

New York ISO
Independent System Operator

Appendices

2026 Reliability Needs Assessment (RNA)

A Report from the New York Independent System Operator

November 17, 2026

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Appendix A - 2026 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.

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 include 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 Case for determining Reliability Needs for the Reliability Needs Assessment Study Period.

New York State Bulk Power Transmission Facilities (BPTFs): 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 ensure 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.

[1] NYSRC, Resource Adequacy Metrics and Their Applications, April 20, 2020: https://www.nysrc.org/wp-content/uploads/2023/03/Resource-Adequacy-Metric-Report-Final-4-20-20206431.pdf

- 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 Services Tariff

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, Inc. (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

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

[2] NYSRC, Resource Adequacy Metrics and Their Applications, April 20, 2020: https://www.nysrc.org/wp-content/uploads/2023/03/Resource-Adequacy-Metric-Report-Final-4-20-20206431.pdf

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, among other things, 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

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.

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.

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

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

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

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

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

Reliability Solutions: Potential solutions that can include generation, transmission, or demand response that are proposed to address reliability needs, which can include the following:

1. **Alternative Regulated Solutions:** 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:** Regulated solutions that are required of the Responsible Transmission Owner(s) to meet Reliability Needs as outlined in the Reliability Needs Assessment.

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. See definition of Reliability.

Responsible Transmission Owner: 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

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

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

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

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

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

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.

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 above.

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 Load Serving Entity'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 through K.

Appendix B - The Reliability Planning Process

This appendix presents an overview of the NYISO's Reliability Planning Process in the context of its overall Comprehensive System Planning Process (CSPP). A detailed discussion of the Reliability Planning Process, including applicable Reliability Criteria, is contained in the NYISO's Reliability Planning Process Manual, which is posted on the NYISO's website.[3]

The CSPP is comprised of the following components:

1. Local Transmission Planning Process (LTPP)
2. Reliability Planning Process (RPP), along with the Short-Term Reliability Process (STRP)
3. Economic Planning Process (EPP)
4. Public Policy Transmission Planning Process (PPTPP)
5. Long-Term Transmission Planning Process[4]

Local Transmission Planning Process

Under the LTPP, the Transmission Owners perform transmission studies for their transmission areas according to all applicable criteria and develop their Local Transmission Owner Plans (LTPs). Every year, each Transmission Owner will update and post its current LTP on its website for review and comment by interested parties, and information would include:

- identification of the planning horizon covered by the LTP,
- data and models used,
- reliability needs, needs driven by Public Policy Requirements, and other needs addressed,
- potential solutions under consideration, and
- a description of the transmission facilities covered by the plan.

The LTP then feeds into the NYISO's determination of system needs through the CSPP following the Transmission Owners' presentation of their LTPs, or any update to their LTPs, to NYISO stakeholders. Links to the Transmission Owners' websites can be found on the NYISO's website.[5]

[3] The NYISO's Reliability Planning Process Manual is available at https://www.nyiso.com/documents/20142/2924447/rpp_mnl.pdf.

[4] The NYISO filed its Long-Term Transmission Planning Process in June 2026, with a requested immediate effective date, to comply with the requirements in Order Nos. 1920, 1920-A, and 1920-B, which was pending with the Federal Energy Regulatory Commission at the publication of the 2026 Reliability Needs Assessment.

[5] A brief guide to the LTPP is available at https://www.nyiso.com/documents/20142/3632262/Local-Transmission-Owner-Planning-Process-LTPP.pdf.

Reliability Planning Process

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. 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 (BPTFs) 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, as applicable.

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). After the Reliability Needs are initially identified as deficiencies based on the applicable reliability criteria, the NYISO translates these deficiencies into MW (or MVAR for reactive power deficiencies) of resources that could satisfy the needs. These resources have locational dependency and are referred to as compensatory MWs or MVARs.

Following approval of the RNA by the NYISO Board of Directors and before issuance of a solicitation for proposed solutions to the identified Reliability Needs, 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, Transmission Owners, 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. The NYISO then will evaluate the solutions for their viability and sufficient to address the need under the CRP and, if needed and as applicable, evaluate and select the more efficient and cost-effective transmission solution. The CRP documents the solutions determined to be viable and sufficient, the transmission solution selected as the more efficient or cost-effective solution, and the need to trigger any regulated solution to meet the identified Reliability Needs.

The RNA analyzes the reliability of the BPTF for adequacy and security. These analyses are performed and Reliability Needs are identified in accordance with existing NERC, NPCC, and NYSRC criteria, as they may change from time to time. 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.

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[6] 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 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 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

[6] 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."

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 to identify plausible changes in conditions or assumptions that might adversely impact the reliability of the system. Transmission security margin analysis determines the ability to meet load plus losses against the generation, interchanges, and temperature-based generation derates (total resources) for a certain locality within NYCA. This assessment is performed using a deterministic approach through a spreadsheet-based method based on the RNA study assumptions. For this assessment, transmission security margins are evaluated for the Lower Hudson Valley, New York City, and Long Island localities. This evaluation will result in the identification of a Reliability Need related to the BPTF 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 triggers a regulated solution by notifying 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.

While the NYISO notifies a Responsible Transmission Owner or Other Developer of an alternative regulated transmission solution to proceed with development, the NYISO does not permit or construct projects. 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.

Short-Term Reliability Process

The 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,[7] 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

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

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.

Economic Planning Process

The third component of the CSPP is the Economic Planning Process and Long-Term Transmission Planning Process. As part of its Economic Planning Process and Long-Term Transmission Planning Process, the NYISO performs the System & Resource Outlook (Outlook), which is a comprehensive study of the New York State Transmission System that identifies transmission expansion opportunities using multiple scenarios and sensitivities within a twenty-year planning horizon and provides valuable information about how New York's power system may evolve over the planning horizon. The Outlook summarizes the current assessments, evaluations, and plans in the CSPP; produces a 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. For the next cycle of the Outlook, the scope will be expanded to serve as the transmission study for the Long-Term Transmission Planning Process, discussed below.

Public Policy Transmission Planning Process

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 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 the proposed solutions and the Board of Directors 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.

Long-Term Transmission Planning Process

The newest component of the CSPP is the Long-Term Transmission Planning Process, which the NYISO recently filed with the Federal Energy Regulatory Commission to comply with the requirements of Order Nos. 1920, 1920-A, and 1920-B and which continues to be pending at the time of this RNA. Under the Long-Term Transmission Planning Process, the NYISO, in coordination with the New York State Department of Public Service and stakeholders, will develop at least three long-term scenarios based on defined factors that will be evaluated in the Outlook. The Outlook will identify transmission expansion opportunities over a 20-year planning horizon, and the NYPSC will then evaluate and identify any Long-Term Transmission

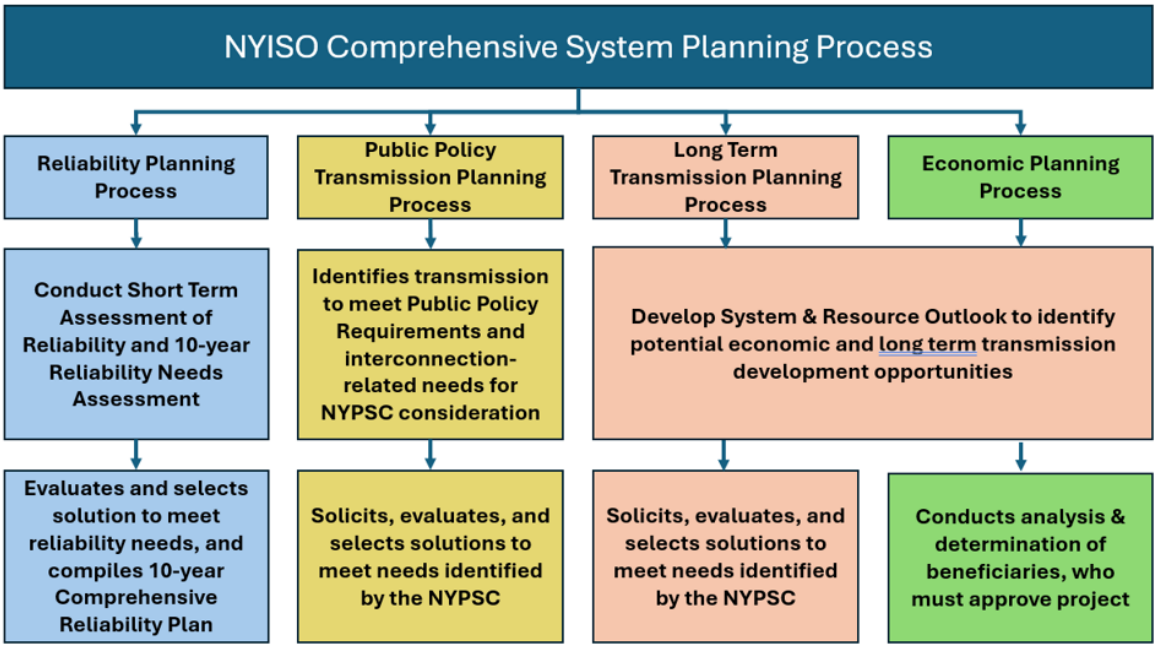
Needs. If the NYPSC identifies a need, the NYISO will then solicit proposed solutions, evaluate them using selection metrics, and select the more efficient or cost-effective transmission solution. The Outlook will be performed every three years on a recurring basis.

Interregional Planning

In concert with these five 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.[8]

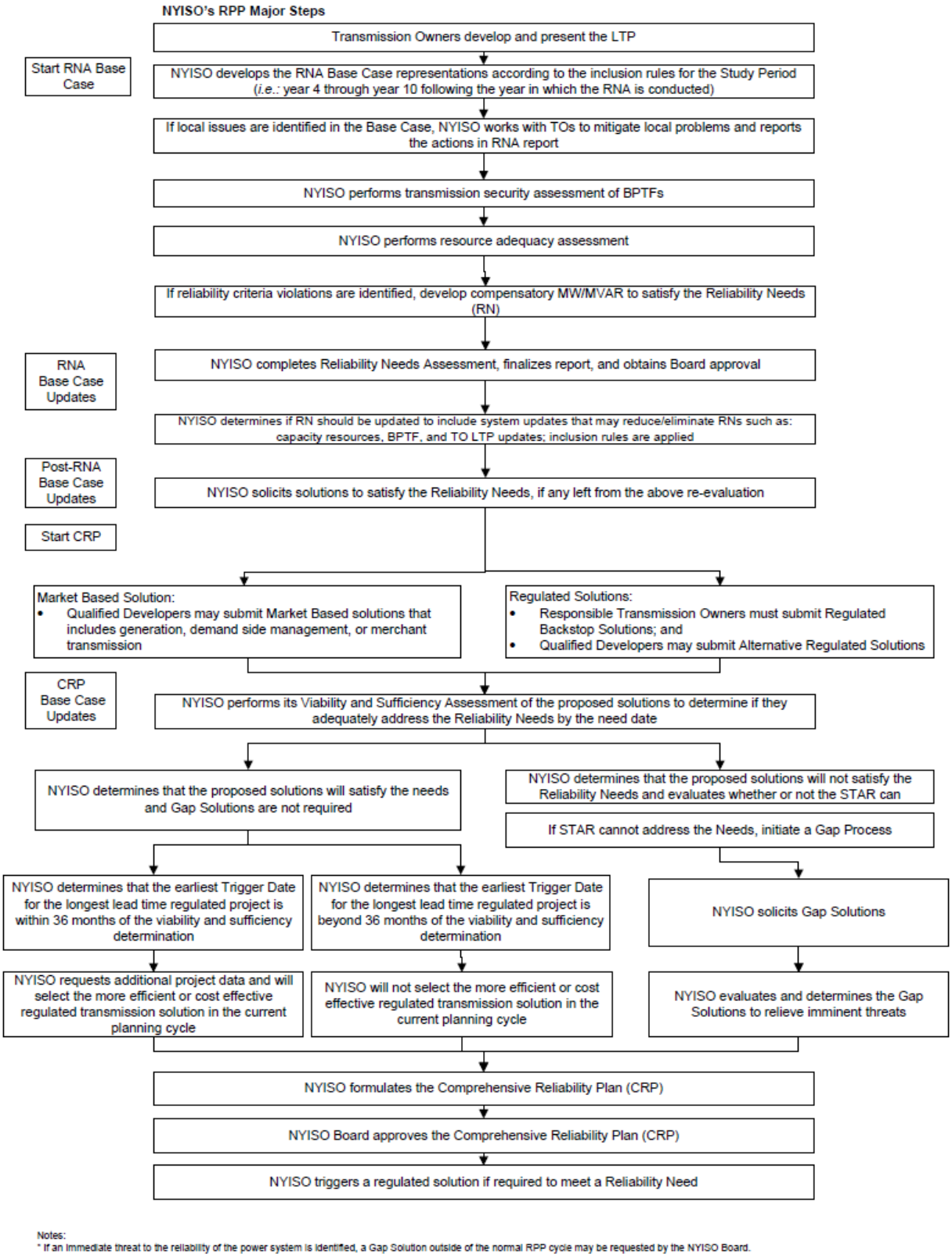
Figure 1 summarizes the CSPP and Figure 2 summarizes the RPP process, with additional details included in Attachment Y.

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



[8] The NYISO will file on or before June 14, 2027 any additional requirements to address the interregional transmission planning process requirements as it relates to the Long-Term Transmission Planning Process.

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 – Inclusion Rules Application

The analysis performed during the Reliability Needs Assessment (RNA) requires the development of a baseline, which is referred to the "RNA 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,[9] which are termed "Reliability Needs" and are actionable for the NYISO to solicit solutions through the development of the Comprehensive Reliability Plan.

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[10] describes the inclusion rules for the RNA Base Case, and its application for the 2026 RNA is summarized below.

Summary of Proposed Generation Assumptions

The NYISO develops a 2026 RNA Base Case that consists of cases that are used for both transmission security and resource adequacy assessments. The RNA Base Case used to analyze the performance of the transmission system stem from the 2026 FERC Form No. 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 the 2026 Gold Book and supplemented with light load forecast information discussed in Appendix E.[11] The system representation external to the New York Control Area is the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) 2025 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 2026 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 2026 RNA 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 2026 RNA Base Case does not include all projects currently listed on the NYISO's interconnection queue or those shown in the 2026 Gold Book. Rather, it includes only those which met the

[9] The electric power system planning and operating policies, standards, criteria, guidelines, procedures, and rules promulgated by the North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), and the New York State Reliability Council (NYSRC), as they may be amended from time to time. .

[10] Reliability Planning Process Manual, *available at* https://www.nyiso.com/documents/20142/2924447/rpp_mnl.pdf.

[11] 2026 Load and Capacity Report (Gold Book), *available at* https://www.nyiso.com/documents/20142/2226333/2026-Gold-Book-Public.pdf.

screening requirements.

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

Figure 3: Large Generation Additions

Proposed Project Inclusion: Large Generation					
Queue	Project Name	MW	Type	Zone	Proposed Date
276	Homer Solar Energy Center	90	Solar	C	Apr-26
396	Baron Winds Phase II	117	Land-Based Wind	C	Dec-26
519	Canisteo Wind Energy LLC	290.7	Land-Based Wind	C	Dec-27
571	Heritage Wind, LLC	126	Land-Based Wind	B	Oct-27
596	Alle Catt II Wind	339.1	Land-Based Wind	A	Dec-26
704	Bear Ridge Solar	100	Solar	A	Apr-28
710	Horseshoe Solar Energy LLC	180	Solar	B	May-28
716	Moraine Solar Energy Center	93.5	Solar	C	Sep-28
720	Trelina Solar Energy Center	79.8	Solar	C	Apr-28
721	Excelsior Energy Center	280	Solar	A	Nov-26
737	Empire Wind 1	816	Offshore Wind	J	Jul-27
766	Sunrise Wind	880	Offshore Wind	K	Jul-27
774	Tracy Solar Energy Centre	119	Solar	E	Dec-28
801	Prattsburgh Wind, LLC	147	Land-Based Wind	C	Sep-27
811	Hecate Energy Cider Solar LLC	500	Solar	B	Jan-27
815	Bayonne Energy Center	49.8	Energy Storage	J	Jul-27
880	Brookside Solar	100	Solar	D	Dec-27
883	Garnet Energy Center, LLC	200	Solar	B	Apr-28
931	Astoria Energy Storage	100	Energy Storage	J	Oct-26
950	Hemlock Ridge Solar	200	Solar	B	Apr-28
987	Sunrise Wind II	44	Offshore Wind	K	Jul-27
1009	Yellow Barn Solar	160	Solar	C	Nov-28
1031	Mill Point Solar	250	Solar+Energy Storage	E	Dec-28
1183	NY125A - Fort Covington Solar	250	Solar	D	Jul-28
1184	NY125B - Two Rivers Solar	200	Solar	D	Sep-28

Figure 4: Small Generation Additions

Proposed Project Inclusion: Small Generation					
Queue	Project Name	MW	Type	Zone	Proposed Date
564	Rock District Solar	20	Solar	F	Feb-27
572	Greene County 1	20	Solar	G	Jun-27
573	Greene County 2	10	Solar	G	Jun-27
575	Little Pond Solar	20	Solar	G	Sep-27
581	Hills Solar	20	Solar	E	Dec-26
584	Dog Corners Solar	20	Solar	C	Jan-27
586	Watkins Rd Solar	20	Solar	E	Feb-27
590	Scipio Solar	18	Solar	C	Dec-26
591	Highview Solar	20	Solar	C	Nov-26
592	Niagara Solar	20	Solar	A	Dec-26
670	SunEast Skyline Solar LLC	20	Solar	E	Apr-28
734	Ticonderoga Solar	20	Solar	F	Dec-26
804	KCE NY 10	20	Energy storage	A	Oct-26
827	Arthur Kill Energy Storage 1	15	Energy storage	J	Dec-26
828	Valley Solar	20	Solar	C	Jan-27
832	CS Hawthorn Solar	20	Solar	F	Dec-26
833	Dolan Solar	20	Solar	F	Dec-26
865	Flat Hill Solar	20	Solar	E	Aug-27
885	Grassy Knoll Solar	20	Solar	E	May-28
1003	Clear View Solar	20	Solar	C	Aug-26
1015	Somers Solar, LLC	20	Solar	F	Dec-26
1047	Millers Grove Solar	20	Solar	E	Mar-28
1166	BR Benson Mines Solar	12	Solar	E	Dec-27
1329	ELP Granby Solar II	20	Solar+Energy	C	Jun-28

Figure 5: Generation Additions by Year

Running Total of MW Additions by Type (2)					
Year (1)	Solar	Offshore Wind	Land-based Wind	Energy Storage	Solar+Energy Storage
2026	90	0	0	0	0
2027	1,158	0	456	135	0
2028	2,130	1,740	1,020	185	20
2029	2,952	1,740	1,020	185	270
2030	2,952	1,740	1,020	185	270
2031	2,952	1,740	1,020	185	270
2032	2,952	1,740	1,020	185	270
2033	2,952	1,740	1,020	185	270
2034	2,952	1,740	1,020	185	270
2035	2,952	1,740	1,020	185	270
2036	2,952	1,740	1,020	185	270

Note:
1. First summer peak period following the addition.
2. MW based on the Nameplate Rating.

Figure 6: Generation Removals by Year

MW Removals			
Generator	Zone	MW Removals (1)	Year (2)
Danskammer 1 - 4	G	494	2026
Pinelawn Power 1	K	73	2026
High Acres	C	10	2026
Coxsackie GT	G	19	2027
Gowanus 2-1 - 2-8	J	141	2029
Gowanus 3-1 - 3-8 (3)	J	122	2029
Narrows 1-1 - 1-8	J	134	2029
Narrows 2-1 - 2-8 (3)	J	91	2029
Gowanus 5	J	40	2031
Gowanus 6	J	40	2031
Kent	J	40	2031
Pouch	J	39	2031
Hellgate 1	J	40	2031
Hellgate 2	J	40	2031
Harlem River 1	J	40	2031
Harlem River 2	J	40	2031
Vernon Boulevard 2	J	40	2031
Vernon Boulevard 3	J	40	2031
Brentwood	K	45	2031
Total Removed Between 2026 and Summer 2031		1,528	

Notes:
1. MW Based on the Summer Capability (DMNC)
2. First summer peak period following removal. For the 2026 RNA Danskammer retirement was modeled as ocurring before summer peak 2026.
3. As identified in the 2026 Gold Book, some units at this plant are in an ICAP Ineligible Forced Outage (IIFO). These units are not counted towards the plant MW total.

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 2026 Gold Book. Many of these projects did not satisfy the inclusion rules and, therefore, are not in the 2026 RNA Base Case. Figure 7 below shows proposed generation projects (highlighted in green) that were included in the 2026 RNA Base Case.

Figure 7: Additional Proposed Generation Projects from the 2026 Gold Book

Queue #	Owner / Operator	Station Unit	Zone	Proposed Date (M-YY)	Nameplate Unit (MW)	Summer CRIS (MW)	Winter CRIS (MW)	Summer ERIS (MW)	Winter ERIS (MW)	Unit Type	Class Year Facilities Study
		Completed Facilities Study									
276	Homer Solar Energy Center LLC	Homer Solar Energy Center	C	Apr-26	90	90	90	90	90	Solar	2019
495	Mohawk Solar LLC	Mohawk Solar	F	Nov-27	90.5	90.5	90.5	90.5	90.5	Solar	2019
519	Canisteo Wind Energy LLC	Canisteo Wind	C	Dec-27	289.8	290.7	290.7	289.8	289.8	Land-Based Wind	2019
522	NYC Energy LLC	NYC Energy	J	Jun-27	79.9	79.9	79.9	79.9	79.9	Energy Storage	2023
535	Riverhead Solar 2, LLC	Riverhead Solar 2	K	Jan-28	36	36	36	36	36	Solar	2019
564	Rock District Solar, LLC	Rock District Solar	F	Feb-27	20	20	20	20	20	Solar	
571	Heritage Wind, LLC	Heritage Wind	B	Oct-27	200.1	126	126	200.1	200.1	Land-Based Wind	2021
572	Hecate Energy Greene 1 LLC	Greene County 1	G	Jun-27	20	20	20	20	20	Solar	
573	Hecate Energy Greene 2 LLC	Greene County 2	G	Jun-27	10	10	10	10	10	Solar	
575	Little Pond Solar, LLC	Little Pond Solar	G	Sep-27	20	20	20	20	20	Solar	
581	SunEast Hills Solar LLC	Hills Solar	E	Dec-26	20	20	20	20	20	Solar	
584	Dog Corners Solar NY LLC	Dog Corners Solar	C	Jan-27	20	20	20	20	20	Solar	
586	Watkins Road Solar NY LLC	Watkins Rd Solar	E	Feb-27	20	20	20	20	20	Solar	
590	Scipio Solar NY LLC	Scipio Solar	C	Dec-26	18	18	18	18	18	Solar	
591	SunEast Highview Solar LLC	Highview Solar	C	Nov-26	20	20	20	20	20	Solar	2019
592	Niagara NY Solar LLC	Niagara Solar	A	Dec-26	20	20	20	20	20	Solar	
596	Alle-Catt Wind Energy LLC	Alle Catt II Wind	A	Dec-26	339.1	339.1	339.1	339.1	339.1	Land-Based Wind	2019
617	Watkins Glen Solar Energy Center, LLC	Watkins Glen Solar	C	Apr-28	54	50	50	50	50	Solar	2019
620	Gateway Solar Energy Center, LLC	Gateway Solar Energy Center	D	Apr-28	180	180	180	180	180	Solar	2019
637	Flint Mine Solar LLC	Flint Mine Solar	G	May-26	100	100	100	100	100	Solar	2019
644	Hecate Energy Columbia County 1, LLC	Columbia County 1	F	Feb-27	60	60	60	60	60	Solar	2019
670	SunEast Skyline Solar LLC	SunEast Skyline Solar LLC	E	Apr-28	20	20	20	20	20	Solar	
683	KCE NY 2, LLC	KCE NY 2	G	Jun-27	200	200	200	200	200	Energy Storage	2019
704	Bear Ridge Solar, LLC	Bear Ridge Solar	A	Apr-28	100	100	100	100	100	Solar	2019
706	High Bridge Wind, LLC	High Bridge Wind	E	Nov-26	100.8	100.8	100.8	100.8	100.8	Land-Based Wind	2019
710	Horseshoe Solar Energy LLC	Horseshoe Solar	B	May-28	180	180	180	180	180	Solar	2021
716	Moraine Solar Energy Center, LLC	Moraine Solar Energy Center	C	Sep-28	93.5	93.5	93.5	93.5	93.5	Solar	2023
720	Trelina Solar Energy Center, LLC	Trelina Solar Energy Center	C	Apr-28	86.8	80	80	79.8	79.8	Solar	2019
721	Excelsior Energy Center, LLC	Excelsior Energy Center	B	Nov-26	280	280	280	280	280	Solar	2019
734	ELP Ticonderoga Solar LLC	Ticonderoga Solar	F	Dec-26	20	20	20	20	20	Solar	
737	Empire Offshore Wind LLC	Empire Wind 1	J	Jul-27	816	816	816	816	816	Offshore Wind	2019
766	Sunrise Wind LLC	Sunrise Wind	K	Jul-27	1,085.7	880	880	880	880	Offshore Wind	2021
774	Tracy Solar Energy Center, LLC	Tracy Solar Energy Center	E	Dec-28	119	119	119	119	119	Solar	2023
777	White Creek Solar, LLC	White Creek Solar	B	Jun-28	135	135	135	135	135	Solar	2023
783	ConnectGen Chautauqua County LLC	South Ripley Solar and BESS	A	Dec-27	274.2	270	270	270	270	Solar+Energy Storage	2021
787	Levy Grid, LLC	Levy Grid, LLC	A	Jan-27	150	150	150	150	150	Energy Storage	2021
800	Rich Road Solar Energy Center, LLC	Rich Road Solar Energy Center	E	Apr-28	240	240	240	240	240	Solar+Energy Storage	2023
801	Prattsburgh Wind, LLC	Prattsburgh Wind Farm	C	Sep-27	147	147	147	147	147	Land-Based Wind	2021
804	KCE NY 10, LLC	KCE NY 10	A	Oct-26	20	20	20	20	20	Energy Storage	

Queue #	Owner / Operator	Station Unit	Zone	Proposed Date (M-YY)	Nameplate Unit (MW)	Summer CRIS (MW)	Winter CRIS (MW)	Summer ERIS (MW)	Winter ERIS (MW)	Unit Type	Class Year Facilities Study
805	Oxbow Hill Solar, LLC	Oxbow Hill Solar	C	Jan-27	140	140	140	140	140	Solar	2021
807	SunEast Hilltop Solar LLC	Hilltop Solar	F	May-28	20	20	20	20	20	Solar	
811	Hecate Energy Cider Solar LLC	Cider Solar	B	Jan-27	500	500	500	500	500	Solar	2021
815	Bayonne Energy Center III, LLC	Bayonne Energy Center III	J	Jul-27	49.8	49.8	49.8	49.8	49.8	Energy Storage	2021
827	Lighthouse Arthur Kill, LLC	Arthur Kill Energy Storage 1	J	Dec-26	15	15	15	15	15	Energy Storage	
828	Valley Solar NY LLC	Valley Solar	C	Jan-27	20	20	20	20	20	Solar	
832	Hawthorn Solar, LLC	CS Hawthorn Solar	F	Dec-26	20	20	20	20	20	Solar	
833	Dolan Solar, LLC	Dolan Solar	F	Dec-26	20	20	20	20	20	Solar	
834	Eastern Generation, LLC	Luyster Creek Energy Storage 2	J	Apr-28	97	79	79	79	79	Energy Storage	2023
835	Eastern Generation, LLC	Luyster Creek Energy Storage 1	J	Jan-27	59.1	56	56	56	56	Energy Storage	2021
843	Greens Corners Solar LLC	NY37 Solar	E	Apr-28	20	N/A	N/A	20	20	Solar	
848	Fairway Solar NY LLC	Fairway Solar	E	May-28	20	20	20	20	20	Solar	
863	Highbanks Solar LLC	Highbanks Solar	B	Feb-26	20	12.5	12.5	20	20	Solar	
864	Greens Corners Solar LLC	NY38 Solar	E	Apr-28	120	120	120	120	120	Solar	2021
865	Flat Hill Solar NY LLC	Flat Hill Solar	E	Aug-27	20	20	20	20	20	Solar	
880	Brookside Solar, LLC	Brookside Solar	D	Dec-27	100	100	100	100	100	Solar	2023
882	Riverside Solar, LLC	Riverside Solar	E	Dec-27	100	100	100	100	100	Solar	2023
883	Garnet Energy Center, LLC	Garnet Energy Center	B	Apr-28	200	200	200	200	200	Solar	2021
885	Grassy Knoll Solar NY LLC	Grassy Knoll Solar	E	May-28	20	20	20	20	20	Solar	
907	Harlem River ESS, LLC	Harlem River Yard	J	Jan-28	100	79.9	79.9	79.9	79.9	Energy Storage	2021
930	Eastern Generation, LLC	Luyster Creek Energy Storage 3	J	Mar-27	15	0	0	15	15	Energy Storage	
931	East River ESS, LLC	Astoria Energy Storage	J	Oct-26	106.7	100	100	100	100	Energy Storage	2021
932	Hatchery Solar LLC	Hatchery Solar	B	Jan-29	20	20	20	20	20	Solar	
950	Hemlock Ridge Solar LLC	Hemlock Ridge Solar	B	Apr-28	200	200	200	200	200	Solar	2023
953	Sugar Maple Solar, LLC	Sugar Maple Solar	E	Dec-27	127	125	125	125	125	Solar	2023
956	Holtsville Energy Storage, LLC	Holtsville 138kV Energy Storage	K	May-28	300.9	110	110	110	110	Energy Storage	2021
967	KCE NY 5 LLC	KCE NY 5	G	Dec-27	94	94	94	94	94	Energy Storage	2023
971	East Setauket Energy Storage, LLC	East Setauket Energy Storage	K	Apr-27	126.8	54.5	54.5	125	125	Energy Storage	2023
987	Sunrise Wind LLC	Sunrise Wind II	K	Jul-27	966	44	44	44	44	Offshore Wind	2021
995	Alabama Solar Park LLC	Alabama Solar Park LLC	B	Oct-28	132.44	130	130	130	130	Solar	2023
1000	Flat Stone Solar NY LLC	Flat Stone Solar	E	May-28	20	20	20	20	20	Solar	
1003	Clear View Solar LLC	Clear View Solar	C	Aug-26	20	20	20	20	20	Solar	
1007	NYC Energy	NYC Energy LLC - Phase 2	J	Jun-27	220.1	220.1	220.1	220.1	220.1	Energy Storage	2023
1009	Yellow Barn Solar, LLC	Yellow Barn Solar	C	Nov-28	160	160	160	160	160	Solar	2023
1015	Somers Solar, LLC	Somers Solar, LLC	F	Dec-26	20	N/A	N/A	20	20	Solar	
1031	ConnectGen Montgomery County LLC	Mill Point Solar	E	Dec-28	250	250	250	250	250	Solar+Energy Storage	2023
1039	Morris Solar NY LLC	Morris Solar	E	Mar-28	20	0	0	20	20	Solar	
1047	SED NY Holdings LLC	Millers Grove Solar	E	Mar-28	20	20	20	20	20	Solar	
1051	SED NY Holdings LLC	Transit Solar	B	May-28	20	20	20	20	20	Solar	
1079	Somerset Solar, LLC	Somerset Solar	A	Jun-28	200	125	125	125	125	Solar	2023
1080	Mineral Basin Solar Power, LLC	Mineral Basin Solar Power	C	Dec-28	450.85	401.6	401.6	401.6	401.6	Solar	2023
1089	Flat Creek Solar NY LLC	Flat Creek Solar	F	Nov-28	200	200	200	200	200	Solar	2023

Queue #	Owner / Operator	Station Unit	Zone	Proposed Date (M-YY)	Nameplate Unit (MW)	Summer CRIS (MW)	Winter CRIS (MW)	Summer ERIS (MW)	Winter ERIS (MW)	Unit Type	Class Year Facilities Study
1113	Caithness LI Energy Storage, LLC	CLIES 20 MW	K	Dec-27	20	20	20	20	20	Energy Storage	
1115	Flat Creek Solar NY LLC	Flat Creek Solar	F	Nov-28	100	100	100	100	100	Solar	2023
1117	Caithness LI Energy Storage, LLC	CLIES 70MW	K	Dec-27	70	30.4	30.4	70	70	Energy Storage	2023
1122	East Fishkill Storage 1, LLC	East Fishkill	G	Dec-29	252	205	205	205	205	Energy Storage	2023
1123	KCE NY 29, LLC	KCE NY 29	K	Dec-27	80.2	79	79	79	79	Energy Storage	2023
1130	Hoffman Falls Wind LLC	Hoffman Falls Wind	C	Dec-27	72	72	72	72	72	Land-Based Wind	2023
1148	Agricola Wind LLC	Agricola Wind	C	Dec-27	99	97	97	97	97	Land-Based Wind	2023
1151	York Run Solar, LLC	York Run Solar	A	Sep-28	93	90	90	90	90	Solar	2023
1166	BR Project 1 LLC	BR Benson Mines Solar	E	Dec-27	12.1	N/A	N/A	12.1	12.1	Solar	
1183	Fort Covington Solar LLC	NY125A- Fort Covington Solar	D	Jul-28	250	250	250	250	250	Solar	2023
1184	Two Rivers Solar Farm, LLC	NY125B- Two Rivers Solar	D	Sep-28	200	200	200	200	200	Solar	2023
1188	North Seneca Solar Project LLC	North Seneca Solar Project, LLC	C	Sep-27	90	105	105	90	90	Solar	2023
1237	Sugar Maple Solar	Sugar Maple Energy Storage	E	Dec-28	20	N/A	N/A	20	20	Energy Storage	
1255	Holtsville Brookhaven Battery Storage LLC	Holtsville Brookhaven Battery Storage	K	Oct-27	82.8	39.9	39.9	79.9	79.9	Energy Storage	2023
1257	Edwards Calverton Battery Storage LLC	Edwards Calverton Battery Storage	K	Nov-27	62.1	26.5	26.5	60	60	Energy Storage	2023
1329	ELP Granby Solar II LLC	ELP Granby Solar II	C	Jun-28	20	20	20	20	20	Solar+Energy Storage	
		Completed CRIS Requests									
94	Atlantic Energy, LLC	Neptune DC PJM-LI	K	I/S	660	660	660	N/A	N/A	Class Year Transmission Project	2003-05
125	East Coast Power, LLC	Linden VFT Inter-Tie	J	I/S	315	315	315	N/A	N/A	Class Year Transmission Project	2006
N/A	HQUS	Chateaugay	D	I/S	N/A	20	20	N/A	N/A		2015
430	HQUS	Cedar Rapids Transmission Upgrade	D	I/S	N/A	80	80	N/A	N/A		2017
N/A	Energy Storage Resources, LLC	Eagle Energy Storage	J	N/A	N/A	20	20	N/A	N/A	Energy Storage	2019
N/A	Hannacroix Solar Facility, LLC	Hannacroix Solar	G	N/A	N/A	5	5	N/A	N/A	Solar	2019
N/A	RWE Solar Development, LLC	Cuddebackville Battery	G	N/A	N/A	10	10	N/A	N/A	Energy Storage	2019
N/A	RWE Solar Development, LLC	Monsey 44-2	G	N/A	N/A	5	5	N/A	N/A	Energy Storage	2019
N/A	RWE Solar Development, LLC	Monsey 44-3	G	N/A	N/A	5	5	N/A	N/A	Energy Storage	2019
N/A	RWE Solar Development, LLC	Monsey 44-6	G	N/A	N/A	5	5	N/A	N/A	Energy Storage	2019
N/A	Strata Storage, LLC	Cleancar Energy Storage	J	N/A	N/A	15	15	N/A	N/A	Energy Storage	2019
N/A	Strata Storage, LLC	Groundvault Energy Storage	J	N/A	N/A	12.5	12.5	N/A	N/A	Energy Storage	2019
N/A	Strata Storage, LLC	Stillwell Energy Storage	J	N/A	N/A	10	10	N/A	N/A	Energy Storage	2019
N/A	Yonkers Grid, LLC	Yonkers Grid	J	N/A	N/A	20	20	N/A	N/A	Energy Storage	2019
631	CHPE LLC	NS Power Express	J	May-26	1,250	1,000	1,000	N/A	N/A	Class Year Transmission Project	2021
887	CHPE LLC	CH Uprate	J	May-26	1,250	250	250	N/A	N/A	Class Year Transmission Project	2021
N/A	West Babylon Energy Storage, LLC	West Babylon Energy Storage	K	Aug-25	12.5	9.9	9.9	N/A	N/A	Energy Storage	2023
N/A	Port Jefferson Energy Storage, LLC	Port Jefferson Energy Storage	K	N/A	N/A	9.9	9.9	N/A	N/A	Energy Storage	
N/A	Suffolk County Energy Storage, LLC	Suffork County Energy Storage	K	N/A	N/A	9.9	9.9	N/A	N/A	Energy Storage	
N/A	Hudson Transmission Partners, LLC	Hudson Transmisson	J	I/S	660	85	85	N/A	N/A	Class Year Transmission Project	
N/A	KCE NY 14, LLC	KCE NY 14, LLC	G	Dec-27	21.1	20	20	N/A	N/A	Energy Storage	
N/A	Soltage, LLC	Brigis 2	J	Jun-26	20	20	20	N/A	N/A	Energy Storage	
N/A	Soltage, LLC	Juniper Valley	J	Jun-26	20	20	20	N/A	N/A	Energy Storage	

Summary of Transmission Assumptions

Figure 8 summarizes NYCA import assumptions for summer and winter peak load conditions. Major transmission projects included in the 2026 RNA Base Case are listed in Figure 9.

All firm transmission plans and transmission interconnection projects included in Table VII of the 2026 Gold Book are included in the 2026 RNA Base Case, except those listed in Figure 10 below.

Figure 8: Base Case Additions, Removals, Net Imports, and Load (MW)

Year (1)	Addition (2)	Removal (3)	Summer Peak			Winter Peak		
			Net Imports (4)	Summer Baseline Coincident Peak	Large Load Demand (5)	Net Imports (4)	Winter Baseline Coincident Peak	Large Load Demand (5)
2026	90	0	3,211	31,578	538	849	24,620	707
2027	1,749	19	2,922	31,880	1,075	560	25,110	1,182
2028	5,095	19	2,922	31,980	1,292	560	25,410	1,351
2029	6,167	525	2,922	32,070	1,517	560	25,880	1,689
2030	6,167	525	2,922	32,250	1,831	560	26,310	1,908
2031	6,167	968	2,922	32,420	1,989	560	26,690	2,075
2032	6,167	968	2,922	32,560	2,131	560	27,120	2,250
2033	6,167	968	2,922	32,760	2,379	560	27,550	2,461
2034	6,167	968	2,922	32,920	2,554	560	28,000	2,623
2035	6,167	968	2,922	33,140	2,643	560	28,480	2,710
2036	6,167	968	2,922	33,430	2,717	560	29,060	2,784

Notes:

1. For Winter Peak, represents the winter beginning with the listed year (e.g. Winter 2034 is Winter 2034-2035).
2. Represents running total of MW based on the Nameplate Rating for the first summer peak period following the addition.
3. Represents Running total of MW based on the Summer Capability (DMNC) for the first summer peak period following removal. Danskammer Units and High Acres both are considered unavailable for the RNA period.
4. Net imports are based on ERAG MMWG values and firm transactions. CHPE is considered available for the RNA summer period. External imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.
5. Large Loads are included in the Baseline Coincident Peak load forecats.

Figure 9: Major Transmission Projects Included in Base Case

Queue	Project Name	MW	POI	Zone	Proposed Date
631/887	TDI Champlain Hudson Power Express (CHPE)	1,250	Astoria Annex 345kV	J	In-service
1125	Northern New York Priority Transmission Project (NNYPTP)	N/A	Moses/Adirondack/Porter path	D&E	In-service
-	Goethals/Foxhills PAR Regulated Feeder	N/A	Goethals 345 kV/Greenwood 138 kV TLA	J	In-service
-	Gowanus/Greenwood PAR Regulated Feeder (third connection)	N/A	Gowanus 345 kV/Greenwood 138 kV TLA	J	In-service
-	Gowanus/Greenwood PAR Regulated Feeder (fourth connection)	N/A	Gowanus 345 kV/Greenwood 138 kV TLA	J	Summer-26
-	Brooklyn Clean Energy Hub	N/A	Between Farragut 345 kV and Rainey 345 kV	J	Summer-28
-	Eastern Queens Clean Energy Hub	N/A	Between Jamaica 138 kV and Valley Stream/Lake Success 138 kV	J	Summer-28
1289	Propel NY Energy - Alternate Sol 5 *(T051 LIPPTN)*	N/A	Sprain Brook, Tremont, East Garden City, Shore Road, additional Long Island Substations	I,J,K	Summer-29

Figure 10: Transmission Projects Not Included in the RNA Base Case

Transmission Project Inclusion Rules Application: Class Year Transmission, TIP, and Firm LTP Projects Not Included in the RNA Base Cases											
Transmission Owner	Terminals		Line Length (Miles) (1)	Proposed In-Service Date		Nominal Voltage (kV)		# of CKTs	Thermal Ratings (3)		Project Description / Conductor Size
				Prior to (2)	Year	Operating	Design		Summer	Winter	
NGRID	Reynolds Rd	Reynolds Rd	-	W	2030	345/115	345/115	-	N/A	N/A	115 kV relaying additions and upgrades
NGRID	Clay	Dewitt	15.7	W	2030	115	115	1	973	1234	Replace existing switch and include remote control capability
NGRID	Dewitt	Dewitt	Substation	W	2030	115	115	-	N/A	N/A	Rebuild DeWitt 115 kV Substation
NGRID	Clay	Dewitt	15.41	W	2030	115	115	1	973	1234	115 kV Taps to new Distribution Station
NGRID	Clay	Teall	11.73	W	2030	115	115	1	1172	1434	115 kV Taps to new Distribution Station
NYSEG	South Owego	Oakdale	18	W	2030	115	115	1	288 MVA	346 MVA	Rebuild the existing 18 mile 115 kV line #961 with 1192 ACSR conductor. Modify terminal bay at South Owego
NYSEG	Oakdale 345	Oakdale 345	Rebuild	S	2031	345	345		N/A	N/A	Expand existing 345 kV bus to 3 bay BAAH. (4)
NYSEG	Oakdale 115	Oakdale 115	Rebuild	S	2031	115	115		N/A	N/A	Complete rebuild of 115 kV to 6 bay BAAH. (4)
NYSEG	Westover 115	Westover	Removal	S	2031	115	115		N/A	N/A	Retire 115 kV Westover Substation. Rebuild Westover 34.5 kV out of flood zone.
NYSEG	Oakdale 345	Oakdale 115	xfmr	S	2031	345/115/34.5	345/115/34.5	1	448 MVA	464 MVA	Add one new 345/115/34.5 kV Transformer (4)
NYSEG	Oakdale 345	Oakdale 115	xfmr	S	2031	345/115/34.5	345/115/34.5	2	448 MVA	464 MVA	Replace Existing B2 & B3 Transformers (4)
NYSEG	Canandaigua	Stoney Ridge	24	S	2031	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	Stolle Rd	Stolle Rd	Rebuild	S	2031	115	115		N/A	N/A	Partial Rebuild of 115 kV to a BAAH in the existing yard. 3 Position 345 kV Ring Bus. 34.5 kV GIS Straight bus with a tie breaker.
NYSEG	Stolle Rd	Stolle Rd	xfmr	S	2031	345/115	345/115	1	448 MVA	448 MVA	One (1) 448 MVA 345/115 kV Transformer
NYSEG	Stolle Rd	Stolle Rd	xfmr	S	2031	345/230	345/230	1	488 MVA	488 MVA	One (1) 448 MVA 345/230 kV Transformer
NYSEG	Robinson Rd	Robinson Rd	Rebuild	S	2031	115	115		N/A	N/A	New four (4) bay 115 kV AIS BAAH. Demolish Hinman Rd 115/34.5 kV Station. Reroute 115 kV and 34.5 kV circuits from Hinman Rd to Robinson Rd. New 34.5 kV MV GIS at Robinson Rd
NYSEG	Robinson Rd	Robinson Rd	xfmr	S	2031	230/115/34.5	230/115/34.5	1	297 MVA	297 MVA	New 230/115/34.5 kV transformer
NYSEG	Robinson Rd	Robinson Rd	xfmr	S	2031	115/34.5	115/34.5	3	50 MVA	60 MVA	Three new 115/34.5 transformers
NYSEG	Stoney Ridge	Hillside	27	S	2031	230	230	1	795 MVA	886 MVA	Rebuild the existing 27 mile 230 kV line #72 with 2156 Bluebird ACSR conductor.

Note:
1. Line Length Miles: Negative values indicate removal of Existing Circuit being tapped.
2. S = Summer, W = Winter. Winter refers to the winter beginning with the year listed. For example, W 2026 refers to winter 2026-27.
3. Thermal Ratings in Amperes, except where labeled otherwise.
4. Following the start of the RNA, the NYISO included these projects.

Summary of Proposed Large Load Assumptions

The 2026 RNA Base Case uses the baseline forecasts from the 2026 Gold Book. Large loads are included in the zonal forecasts. One key assumption in the 2026 RNA is that cryptocurrency mining and hydrogen production large loads will be assumed flexible during system peak demand conditions. This assumption is based on recent operating experience and outreach to load developers. Figure 11 and Figure 12 present the large load peak baseline forecast values for summer and winter peak, respectively.

Figure 11: Large Load Summer Peak Forecast

Large Loads Summer Peak Forecasts (MW) Reflects Cumulative Existing and Future Load Impacts of Large Load Projects													
Year	Forecast	A	B	C	D	E	F	G	H	I	J	K	NYCA
2026	Lower	100	0	0	160	15	0	62	0	0	0	0	337
	Baseline	280	11	0	160	15	0	72	0	0	0	0	538
	Higher	320	11	0	160	15	0	72	0	0	0	0	578
2027	Lower	240	11	0	170	15	0	73	0	0	0	0	509
	Baseline	440	11	0	435	15	0	173	0	0	0	1	1,075
	Higher	440	11	0	439	15	0	173	0	0	0	1	1,079
2028	Lower	340	11	0	170	15	0	84	0	0	0	0	620
	Baseline	440	161	0	435	65	0	184	0	0	0	7	1,292
	Higher	540	161	0	447	65	35	184	0	0	0	7	1,439
2029	Lower	440	11	30	170	15	0	97	0	0	0	0	763
	Baseline	440	291	30	435	65	0	227	0	0	0	29	1,517
	Higher	760	291	70	611	65	140	227	0	0	0	29	2,193
2030	Lower	440	11	170	170	15	0	108	0	0	0	0	914
	Baseline	440	411	170	435	65	0	241	0	0	0	69	1,831
	Higher	760	411	290	611	65	170	241	0	0	0	69	2,617
2031	Lower	440	11	265	170	15	0	109	0	0	0	0	1,010
	Baseline	440	411	270	435	65	0	255	0	0	0	113	1,989
	Higher	760	411	480	711	65	185	255	0	0	0	113	2,980
2032	Lower	440	11	335	170	15	0	110	0	0	0	0	1,081
	Baseline	440	411	370	435	65	0	260	0	0	0	150	2,131
	Higher	760	411	760	711	65	195	260	0	0	0	150	3,312
2033	Lower	440	11	405	170	15	0	110	0	0	0	0	1,151
	Baseline	440	411	590	435	65	0	264	0	0	0	174	2,379
	Higher	760	411	1,120	711	65	205	264	0	0	0	174	3,710
2034	Lower	440	11	475	170	15	0	110	0	0	0	0	1,221
	Baseline	440	411	750	435	65	0	269	0	0	0	184	2,554
	Higher	760	411	1,300	711	65	210	269	0	0	0	184	3,910
2035	Lower	440	11	475	170	15	0	110	0	0	0	0	1,221
	Baseline	440	411	830	435	65	0	275	0	0	0	187	2,643
	Higher	760	411	1,400	711	65	210	275	0	0	0	187	4,019
2036	Lower	440	11	475	170	15	0	110	0	0	0	0	1,221
	Baseline	440	411	900	435	65	0	279	0	0	0	187	2,717
	Higher	760	411	1,490	711	65	210	279	0	0	0	187	4,113

Figure 12: Large Load Winter Peak Forecast

Large Loads Winter Peak Forecasts (MW) Reflects Cumulative Existing and Future Load Impacts of Large Load Projects													
Year	Forecast	A	B	C	D	E	F	G	H	I	J	K	NYCA
2026-27	Lower	190	0	0	169	15	0	62	0	0	0	0	436
	Baseline	440	11	0	169	15	0	72	0	0	0	0	707
	Higher	440	11	0	169	15	0	72	0	0	0	0	707
2027-28	Lower	290	11	0	170	15	0	73	0	0	0	0	559
	Baseline	440	91	0	435	40	0	173	0	0	0	3	1,182
	Higher	490	91	0	443	40	10	173	0	0	0	3	1,250
2028-29	Lower	390	11	0	170	15	0	84	0	0	0	0	670
	Baseline	440	191	0	435	65	0	184	0	0	0	36	1,351
	Higher	650	191	20	531	65	83	184	0	0	0	36	1,760
2029-30	Lower	440	11	70	170	15	0	97	0	0	0	0	803
	Baseline	440	381	70	435	65	0	227	0	0	0	71	1,689
	Higher	760	381	150	611	65	150	227	0	0	0	71	2,415
2030-31	Lower	440	11	180	170	15	0	108	0	0	0	0	924
	Baseline	440	411	180	435	65	0	241	0	0	0	136	1,908
	Higher	760	411	345	661	65	170	241	0	0	0	136	2,789
2031-32	Lower	440	11	275	170	15	0	109	0	0	0	0	1,020
	Baseline	440	411	280	435	65	0	255	0	0	0	189	2,075
	Higher	760	411	580	711	65	185	255	0	0	0	189	3,156
2032-33	Lower	440	11	345	170	15	0	110	0	0	0	0	1,091
	Baseline	440	411	420	435	65	0	260	0	0	0	219	2,250
	Higher	760	411	880	711	65	195	260	0	0	0	219	3,501
2033-34	Lower	440	11	415	170	15	0	110	0	0	0	0	1,161
	Baseline	440	411	610	435	65	0	264	0	0	0	236	2,461
	Higher	760	411	1,150	711	65	205	264	0	0	0	236	3,802
2034-35	Lower	440	11	475	170	15	0	110	0	0	0	0	1,221
	Baseline	440	411	760	435	65	0	269	0	0	0	243	2,623
	Higher	760	411	1,320	711	65	210	269	0	0	0	243	3,989
2035-36	Lower	440	11	475	170	15	0	110	0	0	0	0	1,221
	Baseline	440	411	840	435	65	0	275	0	0	0	244	2,710
	Higher	760	411	1,420	711	65	210	275	0	0	0	244	4,096
2036-37	Lower	440	11	475	170	15	0	110	0	0	0	0	1,221
	Baseline	440	411	910	435	65	0	279	0	0	0	244	2,784
	Higher	760	411	1,510	711	65	210	279	0	0	0	244	4,190

Appendix D - Resource Adequacy Models and Assessments

Resource adequacy is 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.

The NYISO evaluates resource adequacy using probabilistic simulations that capture the effects of uncertain future conditions, including variations in demand and effects of random forced outage of generation and transmission facilities. These simulations use a sequential Monte Carlo approach to calculate reliability metrics such as Loss of Load Expectation (LOLE). The analysis reflects the key drivers discussed in the Key System Trends section of the 2026 RNA Report, including risks associated with an aging generation fleet (beginning in study year six) and limited emergency assistance expected from neighboring systems that are incorporated starting with the 2026 RNA. Large loads are assumed in the baseline demand forecast which is used in the Base Case while lower and higher demand forecasts are used in scenarios. A portion of the proposed large loads were assumed flexible. Existing large loads electing to move from the Special Case Resources (SCR) capacity market program into the newly implemented Distributed Energy Resources (DER) market program were also modeled as flexible.

The NYISO 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. In addition to performing probabilistic simulations on the Base Case, the NYISO also evaluated variations to the Base Case assumptions to identify, through the development and use of 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. In assessing the reliability of a system, the simulations take into consideration several types of randomly occurring events. Among these are forced outages of generation and transmission and deviations from the forecasted loads. Additional modeling details and links to various stakeholders' presentations are in the assumptions 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 key assumptions highlighted below (additional details are

contained in the assumptions matrix).

Winter uncertainties:

- **Dynamic load forecast uncertainty (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, electric vehicle (EV) charging, and large loads.
- **Winter gas unavailability**: on the resources side, risk of gas unavailability mainly related with gas-only plants was implemented.

Data sources for the hourly MW shapes: using five years of hourly MW model-based data (available 2020-2024), as developed by DNV[12] for land-based and offshore wind, as well as front-of-the-meter solar.

Further limiting external reliance: the 3,500 MW NYCA-wide emergency assistance limit is assumed to decrease by 100 MW per study year, beginning in 2027, to reflect tightening margins in neighboring systems.

Special Case Resources (SCRs) model: modeled as duration-limited, demand-side resources with a maximum of one deployment per day during loss-of-load events.

Large loads: incorporated into the zonal load shapes based on the study load forecast assumptions. A portion of large-load demand is assumed to be flexible and available to reduce demand during loss of load events.

Modeling Assumptions

Generation Model

The NYISO models the generation system in GE-MARS using several types of units with associated considerations. Thermal unit considerations include random forced outages, scheduled and unplanned maintenance, and thermal derates (*i.e.*, minimum between CRIS and DMNC MW from the 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 hourly data. Co-generation units are also modeled using a capacity and load profile for each unit.

In addition to unit-type assumptions, approximately 5,400 MW of gas plants NYCA wide are assumed unavailable during winter peak conditions to account for cold weather risks[13] based on the assumptions that (1) all gas-only units with non-firm gas and (2) certain dual-fuel units are modeled at their alternate fuel capability. These assumptions are triggered when the demand is above the forecasted baseline winter coincident peak for each study year.

[12] Additional details here: Home page - VAP Public View Site

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

A growing portion of New York's generation fleet is expected to exceed 70 years of age by the end of the study horizon. To reflect the increasing uncertainty associated with the continued operation of aging generators, the 2026 RNA incorporates a projection of expected unavailable capacity beginning in study year 6 (2032).

Load Model

The NYISO's load model for the resource adequacy model consists of historical load shapes and LFU. The NYISO uses three historical load shapes (8,760 hourly MW) in the model in seven different load levels using a normal distribution. The 2013, 2017, and 2018 load shapes used in the study are adjusted on a seasonal (summer and winter) basis to meet the forecasted zonal peaks, NYCA peak, Zones G through J Locality peak, and NYCA energy forecast.

The baseline load forecast includes large loads from the NYISO's Interconnection Queue with forecasted impacts assumed in the baseline demand for each study year.

The 2026 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 resource adequacy modeling application, projected load reductions from BTM solar are added back to the forecasted load levels and shapes, allowing BTM solar resources to be represented explicitly in the resource adequacy model. BTM solar variability is represented through performance-factor-adjusted solar profiles that preserve the historical relationship between solar production and load.

In addition to projected load at expected weather conditions, the RNA considers the impacts of extreme weather on peak load conditions, known as LFU. 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 are added to the system. To account for forecast uncertainty during winter due to electrification and large loads, an additional LFU concept was added and modeled via the dynamic[14] winter LFU multipliers. LFU is applied to every hour of these historical shapes, and each hour of the seven load levels is run through the resource adequacy model for each replication for resources availability evaluations.

Historical shapes used in the past (*i.e.*, 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

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

by the NYISO.[15] 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. 2018 is 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.

External Areas Model

The NYISO models the four external Control Areas interconnected to the NYCA (*i.e.*, 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 statewide limit to the total emergency assistance from all neighbors (additional to the "pipe" limits), 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 LOLE range of 0.10 to 0.15 event-days/year throughout the Study Period. The statewide limit of 3,500 MW was further reduced by 100 MW per study year for this RNA to reflect trends in resource availability from the external areas.

Additionally, various grandfathered or firm contracts and Unforced Deliverability Rights (UDRs) links with the neighboring systems are generally modeled using the "contracts" feature in the resource adequacy model.

[15] The changes to the historical shapes were presented at the March 24, 2022 LFTF/TPAS/ESPWG and are 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.

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, SCRs, manual voltage reduction, public appeals, 10-minute reserve, 30-minute reserve, and emergency assistance from external areas.

A change was implemented for the 2026 RNA to maintain (*i.e.,* no longer deplete) 450 MW of the 1,310 MW 10-min operating reserves as part of the EOPs. Additionally, several resources participating in NYISO's SCR demand response program were elected to be part of the new DER program and were modeled accordingly.

Resource Adequacy Topology

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

The 2026 RNA leveraged the transfer studies assessments from the Area Transmission Review and reflected updated topology limits, while also adding several winter limits, as shown in the table below.

Figure 13: Topology Transfer Limits Updates

Comparison of 2024 RNA and 2026 RNA Interface Assumptions			2024 RNA				2026 RNA			
			2025-2029	2030-2034	2025-2029	2030-2034	2025-2029	2030-2034	2025-2029	2030-2034
Tag	Interface Name	Direction	Summer		Winter		Summer		Winter	
Internal Interfaces										
A_TO_B	Dysinger East	Forward	2000	2000	2000	2000	2000	2000	2475	2475
		Reverse	Unlimited		Unlimited		2050	2050	2050	2050
B_TO_C	West Central	Forward	1500	1500	1500	1500	1800	1800	2000	2000
		Reverse	2275	2275	2275	2275	2550	2550	2900	2900
C_TO_E	Volney East	Forward	5650	5650	5650	5650	4975	4975	4975	4975
		Reverse	Unlimited		Unlimited		Unlimited		Unlimited	
D_TO_E	Moses South	Forward	3500	3500	3500	3500	3350	3350	3350	3350
		Reverse	1600	1600	1600	1600	1100	1100	2200	2200
E_TO_F	Central East (MARS)	Forward	3925[1]	3925[1]	3925[1]	3925[1]	3700	3700	4125[1]	4125[1]
		Reverse	Unlimited		Unlimited		Unlimited		Unlimited	
F_TO_G	Capital Hudson Valley	Forward	5400	5400	5400	5400	5400	5400	4100	4100
		Reverse	Unlimited		Unlimited		Unlimited		Unlimited	
G_TO_H	UPNY - ConEd	Forward	7050	7050	7050	7050	8025[2]	8025	7575[2]	7575
		Reverse	Unlimited		Unlimited		Unlimited		Unlimited	
Internal Interface Groups										
E_TO_FG	Central East and Marcy Group	Forward	5650[1]	5650[1]	5650[1]	5650[1]	5650[1]	5650[1]	5150[1]	5150[1]
		Reverse	3400	3400	3400	3400	3400	3400	3400	3400
IJ_TO_K	ConEd to LIPA (IJ to K)	Forward	1598	3250	1598	3250	1598	3250	1598	3250
		Reverse	170[1]	1900[1]	170[1]	1900[1]	170[1]	3625	170[1]	3625
LI_WEST	LI West	Forward	Unlimited		Unlimited		Unlimited	3800	Unlimited	3800
		Reverse	84	1240	84	1240	84	2975	84	2975
UPNYSENY	UPNY-SENY (MARS)	Forward	7150	7150	7150	7150	6400	6400	5500	5500
		Reverse	Unlimited		Unlimited		Unlimited		Unlimited	
External Interfaces										
CHAT_HQ	Chateauguay to HQ	Forward	Unlimited		Unlimited		Unlimited		Unlimited	
		Reverse	Unlimited		Unlimited		Unlimited		0	0
External Interface Groups										
NYCA_EA	NY Import Emergency Assistance	Forward	3500	3500	3500	3500	3400 to 3200[3]	3100 to 2500[3]	3400 to 3200[3]	3100 to 2500[3]
		Reverse	Unlimited		Unlimited		Unlimited		Unlimited	

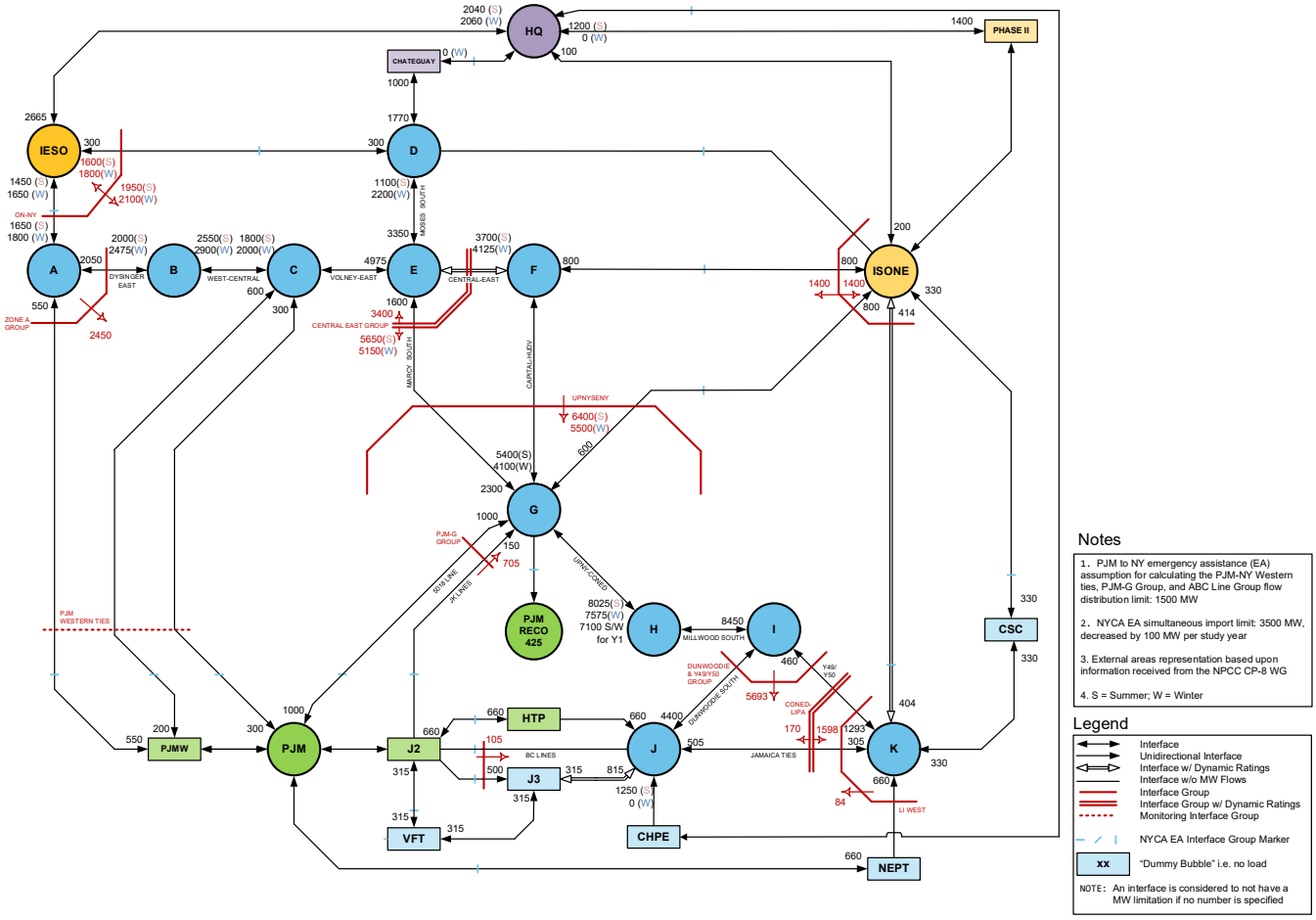
[1] Rating a function of unit availabilities and/or area loads.

[2] The UPNY-ConEd interface limit is 7100 MW in 2027 only.

[3] NYCA simultaneous import limit assumed to decrease by 100 MW per study year beginning in 2027.

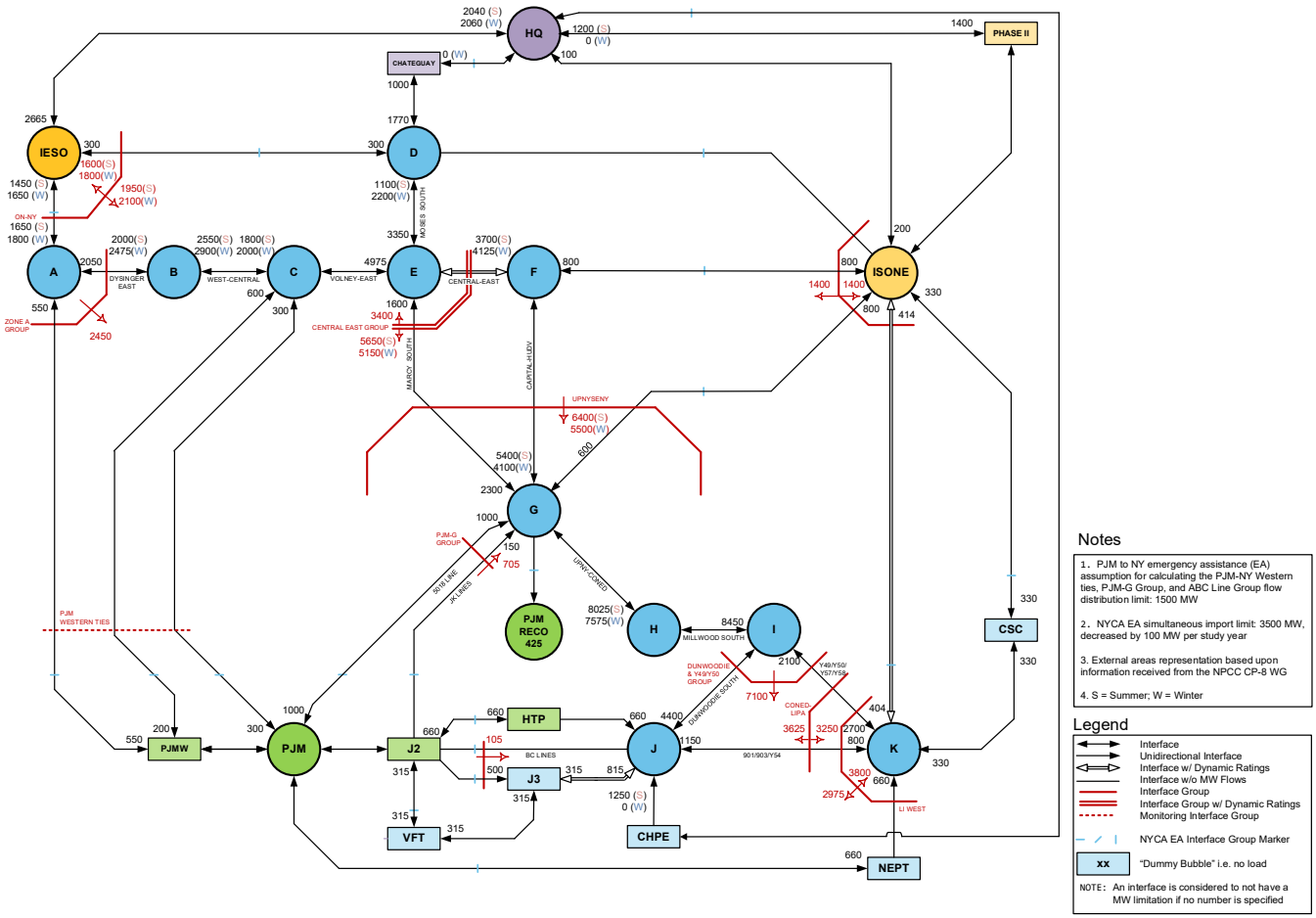
Visual depictions of the resource adequacy topologies used for the 2026 RNA Base Case are below.

Figure 14: 2026 Planning Topology Study Years 1-3



MARS Topology for 2026 RNA Base Cases: Study Years 1 through 3 (2027-2029)

Figure 15: 2026 RNA Topology Study Years 4-10 (2030-2036)



MARS Topology for 2026 RNA Base Cases: Study Years 4 through 10 (2030-2036) – with LIPPTN

Resource Adequacy Assumptions Matrix

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
0	**Relevant Links**	• 2024 RNA Report Appendices • 2025-2034 CRP Report Appendices	• July 23 ESPWG 2025 Q3 STAR Assumptions • Nov. 10, 2025 Q3 STAR Solutions Solicitation • Nov 7 ESPWG 2025 Q4 STAR Assumptions	• May 6, 2026 ESPWG/TPAS: Key assumptions, TS and RA assumptions matrix, inclusion rules • May 20 ESPWG/TPAS: potential scenarios. • June 1 LFTF/ESPWG/TPAS - Additional demand forecasts • June 25 ESPWG/TPAS – scenarios list • July 7 LFTF/ESPWG/TPAS – scenarios list, load forecast uncertainty • July 23, 2026 TPAS/ESPWG RNA preliminary Base Case draft results • Aug 3, 2026 ESPWG/TPAS Scenario List Scenarios Narrative • Sept. 1, 2026 ESPWG/TPAS Base Case Results • Sept 14, 2026 ESPWG/TPAS Scenarios results • September 21, 2026 ESPWG/TPAS Draft 1 Report • October 1, 2026 ESPWG/TPAS Draft 2 Report • October 8, 2026 ESPWG/TPAS Draft 2 Report Draft 1 Appendix
	Load Parameters			
1	**Peak** Load Forecast	Adjusted 2024 Gold Book NYCA baseline peak load forecast. It includes large loads from the NYISO interconnection queue, with forecasted impacts. Baseline load represents coincident summer peak demand and includes the reductions due to projected energy efficiency programs, building codes and standards, BtM storage impacts at peak, distributed energy resources and BtM solar	Adjusted 2025 Gold Book NYCA baseline peak load forecast. It includes large loads from the NYISO interconnection queue, with forecasted impacts. Baseline load represents coincident summer peak demand and includes the reductions due to projected energy efficiency programs, building codes and standards, BtM storage impacts at peak, distributed energy	Adjusted 2026 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

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
		photovoltaic resources; it also reflects expected impacts (increases) from projected electric vehicle usage and electrification. The 2024 GB baseline peak load forecast includes the impact (reduction) of behind-the-meter (BtM) solar at the time of NYCA peak. For the BtM Solar adjustment, gross load forecasts that include the impact of the BtM generation are used for the 2024 RNA, which then allows for a discrete modeling of the BtM solar resources using 5 years of inverter data.	resources and BtM solar photovoltaic resources; it also reflects expected impacts (increases) from projected electric vehicle usage and electrification. The 2025 GB baseline peak load forecast includes the impact (reduction) of behind-the-meter (BtM) solar at the time of NYCA peak. For the BtM Solar adjustment, gross load forecasts that include the impact of the BtM generation are used for the 2025 RPP, which then allows for a discrete modeling of the BtM solar resources using 5 years of inverter data.	photovoltaic resources; it also reflects expected impacts (increases) from projected electric vehicle usage and electrification. The 2026 GB baseline peak load forecast includes the impact (reduction) of behind-the-meter (BtM) solar at the time of NYCA peak. For the BtM Solar adjustment, gross load forecasts that include the impact of the BtM generation are used for the model, which then allows for a discrete modeling of the BtM solar resources.
1a	Proposed large loads	As included in the Baseline Peak Load Forecast from the Gold Book. Certain large loads that are assumed flexible (e.g., crypto, hydrogen) are modeled as EOP step.	As included in the Baseline Peak Load Forecast from the Gold Book. Certain large loads that are assumed flexible (e.g., crypto, hydrogen) are modeled as EOP step.	As included in the Baseline Peak Load Forecast from the Gold Book. Certain large loads that are assumed flexible (e.g., crypto, hydrogen) are modeled as either EOP step or as part of the DER program if elected to participate.
2	Load **Shapes** (Multiple Load Shapes)	Used Multiple Load Shape MARS Feature *(see March 24, 2022 LFTF/ESPWG).* 8,760-hour historical gross load shapes were used as base shapes for LFU bins: Load Bins 1 and 2: 2013 Load Bins 3 and 4: 2018 Load Bins 5 to 7: 2017 Historical load shapes are adjusted to meet zonal (as well as G-J) coincident and non-coincident peak forecasts (summer and winter), while maintaining the energy targets. For the BtM Solar discrete modeling, gross load forecasts that include the impact of the BtM generation are used (additional details under the BtM Solar category below).	Used Multiple Load Shape MARS Feature *(see March 24, 2022 LFTF/ESPWG).* 8,760-hour historical gross load shapes were used as base shapes for LFU bins: Load Bins 1 and 2: 2013 Load Bins 3 and 4: 2018 Load Bins 5 to 7: 2017 Historical load shapes are adjusted to meet zonal (as well as G-J) coincident and non-coincident peak forecasts (summer and winter), while maintaining the energy targets. For the BtM Solar discrete modeling, gross load forecasts that include the impact of the BtM generation are used (additional details under the BtM Solar category below).	Used Multiple Load Shape MARS Feature *(see March 24, 2022 LFTF/ESPWG).* 8,760-hour historical gross load shapes were used as base shapes for LFU bins: Load Bins 1 and 2: 2013 Load Bins 3 and 4: 2018 Load Bins 5 to 7: 2017 Historical load shapes are adjusted to meet zonal (as well as G-J) coincident and non-coincident peak forecasts (summer and winter), while maintaining the energy targets. For the BtM Solar discrete modeling, gross load forecasts that include the impact of the BtM generation are used (additional details under the BtM Solar category below).
3	Load Forecast Uncertainty (LFU)	The LFU model captures the impacts of weather conditions on future loads. Same summer LFU values as the ones presented in 2023 *(as presented at the May 26, 2023 LFTF [link] and also presented at the April 18, 2024 LFTF [link])* **New Additional Method for Winter:**	The LFU model captures the impacts of weather conditions on future loads. Same summer LFU values as the ones presented in 2023 *(as presented at the May 26, 2023 LFTF [link] and also presented at the April 18, 2024 LFTF [link])*	The LFU model captures the impacts of weather conditions on future loads. Summer and Winter LFU values presented at the July 1, 2026 LFTF [Link] **Starting 2024 RNA, winter Dynamic Load Forecast Uncertainty (LFU)**: In order to reflect uncertainty stemming from electrification,

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
		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 match those calculated using recent winter load and weather data. Additional details are available in the April 18 TPAS/ESPWG/LFTF presentation [link]	**Starting 2024 RNA, winter Dynamic Load Forecast Uncertainty (LFU)**: In order to reflect uncertainty stemming from electrification, electric vehicles (EVs), and large loads, starting with the 2024 RNA used a winter LFU multipliers model. Over the study period year 2 through year 10, dynamic winter LFU multipliers were calculated, reflecting the 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 match those calculated using recent winter load and weather data. Additional details are available in the May 29 TPAS/ESPWG/LFTF presentation [link]	electric vehicles (EVs), and large loads, starting with the 2024 RNA used a winter LFU multipliers model. Over the study period year 2 through year 10, dynamic winter LFU multipliers were calculated, reflecting the 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 match those calculated using recent winter load and weather data.
Generation Parameters				
1	**Existing** Generating Unit Capacities (*e.g., thermal units, large hydro)*	2024 Gold Book values: Summer is min of (DMNC, CRIS). Winter is min of (DMNC, CRIS). Adjusted for RNA Base Case inclusion rules application	2025 Gold Book values: Summer is min of (DMNC, CRIS). Winter is min of (DMNC, CRIS). Adjusted for RNA Base Case inclusion rules application	2026 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	2024 Gold Book with RNA Base Case inclusion rules applied	2025 Gold Book with RNA Base Case inclusion rules applied	2026 Gold Book and market participant input with RNA Base Case inclusion rules applied
3	Retirement, Mothballed Units, IIFO	2024 Gold Book with RNA Base Case inclusion rules applied	2025 Gold Book with RNA Base Case inclusion rules applied	2026 Gold Book and market participant input with RNA Base Case inclusion rules applied

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
4	Statistical Retirement Risk	N/A	N/A	**New Method:**[16] Aging generation impacts will be captured for thermal fossil units using the statistical retirement risk model described in Attachment H of the Reliability Planning Process Manual. The P95 threshold age will be applied, and the EIA 860M February 2026 Monthly Generator Inventory data will be used.
5	Forced and Partial Outage Rates (*e.g., thermal units*)	Five-year (2019-2023) GADS data for each unit represented. Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period. For new units or units that are in service for less than three years, NERC 5-year class average EFORd data are used.	Five-year (2020-2024) GADS data for each unit represented. Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period. For new units or units that are in service for less than three years, NERC 5-year class average EFORd data are used.	Five-year (2021-2025) GADS data for each unit represented. Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period. For new units or units that are in service for less than three years, NERC 5-year class average EFORd data are used.
6	Modeling of Non-firm Gas Unavailability During Winter Peak Conditions	New: In order to simulate anticipated risks from cold snaps on the gas availability, gas plants available MWs in NYCA are further derated, *i.e.,* all gas-only units with non-firm gas within the NYCA are assumed unavailable. Also, certain dual-fuel units with duct-burn capability are derated. The forecasted winter coincident peak is used to determine when the gas derates are applied in the RNA Base Cases and for each load bin and Study Year.	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.	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.
7	Daily Maintenance	Fixed maintenance based on schedules received by the NYISO.	Fixed maintenance based on schedules received by the NYISO.	Fixed maintenance based on schedules received by the NYISO.
8	Weekly Planned Maintenance	After planned daily maintenance is applied for the near future, MARS automatically schedules 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.	After planned daily maintenance is applied for the near future, MARS automatically schedules maintenance based on NYCA capacity and demand. Data: 5y (2020-2024) of historical scheduled maintenance data from Operations and GADS system to determine	After planned daily maintenance is applied for the near future, MARS automatically schedules maintenance based on NYCA capacity and demand. Data: 5y (2021-2025) of historical scheduled maintenance data from Operations and GADS system to determine the number of weeks on maintenance for each thermal unit.

[16] *See* Reliability Planning Process Manual (June 1, 2026) at Section 3.2.3 and Attachment H.

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
			the number of weeks on maintenance for each thermal unit.	
9	Summer Maintenance	None	None	None
10	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.	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.
11	Existing Landfill Gas (LFG) Plants	Actual hourly plant output is derived from the most recent available data 2017–2021 across all hourly generation shapes. In each Monte Carlo replication, one LFG hourly production shape is randomly selected from the dataset, with all shapes assigned equal probability.	Actual hourly plant output is derived from the most recent available data 2020–2024 across all hourly generation shapes. In each Monte Carlo replication, one LFG hourly production shape is randomly selected from the dataset, with all shapes assigned equal probability.	Actual hourly plant output is derived from the most recent available data 2020–2024 across all hourly generation shapes. In each Monte Carlo replication, one LFG hourly production shape is randomly selected from the dataset, with all shapes assigned equal probability.
12	Existing and Proposed **Wind** Units	**New data source:** Model-based hourly data derived from the most recent available data (2017-2021, developed by DNV-GL) across all hourly generation shapes. Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process.	Model-based hourly data derived from the most recent available data (2020-2024, developed by DNV-GL) across all hourly generation shapes. Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process.	Model-based hourly data derived from the most recent available data (2020-2024, developed by DNV-GL) across all hourly generation shapes. Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process.
13	Existing and Proposed **Offshore Wind** Units	**New data source:** Model-based hourly data derived from the most recent available data (2017-2021) across all hourly generation shapes Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process.	Model-based hourly data derived from the most recent available data (2020-2024) across all hourly generation shapes Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process.	Model-based hourly data derived from the most recent available data (2020-2024) across all hourly generation shapes Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process.
14	Existing and Proposed **Utility-scale Solar Resources**	**New data source:** Model-based hourly data derived from the most recent available data (2017-2021) across all hourly generation shapes	Model-based hourly data derived from the most recent available data (2020-2024) across all hourly generation shapes	Model-based hourly data derived from the most recent available data (2020-2024) across all hourly generation shapes

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
		Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process	Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process	Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process.
15	**BtM Solar Resources**	**Supply side:** Past five years (2017-2021) of 8,760 hourly MW profiles based on sampled inverter data. . In each Monte Carlo replication, one BTM hourly shape is randomly selected from this dataset, with all shapes assigned equal probability. **Load side:** Gross load forecasts	**Supply side:** Past five years (2020-2024) of 8,760 hourly MW profiles based on sampled inverter data. In each Monte Carlo replication, one BTM hourly shape is randomly selected from this dataset, with all shapes assigned equal probability. **Load side:** Gross load forecasts	**Supply side:** In order to better preserve the correlation between BTM PV production and load, the use of five historical BTM PV shapes is being replaced with a set of five performance factors applied to the 2013 BTM PV shape. The five performance factors are calculated using estimated actual BTM solar generation during high load days over recent years. These factors represent the typical range of BTM solar variability that can be expected during high load days, expressed as five ratios: two with above average solar generation, one with average solar generation (approximately 1.0), and two with below average solar generation. These factors are applied to the 2013 historical BTM PV shape to generate five 8,760-hour profiles, maintaining the inherent correlation of BTM solar and load in the most impactful load bins. In each Monte Carlo replication, one BTM hourly shape is randomly selected from this dataset, with all shapes assigned equal probability. **Load side:** Gross load forecasts
16	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.	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.
17	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.	Actual hourly plant output is derived from the most recent available data (2020–2024) across all hourly generation shapes. In each Monte Carlo replication, one hydro hourly production shape is randomly selected

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
				from this dataset, with all shapes assigned equal probability.
18	Existing **Large Hydro**	Probabilistic Model based on 5 years of GADS data. Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period. Methodology consistent with thermal unit transition rates.	Probabilistic Model based on 5 years of GADS data. Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period. Methodology consistent with thermal unit transition rates.	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.
19	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. Limited to one charge/discharge cycle per day	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	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.
20	Existing Energy Limited Resources (**ELRs)**	GE developed MARS functionality to be used for ELRs. Resource output is aligned with the hours when loss-of-load events are likely to occur.	GE developed MARS functionality to be used for ELRs. Resource output is aligned with the hours when loss-of-load events are likely to occur.	GE developed MARS functionality to be used for ELRs. Resource output is aligned with the hours when loss-of-load events are likely to occur.
21	Distributed Energy Resources (**DER**)	N/A	N/A	**New type**: New market participation 2025 program allowing resources to enroll and participate in any of the NYISO markets. Initial program registration: 2025. Also, certain existing resources (including large loads) elected to move from the SCR program into the DER program. DER aggregations with duration limits are represented as energy-limited resources and aggregated by zone, technology type, and duration. DER aggregations without duration limits are aggregated by zone and technology into a single resource. DERs registered as Energy Storage Resources (ESRs) are represented consistent with existing planning assumptions for energy storage units. Demand-side resources participating as DERs are also represented as energy-limited resources; DERs without a duration election are treated as 24-hour resources.

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
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.	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	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	Model sales for known years Modeled using MARS explicit contracts feature. Contracts sold from ROS (Zones: A-F). ROS ties to external pool are derated by sales MW amount
4	UDRs	Updated with most recent elections/awards information (VFT, HTP, Neptune, CSC) Added CHPE HVDC (from Hydro Quebec into Zone J) at 1250 MW (summer only) starting 2026.	Updated with most recent elections/awards information (VFT, HTP, Neptune, CSC) Added CHPE HVDC (from Hydro Quebec into Zone J) at 1250 MW (summer only) starting 2026.	Updated with most recent elections/awards information (VFT, HTP, Neptune, CSC) Added CHPE HVDC (from Hydro Quebec into Zone J) at 1250 MW (summer only) starting 2026.
5	External Deliverability Rights (EDRs)	Cedars Uprate 80 MW. Modeled reflecting External CRIS rights.	Cedars Uprate 80 MW. Modeled reflecting External CRIS rights.	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.	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				

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
1	Interface Limits	Developed by review of previous studies and specific analysis prior and during the RNA study process.	Developed by review of previous studies and specific analysis prior and during the RNA study process. Starting with the 2025 models, Chateaugay to NY limit set to zero for winter.	Developed by review of previous studies and specific analysis prior and during the RNA study process. Starting with the 2025 models, Chateaugay to NY limit set to zero for winter.
2	New Transmission	Based on TO-provided firm plans via Gold Book/LTP 2024 processes) and proposed merchant transmission and public policy facilities meeting the RNA Base Case inclusion rules.	Based on TO-provided firm plans (via Gold Book/LTP 2025 processes) and proposed merchant transmission and public policy facilities meeting the Base Case inclusion rules.	Based on TO-provided firm plans (via Gold Book/LTP 2025 processes) and proposed merchant transmission and public policy facilities meeting the 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 ten-year history.	All existing cable transition rates updated with data received from ConEd and PSEG-LIPA to reflect most recent ten-year history.
4	UDR unavailability	Five-year history of forced outages.	Ten-year history of forced outages.	Ten-year history of forced outages.
Emergency Operating Procedures (EOPs)				
1	EOP Steps Order	**New order, and new flexible large loads at step 2:** 1. No EOP Support 2. Flexible Large Loads 3. Special Case Resources (SCRs) (Load and Generator) 4. 5% Manual Voltage Reduction 5. 30-Minute Operating Reserve to Zero (655 MW) 6. Voluntary Load Curtailment 7. Public Appeals 8. 5% Remote Controlled Voltage Reduction 9. Emergency Assistance from External Areas 10. Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero	Starting 2024 RNA, new EOP order and flexible large loads: 1. No EOP Support 2. Flexible Large Loads 3. Special Case Resources (SCRs) (Load and Generator) 4. 5% Manual Voltage Reduction 5. 30-Minute Operating Reserve to Zero (655MW) 6. Voluntary Load Curtailment 7. Public Appeals 8. 5% Remote Controlled Voltage Reduction 9. Emergency Assistance from External Areas 10. Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero	Starting 2024 RNA, new EOP order and flexible large loads: 1. No EOP Support 2. Flexible Large Loads 3. Special Case Resources (SCRs) (Load and Generator) 4. 5% Manual Voltage Reduction 5. 30-Minute Operating Reserve to Zero (655MW) 6. Voluntary Load Curtailment, 3 days/month 7. Public Appeals, 3 days/year 8. 5% Remote Controlled Voltage Reduction 9. Emergency Assistance from External Areas 10. Part of the 10-Minute Operating Reserve (860 MW of 1310 MW) to Zero [April 28 ICS]
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 2023 SCR enrollment) held constant for all years of study. **New Method:**	SCRs sold for the program discounted to historic availability (“effective capacity”). Monthly variation based on historical experience. Summer values calculated from the latest available July registrations (July 2024 SCR enrollment) held constant for all years of study.	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 2025 SCR enrollment) held constant for all years of study.

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
		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].	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].	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.	Not modeled if the values are less than 2 MW.
4	Operating Reserves	655 MW 30-min reserve to zero 910 MW (of 1310 MW) 10-min reserve to zero Note: the 10-min reserve modeling method is updated per NYISO's recommendation (approved at the Oct. 3, 2023 NYSRC ICS [link]) to maintain (or no longer deplete/use) 400 MW of the 1,310 MW 10-min operating reserve at the applicable EOP step. Therefore, the 10-min operating reserve MARS EOP step will use, as needed each MARS replication: 910 MW (=1,310 MW–400 MW).	655 MW 30-min reserve to zero 910 MW (of 1310 MW) 10-min reserve to zero Note: the 10-min reserve modeling method is updated per NYISO's recommendation (approved at the Oct. 3, 2023 NYSRC ICS [link]) to maintain (or no longer deplete/use) 400 MW of the 1,310 MW 10-min operating reserve at the applicable EOP step. Therefore, the 10-min operating reserve MARS EOP step will use, as needed each MARS replication: 910 MW (=1,310 MW–400 MW).	655 MW 30-min reserve to zero 860 MW (of 1310 MW) 10-min reserve to zero Note: the 10-min reserve modeling method is updated per NYISO's recommendation at April 28, 2026 ICS to maintain (or no longer deplete/use) 450 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: 860 MW (=1,310 MW–450 MW).
5	Other EOPs *(e.g., manual voltage reduction, voltage curtailments, public appeals, external assistance, as listed above)*	Based on TO information, measured data, and NYISO forecasts. Will use 2024 elections, as available.	Based on TO information, measured data, and NYISO forecasts. Will use 2024 elections, as available.	Based on TO information, measured data, and NYISO forecasts. Will use 2025 elections, as available. **EOP Notes**: 1. Starting with the 2026 RNA, EOP Step 6 and 7 will have a 3 calls/month, 3 calls/year, respectively limit, aligning with the IRM model 2. Emergency external assistance NYCA limit change by gradually lowering it by 100 MW per study year

External Control Areas Modeling Assumptions

- External models (NE, HQ, Ontario, PJM) received via the NPCC CP-8 WG process.
- Starting 2024 RNA, the top 5 (instead of 3) summer and winter peak load days of an external Control Area modeled as coincident with the NYCA top 5 peak load days.
- Load and capacity fixed through the study years.

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
• 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, decreased by 100 MW per study year starting with the 2026 RNA. • 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.	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	Simplified model: The 8 ISO-NE MARS areas (bubbles) were consolidated into one starting 2020 RNA
3	HQ	Per RNA Procedure.	Per RNA Procedure.	Per RNA Procedure.
4	IESO	Per RNA procedure.	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.	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.	Implemented a statewide limit starting at 3,500 MW, decreased by 100 MW each study year. This limit is additional to the “pipe” limits.
Miscellaneous				
1	MARS Model Version	4.14.2179	5.7.3765	v5.7.3765

Resource Adequacy Base Case Results

The 2026 RNA Base Case resource adequacy studies show that the annual NYCA LOLE is above the 0.1 event-days/year NPCC and NYSRC criterion starting 2033 (study year 7). The annual NYCA LOLE increases through the study period are driven by the summer events. As shown below in Figure 16 the statewide deficiency is approximately 200 MW in 2033 and increases rapidly through 2036 to more than 1,800 MW as demand increases and aging generation reduces available supply. This statewide resource deficiency reflects an insufficient amount of available supply to reliably meet projected demand and operating reserve requirements. However, winter conditions contribute an increasing share of the LOLE in the later years, accounting for approximately 40% of annual LOLE by 2036, due to increasing demand from heating electrification, as well as fuel-related generation constraints becoming a more significant planning consideration.

Additional resource adequacy background and supporting analysis, including the impact of internal transmission constraints and reliance on emergency operating procedures, are discussed below.

Figure 16: NYCA Resource Adequacy LOLE Results[17]

Study Year	LOLE (event-days/year)			NYCA Margin (perfect MW)
	Annual	Summer	Winter	
Y2027	0.025	0.025	0.000	1,900
Y2028	0.032	0.032	0.000	1,675
Y2029	0.034	0.034	0.000	1,475
Y2030	0.019	0.019	0.000	1,975
Y2031	0.036	0.036	0.000	1,200
Y2032	0.074	0.074	0.000	350
Y2033	0.115	0.114	0.002	-225
Y2034	0.182	0.170	0.012	-725
Y2035	0.290	0.243	0.047	-1,175
Y2036	0.596	0.358	0.238	-1,850

Further supporting analysis from the resource adequacy assessment are discussed below, including additional metrics, reliability margins, reliance on emergency operating procedures, and the impact of internal transmission constraints.

[17] There is no criterion for summer or winter; the results are provided for information.

Resource Adequacy Metrics

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).[18]

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. The Normalized EUE (NEUE) in parts per million (ppm) is the EUE divided by the Gold Book forecast and multiplied by 1,000,000.

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, 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 17 shows how LOLH and EUE rise at the end of the study period along with LOLE.

[18] 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.

Figure 17: NYCA Resource Adequacy Results with Additional Reliability Indices

Study Year	LOLE	LOLH	EUE	NEUE
	event-days/year	hrs/year	MWh/year	ppm
Y2027	0.025	0.060	25	0.162
Y2028	0.032	0.083	34	0.217
Y2029	0.034	0.090	36	0.228
Y2030	0.019	0.044	26	0.162
Y2031	0.036	0.094	65	0.401
Y2032	0.074	0.222	170	1.039
Y2033	0.115	0.353	311	1.877
Y2034	0.182	0.600	524	3.121
Y2035	0.290	0.978	877	5.152
Y2036	0.596	1.986	1,823	10.537

RNA Base Case 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, 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.

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

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

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

where, 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 for the RNA Base Case.

Figure 18: 2026 RNA Base Case Study Year 10 Bin and Month LOLE Distributions

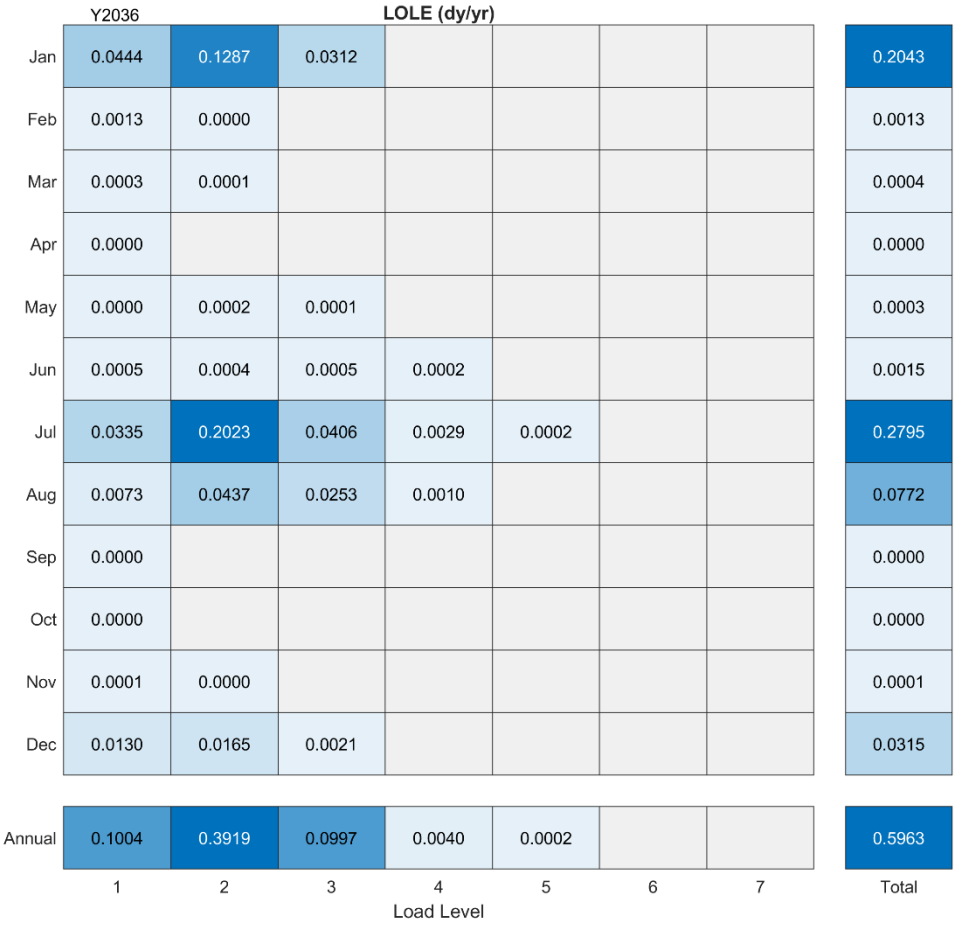
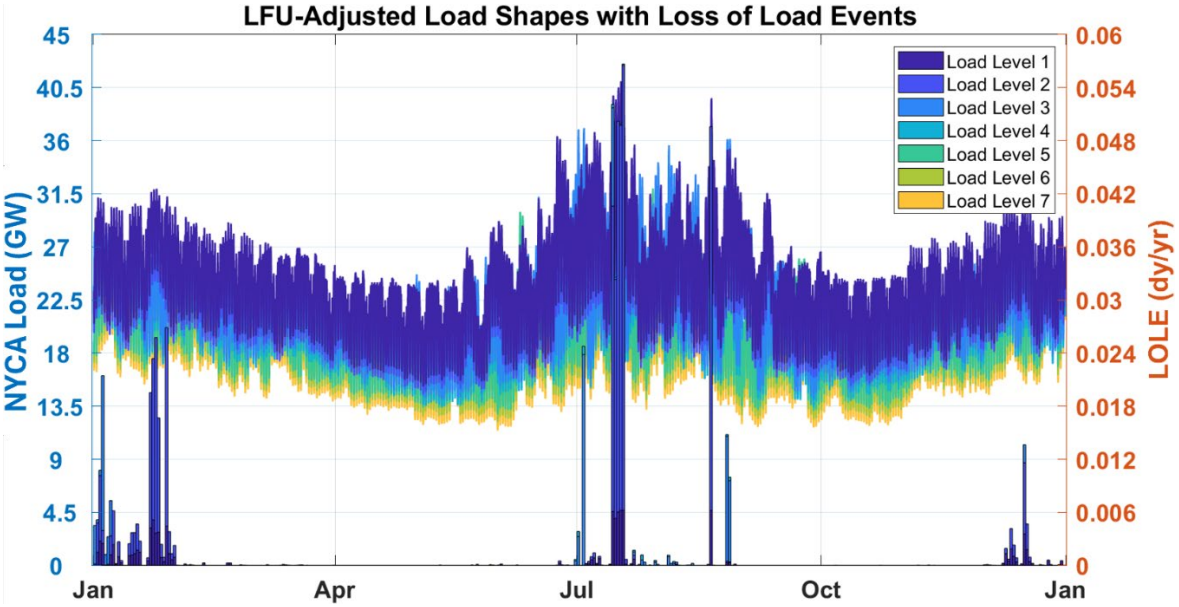


Figure 19: 2026 RNA Base Case Load Shapes and Events



Impact of Emergency Operating Procedures

The New York resource adequacy model incorporates several EOPs, such as operating reserves, SCRs, voltage reduction, public appeals, 10-minute reserve, 30-minute reserve, and emergency assistance from external areas. The LOLE results after utilizing each of the sequential EOP steps are shown in Figure 20. The impact of EOPs can be quantified by the reduction in LOLE between the pre-EOP case and the final EOP step.

Figure 20: LOLE after Each EOP Step

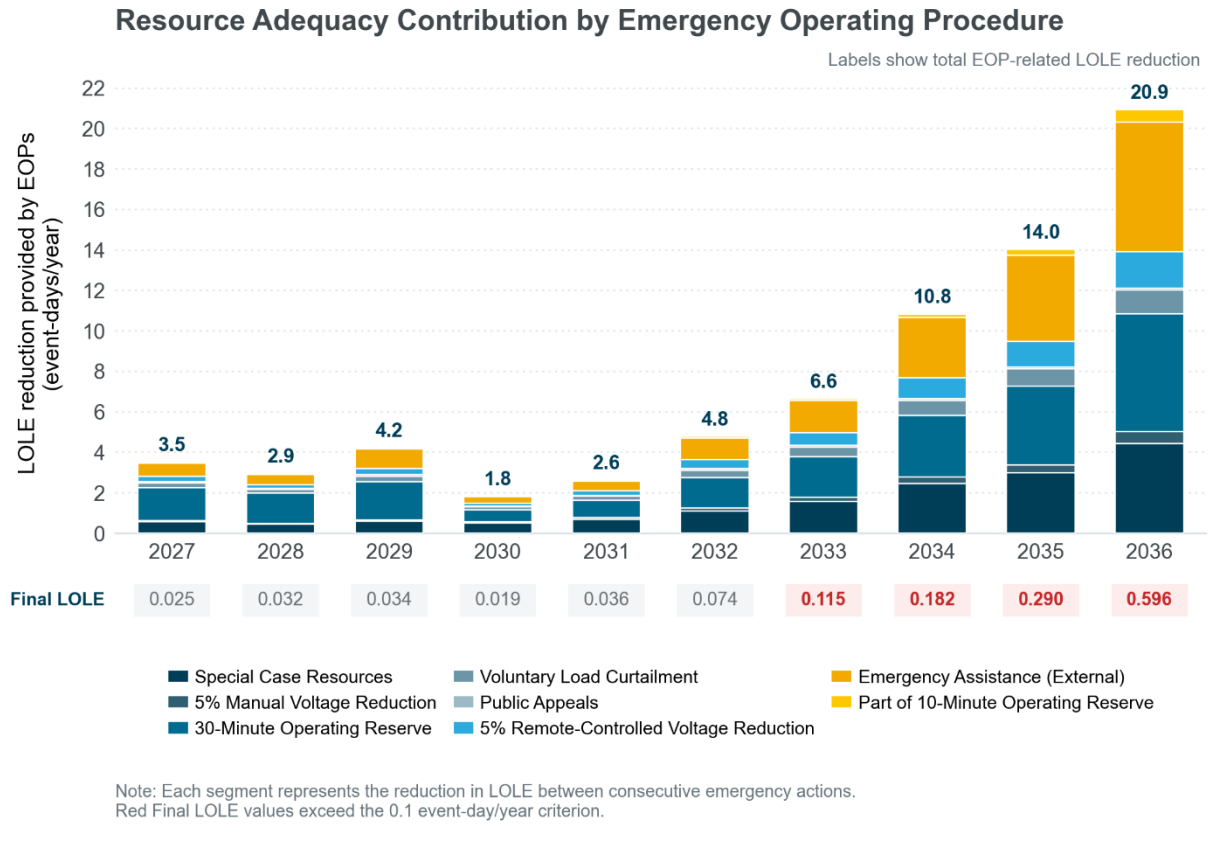
LOLE after EOP Step (event-days/year)	Max MW (S) 2027	Max MW (S) 2036	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Pre-EOP results	-	-	3.524	2.972	4.258	1.861	2.676	4.849	6.762	10.999	14.307	21.527
Special Case Resources (SCRs)	593	593	2.969	2.541	3.668	1.372	2.003	3.750	5.193	8.551	11.328	17.102
5% Manual Voltage Reduction	68	78	2.895	2.487	3.601	1.308	1.910	3.611	4.979	8.234	10.939	16.497
30-Minute Operating Reserve	655	655	1.288	0.994	1.717	0.712	1.060	2.095	2.989	5.177	7.037	10.696
Voluntary Load Curtailment	267	267	1.048	0.815	1.463	0.574	0.857	1.740	2.524	4.459	6.191	9.525
Public Appeals	74	74	0.980	0.749	1.365	0.539	0.811	1.660	2.435	4.366	6.091	9.427
5% Remote Controlled Vol. Reduction	452	488	0.707	0.571	1.065	0.373	0.582	1.220	1.810	3.317	4.838	7.614
Emergency Assistance (External)	3,400	2,500	0.068	0.079	0.086	0.065	0.100	0.160	0.200	0.340	0.568	1.216
Part of the 10-Minute Op. Reserve	**860**	**860**	**0.025**	**0.032**	**0.034**	**0.019**	**0.036**	**0.074**	**0.115**	**0.182**	**0.290**	**0.596**
Total MW	**6,370**	**5,515**										

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

The analysis indicates increasing reliance on emergency operating procedures and external assistance to maintain reliability, reducing the system's ability to withstand unexpected changes in demand, resource performance, or imports.

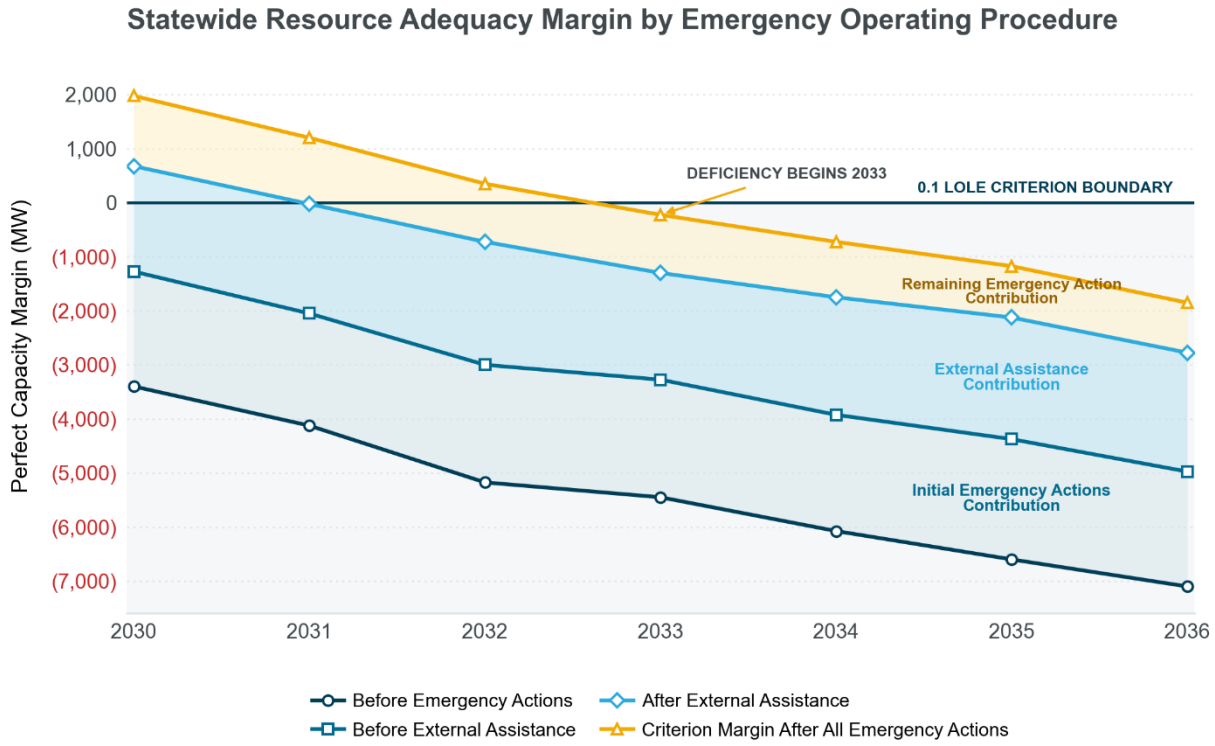
As shown below, the contribution of emergency actions in maintaining reliability increases from approximately 3.5 days per year in 2027 to approximately 21 days per year by 2036. This increased contribution of emergency actions illustrates a system that is becoming increasingly dependent on measures intended for infrequent emergency conditions. The reliability risks primarily occur during the summer months throughout the planning horizon. However, winter risks grow in the later years and account for approximately 40% of the risk by 2036 due to increasing demand for building heating and fuel-related constraints on electricity generation. These results suggest that maintaining reliability will require solutions capable of supporting the system across a wider range of operating conditions and seasons. To date in 2026, grid operations has taken emergency actions well in excess of the projected 3.5 days, an indication that the concerns raised in planning studies may be an operational reality well in advance of projections.

Figure 21: Resource Adequacy Contribution by Emergency Operating Procedure



Note: Each segment represents the reduction in LOLE between consecutive emergency actions.
Red Final LOLE values exceed the 0.1 event-day/year criterion.

Figure 22: Statewide Resource Adequacy Margin by EOP



In particular, the large LOLE drop after the emergency assistance EOP underscores New York's reliance on neighboring systems and highlights that LOLE violations are likely to occur several years earlier without this support.

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 an additional 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.

Zonal Resource Adequacy Margins/Compensatory MW

The resource adequacy margin quantifies how many MW of perfect capacity are needed to bring the system back to within criterion (compensatory MW) without attributing to a specific driver, such as generation unavailability or forecast increase. In the context of resource adequacy analysis, "perfect capacity" is capacity that is always available at full capacity when needed (*e.g.*, not impacted by ambient temperature variation or unit unavailability, not subject to energy durations limitations, not assessed for transmission security or interface impacts). Two methods were used to compute resource adequacy margin or compensatory MW to indicate various ways a deficiency could be solved.

The NYISO calculated compensatory MW (when there is a violation) and resource adequacy margin (when there is surplus) using two methods:

- **Zonal Perfect MW capacity:** calculation performed one zone at a time to provide insights into the amount of MW that is needed in each zone to bring the system back to criterion. The zonal method is used to indicate relative benefit of adding resources in one zone compared to another.
- **Statewide (or NYCA) Load Ratio Perfect MW capacity:** calculation performed by distributing perfect capacity across the state using seasonal load-based ratios to provide a representative system-wide allocation. The statewide method is used to describe the overall margin or deficiency observed in the RNA.

The results in Figure 24 indicate steadily declining reserve margins through 2032. Beginning in 2033, the system becomes capacity deficient, requiring increasing amounts of compensatory "perfect MW" capacity. The deficiency grows each year, from -225 MW in year 2033 and exceeding -1,800 MW by the final study year (2036). Figure 23 shows NYCA zones and their names.

Figure 23: NYISO Load Zone Map

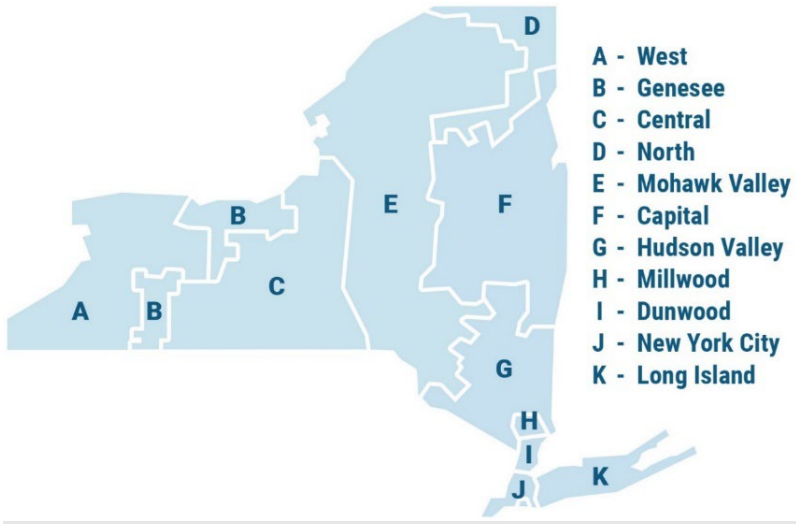
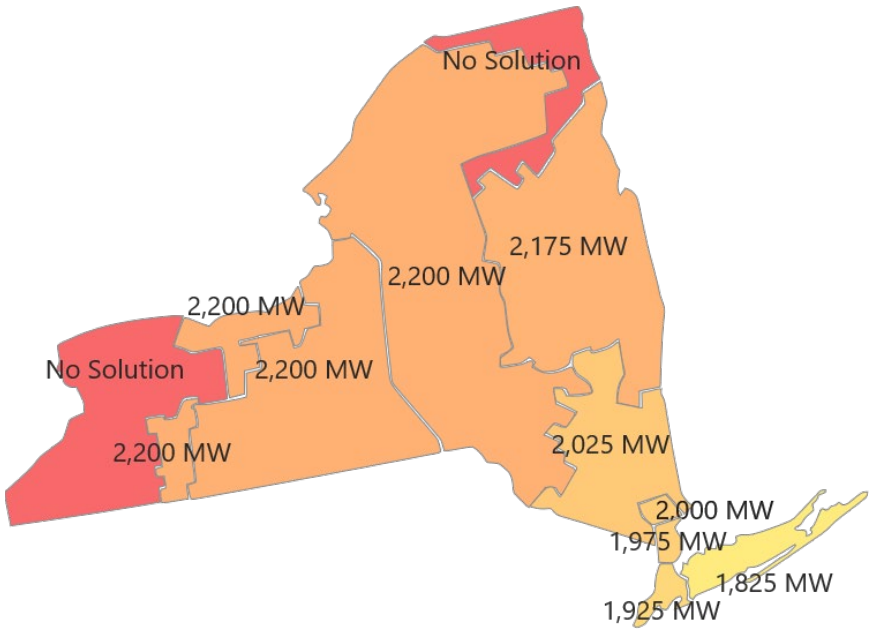


Figure 24: Zonal and NYCA Load Ratio Perfect MW Capacity

Study Year	Zonal Method (perfect MW)											NYCA Method (perfect MW)
	A	B	C	D	E	F	G	H	I	J	K	
2027	1,875	1,875	2,350	2,300	2,350	2,350	2,350	2,350	2,350	1,925	450	1,900
2028	1,775	1,800	2,100	1,975	2,100	2,100	2,075	2,075	2,075	1,900	425	1,675
2029	1,625	1,600	1,725	1,700	1,725	1,725	1,700	1,700	1,700	1,575	375	1,475
2030	1,700	1,700	2,025	2,000	2,025	2,025	1,975	1,975	1,975	1,925	950	1,975
2031	1,250	1,225	1,275	1,250	1,275	1,250	1,200	1,200	1,200	1,200	725	1,200
2032	375	375	375	375	375	375	350	350	350	350	225	350
2033	-225	-225	-225	-225	-225	-225	-225	-225	-225	-225	-200	-225
2034	-800	-775	-775	-775	-775	-775	-775	-775	-775	-775	-700	-725
2035	-1,300	-1,300	-1,275	-1,275	-1,275	-1,275	-1,250	-1,250	-1,250	-1,250	-1,125	-1,175
2036	No Solution	-2,200	-2,200	No Solution	-2,200	-2,175	-2,025	-2,000	-1,975	-1,925	-1,825	-1,850

Note: "no solution" means adding perfect capacity in that zone alone cannot restore the statewide reliability criterion.

Figure 25: Zonal Compensatory MW Study Year 10 (2036) Map



Note: "no solution" means adding perfect capacity in that zone alone cannot restore the statewide reliability criterion.

The zonal resource adequacy margins (ZRAM) or zonal compensatory MW assessment identifies a maximum level of "perfect capacity" that can be removed from or added 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 the capacity's location. Thus, removal of lower amounts of capacity is 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

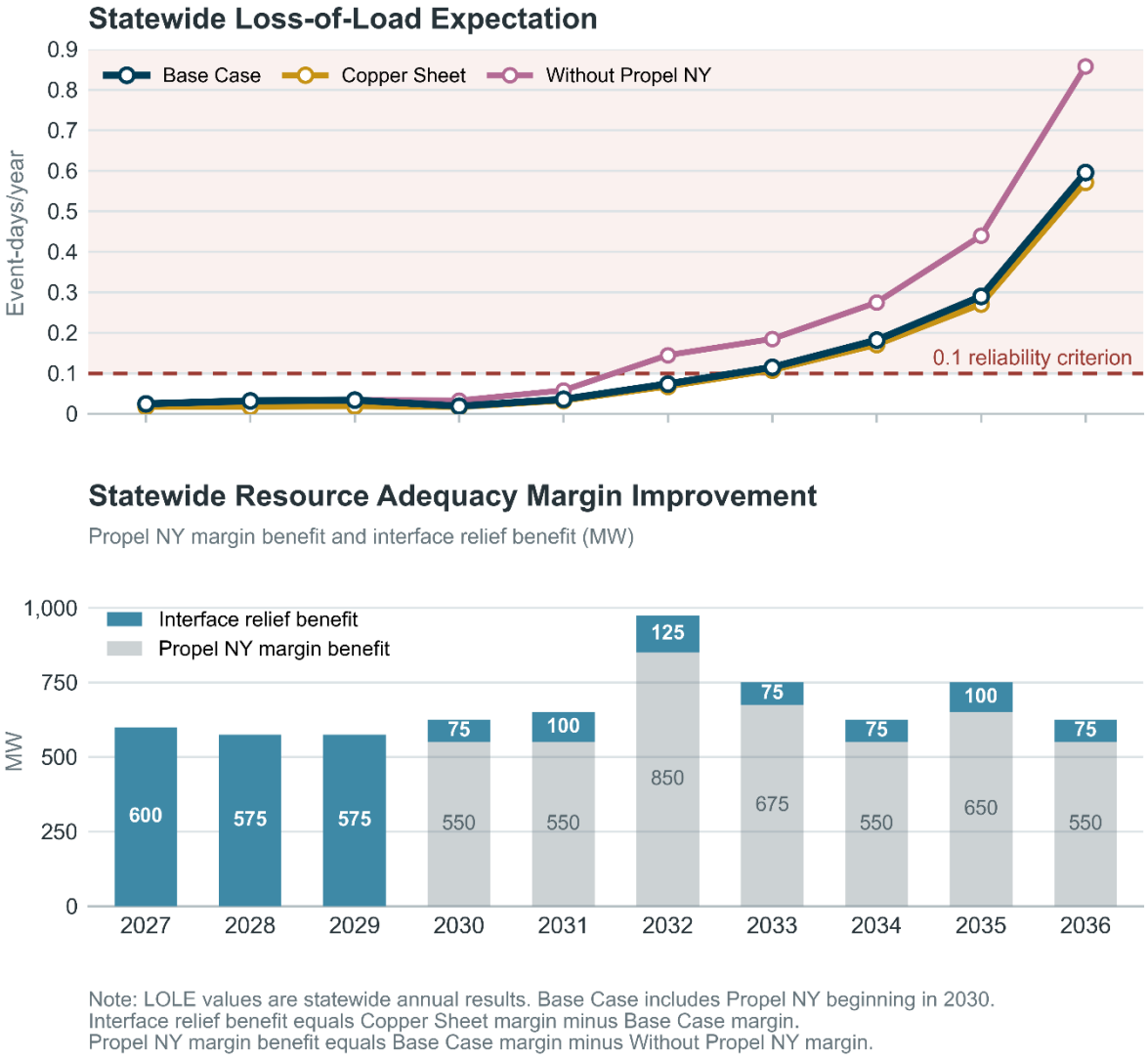
from any of these zones will need to be further studied in light of the specific capacity locations in the transmission network to determine whether any additional violations of reliability criteria would result. Additional transmission security analysis, such as N-1-1 steady-state analysis, transient stability, and short circuit, will be necessary under the applicable process for any contemplated plant retirement in any zone.

Free Flow (or Copper Sheet) and Propel Project Impacts

The statewide resource adequacy results reflect both the amount of available supply and the ability to deliver that supply throughout New York. The analyses below illustrate the significant reliability benefits provided by major transmission investments already included in the Base Case, while also demonstrating that the remaining statewide deficiency is not primarily driven by internal transmission constraints.

To evaluate statewide benefits of planned transmission, the RNA performed a resource adequacy sensitivity analysis on the Base Case without the Propel NY project. Figure 26 shows that the Propel NY project contributes the equivalent of at least 550 MW of statewide compensatory MW due to the new zonal ties from Long Island to the rest of the state. This means that even though the Propel NY project expands the internal transmission system without the addition of new resources, it provides significant value to statewide resource adequacy.

Figure 26: Resource Adequacy Impact of the Propel NY Project



Note: LOLE values are statewide annual results. Base Case includes Propel NY beginning in 2030.
Interface relief benefit equals Copper Sheet margin minus Base Case margin.
Propel NY margin benefit equals Base Case margin minus Without Propel NY margin.

While the Propel NY sensitivity demonstrates the value of planned transmission, the 2026 RNA also performed a free-flow, or "copper sheet," test to determine whether further expansion of the internal transmission system could resolve the remaining statewide deficiency. The test removes the internal interface limits in New York to determine whether internal interface limitations, rather than resource shortages, are driving the results. The results of this sensitivity in Figure 27 are very close to the Base Case results, indicating that additional internal transmission alone would not resolve the resource deficiencies beginning in 2033.

Figure 27: Free Flow Test ("Copper Sheet")

Study Year	LOLE (event-days/year)		Delta
	Base Case	Copper Sheet	
Y2027	0.025	0.018	-0.007
Y2028	0.032	0.018	-0.014
Y2029	0.034	0.019	-0.015
Y2030	0.019	0.017	-0.001
Y2031	0.036	0.033	-0.002
Y2032	0.074	0.068	-0.007
Y2033	0.115	0.108	-0.008
Y2034	0.182	0.171	-0.011
Y2035	0.290	0.271	-0.019
Y2036	0.596	0.572	-0.024

Several interfaces in the resource adequacy model are voltage limited (e.g., Central East, UPNY-ConEd), meaning that the voltage-related limitations are lower than the thermal limitations. As a result, the LOLE results are based on the voltage limitations. If voltage support devices are installed, these limits can be higher and the LOLE would be impacted by the thermal limitations. Therefore, the NYISO developed a model assuming that the voltage limits would be mitigated and evaluated the LOLE based on the interfaces being thermally limited.

Figure 28: No Voltage-Limited Interfaces NYCA Annual LOLE Impacts

Study Year	LOLE (event-days/year)		Delta
	Base Case	No Vol. Limited Interfaces	
Y2027	0.025	0.025	0.000
Y2028	0.032	0.032	0.000
Y2029	0.034	0.034	0.000
Y2030	0.019	0.018	0.000
Y2031	0.036	0.035	0.000
Y2032	0.074	0.073	-0.001
Y2033	0.115	0.114	-0.001
Y2034	0.182	0.181	-0.002
Y2035	0.290	0.287	-0.003
Y2036	0.596	0.594	-0.003

Appendix E - 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 Assumption

The NYISO developed the 2026 RNA Base Case, which is used to analyze the performance of the transmission system, from the 2026 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 2026 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 2026 Gold Book Table 1-3b baseline forecast of coincident peak demand. The system representation for Areas outside the NYCA is from the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) 2025 power flow model library. Within New York, 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[19] 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.

2031 baseline coincident summer peak

2031 daytime light load

2031 nighttime light load

2031-2032 baseline coincident winter peak

2036 baseline coincident summer peak

2036 daytime light load

2036 nighttime light load

2036-2037 baseline coincident winter peak

[19] Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) procedural manual: https://www.rfirst.org/wp-content/uploads/2025/12/MMWG_Procedural_Manual_v44.pdf.

Transmission Security Load Forecast Considerations

In addition to the peak demand forecasts published in the 2026 Gold Book, midday and nighttime light load forecasts are developed for the RNA for use in transmission security analyses.[20] As opposed to midday light load forecasts, which decrease significantly over the Reliability Planning Process horizon due to behind-the-meter (BTM) solar, projected nighttime light loads increase since BTM solar is not a factor.

The midday light load forecast reflects:

- A low 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.

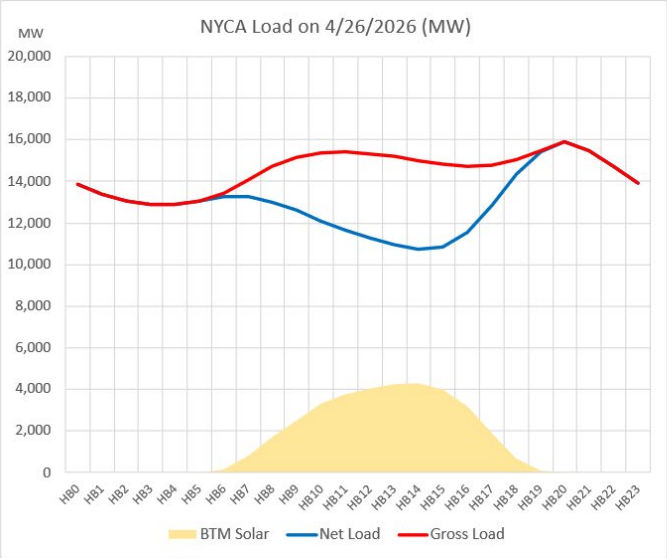
As BTM solar capacity and generation increases over time, minimum net loads during midday hours decrease significantly in later forecast years. These effects are most drastic in some upstate zones, since the relative concentration of BTM solar (relative to load) is generally greatest in these areas during the later study years. These impacts are somewhat mitigated by additional large loads, 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.

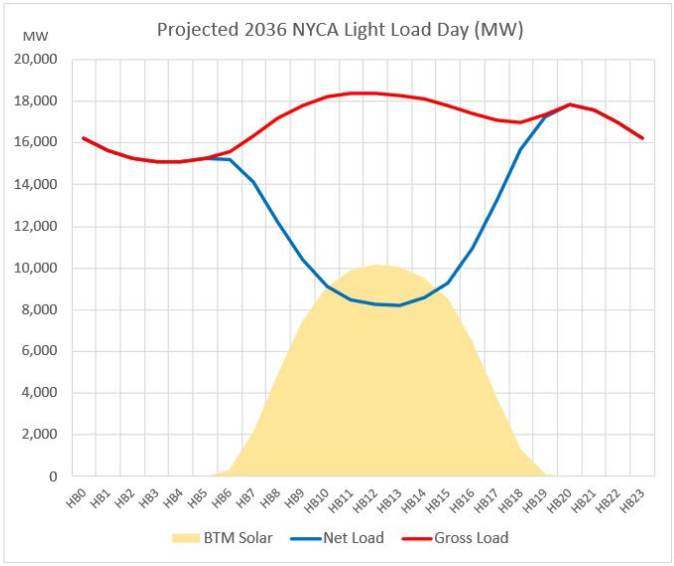
The nighttime light load forecast reflects:

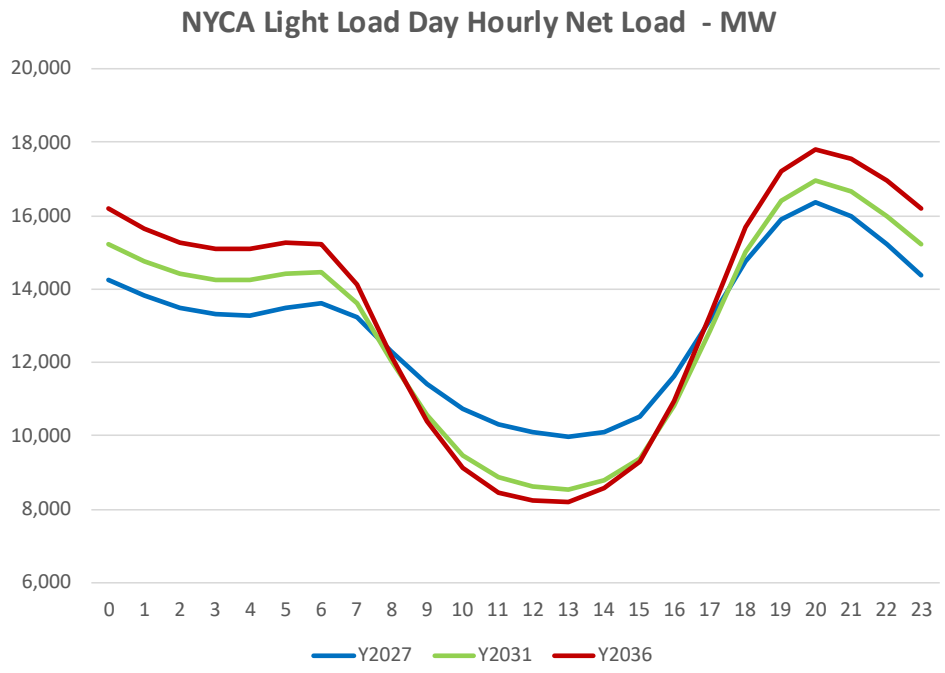
- The projected NYCA minimum overnight load hour, which commonly occurs during a peak weekend with mild temperatures during hour beginning 3 or 4.

[20] Details of the midday and nighttime light load forecast were presented to NYISO stakeholders at the June 1, 2026 TPAS/ESPWG/LFTF (here).

Figure 29: NYCA Light Load Day Shapes







Assumptions Matrix for Transmission Security Assessment

Parameter	2024 RNA Transmission Security Studies Modeling Assumptions	2024 Source	2026 RNA Transmission Security Studies Modeling Assumptions	2026 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. Consideration will be given to NYSRC Proposed Reliability Rules 153a and 154a, which are expected to become effective during the RNA.	NYSRC Reliability Rules, NPCC Directory 1, NERC TPL-001 and other relevant standard	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.	NYSRC Reliability Rules, NPCC Directory 1, NERC TPL-001 and other relevant standard
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	The 2026 Gold Book publishes the baseline coincident peak load forecasts for 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. Additionally, noncoincident peak load forecasts from the 2026 Gold Book for summer and winter will be used in the transmission security margin calculation. Midday light load forecast utilizes the BtM solar generation from the 2026 Gold Book Table I-9d and includes expected load during the midday light load hour. Nighttime light load forecast models a minimum load hour, anticipated to occur in the spring, and BtM and utility-connected solar generation will be offline in this model.	2026 Gold Book
Load Model	ConEd: voltage varying	2024 FERC 715 filing	No Change from 2024 RNA	2026 FERC 715 filing
	Rest of NYCA: constant power		No Change from 2024 RNA	
System Representation	Per updates received through the annual database update process (subject to RNA Base Case inclusion rules)	2024 FERC 715 filing, Quartey Project Status Updates required by RPP Manual	No Change from 2024 RNA	2026 FERC 715 filing, Quartey Project Status Updates required by RPP Manual

Parameter	2024 RNA Transmission Security Studies Modeling Assumptions	2024 Source	2026 RNA Transmission Security Studies Modeling Assumptions	2026 Source
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	Consistent with ERAG MMWG interchange schedule to the extent possible.	2026 FERC 715 filing, MMWG
Inter-area Controllable Tie Schedules	Consistent with applicable tariffs and known firm contracts or rights	2024 FERC 715 filing	No Change from 2024 RNA	2026 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	Consistent with Con Edison series reactor status in the 2026 FERC 715 filing. 2026-2027 Summer Series Reactor Status • 71, 72, M51, M52 are in service • 41, 42, Y49 are bypassed Post-2027 Summer Series Reactor Status • 71, 72, M51, M52, 41, 42 are in service • Y49 is bypassed Spring and Winter Series Reactor Status • 41 and 42 are in-service • 71, 72, M51, M52, and Y49 are bypassed	2026 FERC 715 filing, Con Edison protocol
SVCs, FACTS	Set at zero pre-contingency; allowed to adjust post-contingency	NYISO T&D Manual	No Change from 2024 RNA	NYISO T&D Manual
Transformer & PAR taps	Taps allowed to adjust pre-contingency; fixed post-contingency	2024 FERC 715 filing	No Change from 2024 RNA	2026 FERC 715 filing
Switched Shunts	Allowed to adjust pre-contingency; fixed post-contingency	2024 FERC 715 filing	No Change from 2024 RNA	2026 FERC 715 filing
Fault Current analysis settings	Per Fault Current Assessment Guideline	NYISO Fault Current Assessment Guideline	No Change from 2024 RNA	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 and incorporates the NERC five-year class-average forced outage rate values (EFORd). Consideration will be given to NYSRC Proposed Reliability Rules 153a and 154a, which are expected to become 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,	The impact of thermal generation unavailability is captured in the transmission security margin calculations and incorporates NYCA 5-year zonal-average EFORd values (reflects contribution of 9300 events). Generation fueled by non-firm gas will be modeled as out-of-service during winter peak conditions, while certain dual-fuel units will have reductions in generation capability when running on their alternative fuel source. This assumption is	Reference November 20, 2025 ESPWG/TPAS/ICAP Working Group meeting materials [here]

Parameter	2024 RNA Transmission Security Studies Modeling Assumptions	2024 Source	2026 RNA Transmission Security Studies Modeling Assumptions	2026 Source
		2022 ESPWG meeting materials [here]. Reference January 23, 2024 ESPWG meeting materials [here] and March 1, 2024 ESPWG/TPAS meeting materials [here].	based on information from the latest NYISO annual Generator Fuel and Emissions Reporting (GFER) survey. Aging generation impacts will be captured for thermal fossil units using the statistical retirement risk model described in Attachment H of the Reliability Planning Process Manual. The P95 threshold age will be applied, and the EIA 860M February 2026 Monthly Generator Inventory data will be used.	Annual Generator Fuel and Emissions Reporting Survey
Wind Generation	Dispatch land-based wind (LBW) generation and offshore 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].	Dispatch land-based wind (LBW) generation and offshore wind (OSW) generation to the following percentage of nameplate capacity: LBW • Summer 5% • Winter 15% • Daytime light load 10% • Nighttime light load 15% OSW • Summer 10% • Winter 20% • Daytime light load 15% • Nighttime light load 20%	Reference May 5, 2022 TPAS/ESPWG meeting materials [here] and May 23, 2022 ESPWG meeting materials [here]. Reference May 6, 2026 TPAS/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].	BtM solar reductions in load forecast are included in the Gold Book (Table I-9c and 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 after adjustments to account for inverter losses and AC/DC conversion ratios used in the creation of Table I-9c and I-9d.	Reference May 5, 2022 TPAS/ESPWG meeting materials [here] and May 23, 2022 ESPWG meeting materials [here]. Reference February 22, 2024 LFTF/ESPWG meeting materials [here].

Parameter	2024 RNA Transmission Security Studies Modeling Assumptions	2024 Source	2026 RNA Transmission Security Studies Modeling Assumptions	2026 Source
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].	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 50% • Daytime light load 50% • Nighttime light load 50%	Reference May 5, 2022 TPAS/ESPWG meeting materials [here] and May 23, 2022 ESPWG meeting materials [here]. Reference May 6, 2026 TPAS/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-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.	2024 Gold Book Reference May 5, 2022 TPAS/ESPWG meeting materials [here] and May 23, 2022 ESPWG meeting materials [here].	No Change from 2024 RNA	2026 Gold Book Reference May 5, 2022 TPAS/ESPWG meeting materials [here] and May 23, 2022 ESPWG meeting materials [here].

Transmission Security Base Case Results

2026 RNA Steady State Thermal and Voltage Assessment

No voltage criteria violations were observed under summer peak, winter peak, nighttime light load, or daytime light load conditions for the evaluated cases. However, as discussed in the report, there are potential thermal overloads dependent upon the completion of local transmission plans (*e.g.*, Oakdale upgrades), steady state bus voltages at or near criteria, and breaker fault duty exceedances being addressed through facility studies.

2026 RNA Stability Assessment

No stability criteria violations are observed under summer peak or winter peak cases. However, stability issues were identified primarily in the light load cases.

Stability analysis indicates that the Fitzpatrick nuclear generator can lose synchronism for a stuck breaker fault at Scriba 345kV resulting in loss of Scriba – Volney 345 kV (Line 21) and Scriba – Fitzpatrick 345 kV (FS-10) lines. This issue is observed most prominently in spring midday time light load conditions with high solar and BTM generation output; however, this issue is also observed in nighttime light load conditions. This stability issue may emerge as early as spring 2027 and persists throughout the RNA study horizon. As the issue first appears within the horizon of the Short-Term Reliability Process (STRP), it will be further reviewed and addressed through that process.

2026 RNA Short Circuit Assessment

Figure 30 below provides the results of NYISO's short circuit screening test for year 5 (2031) of the Study Period. Individual Breaker Analysis (IBA) is required for any stations where the lowest circuit breaker rating was exceeded by the maximum bus fault current. NYISO performed analysis for the one station requiring an IBA. Figure 31 provides the results of the Fitzpatrick 345 kV IBA.

Maximum bus fault currents exceed lowest circuit breaker ratings at certain stations in Long Island. These will be addressed in the interconnection process for the Propel NY Energy – Alternate Solution 5 project (Queue No. 1289).

No short circuit criteria violations are identified as Reliability Needs in the 2026 RNA.

Figure 30: 2026 RNA Fault Current Analysis Summary

Substation	Nominal Voltage (kV)	Owner	LCB Rating (kA)	2031 Case			Breaker(s) Overdutied
				Fault Current (kA)	% of Breaker Duty	IBA Required	
MARCY	765	NYPA	63.0	10.2	16.2	No	No
MASSENA	765	NYPA	63.0	7.1	11.3	No	No
ACADEMY	345	Con Ed	63.0	33.3	52.9	No	No
ADIRONDACK	345	NYPA	63.0	14.5	22.9	No	No
ALPS	345	NGRID	39.0	20.4	52.2	No	No
ASTORIA ANNEX	345	NYPA	63.0	45.9	72.9	No	No
ATHENS	345	NGRID	49.0	35.5	72.5	No	No
AUSTIN ROAD	345	NGRID	63.0	13.5	21.5	No	No
BAYONNE	345	Con Ed	50.0	28.6	57.1	No	No
BROOKLYN CLEAN ENERGY HUB	345	Con Ed	63.0	50.2	79.8	No	No
BROOKLYN CLEAN ENERGY HUB	345	Con Ed	63.0	50.2	79.8	No	No
BROOKLYN CLEAN ENERGY HUB	345	Con Ed	63.0	50.2	79.8	No	No
BOWLINE 2	345	O&R	40.0	26.6	66.5	No	No
BOWLINE1	345	O&R	40.0	26.7	66.8	No	No
BUCHANAN NORTH	345	Con Ed	63.0	24.8	39.4	No	No
BUCHANAN SOUTH	345	Con Ed	63.0	36.2	57.5	No	No
CLARKS CORNERS	345	NYSEG	40.0	11.9	29.9	No	No
CLAY	345	NGRID	49.0	34.3	70.1	No	No
COOPERS CORNERS	345	NYSEG	40.0	18.6	46.5	No	No
CRICKET VALLEY	345	Con Ed	63.0	35.8	56.8	No	No
DEWITT	345	NGRID	39.0	19.2	49.1	No	No
DOLSON AVENUE	345	NYPA	63.0	20.7	32.8	No	No
DOVER	345	TRANSCO	63.0	34.3	54.4	No	No
DOVER PAR	345	TRANSCO	63.0	22.6	35.9	No	No
DUFFY AVE	345	LIPA	58.6	8.2	14.0	No	No
DUNWOODIE	345	Con Ed	63.0	52.0	82.6	No	No
DYSINGER PAR	345	NEXTERA	50.0	10.0	20.0	No	No
EAST FISHKILL	345	Con Ed	63.0	44.2	70.2	No	No
EAST 13TH STREET 45	345	Con Ed	63.0	45.8	72.7	No	No
EAST 13TH STREET 45	345	Con Ed	63.0	45.8	72.8	No	No
EAST 13TH STREET 45	345	Con Ed	63.0	46.3	73.4	No	No
EAST 13TH STREET 45	345	Con Ed	63.0	45.9	72.8	No	No
EDIC	345	NGRID	50.0	38.8	77.5	No	No
EMPIRE	345	Empire Generating	50.0	13.9	27.8	No	No
EAST STOLLE ROAD	345	NEXTERA	50.0	9.6	19.2	No	No
FARRAGUT	345	Con Ed	63.0	50.3	79.9	No	No
FARRAGUT EAST	345	Con Ed	63.0	50.3	79.9	No	No
FARRAGUT WEST	345	Con Ed	63.0	50.3	79.9	No	No
FITZPATRICK	345	NYPA	37.0	40.9	110.6	Yes	No
FIVE MILE RD	345	NGRID	49.0	8.5	17.4	No	No
FRASER	345	NYSEG	40.0	19.3	48.1	No	No
FRESH KILLS	345	Con Ed	63.0	29.8	47.2	No	No
GILBOA	345	NYPA	50.0	25.5	51.0	No	No
GORDON ROAD	345	LSPOWER	63.0	27.0	42.8	No	No
GOETHALS	345	Con Ed	63.0	32.8	52.0	No	No
GOWANUS	345	Con Ed	63.0	32.8	52.1	No	No
HAVERSTOCK	345	NYPA	63.0	15.5	24.6	No	No
HURLEY	345	CH	40.0	18.9	47.2	No	No
INDEPENDENCE	345	NGRID	44.0	38.5	87.6	No	No
KINTIGH	345	NYSEG	40.0	15.1	37.8	No	No
KNICKERBOCKER	345	TRANSCO	63.0	28.7	45.5	No	No
LADENTOWN	345	Con Ed	63.0	38.4	61.0	No	No
LAFAYETTE	345	NGRID	40.0	18.0	45.1	No	No
LEEDS	345	NGRID	37.0	36.3	98.2	No	No
LINDEN	345	Linden Cogen	63.0	32.0	50.8	No	No
LOVETT	345	O&R	63.0	34.8	55.3	No	No
MARCY	345	NYPA	63.0	37.3	59.2	No	No
MILLWOOD	345	Con Ed	63.0	44.4	70.5	No	No
MOTT HAVEN	345	Con Ed	63.0	43.7	69.3	No	No
NEW BARRETT	345	Propel	63.0	25.5	40.5	No	No
NEW RULAND ROAD	345	Propel	63.0	22.4	35.6	No	No
NEW SHORE ROAD	345	Propel	63.0	32.6	51.7	No	No

Substation	Nominal Voltage (kV)	Owner	LCB Rating (kA)	2031 Case			Breaker(s) Overdutied
				Fault Current (kA)	% of Breaker Duty	IBA Required	
NEWBRIDGE	345	LIPA	56.0	8.4	15.0	No	No
NIAGARA	345	NYPA	63.0	33.7	53.5	No	No
NINE MILE POINT 1	345	N. Grid	50.0	42.6	85.2	No	No
NINE MILE POINT 2	345	N. Grid	50.0	43.4	86.7	No	No
NEW SCOTLAND 33K	345	NGRID	50.0	39.7	79.3	No	No
NEW SCOTLAND 77K	345	N. Grid	50.0	39.5	78.9	No	No
NEW SCOTLAND 99K	345	NGRID	50.0	39.4	78.9	No	No
OAKDALE	345	NYSEG	40.0	12.9	32.4	No	No
OSWEGO	345	NGRID	44.0	32.4	73.7	No	No
PLEASANTVILLE EAST	345	Con Ed	63.0	22.2	35.2	No	No
PLEASANTVILLE WEST	345	Con Ed	63.0	22.4	35.6	No	No
PLEASANT VALLEY	345	Con Ed	63.0	50.8	80.6	No	No
PRINCETOWN	345	LSPOWER	63.0	32.0	50.8	No	No
Q737	345	Empire Wind	63.0	32.5	51.5	No	No
RAINEY	345	Con Ed	63.0	49.2	78.1	No	No
RAINEY EAST	345	Con Ed	63.0	49.2	78.1	No	No
RAINEY WEST	345	Con Ed	63.0	49.2	78.1	No	No
RAMAPO	345	Con Ed	63.0	43.3	68.7	No	No
REYNOLDS	345	NGRID	39.0	16.5	42.3	No	No
ROCK TAVERN	345	CH	63.0	33.8	53.7	No	No
ROSETON	345	CH	63.0	38.3	60.8	No	No
RULAND PAR	345	Propel	63.0	23.1	36.7	No	No
S080	345	RGE	40.0	18.6	46.6	No	No
S122	345	RGE	40.0	17.9	44.8	No	No
S255	345	RGE	63.0	18.6	29.5	No	No
SCRIBA	345	NGRID	54.0	46.3	85.7	No	No
SHORE RD	345	LIPA	63.0	27.7	44.0	No	No
SHORE ROAD-SPRAINBROOK	345	Propel	63.0	22.6	35.8	No	No
SHORE ROAD-SPRAINBROOK 2	345	Propel	63.0	22.6	35.8	No	No
SPRAINBROOK	345	Con Ed	63.0	54.0	85.6	No	No
STOLLE ROAD	345	NYSEG	40.0	9.6	23.9	No	No
SUGARLOAF	345	O&R	63.0	25.3	40.1	No	No
UNIONDALE-TREMONT	345	NYPA	63.0	18.9	29.9	No	No
UNIONDALE HUB	345	NYPA	63.0	32.8	52.0	No	No
UNIONDALE HUB PAR	345	NYPA	63.0	28.6	45.5	No	No
VAN WAGNER	345	TRANSCO	63.0	48.5	77.0	No	No
VOLNEY	345	NGRID	45.0	35.8	79.6	No	No
WEST 49TH STREET	345	Con Ed	63.0	43.9	69.6	No	No
WATERCURE	345	NYSEG	40.0	9.8	24.5	No	No
BALL HILL	230	N. Grid	50.0	7.4	14.7	No	No
CANANDAIGUA	230	NYSEG	40.0	9.2	23.0	No	No
DULEY	230	NYPA	40.0	7.5	18.9	No	No
DUNKIRK	230	NGRID	33.0	8.1	24.6	No	No
EASTOVER	230	NGRID	49.0	12.0	24.5	No	No
GARDENVILLE	230	NGRID	31.0	19.3	62.2	No	No
HIGH SHELDON	230	NYSEG	40.0	10.2	25.5	No	No
HILLSIDE	230	NYSEG	35.9	13.4	37.4	No	No
HUNTLEY	230	NGRID	30.0	17.3	57.7	No	No
HUNTLEY	230	NGRID	50.0	17.3	34.6	No	No
HUNTLEY	230	NGRID	30.0	17.3	57.7	No	No
MEYER	230	NYSEG	40.0	9.0	22.5	No	No
NEW GARDENVILLE	230	NYSEG	30.9	19.3	62.4	No	No
NIAGARA EAST	230	NYPA	63.0	53.8	85.4	No	No
NIAGARA WEST	230	NYPA	63.0	53.8	85.4	No	No
PACKARD 2&3	230	NGRID	49.0	39.7	81.1	No	No
PACKARD 4&5	230	NGRID	49.0	39.7	81.1	No	No
PACKARD 6	230	NGRID	49.0	39.8	81.3	No	No
PATNODE	230	NYPA	63.0	10.4	16.5	No	No
PORTER	230	NGRID	21.0	14.7	69.8	No	No
ROARING BROOK	230	N. Grid	40.0	8.2	20.5	No	No
ROBINSON ROAD	230	NYSEG	43.1	14.0	32.4	No	No
ROTTERDAM	230	NGRID	23.0	14.9	64.8	No	No

Substation	Nominal Voltage (kV)	Owner	LCB Rating (kA)	2031 Case			Breaker(s) Overdutied
				Fault Current (kA)	% of Breaker Duty	IBA Required	
RYAN	230	NYPA	40.0	11.2	28.0	No	No
SOUTH PERRY	230	NYSEG	63.0	8.1	12.8	No	No
ST LAWRENCE	230	NYPA	32.4	31.7	97.8	No	No
STOLLE ROAD	230	NYSEG	40.0	13.6	33.9	No	No
STONEY RIDGE	230	NYSEG	40.0	8.1	20.2	No	No
STONY CREEK	230	NYSEG	40.0	9.0	22.6	No	No
WATERCURE	230	NYSEG	40.0	13.6	34.1	No	No
WETHERSFIELD	230	NYSEG	40.0	8.8	22.0	No	No
WILLIS	230	NYPA	40.0	12.9	32.3	No	No
WILLIS ANNEX	230	NYPA	40.0	13.1	32.8	No	No
ASTORIA EAST BT	138	Con Ed	63.0	51.1	81.2	No	No
ASTORIA EAST ERG	138	Con Ed	63.0	51.2	81.2	No	No
ASTORIA EAST WRG	138	Con Ed	63.0	51.2	81.2	No	No
ASTORIA WEST N	138	Con Ed	63.0	44.3	70.3	No	No
ASTORIA WEST S	138	Con Ed	63.0	44.3	70.3	No	No
BAGATELLE	138	LIPA	63.0	25.5	40.4	No	No
BARRET PAR	138	LIPA	63.0	29.1	46.1	No	No
BARRETT 1	138	LIPA	63.0	59.1	93.8	No	No
BARRETT 2	138	LIPA	63.0	59.1	93.9	No	No
BROOKHAVEN	138	LIPA	63.0	27.8	44.2	No	No
BUCHANAN	138	Con Ed	40.0	15.7	39.3	No	No
BUCHANAN TA5	138	Con Ed	40.0	15.7	39.2	No	No
CENTRAL ISLIP	138	LIPA	63.0	29.2	46.3	No	No
CANAL	138	LIPA	63.0	12.6	19.9	No	No
CARLE PL	138	LIPA	63.0	40.4	64.1	No	No
CORONA N	138	Con Ed	63.0	51.7	82.0	No	No
CORONA S	138	Con Ed	63.0	51.7	82.0	No	No
DUNWOODIE NORTH	138	Con Ed	63.0	35.6	56.5	No	No
DUNWOODIE NORTH S6	138	Con Ed	63.0	29.9	47.4	No	No
DUNWOODIE SOUTH	138	Con Ed	63.0	32.5	51.5	No	No
DUNWOODIE SOUTH N7	138	Con Ed	63.0	28.0	44.4	No	No
EAST 13TH STREET	138	Con Ed	63.0	48.3	76.7	No	No
EASTVIEW	138	Con Ed	63.0	37.4	59.4	No	No
EDWARDS AVENUE	138	LIPA	63.0	18.7	29.7	No	No
ELWOOD 1	138	LIPA	63.0	47.5	75.5	No	No
ELWOOD 2	138	LIPA	63.0	47.3	75.1	No	No
EASTERN QUEENS BT	138	Con Ed	63.0	49.4	78.4	No	No
EASTERN QUEENS N-BT	138	Con Ed	63.0	49.5	78.6	No	No
EASTERN QUEENS NORTH	138	Con Ed	63.0	49.4	78.4	No	No
EASTERN QUEENS S-BT	138	Con Ed	63.0	49.5	78.6	No	No
EASTERN QUEENS SOUTH	138	Con Ed	63.0	49.4	78.4	No	No
FREEPORT	138	LIPA	63.0	35.8	56.8	No	No
FRESH KILLS	138	Con Ed	40.0	36.8	92.1	No	No
GLENWOOD NORTH	138	LIPA	63.0	54.1	85.8	No	No
GLENWOOD SOUTH	138	LIPA	63.0	53.3	84.6	No	No
GREENLAWN	138	LIPA	63.0	35.7	56.7	No	No
HAUPAGUE	138	LIPA	63.0	22.5	35.8	No	No
HOLBROOK	138	LIPA	63.0	52.6	83.5	No	No
HOLTS GT	138	LIPA	63.0	48.4	76.8	No	No
HOLTS GT NYPA	138	LIPA	63.0	48.3	76.7	No	No
JAMAICA	138	Con Ed	63.0	49.7	78.9	No	No
KINGS	138	LIPA	63.0	30.3	48.1	No	No
LOCUST GROVE	138	LIPA	63.0	42.5	67.4	No	No
LAKE SUCCESS	138	LIPA	63.0	44.0	69.8	No	No
LAKE SUCCESS 2	138	LIPA	63.0	44.1	69.9	No	No
LAKE SUCCESS PAR	138	LIPA	63.0	33.7	53.4	No	No
LOVETT	138	O&R	40.0	28.7	71.8	No	No
MILLER PLACE	138	LIPA	63.0	15.1	23.9	No	No
MILLWOOD	138	Con Ed	40.0	19.5	48.8	No	No
MOTT HAVEN TX1	138	Con Ed	50.0	13.8	27.6	No	No
MOTT HAVEN TX2	138	Con Ed	50.0	14.5	29.1	No	No
MOTT HAVEN TX3	138	Con Ed	50.0	14.6	29.1	No	No

Substation	Nominal Voltage (kV)	Owner	LCB Rating (kA)	2031 Case			Breaker(s) Overdutied
				Fault Current (kA)	% of Breaker Duty	IBA Required	
MOTT HAVEN TX4	138	Con Ed	50.0	13.9	27.7	No	No
NEW BARRETT	138	LIPA	63.0	59.4	94.2	No	No
NEWBRIDGE	138	LIPA	80.0	66.7	83.3	No	No
NORTH SHORE BEACH	138	LIPA	63.0	17.3	27.5	No	No
NORTHPORT 1	138	LIPA	63.0	67.2	106.7	Will be addressed through Propel NY interconnection process	
NORTHPORT 1-2	138	LIPA	63.0	67.3	106.8	Will be addressed through Propel NY interconnection process	
NORTHPORT 2	138	LIPA	63.0	67.3	106.8	Will be addressed through Propel NY interconnection process	
NORTHPORT 3	138	LIPA	63.0	56.8	90.2	No	No
NORTHPORT 4	138	LIPA	63.0	56.8	90.1	No	No
OAKWOOD	138	LIPA	63.0	37.6	59.7	No	No
PARKCHESTER TR1	138	Con Ed	63.0	17.0	27.0	No	No
PARKCHESTER TR2	138	Con Ed	63.0	17.2	27.3	No	No
PILGRIM	138	LIPA	63.0	64.8	102.8	Will be addressed through Propel NY interconnection process	
PORT JEFFERSON	138	LIPA	63.0	32.5	51.5	No	No
Q987	138	Sunrise Wind	63.0	48.3	76.7	No	No
RIVERHEAD	138	LIPA	63.0	21.5	34.1	No	No
RONKONKOMA	138	LIPA	63.0	38.8	61.5	No	No
ROSLYN	138	LIPA	63.0	30.6	48.5	No	No
RULAND ROAD	138	LIPA	63.0	53.2	84.4	No	No
SHORE ROAD 1	138	LIPA	63.0	62.1	98.6	No	No
SHORE ROAD 2	138	LIPA	63.0	61.8	98.1	No	No
SHOREHAM 1	138	LIPA	63.0	28.0	44.4	No	No
SHOREHAM 2	138	LIPA	63.0	28.0	44.4	No	No
SILLS ROAD 1	138	LIPA	63.0	34.0	53.9	No	No
SILLS ROAD 2	138	LIPA	63.0	34.0	53.9	No	No
STEWART AVENUE 1	138	LIPA	80.0	68.7	85.8	No	No
STEWART AVENUE 2	138	LIPA	80.0	68.7	85.8	No	No
SYOSSET	138	LIPA	63.0	53.4	84.8	No	No
VERNON E	138	Con Ed	63.0	47.9	76.0	No	No
VERNON W	138	Con Ed	63.0	34.2	54.4	No	No
VALLEY STREAM 1	138	LIPA	63.0	58.7	93.2	No	No
VALLEY STREAM 2	138	LIPA	63.0	58.9	93.4	No	No
WADING RIVER	138	LIPA	63.0	25.9	41.1	No	No
WEST BUS	138	LIPA	63.0	50.5	80.2	No	No
WEST HAVERSTRAW	138	O&R	40.0	29.6	74.0	No	No
WILDWOOD	138	LIPA	63.0	27.5	43.7	No	No
CHURCHTOWN	115	TRANSCO	40.0	9.3	23.1	No	No
CLARKS CORNERS	115	NYSEG	40.0	19.7	49.1	No	No
CLAY	115	NGRID	45.0	39.6	88.0	No	No
COOPERS CORNERS 4	115	NYSEG	22.6	14.9	66.0	No	No
COOPERS CORNERS 8	115	NYSEG	23.1	14.9	64.6	No	No
DEWITT	115	NGRID	39.0	29.9	76.8	No	No
EAST FISHKILL	115	CH	40.0	24.4	61.0	No	No
EASTOVER	115	NGRID	49.0	26.9	54.8	No	No
ELBRIDGE C	115	NGRID	49.0	26.4	53.9	No	No
ELBRIDGE D	115	NGRID	49.0	26.4	53.9	No	No
ELBRIDGE T1	115	NGRID	49.0	26.4	53.9	No	No
ELBRIDGE T2	115	NGRID	49.0	26.4	53.8	No	No
FISHKILL	115	CH	40.0	24.3	60.8	No	No
FIVE MILE ROAD	115	NGRID	49.0	15.0	30.6	No	No
FRASER	115	NYSEG	40.0	24.3	60.8	No	No
GARDENVILLE	115	NGRID	63.0	37.6	59.7	No	No
GULF ROAD	115	NGRID	23.0	11.4	49.5	No	No
HURLEY AVENUE	115	CH	40.0	16.6	41.5	No	No
LHH WHITE	115	NGRID	23.0	13.7	59.5	No	No
MEYER	115	NYSEG	18.9	12.3	65.0	No	No
NEW GARDENVILLE	115	NYSEG	43.1	37.0	85.7	No	No
NEW GARDENVILLE	115	NYSEG	40.0	37.0	92.4	No	No
NIAGARA EAST	115	NYPA	63.0	37.9	60.1	No	No
NIAGARA WEST	115	NYPA	42.2	29.8	70.7	No	No
NEW SCOTLAND 33	115	NGRID	49.0	45.0	91.8	No	No
NEW SCOTLAND 77	115	NGRID	48.0	45.0	93.7	No	No

Substation	Nominal Voltage (kV)	Owner	LCB Rating (kA)	2031 Case			Breaker(s) Overdutied
				Fault Current (kA)	% of Breaker Duty	IBA Required	
NEW SCOTLAND 99	115	NGRID	49.0	45.0	91.8	No	No
OAKDALE	115	NYSEG	40.0	27.6	69.0	No	No
ONEIDA	115	NGRID	23.0	13.0	56.7	No	No
ONEIDA	115	NGRID	23.0	13.0	56.7	No	No
PACKARD NORTH	115	NGRID	62.0	28.5	46.0	No	No
PACKARD SOUTH	115	NGRID	58.0	26.2	45.2	No	No
PLATTSBURGH	115	NYPA	20.3	17.2	84.7	No	No
PLEASANT VALLEY	115	CH	40.0	24.9	62.4	No	No
PORTER	115	NGRID	59.0	37.2	63.0	No	No
REYNOLDS ROAD	115	NGRID	43.0	42.6	99.1	No	No
ROBINSON ROAD	115	NYSEG	37.9	18.1	47.8	No	No
ROCK TAVERN	115	CH	40.0	28.9	72.2	No	No
ROTTERDAM 33G	115	NGRID	63.0	55.4	87.9	No	No
ROTTERDAM 44G	115	NGRID	63.0	55.5	88.1	No	No
ROTTERDAM 77G	115	NGRID	63.0	55.4	87.9	No	No
ROTTERDAM 99G	115	NGRID	63.0	55.6	88.2	No	No
SOUTH OSWEGO	115	NGRID	37.0	22.8	61.7	No	No
SOUTH OSWEGO 1	115	NGRID	38.0	22.8	60.0	No	No
S013A	115	RGE	37.6	24.6	65.3	No	No
S080 922	115	RGE	40.0	17.1	42.8	No	No
S080 B1	115	RGE	39.1	30.3	77.4	No	No
S080 B2	115	RGE	40.0	25.9	64.8	No	No
S082 B1	115	RGE	40.0	38.4	96.1	No	No
S082 B2	115	RGE	40.0	38.4	95.9	No	No
S082 B3	115	RGE	40.0	38.2	95.6	No	No
S122 B1	115	RGE	50.0	33.4	66.7	No	No
S255	115	RGE	40.0	23.0	57.4	No	No
SCHUYLER	115	NGRID	23.0	14.5	63.0	No	No
SCRIBA C	115	N. Grid	40.0	10.5	26.3	No	No
SCRIBA D	115	N. Grid	40.0	10.5	26.2	No	No
ST LAWRENCE	115	NYPA	50.0	41.0	82.0	No	No
STOLLE	115	NYSEG	23.9	20.4	85.2	No	No
STOLLE ROAD	115	NYSEG	23.9	20.4	85.2	No	No
TEALL A	115	NGRID	39.0	27.3	70.1	No	No
TEALL B	115	NGRID	39.0	27.4	70.1	No	No
TERMINAL	115	NGRID	23.0	15.5	67.5	No	No
VALLEY	115	NGRID	39.0	8.2	21.0	No	No
WATKINS	115	NGRID	39.0	8.4	21.5	No	No
WOOD STREET	115	NYSEG	40.0	22.3	55.9	No	No
WOODARD	115	NGRID	23.0	12.3	53.4	No	No
YAHNUNDASIS	115	NGRID	16.0	6.5	40.4	No	No

Figure 31: Fitzpatrick 345 kV IBA

Circuit Breaker ID	Breaker Rating (kA)	Fault Location	3LG (A)	2LG (A)	1LG (A)	L-L (A)	Max Fault Current (kA)	Overdutied Breaker?
10042	37	Fitzpatrick side	31712	33979	33737	27431	33.98	N
		Scriba side	8228	8688	9027	7123	9.03	N
10052	63	Fitzpatrick side	4235	3956	2859	3665	4.24	N
		Edic side	35290	38192	38408	30525	38.41	N

2026 RNA Transmission Security Margin Assessment

Introduction

The RNA's security analysis also includes transmission security margin analysis to identify plausible changes in conditions or assumptions that might adversely impact the reliability of the system. Transmission security margin analysis determines the ability to meet load plus losses against the generation, interchanges, and generation derates (total resources) for a certain locality within NYCA. This assessment is performed using a deterministic approach through a spreadsheet-based method using the RNA study assumptions. For this assessment, transmission security margins are evaluated for the Lower Hudson Valley, New York City, and Long Island localities, and a Reliability Need is identified when the transmission security margin is less than zero for those localities.

Transmission security analysis represents discrete snapshots in time of various credible combinations of system conditions. Therefore, the identification of needs only indicates the magnitude of the need (*e.g.*, a thermal overload expressed in terms of percentage of the applicable rating) under those specific system conditions. Additional details are required to fully describe the nature of the need. To describe the nature of the transmission security 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.

For each locality, the hourly transmission security margins are created by using the load curve forecast for each hour in the margin calculation with additional adjustments to account for the appropriate derate for solar generation and energy limited resources in each hour. For example, the hourly margin in New York City (*e.g.,* Figure 37) are created by using the load curve forecast for each year in the margin calculation (Figure 35 line-item A) with additional adjustments to account for appropriate derates for solar generation (Figure 35 line-item K) and energy limited resources for each hour (Figure 35 line-item Q). All other values in the margin calculation are held constant. Similar analysis is performed for the Lower Hudson Valley and Long Island localities.

Battery storage is kept offline unless it is needed to reduce or eliminate a margin deficiency. If a margin deficiency is found without the use of battery storage, the hourly margin, which is constructed using the load shapes described above, is examined to find the first hour with a margin deficiency. Battery storage is then dispatched for each hour with a margin deficiency, up to the maximum power (MW) rating of the batteries in the locality or until the margin deficiency is resolved, whichever comes first. Battery storage discharge is stopped when the maximum energy (MWh) rating of the batteries is reached. Depending on the duration and depth of the margin deficiencies, this can lead to battery storage fully

discharging before the locality noncoincident peak hour. The locality hourly margin curve is also used to verify sufficient generation and import capability to fully charge the batteries starting at midnight on the peak day. If battery storage is unable to charge fully, its available energy will be limited in the margin calculation. Using New York City summer margin as an example, battery discharge at the locality noncoincident peak hour based on this method is shown in Figure 35 line-item Q. Figure 37 includes visual representation of the battery storage dispatch method in New York City over two summer peak days.

Lower Hudson Valley (Zones G-J)

The Lower Hudson Valley or southeastern New York (SENY) locality comprises Zones G through 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. Throughout the 2026 RNA study horizon, the limiting first-level contingency is the loss of Knickerbocker – Pleasant Valley 345 kV in summer and winter.

Figure 32 and Figure 33 show the calculation of the summer and winter Lower Hudson Valley transmission security margin for baseline expected weather, expected load conditions for the locality noncoincident peak hour with normal transfer criteria.

Under the baseline forecast for noncoincident summer peak demand, the Lower Hudson Valley transmission security margin would be deficient starting in 2032 with the deficiency of 132 MW for two hours and growing to 1,962 MW for seven hours in 2036. Under the baseline forecast for noncoincident winter peak demand, the Lower Hudson Valley transmission security margin would be sufficient throughout the study horizon.

Figure 32: Summer Peak Lower Hudson Valley Margin Calculation

Lower Hudson Valley Transmission Security Margin Summer Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	G-J Noncoincident Peak Demand Forecast	(15,443)	(15,466)	(15,523)	(15,562)	(15,609)	(15,647)	(15,675)	(15,706)	(15,781)	(15,874)
B	RECO Demand	(414)	(414)	(414)	(410)	(410)	(410)	(410)	(410)	(420)	(420)
C	**Total Demand (A+B)**	(15,857)	(15,880)	(15,937)	(15,972)	(16,019)	(16,057)	(16,085)	(16,116)	(16,201)	(16,294)
D	UPNY-SENY Limit (4)	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	(208)	(141)	(234)	(296)	(367)	(635)	(749)	(799)	(943)	(1,014)
G	**Total SENY AC Import (D+E+F)**	4,606	4,673	4,580	4,518	4,447	4,179	4,065	4,015	3,871	3,800
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(11,251)	(11,207)	(11,357)	(11,454)	(11,572)	(11,878)	(12,020)	(12,101)	(12,330)	(12,494)
J	G-J Generation (1)	12,852	13,767	13,262	13,262	12,864	12,864	12,864	12,864	12,864	12,864
K	G-J Thermal Generation Unavailability - Aging	0	0	0	0	0	(445)	(648)	(1,038)	(1,131)	(1,720)
L	G-J Thermal Generation Unavailability - EFORd (2)	(1,358)	(1,358)	(1,317)	(1,317)	(1,285)	(1,248)	(1,231)	(1,200)	(1,192)	(1,145)
M	G-J Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
N	G-J Renewable Generation Unavailability - Dispatch Assumptions (3)	(162)	(983)	(983)	(983)	(983)	(983)	(991)	(991)	(991)	(991)
O	SCRs	0	0	0	0	0	0	0	0	0	0
P	Net ICAP External Imports (5)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Q	**Total Resources Available (J+K+L+M+N+O+P)**	12,721	12,816	12,351	12,351	11,985	11,578	11,383	11,025	10,939	10,398
R	**Baseline Noncoincident Peak Transmission Security Margin (I+Q)**	1,470	1,609	994	897	413	(300)	(637)	(1,076)	(1,391)	(2,096)
S	Battery Storage MW	118	168	168	168	168	168	168	168	168	168
T	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (6)	0	0	0	0	0	168	168	168	168	134
U	**Noncoincident Peak Transmission Security Margin with Batteries (R+T)**	1,470	1,609	994	897	413	(132)	(469)	(908)	(1,223)	(1,962)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c). Derates for run-of-river hydro are included.
4. Limits for 2027 through 2036 are based on summer peak 2027, 2031, and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item R are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item S, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

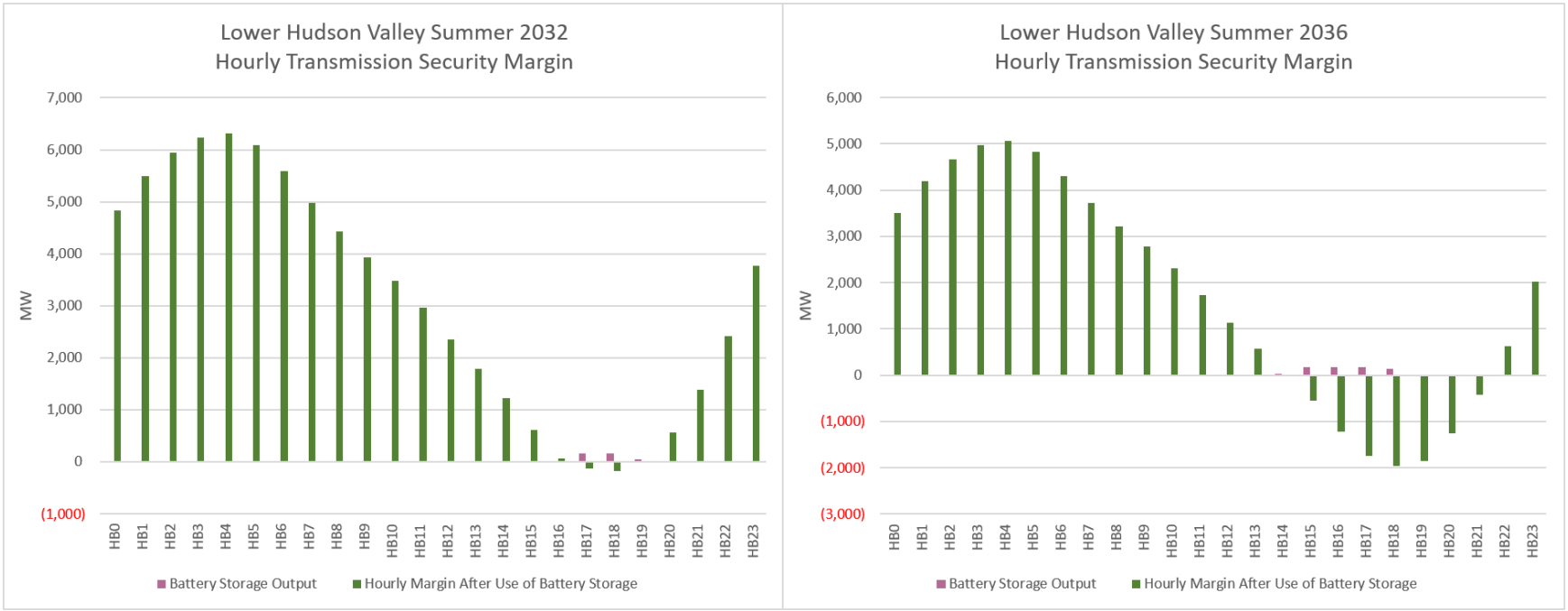
Figure 33: Winter Peak Lower Hudson Valley Margin Calculation

Lower Hudson Valley Transmission Security Margin Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	G-J Noncoincident Peak Demand Forecast	(11,003)	(11,114)	(11,234)	(11,391)	(11,539)	(11,705)	(11,850)	(12,024)	(12,240)	(12,499)
B	RECO Demand	(253)	(253)	(253)	(273)	(273)	(273)	(273)	(273)	(305)	(305)
C	**Total Demand (A+B)**	(11,256)	(11,367)	(11,487)	(11,664)	(11,812)	(11,978)	(12,123)	(12,297)	(12,545)	(12,804)
D	UPNY-SENY Limit (4)	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	(33)	(33)	(33)	1,467	1,364	1,017	899	785	564	405
G	**Total SENY AC Import (D+E+F)**	4,856	4,856	4,856	6,356	6,253	5,906	5,788	5,674	5,453	5,294
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(6,400)	(6,511)	(6,631)	(5,308)	(5,559)	(6,072)	(6,335)	(6,623)	(7,092)	(7,510)
J	G-J Generation (1)	14,681	14,681	14,029	13,618	13,618	13,618	13,618	13,618	13,618	13,618
K	G-J Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(2,141)	(2,141)	(2,141)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)
L	G-J Thermal Generation Unavailability - Aging	0	0	0	0	0	(276)	(459)	(834)	(909)	(1,475)
M	G-J Thermal Generation Unavailability - EFORd (2)	(1,274)	(1,274)	(1,222)	(1,222)	(1,222)	(1,197)	(1,182)	(1,152)	(1,146)	(1,100)
N	G-J Renewable Generation Unavailability - Dispatch Assumptions (3)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)
O	SCRs	0	0	0	0	0	0	0	0	0	0
P	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
Q	**Total Resources Available (J+K+L+M+N+O+P)**	10,499	10,499	9,899	9,899	9,899	9,648	9,480	9,135	9,066	8,546
R	**Baseline Noncoincident Peak Transmission Security Margin (I+Q)**	4,099	3,988	3,268	4,592	4,341	3,576	3,145	2,512	1,975	1,036
S	Battery Storage MW	168	168	168	168	168	168	168	168	168	168
T	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (7)	0	0	0	0	0	0	0	0	0	0
U	**Noncoincident Peak Transmission Security Margin with Batteries (R+T)**	4,099	3,988	3,268	4,592	4,341	3,576	3,145	2,512	1,975	1,036

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour.
4. Limits for 2027 through 2036 are based on winter peak 2027, 2031, and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item R are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item S, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 34: Lower Hudson Valley Margin Chart – Summer Hourly Margin



New York City (Zone J)

The New York City locality comprises Zone J and is served by Con Edison. Within this 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).[21] 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 2026 and continuing throughout the 2026 RNA study period, the limiting contingency combination is loss of the Champlain Hudson Power Express (CHPE) HVDC cable followed by the loss of Ravenswood 3. In winter 2026-2027 and continuing throughout the study period, the limiting contingency combination is loss of Ravenswood 3 followed by the loss of Dunwoodie – Mott Haven (72). The CHPE cable is not included in limiting contingencies in winter due to the assumption that CHPE is scheduled at 0 MW for the winter seasons.

Figure 35 shows the calculation of the New York City transmission security margin at the locality noncoincident peak hour for baseline expected weather and expected load conditions for summer with normal transfer criteria.

Under the baseline forecast for noncoincident summer peak demand, the New York City transmission security margin would be deficient starting in 2032 with the deficiency of 396 MW for seven hours and growing to 1,864 MW for fifteen hours in 2036. Under the baseline forecast for noncoincident winter peak demand, the New York City transmission security margin would be deficient starting in 2036 with a deficiency of 794 MW for sixteen hours.

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

Figure 35: New York City Transmission Security Margin Calculation – Summer Peak

New York City Transmission Security Margin Summer Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
	Item	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone J Noncoincident Peak Demand Forecast**	(11,100)	(11,120)	(11,140)	(11,170)	(11,200)	(11,230)	(11,250)	(11,270)	(11,320)	(11,380)
B	I+K to J (4)	4,725	4,725	4,725	4,825	4,825	4,825	4,825	4,825	4,825	4,825
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	4,714	4,714	4,714	4,814	4,814	4,814	4,814	4,814	4,814	4,814
E	Loss of Source Contingency	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)
F	**Resource Need (A+D+E)**	(8,624)	(8,644)	(8,664)	(8,594)	(8,624)	(8,654)	(8,674)	(8,694)	(8,744)	(8,804)
G	J Generation (1)	8,655	9,521	9,015	9,015	8,617	8,617	8,617	8,617	8,617	8,617
H	J Thermal Generation Unavailability - Aging	0	0	0	0	0	(423)	(624)	(1,011)	(1,102)	(1,688)
I	J Thermal Generation Unavailability - EFORd (2)	(688)	(688)	(647)	(647)	(615)	(581)	(565)	(534)	(526)	(479)
J	J Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
K	J Renewable Generation Unavailability - Dispatch Assumptions (3)	(115)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
N	**Total Resources Available (G+H+I+J+K+L+M)**	9,242	9,324	8,859	8,859	8,493	8,103	7,919	7,562	7,479	6,940
O	**Noncoincident Peak Transmission Security Margin (F+N)**	618	680	195	265	(131)	(551)	(755)	(1,132)	(1,265)	(1,864)
P	Battery Storage MW	115	165	165	165	165	165	165	165	165	165
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (6)	0	0	0	0	132	155	0	0	0	0
R	**Noncoincident Peak Transmission Security Margin with Batteries (O+Q)**	618	680	195	265	0	(396)	(755)	(1,132)	(1,265)	(1,864)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c). This portion of the margin calculation assumes storage is offline. See later section for storage details.
4. Limits for 2027 through 2029 are based on summer peak 2027 representations evaluated in the 2026 RNA. Limits for 2030 through 2036 are based on summer peak 2031 and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 36: New York City Transmission Security Margin Calculation – Winter Peak

New York City Transmission Security Margin Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
	Item	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone J Noncoincident Peak Demand Forecast**	(7,750)	(7,800)	(7,860)	(7,960)	(8,050)	(8,160)	(8,260)	(8,380)	(8,520)	(8,690)
B	I+K to J (4)	3,800	3,800	3,800	3,875	3,875	3,875	3,875	3,875	3,875	3,875
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	3,789	3,789	3,789	3,864	3,864	3,864	3,864	3,864	3,864	3,864
E	Loss of Source Contingency	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)
F	**Resource Need (A+D+E)**	(4,938)	(4,988)	(5,048)	(5,073)	(5,163)	(5,273)	(5,373)	(5,493)	(5,633)	(5,803)
G	J Generation (1)	10,255	10,255	9,603	9,192	9,192	9,192	9,192	9,192	9,192	9,192
H	J Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(2,062)	(2,062)	(2,062)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)
I	J Thermal Generation Unavailability - Aging	0	0	0	0	0	(249)	(428)	(801)	(872)	(1,435)
J	J Thermal Generation Unavailability - EFORd (2)	(587)	(587)	(535)	(535)	(535)	(515)	(500)	(470)	(465)	(419)
K	J Renewable Generation Unavailability - Dispatch Assumptions (3)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
N	**Total Resources Available (G+H+I+J+K+L+M)**	6,929	6,929	6,329	6,329	6,329	6,100	5,935	5,593	5,527	5,009
O	**Noncoincident Peak Transmission Security Margin (F+N)**	1,991	1,941	1,281	1,256	1,166	827	562	100	(106)	(794)
P	Battery Storage MW	165	165	165	165	165	165	165	165	165	165
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (7)	0	0	0	0	0	0	0	0	107	0
R	**Noncoincident Peak Transmission Security Margin with Batteries (O+Q)**	1,991	1,941	1,281	1,256	1,166	827	562	100	1	(794)

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour.
4. Limits for 2027 through 2029 are based on winter peak 2027 representations evaluated in the 2026 RNA. Limits for 2030 through 2036 are based on winter peak 2031 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 37: New York City Hourly Transmission Security Margin Results – Summer Peak

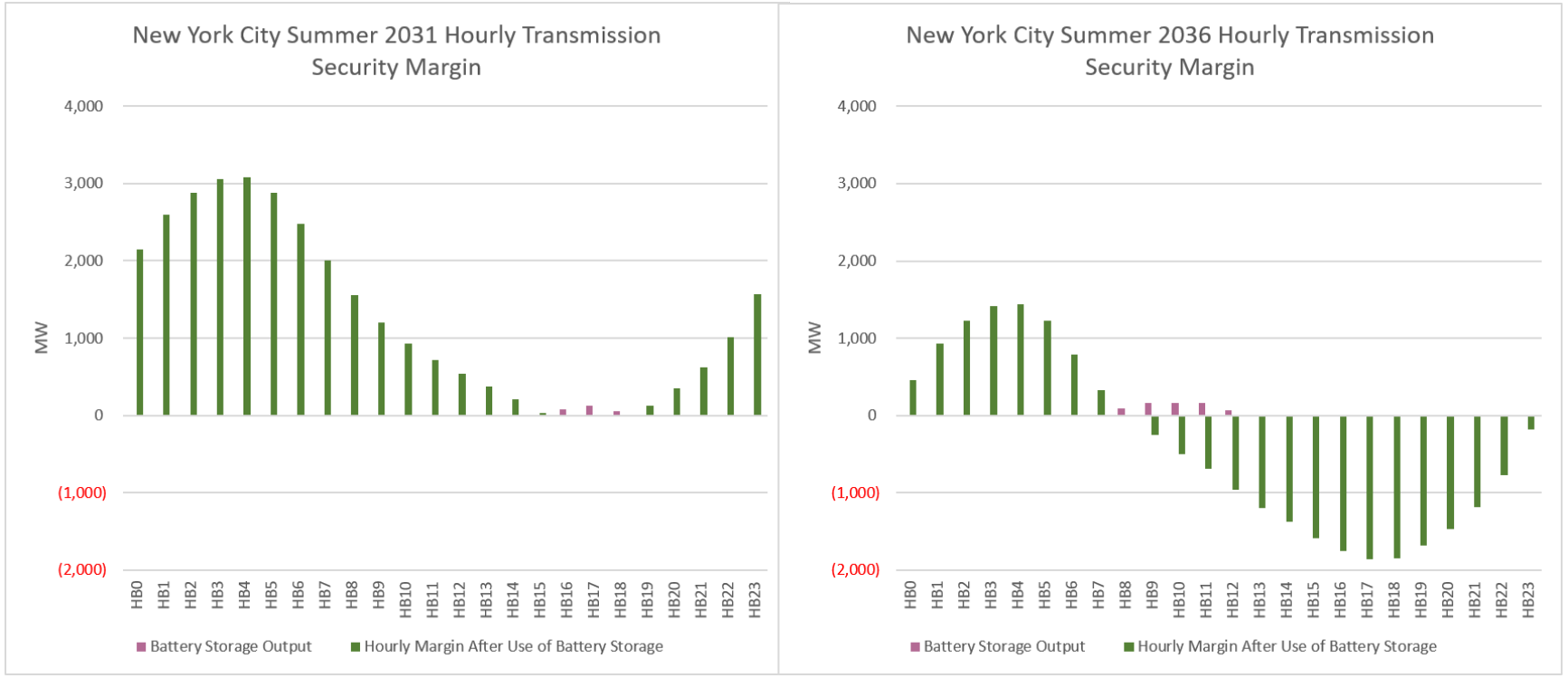
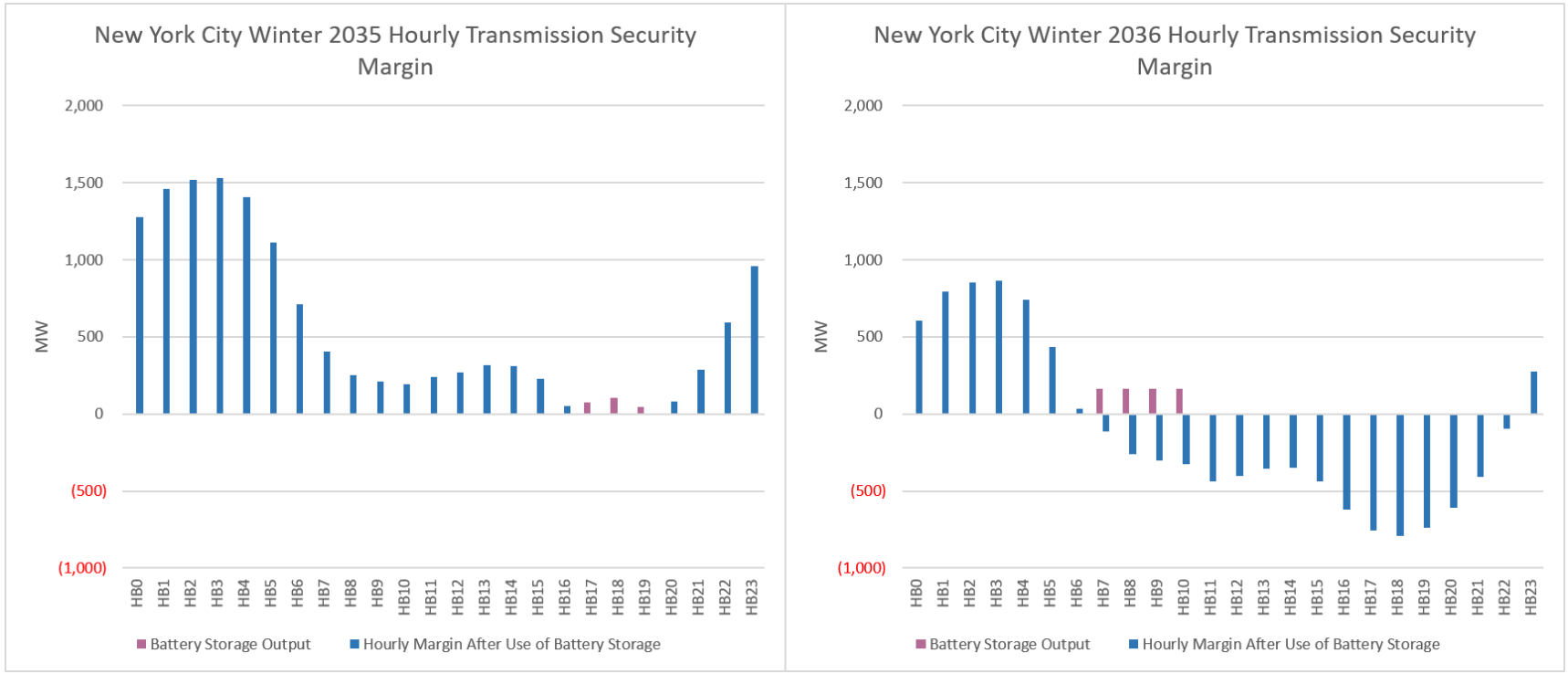


Figure 38: New York City Hourly Transmission Security Margin Results – Winter Peak



Long Island (Zone K)

The Long Island locality comprises Zone K and is served by PSEG Long Island. Within this 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 first level contingency is the loss of the Neptune HVDC cable. From summer 2030 onward, after the Long Island Public Policy transmission project is in service, the limiting first level contingency remains the loss of the Neptune HVDC cable while the limit increases significantly. For winter 2025-2026 through winter 2029-2030, the most limiting first-level contingency is the loss of the Y49 cable. From winter 2030-2031 onward, after the Propel NY Energy transmission project is in service, the limiting first-level contingency changes to the loss of the Neptune HVDC cable. The 1 MW deficiency observed in this RNA under summer peak conditions in 2027 will be addressed in the 2026 Quarter 3 STAR.

Figure 39 and Figure 40 show the calculation of the summer and winter Long Island transmission security margin baseline expected weather, expected load conditions for the locality noncoincident peak hour with normal transfer criteria. Long Island maintains positive transmission security margins throughout the RNA study horizon. Significant increases in transmission security margins are seen after the Propel NY Energy transmission project is placed in service.

Figure 39: Summer Peak Long Island Margin Calculation

Long Island Transmission Security Margin Summer Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone K Noncoincident Peak Demand Forecast**	(5,136)	(5,161)	(5,200)	(5,252)	(5,310)	(5,357)	(5,392)	(5,416)	(5,438)	(5,462)
B	I+J to K (4)	950	950	950	2,900	2,900	2,900	2,900	2,900	2,900	2,900
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	950	950	950	2,900	2,900	2,900	2,900	2,900	2,900	2,900
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	**Resource Need (A+D+E)**	(4,846)	(4,871)	(4,910)	(3,012)	(3,070)	(3,117)	(3,152)	(3,176)	(3,198)	(3,222)
G	K Generation (1)	4,924	5,848	5,848	5,848	5,803	5,803	5,803	5,803	5,803	5,803
H	K Thermal Generation Unavailability - Aging	0	0	0	0	0	(272)	(307)	(340)	(485)	(548)
I	K Thermal Generation Unavailability - EFORd (2)	(580)	(580)	(580)	(580)	(575)	(542)	(537)	(533)	(515)	(508)
J	K Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
K	K Renewable Generation Unavailability - Dispatch Assumptions (3)	(159)	(990)	(999)	(999)	(999)	(999)	(999)	(999)	(999)	(999)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	660	660	660	660	660	660	660	660	660	660
N	**Total Resources Available (G+H+I+J+K+L+M)**	4,845	4,937	4,928	4,928	4,889	4,650	4,619	4,590	4,463	4,408
O	**Noncoincident Peak Transmission Security Margin (F+N)**	(1)	66	18	1,916	1,819	1,533	1,467	1,414	1,265	1,186
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
Q	Battery Storage MWh Used on Locality Noncoincident Peak Day (6)	0	0	0	0	0	0	0	0	0	0
R	**Noncoincident Peak Transmission Security Margin with Batteries (O+Q)**	(1)	66	18	1,916	1,819	1,533	1,467	1,414	1,265	1,186

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c).
4. Limits for 2027 through 2029 are based on the 2025 LIPA Summer Operating Study. Limits for 2030 through 2036 are based on the 2031 summer peak representations evaluated in the 2026RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 40: Winter Peak Long Island Margin Calculation

Long Island Transmission Security Margin Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone K Noncoincident Peak Demand Forecast**	(3,325)	(3,412)	(3,530)	(3,635)	(3,739)	(3,832)	(3,918)	(4,001)	(4,088)	(4,190)
B	I+J to K (4)	350	350	350	3,125	3,125	3,125	3,125	3,125	3,125	3,125
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	350	350	350	3,125	3,125	3,125	3,125	3,125	3,125	3,125
E	Loss of Source Contingency	0	0	0	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	**Resource Need (A+D+E)**	(2,975)	(3,062)	(3,180)	(1,170)	(1,274)	(1,367)	(1,453)	(1,536)	(1,623)	(1,725)
G	K Generation (1)	6,290	6,290	6,290	6,244	6,244	6,244	6,244	6,244	6,244	6,244
H	K Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(374)	(374)	(374)	(328)	(328)	(328)	(328)	(328)	(328)	(328)
I	K Thermal Generation Unavailability - Aging	0	0	0	0	0	(290)	(328)	(363)	(515)	(581)
J	K Thermal Generation Unavailability - EFORd (2)	(589)	(589)	(589)	(589)	(589)	(553)	(549)	(544)	(526)	(518)
K	K Renewable Generation Unavailability - Dispatch Assumptions (3)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	660	660	660	660	660	660	660	660	660	660
N	**Total Resources Available (G+H+I+J+K+L+M)**	5,088	5,088	5,088	5,088	5,088	4,834	4,801	4,770	4,636	4,578
O	**Noncoincident Peak Transmission Security Margin (F+N)**	2,113	2,026	1,908	3,918	3,814	3,467	3,348	3,234	3,013	2,853
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
Q	Battery Storage MWh Used on Locality Noncoincident Peak Day (7)	0	0	0	0	0	0	0	0	0	0
R	**Noncoincident Peak Transmission Security Margin with Batteries (O+Q)**	2,113	2,026	1,908	3,918	3,814	3,467	3,348	3,234	3,013	2,853

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. For winter solar PV output at peak is 0 MW.
4. Limits for 2027 through 2029 are based on the 2025 LIPA Summer Operating Study. As a conservative assumption summer values are used for LIPA Import limits with one line out. Limits for 2030 through 2036 are based on the 2030 winter peak representations evaluated in the 2026RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Appendix F – Scenarios & Sensitivities

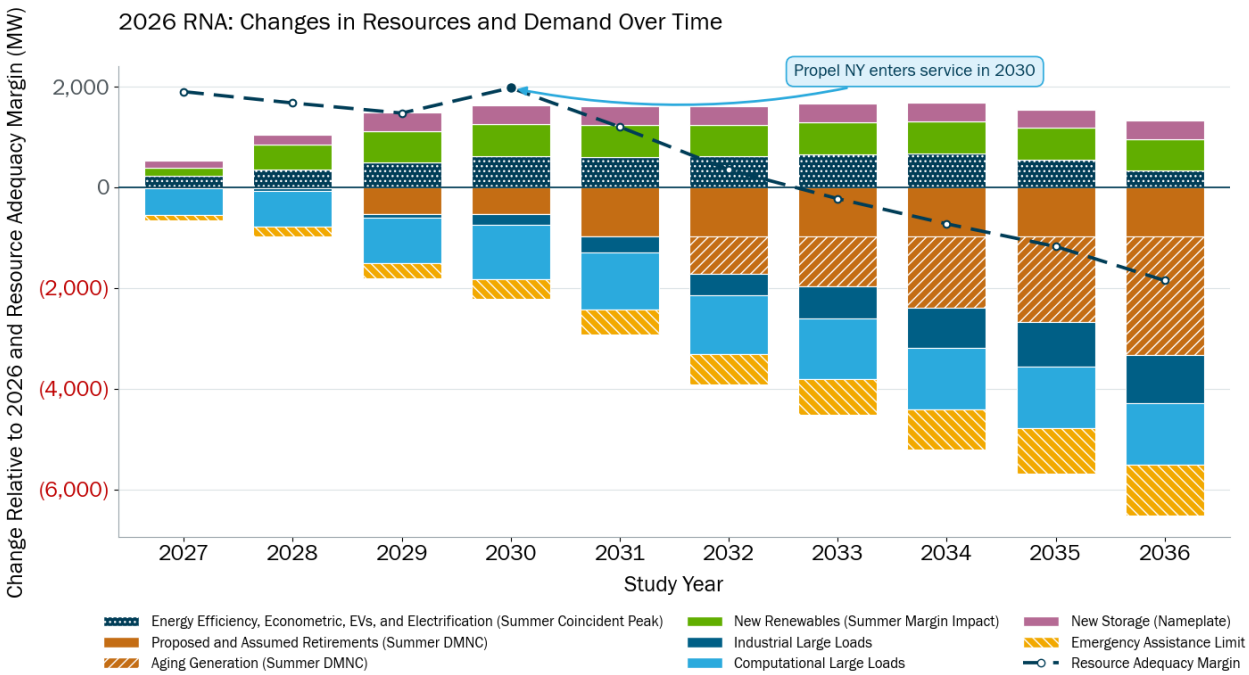
As described in the report, the 2026 RNA developed scenarios to explore how uncertainty could affect reliability outcomes and change the nature of reliability risks in accordance with the OATT and NYISO Procedures. The RNA evaluated two types of scenarios—five plausible scenarios (hereinafter "Scenarios") and other information scenarios and sensitivities—both of which are for information purposes only. This appendix contains detailed analysis results from the five Scenarios and the other informational scenarios and sensitivities evaluated in the 2026 RNA.

Scenarios

For each Scenario, this appendix provides (i) a full description of the key assumptions within each Scenario, (ii) a visualization of how resources and demand change throughout the planning horizon, and (iii) the results of the resource adequacy, transmission security, and transmission security margin analysis, as applicable.

Figure 41 provides how the resources and demand assumed in the Base Case change in each planning year. Figure 41 should be used as a reference to compare and understand how the change in assumptions for each Scenario results in differences in the resources and demand.

Figure 41: Base Case: Change in Resources and Demand Over Time



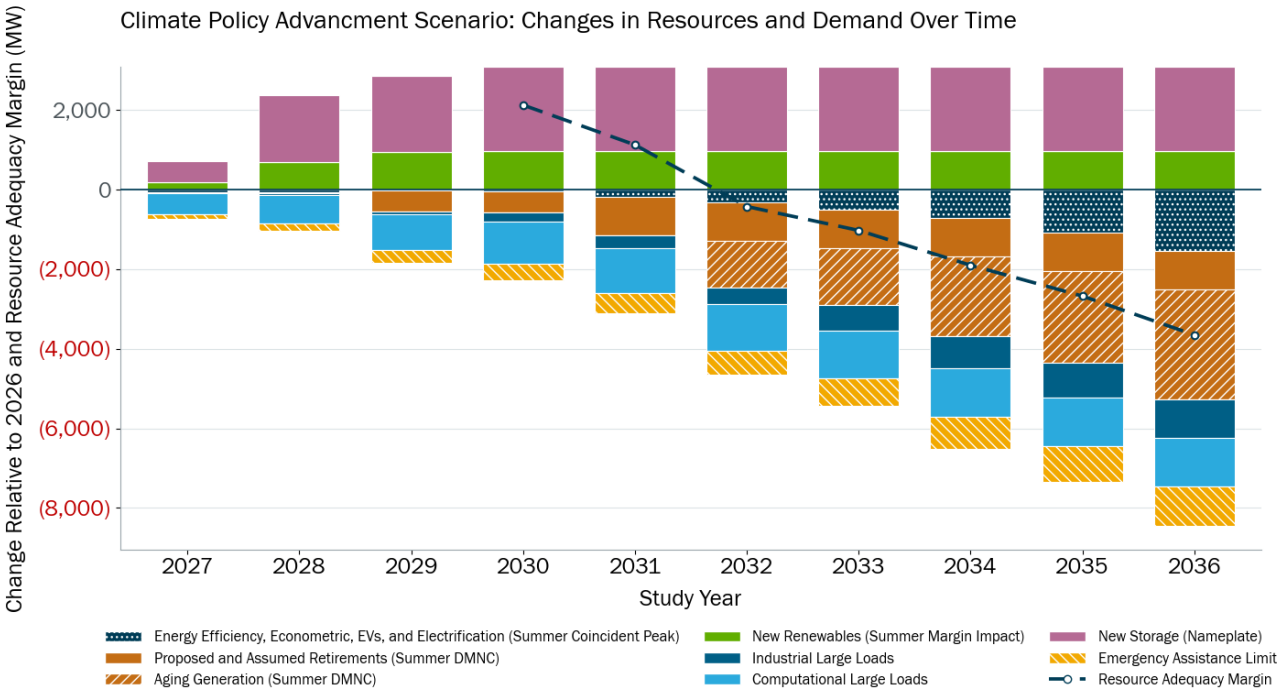
Climate Policy Advancement Scenario

The Climate Policy Advancement Scenario, or Scenario A, represents futures with greater economic growth and advancement toward electrification and clean energy targets. This Scenario varies three key assumptions from the Base Case. The first two assumptions represent advancement towards clean energy and emissions reduction policy targets, while the third assumption represents increased achievement of electric vehicle and heating electrification policy targets.

1. The assumptions in the aging generation model are adjusted to include more generation, such that generators older the age by which 90% of peer capacity had retired are included in the model and contribute to aging generation risk versus the Base Case that is based on the 95th percentile threshold age. Compared to the Base Case, this adds roughly 400 MW of unavailable capacity due to aging generation by 2036.
2. The inclusion of planned generator projects is adjusted to include any planned generation that has accepted its cost allocation in NYISO's interconnection process. Compared to the Base Case, this adds roughly 3,000 MW nameplate of intermittent resources and 1,700 MW nameplate of battery storage by 2036.
3. The demand is increased to use the higher demand forecast from the 2026 Gold Book for load other than large loads. Compared to the Base Case, this adds roughly 1,900 MW of coincident summer peak demand by 2036.

Demand driven by large loads is left at the RNA Base Case assumption, as the interconnection of large loads is not clearly linked to policy achievement. Figure 42 shows how the resources and demand in this Scenario change throughout the planning horizon. Resource Adequacy margin in Scenarios is calculated only for the RNA study horizon (years 4-10).

Figure 42: Climate Policy Advancement Scenario: Change in Resources and Demand Over Time



Resource Adequacy analysis was conducted for the Climate Policy Advancement Scenario. Figure 43 summarizes Resource Adequacy metrics in this Scenario, together with the Base Case for comparison. Based on these results, increased aging and electrification drive Loss of Load Expectation (LOLE) deficiencies beginning in 2033, growing to a severe LOLE of roughly two event-days per year, compared to one event-day in two years identified in the Base Case. These occur despite this Scenario assuming the addition of over 4.5 GW nameplate of intermittent renewables and storage. Statewide resource adequacy margin reaches a substantial magnitude of -3,300 MW by 2036.

Figure 43: Climate Policy Advancement Scenario Resource Adequacy Results

Study Year	Base Case			Climate Policy Advancement		
	LOLE (event-days/yr)	EUE (MWh/yr)	Resource Adequacy Margin (MW)	LOLE (event-days/yr)	EUE (MWh/yr)	Resource Adequacy Margin (MW)
2030	0.019	26	1,975	0.009	12	2,500
2031	0.036	65	1,200	0.023	42	1,500
2032	0.074	170	350	0.099	255	0
2033	0.115	311	-225	0.165	519	-650
2034	0.182	524	-725	0.348	1,165	-1,500
2035	0.290	877	-1,175	0.731	2,514	-2,250
2036	0.596	1,823	-1,850	1.869	6,967	-3,300

Figure 44 through Figure 49 provide the transmission security margin results for the Climate Policy Advancement Scenario.

For the Lower Hudson Valley, summer peak margin results show deficiencies beginning in 2032, growing to 3,550 MW by 2036. These results indicate that increased aging generation and electrification lead to deficiencies of substantial magnitude, well above the deficiency of 1,950 MW for the Lower Hudson Valley in the Base Case. Winter peak margin results show positive margin in all years except 2036 with a margin of 0 MW, indicating that the winter margin is reliant on the availability of battery energy storage resources for discharge in the peak hour.

For New York City, summer peak margin results show deficiencies beginning in 2032, growing to 2,700 MW by 2036. These results indicate that increased aging generation and electrification lead to deficiencies of substantial magnitude, well above the deficiency of 1,800 MW in New York City in the Base Case. Winter peak margin results show deficiencies starting in 2034 and growing to 1,550 MW by 2036.

For Long Island, these results indicate that with the Propel NY project in service, reasonable increases in aging and electrification would not lead to margin deficiencies on Long Island during the study period.

Figure 44: Climate Policy Advancement Scenario Lower Hudson Valley Summer Peak Transmission Security Margin

Climate Policy Advancment Scenario Lower Hudson Valley Transmission Security Margin Summer Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	G-J Demand Forecast	(15,443)	(15,466)	(15,523)	(15,562)	(15,609)	(15,647)	(15,675)	(15,706)	(15,781)	(15,874)
SA.1	Impact of Increased Demand	(251)	(291)	(365)	(401)	(437)	(532)	(681)	(806)	(991)	(1,108)
B	RECO Demand	(414)	(414)	(414)	(410)	(410)	(410)	(410)	(410)	(420)	(420)
C	**Total Demand (A+SA.1+B)**	(16,108)	(16,171)	(16,302)	(16,373)	(16,456)	(16,589)	(16,766)	(16,922)	(17,192)	(17,402)
D	UPNY-SENY Limit (4)	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	(208)	(131)	(231)	(293)	(364)	(649)	(844)	(910)	(1,056)	(1,374)
G	**Total SENY AC Import (D+E+F)**	4,606	4,683	4,583	4,521	4,450	4,165	3,970	3,904	3,758	3,440
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(11,502)	(11,488)	(11,719)	(11,852)	(12,006)	(12,424)	(12,796)	(13,018)	(13,434)	(13,962)
J	G-J Generation (1)	12,852	13,767	13,262	13,262	12,864	12,864	12,864	12,864	12,864	12,864
SA.2	Impact of Cost Allocated Projects -Additional Generation	71	924	924	1,129	1,129	1,129	1,129	1,129	1,129	1,129
K	G-J Thermal Generation Unavailability - Aging	0	0	0	0	0	(445)	(648)	(1,038)	(1,131)	(1,720)
SA.3	Impact of Increased Aging	0	0	0	0	0	(386)	(290)	(425)	(465)	0
L	G-J Thermal Generation Unavailability - EFORd (2)	(1,358)	(1,358)	(1,317)	(1,317)	(1,285)	(1,217)	(1,208)	(1,166)	(1,155)	(1,145)
M	G-J Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
N	G-J Renewable Generation Unavailability - Dispatch Assumptions (3)	(162)	(983)	(983)	(983)	(983)	(983)	(991)	(991)	(991)	(991)
SA.4	Impact of Cost Allocated Projects - Dispatch Assumptions	(71)	(898)	(898)	(1,103)	(1,103)	(1,103)	(1,118)	(1,118)	(1,118)	(1,118)
O	SCRs	0	0	0	0	0	0	0	0	0	0
P	Net ICAP External Imports (5)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Q	**Total Resources Available (J+K+L+M+N+O+P+SA.2+SA.3+SA.4)**	12,721	12,842	12,377	12,377	12,011	11,249	11,127	10,644	10,523	10,409
R	**Climate Policy Advancment ScenarioNoncoincident Peak Transmission Security Margin (I+Q)**	1,219	1,354	659	525	5	(1,175)	(1,668)	(2,374)	(2,911)	(3,553)
S	**Battery Storage MW**	118	168	168	168	168	168	168	168	168	168
SA.5	Impact of Cost Allocated Projects - Additional Battery MW	568	821	821	1,021	1,021	1,021	1,021	1,021	1,021	1,021
T	**Battery Storage MW Discharge at Locality Noncoincident Peak Hour**	0	0	0	0	0	168	168	168	168	134
SA.6	Scenario Impact - Additional Battery at Locality Noncoincident Peak Hour	0	0	0	0	1,189	1,021	1,021	(168)	(168)	(134)
U	**Climate Policy Advancment Scenario Transmission Security Margin with Batteries (Q+T+SA.6)**	1,219	1,354	659	525	1,194	14	(480)	(2,374)	(2,911)	(3,553)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c). Derates for run-of-river hydro are included.
4. Limits for 2027 through 2036 are based on summer peak 2027, 2031, and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item R are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item S, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 45: Climate Policy Advancement Scenario Lower Hudson Valley Winter Peak Transmission Security Margin

Climate Policy Advancment Scenario Lower Hudson Valley Transmission Security Margin Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	G-J Demand Forecast	(11,003)	(11,114)	(11,234)	(11,391)	(11,539)	(11,705)	(11,850)	(12,024)	(12,240)	(12,499)
SA.1	Impact of Increased Demand	(163)	(186)	(351)	(413)	(431)	(511)	(624)	(745)	(942)	(1,087)
B	RECO Demand	(253)	(253)	(253)	(273)	(273)	(273)	(273)	(273)	(305)	(305)
C	**Total Demand (A+SA.1+B)**	(11,419)	(11,553)	(11,838)	(12,077)	(12,243)	(12,489)	(12,747)	(13,042)	(13,487)	(13,891)
D	UPNY-SENY Limit (4)	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	(33)	(33)	(33)	1,467	1,364	997	797	666	425	(10)
G	**Total SENY AC Import (D+E+F)**	4,856	4,856	4,856	6,356	6,253	5,886	5,686	5,555	5,314	4,879
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(6,563)	(6,697)	(6,982)	(5,721)	(5,990)	(6,603)	(7,061)	(7,487)	(8,173)	(9,012)
J	G-J Generation (1)	14,681	14,681	14,029	13,618	13,618	13,618	13,618	13,618	13,618	13,618
SA.2	Impact of Cost Allocated Projects -Additional Generation	665	924	1,129	1,129	1,129	1,129	1,129	1,129	1,129	1,129
K	G-J Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(2,141)	(2,141)	(2,141)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)
L	G-J Thermal Generation Unavailability - Aging	0	0	0	0	0	(276)	(459)	(834)	(909)	(1,475)
SA.3	Impact of Increased Aging	0	0	0	0	0	(391)	(295)	(421)	(460)	0
M	G-J Thermal Generation Unavailability - EFORd (2)	(1,274)	(1,274)	(1,222)	(1,222)	(1,222)	(1,166)	(1,159)	(1,118)	(1,109)	(1,100)
N	G-J Renewable Generation Unavailability - Dispatch Assumptions (3)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)
SA.4	Impact of Cost Allocated Projects - Dispatch Assumptions	(665)	(924)	(1,129)	(1,129)	(1,129)	(1,129)	(1,129)	(1,129)	(1,129)	(1,129)
O	SCRs	0	0	0	0	0	0	0	0	0	0
P	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
Q	**Total Resources Available (J+K+L+M+N+O+P+SA.2+SA.3+SA.4)**	10,499	10,499	9,899	9,899	9,899	9,288	9,209	8,748	8,644	8,546
R	**Climate Policy Advancment Scenario Noncoincident Peak Transmission Security Margin (I+Q)**	3,936	3,802	2,917	4,179	3,910	2,685	2,148	1,261	471	(466)
S	**Battery Storage MW**	168	168	168	168	168	168	168	168	168	168
SA.5	Impact of Cost Allocated Projects - Additional Battery MW	518	821	821	1,021	1,021	1,021	1,021	1,021	1,021	1,021
T	**Battery Storage MW Discharge at Locality Noncoincident Peak Hour**	0	0	0	0	0	0	0	0	0	0
SA.6	Scenario Impact - Additional Battery at Locality Noncoincident Peak Hour	0	0	0	0	0	0	0	0	0	466
U	**Climate Policy Advancment Scenario Transmission Security Margin with Batteries (Q+T+SA.6)**	3,936	3,802	2,917	4,179	3,910	2,685	2,148	1,261	471	0

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour.
4. Limits for 2027 through 2036 are based on winter peak 2027, 2031, and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item R are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item S, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 46: Climate Policy Advancement Scenario New York City Summer Peak Transmission Security Margin

Climate Policy Advancement Scenario New York City Transmission Security Margin Summer Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
	Item	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone J Demand Forecast**	(11,100)	(11,120)	(11,140)	(11,170)	(11,200)	(11,230)	(11,250)	(11,270)	(11,320)	(11,380)
SA.1	Impact of Increased Demand	(130)	(160)	(220)	(240)	(270)	(350)	(470)	(570)	(720)	(820)
B	I+K to J (4)	4,725	4,725	4,725	4,825	4,825	4,825	4,825	4,825	4,825	4,825
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	4,714	4,714	4,714	4,814	4,814	4,814	4,814	4,814	4,814	4,814
E	Loss of Source Contingency	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)
F	**Resource Need (A+SA.1+D+E)**	(8,754)	(8,804)	(8,884)	(8,834)	(8,894)	(9,004)	(9,144)	(9,264)	(9,464)	(9,624)
G	J Generation (1)	8,655	9,521	9,015	9,015	8,617	8,617	8,617	8,617	8,617	8,617
SA.2	Impact of Cost Allocated Projects -Additional Generation	71	530	530	530	530	530	530	530	530	530
H	J Thermal Generation Unavailability - Aging	0	0	0	0	0	(423)	(624)	(1,011)	(1,102)	(1,688)
SA.3	Impact of Increased Aging	0	0	0	0	0	(386)	(290)	(425)	(465)	0
I	J Thermal Generation Unavailability - EFORd (2)	(688)	(688)	(647)	(647)	(615)	(550)	(542)	(500)	(489)	(479)
J	J Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
K	J Renewable Generation Unavailability - Dispatch Assumptions (3)	(115)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)
SA.4	Impact of Cost Allocated Projects - Dispatch Assumptions	(71)	(530)	(530)	(530)	(530)	(530)	(530)	(530)	(530)	(530)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
N	**Total Resources Available (G+H+I+J+K+L+M+SA.2+SA.3+SA.4)**	9,242	9,324	8,859	8,859	8,493	7,748	7,652	7,171	7,051	6,940
O	**Climate Policy Advancement Scenario Noncoincident Peak Transmission Security Margin (F+N)**	488	520	(25)	25	(401)	(1,256)	(1,492)	(2,093)	(2,412)	(2,684)
P	Battery Storage MW	115	165	165	165	165	165	165	165	165	165
SA.5	Impact of Cost Allocated Projects - Additional Battery MW	371	530	530	530	530	530	530	530	530	530
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour	0	0	0	0	132	155	0	0	0	0
SA.6	Scenario Impact - Additional Battery at Locality Noncoincident Peak Hour	0	0	25	0	270	(155)	0	0	0	0
R	**Climate Policy Advancement Scenario Noncoincident Transmission Security Margin with Batteries (O+Q+SA.6)**	488	520	0	25	0	(1,256)	(1,492)	(2,093)	(2,412)	(2,684)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c). This portion of the margin calculation assumes storage is offline. See later section for storage details.
4. Limits for 2027 through 2029 are based on summer peak 2027 representations evaluated in the 2026 RNA. Limits for 2030 through 2036 are based on summer peak 2031 and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 47: Climate Policy Advancement Scenario New York City Winter Peak Transmission Security Margin

Climate Policy Advancement Scenario New York City Transmission Security Margin Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
	Item	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone J Demand Forecast**	(7,750)	(7,800)	(7,860)	(7,960)	(8,050)	(8,160)	(8,260)	(8,380)	(8,520)	(8,690)
SA.1	Impact of Increased Demand	(130)	(140)	(270)	(290)	(310)	(370)	(460)	(510)	(670)	(750)
B	I+K to J (4)	3,800	3,800	3,800	3,875	3,875	3,875	3,875	3,875	3,875	3,875
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	3,789	3,789	3,789	3,864	3,864	3,864	3,864	3,864	3,864	3,864
E	Loss of Source Contingency	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)
F	**Resource Need (A+SA.1+D+E)**	(5,068)	(5,128)	(5,318)	(5,363)	(5,473)	(5,643)	(5,833)	(6,003)	(6,303)	(6,553)
G	J Generation (1)	10,255	10,255	9,603	9,192	9,192	9,192	9,192	9,192	9,192	9,192
SA.2	Impact of Cost Allocated Projects -Additional Generation	371	530	530	530	530	530	530	530	530	530
H	J Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(2,062)	(2,062)	(2,062)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)
I	J Thermal Generation Unavailability - Aging	0	0	0	0	0	(249)	(428)	(801)	(872)	(1,435)
SA.3	Impact of Increased Aging	0	0	0	0	0	(391)	(295)	(421)	(460)	0
J	J Thermal Generation Unavailability - EFORd (2)	(587)	(587)	(535)	(535)	(535)	(483)	(477)	(437)	(428)	(419)
K	J Renewable Generation Unavailability - Dispatch Assumptions (3)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)
SA.4	Impact of Cost Allocated Projects - Dispatch Assumptions	(371)	(530)	(530)	(530)	(530)	(530)	(530)	(530)	(530)	(530)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
N	**Total Resources Available (G+H+I+J+K+L+M+SA.2+SA.3+SA.4)**	6,929	6,929	6,329	6,329	6,329	5,740	5,664	5,206	5,104	5,009
O	**Climate Policy Advancement Scenario Noncoincident Peak Transmission Security Margin (F+N)**	1,861	1,801	1,011	966	856	98	(169)	(797)	(1,199)	(1,544)
P	Battery Storage MW	165	165	165	165	165	165	165	165	165	165
SA.5	Impact of Cost Allocated Projects - Additional Battery MW	321	530	530	530	530	530	530	530	530	530
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour	0	0	0	0	0	0	0	0	107	0
SA.6	Scenario Impact - Additional Battery at Locality Noncoincident Peak Hour	0	0	0	0	0	0	169	0	(107)	0
R	**Climate Policy Advancement Scenario Noncoincident Transmission Security Margin with Batteries (O+Q+SA.6)**	1,861	1,801	1,011	966	856	98	0	(797)	(1,199)	(1,544)

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour.
4. Limits for 2027 through 2029 are based on winter peak 2027 representations evaluated in the 2026 RNA. Limits for 2030 through 2036 are based on winter peak 2031 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 48: Climate Policy Advancement Scenario Long Island Summer Peak Transmission Security Margin

Climate Policy Advancment Scenario Long Island Transmission Security Margin Summer Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone K Demand Forecast**	(5,136)	(5,161)	(5,200)	(5,252)	(5,310)	(5,357)	(5,392)	(5,416)	(5,438)	(5,462)
SA.1	Impact of Increased Demand	(7)	(13)	(15)	(42)	(62)	(83)	(120)	(149)	(203)	(213)
B	I+J to K (4)	950	950	950	2,900	2,900	2,900	2,900	2,900	2,900	2,900
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	950	950	950	2,900	2,900	2,900	2,900	2,900	2,900	2,900
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	**Resource Need (A+D+E+SA.1)**	(4,853)	(4,884)	(4,925)	(3,054)	(3,132)	(3,200)	(3,272)	(3,325)	(3,401)	(3,435)
G	K Generation (1)	4,924	5,848	5,848	5,848	5,803	5,803	5,803	5,803	5,803	5,803
SA.2	Impact of Cost Allocated Projects -Additional Generation	298	674	753	753	753	753	753	753	753	753
H	K Thermal Generation Unavailability - Aging	0	0	0	0	0	(272)	(307)	(340)	(485)	(548)
SA.3	Impact of Increased Aging	0	0	0	0	0	(20)	(111)	(130)	(132)	(413)
I	K Thermal Generation Unavailability - EFORd (2)	(580)	(580)	(580)	(580)	(575)	(539)	(524)	(517)	(499)	(457)
J	K Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
K	K Renewable Generation Unavailability - Dispatch Assumptions (3)	(159)	(990)	(999)	(999)	(999)	(999)	(999)	(999)	(999)	(999)
SA.4	Impact of Cost Allocated Projects - Dispatch Assumptions	(298)	(664)	(749)	(749)	(749)	(749)	(749)	(749)	(749)	(749)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	660	660	660	660	660	660	660	660	660	660
N	**Total Resources Available (G+H+I+J+K+L+M +SA.2+SA.3+SA.4)**	4,845	4,947	4,932	4,932	4,893	4,637	4,525	4,480	4,351	4,049
O	**Climate Policy Advancment Scenario Noncoincident Peak Transmission Security Margin (F+N)**	(8)	63	7	1,878	1,761	1,437	1,253	1,155	950	614
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
SA.5	Impact of Cost Allocated Projects - Additional Battery MW	250	675	754	754	754	754	754	754	754	754
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour	0	0	0	0	0	0	0	0	0	0
SA.6	Scenario Impact - Additional Battery at Locality Noncoincident Peak Hour	8	0	0	0	0	0	0	0	0	0
R	**Climate Policy Advancment Scenario Transmission Security Margin with Batteries (O+P+SA.6)**	0	63	7	1,878	1,761	1,437	1,253	1,155	950	614

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c).
4. Limits for 2027 through 2029 are based on the 2025 LIPA Summer Operating Study. Limits for 2030 through 2036 are based on the 2031 summer peak representations evaluated in the 2026RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 49: Climate Policy Advancement Scenario Long Island Winter Peak Transmission Security Margin

Climate Policy Advancement Scenario Long Island Transmission Security Margin Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone K Demand Forecast**	(3,325)	(3,412)	(3,530)	(3,635)	(3,739)	(3,832)	(3,918)	(4,001)	(4,088)	(4,190)
SA.1	Impact of Increased Demand	(12)	(18)	(23)	(65)	(143)	(181)	(183)	(249)	(244)	(318)
B	I+J to K (4)	350	350	350	3,125	3,125	3,125	3,125	3,125	3,125	3,125
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	350	350	350	3,125	3,125	3,125	3,125	3,125	3,125	3,125
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	**Resource Need (A+D+E+SA.1)**	(3,647)	(3,740)	(3,863)	(1,235)	(1,417)	(1,548)	(1,636)	(1,785)	(1,867)	(2,043)
G	K Generation (1)	6,290	6,290	6,290	6,244	6,244	6,244	6,244	6,244	6,244	6,244
SA.2	Impact of Cost Allocated Projects -Additional Generation	528	753	753	753	753	753	753	753	753	753
H	K Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(374)	(374)	(374)	(328)	(328)	(328)	(328)	(328)	(328)	(328)
I	K Thermal Generation Unavailability - Aging	0	0	0	0	0	(290)	(328)	(363)	(515)	(581)
SA.3	Impact of Increased Aging	0	0	0	0	0	(23)	(116)	(136)	(159)	(473)
J	K Thermal Generation Unavailability - EFORd (2)	(589)	(589)	(589)	(589)	(589)	(551)	(534)	(528)	(506)	(460)
K	K Renewable Generation Unavailability - Dispatch Assumptions (3)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)
SA.4	Impact of Cost Allocated Projects - Dispatch Assumptions	(528)	(753)	(753)	(753)	(753)	(753)	(753)	(753)	(753)	(753)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	660	660	660	660	660	660	660	660	660	660
N	**Total Resources Available (G+H+I+J+K+L+M +SA.2+SA.3+SA.4)**	5,088	5,088	5,088	5,088	5,088	4,814	4,699	4,651	4,497	4,163
O	**Climate Policy Advancment Scenario Noncoincident Peak Transmission Security Margin (F+N)**	1,441	1,348	1,225	3,853	3,671	3,266	3,063	2,866	2,630	2,120
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
SA.5	Impact of Cost Allocated Projects - Additional Battery MW	250	675	754	754	754	754	754	754	754	754
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour	0	0	0	0	0	0	0	0	0	0
SA.6	Scenario Impact - Additional Battery at Locality Noncoincident Peak Hour	0	0	0	0	0	0	0	0	0	0
R	**Climate Policy Advancment Scenario Transmission Security Margin with Batteries (O+P+SA.6)**	1,441	1,348	1,225	3,853	3,671	3,266	3,063	2,866	2,630	2,120

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. For winter solar PV output at peak is 0 MW.
4. Limits for 2027 through 2029 are based on the 2025 LIPA Summer Operating Study. As a conservative assumption summer values are used for LIPA Import limits with one line out. Limits for 2030 through 2036 are based on the 2030 winter peak representations evaluated in the 2026RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Large Loads Scenario

The Large Loads Scenario, or Scenario B, represents a future with accelerated development of large load projects across the power system—both inside and outside of the NYCA. The first two assumptions that are varied from the Base Case look at impacts within the NYCA.

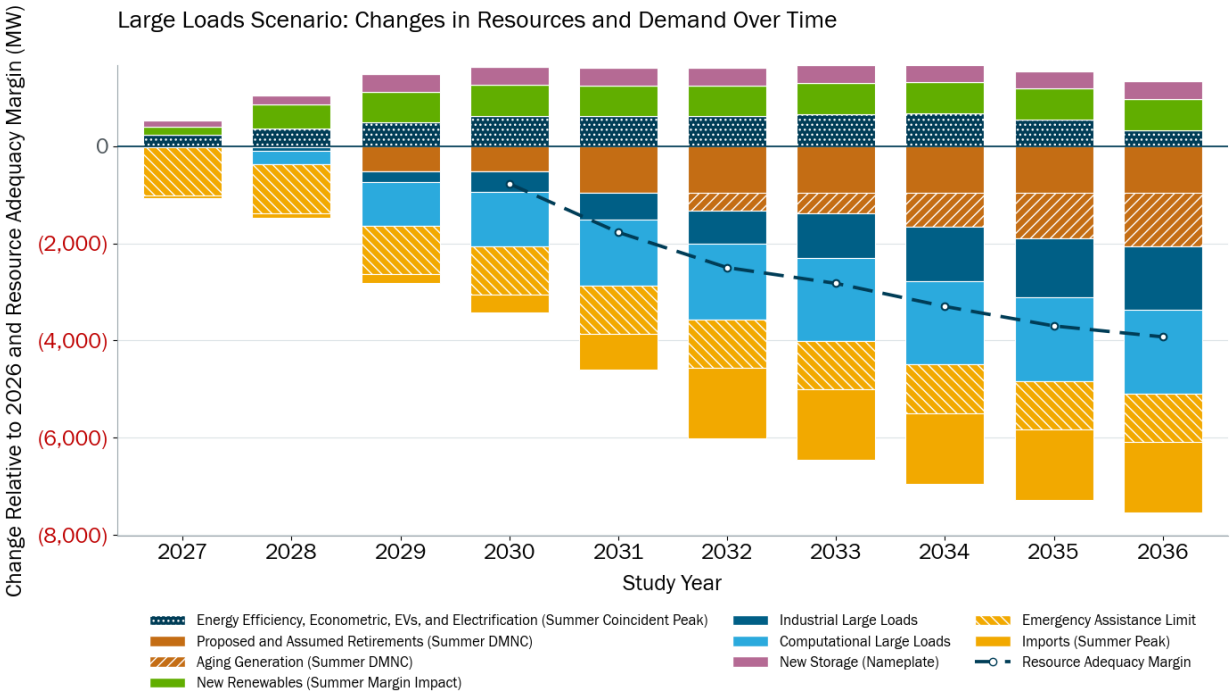
1. The primary assumption in this Scenario is the large loads themselves, which are increased to the Higher Demand Forecast level of 4,100 MW by 2036, compared to 2,700 MW in the Base Case. The increase in large load growth is intended to represent reasonable growth beyond the Base Case and does not include the full NYISO load interconnection queue, which has more than 14,000 MW of proposed load projects.
2. The aging generation model is adjusted such that only those generators beyond the age at which 99% of peer capacity had retired are included in the model and contribute to aging generation risk versus the Base Case that is based on the 95th percentile threshold age. By 2036, this reduces the statewide unavailable capacity due to aging by roughly 1,250 MW compared to the Base Case.

The second two assumptions that differ from the Base Case reflect that accelerated large load development in NYISO's neighbors may reduce the amount of energy they can sell to the NYISO or supply to the NYISO during an emergency.

3. For Resource Adequacy, the limit on emergency assistance is decreased to 2,000 MW in all planning years compared to the Base Case.
4. Contracted imports are reduced to 50% of the levels expected in the Base Case.

Figure 50 shows how the resources and demand in this Scenario change throughout the planning horizon.

Figure 50: Large Loads Scenario Change in Resources and Demand Over Time



Resource Adequacy analysis was conducted for the Large Load Scenario. Figure 51 summarizes Resource Adequacy metrics in this Scenario, together with the Base Case for comparison. Increased large loads and reduced imports drive urgent resource adequacy deficiencies beginning in 2029 that growing to a severe LOLE of nearly 3 event-days per year by 2036. Resource adequacy margin results show that 3,925 MW of statewide perfect capacity would be required to resolve the deficiency in 2036—a substantially greater magnitude than the Base Case, which requires 1,850 MW.

Figure 51: Large Loads Scenario Resource Adequacy Results

Study Year	Base Case			Large Loads		
	LOLE (event-days/yr)	EUE (MWh/yr)	Resource Adequacy Margin (MW)	LOLE (event-days/yr)	EUE (MWh/yr)	Resource Adequacy Margin (MW)
2030	0.019	26	1,975	0.197	606	-775
2031	0.036	65	1,200	0.359	1,629	-1,775
2032	0.074	170	350	0.678	3,092	-2,500
2033	0.115	311	-225	0.896	4,048	-2,825
2034	0.182	524	-725	1.420	6,227	-3,300
2035	0.290	877	-1,175	2.009	8,857	-3,700
2036	0.596	1,823	-1,850	2.780	11,510	-3,925

Transmission Security analysis for the Large Loads Scenario was also conducted for a 2036 summer peak system condition. Figure 52 summarizes thermal issues identified in that analysis. The overloads are all attributable to a grouping of Large Load projects with ongoing interconnection studies. Without that grouping, no new transmission security violations were identified in the Large Loads Scenario.

Figure 52: Large Loads Scenario Transmission Security Thermal Issues

Zone	Owner	Monitored Element	Normal Rating (MVA)	Contingency Rating (MVA)	1st Contingency	2nd Contingnecy	2036 Summer Large Loads Scenario Peak Flow (%)
C	National Grid	Dewitt-Pebble Hill 115kV	187	213	Loss of Clay-General Eletric 115kV	Loss of 345kV Elbrigde bus, Lafaytte-Clark Corner 345kV	101
C	NYSEG	Oakdale Transformer 345-34.5 kV	65	68	Loss of Oakdale-Westover 115kV	Loss of Oakdale-N. Endicott 115kV	151
C	NYSEG	Oakdale-N. Endicott 115kV	175	175	Loss of Oakdale-Westover 115kV	Loss of Oakdale-Northside 115kV	143

Tranmission security margin results for the Large Loads Scenario are provided in Figure 53 through Figure 58.

For the Lower Hudson Valley, deficiencies were found in summer peak transmission security margin due to reduced imports beginning in 2031, which is one year sooner than the Base Case. This deficiency grows to 1,800 MW by 2036. The impact of increased large loads was primarily in the rest of state region and had little impact on the Lower Hudson Valley. The reduced aging generation assumption drives the magnitude of these deficiencies to taper off in later years, relative to the Base Case. The Lower Hudson Valley winter peak margin was sufficient in all planning years for the Large Loads Scenario.

For New York City, deficiencies in summer peak margins start in 2031, which is one year sooner than the Base Case. By 2036, the deficiency in summer margin grows to 1,575 MW. The winter peak margin is sufficient in all planning years but narrows to 125 MW by 2036.

For Long Island, both summer and winter peak margins were sufficient in the Large Loads Scenario. As shown in Figure 57, the summer peak margin remains at 1,000 MW in 2036.

Figure 53: Large Loads Scenario Lower Hudson Valley Summer Peak Transmission Security Margin

Large Loads Scenario Lower Hudson Valley Transmission Security Margin Summer Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	G-J Demand Forecast	(15,443)	(15,466)	(15,523)	(15,562)	(15,609)	(15,647)	(15,675)	(15,706)	(15,781)	(15,874)
B	RECO Demand	(414)	(414)	(414)	(410)	(410)	(410)	(410)	(410)	(420)	(420)
C	**Total Demand (A+B)**	(15,857)	(15,880)	(15,937)	(15,972)	(16,019)	(16,057)	(16,085)	(16,116)	(16,201)	(16,294)
D	UPNY-SENY Limit (4)	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	(208)	(141)	(234)	(296)	(367)	(635)	(749)	(799)	(943)	(1,014)
SB.1	Impact of Decreased Imports on K-SENY	(21)	(41)	(83)	(165)	(330)	(210)	(194)	(249)	(142)	(187)
G	**Total SENY AC Import (D+E+F+SB.1)**	4,585	4,632	4,498	4,353	4,117	3,969	3,871	3,766	3,729	3,613
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(11,272)	(11,248)	(11,439)	(11,619)	(11,902)	(12,088)	(12,214)	(12,350)	(12,472)	(12,681)
J	G-J Generation (1)	12,852	13,767	13,262	13,262	12,864	12,864	12,864	12,864	12,864	12,864
K	G-J Thermal Generation Unavailability - Aging	0	0	0	0	0	(445)	(648)	(1,038)	(1,131)	(1,720)
SB.2	Impact of Decreased Aging Model	0	0	0	0	0	257	437	641	527	1,069
L	G-J Thermal Generation Unavailability - EFORd (2)	(1,358)	(1,358)	(1,317)	(1,317)	(1,285)	(1,269)	(1,266)	(1,251)	(1,234)	(1,231)
M	G-J Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
N	G-J Renewable Generation Unavailability - Dispatch Assumptions (3)	(162)	(983)	(983)	(983)	(983)	(983)	(991)	(991)	(991)	(991)
O	SCRs	0	0	0	0	0	0	0	0	0	0
P	Net ICAP External Imports (5)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
SB.3	Impact of Decreased Imports	(22)	(43)	(87)	(174)	(348)	(695)	(695)	(695)	(695)	(695)
Q	**Total Resources Available (J+K+SB.1+L+M+N+O+P+SB.2+SB.3)**	12,700	12,773	12,264	12,177	11,638	11,120	11,090	10,919	10,729	10,687
R	**Large Loads Scenario Noncoincident Peak Transmission Security Margin (I+Q)**	1,428	1,525	825	558	(265)	(968)	(1,124)	(1,431)	(1,743)	(1,994)
S	Battery Storage MW	118	168	168	168	168	168	168	168	168	168
T	Battery Storage MW Discharge at Locality Noncoincident Peak Hour	0	0	0	0	168	168	168	168	168	168
U	**Large Loads Scenario Noncoincident Peak Transmission Security Margin with Batteries (R+T)**	1,428	1,525	825	558	(97)	(800)	(956)	(1,263)	(1,575)	(1,827)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c). Derates for run-of-river hydro are included.
4. Limits for 2027 through 2036 are based on summer peak 2027, 2031, and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item R are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item S, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 54: Large Loads Scenario Lower Hudson Valley Winter Peak Transmission Security Margin

Large Loads Scenario Lower Hudson Valley Transmission Security Margin Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	G-J Demand Forecast	(11,003)	(11,114)	(11,234)	(11,391)	(11,539)	(11,705)	(11,850)	(12,024)	(12,240)	(12,499)
B	RECO Demand	(253)	(253)	(253)	(273)	(273)	(273)	(273)	(273)	(305)	(305)
C	**Total Demand (A+B)**	(11,256)	(11,367)	(11,487)	(11,664)	(11,812)	(11,978)	(12,123)	(12,297)	(12,545)	(12,804)
D	UPNY-SENY Limit (4)	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	(33)	(33)	(33)	1,467	1,364	1,017	899	785	564	405
SB.1	Impact of Decreased Imports on K-SENY	0	0	0	(165)	(330)	(209)	(193)	(246)	(133)	(179)
G	**Total SENY AC Import (D+E+F+SB.1)**	4,856	4,856	4,856	6,191	5,923	5,697	5,595	5,428	5,320	5,116
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(6,400)	(6,511)	(6,631)	(5,473)	(5,889)	(6,281)	(6,528)	(6,869)	(7,225)	(7,688)
J	G-J Generation (1)	14,681	14,681	14,029	13,618	13,618	13,618	13,618	13,618	13,618	13,618
K	G-J Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(2,141)	(2,141)	(2,141)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)
SB.2	G-J Thermal Generation Unavailability - Aging	0	0	0	0	0	(276)	(459)	(834)	(909)	(1,475)
L	Impact of Decreased Aging Model	0	0	0	0	0	131	295	489	534	1,071
M	G-J Thermal Generation Unavailability - EFORd (2)	(1,274)	(1,274)	(1,222)	(1,222)	(1,222)	(1,208)	(1,206)	(1,191)	(1,188)	(1,186)
N	G-J Renewable Generation Unavailability - Dispatch Assumptions (3)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)
O	SCRs	0	0	0	0	0	0	0	0	0	0
P	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
SB.3	Impact of Decreased Imports	(2)	(4)	(9)	(18)	(35)	(70)	(70)	(70)	(70)	(70)
Q	**Total Resources Available (J+K+SB.1+L+M+N+O+P+SB.2+SB.3)**	10,497	10,494	9,891	9,882	9,864	9,698	9,681	9,515	9,487	9,461
R	**Large Loads Scenario Noncoincident Peak Transmission Security Margin (I+Q)**	4,097	3,983	3,260	4,409	3,976	3,417	3,153	2,646	2,262	1,772
S	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
T	Battery Storage MW Discharge at Locality Noncoincident Peak Hour	0	0	0	0	0	0	0	0	0	0
U	**Large Loads Scenario Noncoincident Peak Transmission Security Margin with Batteries (R+T)**	4,097	3,983	3,260	4,409	3,976	3,417	3,153	2,646	2,262	1,772

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.

2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.

3. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour.

4. Limits for 2027 through 2036 are based on winter peak 2027, 2031, and 2036 representations evaluated in the 2026 RNA.

5. Interchanges are based on ERAG MMWG values and firm transactions.

6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.

7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item R are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item S, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 55: Large Loads Scenario New York City Summer Peak Transmission Security Margin

Large Loads Scenario New York City Transmission Security Margin Summer Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
	Item	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone J Demand Forecast**	(11,100)	(11,120)	(11,140)	(11,170)	(11,200)	(11,230)	(11,250)	(11,270)	(11,320)	(11,380)
B	I+K to J (4)	4,725	4,725	4,725	4,825	4,825	4,825	4,825	4,825	4,825	4,825
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	4,714	4,714	4,714	4,814	4,814	4,814	4,814	4,814	4,814	4,814
E	Loss of Source Contingency	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)
F	**Resource Need (A+D+E)**	(8,624)	(8,644)	(8,664)	(8,594)	(8,624)	(8,654)	(8,674)	(8,694)	(8,744)	(8,804)
G	J Generation (1)	8,655	9,521	9,015	9,015	8,617	8,617	8,617	8,617	8,617	8,617
H	J Thermal Generation Unavailability - Aging	0	0	0	0	0	(423)	(624)	(1,011)	(1,102)	(1,688)
SB.1	Impact of Decreased Aging Model	0	0	0	0	0	257	437	641	527	1,069
I	J Thermal Generation Unavailability - EFORd (2)	(688)	(688)	(647)	(647)	(615)	(602)	(600)	(585)	(569)	(565)
J	J Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
K	J Renewable Generation Unavailability - Dispatch Assumptions (3)	(115)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
SB.2	Impact of Decreased Imports	(22)	(43)	(87)	(174)	(348)	(695)	(695)	(695)	(695)	(695)
N	**Total Resources Available (G+H+SB.1I+J+K+L+M+SB.2)**	9,220	9,280	8,772	8,685	8,145	7,645	7,625	7,457	7,269	7,229
O	**Large Loads Scenario Noncoincident Peak Transmission Security Margin (F+N)**	597	636	108	91	(479)	(1,009)	(1,049)	(1,237)	(1,475)	(1,575)
P	Battery Storage MW	115	165	165	165	165	165	165	165	165	165
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour	0	0	0	0	165	0	0	0	0	0
R	**Large Loads Scenario Noncoincident Peak Transmission Security Margin with Batteries (O+Q)**	597	636	108	91	(314)	(1,009)	(1,049)	(1,237)	(1,475)	(1,575)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c). This portion of the margin calculation assumes storage is offline. See later section for storage details.
4. Limits for 2027 through 2029 are based on summer peak 2027 representations evaluated in the 2026 RNA. Limits for 2030 through 2036 are based on summer peak 2031 and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 56: Large Loads Scenario New York City Winter Peak Transmission Security Margin

Large Loads Scenario New York City Transmission Security Margin Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
	Item	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone J Demand Forecast**	(7,750)	(7,800)	(7,860)	(7,960)	(8,050)	(8,160)	(8,260)	(8,380)	(8,520)	(8,690)
B	I+K to J (4)	3,800	3,800	3,800	3,875	3,875	3,875	3,875	3,875	3,875	3,875
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	3,789	3,789	3,789	3,864	3,864	3,864	3,864	3,864	3,864	3,864
E	Loss of Source Contingency	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)
F	**Resource Need (A+D+E)**	(4,938)	(4,988)	(5,048)	(5,073)	(5,163)	(5,273)	(5,373)	(5,493)	(5,633)	(5,803)
G	J Generation (1)	10,255	10,255	9,603	9,192	9,192	9,192	9,192	9,192	9,192	9,192
H	J Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(2,062)	(2,062)	(2,062)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)
SB.1	J Thermal Generation Unavailability - Aging	0	0	0	0	0	(249)	(428)	(801)	(872)	(1,435)
I	Impact of Decreased Aging Model	0	0	0	0	0	131	295	489	534	1,071
J	J Thermal Generation Unavailability - EFORd (2)	(587)	(587)	(535)	(535)	(535)	(525)	(524)	(510)	(508)	(505)
K	J Renewable Generation Unavailability - Dispatch Assumptions (3)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
SB.2	Impact of Decreased Imports	(2)	(4)	(9)	(18)	(35)	(70)	(70)	(70)	(70)	(70)
N	**Total Resources Available (G+H+SB.1I+J+K+L+M+SB.2)**	6,926	6,924	6,320	6,312	6,294	6,150	6,137	5,973	5,947	5,924
O	**Large Loads Scenario Noncoincident Peak Transmission Security Margin (F+N)**	1,989	1,936	1,273	1,239	1,131	878	764	480	315	121
P	Battery Storage MW	165	165	165	165	165	165	165	165	165	165
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour	0	0	0	0	0	0	0	0	0	0
R	**Large Loads Scenario Noncoincident Peak Transmission Security Margin with Batteries (O+Q)**	1,989	1,936	1,273	1,239	1,131	878	764	480	315	121

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour.
4. Limits for 2027 through 2029 are based on winter peak 2027 representations evaluated in the 2026 RNA. Limits for 2030 through 2036 are based on winter peak 2031 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 57: Large Loads Scenario Long Island Summer Peak Transmission Security Margin

Large Loads Scenario Long Island Transmission Security Margin Summer Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone K Demand Forecast**	(5,136)	(5,161)	(5,200)	(5,252)	(5,310)	(5,357)	(5,392)	(5,416)	(5,438)	(5,462)
B	I+J to K (4)	950	950	950	2,900	2,900	2,900	2,900	2,900	2,900	2,900
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	950	950	950	2,900	2,900	2,900	2,900	2,900	2,900	2,900
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	**Resource Need (A+D+E)**	(4,846)	(4,871)	(4,910)	(3,012)	(3,070)	(3,117)	(3,152)	(3,176)	(3,198)	(3,222)
G	K Generation (1)	4,924	5,848	5,848	5,848	5,803	5,803	5,803	5,803	5,803	5,803
H	K Thermal Generation Unavailability - Aging	0	0	0	0	0	(272)	(307)	(340)	(485)	(548)
SB.1	Impact of Decreased Aging Model	0	0	0	0	0	137	155	92	214	163
I	K Thermal Generation Unavailability - EFORd (2)	(580)	(580)	(580)	(580)	(575)	(558)	(556)	(544)	(542)	(528)
J	K Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
K	K Renewable Generation Unavailability - Dispatch Assumptions (3)	(159)	(990)	(999)	(999)	(999)	(999)	(999)	(999)	(999)	(999)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	660	660	660	660	660	660	660	660	660	660
SB.2	Impact of Decreased Imports	(21)	(41)	(83)	(165)	(330)	(330)	(330)	(330)	(330)	(330)
N	**Total Resources Available (G+H+SB.1+I+J+K+L+M+SB.2)**	4,824	4,896	4,846	4,763	4,559	4,441	4,425	4,341	4,321	4,221
O	**Large Loads Scenario Noncoincident Peak Transmission Security Margin (F+N)**	(22)	25	(64)	1,751	1,489	1,324	1,273	1,165	1,123	999
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour	0	0	0	0	0	0	0	0	0	0
R	**Large Loads Scenario Transmission Security Margin with Batteries (O+Q)**	(22)	25	(64)	1,751	1,489	1,324	1,273	1,165	1,123	999

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c).
4. Limits for 2027 through 2029 are based on the 2025 LIPA Summer Operating Study. Limits for 2030 through 2036 are based on the 2031 summer peak representations evaluated in the 2026RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 58: Large Loads Scenario Long Island Winter Peak Transmission Security Margin

Large Loads Scenario Long Island Transmission Security Margin Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone K Demand Forecast**	(3,325)	(3,412)	(3,530)	(3,635)	(3,739)	(3,832)	(3,918)	(4,001)	(4,088)	(4,190)
B	I+J to K (4)	350	350	350	3,125	3,125	3,125	3,125	3,125	3,125	3,125
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	350	350	350	3,125	3,125	3,125	3,125	3,125	3,125	3,125
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	**Resource Need (A+D+E)**	(3,635)	(3,722)	(3,840)	(1,170)	(1,274)	(1,367)	(1,453)	(1,536)	(1,623)	(1,725)
G	K Generation (1)	6,290	6,290	6,290	6,244	6,244	6,244	6,244	6,244	6,244	6,244
H	K Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(374)	(374)	(374)	(328)	(328)	(328)	(328)	(328)	(328)	(328)
SB.1	K Thermal Generation Unavailability - Aging	0	0	0	0	0	(290)	(328)	(363)	(515)	(581)
I	Impact of Decreased Aging Model	0	0	0	0	0	138	156	96	224	172
J	K Thermal Generation Unavailability - EFORd (2)	(589)	(589)	(589)	(589)	(589)	(570)	(568)	(556)	(553)	(539)
K	K Renewable Generation Unavailability - Dispatch Assumptions (3)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	660	660	660	660	660	660	660	660	660	660
SB.2	Impact of Decreased Imports	(21)	(41)	(83)	(165)	(330)	(330)	(330)	(330)	(330)	(330)
N	**Total Resources Available (G+H+SB.1+I+J+K+L+M+SB.2)**	5,068	5,047	5,006	4,923	4,758	4,625	4,608	4,524	4,503	4,400
O	**Large Loads Scenario Noncoincident Peak Transmission Security Margin (F+N)**	1,433	1,325	1,166	3,753	3,484	3,258	3,155	2,988	2,880	2,675
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour	0	0	0	0	0	0	0	0	0	0
R	**Large Loads Scenario Transmission Security Margin with Batteries (O+Q)**	1,433	1,325	1,166	3,753	3,484	3,258	3,155	2,988	2,880	2,675

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. For winter solar PV output at peak is 0 MW.
4. Limits for 2027 through 2029 are based on the 2025 LIPA Summer Operating Study. As a conservative assumption summer values are used for LIPA Import limits with one line out. Limits for 2030 through 2036 are based on the 2030 winter peak representations evaluated in the 2026RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Economy Slows Scenario

The Economy Slows Scenario, or Scenario C, evaluates a future with lower growth and represented by reduced demand and policy achievement paired with delays in planned resources, due to supply chain constraints and increased procurement times for power systems equipment. The first two assumptions evaluate the impact of slowed economic growth.

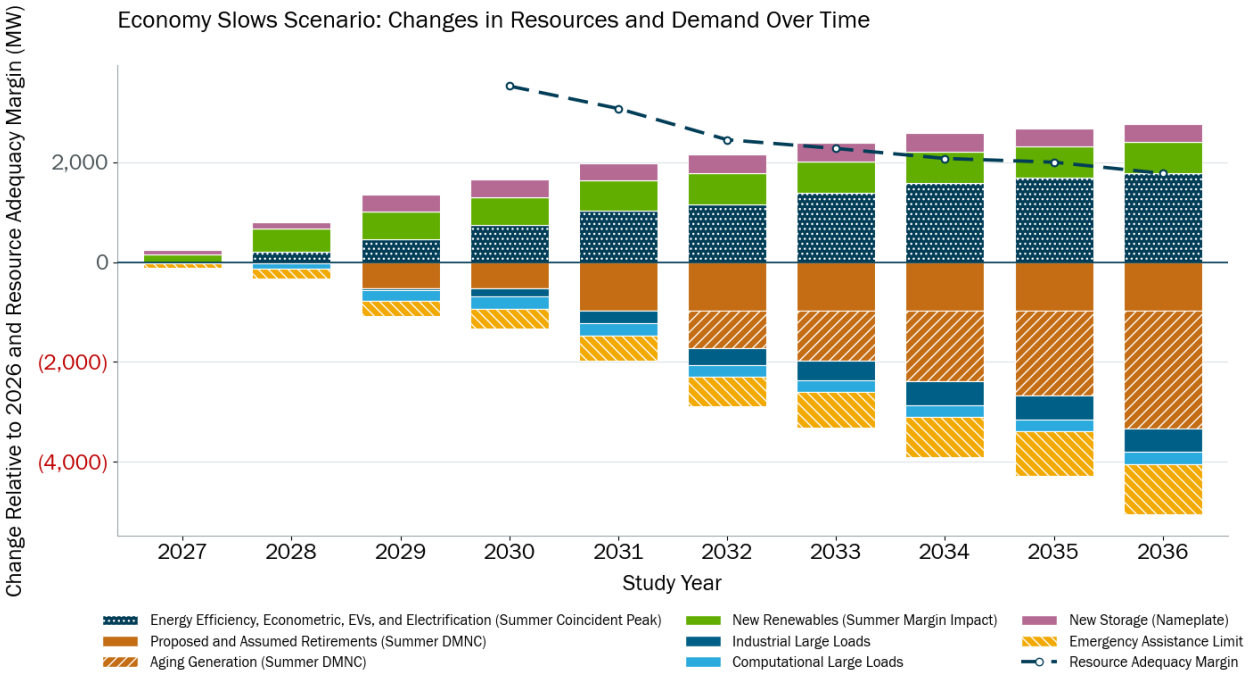
1. The lower demand forecast in the 2026 Gold Book is used for non-large load demand. Compared to the Base Case, this reduces statewide coincident summer peak demand by roughly 1,975 MW in 2036.
2. The lower demand forecast in the 2026 Gold Book is used for large load demand. Compared to the RNA Base Case, this reduces statewide coincident summer peak demand by roughly 1,475 MW in 2036.

The last assumption considers the effect of delays in planned resources due to supply chain constraint on generator project schedules.

3. Generator project commercial operations dates are adjusted such that the mean delay between cost allocation and commercial operation is the minimum delay for each resource type. This delays the entry of about 850 MW of planned projects between one (1) and five (5) years from the commercial operation date assumed in the Base Case.

Figure 59 shows how the resources and demand in this Scenario change throughout the planning horizon.

Figure 59: Economy Slows Scenario Change in Assumption Over Time



Resource Adequacy analysis was conducted for the Economy Slows Scenario. Figure 60 summarizes the Resource Adequacy metrics in this Scenario, together with the Base Case for comparison. Despite assuming that planned projects would be delayed, the Economy Slows Scenario shows that statewide resource adequacy would be sufficient in all planning years with reduced load growth. Figure 60 shows that the resource adequacy margin remains positive, reaching 1,775 MW by 2036, and that LOLE remains below the 0.1 event-day/year criterion

Figure 60: Economy Slows Scenario Resource Adequacy Results

Study Year	Base Case			Economy Slows		
	LOLE (event-days/yr)	EUE (MWh/yr)	Resource Adequacy Margin (MW)	LOLE (event-days/yr)	EUE (MWh/yr)	Resource Adequacy Margin (MW)
2030	0.019	26	1,975	0.004	4	3,525
2031	0.036	65	1,200	0.007	7	3,075
2032	0.074	170	350	0.011	16	2,450
2033	0.115	311	-225	0.017	27	2,275
2034	0.182	524	-725	0.017	25	2,075
2035	0.290	877	-1,175	0.016	25	2,000
2036	0.596	1,823	-1,850	0.018	26	1,775

The transmission security margin results for the Economy Slows Scenario are provided in Figure 61 through Figure 66.

For the Lower Hudson Valley, the Economy Slows Scenario shows positive margins with the exception of the summer peak transmission security margin in 2036. The magnitude of the deficiency is small at 75 MW. If left unaddressed, deficiencies would span one hour on the peak summer day. Since 2036 is the first year of the deficiency and given its size, there would likely be time to consider whether this deficiency would still exist as the system evolves.

For New York City, deficiencies occur earlier than year 10 for the Economy Slows Scenario, starting in year 2033, one year later than the Base Case. Figure 62 and Figure 63 demonstrates that this deficiency would grow to 1,050 MW by 2036. The winter peak transmission security margin is sufficient in all planning years, which narrows to 125 MW by 2036.

For Long Island, sufficient summer and winter margins were found.

Figure 61: Economy Slows Scenario Lower Hudson Valley Summer Peak Transmission Security Margin

Economy Slows Scenario - Lower Hudson Valley Transmission Security Margin Summer Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	G-J Demand Forecast	(15,443)	(15,466)	(15,523)	(15,562)	(15,609)	(15,647)	(15,675)	(15,706)	(15,781)	(15,874)
SC.1	Impact of Lower Demand Forecast Assumption (Non-Large Load)	183	226	291	388	551	621	721	834	955	1,098
SC.2	Impact of Lower Deamand Forecast Assumption (Large Loads)	100	100	130	133	146	150	154	159	165	169
B	RECO Demand	(414)	(414)	(414)	(410)	(410)	(410)	(410)	(410)	(420)	(420)
C	**Total Demand (A+B +SC.1+SC.2)**	(15,574)	(15,554)	(15,516)	(15,451)	(15,322)	(15,286)	(15,210)	(15,123)	(15,081)	(15,027)
D	UPNY-SENY Limit (4)	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY (Impacted by Scenario)	(134)	(33)	(53)	(38)	(18)	(235)	(296)	(306)	(406)	(428)
G	**Total SENY AC Import (D+E+F)**	4,680	4,781	4,761	4,776	4,796	4,579	4,518	4,508	4,408	4,386
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(10,894)	(10,773)	(10,755)	(10,675)	(10,526)	(10,707)	(10,692)	(10,615)	(10,673)	(10,641)
J	G-J Generation (1)	12,852	13,767	13,262	13,262	12,864	12,864	12,864	12,864	12,864	12,864
K	G-J Thermal Generation Unavailability - Aging	0	0	0	0	0	(445)	(648)	(1,038)	(1,131)	(1,720)
L	G-J Thermal Generation Unavailability - EFORd (2)	(1,358)	(1,358)	(1,317)	(1,317)	(1,285)	(1,248)	(1,231)	(1,200)	(1,192)	(1,145)
M	G-J Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
N	G-J Renewable Generation Unavailability - Dispatch Assumptions (3)	(162)	(983)	(983)	(983)	(983)	(983)	(991)	(991)	(991)	(991)
SC.3	Impact of Delayed Generation (With Dispatch Assumptions)	(3)	(3)	(3)	(3)	(3)	0	0	0	0	0
O	SCRs	0	0	0	0	0	0	0	0	0	0
P	Net ICAP External Imports (5)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Q	**Total Resources Available (J+K+L+M+N+SC.3+O+P)**	12,718	12,813	12,348	12,348	11,982	11,578	11,383	11,025	10,939	10,398
R	**Economy Slows Scenario Noncoincident Peak Transmission Security Margin (I+Q)**	1,824	2,040	1,593	1,672	1,456	871	691	410	266	(243)
S	Battery Storage MW	118	168	168	168	168	168	168	168	168	168
SC.4	Battery Storage MW (Impact of Delays)	(15)	(50)	0	0	0	0	0	0	0	0
T	Battery Storage MW Discharge at Locality Noncoincident Peak Hour	0	0	0	0	0	0	0	168	168	168
U	**Economy Slows Scenario Noncoincident Peak Transmission Security Margin with Batteries (R+T)**	1,824	2,040	1,593	1,672	1,456	871	691	578	434	(75)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c). Derates for run-of-river hydro are included.
4. Limits for 2027 through 2036 are based on summer peak 2027, 2031, and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item R are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item S, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 62: Economy Slows Scenario Lower Hudson Valley Winter Peak Transmission Security Margin

Economy Slows Scenario - Lower Hudson Valley Transmission Security Margin Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	G-J Demand Forecast	(11,003)	(11,114)	(11,234)	(11,391)	(11,539)	(11,705)	(11,850)	(12,024)	(12,240)	(12,499)
SC.1	Impact of Lower Demand Forecast Assumption (Non-Large Load)	145	232	308	439	529	642	734	850	1,016	1,221
SC.2	Impact of Lower Deamand Forecast Assumption (Large Loads)	100	100	130	133	146	150	154	159	165	169
B	RECO Demand	(253)	(253)	(253)	(273)	(273)	(273)	(273)	(273)	(305)	(305)
C	**Total Demand (A+B +SC.1+SC.2)**	(11,011)	(11,035)	(11,049)	(11,092)	(11,137)	(11,186)	(11,235)	(11,288)	(11,364)	(11,414)
D	UPNY-SENY Limit (4)	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY (Impacted by Scenario)	(33)	(33)	(33)	1,700	1,700	1,567	1,522	1,474	1,326	1,250
G	**Total SENY AC Import (D+E+F)**	4,856	4,856	4,856	6,589	6,589	6,456	6,411	6,363	6,215	6,139
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(6,155)	(6,179)	(6,193)	(4,503)	(4,548)	(4,730)	(4,824)	(4,925)	(5,149)	(5,275)
J	G-J Generation (1)	14,681	14,681	14,029	13,618	13,618	13,618	13,618	13,618	13,618	13,618
K	G-J Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(2,141)	(2,141)	(2,141)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)
L	G-J Thermal Generation Unavailability - Aging	0	0	0	0	0	(276)	(459)	(834)	(909)	(1,475)
M	G-J Thermal Generation Unavailability - EFORd (2)	(1,274)	(1,274)	(1,222)	(1,222)	(1,222)	(1,197)	(1,182)	(1,152)	(1,146)	(1,100)
N	G-J Renewable Generation Unavailability - Dispatch Assumptions (3)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)
SC.3	Impact of Delayed Generation (With Dispatch Assumptions)	0	0	0	0	0	0	0	0	0	0
O	SCRs	0	0	0	0	0	0	0	0	0	0
P	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
Q	**Total Resources Available (J+K+L+M+N+SC.3+O+P)**	10,499	10,499	9,899	9,899	9,899	9,648	9,480	9,135	9,066	8,546
R	**Economy Slows Scenario Noncoincident Peak Transmission Security Margin (I+Q)**	4,344	4,320	3,706	5,396	5,351	4,918	4,656	4,210	3,918	3,271
S	Battery Storage MW	118	168	168	168	168	168	168	168	168	168
SC.4	Battery Storage MW (Impact of Delays)	(15)	(50)	0	0	0	0	0	0	0	0
T	Battery Storage MW Discharge at Locality Noncoincident Peak Hour	0	0	0	0	0	0	0	0	0	0
U	**Economy Slows Noncoincident Peak Transmission Security Margin with Batteries (R+T)**	4,344	4,320	3,706	5,396	5,351	4,918	4,656	4,210	3,918	3,271

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour.
4. Limits for 2027 through 2036 are based on winter peak 2027, 2031, and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item R are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item S, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 63: Economy Slows Scenario New York City Summer Peak Transmission Security Margin

Economy Slows Scenario New York City Transmission Security Margin Summer Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
	Item	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	Zone J Demand Forecast	(11,100)	(11,120)	(11,140)	(11,170)	(11,200)	(11,230)	(11,250)	(11,270)	(11,320)	(11,380)
SC.1	Impact of Lower Demand Forecast Assumption (Non-Large Load)	140	170	220	290	410	460	530	620	700	800
SC.2	**Total Demand (A+SC.1)**	(10,960)	(10,950)	(10,920)	(10,880)	(10,790)	(10,770)	(10,720)	(10,650)	(10,620)	(10,580)
B	I+K to J (4)	4,725	4,725	4,725	4,825	4,825	4,825	4,825	4,825	4,825	4,825
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	4,714	4,714	4,714	4,814	4,814	4,814	4,814	4,814	4,814	4,814
E	Loss of Source Contingency	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)
F	**Resource Need (SC.2+D+E)**	(8,484)	(8,474)	(8,444)	(8,304)	(8,214)	(8,194)	(8,144)	(8,074)	(8,044)	(8,004)
G	J Generation (1)	8,655	9,521	9,015	9,015	8,617	8,617	8,617	8,617	8,617	8,617
H	J Thermal Generation Unavailability - Aging	0	0	0	0	0	(423)	(624)	(1,011)	(1,102)	(1,688)
I	J Thermal Generation Unavailability - EFORd (2)	(688)	(688)	(647)	(647)	(615)	(581)	(565)	(534)	(526)	(479)
J	J Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
K	J Renewable Generation Unavailability - Dispatch Assumptions (3)	(115)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)
SC.3	Impact of Delayed Generation (With Dispatch Assumptions)	0	0	0	0	0	0	0	0	0	0
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
N	**Total Resources Available (G+H+I+J+K+SC.3+L+M)**	9,242	9,324	8,859	8,859	8,493	8,103	7,919	7,562	7,479	6,940
O	**Economy Slows Scenario Noncoincident Peak Transmission Security Margin (F+N)**	758	850	415	555	279	(91)	(225)	(512)	(565)	(1,064)
P	Battery Storage MW	115	165	165	165	165	165	165	165	165	165
SC.4	Battery Storage MW (Impact of Delays)	(15)	(50)	0	0	0	0	0	0	0	0
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour	0	0	0	0	0	91	165	165	165	0
R	**Economy Slows Scenario Noncoincident Peak Transmission Security Margin with Batteries (O+Q)**	758	850	415	555	279	0	(61)	(347)	(400)	(1,064)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c). This portion of the margin calculation assumes storage is offline. See later section for storage details.
4. Limits for 2027 through 2029 are based on summer peak 2027 representations evaluated in the 2026 RNA. Limits for 2030 through 2036 are based on summer peak 2031 and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 64: Economy Slows Scenario New York City Winter Peak Transmission Security Margin

Economy Slows Scenario New York City Transmission Security Margin Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
	Item	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	Zone J Demand Forecast	(7,750)	(7,800)	(7,860)	(7,960)	(8,050)	(8,160)	(8,260)	(8,380)	(8,520)	(8,690)
SC.1	Impact of Lower Demand Forecast Assumption (Non-Large Load)	80	120	170	250	300	370	430	510	610	740
SC.2	**Total Demand (A+SC.1)**	(7,670)	(7,680)	(7,690)	(7,710)	(7,750)	(7,790)	(7,830)	(7,870)	(7,910)	(7,950)
B	I+K to J (4)	3,800	3,800	3,800	3,875	3,875	3,875	3,875	3,875	3,875	3,875
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	3,789	3,789	3,789	3,864	3,864	3,864	3,864	3,864	3,864	3,864
E	Loss of Source Contingency	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)
F	**Resource Need (SC.2+D+E)**	(4,858)	(4,868)	(4,878)	(4,823)	(4,863)	(4,903)	(4,943)	(4,983)	(5,023)	(5,063)
G	J Generation (1)	10,255	10,255	9,603	9,192	9,192	9,192	9,192	9,192	9,192	9,192
H	J Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(2,062)	(2,062)	(2,062)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)
I	J Thermal Generation Unavailability - Aging	0	0	0	0	0	(249)	(428)	(801)	(872)	(1,435)
J	J Thermal Generation Unavailability - EFORd (2)	(587)	(587)	(535)	(535)	(535)	(515)	(500)	(470)	(465)	(419)
K	J Renewable Generation Unavailability - Dispatch Assumptions (3)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)
SC.3	Impact of Delayed Generation (With Dispatch Assumptions)	0	0	0	0	0	0	0	0	0	0
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
N	**Total Resources Available (G+H+I+J+K+SC.3+L+M)**	6,929	6,929	6,329	6,329	6,329	6,100	5,935	5,593	5,527	5,009
O	**Economy Slows Scenario Noncoincident Peak Transmission Security Margin (F+N)**	2,071	2,061	1,451	1,506	1,466	1,197	992	610	504	(54)
P	Battery Storage MW	115	165	165	165	165	165	165	165	165	165
SC.4	Battery Storage MW (Impact of Delays)	(15)	(50)	0	0	0	0	0	0	0	0
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour	0	0	0	0	0	91	0	0	0	54
R	**Economy Slows Scenario Noncoincident Peak Transmission Security Margin with Batteries (O+Q)**	2,071	2,061	1,451	1,506	1,466	1,288	992	610	504	0

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour.
4. Limits for 2027 through 2029 are based on winter peak 2027 representations evaluated in the 2026 RNA. Limits for 2030 through 2036 are based on winter peak 2031 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 65: Economy Slows Scenario Long Island Summer Peak Transmission Security Margin

Economy Slows Scenario Long Island Transmission Security Margin Summer Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone K Demand Forecast**	(5,136)	(5,161)	(5,200)	(5,252)	(5,310)	(5,357)	(5,392)	(5,416)	(5,438)	(5,462)
SC.1	Impact of Lower Demand Forecast Assumption (Non-Large Load)	74	111	153	190	239	255	281	312	353	403
SC.2	Impact of Lower Demand Forecast Assumption (Large Load)	1	7	29	69	113	150	174	184	187	187
SC.3	**Total Demand (A+SC.1+SC.2)**	(5,061)	(5,043)	(5,018)	(4,993)	(4,958)	(4,952)	(4,937)	(4,920)	(4,898)	(4,872)
B	I+J to K (4)	950	950	950	2,900	2,900	2,900	2,900	2,900	2,900	2,900
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	950	950	950	2,900	2,900	2,900	2,900	2,900	2,900	2,900
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	**Resource Need (SC.3+D+E)**	(4,771)	(4,753)	(4,728)	(2,753)	(2,718)	(2,712)	(2,697)	(2,680)	(2,658)	(2,632)
G	K Generation (1)	4,924	5,848	5,848	5,848	5,803	5,803	5,803	5,803	5,803	5,803
H	K Thermal Generation Unavailability - Aging	0	0	0	0	0	(272)	(307)	(340)	(485)	(548)
I	K Thermal Generation Unavailability - EFORd (2)	(580)	(580)	(580)	(580)	(575)	(542)	(537)	(533)	(515)	(508)
J	K Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
K	K Renewable Generation Unavailability - Dispatch Assumptions (3)	(159)	(990)	(999)	(999)	(999)	(999)	(999)	(999)	(999)	(999)
SC.4	Impact of Delayed Generation (With Dispatch Assumptions)	0	0	0	0	0	0	0	0	0	0
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	660	660	660	660	660	660	660	660	660	660
N	**Total Resources Available (G+H+I+J+K+SC.4+L+M)**	4,845	4,937	4,928	4,928	4,889	4,650	4,619	4,590	4,463	4,408
O	**Economy Slows Scenario Noncoincident Peak Transmission Security Margin (F+N)**	74	184	200	2,175	2,171	1,938	1,922	1,910	1,805	1,776
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour	0	0	0	0	0	0	0	0	0	0
R	**Economy Slows Scenario Peak Transmission Security Margin with Batteries (O+Q)**	74	184	200	2,175	2,171	1,938	1,922	1,910	1,805	1,776

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c).
4. Limits for 2027 through 2029 are based on the 2025 LIPA Summer Operating Study. Limits for 2030 through 2036 are based on the 2031 summer peak representations evaluated in the 2026RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 66: Economy Slows Scenario Long Island Winter Peak Transmission Security Margin

Economy Slows Scenario Long Island Transmission Security Margin Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone K Demand Forecast**	(3,325)	(3,412)	(3,530)	(3,635)	(3,739)	(3,832)	(3,918)	(4,001)	(4,088)	(4,190)
SC.1	Impact of Lower Demand Forecast Assumption (Non-Large Load)	77	116	193	226	271	333	390	449	521	605
SC.2	Impact of Lower Demand Forecast Assumption (Large Load)	3	36	71	136	189	219	236	243	244	244
SC.3	**Total Demand (A+SC.1+SC.2)**	(3,245)	(3,260)	(3,266)	(3,273)	(3,279)	(3,280)	(3,292)	(3,309)	(3,323)	(3,341)
B	I+J to K (4)	350	350	350	3,125	3,125	3,125	3,125	3,125	3,125	3,125
C	New England Import (NNC)	-	-	-	-	-	-	-	-	-	-
D	**Total K AC Import (B+C)**	350	350	350	3,125	3,125	3,125	3,125	3,125	3,125	3,125
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	**Resource Need (SC.3+D+E)**	(3,555)	(3,570)	(3,576)	(808)	(814)	(815)	(827)	(844)	(858)	(876)
G	K Generation (1)	6,290	6,290	6,290	6,244	6,244	6,244	6,244	6,244	6,244	6,244
H	K Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(374)	(374)	(374)	(328)	(328)	(328)	(328)	(328)	(328)	(328)
I	K Thermal Generation Unavailability - Aging	0	0	0	0	0	(290)	(328)	(363)	(515)	(581)
J	K Thermal Generation Unavailability - EFORd (2)	(589)	(589)	(589)	(589)	(589)	(553)	(549)	(544)	(526)	(518)
K	K Renewable Generation Unavailability - Dispatch Assumptions (3)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)
SC.4	Impact of Delayed Generation (With Dispatch Assumptions)	0	0	0	0	0	0	0	0	0	0
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	660	660	660	660	660	660	660	660	660	660
N	**Total Resources Available (G+H+I+J+K+SC.4+L+M)**	5,088	5,088	5,088	5,088	5,088	4,834	4,801	4,770	4,636	4,578
O	**Economy Slows Scenario Noncoincident Peak Transmission Security Margin (F+N)**	1,533	1,518	1,512	4,280	4,274	4,019	3,974	3,926	3,778	3,702
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour	0	0	0	0	0	0	0	0	0	0
R	**Economy Slows Scenario Peak Transmission Security Margin with Batteries (O+Q)**	1,533	1,518	1,512	4,280	4,274	4,019	3,974	3,926	3,778	3,702

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. For winter solar PV output at peak is 0 MW.
4. Limits for 2027 through 2029 are based on the 2025 LIPA Summer Operating Study. As a conservative assumption summer values are used for LIPA Import limits with one line out. Limits for 2030 through 2036 are based on the
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

IBR Voltage Control

The Inverter-Based Resource (IBR) Voltage Control Scenario, or Scenario H, looks at a future where asynchronous generation, which relies on power electronics to convert DC power to AC, replaces synchronous generation, which rotates with the 60 Hz grid frequency. In this future, the new inverter-based technology is relied on to control system voltage. The first two assumptions look at the expanded connection and voltage control settings of inverter-based resources.

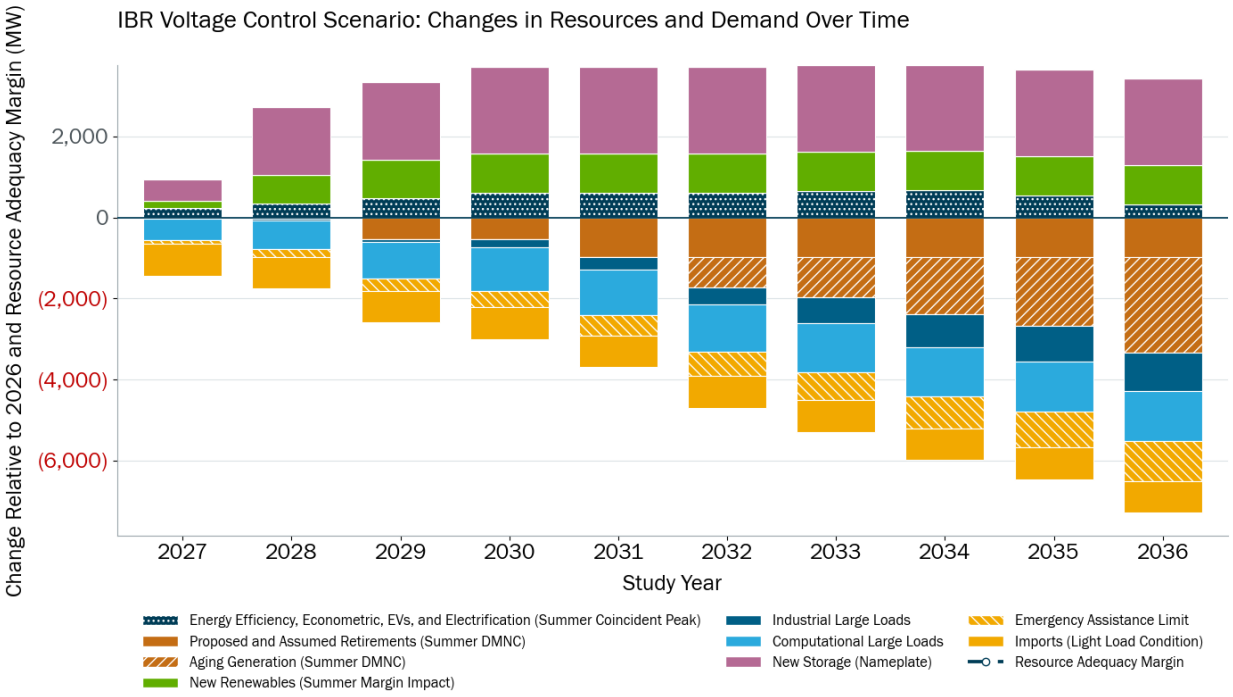
1. The inclusion of planned generator projects is adjusted such that any planned generation that has accepted its cost allocation in NYISO's interconnection process is included. Compared to the RNA Base Case, this adds roughly 3,000 MW nameplate of intermittent resources and 1,700 MW nameplate of storage by 2036.
2. The reactive capability of inverter-based resources is set at the minimum requirement. This means that IBR reactive power output will be proportional to the available real power, rather than the maximum real power.

The second set of assumptions set up a system condition in which the added inverter-based resources would be controlling system voltage and reflect an operational trend in system flows during lightly loaded conditions.

3. Land-based wind is assumed to have 30% of its dependable maximum net capability available in a spring light load condition, which is above the 15% assumed in the Base Case. This increase in wind results in less synchronous generation being dispatched.
4. An export to Hydro-Québec of 1,100 MW over the Chateaugay HVDC line is assumed versus 0 MW in the Base Case, along with an increase in imports from PJM of 965 MW, compared to 643 MW in the Base Case. This creates a South-North flow that has become more prevalent in recent operational history.

Figure 67 shows how the assumptions in this Scenario change throughout the planning horizon.

Figure 67: IBR Voltage Control Scenario Change in Assumption Over Time



Resource adequacy analysis was not conducted given the nature of this Scenario. Transmission Security analysis for the IBR Voltage Control Scenario was conducted for a 2036 light load system condition. No new transmission security violations were identified for the IBR Voltage Control scenario.

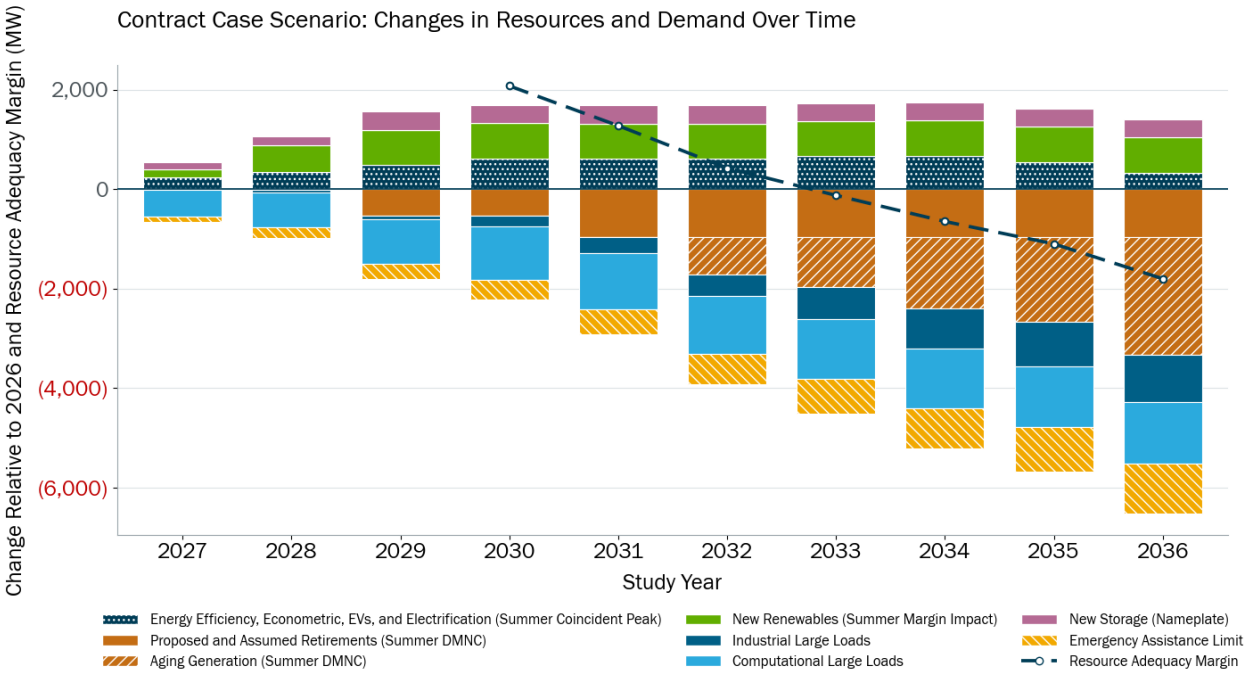
Outlook Contract Scenario

The Outlook Contract Scenario, or Scenario J, represents the future represented in Contract Case for NYISO's 2025-2044 System and Resource Outlook. To achieve this, the inclusion rules for planned generation and transmission projects are adjusted from the Base Case as follows:

1. For planned generation projects, any project with a Tier-1 REC or OREC contract from NYSERDA is included, even if it did not meet other inclusion considerations and progress milestones for the Base Case. This adds about 700 MW nameplate of additional renewable generation by 2036.
2. All Phase 1 and Phase 2 CLCPA local transmission projects are included, even if they did not meet other inclusion considerations and progress milestones for the Base Case.

Taken together, these two assumptions bridge the major differences between the RNA Base Case inclusion rules and the System and Resource Outlook Contract Case assumptions. Figure 68 shows how the resources and demand assumptions in this Scenario change throughout the planning horizon.

Figure 68: Outlook Contract Scenario Change in Assumption Over Time



Resource Adequacy analysis was conducted for the Outlook Contract Scenario. Figure 69 summarizes Resource Adequacy metrics in this Scenario, together with the Base Case for comparison. Despite the addition of 700 MW of nameplate generation compared to the Base Case, the 2036 resource adequacy margin only improves to -1,800 MW from -1,850 MW. This highlights the impact of intermittency on the system, where intermittent resources may provide substantially lower perfect capacity than their nameplate.

Figure 69: Outlook Contract Scenario Resource Adequacy Results

Study Year	Base Case			Contract Case		
	LOLE (event-days/yr)	EUE (MWh/yr)	Resource Adequacy Margin (MW)	LOLE (event-days/yr)	EUE (MWh/yr)	Resource Adequacy Margin (MW)
2030	0.019	26	1,975	0.017	23	2,075
2031	0.036	65	1,200	0.032	58	1,275
2032	0.074	170	350	0.068	155	425
2033	0.115	311	-225	0.107	282	-125
2034	0.182	524	-725	0.171	480	-650
2035	0.290	877	-1,175	0.274	808	-1,100
2036	0.596	1,823	-1,850	0.569	1,703	-1,800

The transmission security margin results for the Outlook Contract Scenario are provided in Figure 70 through Figure 75. The transmission security margin results in the Outlook Contract Scenario did not change in magnitude or the first year of violation compared to the Base Case.

Figure 70: Outlook Contract Scenario Lower Hudson Valley Summer Peak Transmission Security Margin

Outlook Contract Scenario Lower Hudson Valley Transmission Security Margin Summer Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	G-J Noncoincident Peak Demand Forecast	(15,443)	(15,466)	(15,523)	(15,562)	(15,609)	(15,647)	(15,675)	(15,706)	(15,781)	(15,874)
B	RECO Demand	(414)	(414)	(414)	(410)	(410)	(410)	(410)	(410)	(420)	(420)
C	**Total Demand (A+B)**	(15,857)	(15,880)	(15,937)	(15,972)	(16,019)	(16,057)	(16,085)	(16,116)	(16,201)	(16,294)
D	UPNY-SENY Limit (4)	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	(208)	(141)	(234)	(296)	(367)	(635)	(749)	(799)	(943)	(1,014)
G	**Total SENY AC Import (D+E+F)**	4,606	4,673	4,580	4,518	4,447	4,179	4,065	4,015	3,871	3,800
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(11,251)	(11,207)	(11,357)	(11,454)	(11,572)	(11,878)	(12,020)	(12,101)	(12,330)	(12,494)
J	G-J Generation (1)	12,852	13,767	13,262	13,262	12,864	12,864	12,864	12,864	12,864	12,864
K	G-J Thermal Generation Unavailability - Aging	0	0	0	0	0	(445)	(648)	(1,038)	(1,131)	(1,720)
L	G-J Thermal Generation Unavailability - EFORd (2)	(1,358)	(1,358)	(1,317)	(1,317)	(1,285)	(1,248)	(1,231)	(1,200)	(1,192)	(1,145)
M	G-J Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
N	G-J Renewable Generation Unavailability - Dispatch Assumptions (3)	(162)	(983)	(983)	(983)	(983)	(983)	(991)	(991)	(991)	(991)
O	SCRs	0	0	0	0	0	0	0	0	0	0
P	Net ICAP External Imports (5)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Q	**Total Resources Available (J+K+L+M+N+O+P)**	12,721	12,816	12,351	12,351	11,985	11,578	11,383	11,025	10,939	10,398
R	**Outlook Contract Scenario Noncoincident Peak Transmission Security Margin (I+Q)**	1,470	1,609	994	897	413	(300)	(637)	(1,076)	(1,391)	(2,096)
S	Battery Storage MW	118	168	168	168	168	168	168	168	168	168
T	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (6)	0	0	0	0	0	168	168	168	168	134
U	**Outlook Contract Scenario Noncoincident Peak Transmission Security Margin with Batteries (R+T)**	1,470	1,609	994	897	413	(132)	(469)	(908)	(1,223)	(1,962)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c). Derates for run-of-river hydro are included.
4. Limits for 2027 through 2036 are based on summer peak 2027, 2031, and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item R are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item S, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 71: Outlook Contract Scenario Lower Hudson Valley Winter Peak Transmission Security Margin

Outlook Contract Scenario Lower Hudson Valley Transmission Security Margin Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	G-J Noncoincident Peak Demand Forecast	(11,003)	(11,114)	(11,234)	(11,391)	(11,539)	(11,705)	(11,850)	(12,024)	(12,240)	(12,499)
B	RECO Demand	(253)	(253)	(253)	(273)	(273)	(273)	(273)	(273)	(305)	(305)
C	**Total Demand (A+B)**	(11,256)	(11,367)	(11,487)	(11,664)	(11,812)	(11,978)	(12,123)	(12,297)	(12,545)	(12,804)
D	UPNY-SENY Limit (4)	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	(33)	(33)	(33)	1,467	1,364	1,017	899	785	564	405
G	**Total SENY AC Import (D+E+F)**	4,856	4,856	4,856	6,356	6,253	5,906	5,788	5,674	5,453	5,294
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(6,400)	(6,511)	(6,631)	(5,308)	(5,559)	(6,072)	(6,335)	(6,623)	(7,092)	(7,510)
J	G-J Generation (1)	14,681	14,681	14,029	13,618	13,618	13,618	13,618	13,618	13,618	13,618
K	G-J Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(2,141)	(2,141)	(2,141)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)
L	G-J Thermal Generation Unavailability - Aging	0	0	0	0	0	(276)	(459)	(834)	(909)	(1,475)
M	G-J Thermal Generation Unavailability - EFORd (2)	(1,274)	(1,274)	(1,222)	(1,222)	(1,222)	(1,197)	(1,182)	(1,152)	(1,146)	(1,100)
N	G-J Renewable Generation Unavailability - Dispatch Assumptions (3)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)
O	SCRs	0	0	0	0	0	0	0	0	0	0
P	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
Q	**Total Resources Available (J+K+L+M+N+O+P)**	10,499	10,499	9,899	9,899	9,899	9,648	9,480	9,135	9,066	8,546
R	**Outlook Contract Scenario Noncoincident Peak Transmission Security Margin (I+Q)**	4,099	3,988	3,268	4,592	4,341	3,576	3,145	2,512	1,975	1,036
S	Battery Storage MW	168	168	168	168	168	168	168	168	168	168
T	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (7)	0	0	0	0	0	0	0	0	0	0
U	**Outlook Contract Noncoincident Peak Transmission Security Margin with Batteries (R+T)**	4,099	3,988	3,268	4,592	4,341	3,576	3,145	2,512	1,975	1,036

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour.
4. Limits for 2027 through 2036 are based on winter peak 2027, 2031, and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item R are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item S, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 72: Outlook Contract Scenario New York City Summer Peak Transmission Security Margin

	Outlook Contract Scenario New York City Transmission Security Margin Summer Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)										
	Item	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone J Noncoincident Peak Demand Forecast**	(11,100)	(11,120)	(11,140)	(11,170)	(11,200)	(11,230)	(11,250)	(11,270)	(11,320)	(11,380)
B	I+K to J (4)	4,725	4,725	4,725	4,825	4,825	4,825	4,825	4,825	4,825	4,825
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	4,714	4,714	4,714	4,814	4,814	4,814	4,814	4,814	4,814	4,814
E	Loss of Source Contingency	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)
F	**Resource Need (A+D+E)**	(8,624)	(8,644)	(8,664)	(8,594)	(8,624)	(8,654)	(8,674)	(8,694)	(8,744)	(8,804)
G	J Generation (1)	8,655	9,521	9,015	9,015	8,617	8,617	8,617	8,617	8,617	8,617
H	J Thermal Generation Unavailability - Aging	0	0	0	0	0	(423)	(624)	(1,011)	(1,102)	(1,688)
I	J Thermal Generation Unavailability - EFORd (2)	(688)	(688)	(647)	(647)	(615)	(581)	(565)	(534)	(526)	(479)
J	J Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
K	J Renewable Generation Unavailability - Dispatch Assumptions (3)	(115)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
N	**Total Resources Available (G+H+I+J+K+L+M)**	9,242	9,324	8,859	8,859	8,493	8,103	7,919	7,562	7,479	6,940
O	**Outlook Contract Scenario Noncoincident Peak Transmission Security Margin (F+N)**	618	680	195	265	(131)	(551)	(755)	(1,132)	(1,265)	(1,864)
P	Battery Storage MW	115	165	165	165	165	165	165	165	165	165
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (6)	0	0	0	0	132	155	0	0	0	0
R	**Outlook Contract Scenario Noncoincident Peak Transmission Security Margin with Batteries (O+Q)**	618	680	195	265	0	(396)	(755)	(1,132)	(1,265)	(1,864)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c). This portion of the margin calculation assumes storage is offline. See later section for storage details.
4. Limits for 2027 through 2029 are based on summer peak 2027 representations evaluated in the 2026 RNA. Limits for 2030 through 2036 are based on summer peak 2031 and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 73: Outlook Contract Scenario New York City Winter Peak Transmission Security Margin

Outlook Contract Scenario New York City Transmission Security Margin Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
	Item	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone J Noncoincident Peak Demand Forecast**	(7,750)	(7,800)	(7,860)	(7,960)	(8,050)	(8,160)	(8,260)	(8,380)	(8,520)	(8,690)
B	I+K to J (4)	3,800	3,800	3,800	3,875	3,875	3,875	3,875	3,875	3,875	3,875
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	3,789	3,789	3,789	3,864	3,864	3,864	3,864	3,864	3,864	3,864
E	Loss of Source Contingency	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)
F	**Resource Need (A+D+E)**	(4,938)	(4,988)	(5,048)	(5,073)	(5,163)	(5,273)	(5,373)	(5,493)	(5,633)	(5,803)
G	J Generation (1)	10,255	10,255	9,603	9,192	9,192	9,192	9,192	9,192	9,192	9,192
H	J Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(2,062)	(2,062)	(2,062)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)
I	J Thermal Generation Unavailability - Aging	0	0	0	0	0	(249)	(428)	(801)	(872)	(1,435)
J	J Thermal Generation Unavailability - EFORd (2)	(587)	(587)	(535)	(535)	(535)	(515)	(500)	(470)	(465)	(419)
K	J Renewable Generation Unavailability - Dispatch Assumptions (3)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
N	**Total Resources Available (G+H+I+J+K+L+M)**	6,929	6,929	6,329	6,329	6,329	6,100	5,935	5,593	5,527	5,009
O	**Outlook Contract Scenario Noncoincident Peak Transmission Security Margin (F+N)**	1,991	1,941	1,281	1,256	1,166	827	562	100	(106)	(794)
P	Battery Storage MW	165	165	165	165	165	165	165	165	165	165
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (7)	0	0	0	0	0	0	0	0	107	0
R	**Outlook Contract Scenario Noncoincident Peak Transmission Security Margin with Batteries (O+Q)**	1,991	1,941	1,281	1,256	1,166	827	562	100	1	(794)

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour.
4. Limits for 2027 through 2029 are based on winter peak 2027 representations evaluated in the 2026 RNA. Limits for 2030 through 2036 are based on winter peak 2031 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 74: Outlook Contract Scenario Long Island Summer Peak Transmission Security Margin

Outlook Contract Scenario Long Island Transmission Security Margin Summer Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone K Noncoincident Peak Demand Forecast**	(5,136)	(5,161)	(5,200)	(5,252)	(5,310)	(5,357)	(5,392)	(5,416)	(5,438)	(5,462)
B	I+J to K (4)	950	950	950	2,900	2,900	2,900	2,900	2,900	2,900	2,900
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	950	950	950	2,900	2,900	2,900	2,900	2,900	2,900	2,900
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	**Resource Need (A+D+E)**	(4,846)	(4,871)	(4,910)	(3,012)	(3,070)	(3,117)	(3,152)	(3,176)	(3,198)	(3,222)
G	K Generation (1)	4,924	5,848	5,848	5,848	5,803	5,803	5,803	5,803	5,803	5,803
H	K Thermal Generation Unavailability - Aging	0	0	0	0	0	(272)	(307)	(340)	(485)	(548)
I	K Thermal Generation Unavailability - EFORd (2)	(580)	(580)	(580)	(580)	(575)	(542)	(537)	(533)	(515)	(508)
J	K Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
K	K Renewable Generation Unavailability - Dispatch Assumptions (3)	(159)	(990)	(999)	(999)	(999)	(999)	(999)	(999)	(999)	(999)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	660	660	660	660	660	660	660	660	660	660
N	**Total Resources Available (G+H+I+J+K+L+M)**	4,845	4,937	4,928	4,928	4,889	4,650	4,619	4,590	4,463	4,408
O	**Outlook Contract Scenario Noncoincident Peak Transmission Security Margin (F+N)**	(1)	66	18	1,916	1,819	1,533	1,467	1,414	1,265	1,186
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
Q	Battery Storage MWh Used on Locality Noncoincident Peak Day (6)	0	0	0	0	0	0	0	0	0	0
R	**Outlook Contract Scenario Noncoincident Peak Transmission Security Margin with Batteries (O+Q)**	(1)	66	18	1,916	1,819	1,533	1,467	1,414	1,265	1,186

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c).
4. Limits for 2027 through 2029 are based on the 2025 LIPA Summer Operating Study. Limits for 2030 through 2036 are based on the 2031 summer peak representations evaluated in the 2026RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 75: Outlook Contract Scenario Long Island Winter Peak Transmission Security Margin

Outlook Contract Scenario Long Island Transmission Security Margin Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone K Noncoincident Peak Demand Forecast**	(3,325)	(3,412)	(3,530)	(3,635)	(3,739)	(3,832)	(3,918)	(4,001)	(4,088)	(4,190)
B	I+J to K (4)	350	350	350	3,125	3,125	3,125	3,125	3,125	3,125	3,125
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	350	350	350	3,125	3,125	3,125	3,125	3,125	3,125	3,125
E	Loss of Source Contingency	0	0	0	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	**Resource Need (A+D+E)**	(2,975)	(3,062)	(3,180)	(1,170)	(1,274)	(1,367)	(1,453)	(1,536)	(1,623)	(1,725)
G	K Generation (1)	6,290	6,290	6,290	6,244	6,244	6,244	6,244	6,244	6,244	6,244
H	K Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(374)	(374)	(374)	(328)	(328)	(328)	(328)	(328)	(328)	(328)
I	K Thermal Generation Unavailability - Aging	0	0	0	0	0	(290)	(328)	(363)	(515)	(581)
J	K Thermal Generation Unavailability - EFORd (2)	(589)	(589)	(589)	(589)	(589)	(553)	(549)	(544)	(526)	(518)
K	K Renewable Generation Unavailability - Dispatch Assumptions (3)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	660	660	660	660	660	660	660	660	660	660
N	**Total Resources Available (G+H+I+J+K+L+M)**	5,088	5,088	5,088	5,088	5,088	4,834	4,801	4,770	4,636	4,578
O	**Outlook Contract Scenario Noncoincident Peak Transmission Security Margin (F+N)**	2,113	2,026	1,908	3,918	3,814	3,467	3,348	3,234	3,013	2,853
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
Q	Battery Storage MWh Used on Locality Noncoincident Peak Day (7)	0	0	0	0	0	0	0	0	0	0
R	**Outlook Contract Scenario Noncoincident Peak Transmission Security Margin with Batteries (O+Q)**	2,113	2,026	1,908	3,918	3,814	3,467	3,348	3,234	3,013	2,853

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. For winter solar PV output at peak is 0 MW.
4. Limits for 2027 through 2029 are based on the 2025 LIPA Summer Operating Study. As a conservative assumption summer values are used for LIPA Import limits with one line out. Limits for 2030 through 2036 are based on the 2030 winter peak representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Other Informational Scenarios

In addition to the Scenarios discussed above, this RNA also considered other informational scenarios that considered extreme conditions or specific assumptions to inform the nature of the violations and potential violations identified in the Base Case and/or test the robustness of the analysis. Specifically, the results of the other informational scenarios identify key risks to reliability and help inform the nature of potential solutions to identified deficiencies within the Base Case. Figure 76 summarizes the LOLE results from resource adequacy analysis on the other informational scenarios together with the result for the Base Case and Scenarios.

Figure 76: LOLE across the Other Informational Scenarios

Case	LOLE Y10 (event-days/yr)	Earliest Violation	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Loss of all Imports	4.245	2028										
Scenario B (Large Loads)	2.780	2029										
Status Quo	2.159	2029										
No Planned Generation Projects	1.591	2029										
Chateaugay/CHPE limits	0.998	2032										
Base Case without Propel NY	0.858	2032										
Scenario A (Climate Policy Advancement)	1.869	2033										
Base Case	0.596	2033										
No Voltage Limited Interfaces	0.594	2033										
Copper Sheet	0.572	2033										
Scenario J (Contract Case)	0.569	2033										
A + 1 GW Nuclear Gen (Zone C)	0.909	2034										
Addtl Flexible Large Loads	0.232	2035										
No Aging Generation	0.100	2036										
No Planned Large Loads	0.075	> 2036										
Scenario C (Economy Slows)	0.018	> 2036										

- LOLE > 1.0 event-days/yr
- 0.1 < LOLE < 1.0 event-days/yr
- 0.05 < LOLE < 0.1 event-days/yr
- LOLE < 0.05 event-days/yr

Status Quo

Within the context of the RNA, the Status Quo scenario demonstrates the importance of planned projects completing on time and providing their planned capability. Planned projects include new generation projects, solutions to address Short-Term Reliability Process Needs, and transmission projects that are important for meeting growing demand over the planning horizon. Specifically, the Status Quo scenario removes approximately 6,200 MW nameplate of future planned projects, including the following major projects:

- The Propel NY Energy – Alternate 5 project, which was selected by the NYISO Board of Directors in 2023 to address the Long Island Offshore Wind Export Public Policy Transmission Need and increases the MARS topology limits (both imports and exports) starting 2030
- Empire Offshore Wind
- Sunrise Offshore Wind

The NYCA LOLE results for this scenario are detailed in Figure 77 and show that the system would be deficient four years earlier when the proposed projects are excluded from the Base Case.

Figure 77: Status Quo Scenario Loss of Load Expectation Results (LOLE, event-days/year))

Study Year	Base Case	Status Quo	Delta
2027	0.025	0.072	0.047
2028	0.032	0.093	0.061
2029	0.034	0.107	0.073
2030	0.019	0.118	0.099
2031	0.036	0.169	0.134
2032	0.074	0.380	0.306
2033	0.115	0.461	0.345
2034	0.182	0.657	0.474
2035	0.290	1.085	0.796
2036	0.596	2.159	1.563

Note: Gradient data bars compare study-year LOLE deltas within each scenario. Longer bars indicate larger impacts relative to other study-year deltas within the same scenario.

Figure 78 through Figure 83 provide the transmission security margin tables for the Status Quo scenario.

Figure 78: Status Quo Scenario Lower Hudson Valley Summer Peak Transmission Security Margin

Lower Hudson Valley Transmission Security Margin Summer Peak - Status Quo System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	G-J Noncoincident Peak Demand Forecast	(15,443)	(15,466)	(15,523)	(15,562)	(15,609)	(15,647)	(15,675)	(15,706)	(15,781)	(15,874)
B	RECO Demand	(414)	(414)	(414)	(410)	(410)	(410)	(410)	(410)	(420)	(420)
C	**Total Demand (A+B)**	(15,857)	(15,880)	(15,937)	(15,972)	(16,019)	(16,057)	(16,085)	(16,116)	(16,201)	(16,294)
D	UPNY-SENY Limit (4)	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	(310)	(335)	(428)	(490)	(561)	(829)	(943)	(993)	(1,119)	(1,189)
G	**Total SENY AC Import (D+E+F)**	4,504	4,479	4,386	4,324	4,253	3,985	3,871	3,821	3,695	3,625
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(11,353)	(11,401)	(11,551)	(11,648)	(11,766)	(12,072)	(12,214)	(12,295)	(12,506)	(12,669)
J	G-J Generation (1)	12,737	12,737	12,231	12,231	11,833	11,833	11,833	11,833	11,833	11,833
K	G-J Thermal Generation Unavailability - Aging	0	0	0	0	0	(445)	(648)	(1,038)	(1,131)	(1,720)
L	G-J Thermal Generation Unavailability - EFORd	(1,358)	(1,358)	(1,317)	(1,317)	(1,285)	(1,248)	(1,231)	(1,200)	(1,192)	(1,145)
M	G-J Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
N	G-J Renewable Generation Unavailability - Dispatch Assumptions (3)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)
O	SCRs	0	0	0	0	0	0	0	0	0	0
P	Net ICAP External Imports (5)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Q	**Total Resources Available (J+K+L+M+N+O+P)**	12,721	12,721	12,256	12,256	11,890	11,483	11,296	10,938	10,852	10,311
R	**Baseline Noncoincident Peak Transmission Security Margin (I+Q)**	1,369	1,321	706	609	124	(589)	(918)	(1,357)	(1,654)	(2,357)
S	Battery Storage MW	3	3	3	3	3	3	3	3	3	3
T	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (6)	0	0	0	0	0	3	3	3	3	0
U	**Noncoincident Peak Transmission Security Margin with Batteries (R+T)**	1,369	1,321	706	609	124	(586)	(915)	(1,354)	(1,651)	(2,357)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included.
4. Limits for 2027 through 2036 are based on summer peak 2027 representation evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.

Figure 79: Status Quo Scenario Lower Hudson Valley Winter Peak Transmission Security Margin

Lower Hudson Valley Transmission Security Margin Winter Peak - Status Quo System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	G-J Noncoincident Peak Demand Forecast	(11,003)	(11,114)	(11,234)	(11,391)	(11,539)	(11,705)	(11,850)	(12,024)	(12,240)	(12,499)
B	RECO Demand	(253)	(253)	(253)	(273)	(273)	(273)	(273)	(273)	(305)	(305)
C	**Total Demand (A+B)**	(11,256)	(11,367)	(11,487)	(11,664)	(11,812)	(11,978)	(12,123)	(12,297)	(12,545)	(12,804)
D	UPNY-SENY Limit (4)	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)
G	**Total SENY AC Import (D+E+F)**	4,856	4,856	4,856	4,856	4,856	4,856	4,856	4,856	4,856	4,856
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(6,400)	(6,511)	(6,631)	(6,808)	(6,956)	(7,122)	(7,267)	(7,441)	(7,689)	(7,948)
J	G-J Generation (1)	13,650	13,650	12,998	12,587	12,587	12,587	12,587	12,587	12,587	12,587
K	G-J Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(2,141)	(2,141)	(2,141)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)
L	G-J Thermal Generation Unavailability - Aging	0	0	0	0	0	(276)	(459)	(834)	(909)	(1,475)
M	G-J Thermal Generation Unavailability - EFORd (2)	(1,274)	(1,274)	(1,222)	(1,222)	(1,222)	(1,197)	(1,182)	(1,152)	(1,146)	(1,100)
N	G-J Renewable Generation Unavailability - Dispatch Assumptions (3)	(39)	(39)	(39)	(39)	(39)	(39)	(39)	(39)	(39)	(39)
O	SCRs	0	0	0	0	0	0	0	0	0	0
P	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
Q	**Total Resources Available (J+K+L+M+N+O+P)**	10,336	10,336	9,736	9,736	9,736	9,484	9,317	8,972	8,903	8,383
R	**Baseline Noncoincident Peak Transmission Security Margin (I+Q)**	3,936	3,825	3,105	2,928	2,780	2,362	2,050	1,531	1,214	435
S	Battery Storage MW	3	3	3	3	3	3	3	3	3	3
T	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (7)	0	0	0	0	0	0	0	0	0	0
U	**Noncoincident Peak Transmission Security Margin with Batteries (R+T)**	3,936	3,825	3,105	2,928	2,780	2,362	2,050	1,531	1,214	435

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour.
4. Limits for 2027 through 2036 are based on winter peak 2027 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item R are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item S, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 80: Status Quo Scenario New York City Summer Peak Transmission Security Margin

New York City Transmission Security Margin Summer Peak - Status Quo System, Expected Weather, Normal Transfer Criteria (MW)											
	Item	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone J Noncoincident Peak Demand Forecast**	(11,100)	(11,120)	(11,140)	(11,170)	(11,200)	(11,230)	(11,250)	(11,270)	(11,320)	(11,380)
B	I+K to J (4)	4,725	4,725	4,725	4,725	4,725	4,725	4,725	4,725	4,725	4,725
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	4,714	4,714	4,714	4,714	4,714	4,714	4,714	4,714	4,714	4,714
E	Loss of Source Contingency	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)
F	**Resource Need (A+D+E)**	(8,624)	(8,644)	(8,664)	(8,694)	(8,724)	(8,754)	(8,774)	(8,794)	(8,844)	(8,904)
G	J Generation (1)	8,540	8,540	8,034	8,034	7,636	7,636	7,636	7,636	7,636	7,636
H	J Thermal Generation Unavailability - Aging	0	0	0	0	0	(423)	(624)	(1,011)	(1,102)	(1,688)
I	J Thermal Generation Unavailability - EFORd (2)	(688)	(688)	(647)	(647)	(615)	(581)	(565)	(534)	(526)	(479)
J	J Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
K	J Renewable Generation Unavailability - Dispatch Assumptions (3)	0	0	0	0	0	0	0	0	0	0
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
N	**Total Resources Available (G+H+I+J+K+L+M)**	9,242	9,242	8,777	8,777	8,411	8,022	7,837	7,481	7,397	6,859
O	**Noncoincident Peak Transmission Security Margin (F+N)**	618	598	113	83	(313)	(732)	(937)	(1,313)	(1,447)	(2,045)
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (6)	0	0	0	0	0	0	0	0	0	0
R	**Noncoincident Peak Transmission Security Margin with Batteries (O+Q)**	618	598	113	83	(313)	(732)	(937)	(1,313)	(1,447)	(2,045)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c).
4. Limits for 2027 through 2036 are based on summer peak 2027 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 81: Status Quo Scenario New York City Winter Peak Transmission Security Margin

New York City Transmission Security Margin Winter Peak - Status Quo System, Expected Weather, Normal Transfer Criteria (MW)											
	Item	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone J Noncoincident Peak Demand Forecast**	(7,750)	(7,800)	(7,860)	(7,960)	(8,050)	(8,160)	(8,260)	(8,380)	(8,520)	(8,690)
B	I+K to J (4)	3,800	3,800	3,800	3,800	3,800	3,800	3,800	3,800	3,800	3,800
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	3,789	3,789	3,789	3,789	3,789	3,789	3,789	3,789	3,789	3,789
E	Loss of Source Contingency	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)
F	**Resource Need (A+D+E)**	(4,938)	(4,988)	(5,048)	(5,148)	(5,238)	(5,348)	(5,448)	(5,568)	(5,708)	(5,878)
G	J Generation (1)	9,274	9,274	8,622	8,211	8,211	8,211	8,211	8,211	8,211	8,211
H	J Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(2,062)	(2,062)	(2,062)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)
I	J Thermal Generation Unavailability - Aging	0	0	0	0	0	(249)	(428)	(801)	(872)	(1,435)
J	J Thermal Generation Unavailability - EFORd (2)	(587)	(587)	(535)	(535)	(535)	(515)	(500)	(470)	(465)	(419)
K	J Renewable Generation Unavailability - Dispatch Assumptions (3)	0	0	0	0	0	0	0	0	0	0
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
N	**Total Resources Available (G+H+I+J+K+L+M)**	6,765	6,765	6,166	6,166	6,166	5,936	5,772	5,430	5,364	4,846
O	**Noncoincident Peak Transmission Security Margin (F+N)**	1,828	1,778	1,118	1,018	928	589	324	(138)	(344)	(1,032)
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (7)	0	0	0	0	0	0	0	0	0	0
R	**Noncoincident Peak Transmission Security Margin with Batteries (O+Q)**	1,828	1,778	1,118	1,018	928	589	324	(138)	(344)	(1,032)

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour.
4. Limits for 2027 through 2036 are based on winter peak 2027 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 82: Status Quo Scenario Long Island Summer Peak Transmission Security Margin

Long Island Transmission Security Margin Summer Peak - Status Quo System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone K Noncoincident Peak Demand Forecast**	(5,136)	(5,161)	(5,200)	(5,252)	(5,310)	(5,357)	(5,392)	(5,416)	(5,438)	(5,462)
B	I+J to K (4)	950	950	950	950	950	950	950	950	950	950
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	950	950	950	950	950	950	950	950	950	950
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	**Resource Need (A+D+E)**	(4,846)	(4,871)	(4,910)	(4,962)	(5,020)	(5,067)	(5,102)	(5,126)	(5,148)	(5,172)
G	K Generation (1)	4,808	4,808	4,808	4,808	4,763	4,763	4,763	4,763	4,763	4,763
H	K Thermal Generation Unavailability - Aging	0	0	0	0	0	(272)	(307)	(340)	(465)	(526)
I	K Thermal Generation Unavailability - EFORd (2)	(566)	(566)	(566)	(566)	(561)	(527)	(523)	(519)	(504)	(496)
J	K Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
K	K Renewable Generation Unavailability - Dispatch Assumptions (3)	(159)	(159)	(167)	(167)	(167)	(167)	(167)	(167)	(167)	(167)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	660	660	660	660	660	660	660	660	660	660
N	**Total Resources Available (G+H+I+J+K+L+M)**	4,743	4,743	4,734	4,734	4,695	4,456	4,425	4,396	4,287	4,233
O	**Noncoincident Peak Transmission Security Margin (F+N)**	(103)	(128)	(176)	(228)	(325)	(611)	(677)	(730)	(861)	(939)
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
Q	Battery Storage MWh Used on Locality Noncoincident Peak Day (6)	0	0	0	0	0	0	0	0	0	0
R	**Noncoincident Peak Transmission Security Margin with Batteries (O+Q)**	(103)	(128)	(176)	(228)	(325)	(611)	(677)	(730)	(861)	(939)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c).
4. Limits for 2027 through 2036 are based on the 2025 LIPA Summer Operating Study.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

Figure 83: Status Quo Scenario Long Island Winter Peak Transmission Security Margin

Long Island Transmission Security Margin Winter Peak - Status Quo System, Expected Weather, Normal Transfer Criteria (MW)											
Line	**Item**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
A	**Zone K Noncoincident Peak Demand Forecast**	(3,325)	(3,412)	(3,530)	(3,635)	(3,739)	(3,832)	(3,918)	(4,001)	(4,088)	(4,190)
B	I+J to K (4)	350	350	350	350	350	350	350	350	350	350
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	350	350	350	350	350	350	350	350	350	350
E	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
F	**Resource Need (A+D+E)**	(2,975)	(3,062)	(3,180)	(3,285)	(3,389)	(3,482)	(3,568)	(3,651)	(3,738)	(3,840)
G	K Generation (1)	5,225	5,225	5,225	5,179	5,179	5,179	5,179	5,179	5,179	5,179
H	K Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(374)	(374)	(374)	(328)	(328)	(328)	(328)	(328)	(328)	(328)
I	K Thermal Generation Unavailability - Aging	0	0	0	0	0	(290)	(328)	(363)	(491)	(555)
J	K Thermal Generation Unavailability - EFORd (2)	(572)	(572)	(572)	(572)	(572)	(536)	(531)	(527)	(511)	(504)
K	K Renewable Generation Unavailability - Dispatch Assumptions (3)	(160)	(160)	(160)	(160)	(160)	(160)	(160)	(160)	(160)	(160)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	660	660	660	660	660	660	660	660	660	660
N	**Total Resources Available (G+H+I+J+K+L+M)**	4,780	4,780	4,780	4,780	4,780	4,525	4,492	4,461	4,349	4,293
O	**Noncoincident Peak Transmission Security Margin (F+N)**	1,805	1,718	1,600	1,495	1,391	1,043	924	810	611	453
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
Q	Battery Storage MWh Used on Locality Noncoincident Peak Day (7)	0	0	0	0	0	0	0	0	0	0
R	**Noncoincident Peak Transmission Security Margin with Batteries (O+Q)**	1,805	1,718	1,600	1,495	1,391	1,043	924	810	611	453

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. For winter solar PV output at peak is 0 MW.
4. Limits for 2027 through 2036 are based on the 2025 LIPA Summer Operating Study. As a conservative assumption summer values are used for LIPA Import limits with one line out.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do no have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.

No Planned Generation Projects

Continuing to build on the Status Quo scenario, the No Planned Generation Projects scenario slightly alters the assumptions to maintain the Propel NY project on schedule similar to the Base Case but to remove the planned generation projects included in the Base Case.

With Propel NY project entering service in 2030 without the other planned generation projects, the statewide deficiency seen in the Status Quo scenario would be deferred by one year, shifting from 2030 to 2031. However, the 2029 deficiency seen in the Status Quo scenario would remain, as the Propel NY project has a proposed commercial operation date of 2030.

Figure 84: No Planned Generation Projects Scenario NYCA Annual LOLE Results

Study Year	Status Quo	Status Quo with Propel Back	Delta
2027	0.072	0.072	0.000
2028	0.093	0.093	0.000
2029	0.107	0.107	0.000
2030	0.118	0.085	-0.033
2031	0.169	0.114	-0.055
2032	0.380	0.200	-0.180
2033	0.461	0.255	-0.206
2034	0.657	0.421	-0.236
2035	1.085	0.709	-0.376
2036	2.159	1.591	-0.568

Note: Gradient data bars compare study-year LOLE deltas within each scenario. Longer bars indicate larger impacts relative to other study-year deltas within the same scenario.

No Planned Large Loads

The Base Case assumes that certain proposed large loads are in service, growing from roughly 500 MW in the 2026 baseline forecast to about 2,700 MW. The No Planned Large Loads scenario removes the 2,200 MW of large load growth after 2026 from the Base Case. As detailed in Figure 85, the analysis indicates there would be no resource adequacy deficiency throughout the study period.

Figure 85: No Planned Large Loads Scenario NYCA Annual LOLE Results

Study Year	Base Case	No Planned Large Loads	Delta
2027	0.025	0.017	-0.007
2028	0.032	0.023	-0.009
2029	0.034	0.021	-0.013
2030	0.019	0.005	-0.014
2031	0.036	0.009	-0.027
2032	0.074	0.016	-0.058
2033	0.115	0.025	-0.090
2034	0.182	0.032	-0.151
2035	0.290	0.040	-0.249
2036	0.596	0.075	-0.521

Note: Gradient data bars compare study-year LOLE deltas within each scenario. Longer bars indicate larger impacts relative to other study-year deltas within the same scenario.

Additional Flexible Large Loads

The Base Case assumes certain large loads as flexible. In this scenario, an additional 1,050 MW of computational large loads are treated as flexible (*e.g.*, demand response participation or co-location with generation). As shown in Figure 86, the results indicate the resource adequacy deficiencies would be shifted from 2033 in the Base Case to 2035 while reducing the total deficiency in 2036.

Figure 86: Additional Flexible Large Loads Scenario NYCA Annual LOLE Results

Study Year	Base Case	Addtl Flex Large Loads	Delta
2027	0.025	0.021	-0.004
2028	0.032	0.026	-0.006
2029	0.034	0.025	-0.009
2030	0.019	0.009	-0.010
2031	0.036	0.016	-0.020
2032	0.074	0.033	-0.041
2033	0.115	0.058	-0.057
2034	0.182	0.082	-0.100
2035	0.290	0.119	-0.170
2036	0.596	0.232	-0.365

Note: Gradient data bars compare study-year LOLE deltas within each scenario. Longer bars indicate larger impacts relative to other study-year deltas within the same scenario.

No Aging Generation

The No Aging Generation scenario assumes that there is no unavailable capacity due to aging risk, which could occur if all aging generation risk was mitigated through repowering or other solutions. Without the assumption for aging risk, the resource adequacy deficiency would shift ahead by three years to 2036 (*i.e.*, study year 10).

Figure 87: No Aging Generation Scenario NYCA Annual LOLE Results

Study Year	Base Case	No Aging Gen.	Delta
2027	0.025	0.025	0.000
2028	0.032	0.032	0.000
2029	0.034	0.034	0.000
2030	0.019	0.019	0.000
2031	0.036	0.036	0.000
2032	0.074	0.041	-0.034
2033	0.115	0.059	-0.056
2034	0.182	0.062	-0.120
2035	0.290	0.075	-0.215
2036	0.596	0.100	-0.496

Note: Gradient data bars compare study-year LOLE deltas within each scenario. Longer bars indicate larger impacts relative to other study-year deltas within the same scenario.

Loss of All Imports

This scenario assumes all contracts with external areas are removed from the Base Case, which amounts to the removal of about 3,000 MW net imports for summer. Figure 88 sets forth the results of this analysis and highlights the NYCA's reliance on contractual transactions with its neighbors. Specifically, resource deficiencies are observed starting as early as 2028 if the contracts are no longer in place.

Figure 88: Loss of External Contracts Scenario NYCA Annual LOLE Results

Study Year	Base Case	Loss of External Contracts	Delta
2027	0.025	0.098	0.073
2028	0.032	0.113	0.082
2029	0.034	0.158	0.124
2030	0.019	0.172	0.153
2031	0.036	0.296	0.260
2032	0.074	0.637	0.563
2033	0.115	0.909	0.794
2034	0.182	1.560	1.378
2035	0.290	2.384	2.095
2036	0.596	4.245	3.648

Note: Gradient data bars compare study-year LOLE deltas within each scenario. Longer bars indicate larger impacts relative to other study-year deltas within the same scenario.

Chateaugay/CHPE Limits

This scenario limits the emergency imports from both Chateaugay and CHPE to a total of 1,250 MW. Figure 89 sets forth the results of this analysis and highlights the NYCA's reliance on contractual transactions with its neighbors. Specifically, the resource deficiency starts one year earlier due to limited imports from Chateaugay and CHPE.

Figure 89: Chateaugay/CHPE Limits Scenario NYCA Annual LOLE Results

Study Year	Base Case	HQ Limited	Delta
2027	0.025	0.043	0.018
2028	0.032	0.050	0.018
2029	0.034	0.054	0.019
2030	0.019	0.042	0.023
2031	0.036	0.082	0.046
2032	0.074	0.167	0.093
2033	0.115	0.212	0.097
2034	0.182	0.358	0.176
2035	0.290	0.544	0.255
2036	0.596	0.998	0.402

Note: Gradient data bars compare study-year LOLE deltas within each scenario. Longer bars indicate larger impacts relative to other study-year deltas within the same scenario.

No Propel NY

This scenario removes the Propel NY project from the Base Case to evaluate the impact if the project were to not enter service within the planning horizon. Appendix D contemplates the change in resource adequacy margin without the Propel NY project in service during the planning horizon, and Figure 90 shows that LOLE violations that would occur one year earlier than the Base Case.

Figure 90: No Propel NY Scenario NYCA Annual LOLE Results

Study Year	Base Case	Base Case without Propel NY	Delta
2027	0.025	0.025	0.000
2028	0.032	0.032	0.000
2029	0.034	0.034	0.000
2030	0.019	0.033	0.015
2031	0.036	0.058	0.022
2032	0.074	0.145	0.071
2033	0.115	0.185	0.069
2034	0.182	0.275	0.092
2035	0.290	0.440	0.151
2036	0.596	0.858	0.262

Note: Gradient data bars compare study-year LOLE deltas within each scenario. Longer bars indicate larger impacts relative to other study-year deltas within the same scenario.

Copper Sheet

This scenario removes all transmission limitations internal to New York. It informs the maximum potential improvement to resource adequacy that could be achieved with in-state transmission buildout in the absence of additional generation buildout. Results can be found in Appendix D.

No Voltage Limits

This scenario removes all transmission limitations internal to NY that are driven by voltage limitations. It informs the potential improvement to resource adequacy that could be achieved with additional voltage support devices, without additional generation or transmission buildout. Results can be found in Appendix D.

1 GW Nuclear Sensitivity: Climate Policy Advancement

This scenario represents a sensitivity on the Climate Policy Advancement Scenario by assuming a 1 GW nuclear unit added to Zone C in year 2036. Figure 91 informs the impact that such a buildout could

have on resource adequacy.

Figure 91: 1 GW Nuclear Sensitivity NYCA LOLE Results

Study Year	Climate Policy Adv.	+ 1 GW Nuclear	Delta
2027	0.023	0.013	-0.009
2028	0.014	0.009	-0.005
2029	0.015	0.010	-0.006
2030	0.009	0.004	-0.006
2031	0.023	0.010	-0.014
2032	0.099	0.043	-0.056
2033	0.165	0.081	-0.084
2034	0.348	0.164	-0.184
2035	0.731	0.341	-0.390
2036	1.869	0.909	-0.960

Note: Gradient data bars compare study-year LOLE deltas within each scenario. Longer bars indicate larger impacts relative to other study-year deltas within the same scenario.

Other Informational Scenarios Informing Solutions

There are several potential solution combinations that could resolve the Reliability Needs identified in the 2026 RNA, including new generator projects, new transmission expansion, retention of existing units, and modern replacements for aging generation and units impacted by the DEC Peaker Rule. The use of two scenarios on the Base Case explores and informs how known potential projects and existing units could bridge the gap between the results of this RNA and a reliable system.

New Resources and Transmission Solution Combination

The New Resources and Transmission solution combination scenario adds generation that is currently in NYISO's interconnection queue and planned transmission projects that have not met the RNA Base Case inclusion rules and that are proposed to connect to New York City. Projects are added in three separate steps to help evaluate and define the reliability impact of increasing amounts of added projects.

Step 1: Addition of all Cost-Allocated Projects that did not meet the Base Case inclusion rules

Step 2: Addition of the remaining projects in the ongoing 2024 Transitional Cluster Study

Step 3: Addition of transmission buildout plans for New York City[22]

The type of added resources and MW amount is shown in Figure 92 below. Each resource type contributes significantly less than the nameplate MW in resolving needs due to dispatch assumptions on solar and wind or duration limits of battery energy storage. Detailed examples of how 500 MW nameplate of various resource types may translate into the reduction of a Reliability Need can be found later in this section.

Figure 92: New Resources and Transmission Solution Combination - Summary

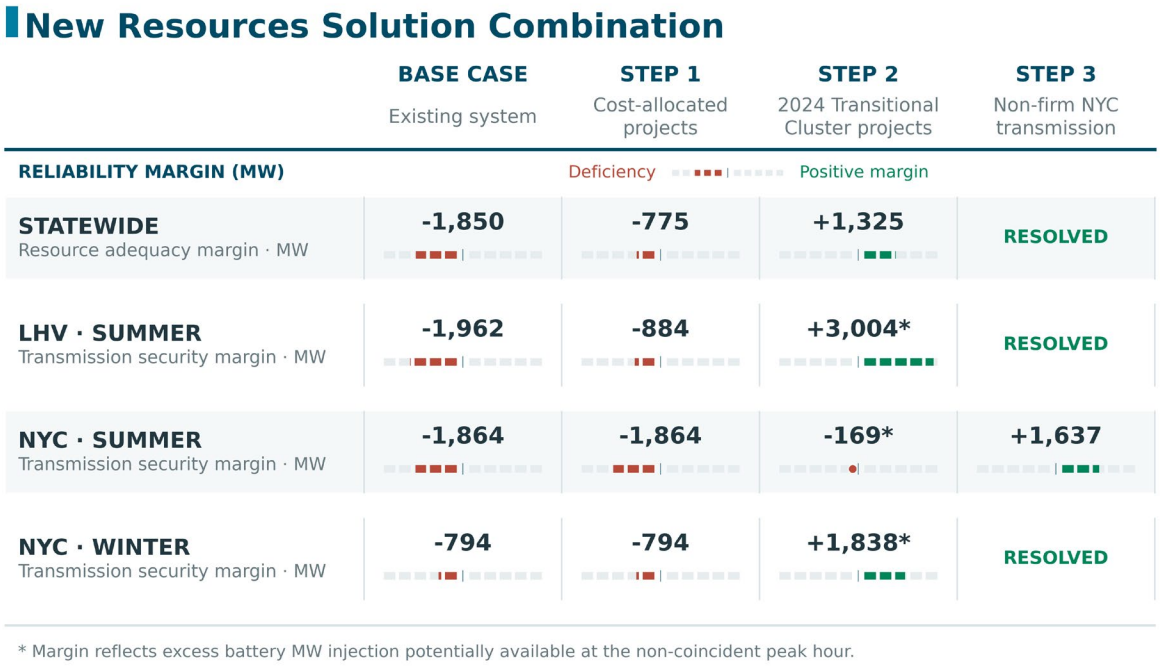
New Resources Solution Combination - Added Resources (MW)						
		A-F	G-I	J	K	Total
Step 1	LBW	169	0	0	0	169
	OSW	0	0	0	0	0
	Solar	2,140	100	0	36	2,276
	BESS	0	499	530	577	1,606
	CSR	510	0	0	0	510
	Step Total	2,819	599	530	613	4,561
Step 2	LBW	1,248	0	0	0	1,248
	OSW	0	0	1,310	1,321	2,631
	Solar	1,210	0	0	0	1,210
	BESS	4,310	1,949	1,676	1,107	9,042
	CSR	1,350	0	0	0	1,350
	Step Total	8,118	1,949	2,986	2,428	15,481
Step 3	Transmission	0	0	1,000 (1)	0	-

Notes:
1. Additional transmission into Zone J will improve Zone J Margin but does not improve Lower Hudson Valley margin.

The impact of each step on the Reliability Needs identified in the 2026 RNA is summarized in Figure 93 below. The table starts with the size of each statewide or locality deficiency in the Base Case and then presents the resulting margin after each step, until the reliability margin becomes positive.

[22] Transmission buildout plans connected to New York City include the Con Edison proposed Ridge Hill 345 kV transmission path (750 MW from I to J) identified in the Joint Utilities Coordinated Grid Planning Process Cycle 1 Report and the Con Edison identified cooling systems on underground transmission feeders (up to 300 MW from I to J) identified in its Reliability Contingency Plan. For this assessment, the assumed collective capability of these transmission plans is 1,000 MW.

Figure 93: New Resources and Transmission Solution Combination Results



The Lower Hudson Valley transmission security margin need and statewide resource need are improved in Step 1 with generation projects that have accepted cost allocation through the NYISO's interconnection procedures, which include solar and battery storage within the locality. New York City does not see improvement, despite the added battery storage, as that storage would be depleted before the peak hour. When applying Step 2, the remaining projects in the NYISO's Transition Cluster Study could contribute over 1,500 MW of new battery storage and 1,300 MW of new offshore wind to the New York City locality. This is sufficient to resolve the statewide resource need, the summer needs in the Lower Hudson Valley, and the winter needs in New York City. However, the summer transmission security margin need in New York City would persist. Adding new transmission capability into New York City in Step 3 would be required to address the summer transmission security margin need in New York City.

Resource Retention Solution Combination

This solution combination considers the impact to the Reliability Needs by retaining some and replacing other fossil-fuel generation. This is meant to encompass, for example, keeping the newer existing units in service beyond planned removal dates; actions that could reduce the risks of aging generation; or replacing other units with new generators that provide equivalent dependability, without attempting to predict what actions would be taken for a given generator.

Step 1: Retention or replacement of equivalent capacity to the NYPA small gas plants

Step 2: Replacement of equivalent capacity as the Gowanus and Narrows barges

Step 3: Additional steps to mitigate aging generation risks or repower approximately 2,250 MW of the oldest generation in New York City

Figure 94: Resource Retention Solution Combination Summary

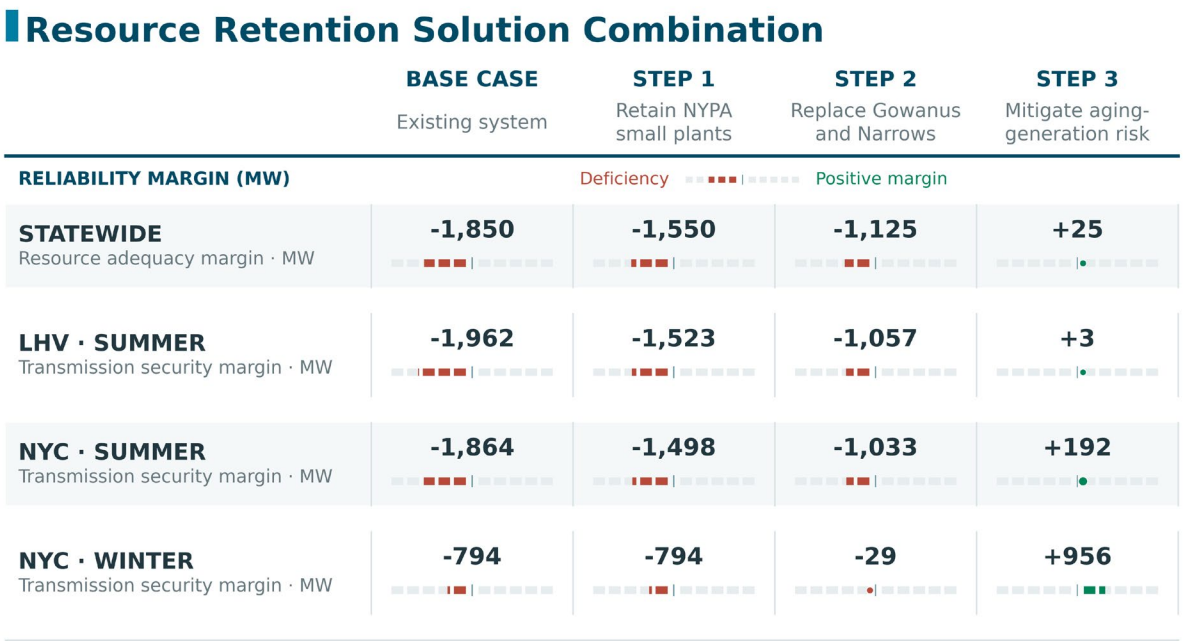
Resource Retention Solution Combination		
Steps		Total (MW)
Step 1	NYPA Small Plants Retained or Replaced	450
Step 2	Gowanus & Narrows Replaced with Equivalent Capacity	500
Step 3	Aging Generation Risk Mitigated or Replaced (1)	2,250

Notes:

1. Indicates the approximate quantity, in nameplate MW, of oldest generation in NYC that would need to undergo aging risk mitigation or equivalent replacement by 2036 in order to achieve system reliability. Equivalent to approximately 1,100 MW of perfect capacity.

The impact of each step on the reliability needs identified in the 2026 RNA is summarized in Figure 95 below.

Figure 95: Resource Retention Solution Combination Results



In Step 1, retaining or replacing the NYPA small plants adds statewide resources and summer margin

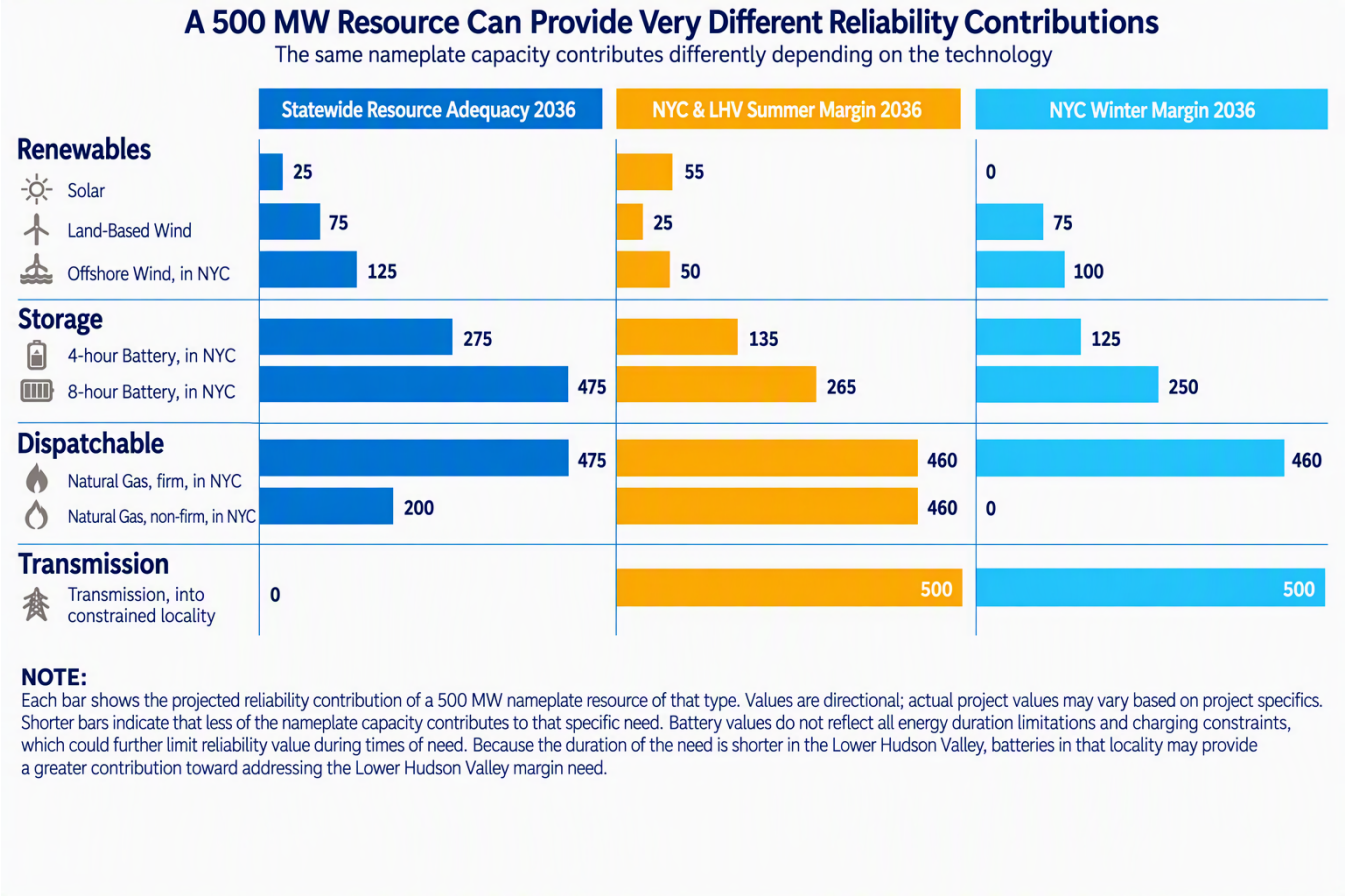
to both the Lower Hudson Valley and New York City localities, but these actions alone are not sufficient to satisfy Reliability Criteria. Replacing the capacity of the Gowanus and Narrows Barges in Step 2 is nearly sufficient to resolve the New York City winter need but not enough to resolve summer needs in either locality. To resolve the statewide resource need, repowering or mitigation of the aging generation risk of roughly 2,250 MW of aging units in the locality could return the summer margin to 0 MW. If the 2,250 MW of affected aging generation is located in New York City, this is sufficient to simultaneously resolve the Lower Hudson Valley and New York City summer need due to the nested nature of the localities.

Resource Adequacy and Transmission Security Margin Value by Resource Type

The following table highlights the varying resource adequacy and transmission security margin value of building a 500 MW nameplate project with different resource types. Resource adequacy analysis was performed without transmission constraints within New York, which provided the perfect capacity equivalent of each project irrespective of location. Transmission security margin applies the assumed availability of the resource type at the locality non-coincident peak hour.

From the results, solar has the least reliability value, as the summer peak occurs in the evening, when less direct sunlight is available, and the winter peak occurs at night. Battery storage of 8-hour duration provides 95% of its nameplate in perfect capacity, while a 4-hour battery provided only 55%. The results highlight the importance of duration for energy-limited resources. The actual value of storage depends on the full nature of the need, and the long duration of the transmission security margin need seen by 2036 could decrease the effectiveness of storage. For example, the NYC summer margin deficiency extends over approximately 15 hours and totals 17,298 MWh, while only about 7,150 MWh of charging capability is available during surplus hours, leaving about a 10,150 MWh energy shortfall. Appendix E provides details of storage dispatch in the margin calculation. The value to resource adequacy and winter margin of a 500 MW combined cycle plant depends on whether it has firm fuel. For resource adequacy, firm fuel on a 500 MW combined cycle plant increased its equivalent perfect capacity by 275 MW.

Figure 96: Reliability Value of 500 MW by Resource Type



Appendix G - 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 H - Reliability Compliance Obligations and Activities

The NYISO has various compliance obligations under NERC, NPCC, and the NYSRC. The purpose of this section is to discuss the NERC Planning Coordinator and Transmission Planner obligations, as well as the other NPCC and NYSRC planning compliance obligations, fulfilled by the NYISO. 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 aligns with the Reliability Planning Process. 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 objectives 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 97 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 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,

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

such as in the Reliability Planning Process, and for other compliance obligations, such as those listed in Figure 97. Planning assessments similar to those conducted in the Reliability Planning Process include the NPCC/NYSRC Area Transmission Reviews (ATRs) and the NERC TPL-001 assessments.

Figure 97: 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-014	Establish and Communicate System Operating Limits	To ensure that System Operating Limits used in the reliable planning and operation of the Bulk Electric System 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 and Validation of Dynamic Models and Data	To verify and validate that the dynamic models and associated parameters used to assess Bulk Electric System (BES) reliability represent the in-service equipment of Bulk Power System (BPS) facilities including generating facilities, transmission connected dynamic reactive resources, and high-voltage directed current (HVDC) systems.
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 Disturbances
PRC-006	Automatic Underfrequency Load Shedding	To establish design and documentation requirements for automatic underfrequency load shedding 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 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.

Standard Name	Title	Purpose
PRC-012	**Remedial Action Schemes**	To ensure that Remedial Action Schemes do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System.
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 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 events.
TPL-008	**Transmission System Planning Performance Requirements for Extreme Temperature Events**	Establish Transmission system planning performance requirements to develop a Bulk Power System (BPS) that will operate reliably during extreme heat and extreme cold temperature events.

NPCC/NYSRC Area Transmission Reviews

The NPCC/NYSRC ATRs are performed on an annual basis to demonstrate that the system conforms to 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 2025 ATR,[25] which is the most recently completed ATR, evaluated study year 2030 and found that the planned system through year 2030 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 2026

[25] 2025 Comprehensive Area Transmission Review of the New York State Pulk Power Transmission System.

or early 2027. 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 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. This review evaluates the designed operation and possible consequences of failure to operate or mis-operation of the Special Protection System 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 98 provides a description of the steady state, dynamics, and short circuit cases required to be evaluated in the Planning Assessment.

Figure 98: 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 Local Transmission Owner Plan 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]

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

[26] *See* NYSRC Reliability Rule A.3, R.2 and A3.R3.

[27] Links to the latest available report and presentation are available at: https://www.nysrc.org/wp-content/uploads/2026/01/A.3-R3-2025-NY-LTRAA-Intervening-Year-Report.pdf.

Appendix I - Reliability Attributes of Dispatchable Resources

The New York power grid is reliant on several electrical attributes to maintain reliability. One key attribute that is critical to reliability is the ability to balance generation with fluctuating demand. Historically, the majority of the energy and capacity within New York has been provided by dispatchable generating resources with very little provided by intermittent generation resources. As such, the New York generating fleet has been collectively able to respond to dispatch signals, run for long periods, and use multiple fuel sources. However, wind and solar resources have an intermittent fuel that is dependent on the weather. These resources may not be available to produce energy when needed or for the length of time that it is needed. In addition, the weather conditions that impact these resources may persist over a broad area resulting in reduced output across the fleet as compared to just individual generators.

To address these concerns, dispatchable resources are required to ensure reliability as a larger share of intermittent resources connect to the grid. Generally speaking, dispatchable resources that provide the reliability attributes of synchronous generation can be dispatched to provide both energy and capacity over long durations, especially when the output of intermittent resources is insufficient to meet demand. This can occur during prolonged wind lulls that impact wind output or extended periods of cloud cover that will reduce solar generation. During these events, continuous operation of dispatchable resources will be required to compensate for the energy lost from intermittent sources. This capability will become more important as New York integrates larger amounts of solar and wind resources and decommissions fossil-fuel generation.

Additionally, inverter-based resources, such as wind and solar, do not provide the same reliability attributes as synchronous generators that are being decommissioned. The essential characteristics or reliability services that are provided on today's grid, in large part, by fossil-fuel generation do not need to be encapsulated in a singular technology. In the aggregate, the system needs a collection of these reliability services to maintain reliability and replace the reliability attributes of the retiring fossil-fuel generation.

The fleet of resources must collectively maintain a balance of the attributes listed below:

1. **Dependable Fuel Sources** that allow these resources to be brought online when required;
2. **Non-Energy Limited** and capable of providing energy for multiple hours and days regardless of weather, storage, or fuel constraints;
3. **Dispatchable** to follow instructions to increase or decrease output on a minute-to-minute basis;
4. **Quick-Start** to come online within 15 minutes;
5. **Flexibility** to be dispatched through a wide operating range with a low minimum output;

6. **Fast Ramping** to inject or reduce the energy based on changes to net load which may be driven by changes to load or intermittent generation output;
7. **Multiple starts** so resources can be brought online or switched off multiple times through the day as required based on changes to the generation profile and load;
8. **Inertial Response** and frequency control to maintain power system stability and arrest frequency decline post-fault;
9. **Dynamic Reactive Control** to support grid voltage; and
10. **High Short Circuit Current** contribution to ensure appropriate fault detection and clearance.

The above list of attributes is not exhaustive, and as the grid evolves with resources that provide these attributes, new needs may be identified due to lack of certain, necessary attributes. As an example, fast frequency response, which can help stabilize system frequency, can be provided by resources that can rapidly adjust their output. However, these systems have an inherent time delay required for detection and response and do not entirely offset the need for inertia.

Figure 99 illustrates several potential types of generation technologies and highlights some of their attributes.

Figure 99 Energy and Reliability Attributes of Sample Generation Technologies

		2026 NYCA Summer Capability (MW)	Energy Attributes						Other Reliability Attributes			
			Carbon Free	Dependable Fuel Source	Energy Limited	Dispatchable	Quick start	Flexible	Multi start	Inertial Response	Dynamic Reactive control	High Short Circuit current
Sample Technology	Fossil	23,676	No	Yes[28]	No	Yes	Yes[29]	Yes	Yes	Yes	Yes	Yes
	Hydro	4,211	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Pumped Hydro	1,409	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Hydrogen Fuel Cell	0	Yes	Yes[30]	No	Yes	Yes	Yes	Yes	No	Yes	No
	Hydrogen Combustion	0	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Nuclear	3,302	Yes	Yes	No	No	No	No	No	Yes	Yes	Yes
	Modular Nuclear	0	Yes	Yes	No	No	No	Yes	No	Yes	Yes	Yes
	Battery	23	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	No
	Solar	774	Yes	No	Yes	No[31]	Yes	Yes	Yes	No	Yes	No
	Wind	2,710	Yes	No	Yes	No	Yes	Yes	Yes	No	Yes	No
	Demand Response[32]	1,271	Yes[33]	Yes	Yes	No	No	Yes	No	No	No	No
	Synchronous Condenser[34]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Yes	Yes	Yes	Yes

[28] Firm fuel contract or dual fuel capable

[29] Simple cycle turbines

[30] Contingent on ability to manufacture and transport hydrogen at scale required for power generation

[31] Resources are energy limited or have intermittent fuel sources, which limit their operational capability

[32] Demand response participating in SCR, EDRP, or DER programs

[33] Provided demand reduction is achieved through curtailing electrical consumption or by increasing carbon-free generation source

[34] Synchronous condensers do not provide energy

The lead time associated with construction and deployment of the different resource types is also an important factor in considering a path forward. Depending on the duration of need, enhancements to various market design aspects—such as reserves, regulation, ramping, and load forecasting—may be required. Long-duration, dispatchable, and emission-free resources will be necessary to maintain reliability and meet the CLCPA. Resources with this combination of attributes are not commercially available at this time but will be critical to future grid reliability.