserves for Transmission Security Analysis

In the establishment of credible combinations of system conditions as modeled in the power flow cases, typical transmission security cases for NYISO's reliability studies have at least 2,620 MW of reserve generation—an amount approximately twice the size of the largest loss of source event in the NYCA. This reserve allows for enough flexibility in the system to redispatch generation to avoid potential overloads in contingency analysis and mimics the 30-minute operating reserves maintained in real time operations. While 2,620 MW is typical, the power flow base cases must be modeled with a minimum reserve equal to at least one times the largest loss of source event (1,310 MW) in order to perform N-1-1 contingency analysis. The N-1-1 contingency analysis simulates the effect(s) of two contingency events—one following the other—on the system. Since the first contingency event can include the largest loss of source event, there must be sufficient reserve to return the system to a steady-state condition prior to simulating the second contingency event. NPCC criteria for this type of analysis specifies that area generation is adjusted between outages by use of resources available within ten minutes.

For 2034-2035 winter peak, using baseline assumptions including the unavailability of 6,400 MW of non-firm gas generation and forecasted winter peak load levels, there was a shortfall of approximately 600 MW to serve load. After considering the flexibility of approximately1,200 MW of large loads, the NYCA system would be able to serve load under peak load conditions but would fall short of the minimum 1,310 MW of reserve required for valid transmission security analysis by approximately 700 MW. Energy storage units are typically modeled offline in transmission security base cases and if a potential transmission security violation is observed, post-processing analysis is performed to understand the nature of the need and how the characteristics of the battery storage resources may address the need. However, for this winter 2034-2035 case, batteries are turned on and contribute approximately 100 MW, resulting in a net shortfall of 600 MW.

The remaining MW shortfall is addressed through reductions in modeled NYCA load. This 600 MW load reduction in the year 10 winter peak case is a modeling choice to complete transmission security analysis and does not necessarily reflect how NYISO would respond to such conditions if they were to occur in operations. Figure 36 shows the duration and degree of load reduction that would be required during the winter peak day under these transmission security analysis assumptions. Reserve levels remain lower than in a typical case, even after load reductions, and this low level of reserves restricts the ability of the system to redispatch around potential overloads in contingency analysis. Winter peak base cases first fall below the 2,620 MW reserve target in 2033-2034 winter and first fall below the 1,310 MW reserve minimum for valid transmission security analysis in 2034-2035 winter.

Moderately low reserve levels are seen in the creation of the 2034 summer peak case with flexible large loads modeled online at their peak forecasted value. As the system maintains at least one times the largest loss of source in reserves during the summer peak hour, this is considered a valid transmission security base case without further adjustments. However, this low level of reserves restricts the ability of the system to redispatch to avoid potential overloads in contingency analysis. Figure 37 shows the summer peak day under these transmission security analysis assumptions. Summer peak base cases first fall below the 2,620 MW reserve target in 2033. Modeling the flexibility of certain large loads significantly increases reserves under summer peak conditions.

Figure 36: 2034-2035 Winter Peak Day Reserve Levels

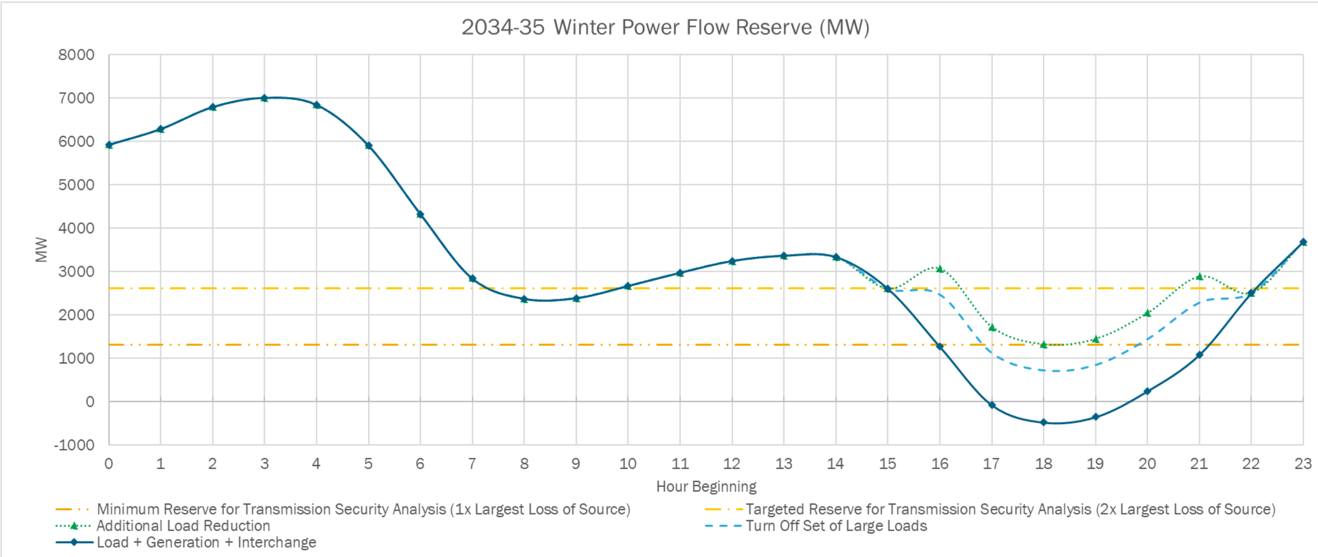
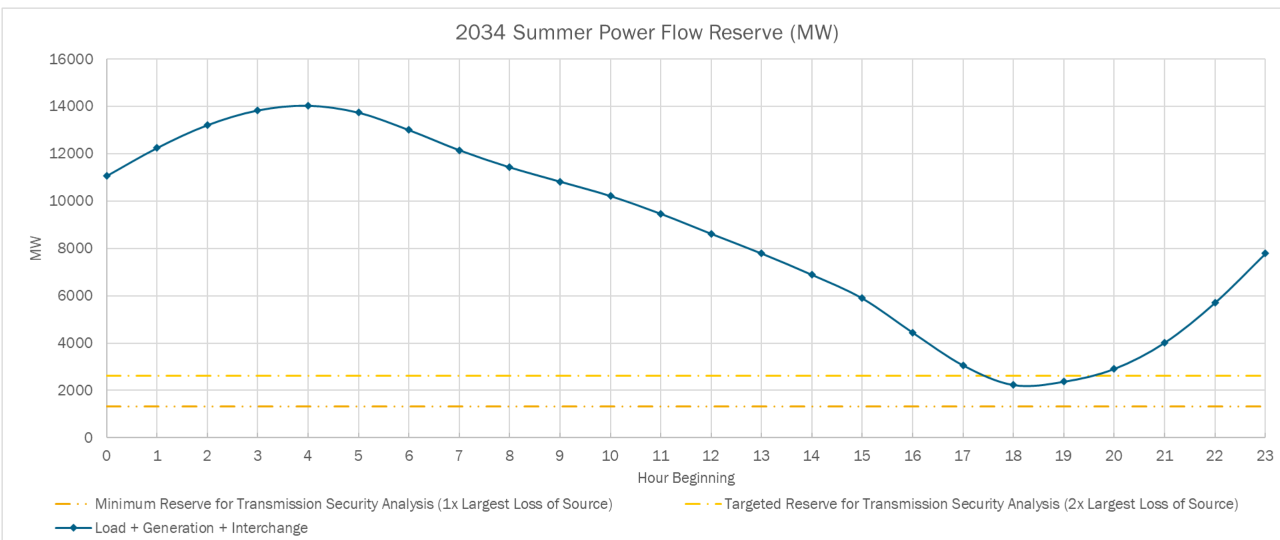


Figure 37: 2034 Summer Peak Day Reserve Levels



Transmission Security Base Case Results

2024 RNA Steady State Thermal and Voltage Assessment

No voltage criteria violations were observed under summer peak, winter peak, or daytime light load conditions for the evaluated cases.

Potential thermal criteria violations were observed in the summer peak and winter peak load conditions in the later years of the study horizon. No thermal violations were observed under daytime light load conditions.

2034-2035 Winter Peak

Potential steady-state transmission security thermal overloads are observed for the study period under 2034-2035 winter peak conditions. Figure 38 provides a summary of the BPTF overloads under N-1-1 conditions. Thermal overloads are observed beginning in 2034-2035 winter, the last winter of the RNA study horizon, under the case modeling assumptions described above.

Figure 38: Winter Peak Steady State Transmission Security N-1-1 Thermal Overloads

e	Owner	Monitored Element	Norm Rating (MVA)	Cont Rating (MVA)	Worst 1st Contingency	Worst 2nd Contingency	2034-35 Flow (%)
C	National Grid	Clay - Volney (6) 345 kV	1474	1626	Clay - Nine Mile 1 (8) 345 kV	Clay - Independence (26) 345 kV	101
C	National Grid	Clay - Volney (6) 345 kV	1474	1626	Clay - Independence (26) 345 kV	Clay - Nine Mile 1 (8) 345 kV	101
K	PSEG-LI	Barrett - Barrett OSW (2) 138 kV	213	305	Loss of Gas Fuel Supply at Cricket Valley	Barrett - Barrett OSW (1) 138 kV	121
K	PSEG-LI	Barrett - Barrett OSW (1) 138 kV	218	308	Loss of Gas Fuel Supply at Cricket Valley	Barrett - Barrett OSW (2) 138 kV	120
K	PSEG-LI	East Garden City - Newbridge (462) 138 kV	194	284	Loss of Gas Fuel Supply at Cricket Valley	Base Case	101

Investigation shows that the set of overloaded transmission elements that are produced by a single simulation run are highly sensitive to changes in relative priorities given to resolving overloads in certain areas, with multiple valid choices producing overloads on lines leading out of the Barrett generation pocket in Long Island or lines leading out of the Oswego complex. This indicates the system is short of generation to serve load when respecting all transmission element ratings across the system. Adjusting simulation priorities can mitigate certain line overloads but shifts the overloads to other lines. There is no set of generation dispatches that results in a system where all lines are within applicable ratings post-contingency.

Approximately 75 MW of additional resources (or load reduction) are needed to fully resolve the observed thermal overloads. Testing shows that resources located anywhere in the NYCA can fully resolve the overloads.

Low reserve levels in the base case, high sensitivity to small changes in relative prioritization of line ratings, and insensitivity to changes in location of additional resources indicate that the overloads observed in the year 10 winter transmission security analysis are driven by a statewide resource deficiency and do not represent conventional transmission security thermal loading criteria violations.

2034 Summer Peak

Potential steady-state transmission security thermal overloads are observed for the study period under 2034 summer peak conditions before accounting for the flexibility of approximately 1,200 MW of large loads. Figure 39 provides a summary of the BPTF overloads under N-1-1 conditions. These thermal overloads are observed beginning in the summer of 2033.

Figure 39: Summer Peak Steady State Transmission Security N-1-1 Thermal Overloads

Zone	Owner	Monitored Element	Norm Rating (MVA)	Cont Rating (MVA)	Worst 1st Contingency	Worst 2nd Contingency	2034 Flow (%)
C	National Grid	Clay - Volney (6) 345 kV	1200	1396	Clay - Nine Mile 1 (8) 345 kV	Clay - Independence (26) 345 kV	114
C	National Grid	Clay - Volney (6) 345 kV	1200	1396	Loss of Nine Mile Point 1	Clay - Independence (26) 345 kV	113
C	National Grid	Clay - Volney (6) 345 kV	1200	1396	Clay - Nine Mile 1 (8) 345 kV	Clay 345 kV Stuck Breaker (R260)	113
C	National Grid	Clay - Volney (6) 345 kV	1200	1396	Clay - Independence (26) 345 kV	Clay - Nine Mile 1 (8) 345 kV	112
C	National Grid	Clay - Volney (6) 345 kV	1200	1396	Loss of Nine Mile Point 1	Clay 345 kV Stuck Breaker (R260)	112
C	National Grid	Clay - Volney (6) 345 kV	1200	1396	Clay - Independence (26) 345 kV	Clay 345 kV Stuck Breaker (R925)	111
C	National Grid	Clay - Nine Mile 1 (8) 345 kV	1032	1271	Clay - Volney (6) 345 kV	Clay - Independence (26) 345 kV	111
C	National Grid	Clay - Volney (6) 345 kV	1200	1396	Clay - Independence (26) 345 kV	Clay 345 kV Stuck Breaker (R80)	111
C	National Grid	Clay - Nine Mile 1 (8) 345 kV	1032	1271	Clay - Volney (6) 345 kV	Clay 345 kV Stuck Breaker (R260)	110
C	National Grid	Clay - Nine Mile 1 (8) 345 kV	1032	1271	Clay - Independence (26) 345 kV	Volney 345 kV Stuck Breaker (R935)	108
C	National Grid	Clay - Nine Mile 1 (8) 345 kV	1032	1271	Clay - Independence (26) 345 kV	Clay - Volney (6) 345 kV	107
C	National Grid	Clay - Nine Mile 1 (8) 345 kV	1032	1271	Clay - Independence (26) 345 kV	Clay 345 kV Stuck Breaker (R35)	106
C	National Grid	Clay - Volney (6) 345 kV	1200	1396	Clay - Nine Mile 1 (8) 345 kV	Loss of Tower with Lines 25 (345 kV) and 26 (345 kV)	102

Modeling the flexibility of certain large loads mitigates these overloads, and they are, therefore, not considered violations of Reliability Criteria.

2024 RNA Stability Assessment

No stability criteria violations are observed under summer peak, winter peak, or daytime light load conditions for the evaluated cases.

2024 RNA Short Circuit Assessment

Figure 40 below provides the results of NYISO's short circuit screening test for year 5 (2029) and year 10 (2034) of the Study Period for both ozone and non-ozone seasons. Individual Breaker Analysis (IBA) is required for any breakers the ratings of which were exceeded by the maximum bus fault current. Either NYISO or the responsible Transmission Owner performed the analyses, depending on the substation in question. Figure 41 provides the results of the Fitzpatrick 345 kV IBA, and Figure 42 provides the results of the New Scotland 345 kV IBA.

No short circuit criteria violations are observed.

Figure 40: 2024 RNA Fault Current Analysis Summary

Substation	Nominal Voltage (kV)	Owner	LCB Rating (kA)	2029 Ozone			2029 Non-Ozone			2034 Ozone			2034 Non-Ozone			Breaker(s) Overdutied ?
				Fault Current (kA)	Percentage of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	
MARCY	765	NYPA	63	10.1	16.1	N	10.1	16.1	N	10.1	16.1	N	10.1	16.1	N	N
MASSENA	765	NYPA	63	7.1	11.3	N	7.1	11.3	N	7.1	11.3	N	7.1	11.3	N	N
ACADEMY	345	Con Ed	63	31.4	49.9	N	31.5	50	N	32.9	52.2	N	32.9	52.3	N	N
ADIRONDACK	345	NYPA	63	14.2	22.5	N	14.2	22.5	N	14.1	22.4	N	14.1	22.4	N	N
ALPS	345	N. Grid	39	20.5	52.5	N	20.5	52.5	N	20.5	52.5	N	20.5	52.5	N	N
ASTORIA ANNEX	345	NYPA	63	50.3	79.8	N	52.4	83.2	N	49.9	79.2	N	52	82.5	N	N
ATHENS	345	N. Grid	49	35.4	72.2	N	35.4	72.2	N	35.5	72.4	N	35.5	72.4	N	N
AUSTIN ROAD	345	N. Grid	50	13.3	26.6	N	13.3	26.6	N	13.3	26.6	N	13.3	26.6	N	N
BAYONNE	345	Con Ed	50	41.6	83.2	N	42.2	84.4	N	41.3	82.7	N	42.1	84.1	N	N
BOWLINE 1	345	O&R	40	26.6	66.4	N	26.6	66.4	N	26.8	66.9	N	26.8	66.9	N	N
BOWLINE 2	345	O&R	40	26.4	66.1	N	26.5	66.2	N	26.7	66.6	N	26.7	66.7	N	N
BROOKLYN CLEAN ENERGY HUB	345	CONED	63	59	93.6	N	60	95.3	N	58.6	93	N	59.8	95	N	N
BROOKLYN CLEAN ENERGY HUB	345	CONED	63	59	93.6	N	60	95.3	N	58.6	93	N	59.8	95	N	N
BROOKLYN CLEAN ENERGY HUB	345	CONED	63	59	93.6	N	60	95.3	N	58.6	93	N	59.8	95	N	N
BUCHANAN NORTH	345	Con Ed	63	24.4	38.8	N	24.5	38.8	N	24.8	39.3	N	24.8	39.3	N	N
BUCHANAN SOUTH	345	Con Ed	63	35.3	56.1	N	35.4	56.1	N	36.1	57.2	N	36.1	57.3	N	N
CLARKS CORNER	345	NYSEG	40	11.9	29.8	N	11.9	29.8	N	11.9	29.7	N	11.9	29.7	N	N
CLAY	345	N. Grid	49	33.7	68.8	N	33.7	68.8	N	33.7	68.8	N	33.7	68.8	N	N
COOPERS CORNER	345	NYSEG	40	19.1	47.7	N	19.1	47.7	N	19.1	47.7	N	19.1	47.7	N	N
CRICKET VALLEY	345	Con Ed	63	35.8	56.9	N	35.8	56.9	N	35.9	57.1	N	36	57.1	N	N
DEWITT	345	N. Grid	39	19	48.7	N	19	48.7	N	19	48.7	N	19	48.7	N	N
DOLSON AVENUE	345	NYPA	63	20.8	33	N	20.8	33	N	20.8	33.1	N	20.8	33.1	N	N
DOVER	345	TransCo	63	35.2	55.8	N	35.2	55.9	N	35.3	56	N	35.3	56	N	N
DUFFY AVENUE	345	LIPA	58.6	8.3	14.1	N	8.3	14.1	N	8.2	14	N	8.2	14	N	N
DUNWOODIE	345	Con Ed	63	48.2	76.5	N	48.4	76.8	N	51.5	81.7	N	51.6	82	N	N
DYSINGER	345	Nextera	50	20.9	41.8	N	20.9	41.8	N	20.9	41.8	N	20.9	41.8	N	N
DYSINGER PAR	345	Nextera	50	9.5	18.9	N	9.5	18.9	N	9.5	18.9	N	9.5	18.9	N	N
E13ST 45	345	Con Ed	63	52.1	82.7	N	53.2	84.5	N	51.8	82.2	N	53.2	84.4	N	N
E13ST 46	345	Con Ed	63	52.2	82.8	N	53	84.2	N	51.3	81.4	N	53	84.1	N	N
E13ST 47	345	Con Ed	63	52.8	83.8	N	54.1	85.9	N	51.9	82.4	N	53.8	85.5	N	N
E13ST 48	345	Con Ed	63	52.6	83.5	N	53.5	84.9	N	51.8	82.3	N	52.9	84	N	N
EAST FISHKILL	345	Con Ed	63	43.6	69.3	N	43.7	69.3	N	44.1	70	N	44.2	70.1	N	N
EAST GARDEN CITY PAR	345	NYPA	63	N/A	N/A	N/A	N/A	N/A	N/A	28.1	44.6	N	28.2	44.7	N	N
EAST STOLLE	345	Nextera	50	8.9	17.7	N	8.9	17.7	N	8.9	17.7	N	8.9	17.7	N	N
EDIC	345	N. Grid	39	38.2	98	N	38.2	98	N	38.2	97.9	N	38.2	97.9	N	N
ELBRIDGE	345	N. Grid	40	16.1	40.1	N	16.1	40.1	N	16	40.1	N	16	40.1	N	N
FARRAGUT	345	Con Ed	63	59	93.7	N	60.1	95.4	N	58.6	93.1	N	59.9	95.1	N	N
FILE MILE ROAD	345	N. Grid	49	7.7	15.8	N	7.7	15.8	N	7.7	15.8	N	7.7	15.8	N	N
FITZPATRICK	345	NYPA	37	41	110.9	Y	41	110.9	Y	41	110.8	Y	41	110.8	Y	N
FRASER	345	NYSEG	40	19.6	49.1	N	19.6	49.1	N	19.6	49.1	N	19.6	49.1	N	N

Substation	Nominal Voltage (kV)	Owner	LCB Rating (kA)	2029 Ozone			2029 Non-Ozone			2034 Ozone			2034 Non-Ozone			Breaker(s) Overdutied ?
				Fault Current (kA)	Percentage of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	
FRESH KILLS	345	Con Ed	63	39.6	62.9	N	39.8	63.2	N	38.5	61.2	N	39.6	62.9	N	N
GILBOA	345	NYPA	50	25.6	51.2	N	25.6	51.2	N	25.6	51.2	N	25.6	51.2	N	N
GOETHALS	345	Con Ed	63	44.9	71.3	N	45.9	72.8	N	44.5	70.7	N	45.6	72.4	N	N
GORDON ROAD	345	LSPower	63	26.9	42.7	N	26.9	42.7	N	26.9	42.7	N	26.9	42.7	N	N
GOWANUS	345	Con Ed	63	55.4	87.9	N	56.8	90.1	N	55.1	87.4	N	56	88.9	N	N
HAVERSTOCK	345	NYPA	63	14.3	22.7	N	14.3	22.7	N	14.3	22.6	N	14.3	22.6	N	N
HENRIETTA	345	RGE	63	17.9	28.4	N	17.9	28.4	N	17.9	28.4	N	17.9	28.4	N	N
HURLEY	345	CH	40	18.9	47.2	N	18.9	47.2	N	18.9	47.3	N	18.9	47.3	N	N
INDEPENDENCE	345	N. Grid	44	39	88.6	N	39	88.6	N	39	88.5	N	39	88.5	N	N
KNICKERBOCKER	345	TransCo	63	28.7	45.6	N	28.7	45.6	N	28.7	45.6	N	28.7	45.6	N	N
LADENTOWN	345	O&R	63	38	60.3	N	38	60.4	N	38.5	61.1	N	38.5	61.1	N	N
LAFAYETTE	345	N. Grid	40	17.9	44.8	N	17.9	44.8	N	17.9	44.7	N	17.9	44.7	N	N
LEEDS	345	N. Grid	37	36.2	97.9	N	36.2	97.9	N	36.3	98.1	N	36.3	98.1	N	N
LOVETTE	345	O&R	63	34.1	54.1	N	34.1	54.2	N	34.7	55.1	N	34.8	55.2	N	N
MARCY	345	NYPA	63	36.8	58.4	N	36.8	58.4	N	36.7	58.3	N	36.7	58.3	N	N
MIDDLETOWN	345	O&R	50	19.1	38.2	N	19.1	38.2	N	19.1	38.2	N	19.1	38.2	N	N
MILLWOOD	345	Con Ed	63	42.7	67.7	N	42.8	67.9	N	44.1	70	N	44.2	70.2	N	N
MOTT HAVEN	345	Con Ed	63	47.6	75.6	N	48.3	76.7	N	47.4	75.3	N	48.2	76.6	N	N
NEW BARRETT	345	LIPA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	24.1	N/A	N	24.1	N/A	N	N
NEW BRIDGE	345	LIPA	56	8.4	15.1	N	8.4	15.1	N	8.4	14.9	N	8.4	15	N	N
NEW EGC PAR	345	LIPA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	18.6	N/A	N	18.6	N/A	N	N
NEW RULAND ROAD	345	LIPA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	22	N/A	N	22	N/A	N	N
NEW SCOTLAND 33K	345	N. Grid	39	39.4	100.9	Y	39.4	100.9	Y	39.4	101	Y	39.4	101	Y	N
NEW SCOTLAND 77K	345	N. Grid	50	39.2	78.3	N	39.2	78.3	N	39.2	78.4	N	39.2	78.4	N	N
NEW SCOTLAND 99K	345	N. Grid	39	39.1	100.3	Y	39.1	100.3	Y	39.1	100.4	Y	39.2	100.4	Y	N
NEW SHORE ROAD	345	LIPA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	31.8	N/A	N	31.9	N/A	N	N
NIAGARA	345	NYPA	63	33	52.4	N	33	52.4	N	33	52.4	N	33	52.4	N	N
NINE MILE POINT #1	345	N. Grid	50	42.7	85.4	N	42.7	85.4	N	42.7	85.3	N	42.7	85.3	N	N
NINE MILE POINT #2	345	N. Grid	50	43.5	86.9	N	43.5	86.9	N	43.4	86.8	N	43.4	86.8	N	N
OAKDALE	345	NYSEG	40	13.1	32.8	N	13.1	32.8	N	13.1	32.8	N	13.1	32.8	N	N
OSWEGO	345	N. Grid	44	32.6	74.2	N	32.6	74.2	N	32.6	74.1	N	32.6	74.1	N	N
PANNELL ROAD	345	RGE	40	17.2	43	N	17.2	43	N	17.2	43	N	17.2	43	N	N
PLEASANT VALLEY	345	Con Ed	63	50.2	79.8	N	50.3	79.8	N	50.7	80.5	N	50.8	80.6	N	N
PLESANTVILLE EAST	345	Con Ed	63	21.6	34.3	N	21.6	34.3	N	22	34.9	N	22	34.9	N	N
PLESANTVILLE WEST	345	Con Ed	63	21.8	34.6	N	21.9	34.7	N	22.2	35.2	N	22.2	35.3	N	N
PRINCETWON	345	LSPower	63	31.9	50.6	N	31.9	50.6	N	31.9	50.6	N	31.9	50.6	N	N
Q1446 POI	345	Air Products	50	11.9	23.7	N	11.9	23.7	N	11.8	23.7	N	11.8	23.7	N	N
Q1536 POI	345	Micron	40	32.9	82.3	N	32.9	82.3	N	32.9	82.2	N	32.9	82.2	N	N
Q580 POI 1	345	NYPA	63	19.1	30.3	N	19.1	30.3	N	19.1	30.3	N	19.1	30.3	N	N
Q580 POI 2	345	NYPA	63	19.1	30.3	N	19.1	30.3	N	19.1	30.3	N	19.1	30.3	N	N

Substation	Nominal Voltage (kV)	Owner	LCB Rating (kA)	2029 Ozone			2029 Non-Ozone			2034 Ozone			2034 Non-Ozone			Breaker(s) Overdutied ?
				Fault Current (kA)	Percentage of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	
Q737 ONSHORE	345	Empire Wind	63	52.8	83.8	N	53.9	85.5	N	51.9	82.4	N	53.6	85.1	N	N
RAINEY	345	Con Ed	63	54.7	86.8	N	55.6	88.3	N	54.3	86.2	N	55.4	88	N	N
RAMAPO	345	Con Ed	63	43.1	68.5	N	43.2	68.5	N	43.6	69.3	N	43.7	69.3	N	N
REYNOLDS	345	N. Grid	39	16.6	42.6	N	16.6	42.6	N	16.6	42.6	N	16.6	42.6	N	N
ROCHESTER	345	RGE	40	17.9	44.8	N	17.9	44.8	N	17.9	44.8	N	17.9	44.8	N	N
ROCK TAVERN	345	CH	63	33.9	53.8	N	33.9	53.9	N	34.1	54.1	N	34.1	54.1	N	N
ROSETON	345	CH	63	38	60.4	N	38.1	60.4	N	38.3	60.8	N	38.3	60.8	N	N
SCRIBA	345	N. Grid	54	46.3	85.8	N	46.3	85.8	N	46.3	85.7	N	46.3	85.7	N	N
SHORE ROAD	345	LIPA	63	26.8	42.5	N	26.8	42.6	N	27.8	44.1	N	27.8	44.2	N	N
SOMERSET	345	NYSEG	40	14.8	36.9	N	14.8	36.9	N	14.8	36.9	N	14.8	36.9	N	N
SPRAINBROOK	345	Con Ed	63	49.2	78.2	N	49.4	78.4	N	53.3	84.6	N	53.5	84.9	N	N
STOLLE ROAD	345	NYSEG	40	8.8	22.1	N	8.8	22.1	N	8.8	22.1	N	8.8	22.1	N	N
SUGARLOAD	345	O&R	63	25.5	40.5	N	25.5	40.5	N	25.6	40.7	N	25.6	40.7	N	N
VAN WAGNER	345	TransCo	63	48.1	76.3	N	48.1	76.3	N	48.5	77	N	48.5	77	N	N
VOLNEY	345	N. Grid	45	36.7	81.6	N	36.7	81.6	N	36.7	81.5	N	36.7	81.5	N	N
W49 ST	345	Con Ed	63	49.6	78.7	N	50.5	80.1	N	49.2	78.2	N	50.4	80	N	N
WATERCURE	345	NYSEG	40	10	24.9	N	10	24.9	N	9.9	24.9	N	9.9	24.9	N	N
AUSTIN ROAD	230	N. Grid	39	8.6	22	N	8.6	22	N	8.6	22	N	8.6	22	N	N
BALL HILL POI	230	N. Grid	50	7.2	14.5	N	7.2	14.5	N	7.2	14.5	N	7.2	14.5	N	N
CANANDAUGUA	230	NYSEG	40	8.8	22.1	N	8.8	22.1	N	8.8	22.1	N	8.8	22.1	N	N
DULEY	230	NYPA	40	7.7	19.1	N	7.7	19.1	N	7.6	19.1	N	7.6	19.1	N	N
DUNKIRK	230	N. Grid	33	7.9	24	N	7.9	24	N	7.9	24	N	7.9	24	N	N
EASTOVER	230	N. Grid	49	12.4	25.4	N	12.4	25.4	N	12.4	25.4	N	12.4	25.4	N	N
GARDENVILLE 1	230	N. Grid	31	18.9	61.1	N	18.9	61.1	N	18.9	61.1	N	18.9	61.1	N	N
GARDENVILLE 230	230	NYSEG	30.859	18.9	61.4	N	18.9	61.4	N	18.9	61.4	N	18.9	61.4	N	N
HIGH SHELDON	230	NYSEG	40	10.5	26.2	N	10.5	26.2	N	10.5	26.2	N	10.5	26.2	N	N
HILLSIDE	230	NYSEG	35.86	13.5	37.6	N	13.5	37.6	N	13.5	37.6	N	13.5	37.6	N	N
HUNTLEY 68	230	N. Grid	30	17	56.8	N	17	56.8	N	17	56.7	N	17	56.7	N	N
HUNTLEY 70	230	N. Grid	50	17	34.1	N	17	34.1	N	17	34.1	N	17	34.1	N	N
MEYER	230	NYSEG	40	8.9	22.3	N	8.9	22.3	N	8.9	22.2	N	8.9	22.2	N	N
NIAGARA EAST	230	NYPA	63	53.3	84.6	N	53.3	84.6	N	53.3	84.6	N	53.3	84.6	N	N
NIAGARA WEST	230	NYPA	63	53.3	84.6	N	53.3	84.6	N	53.3	84.6	N	53.3	84.6	N	N
PACKARD 2&3	230	N. Grid	49	38.9	79.4	N	38.9	79.4	N	38.9	79.4	N	38.9	79.4	N	N
PACKARD 4&5	230	N. Grid	49	38.9	79.4	N	38.9	79.4	N	38.9	79.4	N	38.9	79.4	N	N
PACKARD 6	230	N. Grid	49	39	79.6	N	39	79.6	N	39	79.6	N	39	79.6	N	N
PATNODE	230	NYPA	63	11.5	18.2	N	11.5	18.2	N	11.5	18.2	N	11.5	18.2	N	N
PORTER	230	N. Grid	21	14.8	70.6	N	14.8	70.6	N	14.7	70.2	N	14.7	70.2	N	N
Q396 BARRON WIND PSU	230	NYSEG	40	7.8	19.4	N	7.8	19.4	N	7.8	19.4	N	7.8	19.4	N	N
Q546 POI	230	N. Grid	40	8.2	20.4	N	8.2	20.4	N	8.2	20.4	N	8.2	20.4	N	N
Q717 POI	230	Morris Ridge Solar	40	8.9	22.3	N	8.9	22.3	N	8.9	22.3	N	8.9	22.3	N	N

Substation	Nominal Voltage (kV)	Owner	LCB Rating (kA)	2029 Ozone			2029 Non-Ozone			2034 Ozone			2034 Non-Ozone			Breaker(s) Overdutied ?
				Fault Current (kA)	Percentage of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	
ROBINSON ROAD	230	NYSEG	43.089	13.8	31.9	N	13.8	31.9	N	13.8	31.9	N	13.8	31.9	N	N
ROTTERDAM 66H	230	N. Grid	39	18.5	47.4	N	18.5	47.4	N	18.5	47.3	N	18.5	47.3	N	N
ROTTERDAM 77H	230	N. Grid	23	18.4	79.9	N	18.4	79.9	N	18.4	79.8	N	18.4	79.8	N	N
ROTTERDAM 99H	230	N. Grid	23	18.5	80.5	N	18.5	80.5	N	18.5	80.4	N	18.5	80.4	N	N
RYAN	230	NYPA	40	11.6	29	N	11.6	29	N	11.6	29	N	11.6	29	N	N
SAINT LAWRENCE	230	NYPA	50	31.1	62.1	N	31.1	62.1	N	31	62.1	N	31	62.1	N	N
SOUTH RIPLEY	230	N. Grid	40	4.3	10.7	N	4.3	10.7	N	4.3	10.7	N	4.3	10.7	N	N
STOLLE ROAD	230	NYSEG	40	13.6	33.9	N	13.6	33.9	N	13.6	33.9	N	13.6	33.9	N	N
STONEY CREEK	230	NYSEG	40	9.6	24.1	N	9.6	24.1	N	9.6	24.1	N	9.6	24.1	N	N
STONEY RIDGE	230	NYSEG	40	8.1	20.2	N	8.1	20.2	N	8.1	20.2	N	8.1	20.2	N	N
WATERCURE	230	NYSEG	40	13.7	34.1	N	13.7	34.1	N	13.6	34.1	N	13.6	34.1	N	N
WETHERSFIELD	230	NYSEG	40	9.5	23.8	N	9.5	23.8	N	9.5	23.8	N	9.5	23.8	N	N
WILLIS	230	NYPA	40	13.2	32.9	N	13.2	32.9	N	13.1	32.8	N	13.1	32.8	N	N
ASTORIA ENERGY East	138	Con Ed	63	50.7	80.5	N	50.8	80.6	N	50.3	79.8	N	50.4	79.9	N	N
ASTORIA ENERGY West	138	Con Ed	63	50.7	80.5	N	50.8	80.6	N	50.3	79.8	N	50.4	79.9	N	N
ASTORIA W-N	138	Con Ed	63	43.3	68.8	N	43.4	68.9	N	43	68.3	N	43.2	68.5	N	N
ASTORIA W-S	138	Con Ed	63	43.3	68.8	N	43.4	68.9	N	43	68.3	N	43.2	68.5	N	N
BARRETT 1	138	LIPA	63	50.5	80.1	N	50.5	80.1	N	54.7	86.8	N	54.7	86.9	N	N
BARRETT 2	138	LIPA	63	50.5	80.2	N	50.5	80.2	N	54.7	86.9	N	54.8	87	N	N
BROOKHAVEN	138	LIPA	63	27.3	43.3	N	27.3	43.3	N	27.4	43.5	N	27.4	43.5	N	N
BUCHANAN	138	Con Ed	40	15.6	39.1	N	15.6	39.1	N	15.7	39.2	N	15.7	39.3	N	N
CARLE PLACE	138	LIPA	63	40.5	64.2	N	40.5	64.2	N	40.4	64.1	N	40.4	64.1	N	N
CENTRAL ISLIP	138	LIPA	63	28.6	45.5	N	28.6	45.5	N	29	46.1	N	29	46.1	N	N
CORONA NORTH	138	Con Ed	63	51.2	81.3	N	51.3	81.4	N	50.7	80.5	N	50.8	80.6	N	N
CORONA SOUTH	138	Con Ed	63	51.2	81.3	N	51.3	81.4	N	50.7	80.5	N	50.8	80.6	N	N
DUNWOOD NORTH	138	Con Ed	63	29.3	46.5	N	29.3	46.6	N	29.4	46.6	N	29.4	46.7	N	N
DUNWOODIE NORTH	138	Con Ed	40	34.8	86.9	N	34.8	87	N	34.9	87.3	N	34.9	87.3	N	N
DUNWOODIE SOUTH	138	Con Ed	40	31.7	79.3	N	31.7	79.4	N	31.9	79.8	N	32	79.9	N	N
DUNWOODIE SOUTH N7	138	Con Ed	63	27.5	43.6	N	27.5	43.6	N	27.6	43.8	N	27.6	43.8	N	N
EAST 13 STREET	138	Con Ed	63	48.8	77.5	N	49.1	78	N	48.7	77.4	N	49.1	77.9	N	N
EAST GARDEN CITY 1	138	LIPA	80	70.4	88	N	70.4	88	N	68.8	86.1	N	68.9	86.1	N	N
EAST GARDEN CITY 2	138	LIPA	80	70.4	88	N	70.4	88	N	68.8	86	N	68.9	86.1	N	N
EASTVIEW	138	Con Ed	63	36.6	58.1	N	36.6	58.1	N	37.1	59	N	37.2	59	N	N
ELWOOD 1	138	LIPA	63	38.6	61.2	N	38.6	61.2	N	47.2	75	N	47.2	75	N	N
ELWOOD 2	138	LIPA	63	38.4	61	N	38.4	61	N	47.1	74.7	N	47.1	74.7	N	N
FREEPORT	138	LIPA	63	35.3	56.1	N	35.3	56.1	N	35.6	56.5	N	35.6	56.5	N	N
FRESH KILLS	138	Con Ed	40	35.2	87.9	N	38.4	96.1	N	33.4	83.6	N	37	92.6	N	N
GLENWOOD NORTH	138	LIPA	63	42.8	67.9	N	42.8	68	N	53.5	84.9	N	53.5	85	N	N
GLENWOOD SOUTH	138	LIPA	63	42.5	67.5	N	42.5	67.5	N	52.9	84	N	53	84.1	N	N
GREENLAWN	138	LIPA	63	29.2	46.4	N	29.2	46.4	N	35.4	56.1	N	35.4	56.1	N	N

Substation	Nominal Voltage (kV)	Owner	LCB Rating (kA)	2029 Ozone			2029 Non-Ozone			2034 Ozone			2034 Non-Ozone			Breaker(s) Overdutied ?
				Fault Current (kA)	Percentage of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	
HAUPPAGUE	138	LIPA	63	22.1	35.1	N	22.1	35.1	N	22.5	35.7	N	22.5	35.7	N	N
HOLBROOK	138	LIPA	63	51.1	81.1	N	51.1	81.1	N	51.9	82.5	N	51.9	82.5	N	N
HOLT	138	LIPA	63	47.2	74.8	N	47.2	74.8	N	47.9	76	N	47.9	76	N	N
JAMAICA	138	Con Ed	63	48.9	77.6	N	48.9	77.7	N	49.2	78.1	N	49.3	78.3	N	N
LAKE SUCCESS	138	LIPA	63	32.4	51.5	N	32.5	51.5	N	33.4	53	N	33.5	53.1	N	N
LOCUST GROVE	138	LIPA	63	39.3	62.4	N	39.3	62.4	N	42.5	67.4	N	42.5	67.4	N	N
LOVETTE	138	O&R	40	28.8	72	N	28.8	72	N	28.9	72.3	N	28.9	72.3	N	N
MILLER PLACE	138	LIPA	63	14.9	23.6	N	14.9	23.6	N	14.9	23.7	N	14.9	23.7	N	N
MILLWOOD	138	Con Ed	40	19.4	48.4	N	19.4	48.4	N	19.5	48.6	N	19.5	48.7	N	N
MOTT HAVEN	138	Con Ed	50	13.6	27.2	N	13.6	27.2	N	13.6	27.2	N	13.6	27.2	N	N
MOTT HAVEN	138	Con Ed	50	13.5	27	N	13.5	27.1	N	13.5	27	N	13.5	27.1	N	N
MOTT HAVEN	138	Con Ed	50	13.5	27.1	N	13.6	27.1	N	13.5	27.1	N	13.6	27.1	N	N
MOTT HAVEN	138	Con Ed	50	13.5	27	N	13.5	27.1	N	13.5	27	N	13.5	27.1	N	N
NEW BARRETT	138	LIPA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	54.9	N/A	N	55	N/A	N	N
NEW BRIDGE	138	LIPA	80	68.6	85.8	N	68.7	85.8	N	66.8	83.5	N	66.8	83.5	N	N
NORTHPORT 1	138	LIPA	63	60.5	96	N	60.5	96	N	67.2	106.7	Y	67.2	106.7	Y	N
NORTHPORT 1-2	138	LIPA	63	60.5	96.1	N	60.5	96.1	N	67.2	106.7	Y	67.3	106.8	Y	N
NORTHPORT 2	138	LIPA	63	60.5	96.1	N	60.5	96.1	N	67.3	106.8	Y	67.3	106.8	Y	N
NORTHPORT 3	138	LIPA	63	45.4	72	N	45.4	72.1	N	56.6	89.8	N	56.6	89.8	N	N
NORTHPORT 4	138	LIPA	63	45.4	72	N	45.4	72	N	56.5	89.8	N	56.6	89.8	N	N
OAKWOOD	138	LIPA	63	27.9	44.3	N	27.9	44.3	N	35.5	56.4	N	35.5	56.4	N	N
PARKCHESTER TRANSFORMER 1	138	Con Ed	63	16.7	26.6	N	16.7	26.6	N	16.7	26.5	N	16.7	26.5	N	N
PARKCHESTER TRANSFORMER 2	138	Con Ed	63	16.9	26.9	N	16.9	26.9	N	16.9	26.8	N	16.9	26.8	N	N
PILGRIM	138	LIPA	63	59.1	93.9	N	59.2	93.9	N	64.7	102.7	Y	64.7	102.7	Y	N
PORT JEFFERSON	138	LIPA	63	32.3	51.2	N	32.3	51.2	N	32.4	51.4	N	32.4	51.4	N	N
Q987 ONSHORE	138	Sunrise Wind	N/A	47.2	N/A	N	47.2	N/A	N	47.9	N/A	N	47.9	N/A	N	N
RIVERHEAD	138	LIPA	63	21	33.3	N	21	33.3	N	21	33.4	N	21	33.4	N	N
RONKONKOMA	138	LIPA	63	38	60.2	N	38	60.2	N	38.5	61.1	N	38.5	61.1	N	N
ROSLYM	138	LIPA	63	29.6	47	N	29.6	47	N	30.5	48.4	N	30.5	48.4	N	N
RULAND ROAD	138	LIPA	63	45.1	71.7	N	45.1	71.7	N	53.2	84.4	N	53.2	84.4	N	N
SHORE ROAD 1	138	LIPA	63	46.3	73.5	N	46.4	73.6	N	61.3	97.4	N	61.4	97.5	N	N
SHORE ROAD 2	138	LIPA	63	46.3	73.5	N	46.4	73.6	N	61.1	96.9	N	61.1	97	N	N
SHOREHAM 1	138	LIPA	63	27.3	43.3	N	27.3	43.3	N	27.3	43.4	N	27.3	43.4	N	N
SHOREHAM 2	138	LIPA	63	27.3	43.3	N	27.3	43.3	N	27.3	43.4	N	27.3	43.4	N	N
SILLS ROAD 1	138	LIPA	63	32.4	51.4	N	32.4	51.4	N	32.6	51.8	N	32.6	51.8	N	N
SOUTH MAHWAH	138	RECO	40	26	64.9	N	26	64.9	N	26	65.1	N	26	65.1	N	N
SYOSSET	138	LIPA	63	33.9	53.8	N	33.9	53.8	N	52.7	83.6	N	52.7	83.6	N	N
VALLEY STREAM 1	138	LIPA	63	57.3	90.9	N	57.3	91	N	56.6	89.9	N	56.7	89.9	N	N
VALLEY STREAM 2	138	LIPA	63	57.5	91.3	N	57.6	91.4	N	56.8	90.1	N	56.8	90.2	N	N
VERNON EAST	138	Con Ed	63	45.4	72	N	46	73	N	44.8	71.1	N	45.6	72.3	N	N

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				Fault Current (kA)	Percentage of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	
VERNON WEST	138	Con Ed	63	32.9	52.2	N	33.4	53	N	30.6	48.5	N	31.2	49.5	N	N
WADING RIVER	138	LIPA	63	25.3	40.2	N	25.3	40.2	N	25.4	40.3	N	25.4	40.3	N	N
WEST HAVERSTRAW	138	O&R	40	29.7	74.2	N	29.7	74.2	N	29.8	74.5	N	29.8	74.5	N	N
WILDWOOD	138	LIPA	63	26.8	42.5	N	26.8	42.5	N	26.9	42.6	N	26.9	42.6	N	N
BOONVILLE	115	N. Grid	23	11.2	48.8	N	11.2	48.8	N	11.2	48.6	N	11.2	48.6	N	N
CHURCHTOWN	115	TransCo	40	9.6	23.9	N	9.6	23.9	N	9.6	23.9	N	9.6	23.9	N	N
CLARKS CORNER	115	NYSEG	40	19.1	47.7	N	19.1	47.7	N	19	47.6	N	19	47.6	N	N
CLAY	115	N. Grid	45	38.3	85	N	38.3	85	N	38.2	84.9	N	38.2	84.9	N	N
COOPERS CORNER	115	NYSEG	22.637	15	66	N	15	66	N	14.9	66	N	14.9	66	N	N
COOPERS CORNER	115	NYSEG	23.086	15	64.8	N	15	64.8	N	14.9	64.7	N	14.9	64.7	N	N
DEWITT	115	N. Grid	39	29.8	76.3	N	29.8	76.3	N	29.7	76.2	N	29.7	76.2	N	N
EAST FISHKILL	115	CH	40	24.4	61.1	N	24.4	61.1	N	24.5	61.1	N	24.5	61.1	N	N
EASTOVER NORTH	115	N. Grid	49	27.3	55.7	N	27.3	55.7	N	27.3	55.7	N	27.3	55.7	N	N
ELBRIDGE D	115	N. Grid	49	26.2	53.4	N	26.2	53.4	N	26.2	53.4	N	26.2	53.4	N	N
FILE MILE ROAD	115	N. Grid	49	14.8	30.2	N	14.8	30.2	N	14.8	30.2	N	14.8	30.2	N	N
FRASER	115	NYSEG	40	19.5	48.7	N	19.5	48.7	N	19.5	48.7	N	19.5	48.7	N	N
GARDENVILLE	115	N. Grid	63	37	58.8	N	37	58.8	N	37	58.8	N	37	58.8	N	N
GARDENVILLE	115	NYSEG	39.995	36.4	91	N	36.4	91	N	36.4	91	N	36.4	91	N	N
GARDENVILLE	115	NYSEG	43.089	36.4	84.5	N	36.4	84.5	N	36.4	84.5	N	36.4	84.5	N	N
HENRIETTA	115	RGE	40	22.5	56.3	N	22.5	56.3	N	22.5	56.3	N	22.5	56.3	N	N
HILLSIDE	115	NYSEG	22.008	0	0	N	0	0	N	0	0	N	0	0	N	N
HURLEY AVENUE	115	CH	40	16.7	41.6	N	16.7	41.6	N	16.7	41.6	N	16.7	41.6	N	N
LIGHT HOUSE HILL	115	N. Grid	23	11.6	50.5	N	11.6	50.5	N	11.6	50.4	N	11.6	50.4	N	N
MEYER	115	NYSEG	18.889	12.2	64.4	N	12.2	64.4	N	12.2	64.3	N	12.2	64.3	N	N
NEW SCOTLAND 33K	115	N. Grid	49	45.4	92.6	N	45.4	92.6	N	45.4	92.6	N	45.4	92.6	N	N
NEW SCOTLAND 77K	115	N. Grid	48	45.4	94.5	N	45.4	94.5	N	45.3	94.4	N	45.3	94.4	N	N
NEW SCOTLAND 99K	115	N. Grid	49	45.3	92.5	N	45.3	92.5	N	45.3	92.5	N	45.3	92.5	N	N
NIAGARA EAST	115	NYPA	63	37	58.8	N	37	58.8	N	37	58.8	N	37	58.8	N	N
NIAGARA WEST	115	NYPA	42.2	29.6	70.2	N	29.6	70.2	N	29.6	70.2	N	29.6	70.2	N	N
OAKDALE	115	NYSEG	40	30	75.1	N	30	75.1	N	30	75	N	30	75	N	N
ONEIDA EAST	115	N. Grid	23	13.4	58.5	N	13.4	58.5	N	13	56.6	N	13	56.6	N	N
ONEIDA WEST	115	N. Grid	23	13.4	58.4	N	13.4	58.4	N	13	56.6	N	13	56.6	N	N
OSWEGO M3	115	N. Grid	40	21.4	53.5	N	21.4	53.5	N	21.4	53.4	N	21.4	53.4	N	N
PACKARD NORTH	115	N. Grid	62	28	45.1	N	28	45.1	N	28	45.1	N	28	45.1	N	N
PACKARD SOUTH	115	N. Grid	58	26	44.8	N	26	44.8	N	26	44.8	N	26	44.8	N	N
PANNELL ROAD	115	RGE	50	32.1	64.2	N	32.1	64.2	N	32.1	64.1	N	32.1	64.1	N	N
PLATTSBURGH	115	NYPA	20.3	17.6	86.8	N	17.6	86.8	N	17.6	86.7	N	17.6	86.7	N	N
PLEASANT VALLEY	115	CH	37.867	25	66.1	N	25	66.1	N	25	66.1	N	25	66.1	N	N
PORTER	115	N. Grid	59	37.7	63.9	N	37.7	63.9	N	37.5	63.5	N	37.5	63.5	N	N
REYNOLDS ROAD	115	N. Grid	63	42.9	68.1	N	42.9	68.1	N	42.9	68.1	N	42.9	68.1	N	N

Substation	Nominal Voltage (kV)	Owner	LCB Rating (kA)	2029 Ozone			2029 Non-Ozone			2034 Ozone			2034 Non-Ozone			Breaker(s) Overdutied ?
				Fault Current (kA)	Percentage of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	Fault Current (kA)	% of Breaker Duty	IBA Required	
ROBINSON ROAD	115	NYSEG	37.932	17.6	46.5	N	17.6	46.5	N	17.6	46.5	N	17.6	46.5	N	N
ROCHESTER	115	RGE	40	16.6	41.5	N	16.6	41.5	N	16.6	41.5	N	16.6	41.5	N	N
ROCK TAVERN	115	CH	40	29.1	72.8	N	29.1	72.8	N	29.1	72.9	N	29.2	72.9	N	N
SAINT LAWRENCE	115	NYPA	50	40.7	81.3	N	40.7	81.3	N	40.6	81.2	N	40.6	81.2	N	N
SCHUYLER	115	N. Grid	23	14.8	64.2	N	14.8	64.2	N	14.6	63.7	N	14.6	63.7	N	N
SCRIBA C	115	N. Grid	40	10.5	26.4	N	10.5	26.4	N	10.5	26.3	N	10.5	26.3	N	N
SCRIBA D	115	N. Grid	40	10.5	26.2	N	10.5	26.2	N	10.5	26.1	N	10.5	26.1	N	N
SOUTH OSWEGO	115	N. Grid	37	21	56.7	N	21	56.7	N	20.9	56.6	N	20.9	56.6	N	N
STATION 13A	115	RGE	37.611	26.9	71.4	N	26.9	71.4	N	26.9	71.4	N	26.9	71.4	N	N
STATION 82 B2	115	RGE	40	36.9	92.1	N	36.9	92.1	N	36.8	92.1	N	36.8	92.1	N	N
STATION 82 B3	115	RGE	40	36.7	91.9	N	36.7	91.9	N	36.7	91.8	N	36.7	91.8	N	N
STOLLE ROAD	115	NYSEG	23.907	19.7	82.5	N	19.7	82.5	N	19.7	82.5	N	19.7	82.5	N	N
TEALL A	115	N. Grid	39	27.2	69.7	N	27.2	69.7	N	27.1	69.6	N	27.1	69.6	N	N
TEALL B	115	N. Grid	39	27.2	69.8	N	27.2	69.8	N	27.2	69.7	N	27.2	69.7	N	N
TERMINAL	115	N. Grid	23	15.8	68.7	N	15.8	68.7	N	15.7	68.1	N	15.7	68.1	N	N
VALLEY	115	N. Grid	39	8.8	22.5	N	8.8	22.5	N	8.7	22.3	N	8.7	22.3	N	N
WATKINS	115	N. Grid	39	8.7	22.2	N	8.7	22.2	N	8.6	22.1	N	8.6	22.1	N	N
WOOD STREET	115	NYSEG	40	19.7	49.2	N	19.7	49.2	N	19.8	49.4	N	19.8	49.4	N	N
WOODARD	115	N. Grid	23	12.2	53.2	N	12.2	53.2	N	12.2	53.1	N	12.2	53.1	N	N
YAHNUNDASIS	115	N. Grid	16	6.6	41.2	N	6.6	41.2	N	6.5	40.8	N	6.5	40.8	N	N

Figure 41: Fitzpatrick 345 kV IBA

2029 Ozone								
Circuit Breaker ID	Breaker Rating (kA)	Fault Location	3LG (A)	2LG (A)	1LG (A)	L-L (A)	Max Fault Current	Overdutied breaker?
10042	37	Fitzpatrick side	31890	34003	33747	27674	34	N
		Scriba side	8272	8790	9107	7162	9.11	N
10052	63	Fitzpatrick side	4248	3968	2868	3678	4.25	N
		Edic side	35482	38257	38513	30784	38.51	N

Figure 42: New Scotland 345 kV IBA

2029 Ozone					
Station	Circuit Breaker ID	Breaker Rating (kA)	Max Fault Current	Duty Percentage	Overdutied breaker?
NSCOT 33K 345.kV	R93	40	38.2	95.6	N
NSCOT 99K 345.kV	R94	40	38	94.9	N
NSCOT 77K 345.kV	R21	50	41	82	N
NSCOT 77K 345.kV	R23	50	41	82	N
NSCOT 77K 345.kV	R86	50	41	82	N
NSCOT 99K 345.kV	R22	50	41	81.9	N
NSCOT 33K 345.kV	R62	50	40.3	80.7	N
NSCOT 33K 345.kV	R85	50	40.3	80.7	N
NSCOT 33K 345.kV	R55	50	40.3	80.6	N
NSCOT 77K 345.kV	R361	50	40.1	80.1	N
NSCOT 77K 345.kV	R362	50	40.1	80.1	N
NSCOT 99K 345.kV	R61	50	40	80	N
NSCOT 99K 345.kV	R18	50	39	78	N
NSCOT 99K 345.kV	R1	50	37.5	75	N
NSCOT 77K 345.kV	R2	50	33.5	67.1	N
NSCOT 33K 345.kV	R81	50	31.5	63	N
NSCOT 99K 345.kV	R82	50	30.7	61.4	N

2024 RNA 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 2024 Gold Book and the projects that meet the reliability planning inclusion rules for the 2024 RNA. At the May 5, 2022[19] and May 23, 2022[20] joint meetings of the Transmission Planning Advisory Subcommittee (TPAS) and the Electric System Planning Working Group (ESPWG), the NYISO discussed with stakeholders several enhancements to its reliability planning practices. The proposed changes to reliability planning practices include: (1) modeling intermittent resources according to their expected availability coincident with the represented system condition, (2) accounting for the availability of thermal generation based on NERC class average five-year outage rate data in transmission security assessments, and (3) incorporating the ability to identify reliability needs through the spreadsheet-based method of calculating transmission security margins (a.k.a. "tipping points") within the Lower Hudson Valley (Zones G-J), New York City (Zone J), and Long Island (Zone K) localities, as well as other enhancements to reliability planning practices. At its June 23, 2022, meeting, the Operating Committee approved revisions to the Reliability Planning Process Manual that reflect these enhancements. For this assessment, the margins are evaluated statewide as well as Lower Hudson Valley, New York City, and Long Island localities.

A BPTF reliability need is identified when the transmission security margin under expected weather conditions in the Lower Hudson Valley, New York City, and Long Island localities are less than zero. Additional details regarding the statewide system margin, impact of extreme weather, or other scenario conditions are provided for informational purposes.

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 6,350 MW of gas generation throughout the NYCA.

Transmission security analysis represents discrete snapshots in time of various credible combinations

[19] https://www.nyiso.com/documents/20142/30451285/08_Reliability_Practices_TPAS-ESPWG_2022-05-05.pdf/.

[20] https://www.nyiso.com/documents/20142/30860639/04%20Response%20to%20SHQuestions%20and%20Feedback%20on%202022%20RNA%202022%20Quarter%202%20STAR.pdf/.

of system conditions. Therefore, the identification of reliability needs only indicate 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 later in this appendix.

Statewide System Margin

The statewide system margin for New York is evaluated under baseline 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 base case 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.[21] Additionally, for the statewide system margin, the NYCA generation includes the Oswego export limit with all lines in service.

As shown in Figure 43, under summer peak baseline expected weather load, normal transfer criteria, the statewide system margin (line-item I) ranges between 1,064 MW in 2025 to -12 MW in 2034 with flexible large loads modeled as offline. When flexible large loads are modeled online during the summer peak day, the statewide system margin (line-item I) ranges between 453 MW in 2025 to –1,192 MW in 2034 as shown in Figure 44. Figure 45 shows the statewide system margin for summer with and without the flexible large loads online for comparison. Figure 46 shows the summer peak statewide system margin through the study horizon for baseline load and the impacts of the higher demand load forecast, SCRs, and with full operating reserve with flexible large loads offline. Figure 47 shows the summer peak statewide system margin through the study horizon for baseline load and the impacts of the higher demand load forecast, SCRs, and with full operating reserve with flexible large loads modeled as online. Figure 48 shows the hourly statewide system margin for the summer peak day for 2025, 2029, and 2034 with flexible large loads online.

As shown in Figure 49, under winter peak baseline expected weather load, normal transfer criteria, the statewide system margin (line-item J) ranges between 4,221 MW in 2025 to -2,283 MW in 2034 with

[21] NERC five-year class average EFORd data

flexible large loads modeled as offline. When flexible large loads are modeled as online during the winter peak day, the statewide system margin (line-item J) ranges between 3,459 MW in 2025 to –3463 MW in 2034 as shown in Figure 50. Figure 51 shows the statewide system margin for winter with and without the flexible large loads online for comparison. Figure 52 shows the winter peak statewide system margin through the study horizon for baseline load and the impacts of SCRs with full operating reserve and flexible large loads modeled as offline. Figure 53 shows the summer peak statewide system margin through the study horizon for baseline load and the impacts of SCRs with full operating reserve and with flexible large loads modeled as online.

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 that the system is unable to securely meet system load under applicable normal transfer criteria, which is observed in the RNA transmission security results as described previously in this appendix.

Figure 43: Summer Peak Statewide System Margin Calculation (Flexible Large Loads Offline)

Line	Item	Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW)									
		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
A	NYCA Generation (1)	38,045	39,069	39,885	39,885	39,885	39,885	39,429	39,429	39,429	39,429
B	NYCA Generation Derates (2)	(6,476)	(7,419)	(8,165)	(8,187)	(8,198)	(8,210)	(8,173)	(8,184)	(8,195)	(8,195)
C	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
D	External Area Interchanges (3)	1,844	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094
E	**Total Resources (A+B+C+D)**	33,413	34,743	34,814	34,791	34,780	34,769	34,351	34,339	34,328	34,328
F	Demand Forecast (5)	(31,039)	(30,902)	(30,930)	(30,950)	(31,160)	(31,400)	(31,700)	(32,140)	(32,650)	(33,030)
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)**	(32,349)	(32,212)	(32,240)	(32,260)	(32,470)	(32,710)	(33,010)	(33,450)	(33,960)	(34,340)
I	**Statewide System Margin (E+H)**	1,064	2,531	2,574	2,531	2,310	2,059	1,341	889	368	(12)
J	Higher Demand Impact	(550)	(1,010)	(1,340)	(1,810)	(2,060)	(2,330)	(2,600)	(2,810)	(2,980)	(3,270)
K	**Higher Demand Statewide System Margin (I+J)**	514	1,521	1,234	721	250	(271)	(1,259)	(1,921)	(2,612)	(3,282)
L	SCRs (6), (7)	989	989	989	989	989	989	989	989	989	989
M	**Statewide System Margin with SCR (K+L)**	1,503	2,511	2,223	1,711	1,239	718	(270)	(931)	(1,623)	(2,293)
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)**	193	1,201	913	401	(71)	(592)	(1,580)	(2,241)	(2,933)	(3,603)

Notes:

1. Reflects the 2024 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 (2024 Gold Book Table I-9a) and solar PV peak reductions (2024 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 August 2023 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Interchanges are based on ERAG MMWG values.
4. For informational purposes.
5. Reflects the 2024 Gold Book Forecast with flexible large loads considered offline.
6. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
7. Includes a derate of 384 MW for SCRs

Figure 44: Summer Peak Statewide System Margin Calculation (Flexible Large Loads Online)

Line	Item	Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW)									
		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
A	NYCA Generation (1)	38,045	39,069	39,885	39,885	39,885	39,885	39,429	39,429	39,429	39,429
B	NYCA Generation Derates (2)	(6,476)	(7,419)	(8,165)	(8,187)	(8,198)	(8,210)	(8,173)	(8,184)	(8,195)	(8,195)
C	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
D	External Area Interchanges (3)	1,844	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094
E	**Total Resources (A+B+C+D)**	33,413	34,743	34,814	34,791	34,780	34,769	34,351	34,339	34,328	34,328
F	Demand Forecast (5)	(31,650)	(31,900)	(32,110)	(32,130)	(32,340)	(32,580)	(32,880)	(33,320)	(33,830)	(34,210)
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)**	(32,960)	(33,210)	(33,420)	(33,440)	(33,650)	(33,890)	(34,190)	(34,630)	(35,140)	(35,520)
I	**Statewide System Margin (E+H)**	453	1,533	1,394	1,351	1,130	879	161	(291)	(812)	(1,192)
J	Higher Demand Impact	(550)	(1,010)	(1,340)	(1,810)	(2,060)	(2,330)	(2,600)	(2,810)	(2,980)	(3,270)
K	**Higher Demand Statewide System Margin (I+J)**	(97)	523	54	(459)	(930)	(1,451)	(2,439)	(3,101)	(3,792)	(4,462)
L	SCRs (6), (7)	989	989	989	989	989	989	989	989	989	989
M	**Statewide System Margin with SCR (K+L)**	892	1,513	1,043	531	59	(462)	(1,450)	(2,111)	(2,803)	(3,473)
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)**	(418)	203	(267)	(779)	(1,251)	(1,772)	(2,760)	(3,421)	(4,113)	(4,783)

Notes:

1. Reflects the 2024 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 (2024 Gold Book Table I-9a) and solar PV peak reductions (2024 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 August 2023 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Interchanges are based on ERAG MMWG values.
4. For informational purposes.
5. Reflects the 2024 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 384 MW for SCRs

Figure 45: Summer Peak Statewide System Margin – Flexible Large Loads Comparison

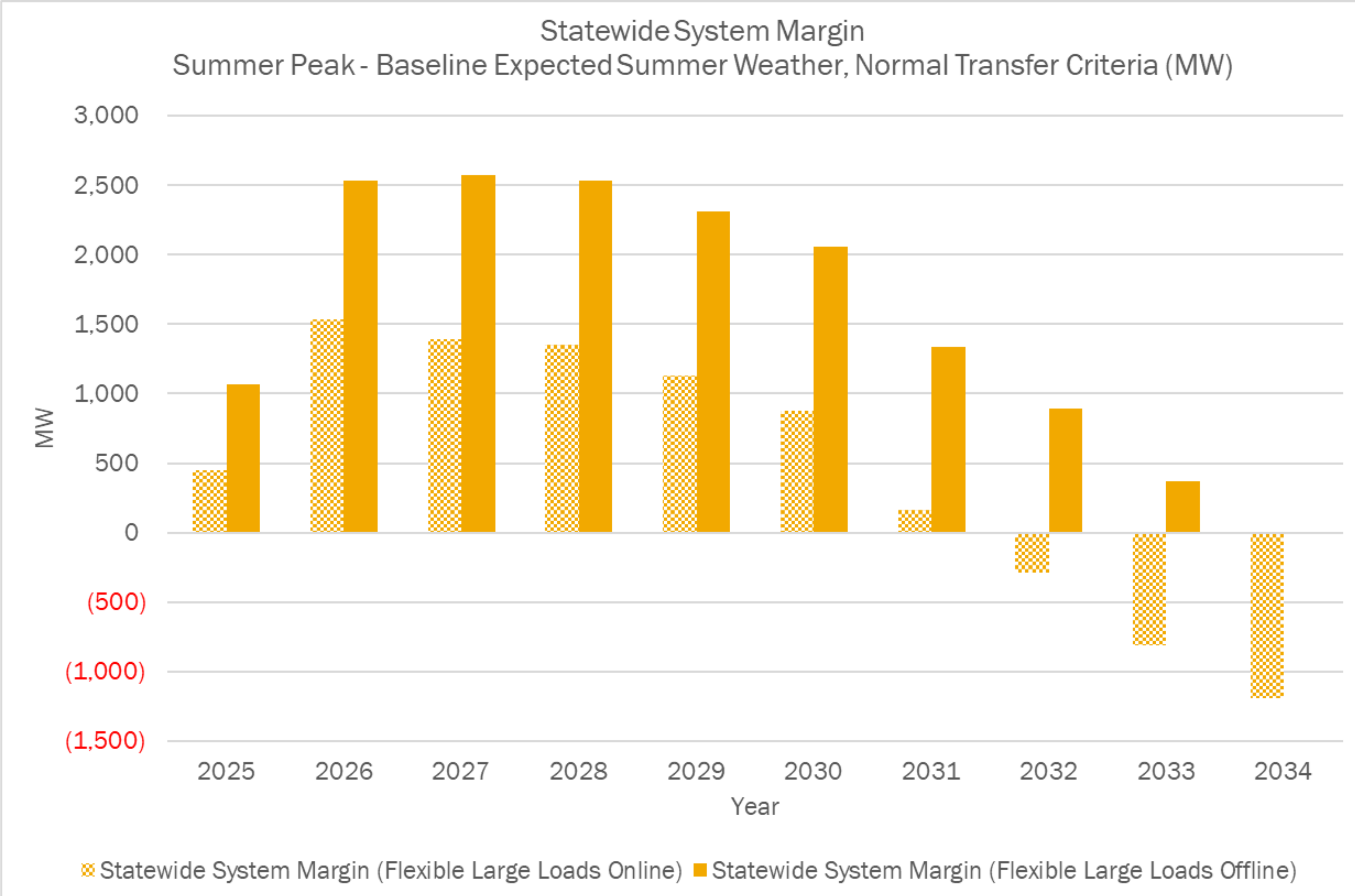


Figure 46: Summer Peak Statewide System Margin Chart (Flexible Large Loads Offline)

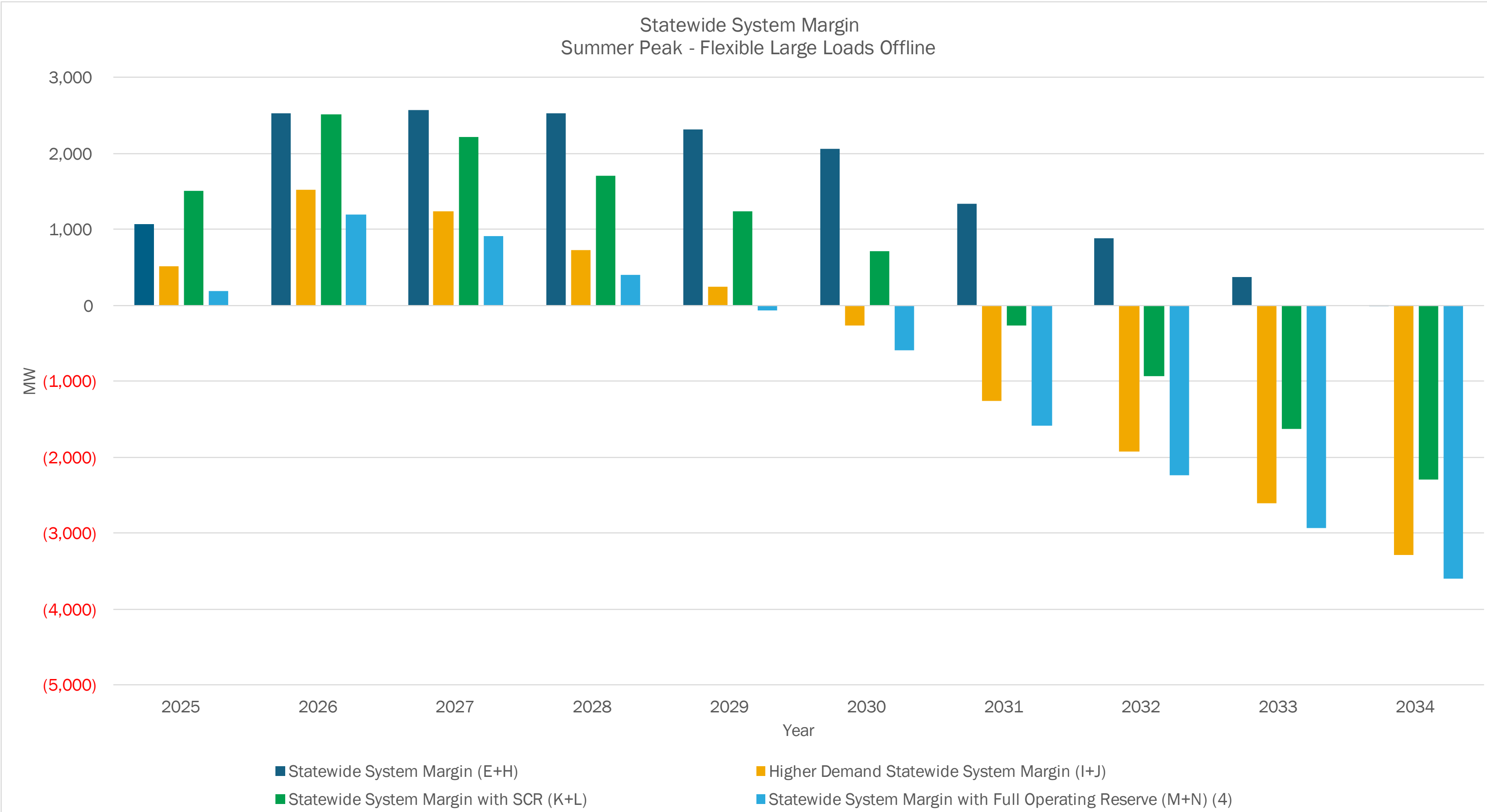


Figure 47: Summer Peak Statewide System Margin Chart (Flexible Large Loads Online)

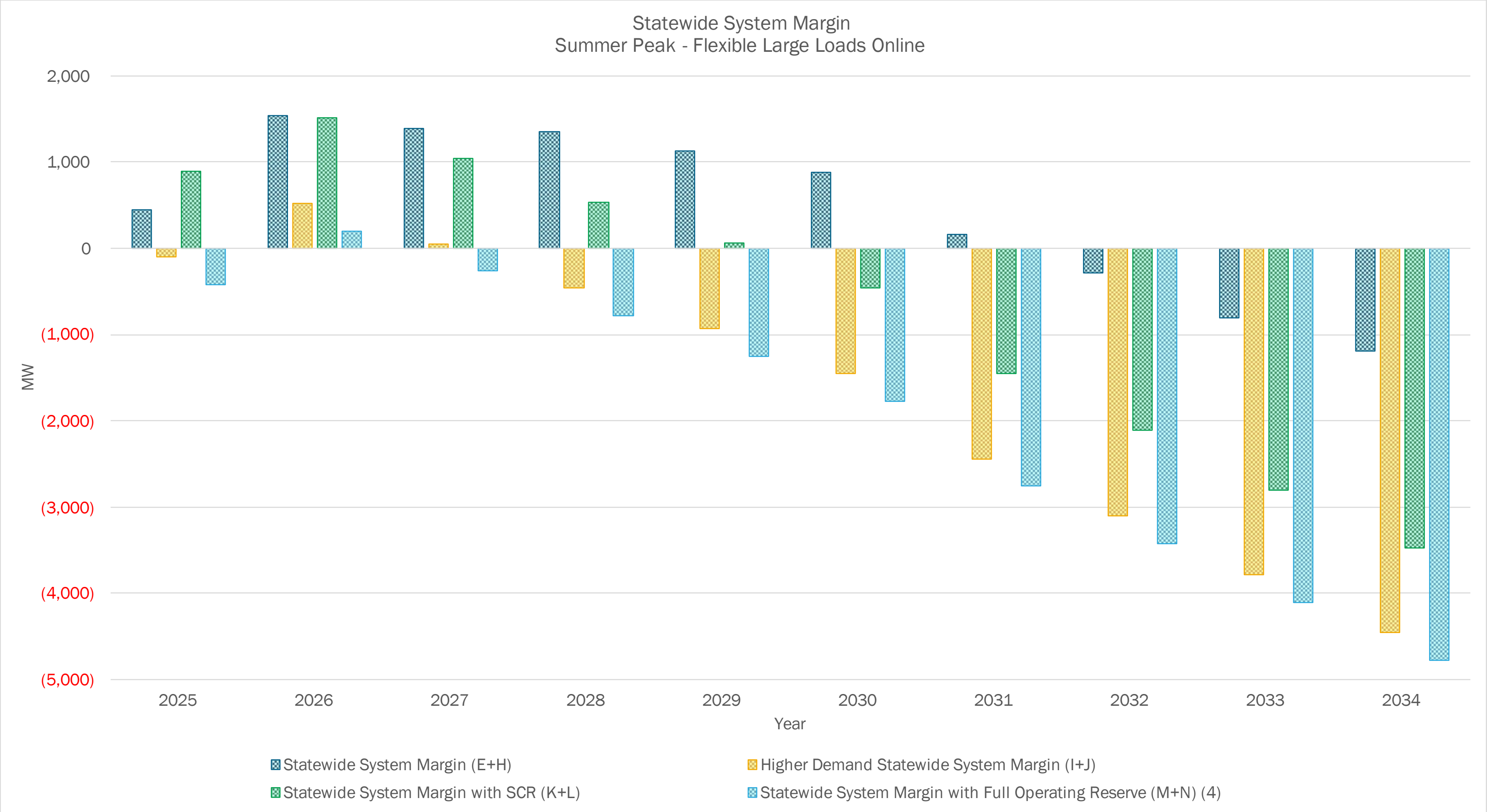


Figure 48: Summer Peak Statewide System Hourly Margin Chart (Flexible Large Loads Online)

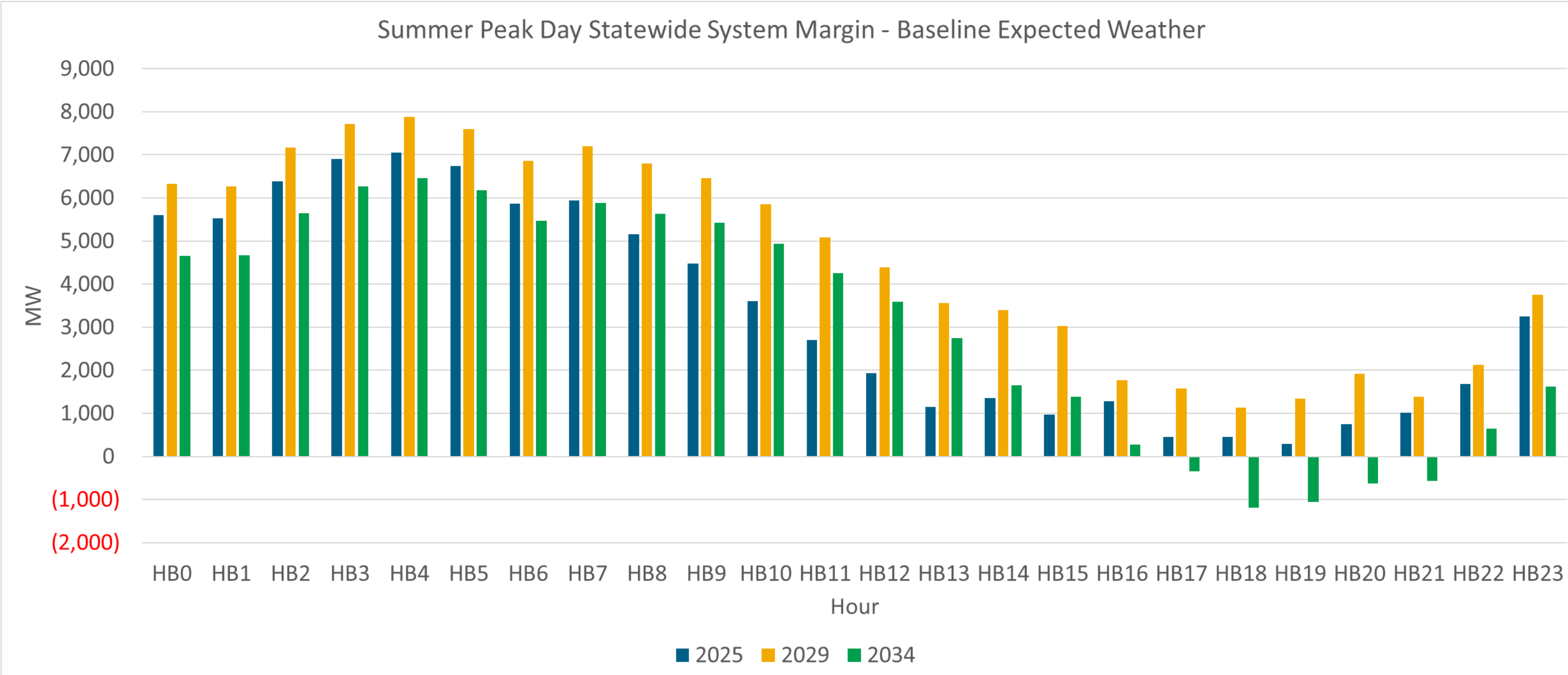


Figure 49: Winter Peak Statewide System Margin Calculation (Flexible Large Loads Offline)

Line	Item	Winter Peak - Baseline Expected Winter Weather, Normal Transfer Criteria (MW)									
		2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
A	NYCA Generation (1)	40,980	42,720	42,720	42,720	42,720	42,262	42,262	42,262	42,262	42,262
B	NYCA Generation Derates (2)	(6,417)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)
C	Unavailability of Non-Firm Gas (6)	(6,319)	(6,319)	(6,319)	(6,319)	(6,319)	(5,861)	(5,861)	(5,861)	(5,861)	(5,861)
D	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
E	External Area Interchanges (3)	735	735	735	735	735	735	735	735	735	735
F	**Total Resources (A+B+C+D+E)**	28,979	29,327	29,327	29,327	29,327	29,327	29,327	29,327	29,327	29,327
G	Demand Forecast (5)	(23,448)	(23,622)	(24,090)	(24,580)	(25,170)	(25,840)	(26,720)	(27,670)	(28,770)	(30,300)
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)**	(24,758)	(24,932)	(25,400)	(25,890)	(26,480)	(27,150)	(28,030)	(28,980)	(30,080)	(31,610)
J	**Statewide System Margin (F+I)**	4,221	4,395	3,927	3,437	2,847	2,177	1,297	347	(753)	(2,283)
K	SCRs (7), (8)	684	684	684	684	684	684	684	684	684	684
L	**Statewide System Margin with SCR (J+K)**	4,905	5,079	4,611	4,121	3,531	2,861	1,981	1,031	(69)	(1,599)
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) (4)**	3,595	3,769	3,301	2,811	2,221	1,551	671	(279)	(1,379)	(2,909)

Notes:

1. Reflects the 2024 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 10% 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 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 August 2023 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Interchanges are based on ERAG MMWG values.
4. For informational purposes.
5. Reflects the 2024 Gold Book Forecast with flexible large loads offline.
6. Includes all gas only units that do not have a firm gas contract. Also includes reductions in units with duct burner capabilities. Duct burner derates on dual fual combined cycle units with non-firm gas account for approximately 500 MW of derated capacity.
7. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
8. Includes a derate of 221 MW for SCRs.

Figure 50: Winter Peak Statewide System Margin Calculation (Flexible Large Loads Online)

Line	Item	Winter Peak - Baseline Expected Winter Weather, Normal Transfer Criteria (MW)									
		2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
A	NYCA Generation (1)	40,980	42,720	42,720	42,720	42,720	42,262	42,262	42,262	42,262	42,262
B	NYCA Generation Derates (2)	(6,417)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)
C	Unavailability of Non-Firm Gas (6)	(6,319)	(6,319)	(6,319)	(6,319)	(6,319)	(5,861)	(5,861)	(5,861)	(5,861)	(5,861)
D	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
E	External Area Interchanges (3)	735	735	735	735	735	735	735	735	735	735
F	**Total Resources (A+B+C+D+E)**	28,979	29,327	29,327	29,327	29,327	29,327	29,327	29,327	29,327	29,327
G	Demand Forecast (5)	(24,210)	(24,730)	(25,270)	(25,760)	(26,350)	(27,020)	(27,900)	(28,850)	(29,950)	(31,480)
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)**	(25,520)	(26,040)	(26,580)	(27,070)	(27,660)	(28,330)	(29,210)	(30,160)	(31,260)	(32,790)
J	**Statewide System Margin (F+I)**	3,459	3,287	2,747	2,257	1,667	997	117	(833)	(1,933)	(3,463)
K	SCRs (7), (8)	684	684	684	684	684	684	684	684	684	684
L	**Statewide System Margin with SCR (J+K)**	4,143	3,971	3,431	2,941	2,351	1,681	801	(149)	(1,249)	(2,779)
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) (4)**	2,833	2,661	2,121	1,631	1,041	371	(509)	(1,459)	(2,559)	(4,089)

Notes:

1. Reflects the 2024 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 10% 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 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 August 2023 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Interchanges are based on ERAG MMWG values.
4. For informational purposes.
5. Reflects the 2024 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. Duct burner derates on dual fual combined cycle units with non-firm gas account for approximately 500 MW of derated capacity.
7. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
8. Includes a derate of 221 MW for SCRs.

Figure 51: Winter Peak Statewide System Margin – Flexible Large Loads Comparison

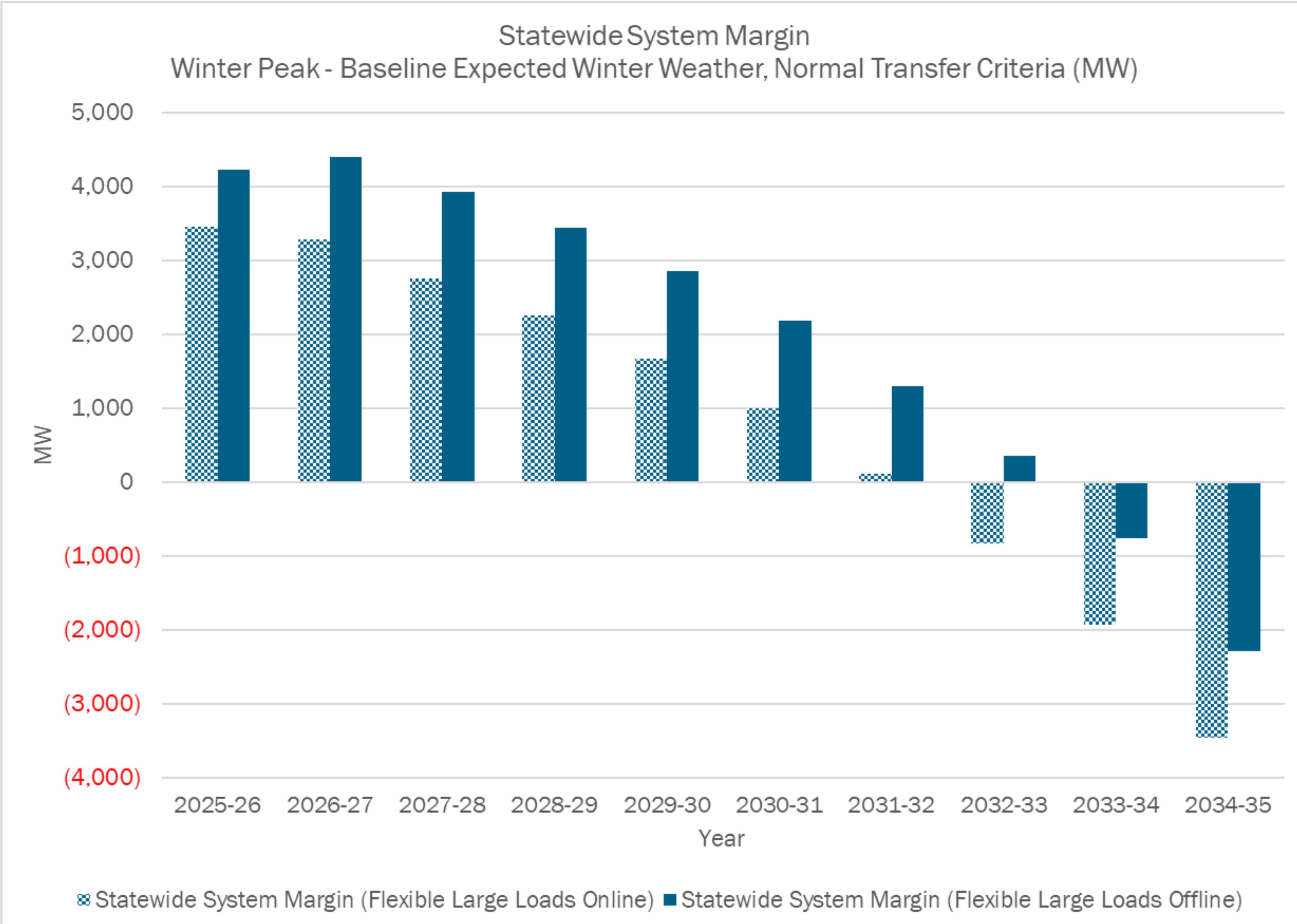


Figure 52: Winter Peak Statewide System Margin Chart (Flexible Large Loads Offline)

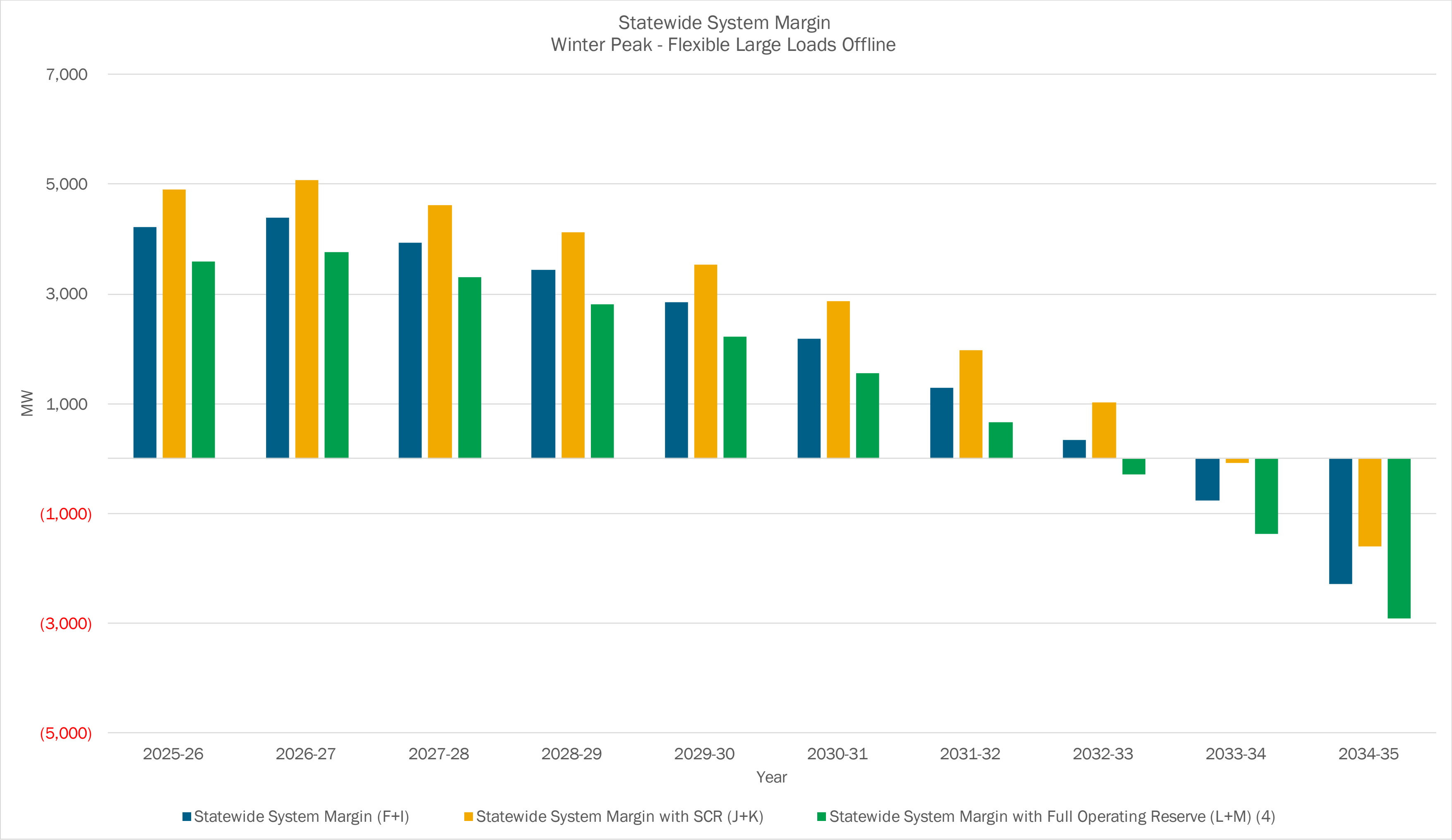
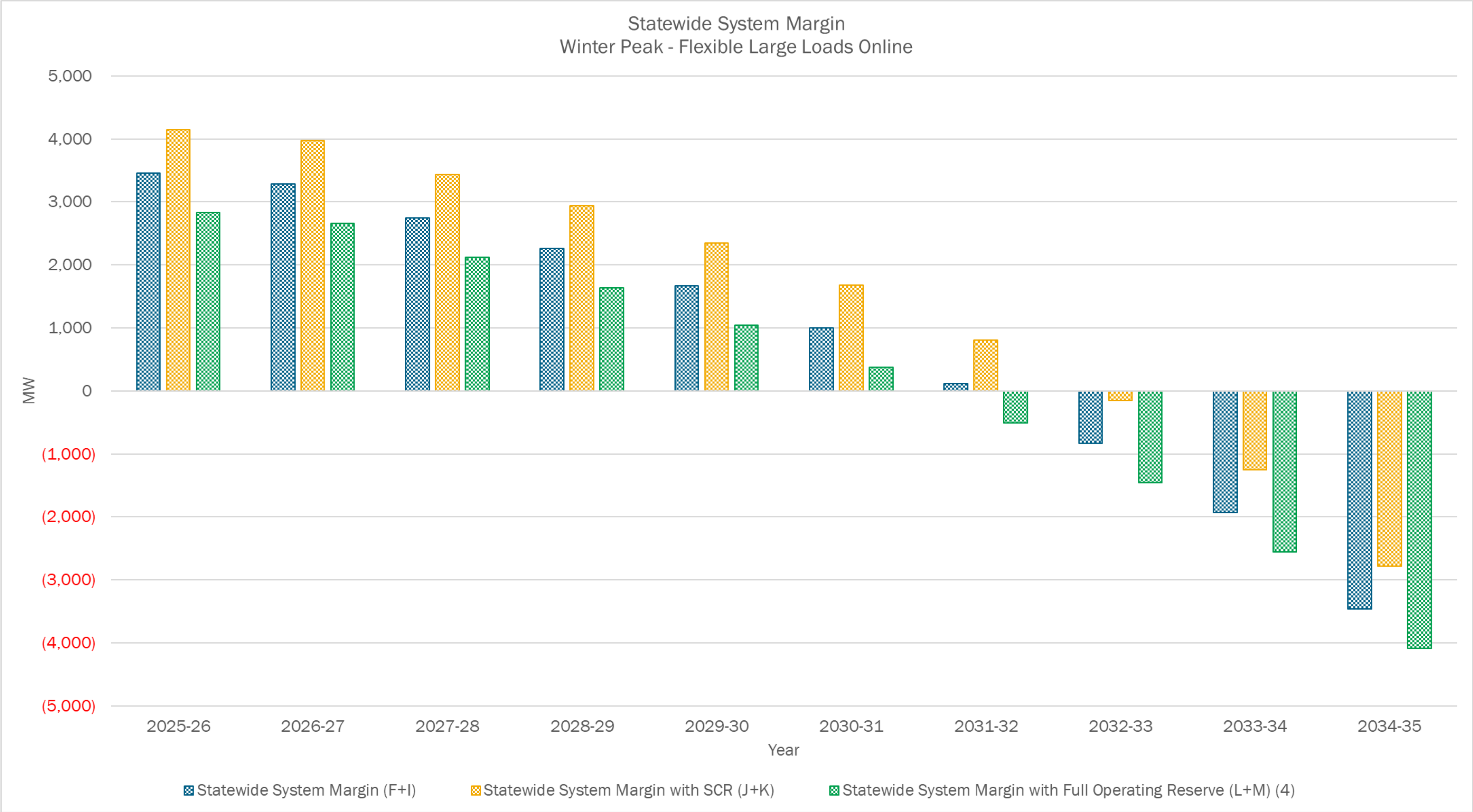


Figure 53: Winter Peak Statewide System Margin Chart (Flexible Large Loads Online)



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 most limiting combination of two non-simultaneous contingency events (N-1-1) to the transmission security margin is determined. As the system changes the limiting contingency combination may also change.

In summer 2025, the limiting contingency combination is the loss of Ravenswood 3 followed by the loss of Pleasant Valley-Wood St. 345 kV (F30/F31). Starting in summer 2026, the limiting contingency combination changes to 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 54 and Figure 55 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. Figure 56 summarizes the margin calculation tables. The Lower Hudson Valley maintains positive transmission security margins throughout the RNA study horizon.

Figure 54: Summer Peak Lower Hudson Valley Margin Calculation

Summer Peak - Baseline Expected Weather, Normal Transfer Criteria (MW)											
e	Item	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
A	G-J Demand Forecast	(15,066)	(15,118)	(15,179)	(15,244)	(15,323)	(15,414)	(15,535)	(15,701)	(15,891)	(16,056)
B	RECO Demand	(419)	(419)	(419)	(419)	(419)	(419)	(419)	(419)	(419)	(419)
C	**Total Demand (A+B)**	(15,485)	(15,537)	(15,598)	(15,663)	(15,742)	(15,833)	(15,954)	(16,120)	(16,310)	(16,475)
D	UPNY-SENY Limit (3)	5,700	4,700	4,700	4,700	4,700	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	47	0	47	47	185	99	44	(33)	(96)
G	**Total SENY AC Import (D+E+F)**	5,736	4,736	4,689	4,736	4,736	4,674	4,588	4,533	4,456	4,393
H	Loss of Source Contingency	(987)	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(10,737)	(10,801)	(10,909)	(10,927)	(11,006)	(11,159)	(11,366)	(11,587)	(11,854)	(12,082)
J	G-J Generation (1)	13,054	13,054	13,870	13,870	13,870	13,870	13,460	13,460	13,460	13,460
K	G-J Generation Derates (2)	(1,225)	(1,228)	(1,965)	(1,967)	(1,970)	(1,971)	(1,930)	(1,931)	(1,931)	(1,933)
L	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports	315	1,565	1,565	1,565	1,565	1,565	1,565	1,565	1,565	1,565
N	**Total Resources Available (J+K+L+M)**	12,145	13,392	13,470	13,469	13,466	13,464	13,096	13,094	13,094	13,093
O	**Transmission Security Margin (I+N)**	1,408	2,590	2,561	2,542	2,460	2,305	1,730	1,507	1,240	1,011
P	Higher Demand Impact	(215)	(334)	(454)	(583)	(711)	(849)	(968)	(1,071)	(1,159)	(1,278)
Q	**Higher Demand Transmission Security Margin (O+P)**	1,193	2,256	2,107	1,959	1,749	1,456	762	436	81	(267)

Notes:

1. Reflects the 2024 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 (2024 Gold Book Table I-9a) and solar PV peak reductions (2024 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 August 2023 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Limits for 2025 are based on the summer peak 2025 representations evaluated in the post-2020 RNA updates. 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 the summer peak 2034 representations evaluated in the 2024 RNA.

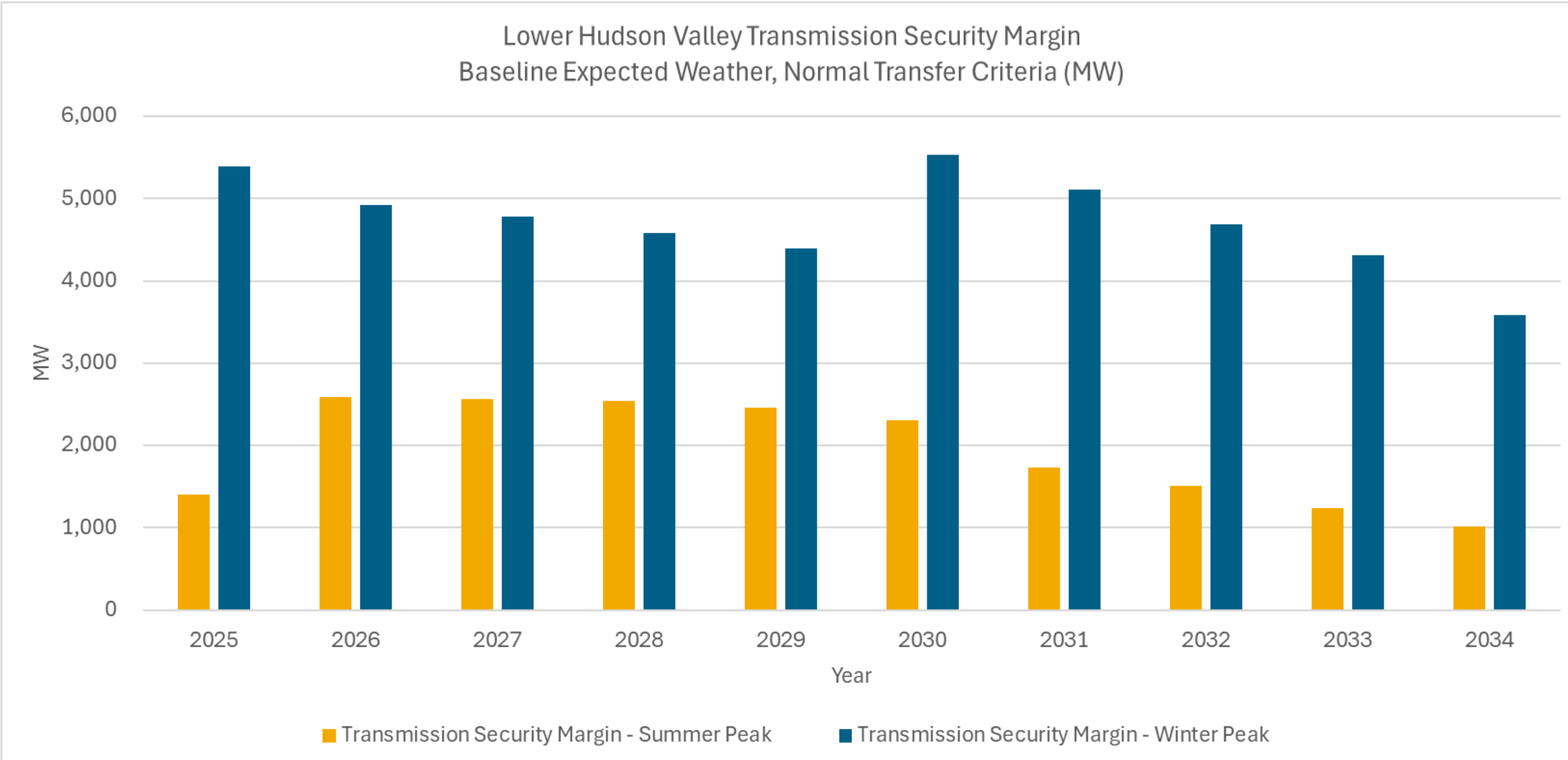
Figure 55: Winter Peak Lower Hudson Valley Margin Calculation

Winter Peak - Baseline Expected Weather, Normal Transfer Criteria (MW)											
e	Item	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
A	G-J Demand Forecast	(10,327)	(10,446)	(10,587)	(10,765)	(10,962)	(11,185)	(11,603)	(12,029)	(12,398)	(13,127)
B	RECO Demand	(231)	(231)	(231)	(243)	(243)	(243)	(243)	(243)	(248)	(248)
C	**Total Demand (A+B)**	(10,558)	(10,677)	(10,818)	(11,008)	(11,205)	(11,428)	(11,846)	(12,272)	(12,646)	(13,375)
D	UPNY-SENY Limit (3)	5,700	5,300	5,300	5,300	5,300	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	47	1,013	1,013	1,013	1,013	1,013
G	**Total SENY AC Import (D+E+F)**	5,736	5,336	5,336	5,336	5,336	6,702	6,702	6,702	6,702	6,702
H	Loss of Source Contingency	(968)	(1,090)	(1,090)	(1,090)	(1,090)	(1,090)	(1,090)	(1,090)	(1,090)	(1,090)
I	**Resource Need (C+G+H)**	(5,790)	(6,431)	(6,572)	(6,762)	(6,959)	(5,816)	(6,234)	(6,660)	(7,034)	(7,763)
J	G-J Generation (1)	14,530	15,346	15,346	15,346	15,346	14,934	14,934	14,934	14,934	14,934
K	G-J Generation Derates (2)	(1,166)	(1,819)	(1,819)	(1,819)	(1,819)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)
L	Shortage of Gas Fuel Supply (4)	(2,495)	(2,495)	(2,495)	(2,495)	(2,495)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)
M	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
N	Net ICAP External Imports	315	315	315	315	315	315	315	315	315	315
O	**Total Resources Available (J+K+L+M+N)**	11,184	11,347	11,347	11,347	11,347	11,348	11,348	11,348	11,348	11,348
P	**Transmission Security Margin (I+O)**	5,394	4,916	4,775	4,585	4,388	5,532	5,114	4,688	4,314	3,585

Notes:

1. Reflects the 2024 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 10% 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 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 August 2023
3. Limits for 2025-26 are based on the summer peak 2025 representations evaluated in the post-2020 RNA updates (as a conservative winter peak assumption these limits utilize the summer values). Limits for 2026-27 through 2029-30 are based on winter peak 2029-30 representations evaluated in the 2024 RNA. Limits for 2030-31 through 2034-35 are based on the winter peak 2034-35 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. Also includes reductions in units with duct burner capabilities.

Figure 56: Lower Hudson Valley Margin Chart – Summer and Winter



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).[22] 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.

In summer 2025, the most limiting N-1-1-0 contingency combination is the loss of Ravenswood 3 followed by the loss of Mott Haven – Rainey 345 kV (Q12). Starting in summer 2026 and continuing throughout the remainder of the study period, the limiting contingency combination changes to the loss of the CHPE HVDC cable followed by the loss of Ravenswood 3. In winter 2025-2026 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 in December 2025, it is scheduled at 0 MW for the winter seasons.

This assessment recognizes that there is uncertainty in the demand forecast driven by uncertainties in key assumptions, such as population and economic growth, energy efficiency, the installation of BtM renewable energy resources, and electric vehicle adoption and charging patterns. These risks are considered in the transmission security margin calculations by incorporating the lower and higher forecast bounds as a range of conditions during expected weather, as shown in Figure 57. Baseline demand lies approximately in the middle of the uncertainty band and is used for the baseline margin (line-item L) in Figure 58. The upper range of this forecast band is used for the higher demand margin (line-item N). Heatwave conditions, also shown in Figure 57 are separate, single forecasts, which are discussed as risk scenarios below.

Figure 58 shows the calculation of the New York City transmission security margin at the statewide coincident peak hour for baseline expected weather and expected load conditions for summer with normal transfer criteria. The New York City transmission security margin coincident with the statewide system peak ranges from 489 MW in summer 2026, increases to 580 in summer 2030, decreases to -17 MW by

[22] Con Edison, TP-7100-18 Transmission Planning Criteria, dated August 2019.

summer 2033, and decreases further to -97 MW by summer 2034 (line-item L). Figure 59 plots the summer margin results under baseline and high forecast demand levels. As shown in Figure 60, major drivers of the New York City margin results throughout the study period include the addition of the CHPE project, planned removal of certain NYPA generators by the summer of 2031, moderate increases in the baseline demand forecast, and significant forecast uncertainty in later study years.

All figures below also show a margin deficiency in 2025. This reflects the margin result without the capacity provided by certain units that are temporarily retained to continue to operate past May 2025 under the Peaker Rule to address a Near-Term Reliability Need identified in the 2023 Q2 STAR. With the retention of these generators, the New York City locality has a positive transmission security margin in 2025 under expected summer weather peak demand periods. Summer 2026 margins are positive without these retained generators due to the CHPE project's planned in-service date.

As transmission security analysis represents discrete snapshots in time of various credible combinations of system conditions, when reliability needs are identified only the magnitude of the need can be identified under those system conditions. Additional details are required to fully describe the nature of the need, such as evaluating the hourly load shape and its impact on the need. To describe the nature of the New York City transmission security margin, load shapes are developed for the Zone J component of the statewide load shape. For this assessment, load shapes are not developed past 2034 and are only developed for the summer conditions.

Utilizing the load shape for the baseline expected weather summer peak day, the New York City transmission security margin for each hour is shown in Figure 61 for the 2033 summer peak day and Figure 62 for the 2034 summer peak day for the baseline forecast and high demand forecast. The hourly margins are created by using the load curve forecast for each hour in the margin calculation (Figure 58 line-item A) with additional adjustments to account for the appropriate derate for solar generation and energy limited resources in each hour (Figure 58 line-item H). All other values in the margin calculation are held constant. Hourly margin data for all years within the study period is tabulated in Figure 63.

Under the baseline forecast for coincident summer peak demand, the New York City transmission security margin would be deficient starting in 2033 with the deficiency of 17 MW for one hour and growing to 97 MW for three hours in 2034. Accounting for uncertainties in key demand forecast assumptions, the higher bound of expected demand under baseline weather conditions (95 degrees Fahrenheit) in 2034 results in a deficiency of up to 1,137 MW over 11 hours.

Several scenarios are analyzed that represent generic potential solutions to mitigate the summer margin violations noted above. Figure 65 provides a summary of expected margins under these mitigation scenarios, while Figure 64 tabulates all scenario margin results. Each mitigation scenario involves increasing generation available inside the New York City locality or decreasing demand. Transmission capacity into New York City remains consistent with the baseline margin assumptions in these scenarios. Additional generation resources in New York City are modeled in the Additional Queue Projects and Offshore Wind scenarios. Load flexibility, where a portion of the forecast peak load is responsive to price or operations signals and temporarily disconnects under peak conditions, is modeled in the Demand Response scenario as the equivalent of 250 MW of load reduction in New York City. Detailed definitions and discussion of these scenarios are located in the "Scenarios" section of the 2024 RNA report. All three potential mitigation scenarios resolve the summer peak margin violations for the peak hour based on the quantity of additional resources modeled and positively affects the transmission security margin. The results should not be interpreted as informing which resources are more effective at addressing the transmission security deficiency.

Certain scenarios of extreme weather or adverse system changes present risks of worsened summer transmission security margins in New York City. Figure 66 provides a summary of expected margins under these risk scenarios. Extreme weather scenarios include a 1-in-10-year heatwave and a 1-in-100-year heatwave, resulting in load levels higher than the baseline summer peak forecast. Under a 1-in-10-year heatwave, positive margins are maintained until the summer of 2031. Under a 1-in-100-year heatwave, margins are negative throughout the study period. Other risk scenarios examine the impact of adverse changes to the planned system. Delay of the CHPE HVDC transmission project would remove approximately 1,250 MW from the New York City margin, causing negative margins throughout the study period if delayed indefinitely, or until a hypothetical delayed in-service date. The Additional Generation Retirements scenario shows the impact of the hypothetical retirement of the largest generation plant in Zone J which includes Ravenswood 1, 2 and 3 and approximately 1,730 MW of summer capability. As a result, negative margins are observed throughout the study period. Detailed definitions and discussion of the CHPE Delay and Additional Generation Retirements scenarios are located in the "Scenarios" section of the 2024 RNA report.

In addition to the risk scenarios noted above, the retirement of certain key generators or groups of generators may result in a worse transmission security margin. Considering the summer baseline peak load transmission security margin, several different single generator outages (or combinations of generator outages) including whole plant outages, within New York City beyond those included in the RNA Base Case assumptions could result in a degraded transmission security margin. Details of specific generator outage impacts on the New York City transmission security margin are shown in Figure 74 of Appendix G. Note that margin numbers in Figure 74 are based on a high demand forecast rather than a baseline forecast.

Figure 67 shows the New York City transmission security margin calculation under winter peak baseline expected weather load conditions with normal transfer criteria. For winter peak, the margin is sufficient for all years and ranges from 2,629 MW in winter 2025-2026 to 2,319 in winter 2034-35 (line-item L). Results are presented graphically in Figure 68.

Figure 57: New York City Demand Forecasts and Forecast Uncertainty

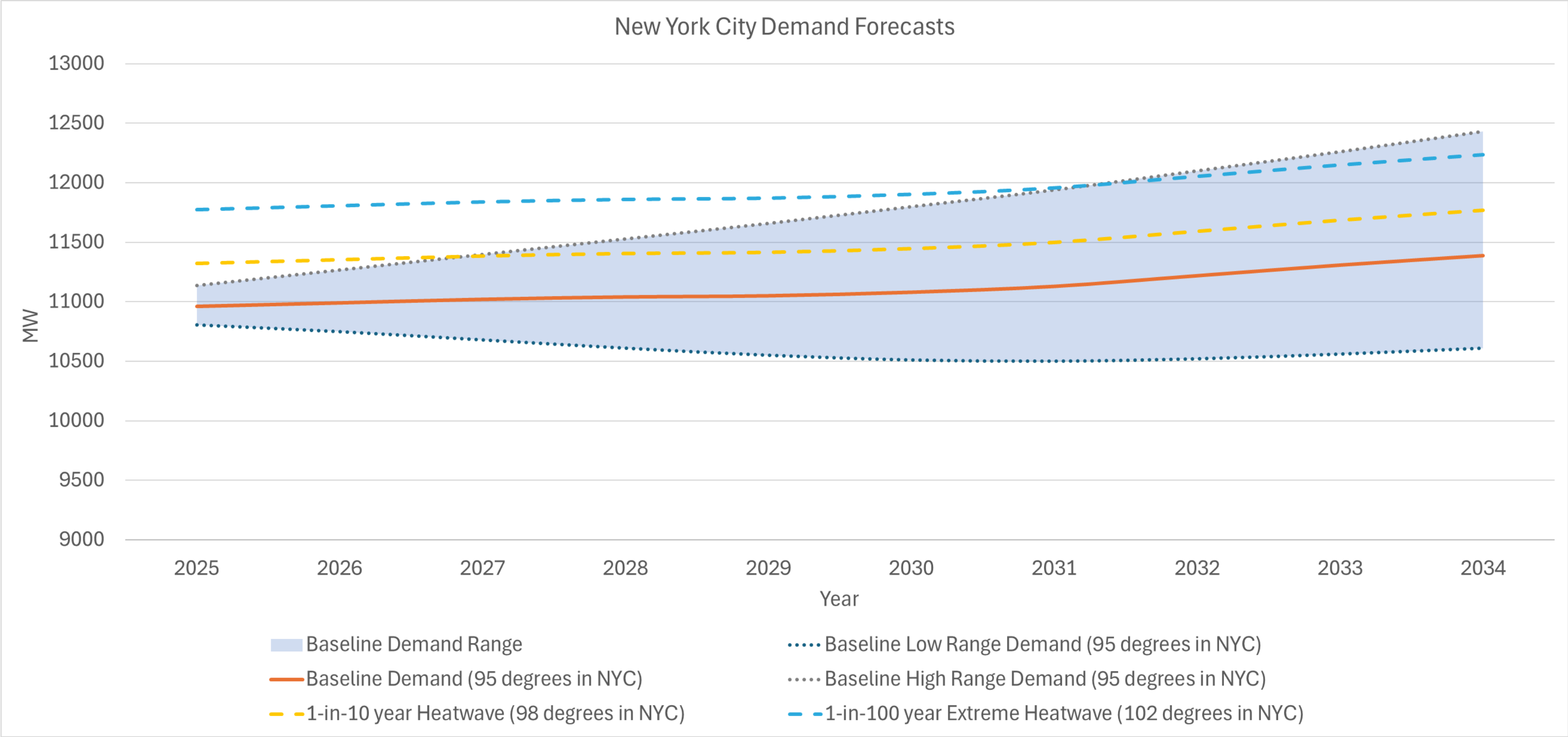


Figure 58: New York City Transmission Security Margin Calculation – Summer Peak

Summer Peak - Baseline Expected Weather, Normal Transfer Criteria (MW)											
Line	Item	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
A	**Zone J Demand Forecast (4)**	(10,960)	(10,990)	(11,020)	(11,040)	(11,050)	(11,080)	(11,130)	(11,220)	(11,310)	(11,390)
B	I+K to J (3)	3,900	4,700	4,700	4,700	4,700	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)**	3,889	4,689	4,689	4,689	4,689	4,789	4,789	4,789	4,789	4,789
E	Loss of Source Contingency	(987)	(2,237)	(2,237)	(2,237)	(2,237)	(2,237)	(2,237)	(2,237)	(2,237)	(2,237)
F	**Resource Need (A+D+E)**	(8,058)	(8,538)	(8,568)	(8,588)	(8,598)	(8,528)	(8,578)	(8,668)	(8,758)	(8,838)
G	J Generation (1)	8,104	8,104	8,920	8,920	8,920	8,920	8,510	8,510	8,510	8,510
H	J Generation Derates (2)	(642)	(642)	(1,377)	(1,377)	(1,377)	(1,377)	(1,334)	(1,334)	(1,334)	(1,334)
I	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
J	Net ICAP External Imports	315	1,565	1,565	1,565	1,565	1,565	1,565	1,565	1,565	1,565
K	**Total Resources Available (G+H+I+J)**	7,777	9,027	9,109	9,109	9,109	9,109	8,741	8,741	8,741	8,741
L	**Baseline Transmission Security Margin (F+K)**	(281)	489	540	520	510	580	163	73	(17)	(97)
M	Higher Demand Impact	(180)	(280)	(380)	(490)	(610)	(720)	(810)	(880)	(950)	(1,040)
N	**Higher Demand Transmission Security Margin (L+M)**	(461)	209	160	30	(100)	(140)	(647)	(807)	(967)	(1,137)

Notes:

1. Reflects the 2024 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 (2024 Gold Book Table I-9a) and solar PV peak reductions (2024 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 August 2023 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. The limit 2025 is based on the summer peak 2025 representations evaluated in the post-2020 RNA updates. 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. Reflects the 2024 Gold Book Forecast.

Figure 59: New York City Transmission Security Margin Results – Summer Peak

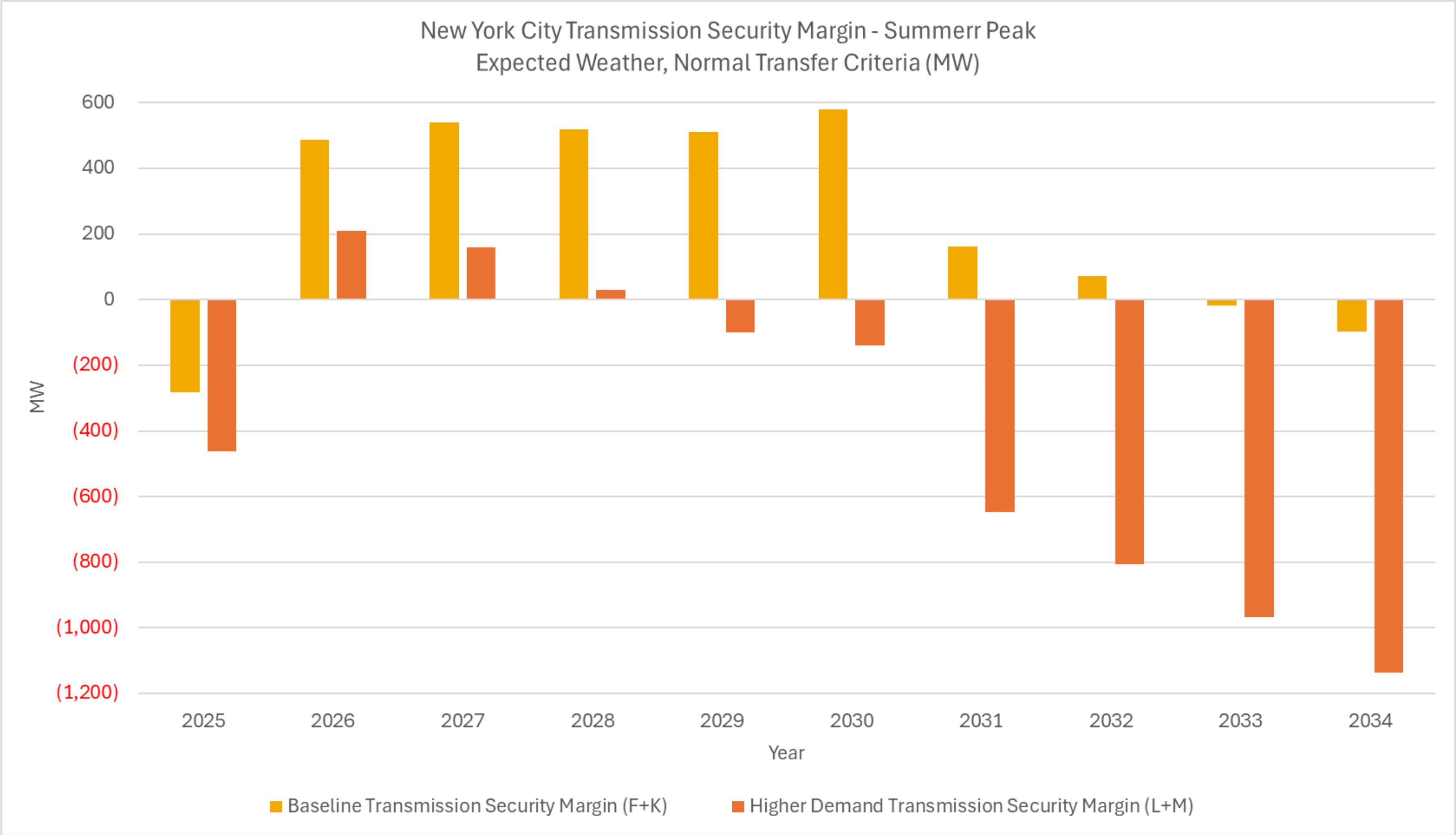


Figure 60: New York City Transmission Security Margin Summary – Summer Peak

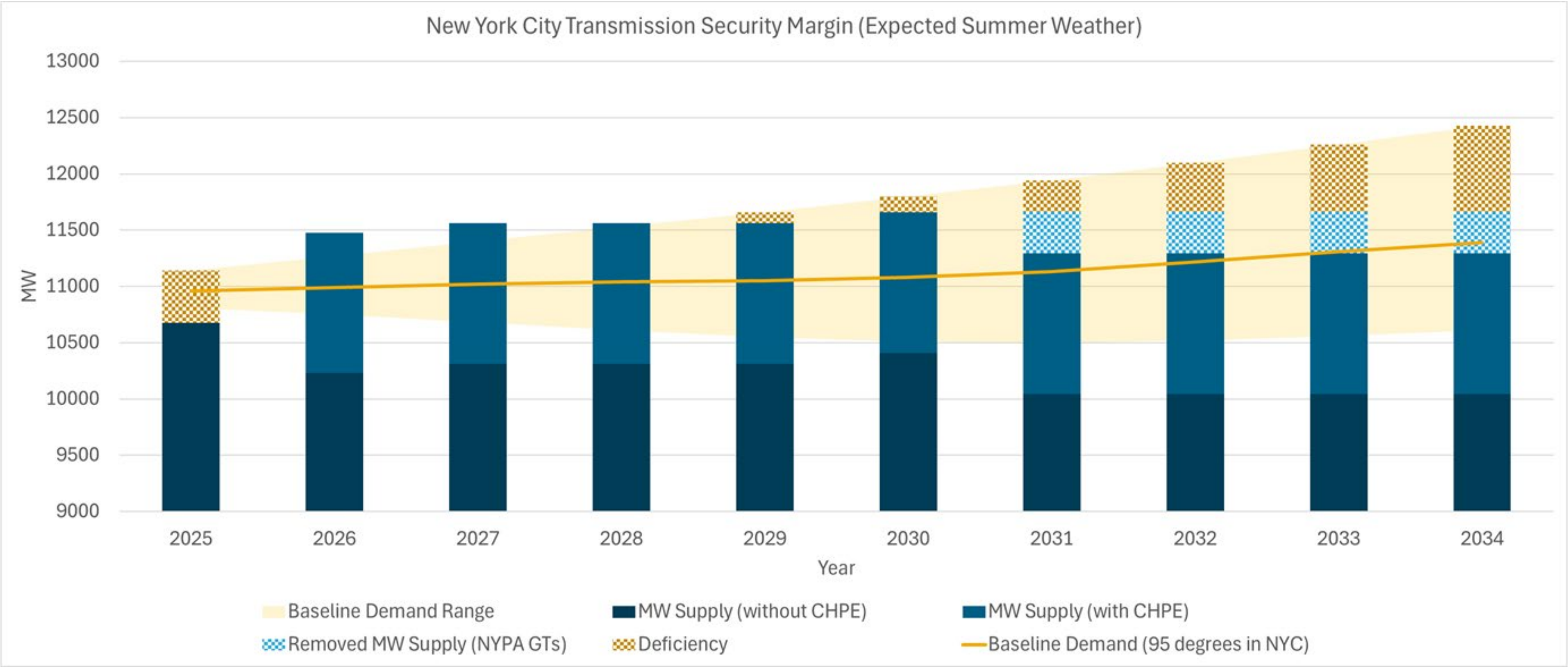


Figure 61: New York City Hourly Transmission Security Margin – 2033 Summer Peak Day

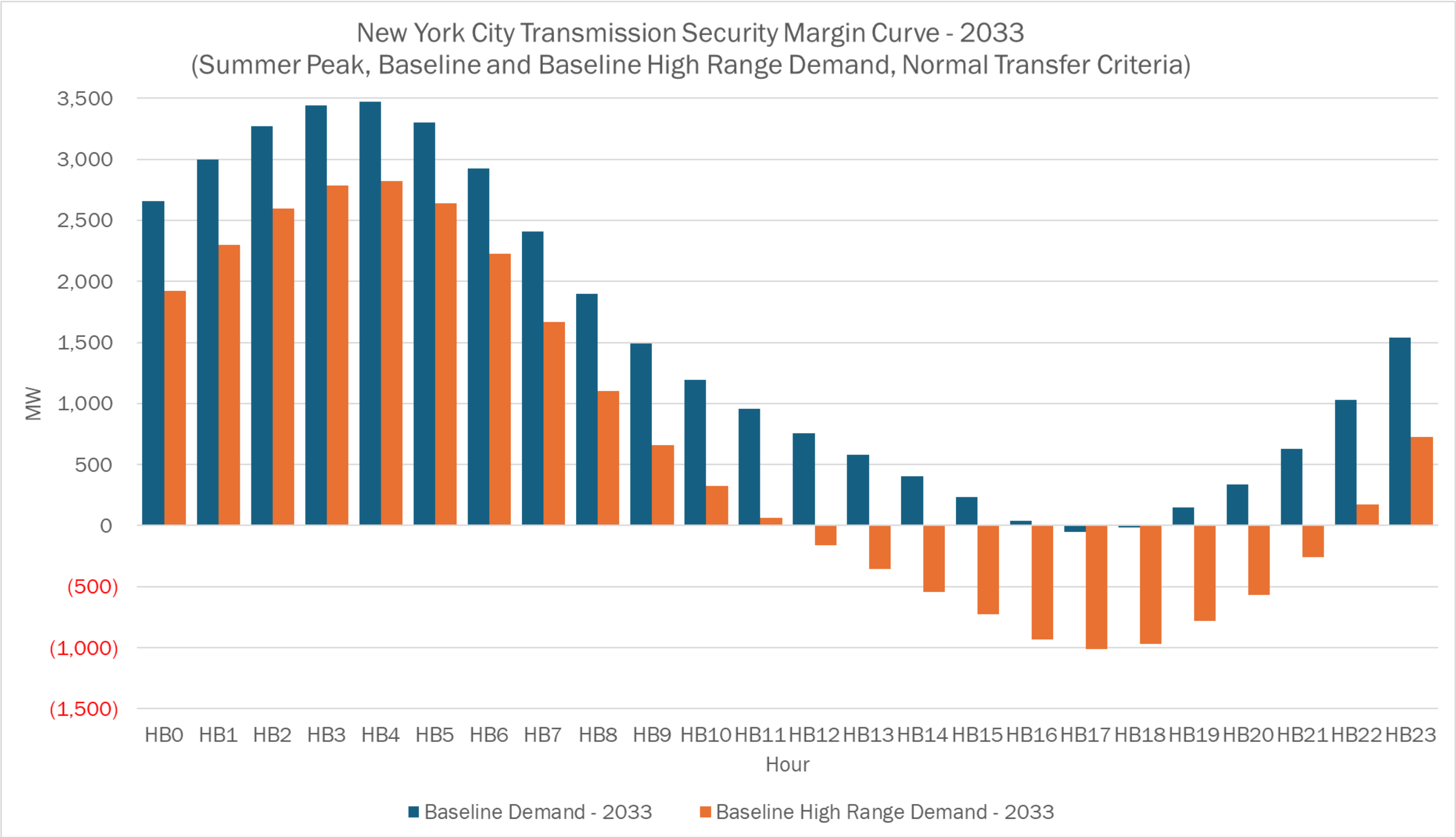
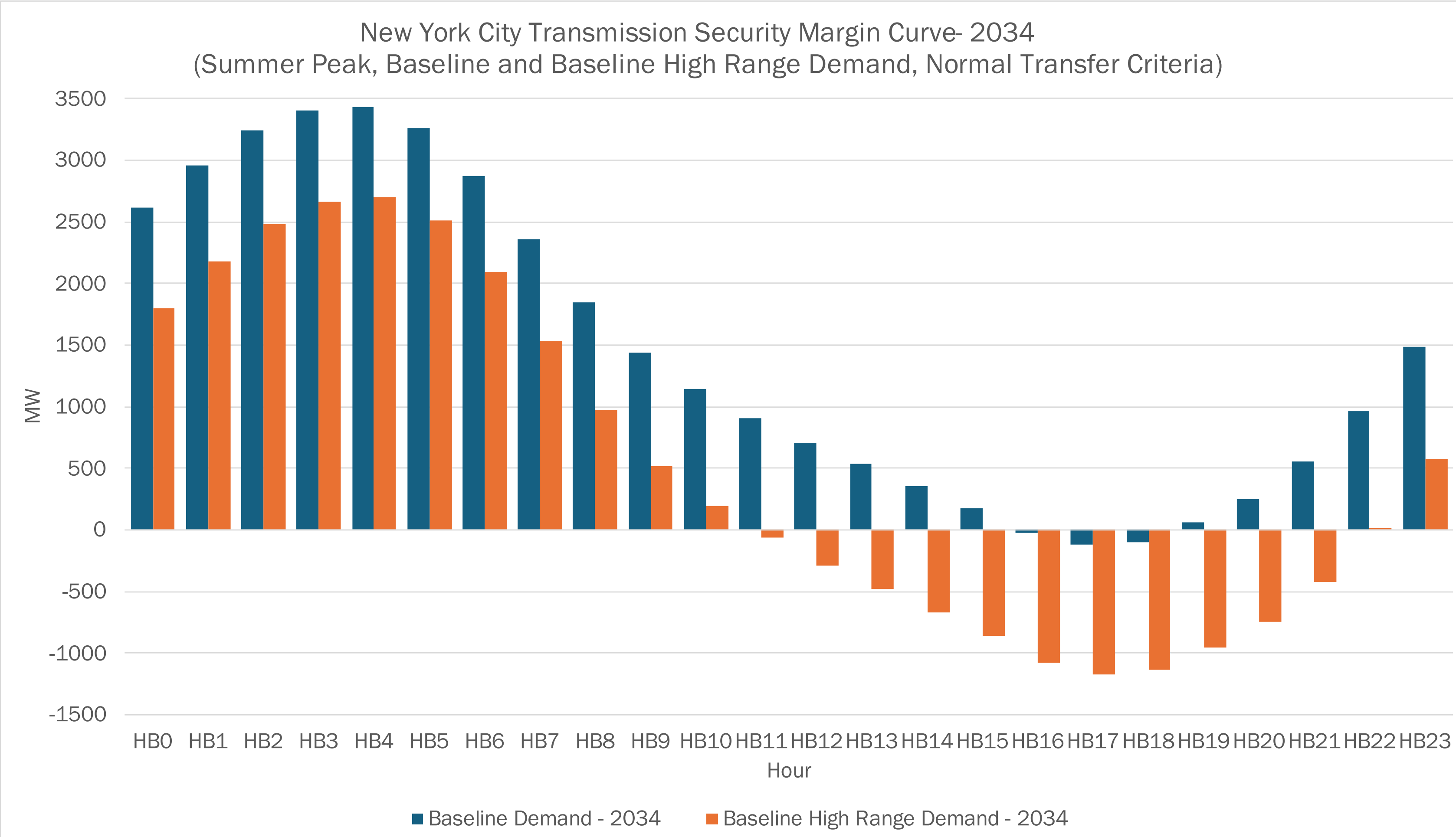


Figure 62: New York City Hourly Transmission Security Margin – 2034 Summer Peak Day



New York ISO

Figure 63: New York City Hourly Transmission Security Margin – 2025 through 2034 Summer Peak Days

Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW)											Summer Peak - Higher Demand with Expected Summer Weather, Normal Transfer Criteria (MW)										
J Transmission Security Margin											J Transmission Security Margin										
Hour	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Hour	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
HB0	2,356	3,022	3,070	3,074	3,074	3,169	2,780	2,719	2,658	2,618	HB0	2,259	2,829	2,787	2,677	2,597	2,598	2,143	2,038	1,924	1,803
HB1	2,694	3,360	3,408	3,414	3,415	3,509	3,121	3,060	2,998	2,961	HB1	2,605	3,180	3,138	3,031	2,957	2,962	2,509	2,409	2,297	2,177
HB2	2,967	3,634	3,682	3,689	3,690	3,784	3,396	3,336	3,274	3,237	HB2	2,884	3,464	3,422	3,317	3,247	3,256	2,806	2,708	2,598	2,480
HB3	3,142	3,810	3,856	3,863	3,863	3,956	3,568	3,507	3,443	3,405	HB3	3,063	3,646	3,605	3,499	3,431	3,441	2,991	2,895	2,785	2,666
HB4	3,184	3,852	3,898	3,903	3,902	3,992	3,602	3,538	3,472	3,431	HB4	3,107	3,690	3,648	3,543	3,473	3,482	3,030	2,932	2,819	2,698
HB5	3,036	3,703	3,747	3,752	3,749	3,836	3,442	3,375	3,304	3,258	HB5	2,955	3,536	3,494	3,385	3,314	3,319	2,862	2,758	2,641	2,513
HB6	2,655	3,322	3,371	3,375	3,373	3,460	3,066	2,996	2,924	2,874	HB6	2,561	3,140	3,099	2,992	2,915	2,917	2,457	2,349	2,227	2,095
HB7	2,123	2,795	2,850	2,857	2,858	2,947	2,553	2,483	2,410	2,358	HB7	2,009	2,587	2,552	2,447	2,368	2,367	1,904	1,791	1,666	1,530
HB8	1,572	2,250	2,316	2,328	2,335	2,428	2,038	1,969	1,899	1,847	HB8	1,433	2,014	1,987	1,888	1,810	1,809	1,344	1,231	1,105	969
HB9	1,124	1,809	1,884	1,901	1,914	2,012	1,623	1,558	1,490	1,437	HB9	963	1,549	1,529	1,436	1,359	1,359	896	780	656	519
HB10	784	1,476	1,559	1,580	1,599	1,702	1,316	1,254	1,191	1,139	HB10	607	1,195	1,184	1,096	1,020	1,023	562	446	323	191
HB11	518	1,215	1,303	1,326	1,351	1,457	1,075	1,017	958	909	HB11	328	919	913	828	751	758	298	184	65	(65)
HB12	295	993	1,086	1,109	1,138	1,246	867	812	757	711	HB12	97	687	683	601	522	531	71	(42)	(160)	(286)
HB13	117	815	907	929	959	1,068	688	635	581	536	HB13	(86)	502	498	414	332	339	(121)	(236)	(353)	(480)
HB14	(34)	660	750	768	795	901	518	462	405	357	HB14	(237)	345	337	250	162	164	(301)	(421)	(542)	(673)
HB15	(156)	531	615	627	646	747	357	295	233	179	HB15	(355)	218	204	108	13	5	(467)	(596)	(724)	(862)
HB16	(278)	398	473	474	485	577	178	107	37	(26)	HB16	(470)	92	66	(40)	(149)	(167)	(650)	(791)	(930)	(1,078)
HB17	(281)	384	447	437	438	518	110	30	(51)	(122)	HB17	(461)	88	51	(67)	(188)	(217)	(714)	(865)	(1,014)	(1,174)
HB18	(165)	489	540	520	510	580	163	73	(17)	(97)	HB18	(330)	209	160	30	(100)	(140)	(647)	(807)	(967)	(1,137)
HB19	54	702	744	717	700	763	340	245	148	64	HB19	(98)	437	381	243	108	63	(450)	(615)	(779)	(956)
HB20	260	905	943	915	895	958	534	437	340	256	HB20	116	651	592	452	317	271	(240)	(404)	(569)	(745)
HB21	521	1,168	1,207	1,183	1,166	1,234	815	724	631	554	HB21	386	922	864	728	600	561	58	(98)	(256)	(425)
HB22	879	1,528	1,569	1,553	1,540	1,613	1,201	1,117	1,031	963	HB22	752	1,294	1,238	1,107	991	960	466	321	174	15
HB23	1,349	2,002	2,044	2,035	2,025	2,104	1,699	1,621	1,541	1,482	HB23	1,233	1,782	1,729	1,604	1,500	1,478	995	863	724	575

Figure 64: New York City Transmission Security Margin Scenarios

	New York City Transmission Security Margin Scenarios	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
-	Base Case with Baseline Forecast	(281)	489	540	520	510	580	163	73	(17)	(97)
1	Additional Queue Projects Scenario	(175)	704	1506	1486	1476	1546	1129	1039	949	869
2	Additional Offshore Wind Scenario	(281)	489	540	520	597	753	422	419	415	421
3	Demand Response Scenario	(43)	727	778	758	748	818	401	311	221	141
4	High Demand Forecast	(461)	209	160	30	(100)	(140)	(647)	(807)	(967)	(1137)
5	CHPE Delay Scenario	(281)	(610)	(558)	(578)	(588)	(120)	(537)	(627)	(717)	(797)
6	Additional Generation Retirements Scenario	(1642)	(872)	(820)	(840)	(850)	(780)	(1198)	(1288)	(1378)	(1458)
7	1-in-10 Year Heatwave	(489)	280	331	310	300	369	(51)	(144)	(237)	(320)
8	1-in-100 Year Heatwave	(1002)	(235)	(185)	(206)	(217)	(149)	(571)	(668)	(764)	(850)

Scenario Descriptions:

1. This scenario adds roughly 5,000 MW of additional generation projects, which have accepted their Class Year cost allocations but have not yet meet the Base Case inclusion rules. The New York City transmission security margin would be sufficient in the summer of year 10 of the study period. However, this conclusion assumes that the Zone J battery storage in this scenario is available to inject throughout the duration of the deficiency.

2. This scenario models a total of 6,000 MW of offshore wind generation in New York City and 3,000 MW of offshore wind generation in Long Island by 2034. The additional offshore wind generation would contribute 518 MW in New York City considering transmission security renewable dispatch assumptions in the summer peak case.

3. This scenario looks at the impact of 1,200 MW of flexible demand (beyond the flexible large loads) across the system on the transmission security results. To reflect uncertainty in demand response participation, a generic 50% derate is modeled. Of the 1,200 MW of flexible demand, about 500 MW is assumed to be in Zone J. At the generic derate factor, this would result in 250 MW of load reduction and would resolve the New York City transmission security margin deficiency in the peak hour.

4. The higher demand scenario represents a higher bound on forecast growth, including faster economic growth and electrification sufficient to meet state policy targets, and includes additional large load growth not included in the baseline forecast.

5. This scenario delays the CHPE project from entering service until after this RNA's study period.

6. This scenario is intended to show the impact of additional generation deactivations. The impact of the retirement of the largest plant in New York City (Ravenswood 1, 2, and 3) is shown.

7. This scenario shows the New York City transmission security margin for the statewide coincident peak hour under the 1-in-10-year heatwave condition with the assumption that the system is using emergency transfer criteria.

8. This scenario shows the New York City transmission security margin for the statewide coincident peak hour under the 1-in-100-year heatwave condition with the assumption that the system is using emergency transfer criteria.

Figure 65: New York City Transmission Security Margin Mitigation Scenarios

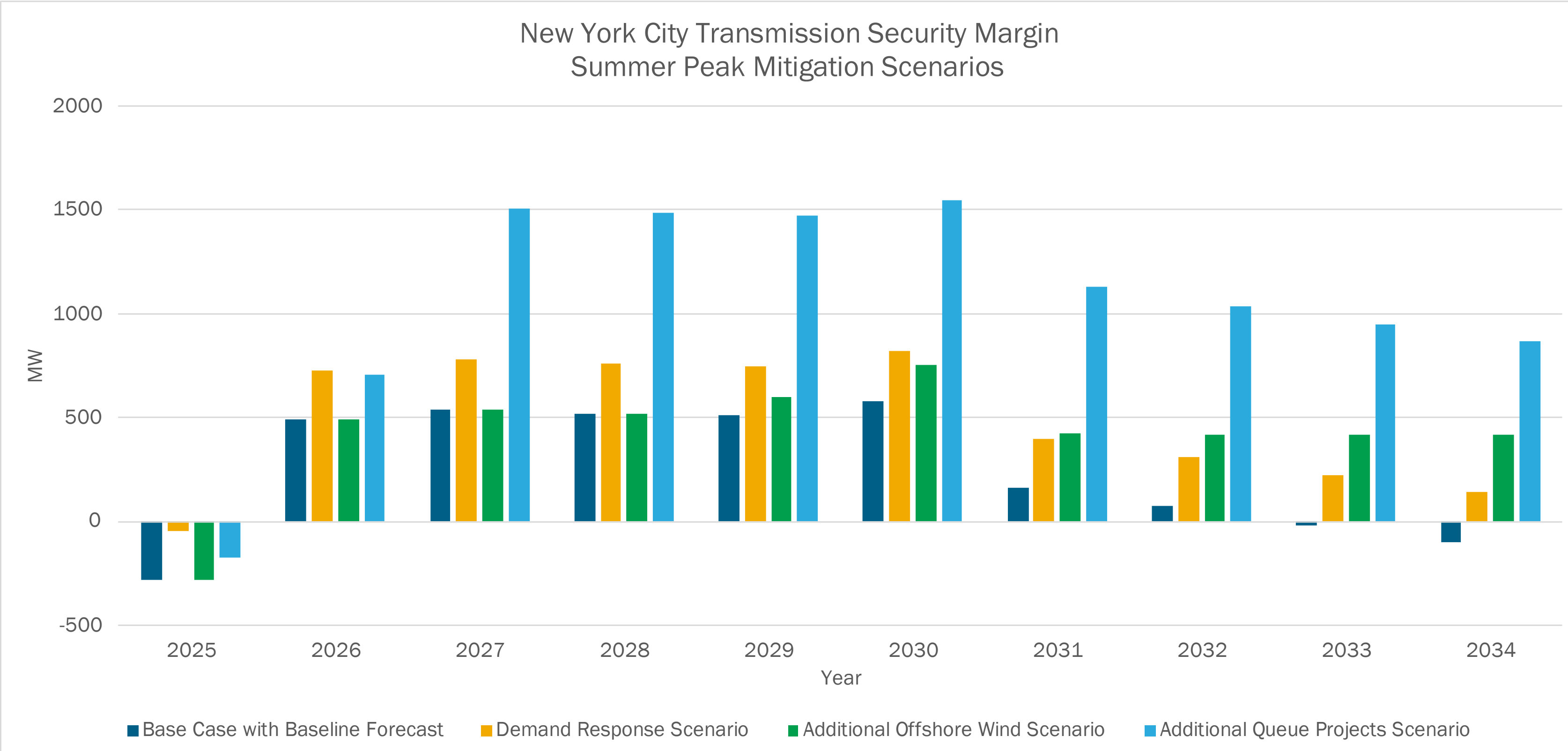


Figure 66: New York City Transmission Security Margin Risk Scenarios

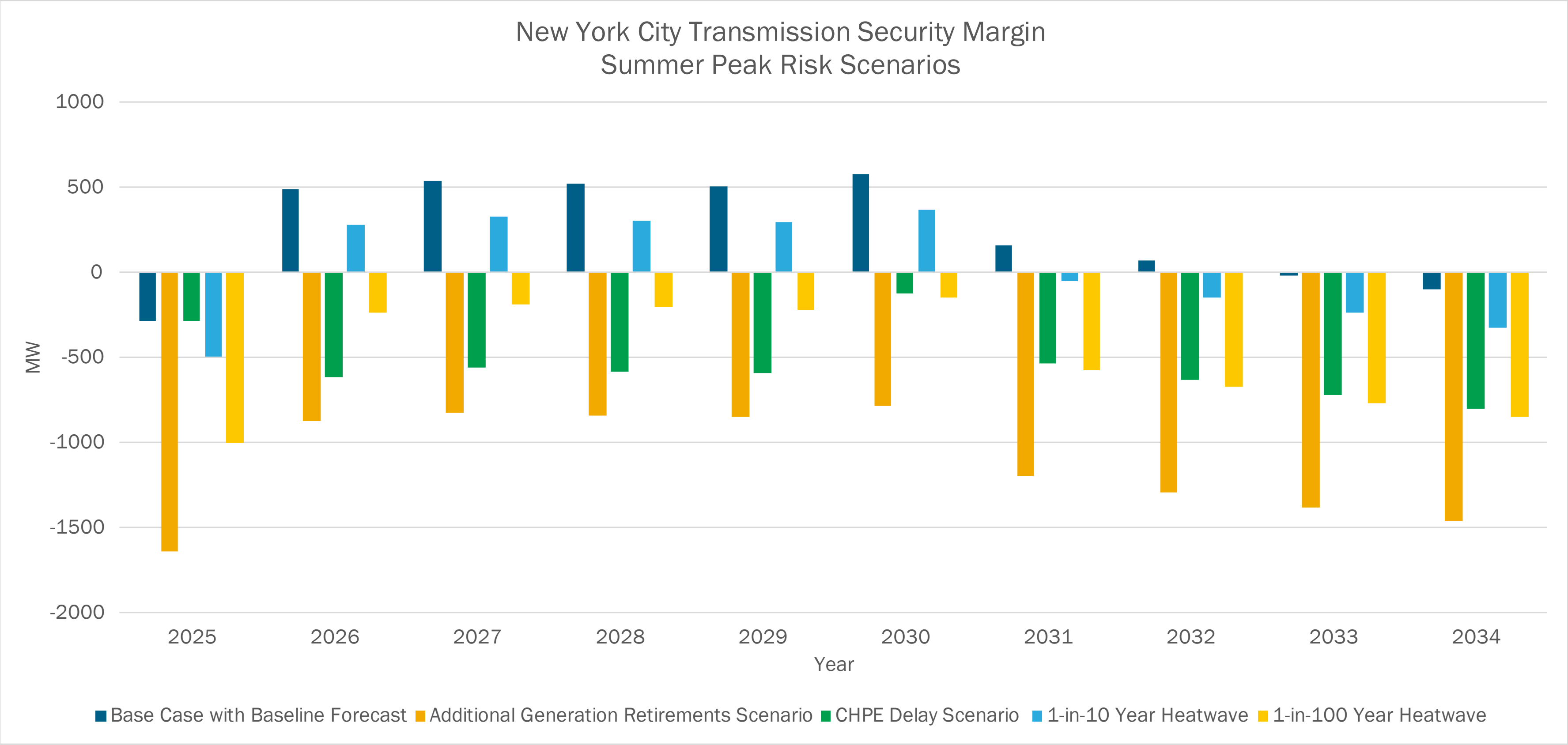


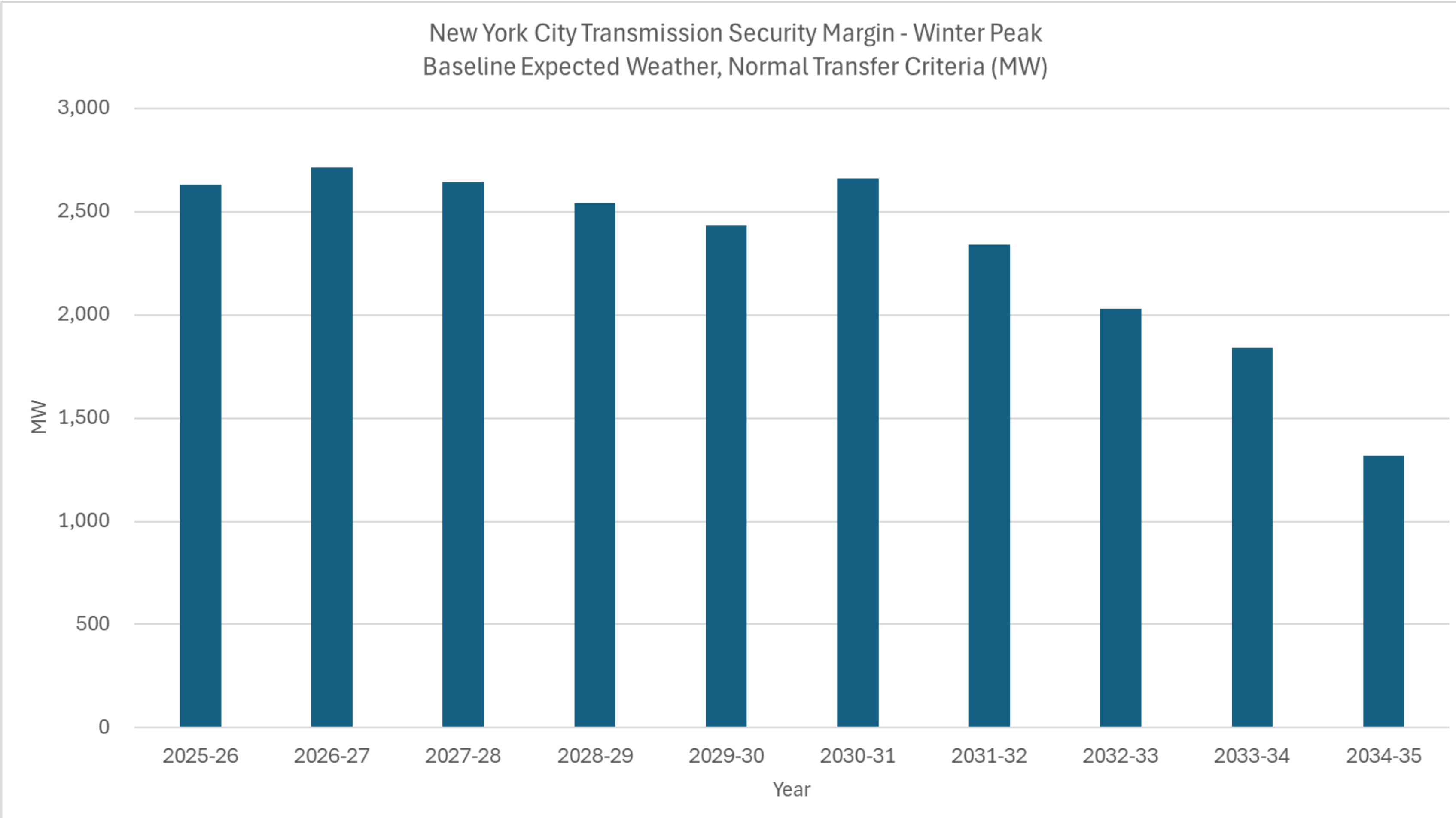
Figure 67: New York City Transmission Security Margin Calculation – Winter Peak

Winter Peak - Baseline Expected Weather, Normal Transfer Criteria (MW)											
Line	Item	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
A	**Zone J Demand Forecast (4)**	(7,410)	(7,490)	(7,560)	(7,660)	(7,770)	(7,910)	(8,230)	(8,540)	(8,730)	(9,250)
B	I+K to J (3), (4)	3,900	3,900	3,900	3,900	3,900	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	3,889	4,889	4,889	4,889	4,889	4,889
E	Loss of Source Contingency	(996)	(996)	(996)	(996)	(996)	(1,630)	(1,630)	(1,630)	(1,630)	(1,630)
F	**Resource Need (A+D+E)**	(4,517)	(4,597)	(4,667)	(4,767)	(4,877)	(4,651)	(4,971)	(5,281)	(5,471)	(5,991)
G	J Generation (1)	9,362	10,178	10,178	10,178	10,178	9,766	9,766	9,766	9,766	9,766
H	J Generation Derates (2)	(595)	(1,248)	(1,248)	(1,248)	(1,248)	(1,247)	(1,247)	(1,247)	(1,247)	(1,247)
I	Unavailability of Non-Firm Gas (5)	(1,936)	(1,936)	(1,936)	(1,936)	(1,936)	(1,524)	(1,524)	(1,524)	(1,524)	(1,524)
J	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
K	Net ICAP External Imports	315	315	315	315	315	315	315	315	315	315
L	**Total Resources Available (G+H+I+J+K)**	7,146	7,309	7,309	7,309	7,309	7,310	7,310	7,310	7,310	7,310
M	**Transmission Security Margin (F+L)**	2,629	2,712	2,642	2,542	2,432	2,659	2,339	2,029	1,839	1,319

Notes:

1. Reflects the 2024 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 10% 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 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 August 2023
3. Limits for 2025-26 are based on the summer peak 2025 representations evaluated in the post-2020 RNA updates (as a conservative winter peak assumption these limits utilize the summer values). Limits for 2026-27 through 2029-30 are based on winter peak 2029-30 representations evaluated in the 2024 RNA. Limits for 2030-31 through 2034-35 are based on the winter peak 2034-35 representations evaluated in the 2024 RNA.
4. Reflects the 2024 Gold Book Forecast.
5. 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.

Figure 68: New York City Transmission Security Margin Results - Winter Peak



Long Island (Zone K)

The Long Island locality comprises Zone K. Within the PSEG Long Island 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 2025 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 Long Island Public Policy transmission project is in service, the limiting contingency combination changes to the loss of the Y50 cable followed by a stuck breaker event at East Garden City. For winter 2025-2026 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 Long Island Public Policy transmission 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 138kV line (367).

Figure 69 and Figure 70 show the calculation of the summer and winter Long Island transmission security margin baseline expected weather, expected load conditions for the statewide coincident peak hour with normal transfer criteria. Figure 71 summarizes the margin calculation tables. Long Island maintains positive transmission security margins throughout the RNA study horizon. Significant increases in transmission security margins are seen after the Long Island Public Policy transmission project is placed in-service.

Figure 69: Summer Peak Long Island Margin Calculation

Summer Peak - Baseline Expected Weather, Normal Transfer Criteria (MW)											
Line	Item	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
A	**Zone K Demand Forecast (3)**	(4,956)	(4,955)	(4,968)	(4,982)	(5,009)	(5,030)	(5,074)	(5,129)	(5,205)	(5,268)
B	I+J to K	900	900	900	900	900	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	900	2,200	2,200	2,200	2,200	2,200
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	0	0	0	0	0
F	**Resource Need (A+D+E)**	(4,716)	(4,715)	(4,728)	(4,742)	(4,769)	(2,830)	(2,874)	(2,929)	(3,005)	(3,068)
G	K Generation (1)	5,097	6,021	6,021	6,021	6,021	6,021	5,976	5,976	5,976	5,976
H	K Generation Derates (2)	(630)	(1,463)	(1,464)	(1,465)	(1,465)	(1,466)	(1,463)	(1,463)	(1,464)	(1,464)
I	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
J	Net ICAP External Imports	660	660	660	660	660	660	660	660	660	660
K	**Total Resources Available (G+H+I+J)**	5,127	5,218	5,217	5,216	5,216	5,215	5,173	5,173	5,172	5,172
L	**Transmission Security Margin (F+K)**	411	503	489	474	447	2,385	2,299	2,244	2,167	2,104
M	Higher Demand Impact	(43)	(66)	(80)	(102)	(121)	(157)	(186)	(220)	(244)	(283)
N	**Higher Demand Transmission Security Margin (L+M)**	368	437	409	372	326	2,228	2,113	2,024	1,923	1,821

Notes:

1. Reflects the 2024 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 (2024 Gold Book Table I-9a) and solar PV peak reductions (2024 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 August 2023 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Reflects the 2024 Gold Book Forecast.

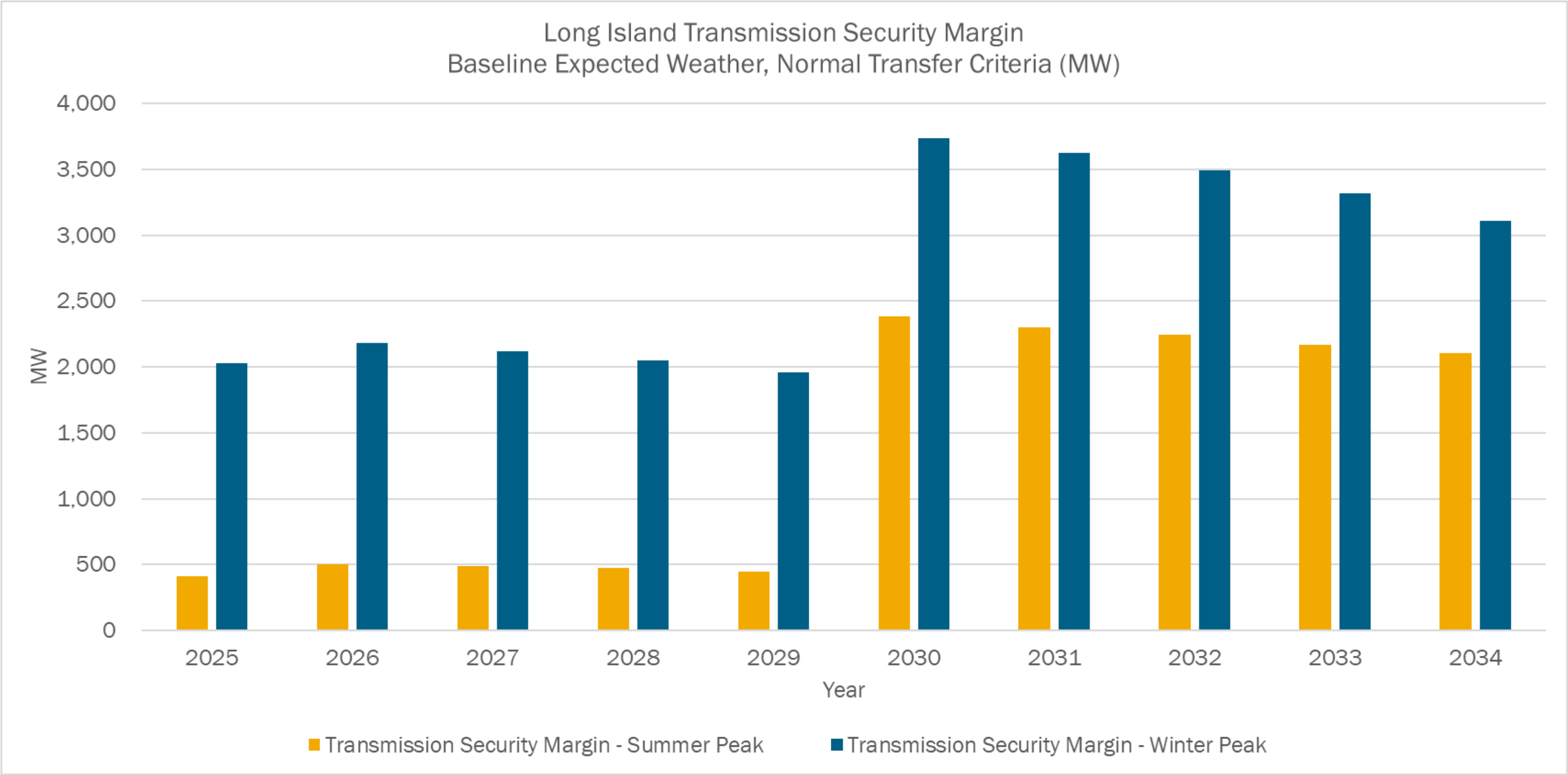
Figure 70: Winter Peak Long Island Margin Calculation

Winter Peak - Baseline Expected Weather, Normal Transfer Criteria (MW)											
Line	Item	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
A	**Zone K Demand Forecast (4)**	(3,299)	(3,334)	(3,396)	(3,465)	(3,553)	(3,639)	(3,750)	(3,880)	(4,058)	(4,266)
B	I+J to K (3)	900	900	900	900	900	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	900	2,500	2,500	2,500	2,500	2,500
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	(400)	(400)	(400)	(400)	(400)
F	**Resource Need (A+D+E)**	(3,059)	(3,094)	(3,156)	(3,225)	(3,313)	(1,539)	(1,650)	(1,780)	(1,958)	(2,166)
G	K Generation (1)	5,505	6,429	6,429	6,429	6,429	6,383	6,383	6,383	6,383	6,383
H	K Generation Derates (2)	(634)	(1,374)	(1,374)	(1,374)	(1,374)	(1,374)	(1,374)	(1,374)	(1,374)	(1,374)
I	Shortage of Gas Fuel Supply (5)	(441)	(441)	(441)	(441)	(441)	(395)	(395)	(395)	(395)	(395)
J	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
K	Net ICAP External Imports	660	660	660	660	660	660	660	660	660	660
L	**Total Resources Available (G+H+I+J+K)**	5,090	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275
M	**Transmission Security Margin (F+L)**	2,031	2,181	2,119	2,050	1,962	3,736	3,625	3,495	3,317	3,109

Notes:

1. Reflects the 2024 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 10% 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 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 August 2023 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Limits for 2025-26 are based on the summer peak 2025 representations evaluated in the post-2020 RNA updates (as a conservative winter peak assumption these limits utilize the summer values). Limits for 2026-27 through 2029-30 are based on winter peak 2029-30 representations evaluated in the 2024 RNA. Limits for 2030-31 through 2034-35 are based on the winter peak 2034-35 representations evaluated in the 2024 RNA.
4. Reflects the 2024 Gold Book Forecast.
5. 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.

Figure 71: Long Island Margin Chart – Summer and Winter



Appendix G – 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 online.

- Figure 72: AOI - Statewide System Margin
- Figure 73: AOI - Lower Hudson Valley Transmission Security Margin
- Figure 74: AOI - New York City Transmission Security Margin
- Figure 75: AOI - Long Island Transmission Security Margin

Figure 72: AOI - Statewide System Margin

Additional Outage Impacts - Statewide System Margin													
Year				2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				(97)	523	54	(459)	(930)	(1,451)	(2,439)	(3,101)	(3,792)	(4,462)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)									
Jamestown 5, 6 & 7	80.8	(8.48)	72.32	(170)	451	(18)	(531)	(1,002)	(1,523)	(2,512)	(3,173)	(3,864)	(4,534)
Jamestown 5	21.9	(2.30)	19.60	(117)	504	34	(478)	(949)	(1,471)	(2,459)	(3,120)	(3,811)	(4,481)
Jamestown 6	19.1	(2.01)	17.09	(115)	506	37	(476)	(947)	(1,468)	(2,456)	(3,118)	(3,809)	(4,479)
Jamestown 7	39.8	(4.18)	35.62	(133)	488	18	(494)	(965)	(1,487)	(2,475)	(3,136)	(3,827)	(4,497)
Indeck-Yerkes	43.8	(1.94)	41.86	(139)	482	12	(500)	(972)	(1,493)	(2,481)	(3,142)	(3,834)	(4,504)
Indeck-Olean	77.5	(3.43)	74.07	(171)	449	(20)	(533)	(1,004)	(1,525)	(2,513)	(3,175)	(3,866)	(4,536)
American Ref-Fuel 1 & 2	37.6	(3.95)	33.65	(131)	490	20	(492)	(963)	(1,485)	(2,473)	(3,134)	(3,825)	(4,495)
American Ref-Fuel 1	18.8	(1.97)	16.83	(114)	507	37	(475)	(947)	(1,468)	(2,456)	(3,117)	(3,809)	(4,479)
American Ref-Fuel 2	18.8	(1.97)	16.83	(114)	507	37	(475)	(947)	(1,468)	(2,456)	(3,117)	(3,809)	(4,479)
Fortistar - N.Tonawanda (BTM:NG)	53.3	(2.36)	50.94	(148)	472	3	(510)	(981)	(1,502)	(2,490)	(3,151)	(3,843)	(4,513)
Model City Energy	5.6	(0.71)	4.89	(102)	519	49	(463)	(935)	(1,456)	(2,444)	(3,105)	(3,797)	(4,467)
Modern LF	6.4	(0.81)	5.59	(103)	518	48	(464)	(935)	(1,457)	(2,445)	(3,106)	(3,797)	(4,467)
Chaffee	6.4	(0.81)	5.59	(103)	518	48	(464)	(935)	(1,457)	(2,445)	(3,106)	(3,797)	(4,467)
Chautauqua LFGE	0.0	0.00	0.00	(97)	523	54	(459)	(930)	(1,451)	(2,439)	(3,101)	(3,792)	(4,462)
Lockport CC1, CC2, and CC3	208.8	(9.25)	199.55	(297)	324	(146)	(658)	(1,129)	(1,651)	(2,639)	(3,300)	(3,991)	(4,661)
Lockport CC1	69.6	(3.08)	66.52	(164)	457	(13)	(525)	(996)	(1,517)	(2,506)	(3,167)	(3,858)	(4,528)
Lockport CC2	69.6	(3.08)	66.52	(164)	457	(13)	(525)	(996)	(1,517)	(2,506)	(3,167)	(3,858)	(4,528)
Lockport CC3	69.6	(3.08)	66.52	(164)	457	(13)	(525)	(996)	(1,517)	(2,506)	(3,167)	(3,858)	(4,528)
Allegany	62.8	(2.78)	60.02	(157)	463	(6)	(519)	(990)	(1,511)	(2,499)	(3,161)	(3,852)	(4,522)
R. E. Ginna	581.5	(10.99)	570.51	(668)	(47)	(517)	(1,029)	(1,500)	(2,021)	(3,010)	(3,671)	(4,362)	(5,032)
Batavia	47.7	(2.11)	45.59	(143)	478	8	(504)	(975)	(1,497)	(2,485)	(3,146)	(3,837)	(4,507)
Nine Mile Point 2	1,274.7	(27.53)	1,247.17	(1,085)	(465)	(934)	(1,447)	(1,918)	(2,439)	(3,427)	(4,089)	(4,780)	(5,450)
Mill Seat	6.4	(0.81)	5.59	(103)	518	48	(464)	(935)	(1,457)	(2,445)	(3,106)	(3,797)	(4,467)
Hyland LFGE	4.8	(0.60)	4.20	(102)	519	50	(463)	(934)	(1,455)	(2,444)	(3,105)	(3,796)	(4,466)
Synergy Biogas	0.0	0.00	0.00	(97)	523	54	(459)	(930)	(1,451)	(2,439)	(3,101)	(3,792)	(4,462)
Red Rochester (BTM:NG)	13.3	(1.40)	11.90	(109)	512	42	(470)	(942)	(1,463)	(2,451)	(3,112)	(3,804)	(4,474)
James A. FitzPatrick	852.8	(18.42)	834.38	(932)	(311)	(781)	(1,293)	(1,764)	(2,285)	(3,274)	(3,935)	(4,626)	(5,296)
Oswego 6	803.0	(84.32)	718.69	(816)	(195)	(665)	(1,177)	(1,648)	(2,170)	(3,158)	(3,819)	(4,510)	(5,180)
Oswego 5	809.5	(85.00)	724.50	(822)	(201)	(671)	(1,183)	(1,654)	(2,175)	(3,164)	(3,825)	(4,516)	(5,186)
Nine Mile Point 1	621.4	(13.42)	607.98	(705)	(85)	(554)	(1,067)	(1,538)	(2,059)	(3,047)	(3,709)	(4,400)	(5,070)
Independence GS1, GS2, GS3, & GS4	980.4	(43.43)	936.97	(1,034)	(414)	(883)	(1,396)	(1,867)	(2,388)	(3,376)	(4,038)	(4,729)	(5,399)
Independence GS1	245.1	(10.86)	234.24	(332)	289	(180)	(693)	(1,164)	(1,685)	(2,674)	(3,335)	(4,026)	(4,696)
Independence GS2	245.1	(10.86)	234.24	(332)	289	(180)	(693)	(1,164)	(1,685)	(2,674)	(3,335)	(4,026)	(4,696)
Independence GS3	245.1	(10.86)	234.24	(332)	289	(180)	(693)	(1,164)	(1,685)	(2,674)	(3,335)	(4,026)	(4,696)
Independence GS4	245.1	(10.86)	234.24	(332)	289	(180)	(693)	(1,164)	(1,685)	(2,674)	(3,335)	(4,026)	(4,696)
Syracuse	83.2	(3.69)	79.51	(177)	444	(26)	(538)	(1,009)	(1,530)	(2,519)	(3,180)	(3,871)	(4,541)
Carr St.-E. Syr	89.8	(3.98)	85.82	(183)	438	(32)	(544)	(1,016)	(1,537)	(2,525)	(3,186)	(3,878)	(4,548)
Indeck-Oswego	51.8	(2.29)	49.51	(147)	474	4	(508)	(979)	(1,500)	(2,489)	(3,150)	(3,841)	(4,511)
Indeck-Silver Springs	51.4	(2.28)	49.12	(147)	474	5	(508)	(979)	(1,500)	(2,488)	(3,150)	(3,841)	(4,511)
Greenidge 4 (BTM:NG)	25.9	(2.72)	23.18	(121)	(1,047)	169	(36)	(240)	(494)	(834)	(1,328)	(1,823)	(2,393)
Ontario LFGE	11.2	(1.41)	9.79	(107)	514	44	(468)	(940)	(1,461)	(2,449)	(3,110)	(3,802)	(4,472)
High Acres	9.6	(1.21)	8.39	(106)	515	45	(467)	(938)	(1,459)	(2,448)	(3,109)	(3,800)	(4,470)
Seneca Energy 1 & 2	17.6	(2.22)	15.38	(113)	508	38	(474)	(945)	(1,466)	(2,455)	(3,116)	(3,807)	(4,477)
Seneca Energy 1	8.8	(1.11)	7.69	(105)	516	46	(466)	(937)	(1,459)	(2,447)	(3,108)	(3,799)	(4,469)
Seneca Energy 2	8.8	(1.11)	7.69	(105)	516	46	(466)	(937)	(1,459)	(2,447)	(3,108)	(3,799)	(4,469)
Broome LFGE	2.4	(0.30)	2.10	(100)	521	52	(461)	(932)	(1,453)	(2,441)	(3,103)	(3,794)	(4,464)
Massena	79.5	(3.52)	75.98	(173)	447	(22)	(535)	(1,006)	(1,527)	(2,515)	(3,177)	(3,868)	(4,538)
Clinton LFGE	6.4	(0.81)	5.59	(103)	518	48	(464)	(935)	(1,457)	(2,445)	(3,106)	(3,797)	(4,467)
Saranac Energy CC1 & CC2	237.9	(10.54)	227.36	(325)	296	(174)	(686)	(1,157)	(1,678)	(2,667)	(3,328)	(4,019)	(4,689)
Saranac Energy CC1	121.8	(5.40)	116.40	(214)	407	(63)	(575)	(1,046)	(1,567)	(2,556)	(3,217)	(3,908)	(4,578)
Saranac Energy CC2	116.1	(5.14)	110.96	(208)	412	(57)	(570)	(1,041)	(1,562)	(2,550)	(3,212)	(3,903)	(4,573)
Sterling	49.7	(2.20)	47.50	(145)	476	6	(506)	(977)	(1,498)	(2,487)	(3,148)	(3,839)	(4,509)
Carthage Energy	56.4	(2.50)	53.90	(151)	470	(0)	(512)	(984)	(1,505)	(2,493)	(3,154)	(3,846)	(4,516)
Beaver Falls	78.1	(3.46)	74.64	(172)	449	(21)	(533)	(1,004)	(1,526)	(2,514)	(3,175)	(3,866)	(4,536)
Broome 2 LFGE	2.1	(0.26)	1.84	(99)	522	52	(460)	(932)	(1,453)	(2,441)	(3,102)	(3,794)	(4,464)
DANC LFGE	6.4	(0.81)	5.59	(103)	518	48	(464)	(935)	(1,457)	(2,445)	(3,106)	(3,797)	(4,467)
Oneida-Herkimer LFGE	3.2	(0.40)	2.80	(100)	521	51	(461)	(933)	(1,454)	(2,442)	(3,103)	(3,795)	(4,465)
Athens 1, 2, and 3	993.8	(44.03)	949.77	(1,047)	(426)	(896)	(1,408)	(1,880)	(2,401)	(3,389)	(4,050)	(4,742)	(5,412)
Athens 1	329.4	(14.59)	314.81	(412)	209	(261)	(773)	(1,245)	(1,766)	(2,754)	(3,415)	(4,107)	(4,777)
Athens 2	333.3	(14.77)	318.53	(416)	205	(265)	(777)	(1,248)	(1,769)	(2,758)	(3,419)	(4,110)	(4,780)
Athens 3	331.1	(14.67)	316.43	(414)	207	(263)	(775)	(1,246)	(1,767)	(2,756)	(3,417)	(4,108)	(4,778)
Rensselaer	76.3	(3.38)	72.92	(170)	450	(19)	(531)	(1,003)	(1,524)	(2,512)	(3,173)	(3,865)	(4,535)
Wheelabrator Hudson Falls	10.4	(1.09)	9.31	(107)	514	45	(468)	(939)	(1,460)	(2,449)	(3,110)	(3,801)	(4,471)

Additional Outage Impacts - Statewide System Margin													
			Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				(97)	523	54	(459)	(930)	(1,451)	(2,439)	(3,101)	(3,792)	(4,462)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)									
Selkirk I & II	353.3	(15.65)	337.65	(435)	186	(284)	(796)	(1,267)	(1,789)	(2,777)	(3,438)	(4,129)	(4,799)
Selkirk-I	76.1	(3.37)	72.73	(170)	451	(19)	(531)	(1,002)	(1,524)	(2,512)	(3,173)	(3,864)	(4,534)
Selkirk-II	277.2	(12.28)	264.92	(362)	258	(211)	(723)	(1,195)	(1,716)	(2,704)	(3,365)	(4,057)	(4,727)
Indeck-Corinth	131.1	(5.81)	125.29	(223)	398	(71)	(584)	(1,055)	(1,576)	(2,565)	(3,226)	(3,917)	(4,587)
Castleton Energy Center	67.9	(3.01)	64.89	(162)	459	(11)	(523)	(995)	(1,516)	(2,504)	(3,165)	(3,857)	(4,527)
Bethlehem GS1, GS2, GS3	818.4	(36.26)	782.14	(880)	(259)	(728)	(1,241)	(1,712)	(2,233)	(3,221)	(3,883)	(4,574)	(5,244)
Bethlehem GS1	272.8	(12.09)	260.71	(358)	263	(207)	(719)	(1,190)	(1,712)	(2,700)	(3,361)	(4,052)	(4,722)
Bethlehem GS2	272.8	(12.09)	260.71	(358)	263	(207)	(719)	(1,190)	(1,712)	(2,700)	(3,361)	(4,052)	(4,722)
Bethlehem GS3	272.8	(12.09)	260.71	(358)	263	(207)	(719)	(1,190)	(1,712)	(2,700)	(3,361)	(4,052)	(4,722)
Colonie LFGTE	6.4	(0.81)	5.59	(103)	518	48	(464)	(935)	(1,457)	(2,445)	(3,106)	(3,797)	(4,467)
Albany LFGE	5.6	(0.71)	4.89	(102)	519	49	(463)	(935)	(1,456)	(2,444)	(3,105)	(3,797)	(4,467)
Fulton LFGE	3.2	(0.40)	2.80	(100)	521	51	(461)	(933)	(1,454)	(2,442)	(3,103)	(3,795)	(4,465)
Empire CC1 & CC2	587.4	(26.02)	561.38	(659)	(38)	(508)	(1,020)	(1,491)	(2,012)	(3,001)	(3,662)	(4,353)	(5,023)
Empire CC1	293.7	(13.01)	280.69	(378)	243	(227)	(739)	(1,210)	(1,732)	(2,720)	(3,381)	(4,072)	(4,742)
Empire CC2	293.7	(13.01)	280.69	(378)	243	(227)	(739)	(1,210)	(1,732)	(2,720)	(3,381)	(4,072)	(4,742)
Bowline 1 & 2	1,143.0	(120.02)	1,022.99	(1,120)	(500)	(969)	(1,482)	(1,953)	(2,474)	(3,462)	(4,124)	(4,815)	(5,485)
Bowline 1	577.8	(60.67)	517.13	(615)	6	(463)	(976)	(1,447)	(1,968)	(2,956)	(3,618)	(4,309)	(4,979)
Bowline 2	565.2	(59.35)	505.85	(603)	18	(452)	(964)	(1,436)	(1,957)	(2,945)	(3,606)	(4,298)	(4,968)
Danskammer 1, 2, 3, & 4	499.4	(52.44)	446.96	(544)	76	(393)	(906)	(1,377)	(1,898)	(2,886)	(3,548)	(4,239)	(4,909)
Danskammer 1	68.5	(7.19)	61.31	(159)	462	(7)	(520)	(991)	(1,512)	(2,501)	(3,162)	(3,853)	(4,523)
Danskammer 2	65.0	(6.83)	58.18	(156)	465	(4)	(517)	(988)	(1,509)	(2,498)	(3,159)	(3,850)	(4,520)
Danskammer 3	140.1	(14.71)	125.39	(223)	398	(72)	(584)	(1,055)	(1,576)	(2,565)	(3,226)	(3,917)	(4,587)
Danskammer 4	225.8	(23.71)	202.09	(299)	321	(148)	(661)	(1,132)	(1,653)	(2,641)	(3,303)	(3,994)	(4,664)
Roseton 1 & 2	1,228.2	(128.96)	1,099.24	(1,197)	(576)	(1,045)	(1,558)	(2,029)	(2,550)	(3,539)	(4,200)	(4,891)	(5,561)
Roseton 1	615.7	(64.65)	551.05	(648)	(28)	(497)	(1,010)	(1,481)	(2,002)	(2,990)	(3,652)	(4,343)	(5,013)
Roseton 2	612.5	(64.31)	548.19	(646)	(25)	(494)	(1,007)	(1,478)	(1,999)	(2,988)	(3,649)	(4,340)	(5,010)
Hillburn GT	36.0	(3.31)	32.69	(130)	491	21	(491)	(962)	(1,484)	(2,472)	(3,133)	(3,824)	(4,494)
Shoemaker GT	35.4	(3.25)	32.15	(130)	491	22	(491)	(962)	(1,483)	(2,471)	(3,133)	(3,824)	(4,494)
DCRRA	6.2	(0.65)	5.55	(103)	518	48	(464)	(935)	(1,457)	(2,445)	(3,106)	(3,797)	(4,467)
CPV Valley CC1 & CC2	645.4	(28.59)	616.81	(714)	(93)	(563)	(1,075)	(1,547)	(2,068)	(3,056)	(3,717)	(4,409)	(5,079)
CPV Valley CC1	322.7	(14.30)	308.40	(406)	215	(255)	(767)	(1,238)	(1,759)	(2,748)	(3,409)	(4,100)	(4,770)
CPV Valley CC2	322.7	(14.30)	308.40	(406)	215	(255)	(767)	(1,238)	(1,759)	(2,748)	(3,409)	(4,100)	(4,770)
Cricket Valley CC1, CC2, & CC3	1,050.8	(46.55)	1,004.25	(1,102)	(481)	(950)	(1,463)	(1,934)	(2,455)	(3,444)	(4,105)	(4,796)	(5,466)
Cricket Valley CC1	347.1	(15.38)	331.72	(429)	192	(278)	(790)	(1,261)	(1,783)	(2,771)	(3,432)	(4,123)	(4,793)
Cricket Valley CC2	345.0	(15.28)	329.72	(427)	194	(276)	(788)	(1,259)	(1,781)	(2,769)	(3,430)	(4,121)	(4,791)
Cricket Valley CC3	358.7	(15.89)	342.81	(440)	181	(289)	(801)	(1,273)	(1,794)	(2,782)	(3,443)	(4,135)	(4,805)
Wheelabrator Westchester	52.5	(5.51)	46.99	(144)	476	7	(506)	(977)	(1,498)	(2,486)	(3,148)	(3,839)	(4,509)
Arthur Kill ST 2 & 3	884.9	(92.91)	791.99	(889)	(269)	(738)	(1,251)	(1,722)	(2,243)	(3,231)	(3,893)	(4,584)	(5,254)
Arthur Kill ST 2	362.2	(38.03)	324.17	(422)	199	(270)	(783)	(1,254)	(1,775)	(2,764)	(3,425)	(4,116)	(4,786)
Arthur Kill ST 3	522.7	(54.88)	467.82	(565)	56	(414)	(926)	(1,398)	(1,919)	(2,907)	(3,568)	(4,260)	(4,930)
Brooklyn Navy Yard	247.5	(10.96)	236.54	(334)	287	(183)	(695)	(1,166)	(1,687)	(2,676)	(3,337)	(4,028)	(4,698)
Astoria 2, 3, & 5	916.9	(96.27)	820.63	(918)	(297)	(767)	(1,279)	(1,750)	(2,272)	(3,260)	(3,921)	(4,612)	(5,282)
Astoria 2	171.2	(17.98)	153.22	(251)	370	(99)	(612)	(1,083)	(1,604)	(2,593)	(3,254)	(3,945)	(4,615)
Astoria 3	372.4	(39.10)	333.30	(431)	190	(279)	(792)	(1,263)	(1,784)	(2,773)	(3,434)	(4,125)	(4,795)
Astoria 5	373.3	(39.20)	334.10	(432)	189	(280)	(793)	(1,264)	(1,785)	(2,773)	(3,435)	(4,126)	(4,796)
Ravenswood ST 01, 02, & 03	1,958.2	(191.73)	1,766.47	(1,864)	(1,243)	(1,713)	(2,225)	(2,696)	(3,217)	(4,206)	(4,867)	(5,558)	(6,228)
Ravenswood ST 01	367.0	(38.54)	328.47	(426)	195	(275)	(787)	(1,258)	(1,779)	(2,768)	(3,429)	(4,120)	(4,790)
Ravenswood ST 02	375.3	(39.41)	335.89	(433)	188	(282)	(794)	(1,266)	(1,787)	(2,775)	(3,436)	(4,128)	(4,798)
Ravenswood ST 03	987.3	(103.67)	883.63	(981)	(360)	(830)	(1,342)	(1,813)	(2,335)	(3,323)	(3,984)	(4,675)	(5,345)
Ravenswood CC 04	228.6	(10.13)	218.47	(316)	305	(165)	(677)	(1,148)	(1,669)	(2,658)	(3,319)	(4,010)	(4,680)
East River 1, 2, 6, & 7	620.5	(46.55)	573.95	(671)	(51)	(520)	(1,033)	(1,504)	(2,025)	(3,013)	(3,674)	(4,366)	(5,036)
East River 1	151.5	(6.71)	144.79	(242)	379	(91)	(603)	(1,075)	(1,596)	(2,584)	(3,245)	(3,937)	(4,607)
East River 2	155.0	(6.87)	148.13	(246)	375	(94)	(607)	(1,078)	(1,599)	(2,587)	(3,249)	(3,940)	(4,610)
East River 6	131.6	(13.82)	117.78	(215)	406	(64)	(576)	(1,048)	(1,569)	(2,557)	(3,218)	(3,910)	(4,580)
East River 7	182.4	(19.15)	163.25	(261)	360	(109)	(622)	(1,093)	(1,614)	(2,603)	(3,264)	(3,955)	(4,625)
Linden Cogen	737.1	(32.65)	704.45	(802)	(181)	(651)	(1,163)	(1,634)	(2,155)	(3,144)	(3,805)	(4,496)	(5,166)
KIAC_JFK (BTM:NG)	106.4	(4.71)	101.69	(199)	422	(48)	(560)	(1,031)	(1,553)	(2,541)	(3,202)	(3,893)	(4,563)
Gowanus 5 & 6	79.9	(8.39)	71.51	(169)	452	(18)	(530)	(1,001)	(1,522)	(2,511)	(3,172)	(3,863)	(4,533)
Gowanus 5	40.0	(4.20)	35.80	(133)	488	18	(494)	(966)	(1,487)	(2,475)	(3,136)	(3,828)	(4,498)
Gowanus 6	39.9	(4.19)	35.71	(133)	488	18	(494)	(965)	(1,487)	(2,475)	(3,136)	(3,827)	(4,497)
Kent	46.0	(4.83)	41.17	(139)	482	13	(500)	(971)	(1,492)	(2,481)	(3,142)	(3,833)	(4,503)
Pouch	45.4	(4.77)	40.63	(138)	483	13	(499)	(970)	(1,492)	(2,480)	(3,141)	(3,832)	(4,502)

Additional Outage Impacts - Statewide System Margin													
Year				2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				(97)	523	54	(459)	(930)	(1,451)	(2,439)	(3,101)	(3,792)	(4,462)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)									
Hellgate 1 & 2	79.5	(8.35)	71.15	(169)	452	(17)	(530)	(1,001)	(1,522)	(2,511)	(3,172)	(3,863)	(4,533)
Hellgate 1	39.9	(4.19)	35.71	(133)	488	18	(494)	(965)	(1,487)	(2,475)	(3,136)	(3,827)	(4,497)
Hellgate 2	39.6	(4.16)	35.44	(133)	488	18	(494)	(965)	(1,486)	(2,475)	(3,136)	(3,827)	(4,497)
Harlem River 1 & 2	79.5	(8.35)	71.15	(169)	452	(17)	(530)	(1,001)	(1,522)	(2,511)	(3,172)	(3,863)	(4,533)
Harlem River 1	39.9	(4.19)	35.71	(133)	488	18	(494)	(965)	(1,487)	(2,475)	(3,136)	(3,827)	(4,497)
Harlem River 2	39.6	(4.16)	35.44	(133)	488	18	(494)	(965)	(1,486)	(2,475)	(3,136)	(3,827)	(4,497)
Vernon Blvd 2 & 3	79.9	(8.39)	71.51	(169)	452	(18)	(530)	(1,001)	(1,522)	(2,511)	(3,172)	(3,863)	(4,533)
Vernon Blvd 2	40.0	(4.20)	35.80	(133)	488	18	(494)	(966)	(1,487)	(2,475)	(3,136)	(3,828)	(4,498)
Vernon Blvd 3	39.9	(4.19)	35.71	(133)	488	18	(494)	(965)	(1,487)	(2,475)	(3,136)	(3,827)	(4,497)
Astoria CC 1 & 2	474.0	(21.00)	453.00	(550)	70	(399)	(912)	(1,383)	(1,904)	(2,892)	(3,554)	(4,245)	(4,915)
Astoria CC 1	237.0	(10.50)	226.50	(324)	297	(173)	(685)	(1,156)	(1,677)	(2,666)	(3,327)	(4,018)	(4,688)
Astoria CC 2	237.0	(10.50)	226.50	(324)	297	(173)	(685)	(1,156)	(1,677)	(2,666)	(3,327)	(4,018)	(4,688)
Astoria East Energy CC1 & CC2	579.2	(25.66)	553.54	(651)	(30)	(500)	(1,012)	(1,483)	(2,005)	(2,993)	(3,654)	(4,345)	(5,015)
Astoria East Energy - CC1	289.6	(12.83)	276.77	(374)	247	(223)	(735)	(1,207)	(1,728)	(2,716)	(3,377)	(4,069)	(4,739)
Astoria East Energy - CC2	289.6	(12.83)	276.77	(374)	247	(223)	(735)	(1,207)	(1,728)	(2,716)	(3,377)	(4,069)	(4,739)
Astoria Energy 2 - CC3 & CC4	570.6	(25.28)	545.32	(643)	(22)	(492)	(1,004)	(1,475)	(1,996)	(2,985)	(3,646)	(4,337)	(5,007)
Astoria Energy 2 - CC3	285.3	(12.64)	272.66	(370)	251	(219)	(731)	(1,202)	(1,724)	(2,712)	(3,373)	(4,064)	(4,734)
Astoria Energy 2 - CC4	285.3	(12.64)	272.66	(370)	251	(219)	(731)	(1,202)	(1,724)	(2,712)	(3,373)	(4,064)	(4,734)
Bayonne EC CT G1 through G10	598.6	(55.01)	543.59	(641)	(20)	(490)	(1,002)	(1,473)	(1,995)	(2,983)	(3,644)	(4,335)	(5,005)
Bayonne EC CTG1	62.0	(5.70)	56.30	(154)	467	(2)	(515)	(986)	(1,507)	(2,496)	(3,157)	(3,848)	(4,518)
Bayonne EC CTG2	58.0	(5.33)	52.67	(150)	471	1	(511)	(982)	(1,504)	(2,492)	(3,153)	(3,844)	(4,514)
Bayonne EC CTG3	58.0	(5.33)	52.67	(150)	471	1	(511)	(982)	(1,504)	(2,492)	(3,153)	(3,844)	(4,514)
Bayonne EC CTG4	61.1	(5.62)	55.48	(153)	468	(2)	(514)	(985)	(1,506)	(2,495)	(3,156)	(3,847)	(4,517)
Bayonne EC CTG5	58.5	(5.38)	53.12	(151)	470	1	(512)	(983)	(1,504)	(2,492)	(3,154)	(3,845)	(4,515)
Bayonne EC CTG6	59.0	(5.42)	53.58	(151)	470	0	(512)	(983)	(1,505)	(2,493)	(3,154)	(3,845)	(4,515)
Bayonne EC CTG7	59.3	(5.45)	53.85	(151)	470	(0)	(512)	(984)	(1,505)	(2,493)	(3,154)	(3,846)	(4,516)
Bayonne EC CTG8	60.0	(5.51)	54.49	(152)	469	(1)	(513)	(984)	(1,505)	(2,494)	(3,155)	(3,846)	(4,516)
Bayonne EC CTG9	61.3	(5.63)	55.67	(153)	468	(2)	(514)	(985)	(1,507)	(2,495)	(3,156)	(3,847)	(4,517)
Bayonne EC CTG10	61.4	(5.64)	55.76	(153)	468	(2)	(514)	(986)	(1,507)	(2,495)	(3,156)	(3,847)	(4,517)
Greenport IC 4, 5, & 6	5.6	(0.80)	4.80	(102)	519	49	(463)	(935)	(1,456)	(2,444)	(3,105)	(3,797)	(4,467)
Greenport IC 4	1.0	(0.14)	0.86	(98)	523	53	(459)	(931)	(1,452)	(2,440)	(3,101)	(3,793)	(4,463)
Greenport IC 5	1.5	(0.21)	1.29	(99)	522	53	(460)	(931)	(1,452)	(2,441)	(3,102)	(3,793)	(4,463)
Greenport IC 6	3.1	(0.44)	2.66	(100)	521	51	(461)	(932)	(1,454)	(2,442)	(3,103)	(3,794)	(4,464)
Freeport 1-2, 1-3, & 2-3	21.1	(2.42)	18.68	(116)	505	35	(477)	(948)	(1,470)	(2,458)	(3,119)	(3,810)	(4,480)
Freeport 1-2	2.5	(0.36)	2.14	(100)	521	52	(461)	(932)	(1,453)	(2,441)	(3,103)	(3,794)	(4,464)
Freeport 1-3	2.9	(0.42)	2.48	(100)	521	51	(461)	(932)	(1,453)	(2,442)	(3,103)	(3,794)	(4,464)
Freeport 2-3	15.7	(1.65)	14.05	(111)	509	40	(473)	(944)	(1,465)	(2,453)	(3,115)	(3,806)	(4,476)
Charles P Killer 09 through 14	16.0	(1.50)	14.50	(112)	509	39	(473)	(944)	(1,465)	(2,454)	(3,115)	(3,806)	(4,476)
Charles P Keller 09	1.9	(0.18)	1.72	(99)	522	52	(460)	(931)	(1,453)	(2,441)	(3,102)	(3,793)	(4,463)
Charles P Keller 10	1.9	(0.18)	1.72	(99)	522	52	(460)	(931)	(1,453)	(2,441)	(3,102)	(3,793)	(4,463)
Charles P Keller 11	2.8	(0.26)	2.54	(100)	521	51	(461)	(932)	(1,453)	(2,442)	(3,103)	(3,794)	(4,464)
Charles P Keller 12	3.0	(0.28)	2.72	(100)	521	51	(461)	(932)	(1,454)	(2,442)	(3,103)	(3,794)	(4,464)
Charles P Keller 13	3.0	(0.28)	2.72	(100)	521	51	(461)	(932)	(1,454)	(2,442)	(3,103)	(3,794)	(4,464)
Charles P Keller 14	3.4	(0.32)	3.08	(100)	520	51	(462)	(933)	(1,454)	(2,442)	(3,104)	(3,795)	(4,465)
Wading River 1, 2, & 3	231.4	(24.30)	207.10	(305)	316	(153)	(666)	(1,137)	(1,658)	(2,646)	(3,308)	(3,999)	(4,669)
Wading River 1	79.7	(8.37)	71.33	(169)	452	(18)	(530)	(1,001)	(1,522)	(2,511)	(3,172)	(3,863)	(4,533)
Wading River 2	76.4	(8.02)	68.38	(166)	455	(15)	(527)	(998)	(1,519)	(2,508)	(3,169)	(3,860)	(4,530)
Wading River 3	75.3	(7.91)	67.39	(165)	456	(14)	(526)	(997)	(1,518)	(2,507)	(3,168)	(3,859)	(4,529)
Barrett ST 01 & 02	383.0	(40.22)	342.79	(440)	181	(289)	(801)	(1,273)	(1,794)	(2,782)	(3,443)	(4,135)	(4,805)
Barrett ST 01	195.0	(20.48)	174.53	(272)	349	(121)	(633)	(1,104)	(1,625)	(2,614)	(3,275)	(3,966)	(4,636)
Barrett ST 02	188.0	(19.74)	168.26	(266)	355	(114)	(627)	(1,098)	(1,619)	(2,608)	(3,269)	(3,960)	(4,630)
Barrett GT 01 through 12	246.2	(23.90)	222.30	(320)	301	(168)	(681)	(1,152)	(1,673)	(2,662)	(3,323)	(4,014)	(4,684)
Barrett GT 01	14.0	(1.47)	12.53	(110)	511	41	(471)	(942)	(1,463)	(2,452)	(3,113)	(3,804)	(4,474)
Barrett GT 02	13.6	(1.43)	12.17	(110)	511	42	(471)	(942)	(1,463)	(2,452)	(3,113)	(3,804)	(4,474)
Barrett 03	13.7	(1.44)	12.26	(110)	511	42	(471)	(942)	(1,463)	(2,452)	(3,113)	(3,804)	(4,474)
Barrett 04	15.8	(1.66)	14.14	(112)	509	40	(473)	(944)	(1,465)	(2,453)	(3,115)	(3,806)	(4,476)
Barrett 05	13.5	(1.42)	12.08	(109)	511	42	(471)	(942)	(1,463)	(2,451)	(3,113)	(3,804)	(4,474)
Barrett 06	14.1	(1.48)	12.62	(110)	511	41	(471)	(942)	(1,464)	(2,452)	(3,113)	(3,804)	(4,474)
Barrett 08	12.3	(1.29)	11.01	(108)	512	43	(470)	(941)	(1,462)	(2,450)	(3,112)	(3,803)	(4,473)
Barrett 09	31.2	(2.87)	28.33	(126)	495	25	(487)	(958)	(1,479)	(2,468)	(3,129)	(3,820)	(4,490)
Barrett 10	39.6	(3.64)	35.96	(133)	487	18	(495)	(966)	(1,487)	(2,475)	(3,137)	(3,828)	(4,498)
Barrett 11	39.0	(3.58)	35.42	(133)	488	18	(494)	(965)	(1,486)	(2,475)	(3,136)	(3,827)	(4,497)
Barrett 12	39.4	(3.62)	35.78	(133)	488	18	(494)	(966)	(1,487)	(2,475)	(3,136)	(3,828)	(4,498)

Additional Outage Impacts - Statewide System Margin													
			Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				(97)	523	54	(459)	(930)	(1,451)	(2,439)	(3,101)	(3,792)	(4,462)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)									
Northport 1, 2, 3, and 4	1,553.9	(163.16)	1,390.74	(1,488)	(867)	(1,337)	(1,849)	(2,321)	(2,842)	(3,830)	(4,491)	(5,182)	(5,852)
Northport 1	398.0	(41.79)	356.21	(454)	167	(302)	(815)	(1,286)	(1,807)	(2,796)	(3,457)	(4,148)	(4,818)
Northport 2	399.4	(41.94)	357.46	(455)	166	(304)	(816)	(1,287)	(1,808)	(2,797)	(3,458)	(4,149)	(4,819)
Northport 3	388.5	(40.79)	347.71	(445)	176	(294)	(806)	(1,277)	(1,799)	(2,787)	(3,448)	(4,139)	(4,809)
Northport 4	368.0	(38.64)	329.36	(427)	194	(276)	(788)	(1,259)	(1,780)	(2,769)	(3,430)	(4,121)	(4,791)
Port Jefferson GT 02 & 03	80.6	(8.46)	72.14	(170)	451	(18)	(531)	(1,002)	(1,523)	(2,511)	(3,173)	(3,864)	(4,534)
Port Jefferson GT 02	40.6	(4.26)	36.34	(134)	487	17	(495)	(966)	(1,487)	(2,476)	(3,137)	(3,828)	(4,498)
Port Jefferson GT 03	40.0	(4.20)	35.80	(133)	488	18	(494)	(966)	(1,487)	(2,475)	(3,136)	(3,828)	(4,498)
Port Jefferson 3 & 4	383.7	(40.29)	343.41	(441)	180	(290)	(802)	(1,273)	(1,794)	(2,783)	(3,444)	(4,135)	(4,805)
Port Jefferson 3	189.7	(19.92)	169.78	(267)	354	(116)	(628)	(1,100)	(1,621)	(2,609)	(3,270)	(3,962)	(4,632)
Port Jefferson 4	194.0	(20.37)	173.63	(271)	350	(120)	(632)	(1,103)	(1,625)	(2,613)	(3,274)	(3,965)	(4,635)
Hempstead (RR)	74.8	(7.85)	66.95	(164)	456	(13)	(526)	(997)	(1,518)	(2,506)	(3,167)	(3,859)	(4,529)
Glenwood GT 02, 04, & 05	146.7	(15.40)	131.30	(229)	392	(77)	(590)	(1,061)	(1,582)	(2,571)	(3,232)	(3,923)	(4,593)
Glenwood GT 02	59.3	(6.23)	53.07	(150)	470	1	(512)	(983)	(1,504)	(2,492)	(3,154)	(3,845)	(4,515)
Glenwood GT 04	43.3	(4.55)	38.75	(136)	485	15	(497)	(969)	(1,490)	(2,478)	(3,139)	(3,830)	(4,500)
Glenwood GT 05	44.1	(4.63)	39.47	(137)	484	14	(498)	(969)	(1,490)	(2,479)	(3,140)	(3,831)	(4,501)
Holtsville 01 through 10	525.3	(48.28)	477.02	(574)	46	(423)	(936)	(1,407)	(1,928)	(2,916)	(3,578)	(4,269)	(4,939)
Holtsville 01	55.0	(5.05)	49.95	(147)	473	4	(509)	(980)	(1,501)	(2,489)	(3,150)	(3,842)	(4,512)
Holtsville 02	57.0	(5.24)	51.76	(149)	472	2	(510)	(982)	(1,503)	(2,491)	(3,152)	(3,844)	(4,514)
Holtsville 03	51.1	(4.70)	46.40	(144)	477	7	(505)	(976)	(1,497)	(2,486)	(3,147)	(3,838)	(4,508)
Holtsville 04	54.3	(4.99)	49.31	(147)	474	5	(508)	(979)	(1,500)	(2,489)	(3,150)	(3,841)	(4,511)
Holtsville 05	53.4	(4.91)	48.49	(146)	475	5	(507)	(978)	(1,499)	(2,488)	(3,149)	(3,840)	(4,510)
Holtsville 06	49.1	(4.51)	44.59	(142)	479	9	(503)	(974)	(1,496)	(2,484)	(3,145)	(3,836)	(4,506)
Holtsville 07	53.0	(4.87)	48.13	(146)	475	6	(507)	(978)	(1,499)	(2,487)	(3,149)	(3,840)	(4,510)
Holtsville 08	52.1	(4.79)	47.31	(145)	476	7	(506)	(977)	(1,498)	(2,487)	(3,148)	(3,839)	(4,509)
Holtsville 09	54.2	(4.98)	49.22	(147)	474	5	(508)	(979)	(1,500)	(2,489)	(3,150)	(3,841)	(4,511)
Holtsville 10	46.1	(4.24)	41.86	(139)	482	12	(500)	(972)	(1,493)	(2,481)	(3,142)	(3,834)	(4,504)
Shoreham GT 3 & 4	83.3	(8.75)	74.55	(172)	449	(21)	(533)	(1,004)	(1,526)	(2,514)	(3,175)	(3,866)	(4,536)
Shoreham GT3	42.1	(4.42)	37.68	(135)	486	16	(496)	(967)	(1,489)	(2,477)	(3,138)	(3,829)	(4,499)
Shoreham GT4	41.2	(4.33)	36.87	(134)	487	17	(495)	(967)	(1,488)	(2,476)	(3,137)	(3,829)	(4,499)
East Hampton GT 01, 2, 3, & 4	24.2	(2.53)	21.67	(119)	502	32	(480)	(951)	(1,473)	(2,461)	(3,122)	(3,813)	(4,483)
East Hampton GT 01	18.2	(1.67)	16.53	(114)	507	37	(475)	(946)	(1,467)	(2,456)	(3,117)	(3,808)	(4,478)
East Hampton 2	2.0	(0.29)	1.71	(99)	522	52	(460)	(931)	(1,453)	(2,441)	(3,102)	(3,793)	(4,463)
East Hampton 3	2.0	(0.29)	1.71	(99)	522	52	(460)	(931)	(1,453)	(2,441)	(3,102)	(3,793)	(4,463)
East Hampton 4	2.0	(0.29)	1.71	(99)	522	52	(460)	(931)	(1,453)	(2,441)	(3,102)	(3,793)	(4,463)
Southold 1	9.4	(0.99)	8.41	(106)	515	45	(467)	(938)	(1,459)	(2,448)	(3,109)	(3,800)	(4,470)
S Hampton 1	7.8	(0.82)	6.98	(104)	516	47	(466)	(937)	(1,458)	(2,446)	(3,108)	(3,799)	(4,469)
Freeport CT 1 & 2	88.9	(9.33)	79.57	(177)	444	(26)	(538)	(1,009)	(1,531)	(2,519)	(3,180)	(3,871)	(4,541)
Freeport CT 1	45.9	(4.82)	41.08	(138)	482	13	(500)	(971)	(1,492)	(2,480)	(3,142)	(3,833)	(4,503)
Freeport CT 2	43.0	(4.52)	38.49	(136)	485	15	(497)	(968)	(1,489)	(2,478)	(3,139)	(3,830)	(4,500)
Flynn	139.5	(6.18)	133.32	(231)	390	(80)	(592)	(1,063)	(1,584)	(2,573)	(3,234)	(3,925)	(4,595)
Greenport GT1	51.2	(4.71)	46.49	(144)	477	7	(505)	(976)	(1,497)	(2,486)	(3,147)	(3,838)	(4,508)
Far Rockaway GT1 & GT2	104.6	(9.61)	94.99	(192)	428	(41)	(554)	(1,025)	(1,546)	(2,534)	(3,196)	(3,887)	(4,557)
Far Rockaway GT1	48.9	(4.49)	44.41	(142)	479	9	(503)	(974)	(1,495)	(2,484)	(3,145)	(3,836)	(4,506)
Far Rockaway GT2	55.7	(5.12)	50.58	(148)	473	3	(509)	(980)	(1,502)	(2,490)	(3,151)	(3,842)	(4,512)
Bethpage	52.0	(2.30)	49.70	(147)	474	4	(508)	(979)	(1,501)	(2,489)	(3,150)	(3,841)	(4,511)
Bethpage 3	76.0	(3.37)	72.63	(170)	451	(19)	(531)	(1,002)	(1,524)	(2,512)	(3,173)	(3,864)	(4,534)
Bethpage GT4	43.6	(4.58)	39.02	(136)	484	15	(498)	(969)	(1,490)	(2,478)	(3,140)	(3,831)	(4,501)
Stony Brook (BTM:NG)	0.0	0.00	0.00	(97)	523	54	(459)	(930)	(1,451)	(2,439)	(3,101)	(3,792)	(4,462)
Brentwood	45.0	(4.73)	40.28	(138)	483	14	(499)	(970)	(1,491)	(2,480)	(3,141)	(3,832)	(4,502)
Pilgrim GT1 & GT2	83.8	(8.80)	75.00	(172)	448	(21)	(534)	(1,005)	(1,526)	(2,514)	(3,176)	(3,867)	(4,537)
Pilgrim GT1	41.9	(4.40)	37.50	(135)	486	16	(496)	(967)	(1,488)	(2,477)	(3,138)	(3,829)	(4,499)
Pilgrim GT2	41.9	(4.40)	37.50	(135)	486	16	(496)	(967)	(1,488)	(2,477)	(3,138)	(3,829)	(4,499)
Pinelawn Power 1	73.4	(3.25)	70.15	(168)	453	(16)	(529)	(1,000)	(1,521)	(2,510)	(3,171)	(3,862)	(4,532)
Caithness_CC_1	306.9	(13.60)	293.30	(391)	230	(239)	(752)	(1,223)	(1,744)	(2,733)	(3,394)	(4,085)	(4,755)
Islip (RR)	8.5	(0.89)	7.61	(105)	516	46	(466)	(937)	(1,459)	(2,447)	(3,108)	(3,799)	(4,469)
Babylon (RR)	15.6	(1.64)	13.96	(111)	509	40	(473)	(944)	(1,465)	(2,453)	(3,115)	(3,806)	(4,476)
Huntington (RR)	24.7	(2.59)	22.11	(120)	501	32	(481)	(952)	(1,473)	(2,461)	(3,123)	(3,814)	(4,484)

Notes

1. Utilizes the Higher Demand Statewide 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.

Figure 73: AOI - Lower Hudson Valley Transmission Security Margin

Additional Outage Impacts - Lower Hudson Valley													
			Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Lower Hudson Valley Transmission Security Margin, Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,193	2,256	2,107	1,959	1,749	1,456	762	436	81	(267)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)									
Bowline 1 & 2	1,143.0	(120.02)	1,022.99	170	1,233	1,084	936	726	433	(261)	(587)	(942)	(1,290)
Bowline 1	577.8	(60.67)	517.13	676	1,739	1,590	1,442	1,232	939	245	(81)	(436)	(784)
Bowline 2	565.2	(59.35)	505.85	687	1,750	1,601	1,453	1,243	950	256	(70)	(425)	(773)
Danskammer 1, 2, 3, & 4	499.4	(52.44)	446.96	746	1,809	1,660	1,512	1,302	1,009	315	(11)	(366)	(714)
Danskammer 1	68.5	(7.19)	61.31	1,132	2,195	2,046	1,898	1,688	1,395	701	374	20	(329)
Danskammer 2	65.0	(6.83)	58.18	1,135	2,198	2,049	1,901	1,691	1,398	704	378	23	(325)
Danskammer 3	140.1	(14.71)	125.39	1,068	2,131	1,982	1,833	1,623	1,331	636	310	(44)	(393)
Danskammer 4	225.8	(23.71)	202.09	991	2,054	1,905	1,757	1,547	1,254	560	234	(121)	(469)
Roseton 1 & 2	1,228.2	(128.96)	1,099.24	94	1,157	1,008	860	650	357	(337)	(663)	(1,018)	(1,366)
Roseton 1	615.7	(64.65)	551.05	642	1,705	1,556	1,408	1,198	905	211	(115)	(470)	(818)
Roseton 2	612.5	(64.31)	548.19	645	1,708	1,559	1,411	1,201	908	214	(112)	(467)	(815)
Hillburn GT	36.0	(3.31)	32.69	1,160	2,224	2,074	1,926	1,716	1,423	729	403	49	(300)
Shoemaker GT	35.4	(3.25)	32.15	1,161	2,224	2,075	1,927	1,717	1,424	730	404	49	(299)
DCRRA	6.2	(0.65)	5.55	1,188	2,251	2,101	1,953	1,743	1,451	756	430	76	(273)
CPV Valley CC1 & CC2	645.4	(28.59)	616.81	576	1,640	1,490	1,342	1,132	839	145	(181)	(536)	(884)
CPV Valley CC1	322.7	(14.30)	308.40	885	1,948	1,799	1,650	1,440	1,148	453	127	(227)	(576)
CPV Valley CC2	322.7	(14.30)	308.40	885	1,948	1,799	1,650	1,440	1,148	453	127	(227)	(576)
Cricket Valley CC1, CC2, & CC3	1,050.8	(46.55)	1,004.25	189	1,252	1,103	955	745	452	(242)	(568)	(923)	(1,271)
Cricket Valley CC1	347.1	(15.38)	331.72	861	1,925	1,775	1,627	1,417	1,124	430	104	(250)	(599)
Cricket Valley CC2	345.0	(15.28)	329.72	863	1,927	1,777	1,629	1,419	1,126	432	106	(248)	(597)
Cricket Valley CC3	358.7	(15.89)	342.81	850	1,914	1,764	1,616	1,406	1,113	419	93	(262)	(610)
Wheelabrator Westchester	52.5	(5.51)	46.99	1,146	2,209	2,060	1,912	1,702	1,409	715	389	34	(314)
Arthur Kill ST 2 & 3	884.9	(92.91)	791.99	401	1,464	1,315	1,167	957	664	(30)	(356)	(711)	(1,059)
Arthur Kill ST 2	362.2	(38.03)	324.17	869	1,932	1,783	1,635	1,425	1,132	438	112	(243)	(591)
Arthur Kill ST 3	522.7	(54.88)	467.82	725	1,789	1,639	1,491	1,281	988	294	(32)	(387)	(735)
Brooklyn Navy Yard	247.5	(10.96)	236.54	957	2,020	1,870	1,722	1,512	1,220	525	199	(155)	(504)
Astoria 2, 3, & 5	916.9	(96.27)	820.63	372	1,436	1,286	1,138	928	635	(59)	(385)	(739)	(1,088)
Astoria 2	171.2	(17.98)	153.22	1,040	2,103	1,954	1,806	1,596	1,303	609	283	(72)	(420)
Astoria 3	372.4	(39.10)	333.30	860	1,923	1,774	1,626	1,416	1,123	429	103	(252)	(601)
Astoria 5	373.3	(39.20)	334.10	859	1,922	1,773	1,625	1,415	1,122	428	102	(253)	(601)
Ravenswood ST 01, 02, & 03	1,729.6	(181.61)	1,547.99	(68)	708	559	411	201	(92)	(786)	(1,112)	(1,467)	(1,815)
Ravenswood ST 01	367.0	(38.54)	328.47	865	1,928	1,778	1,630	1,420	1,128	433	107	(247)	(596)
Ravenswood ST 02	375.3	(39.41)	335.89	857	1,920	1,771	1,623	1,413	1,120	426	100	(255)	(603)
Ravenswood ST 03	987.3	(103.67)	883.63	597	1,373	1,223	1,075	865	572	(122)	(448)	(802)	(1,151)
Ravenswood CC 04	228.6	(10.13)	218.47	975	2,038	1,888	1,740	1,530	1,238	543	217	(137)	(486)
East River 1, 2, 6, & 7	620.5	(46.55)	573.95	619	1,682	1,533	1,385	1,175	882	188	(138)	(493)	(841)
East River 1	151.5	(6.71)	144.79	1,048	2,112	1,962	1,814	1,604	1,311	617	291	(64)	(412)
East River 2	155.0	(6.87)	148.13	1,045	2,108	1,959	1,811	1,601	1,308	614	288	(67)	(415)
East River 6	131.6	(13.82)	117.78	1,075	2,139	1,989	1,841	1,631	1,338	644	318	(37)	(385)
East River 7	182.4	(19.15)	163.25	1,030	2,093	1,944	1,796	1,586	1,293	599	273	(82)	(430)
Linden Cogen	737.1	(32.65)	704.45	489	1,552	1,402	1,254	1,044	752	57	(269)	(623)	(972)
KIAC_JFK (BTM:NG)	106.4	(4.71)	101.69	1,091	2,155	2,005	1,857	1,647	1,354	660	334	(20)	(369)
Gowanus 5 & 6	79.9	(8.39)	71.51	1,122	2,185	2,035	1,887	1,677	1,385	690	364	10	(339)
Gowanus 5	40.0	(4.20)	35.80	1,157	2,221	2,071	1,923	1,713	1,420	726	400	45	(303)
Gowanus 6	39.9	(4.19)	35.71	1,157	2,221	2,071	1,923	1,713	1,420	726	400	46	(303)
Kent	46.0	(4.83)	41.17	1,152	2,215	2,066	1,918	1,708	1,415	721	395	40	(308)
Pouch	45.4	(4.77)	40.63	1,152	2,216	2,066	1,918	1,708	1,415	721	395	41	(308)
Hellgate 1 & 2	79.5	(8.35)	71.15	1,122	2,185	2,036	1,888	1,678	1,385	691	365	10	(338)
Hellgate 1	39.9	(4.19)	35.71	1,157	2,221	2,071	1,923	1,713	1,420	726	400	46	(303)
Hellgate 2	39.6	(4.16)	35.44	1,158	2,221	2,071	1,923	1,713	1,421	726	400	46	(303)
Harlem River 1 & 2	79.5	(8.35)	71.15	1,122	2,185	2,036	1,888	1,678	1,385	691	365	10	(338)
Harlem River 1	39.9	(4.19)	35.71	1,157	2,221	2,071	1,923	1,713	1,420	726	400	46	(303)
Harlem River 2	39.6	(4.16)	35.44	1,158	2,221	2,071	1,923	1,713	1,421	726	400	46	(303)
Vernon Blvd 2 & 3	79.9	(8.39)	71.51	1,122	2,185	2,035	1,887	1,677	1,385	690	364	10	(339)
Vernon Blvd 2	40.0	(4.20)	35.80	1,157	2,221	2,071	1,923	1,713	1,420	726	400	45	(303)
Vernon Blvd 3	39.9	(4.19)	35.71	1,157	2,221	2,071	1,923	1,713	1,420	726	400	46	(303)
Astoria CC 1 & 2	474.0	(21.00)	453.00	740	1,803	1,654	1,506	1,296	1,003	309	(17)	(372)	(720)
Astoria CC 1	237.0	(10.50)	226.50	967	2,030	1,880	1,732	1,522	1,230	535	209	(145)	(494)
Astoria CC 2	237.0	(10.50)	226.50	967	2,030	1,880	1,732	1,522	1,230	535	209	(145)	(494)
Astoria East Energy CC1 & CC2	579.2	(25.66)	553.54	640	1,703	1,553	1,405	1,195	903	208	(118)	(472)	(821)
Astoria East Energy - CC1	289.6	(12.83)	276.77	916	1,980	1,830	1,682	1,472	1,179	485	159	(196)	(544)
Astoria East Energy - CC2	289.6	(12.83)	276.77	916	1,980	1,830	1,682	1,472	1,179	485	159	(196)	(544)

Additional Outage Impacts - Lower Hudson Valley

			Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Lower Hudson Valley Transmission Security Margin, Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,193	2,256	2,107	1,959	1,749	1,456	762	436	81	(267)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)									
Astoria Energy 2 - CC3 & CC4	570.6	(25.28)	545.32	648	1,711	1,562	1,413	1,203	911	217	(110)	(464)	(813)
Astoria Energy 2 - CC3	285.3	(12.64)	272.66	920	1,984	1,834	1,686	1,476	1,183	489	163	(191)	(540)
Astoria Energy 2 - CC4	285.3	(12.64)	272.66	920	1,984	1,834	1,686	1,476	1,183	489	163	(191)	(540)
Bayonne EC CT G1 through G10	598.6	(55.01)	543.59	650	1,713	1,563	1,415	1,205	913	218	(108)	(462)	(811)
Bayonne EC CTG1	62.0	(5.70)	56.30	1,137	2,200	2,051	1,903	1,693	1,400	706	380	25	(324)
Bayonne EC CTG2	58.0	(5.33)	52.67	1,140	2,204	2,054	1,906	1,696	1,403	709	383	29	(320)
Bayonne EC CTG3	58.0	(5.33)	52.67	1,140	2,204	2,054	1,906	1,696	1,403	709	383	29	(320)
Bayonne EC CTG4	61.1	(5.62)	55.48	1,138	2,201	2,051	1,903	1,693	1,401	706	380	26	(323)
Bayonne EC CTG5	58.5	(5.38)	53.12	1,140	2,203	2,054	1,906	1,696	1,403	709	383	28	(320)
Bayonne EC CTG6	59.0	(5.42)	53.58	1,140	2,203	2,053	1,905	1,695	1,403	708	382	28	(321)
Bayonne EC CTG7	59.3	(5.45)	53.85	1,139	2,202	2,053	1,905	1,695	1,402	708	382	27	(321)
Bayonne EC CTG8	60.0	(5.51)	54.49	1,139	2,202	2,052	1,904	1,694	1,402	707	381	27	(322)
Bayonne EC CTG9	61.3	(5.63)	55.67	1,137	2,201	2,051	1,903	1,693	1,400	706	380	26	(323)
Bayonne EC CTG10	61.4	(5.64)	55.76	1,137	2,201	2,051	1,903	1,693	1,400	706	380	26	(323)

Notes
1. Utilizes the High Demand Transmission Security Margin for Summer Peak with Expected Weather.
2. In 2025 the most limiting contingency combination includes the loss of Ravenswood 3. 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.

Figure 74: AOI - New York City Transmission Security Margin

Additional Outage Impacts - New York City													
			Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
New York City Transmission Security Margin, Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				(461)	209	160	30	(100)	(140)	(647)	(807)	(967)	(1,137)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)									
Arthur Kill ST 2 & 3	884.9	(92.91)	791.99	(1,253)	(583)	(632)	(762)	(892)	(932)	(1,439)	(1,599)	(1,759)	(1,929)
Arthur Kill ST 2	362.2	(38.03)	324.17	(785)	(115)	(164)	(294)	(424)	(464)	(971)	(1,131)	(1,291)	(1,461)
Arthur Kill ST 3	522.7	(54.88)	467.82	(929)	(259)	(308)	(438)	(568)	(608)	(1,115)	(1,275)	(1,435)	(1,605)
Brooklyn Navy Yard	247.5	(10.96)	236.54	(698)	(28)	(76)	(206)	(336)	(376)	(883)	(1,043)	(1,203)	(1,373)
Astoria 2, 3, & 5	916.9	(96.27)	820.63	(1,282)	(612)	(660)	(790)	(920)	(960)	(1,468)	(1,628)	(1,788)	(1,958)
Astoria 2	171.2	(17.98)	153.22	(615)	55	7	(123)	(253)	(293)	(800)	(960)	(1,120)	(1,290)
Astoria 3	372.4	(39.10)	333.30	(795)	(125)	(173)	(303)	(433)	(473)	(980)	(1,140)	(1,300)	(1,470)
Astoria 5	373.3	(39.20)	334.10	(795)	(125)	(174)	(304)	(434)	(474)	(981)	(1,141)	(1,301)	(1,471)
Ravenswood ST 01, 02, & 03 (2)	1,729.6	(181.61)	1,547.99	(1,822)	(1,152)	(1,200)	(1,330)	(1,460)	(1,500)	(2,008)	(2,168)	(2,328)	(2,498)
Ravenswood ST 01	367.0	(38.54)	328.47	(790)	(120)	(168)	(298)	(428)	(468)	(975)	(1,135)	(1,295)	(1,465)
Ravenswood ST 02	375.3	(39.41)	335.89	(797)	(127)	(176)	(306)	(436)	(476)	(983)	(1,143)	(1,303)	(1,473)
Ravenswood ST 03 (2)	987.3	(103.67)	883.63	(1,158)	(488)	(156)	(666)	(796)	(836)	(1,343)	(1,503)	(1,663)	(1,833)
Ravenswood CC 04	228.6	(10.13)	218.47	(680)	(10)	(58)	(188)	(318)	(358)	(865)	(1,025)	(1,185)	(1,355)
East River 1, 2, 6, & 7	620.5	(46.55)	573.95	(1,035)	(365)	(414)	(544)	(674)	(714)	(1,221)	(1,381)	(1,541)	(1,711)
East River 1	151.5	(6.71)	144.79	(606)	64	16	(114)	(244)	(284)	(792)	(952)	(1,112)	(1,282)
East River 2	155.0	(6.87)	148.13	(609)	61	12	(118)	(248)	(288)	(795)	(955)	(1,115)	(1,285)
East River 6	131.6	(13.82)	117.78	(579)	91	43	(87)	(217)	(257)	(765)	(925)	(1,085)	(1,255)
East River 7	182.4	(19.15)	163.25	(625)	45	(3)	(133)	(263)	(303)	(810)	(970)	(1,130)	(1,300)
Linden Cogen	737.1	(32.65)	704.45	(1,166)	(496)	(544)	(674)	(804)	(844)	(1,351)	(1,511)	(1,671)	(1,841)
KIAC_JFK (BTM:NG)	106.4	(4.71)	101.69	(563)	107	59	(71)	(201)	(241)	(749)	(909)	(1,069)	(1,239)
Gowanus 5 & 6	79.9	(8.39)	71.51	(533)	137	89	(41)	(171)	(211)	(718)	(878)	(1,038)	(1,208)
Gowanus 5	40.0	(4.20)	35.80	(497)	173	124	(6)	(136)	(176)	(683)	(843)	(1,003)	(1,173)
Gowanus 6	39.9	(4.19)	35.71	(497)	173	125	(5)	(135)	(175)	(683)	(843)	(1,003)	(1,173)
Kent	46.0	(4.83)	41.17	(502)	168	119	(11)	(141)	(181)	(688)	(848)	(1,008)	(1,178)
Pouch	45.4	(4.77)	40.63	(502)	168	120	(10)	(140)	(180)	(688)	(848)	(1,008)	(1,178)
Hellgate 1 & 2	79.5	(8.35)	71.15	(532)	138	89	(41)	(171)	(211)	(718)	(878)	(1,038)	(1,208)
Hellgate 1	39.9	(4.19)	35.71	(497)	173	125	(5)	(135)	(175)	(683)	(843)	(1,003)	(1,173)
Hellgate 2	39.6	(4.16)	35.44	(497)	173	125	(5)	(135)	(175)	(682)	(842)	(1,002)	(1,172)
Harlem River 1 & 2	79.5	(8.35)	71.15	(532)	138	89	(41)	(171)	(211)	(718)	(878)	(1,038)	(1,208)
Harlem River 1	39.9	(4.19)	35.71	(497)	173	125	(5)	(135)	(175)	(683)	(843)	(1,003)	(1,173)
Harlem River 2	39.6	(4.16)	35.44	(497)	173	125	(5)	(135)	(175)	(682)	(842)	(1,002)	(1,172)
Vernon Blvd 2 & 3	79.9	(8.39)	71.51	(533)	137	89	(41)	(171)	(211)	(718)	(878)	(1,038)	(1,208)
Vernon Blvd 2	40.0	(4.20)	35.80	(497)	173	124	(6)	(136)	(176)	(683)	(843)	(1,003)	(1,173)
Vernon Blvd 3	39.9	(4.19)	35.71	(497)	173	125	(5)	(135)	(175)	(683)	(843)	(1,003)	(1,173)
Astoria CC 1 & 2	474.0	(21.00)	453.00	(914)	(244)	(293)	(423)	(553)	(593)	(1,100)	(1,260)	(1,420)	(1,590)
Astoria CC 1	237.0	(10.50)	226.50	(688)	(18)	(66)	(196)	(326)	(366)	(873)	(1,033)	(1,193)	(1,363)
Astoria CC 2	237.0	(10.50)	226.50	(688)	(18)	(66)	(196)	(326)	(366)	(873)	(1,033)	(1,193)	(1,363)
Astoria East Energy CC1 & CC2	579.2	(25.66)	553.54	(1,015)	(345)	(393)	(523)	(653)	(693)	(1,200)	(1,360)	(1,520)	(1,690)
Astoria East Energy - CC1	289.6	(12.83)	276.77	(738)	(68)	(116)	(246)	(376)	(416)	(924)	(1,084)	(1,244)	(1,414)
Astoria East Energy - CC2	289.6	(12.83)	276.77	(738)	(68)	(116)	(246)	(376)	(416)	(924)	(1,084)	(1,244)	(1,414)
Astoria Energy 2 - CC3 & CC4	570.6	(25.28)	545.32	(1,007)	(337)	(385)	(515)	(645)	(685)	(1,192)	(1,352)	(1,512)	(1,682)
Astoria Energy 2 - CC3	285.3	(12.64)	272.66	(734)	(64)	(112)	(242)	(372)	(412)	(920)	(1,080)	(1,240)	(1,410)
Astoria Energy 2 - CC4	285.3	(12.64)	272.66	(734)	(64)	(112)	(242)	(372)	(412)	(920)	(1,080)	(1,240)	(1,410)
Bayonne EC CT G1 through G10	598.6	(55.01)	543.59	(1,005)	(335)	(383)	(513)	(643)	(683)	(1,190)	(1,350)	(1,510)	(1,680)
Bayonne EC CTG1	62.0	(5.70)	56.30	(518)	152	104	(26)	(156)	(196)	(703)	(863)	(1,023)	(1,193)
Bayonne EC CTG2	58.0	(5.33)	52.67	(514)	156	108	(22)	(152)	(192)	(700)	(860)	(1,020)	(1,190)
Bayonne EC CTG3	58.0	(5.33)	52.67	(514)	156	108	(22)	(152)	(192)	(700)	(860)	(1,020)	(1,190)
Bayonne EC CTG4	61.1	(5.62)	55.48	(517)	153	105	(25)	(155)	(195)	(702)	(862)	(1,022)	(1,192)
Bayonne EC CTG5	58.5	(5.38)	53.12	(514)	156	107	(23)	(153)	(193)	(700)	(860)	(1,020)	(1,190)
Bayonne EC CTG6	59.0	(5.42)	53.58	(515)	155	107	(23)	(153)	(193)	(700)	(860)	(1,020)	(1,190)
Bayonne EC CTG7	59.3	(5.45)	53.85	(515)	155	106	(24)	(154)	(194)	(701)	(861)	(1,021)	(1,191)
Bayonne EC CTG8	60.0	(5.51)	54.49	(516)	154	106	(24)	(154)	(194)	(701)	(861)	(1,021)	(1,191)
Bayonne EC CTG9	61.3	(5.63)	55.67	(517)	153	105	(25)	(155)	(195)	(703)	(863)	(1,023)	(1,193)
Bayonne EC CTG10	61.4	(5.64)	55.76	(517)	153	105	(25)	(155)	(195)	(703)	(863)	(1,023)	(1,193)

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 3. 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.

Figure 75: AOI - Long Island Transmission Security Margin

Additional Outage Impacts - Long Island													
			Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Long Island Transmission Security Margin, Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				368	437	409	372	326	2,228	2,113	2,024	1,923	1,821
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)									
Greenport IC 4, 5, & 6	5.6	(0.80)	4.80	363	432	404	368	321	2,223	2,108	2,019	1,918	1,816
Greenport IC 4	1.0	(0.14)	0.86	367	436	408	372	325	2,227	2,112	2,023	1,922	1,820
Greenport IC 5	1.5	(0.21)	1.29	366	436	408	371	325	2,226	2,112	2,022	1,922	1,820
Greenport IC 6	3.1	(0.44)	2.66	365	434	406	370	323	2,225	2,111	2,021	1,920	1,818
Freeport 1-2, 1-3, & 2-3	21.1	(2.42)	18.68	349	418	390	354	307	2,209	2,095	2,005	1,904	1,802
Freeport 1-2	2.5	(0.36)	2.14	366	435	407	370	324	2,226	2,111	2,022	1,921	1,819
Freeport 1-3	2.9	(0.42)	2.48	365	435	406	370	323	2,225	2,111	2,021	1,921	1,819
Freeport 2-3	15.7	(1.65)	14.05	354	423	395	358	312	2,214	2,099	2,010	1,909	1,807
Charles P Killer 09 through 14	16.0	(1.50)	14.50	353	423	394	358	311	2,213	2,099	2,009	1,909	1,807
Charles P Keller 09	1.9	(0.18)	1.72	366	435	407	371	324	2,226	2,112	2,022	1,921	1,819
Charles P Keller 10	1.9	(0.18)	1.72	366	435	407	371	324	2,226	2,112	2,022	1,921	1,819
Charles P Keller 11	2.8	(0.26)	2.54	365	434	406	370	323	2,225	2,111	2,021	1,921	1,819
Charles P Keller 12	3.0	(0.28)	2.72	365	434	406	370	323	2,225	2,111	2,021	1,920	1,818
Charles P Keller 13	3.0	(0.28)	2.72	365	434	406	370	323	2,225	2,111	2,021	1,920	1,818
Charles P Keller 14	3.4	(0.32)	3.08	365	434	406	369	323	2,225	2,110	2,021	1,920	1,818
Wading River 1, 2, & 3	231.4	(24.30)	207.10	161	230	202	165	119	2,021	1,906	1,817	1,716	1,614
Wading River 1	79.7	(8.37)	71.33	296	366	338	301	255	2,156	2,042	1,952	1,852	1,750
Wading River 2	76.4	(8.02)	68.38	299	369	341	304	257	2,159	2,045	1,955	1,855	1,753
Wading River 3	75.3	(7.91)	67.39	300	370	342	305	258	2,160	2,046	1,956	1,856	1,754
Barrett ST 01 & 02	383.0	(40.22)	342.79	25	94	66	30	(17)	1,885	1,770	1,681	1,580	1,478
Barrett ST 01	195.0	(20.48)	174.53	193	263	234	198	151	2,053	1,939	1,849	1,749	1,647
Barrett ST 02	188.0	(19.74)	168.26	199	269	241	204	158	2,060	1,945	1,855	1,755	1,653
Barrett GT 01 through 12	246.2	(23.90)	222.30	145	215	187	150	104	2,005	1,891	1,801	1,701	1,599
Barrett GT 01	14.0	(1.47)	12.53	355	425	396	360	313	2,215	2,101	2,011	1,911	1,809
Barrett GT 02	13.6	(1.43)	12.17	356	425	397	360	314	2,216	2,101	2,012	1,911	1,809
Barrett 03	13.7	(1.44)	12.26	355	425	397	360	314	2,216	2,101	2,011	1,911	1,809
Barrett 04	15.8	(1.66)	14.14	354	423	395	358	312	2,214	2,099	2,010	1,909	1,807
Barrett 05	13.5	(1.42)	12.08	356	425	397	360	314	2,216	2,101	2,012	1,911	1,809
Barrett 06	14.1	(1.48)	12.62	355	424	396	360	313	2,215	2,101	2,011	1,911	1,809
Barrett 08	12.3	(1.29)	11.01	357	426	398	361	315	2,217	2,102	2,013	1,912	1,810
Barrett 09	31.2	(2.87)	28.33	339	409	381	344	298	2,199	2,085	1,995	1,895	1,793
Barrett 10	39.6	(3.64)	35.96	332	401	373	336	290	2,192	2,077	1,988	1,887	1,785
Barrett 11	39.0	(3.58)	35.42	332	402	374	337	290	2,192	2,078	1,988	1,888	1,786
Barrett 12	39.4	(3.62)	35.78	332	401	373	337	290	2,192	2,077	1,988	1,887	1,785
Northport 1, 2, 3, and 4	1,553.9	(163.16)	1,390.74	(1,023)	(954)	(982)	(1,018)	(1,065)	837	722	633	532	430
Northport 1	398.0	(41.79)	356.21	12	81	53	16	(30)	1,872	1,757	1,667	1,567	1,465
Northport 2	399.4	(41.94)	357.46	10	80	51	15	(32)	1,870	1,756	1,666	1,566	1,464
Northport 3	388.5	(40.79)	347.71	20	89	61	25	(22)	1,880	1,766	1,676	1,575	1,473
Northport 4	368.0	(38.64)	329.36	38	108	80	43	(4)	1,898	1,784	1,694	1,594	1,492
Port Jefferson GT 02 & 03	80.6	(8.46)	72.14	296	365	337	300	254	2,156	2,041	1,952	1,851	1,749
Port Jefferson GT 02	40.6	(4.26)	36.34	331	401	373	336	290	2,191	2,077	1,987	1,887	1,785
Port Jefferson GT 03	40.0	(4.20)	35.80	332	401	373	337	290	2,192	2,077	1,988	1,887	1,785
Port Jefferson 3 & 4	383.7	(40.29)	343.41	24	94	66	29	(18)	1,884	1,770	1,680	1,580	1,478
Port Jefferson 3	189.7	(19.92)	169.78	198	267	239	203	156	2,058	1,943	1,854	1,753	1,651
Port Jefferson 4	194.0	(20.37)	173.63	194	263	235	199	152	2,054	1,940	1,850	1,750	1,648
Hempstead (RR)	74.8	(7.85)	66.95	301	370	342	305	259	2,161	2,046	1,957	1,856	1,754
Glenwood GT 02, 04, & 05	146.7	(15.40)	131.30	236	306	278	241	195	2,096	1,982	1,892	1,792	1,690
Glenwood GT 02	59.3	(6.23)	53.07	315	384	356	319	273	2,175	2,060	1,971	1,870	1,768
Glenwood GT 04	43.3	(4.55)	38.75	329	398	370	334	287	2,189	2,074	1,985	1,884	1,782
Glenwood GT 05	44.1	(4.63)	39.47	328	398	369	333	286	2,188	2,074	1,984	1,884	1,782
Holtsville 01 through 10	525.3	(48.28)	477.02	(109)	(40)	(68)	(105)	(151)	1,751	1,636	1,547	1,446	1,344
Holtsville 01	55.0	(5.05)	49.95	318	387	359	322	276	2,178	2,063	1,974	1,873	1,771
Holtsville 02	57.0	(5.24)	51.76	316	385	357	321	274	2,176	2,061	1,972	1,871	1,769
Holtsville 03	51.1	(4.70)	46.40	321	391	363	326	279	2,181	2,067	1,977	1,877	1,775
Holtsville 04	54.3	(4.99)	49.31	318	388	360	323	277	2,178	2,064	1,974	1,874	1,772
Holtsville 05	53.4	(4.91)	48.49	319	389	360	324	277	2,179	2,065	1,975	1,875	1,773
Holtsville 06	49.1	(4.51)	44.59	323	392	364	328	281	2,183	2,069	1,979	1,879	1,777
Holtsville 07	53.0	(4.87)	48.13	320	389	361	324	278	2,180	2,065	1,976	1,875	1,773
Holtsville 08	52.1	(4.79)	47.31	320	390	362	325	279	2,180	2,066	1,976	1,876	1,774
Holtsville 09	54.2	(4.98)	49.22	319	388	360	323	277	2,179	2,064	1,974	1,874	1,772
Holtsville 10	46.1	(4.24)	41.86	326	395	367	331	284	2,186	2,071	1,982	1,881	1,779

Additional Outage Impacts - Long Island													
			Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Long Island Transmission Security Margin, Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				368	437	409	372	326	2,228	2,113	2,024	1,923	1,821
Unit Name	**Summer DMNC (MW)**	**NERC 5-Year Class Average De-Rate (MW)**	**Summer De-Rated Capability (MW)**	**Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)**									
Shoreham GT 3 & 4	83.3	(8.75)	74.55	293	362	334	298	251	2,153	2,039	1,949	1,849	1,747
Shoreham GT3	42.1	(4.42)	37.68	330	399	371	335	288	2,190	2,076	1,986	1,885	1,783
Shoreham GT4	41.2	(4.33)	36.87	331	400	372	336	289	2,191	2,076	1,987	1,886	1,784
East Hampton GT 01, 2, 3, & 4	24.2	(2.53)	21.67	346	415	387	351	304	2,206	2,092	2,002	1,901	1,799
East Hampton GT 01	18.2	(1.67)	16.53	351	421	392	356	309	2,211	2,097	2,007	1,907	1,805
East Hampton 2	2.0	(0.29)	1.71	366	435	407	371	324	2,226	2,112	2,022	1,921	1,819
East Hampton 3	2.0	(0.29)	1.71	366	435	407	371	324	2,226	2,112	2,022	1,921	1,819
East Hampton 4	2.0	(0.29)	1.71	366	435	407	371	324	2,226	2,112	2,022	1,921	1,819
Southold 1	9.4	(0.99)	8.41	359	429	401	364	317	2,219	2,105	2,015	1,915	1,813
S Hampton 1	7.8	(0.82)	6.98	361	430	402	365	319	2,221	2,106	2,017	1,916	1,814
Freeport CT 1 & 2	88.9	(9.33)	79.57	288	357	329	293	246	2,148	2,034	1,944	1,844	1,742
Freeport CT 1	45.9	(4.82)	41.08	327	396	368	331	285	2,187	2,072	1,983	1,882	1,780
Freeport CT 2	43.0	(4.52)	38.49	329	399	370	334	287	2,189	2,075	1,985	1,885	1,783
Flynn	139.5	(6.18)	133.32	234	304	276	239	193	2,094	1,980	1,890	1,790	1,688
Greenport GT1	51.2	(4.71)	46.49	321	391	362	326	279	2,181	2,067	1,977	1,877	1,775
Far Rockaway GT1 & GT2	104.6	(9.61)	94.99	273	342	314	277	231	2,133	2,018	1,929	1,828	1,726
Far Rockaway GT1	48.9	(4.49)	44.41	323	393	365	328	281	2,183	2,069	1,979	1,879	1,777
Far Rockaway GT2	55.7	(5.12)	50.58	317	386	358	322	275	2,177	2,063	1,973	1,873	1,771
Bethpage	52.0	(2.30)	49.70	318	387	359	323	276	2,178	2,064	1,974	1,873	1,771
Bethpage 3	76.0	(3.37)	72.63	295	364	336	300	253	2,155	2,041	1,951	1,851	1,749
Bethpage GT4	43.6	(4.58)	39.02	329	398	370	333	287	2,189	2,074	1,985	1,884	1,782
Stony Brook (BTM:NG)	0.0	0.00	0.00	368	437	409	372	326	2,228	2,113	2,024	1,923	1,821
Brentwood	45.0	(4.73)	40.28	327	397	369	332	286	2,187	2,073	1,983	1,883	1,781
Pilgrim GT1 & GT2	83.8	(8.80)	75.00	293	362	334	297	251	2,153	2,038	1,949	1,848	1,746
Pilgrim GT1	41.9	(4.40)	37.50	330	400	371	335	288	2,190	2,076	1,986	1,886	1,784
Pilgrim GT2	41.9	(4.40)	37.50	330	400	371	335	288	2,190	2,076	1,986	1,886	1,784
Pinelawn Power 1	73.4	(3.25)	70.15	298	367	339	302	256	2,158	2,043	1,954	1,853	1,751
Caithness_CC_1	306.9	(13.60)	293.30	74	144	116	79	33	1,934	1,820	1,730	1,630	1,528
Islip (RR)	8.5	(0.89)	7.61	360	429	401	365	318	2,220	2,106	2,016	1,916	1,814
Babylon (RR)	15.6	(1.64)	13.96	354	423	395	358	312	2,214	2,099	2,010	1,909	1,807
Huntington (RR)	24.7	(2.59)	22.11	346	415	387	350	304	2,206	2,091	2,002	1,901	1,799

Notes

1. Utilizes the Higher Demand Transmission Security Margin for Summer Peak with Expected Weather.

Appendix H - Historic Congestion

Appendix A of Attachment Y of the OATT states:

> As part of its CSPP, the ISO will prepare summaries and detailed analysis of historic and projected congestion across the NYS Transmission System. This will include analysis to identify the significant causes of historic congestion in an effort to help market participants and other interested parties distinguish persistent and addressable congestion from congestion that results from onetime events or transient adjustments in operating procedures that may or may not recur. This information will assist market participants and other stakeholders to make appropriately informed decisions.

The historic congestion information can be found on the NYISO website:

https://www.nyiso.com/ny-power-system-information-outlook (Congested Elements Reports)

Also, information on the NYISO's Economic Planning Studies can be found here:

https://www.nyiso.com/library (Planning Reports, System & Resource Outlook)

Appendix I - Reliability Compliance Obligations and Activities

The Reliability Needs Assessment (RNA) is not the only NYISO work product or activity related to reliability planning. The NYISO has various compliance obligations under NERC, NPCC, and the NYSRC. The periodicity of these requirements varies among the standards and requirements. The purpose of this section is to discuss the NERC Planning Coordinator and Transmission Planner obligations fulfilled by the NYISO, as well as the other NPCC and NYSRC planning compliance obligations. While achieving compliance with all NERC, NPCC, and NYSRC obligations is critical to ensuring the continued reliability of the transmission system, this section primarily discusses the planning compliance requirements that closely align with this RNA. The full details of the compliance obligations are found within the reliability standards and requirements themselves. Publicly available results for the compliance activities listed below can be found on the NYISO's website under Planning – Reliability Compliance.[23]

The purpose of the NERC Reliability Standards is to "define the reliability requirements for planning and operating the North American bulk power system and are developed using a results-based approach that focuses on performance, risk management, and entity capabilities." The objective of NPCC Directory #1 and the NYSRC Reliability Rules and Compliance Manual are to provide a "design-based approach" to design and operate the bulk power system to a level of reliability that will not result in the loss or unintentional separation of a major portion of the system from any of the planning and operations contingencies with the intent of avoiding instability, voltage collapse and widespread cascading outages. Figure 76 shows the various NERC Reliability Standards with requirements applicable to the NYISO as a NERC registered Planning Coordinator and/or Transmission Planner. The NPCC planning compliance obligations are primarily located in NPCC Regional Reliability Reference Directory #1 Design and Operation of the Bulk Power System. The NYSRC planning compliance obligations are located in the Reliability Rules and Compliance Manual.

Fundamental to any reliability study is the accuracy modeling data provided by the entities responsible for providing the data. The data requirements for the development of the steady state, dynamics, and short circuit models are provided in the NYISO Reliability Analysis Data Manual (RAD Manual).[24] This data primarily comes from compliance with NERC MOD standards. Much of this data is collected through the annual database update process outlined in the RAD Manual and the annual FERC Form 715 filing to which the transmitting utilities certify, to the best of their knowledge, the accuracy of the data. Additional compliance obligations provide for the accuracy of the modeling data through comparison

[23] https://www.nyiso.com/planning-reliability-compliance.
[24] https://www.nyiso.com/documents/20142/2924447/rel-anl-data-mnl.pdf.

to actual system events (*e.g.,* MOD-026, MOD-026, and MOD-033).

Following the completion of the annual database update, these databases are used for study work, such as in the Reliability Planning Process, and for many other compliance obligations, such as those listed in Figure 76. Planning studies similar to the Reliability Planning Process include the NPCC/NYSRC Area Transmission Reviews (ATRs) and the NERC TPL-001 assessments.

Figure 76: List of NERC Standards for Planning Coordinators and Transmission Planners

Standard Name	Title	Purpose
FAC-002	**Facility Interconnection Studies**	To study the impact of interconnecting new or materially modified Facilities to the Bulk Electric System.
FAC-010	**System Operating Limits Methodology for the Planning Horizon**	To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
FAC-014	**Establish and Communicate System Operating Limits**	To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
IRO-017	**Outage Coordination**	To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.
MOD-026	**Verification of Models and Data for Generator Excitation Control System or Plant Volt/VAR Control Functions**	To verify that the generator excitation control system or plant volt/var control function model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation control system or plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability.
MOD-027	**Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions**	To verify that the turbine/governor and load control or active power/frequency control model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, accurately represent generator unit real power response to system frequency variations.
MOD-031	**Demand and Energy Data**	To provide authority for applicable entities to collect Data, energy and related data to support reliability studies and assessments to enumerate the responsibilities and obligations of requestors and respondents of that data.
MOD-032	**Data for Power System Modeling and Analysis**	To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.
MOD-033	**Steady State and Dynamic System Model Validation**	To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.
PRC-002	**Disturbance Monitoring and Reporting Requirements**	To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances

Standard Name	Title	Purpose
PRC-006	**Automatic Underfrequency Load Shedding**	To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.
PRC-006-NPCC	**Automatic Underfrequency Load Shedding**	The NPCC Automatic Underfrequency Load Shedding (UFLS) regional Reliability Standard establishes more stringent and specific NPCC UFLS program requirements than the NERC continent-wide PRC-006 standard. The program is designed such that declining frequency is arrested and recovered in accordance with established NPCC performance requirements stipulated in this document.
PRC-010	**Undervoltage Load Shedding**	To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).
PRC-012	**Remedial Action Schemes**	To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).
PRC-023	**Transmission Relay Loadability**	Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and be set to reliably detect all fault conditions and protect the electrical network from these faults.
PRC-026	**Relay Performance During Stable Power Swings**	To ensure that load-responsible protective relays are expected to not trip in response to stable power swings during non-Fault conditions.
TPL-001	**Transmission System Planning Performance Requirements**	Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.
TPL-007	**Transmission System Planned Performance for Geomagnetic Disturbance Events**	Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

NPCC/NYSRC Area Transmission Reviews

The NPCC/NYSRC Area Transmission Reviews (ATRs) are performed on an annual basis to demonstrate that conformance with the performance criteria specified in NPCC Directory #1 and the NYSRC Reliability Rules. The ATR is prepared in accordance with NPCC and NYSRC procedures that require the assessment to be performed annually, with a Comprehensive Area Transmission Review performed at least every five years. Either an “Interim” or an “Intermediate” review can be conducted between comprehensive reviews, as appropriate. In an Interim review, the planning coordinator summarizes the changes in planned facilities and forecasted system conditions since the last comprehensive review and assesses the impact of those changes. No new analyses are required for an Interim review. An Intermediate review covers all the elements of a comprehensive review, but the analysis may be limited to addressing only significant issues, considering the extent of the system changes. In the ATRs, the NYISO assesses the

BPTF for a period of four to six years in the future (the NYISO evaluates year five of the study period).

The 2023 ATR,[25] which is the most recently completed ATR, evaluated study year 2028 and found that the planned system through year 2028 conforms to the reliability criteria described in the NYSRC Reliability Rules and NPCC Directory #1. The next ATR is planned to be completed in the latter part of 2024 or early 2025. Seven assessments are required as part of each ATR.

The first assessment evaluates the steady state and dynamics transmission security. For instances where the transmission security assessments results indicate that the planned system does not meet the specified criteria, a corrective action plan is incorporated to achieve conformance. The most recent ATR found that with the identified corrective action plans identified in the reliability planning process, the system meets the applicable performance criteria.

For the second assessment, steady state and dynamics analyses are conducted to evaluate the performance of the system for low probability extreme contingencies. The purpose of the extreme contingency analysis is to examine the post-contingency steady state conditions, as well as stability, overload, cascading outages, and voltage collapse, to obtain an indication of system robustness and to determine the extent of any potential widespread system disturbance. In instances where the extreme contingency assessment concludes there are serious consequences, the NYISO evaluates implementing a change to design or operating practices to address the issues.

The extreme contingency analysis included in the most recent ATR concluded that most events are stable and showed no thermal overloads over Short-Term Emergency (STE) ratings or significant voltage violations on the BPTF. For the events that did show voltage, thermal, or dynamics issues, these events were local in nature (*i.e.*, loss of local load or reduction of location generation) and do not result in a widespread system disturbance.

The third assessment evaluates extreme system conditions that have a low probability of occurrence, such as high peak load conditions (*e.g.*, 90th percentile load) resulting from extreme weather or the loss of fuel supply from a given resource (*e.g.,* loss of all gas units under winter peak load). The extreme system conditions evaluate various design criteria contingencies to evaluate the post-contingency steady state conditions, as well as stability, overload, cascading outages, and voltage collapse. The evaluation of extreme contingencies indicates system robustness and determine the extent of any potential widespread system disturbance. In instances where the extreme contingency assessment concludes that there are serious consequences, the NYISO evaluates implementing a change to design or operating practices to address the

[25] 2021 Interim Area Transmission Review of the New York State Bulk Power Transmission System.

issues. For the extreme system conditions evaluated in the most recent ATR, the assessment found no steady state or dynamics transmission security criteria violations.

The fourth assessment evaluates the breaker fault duty at BPTF buses. The most recent ATR found no over-dutied breakers on BPTF buses.

The fifth assessment evaluates other requirements specific to the NYSRC Reliability Rules including an evaluation of the impacts of planned system expansion or configuration facilities on the NYCA System Restoration Plan and Local Area Operation Rules for New York City Operations, loss of gas supply — New York City, and loss of gas supply — Long Island.

The sixth assessment is a review of Special Protection Systems (SPSs). This review evaluates the designed operation and possible consequences of failure to operate or mis-operation of the SPS within the NYCA.

The seventh assessment is a review of requested exclusions to the NPCC Directory #1 criteria.

NERC Planning Assessments (TPL-001)

The NERC TPL-001 assessment (Planning Assessment) is performed annually. The purpose of the Planning Assessment is to demonstrate conformance with the applicable NERC transmission system planning performance requirements for the NYCA Bulk Electric System (BES). The Planning Assessment is a coordinated study between the NYISO and Transmission Owners in the NYCA.

The required system conditions to evaluate for this assessment include planned system representations over a 10-year study period for a variety of system conditions. Figure 77 provides a description of the steady state, dynamics, and short circuit cases required to be evaluated in the Planning Assessment.

Figure 77: Description of NERC TPL-001 Planning Assessment Study Cases

Case Description	Steady State	Dynamics	Short Circuit
System Peak Load (Year 1 or 2)	x		
System Peak Load (Year 5)	x	x	x
System Peak Load (Year 10)	x	x[1]	
System Off-Peak Load (One of the 5 years)	x	x	
System Peak Load (Year 1 or 2) Sensitivity	x		
System Peak Load (Year 5) Sensitivity	x	x	
System Off-Peak Load (One of the 5 years) Sensitivity	x	x	

Notes:

1. Only required to be assessed to address the impact of proposed material generation additions or changes in that timeframe.

The steady state and dynamics transmission security analyses evaluate the NYCA BES to meet the applicable criteria. As part of this assessment, the unavailability of major transmission equipment with a lead time of more than a year is also assessed. The fault duty at BES buses is evaluated in the short-circuit representation. When the steady state, dynamics, or short circuit analysis indicates an inability of the system to meet the performance requirements in the standard, a corrective action plan is developed addressing how the performance requirements will be met. Corrective action plans are reviewed in subsequent Planning Assessments for continued validity and implementation status.

For each steady state and dynamics case, the Planning Assessment evaluates the system response to extreme contingencies. Similar to the ATR, when the Planning Assessment extreme contingency analysis concludes that there is cascading caused by an extreme contingency, the NYISO evaluates possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts.

The most recent NERC Planning Assessment for compliance with TPL-001 was completed in July 2024. As this study contains Critical Energy Infrastructure Information (CEII), it is not posted on the NYISO website. Generally, the results of this study are consistent with the ATR studies. The study scope of this assessment is different from the ATR because the ATR evaluates the BPTF while the TPL evaluates the BES. The corrective action plans for criteria violations on the BES are generally addressed in the affected Transmission Owner's LTP and/or the proposed transmission facilities listed in Section 7 of the Load and Capacity Data Report.

Resource Adequacy Compliance Efforts

NPCC's Directory 1 defines a compliance obligation for the NYISO, as Resource Planner and Planning Coordinator, to perform a resource adequacy study evaluating a five-year planning horizon. The NYISO delivers a report every year under this study process to verify the system against the one-day-in-ten-years loss of load expectation (LOLE) criterion, usually based on the latest available RNA/Comprehensive Reliability Plan results and assumptions. The New York Area Review of Resource Adequacy completed reports are available at: https://www.nyiso.com/planning-reliability-compliance.

NYSRC Reliability Rules require[26] that the NYISO deliver a Long-Term Resource Adequacy Assessment report every RNA year, and an annual update in the non-RNA years. The NYISO first implemented this requirement after finalizing the 2020 RNA.[27]

[26] *See* NYSRC Reliability Rule A.3, R.3.

[27] Links to the latest available 2021 report and presentation are available at: https://www.nysrc.org/PDF/MeetingMaterial/RCMSMeetingMaterial/RCMS%20Agenda%20262/2021NYSRCLongTermResourceAdequacyAssessment-InterveningYear_Feb3-2022RCMS_Report.pdf and https://www.nysrc.org/PDF/MeetingMaterial

The NYISO is also actively involved in other activities such as the NERC's annual Long-Term Reliability Assessment (LTRA), along with its biennial Probabilistic Assessment (ProbA), performed by NERC with the input from all the NERC Regions and Areas, as well as NPCC's Long Range Adequacy Overview (LROA).

/RCMSMeetingMaterial/RCMS%20Agenda%20262/2021NYSRCLongTermResourceAdequacyAssessment-InterveningYear_Feb3-2022RCMS_Presentation%20(1).pdf.