New York ISO
Independent System Operator

Appendices

2025-2034
Comprehensive Reliability Plan

A Report from the
New York Independent
System Operator

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Appendix A: 2025-2034 Comprehensive System Plan Glossary

The following glossary offers definitions and explanations of terms used in the Reliability Planning Processes.

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

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

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

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

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

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

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

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

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

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

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

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

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

Fault: An electrical short circuit. See NYSRC.org

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[1] NYSRC's "Resource Adequacy Metrics and their Application": https://www.nysrc.org/wp-content/uploads/2023/03/Resource-Adequacy-Metric-Report-Final-4-20-20206431.pdf

[2] NYSRC's "Resource Adequacy Metrics and their Application": https://www.nysrc.org/wp-content/uploads/2023/03/Resource-Adequacy-Metric-Report-Final-4-20-20206431.pdf

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Appendix B: Reliability Planning Process

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

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

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

The CSPP is comprised of four components:

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

Under the LTPP, the local Transmission Owners (TOs) are responsible to plan for their respective transmission facilities and/or areas by performing transmission studies according to all applicable criteria. Under this process, each TO produces a Local Transmission Owner Plan (LTP), which feeds into the NYISO's determination of system needs through the CSPP. Links to LTPs can be found on the NYISO's website.[4]

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

During the RPP, the NYISO conducts the Reliability Needs Assessment (RNA) followed by the Comprehensive Reliability Plan (CRP). The reliability studies assesses the resource adequacy and transmission security of the BPTFs over the study period (i.e., the RNA evaluates years 4 through 10). In identifying resource adequacy needs, the NYISO identifies the amount of resources in megawatts (MW),

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

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

which is known as "compensatory MW," and the locations in which they are needed to meet those needs.

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

Transmission 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. Transmission 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 transmission security assessment, the NYISO evaluates over 1,000 design criteria contingencies 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

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

critical element, such as a generator, a transmission circuit, a transformer, series or shunt compensating device, or a HVDC pole, has already been lost. For N-1-0 and N-1-1 analysis, generation and power flows can be adjusted between contingencies by the use of 10-minute operating reserve, phase angle regulator control, and HVDC control. Following such adjustments, a second single disturbance is analyzed. An N-1-0 violation occurs when the system cannot meet applicable Reliability Criteria after the first element is lost following system adjustments but prior to the occurrence of another event. An N-1-1 violation occurs when the system cannot meet applicable Reliability Criteria after the first element is lost following system adjustments and securing for all applicable second-level contingencies. Within the Con Edison service territory, the 345 kV transmission system and specific portions of the 138 kV transmission system are designed for the occurrence of two non-simultaneous outages and a return to normal ratings (N-1-1-0). For N-1-1-0 analysis, after the second contingency occurs, system adjustments are allowed to secure the system back to normal ratings. The requirement to plan for the occurrence of a second contingency in the Con Edison transmission system is contained in the NYSRC Reliability Rules, Rule G.1.

The NYISO's transmission security analysis also includes transmission security margin analysis. Transmission security margins identify plausible changes in conditions or assumptions that might adversely impact the reliability of the BPTF or "tip" the system into violation of a transmission security criterion. The transmission security margin is the ability to meet load plus losses and system reserve (i.e., total capacity requirement) against the NYCA generation, interchanges, and temperature-based generation derates (i.e., total resources). This assessment is performed using a deterministic approach through a spreadsheet-based method based on the applicable study assumptions. For this assessment, "tipping points" are evaluated for the statewide system margin, as well as Lower Hudson Valley, New York City, and Long Island localities. While the NYISO evaluates the statewide margin for information purposes, the NYISO will identify 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.

Following approval of the RNA by its Board of Directors and before the NYISO issues a solicitation for potential solutions to address an identified Reliability Need, the NYISO will request updated LTPs and other updates to the system relevant to reducing, or eliminating, the Reliability Needs, as timely received from Market Participants, Developers, TOs, and other parties. Any update must meet, in NYISO's determination, the RNA Base Case inclusion rules, as defined in Section 3 of the Reliability Planning Process Manual. If there are remaining Reliability Needs after these updates, the NYISO will request solutions for the remaining Reliability Needs.

Following receipt of proposed solutions, the NYISO will perform a Viability and Sufficiency

Assessments as a part of the CRP. The RPP is anchored in the market-based philosophy of the NYISO and its Market Participants that posits that market solutions should be the preferred choice to meet the identified needs related to reliability. Therefore, the NYISO will not select or trigger a regulated solution if there the market-based solutions that are viable and sufficient address the Reliability Need. In the event that market-based solutions do not materialize to meet a Reliability Need in a timely manner, the NYISO notifies the Responsible Transmission Owner(s) or Other Developer of an alternative regulated solution to proceed with a regulated solution in order to maintain system reliability.

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

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

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

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

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

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

The fourth component of the CSPP is the Public Policy Transmission Planning Process. Under this process interested entities propose, and the New York State Public Service Commission (NYPSC) identifies, transmission needs related to the BPTF driven by Public Policy Requirements. The NYISO then requests that interested entities submit proposed solutions to the identified Public Policy Transmission Need. The NYISO evaluates the viability and sufficiency of the proposed solutions to satisfy the identified Public Policy Transmission Need. The NYISO then evaluates and may select the more efficient or cost-effective transmission solution to the identified need. The NYISO develops the Public Policy Transmission Planning Report that sets forth its findings regarding the proposed solutions. This report is reviewed by NYISO stakeholders and approved by the Board of Directors.

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

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

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

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

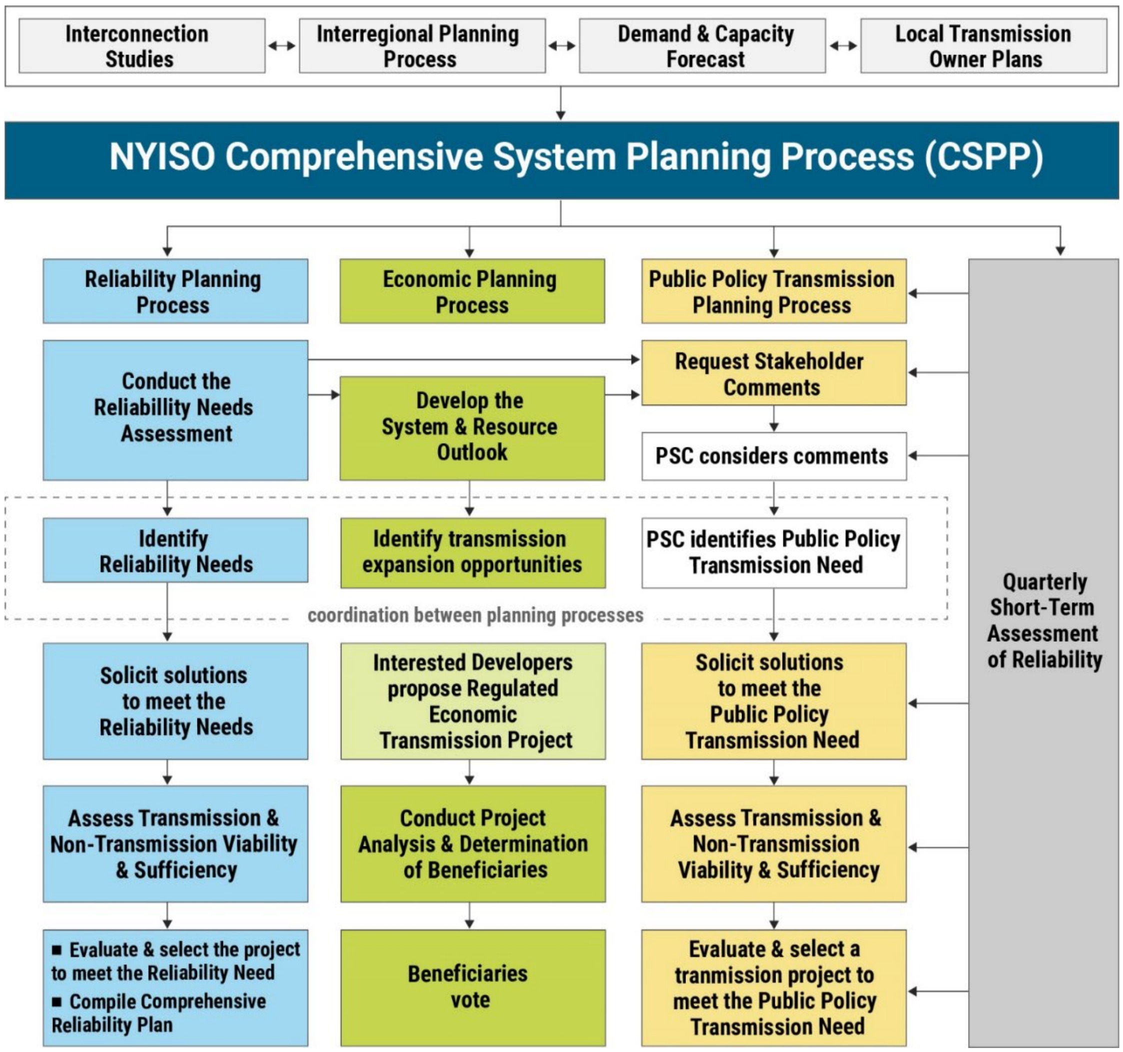
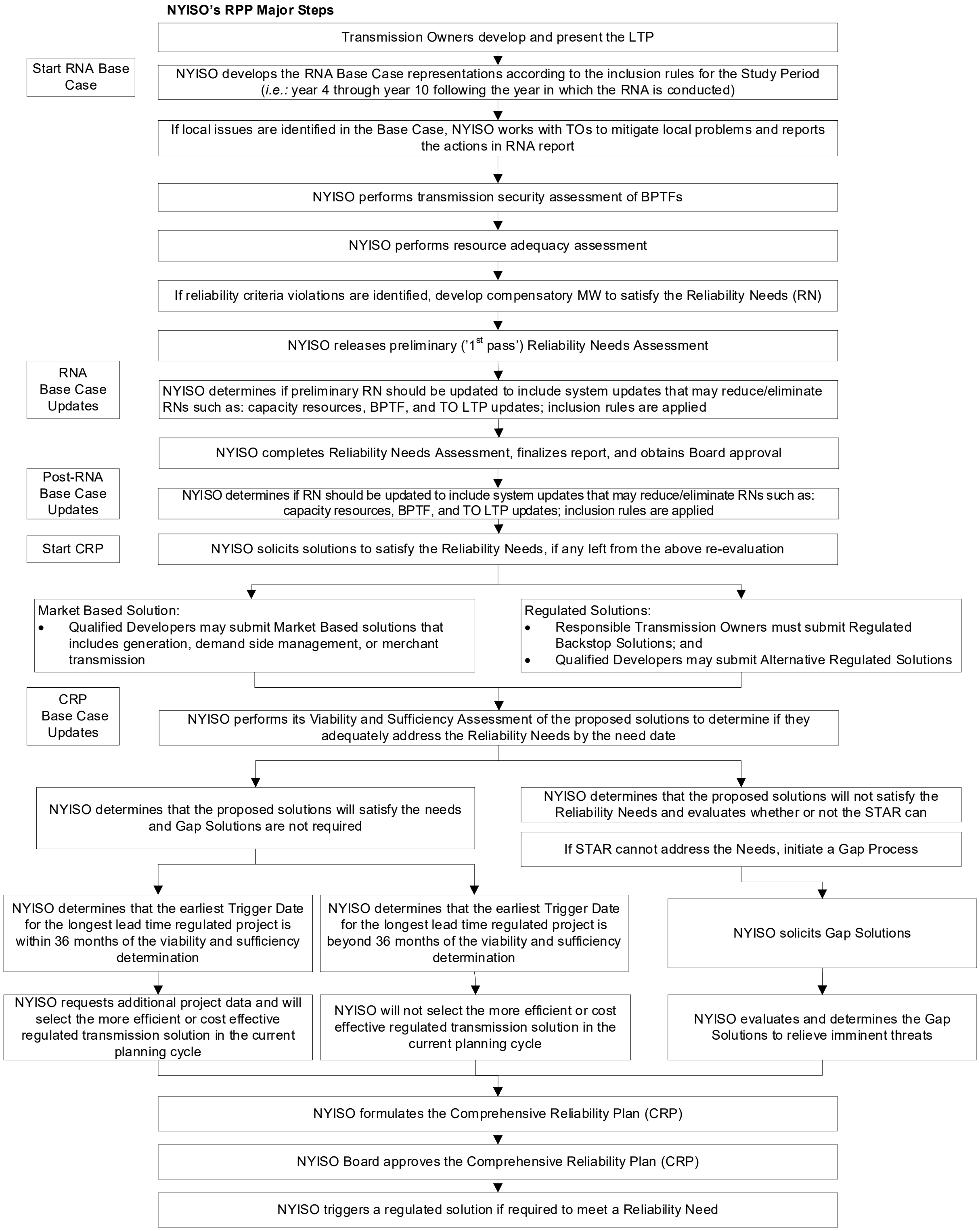


Figure 2: NYISO Reliability Planning Process



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

Appendix C: Aging Generation Methodology

Introduction

This appendix summarizes the "statistical retirement risk model," which was used in scenarios to assess the risk of reliance on aging fossil-fuel generation presented in the CRP. This model examines the risk of end-of-life failures for generating units as they advance in age. This model computes a derate that is applied to generators that reach a critical age that is intended to help account for the likelihood of generator retirement during the planning horizon. It is separate from the forced outage considerations already included in reliability planning models that look at outages and maintenance periods where a generator will be temporarily out of service for repair.

Retirement Curves: Concept

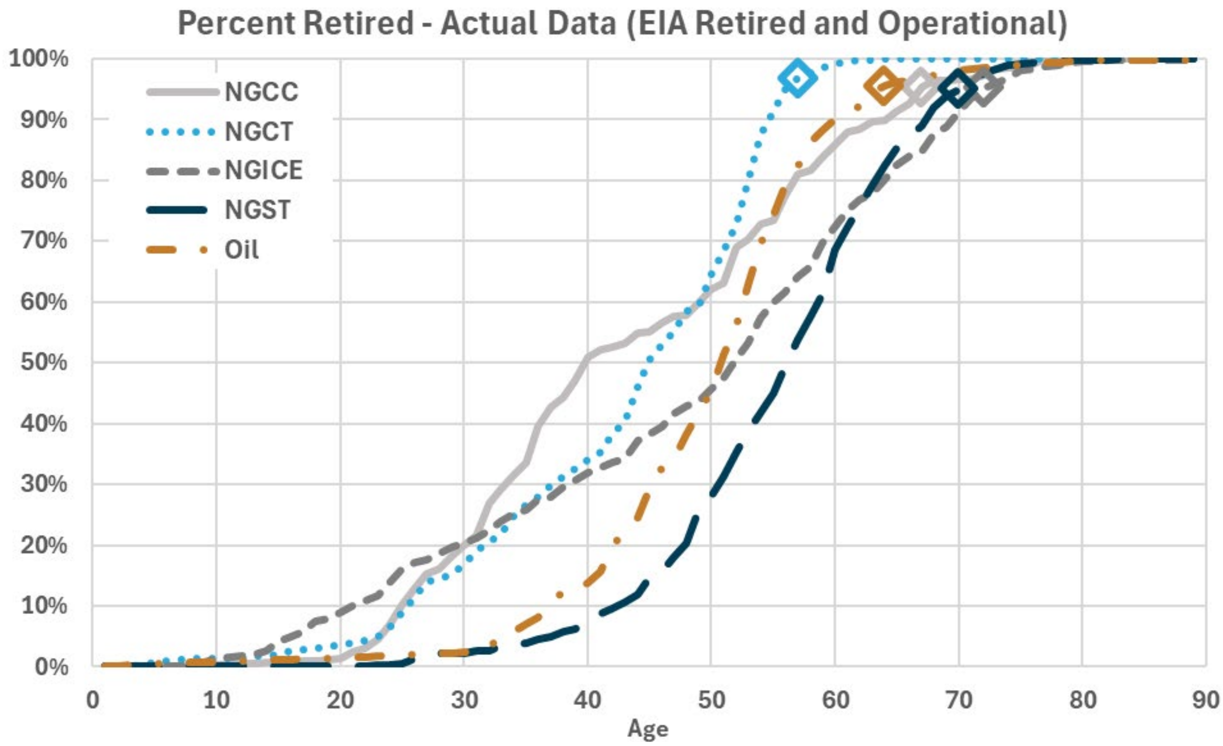
The statistical retirement risk model begins with technology-level information for operating and retired generating units from the U.S. Energy Information Administration's (EIA) EIA-860 data form.[7]

The EIA-860 dataset captures both retired and operational generation units and, therefore, provides a full historical record of unit in-service dates and retirement years.

Figure 3 shows the "Observed Retirement Curves," as the share of capacity that has retired by each age, derived from the June 2025 EIA-860 data. These curves are cumulative distribution functions (CDF), which means they represent the expected percentage of capacity (MW) retiring on or before reaching a certain age. Units that are still operational contribute to the surviving population at each age and prevent overestimating early retirements. As an example, when natural gas combustion turbine (NGCT) units reach 57 years of age, the percent retired is 95%. This means that 95% of NGCT capacity is retired within 57 years of going into service. It also means that 5% of NGCT capacity survives longer than 57 years.

[7] Data from U.S. Energy Information Administration Form EIA-860, https://www.eia.gov/electricity/data/eia860m/

Figure 3: Observed Retirement Curves for Several Technology Types, using the EIA-860 report, 06-2025



Annual Retirement Risks and Smoothing:

Figure 3 gives an idea of how long capacity is expected to last before retirement. To consider retirement risks of existing generation, this data must be analyzed to determine the likelihood a unit is expected to survive through the planning horizon. The annual retirement risk for a given age, i, is the risk that a generator that is i years old will retire this year. In other words, if annual retirement risk for 55-year-old NGST units is 5%, it means 5% of the cumulative capacity (MW) provided by 55-year-old NGST units is expected to retire before turning 56. For a single data point, the observed (measured from data) annual retirement risk $\hat{h}_i$ is given in Equation 1:

Equation 1: Observed Annual Retirement Risks from Measured Data

$$\hat{h}_i = \frac{Capacity\ retired\ in\ year\ i\ (MW)}{Capacity\ of\ units\ that\ have\ in\ service\ for\ i\ years\ (MW)}$$

Importantly, the annual retirement risk is a special type of probability known as a conditional probability. It provides the risk of retirement for capacity given that the units providing that capacity have already been in service for i years. In other words, the existing units have already survived to the present day, and the annual retirement risk informs how likely these units are to retire each year.

The raw data from EIA-860 is somewhat scattered, so a smoothing process is first used to model the underlying trend of annual retirements. Two types of techniques were investigated for use in the statistical retirement risk model.

1. Parametric Technique. This technique takes a family of curves with an existing equation, and certain values in that equation (parameters) are tuned to best fit the raw data. The Weibull Distribution[8] is one such method and requires two parameters to be found. For purposes of the annual retirement risk model, the first parameter, η, represents an estimate of the typical lifetime of a unit, and the second parameter, β, represents how sharply retirement rates increase with older ages. Then, $F(t)$ gives an estimate of the probability a hypothetical unit will retire on or before t years of age.

Equation 2: Weibull Distribution

$$F(t) = 1 - e^{-(t/\eta)^{\beta}}$$

2. Non-Parametric Technique. This technique averages the data points in some way to fit a curve directly to the observed data. The resulting curve may not be possible to describe using any single mathematical equation. For purposes of the annual retirement risk model, the NYISO used an Isotonic Regression[9] to fit the raw data from the EIA-860 dataset. An Isotonic Regression finds a non-decreasing curve, meaning that the next point to the right must be greater than or equal to the first point. This property is known as monotonicity. In terms of retirement, if h_i gives the smoothed annual retirement risk for each unit age, then the annual retirement risk for older units must be equal or higher, as in Equation 3:

Equation 3: Monotonicity Property

$$Monotonicity\colon \quad h_1 \leq h_2 \leq \cdots \leq h_n$$

The Isotonic Regression then finds the monotone curve that is closest to the center of the data using the weighted sum of squares per Equation 4:

Equation 4: Weighted Sum of Squares

$$\min_{h_1 \leq h_2 \leq \cdots \leq h_n} WSSE = \sum_{a=1}^{a_{max}} w_i \left(\hat{h}_i^{CMA} - h_i\right)^2$$

In Equation 4, w_i is weight for capacity at age i, equivalent to the capacity that survived to age i. $\hat{h}_i^{CMA}$

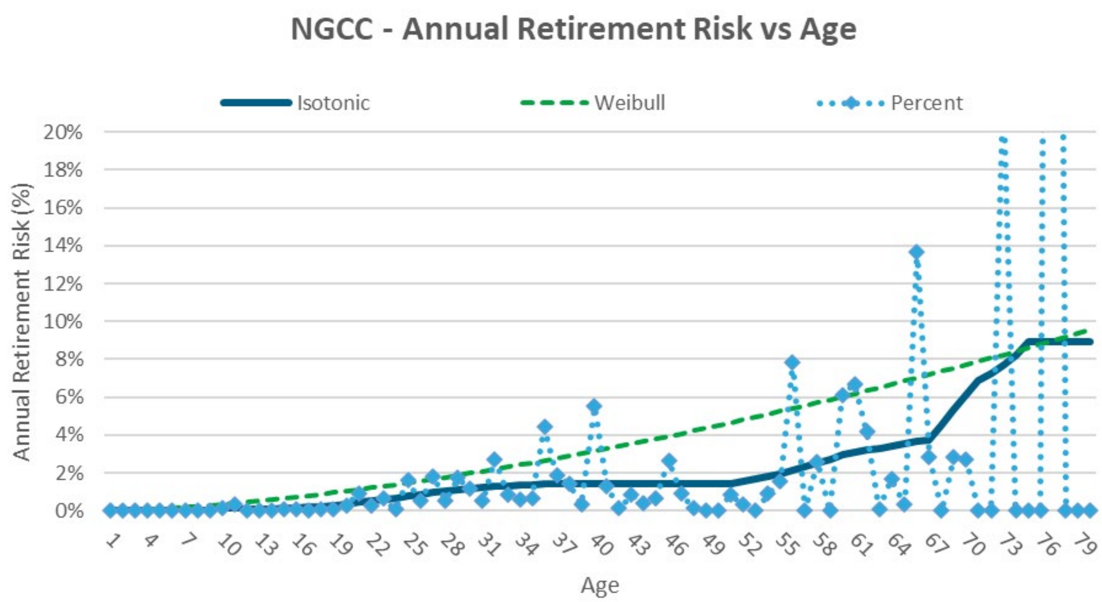
[8] *See Risk assessment of power systems: models, methods, and applications*. Wenyuan Li (2014).

[9] *See Nonparametric Estimation under Shape Constraints*. Groeneboom & Jongbloed (2014).

is the 10-year centered moving average (10-CMA) centered at age i, of the observed annual retirement risk $\hat{h}_i$ defined by Equation 1, and h_i is the smoothed annual retirement risk at age i. n is the maximum age for smoothing. This is taken at the age where surviving capacity w_i falls below 0.5% of initial capacity. This places the smoothed curve into the center of the raw data and helps reduce the impact of outliers. The Pool Adjacent Violators Algorithm (PAVA)[10] is used to solve Equation 4.

Figure 4, Figure 5, Figure 6, Figure 7, and Figure 8 show the raw EIA-860 data (as a percentage) in light blue with dotted lines, the Weibull Distribution method in green dashed lines, and the Isotonic Regression in dark blue solid lines.

Figure 4: Smoothed Annual Retirement Risk Curves from the EIA-860 dataset: Natural Gas Combined Cycle



[10] *Stat 8054 Lecture Notes: Isotonic Regression.* University of Minnesota. C.J. Geyer (2025)

Figure 5: Smoothed Annual Retirement Risk Curves from the EIA-860 dataset: Natural Gas Combustion Turbine

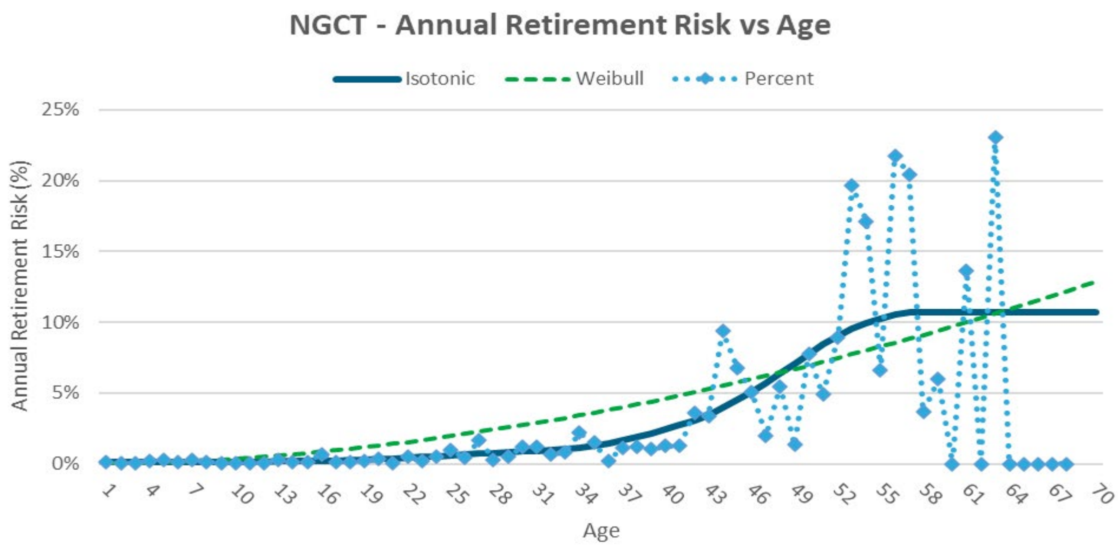


Figure 6: Smoothed Annual Retirement Risk Curves from the EIA-860 dataset: Natural Gas Steam Turbine

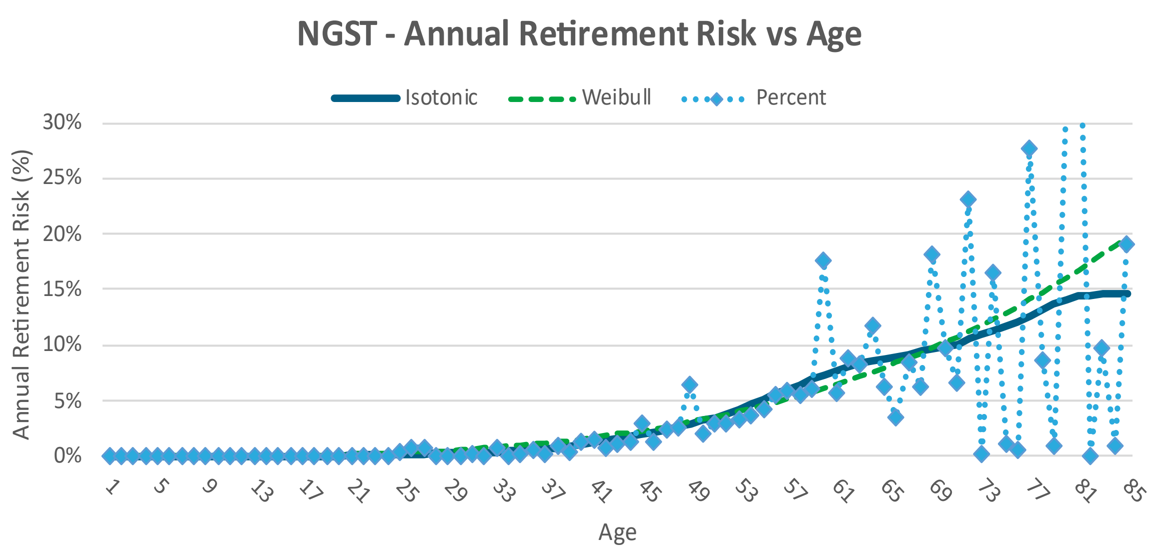


Figure 7: Smoothed Annual Retirement Risk Curves from the EIA-860 dataset: NG Internal Combustion Engine

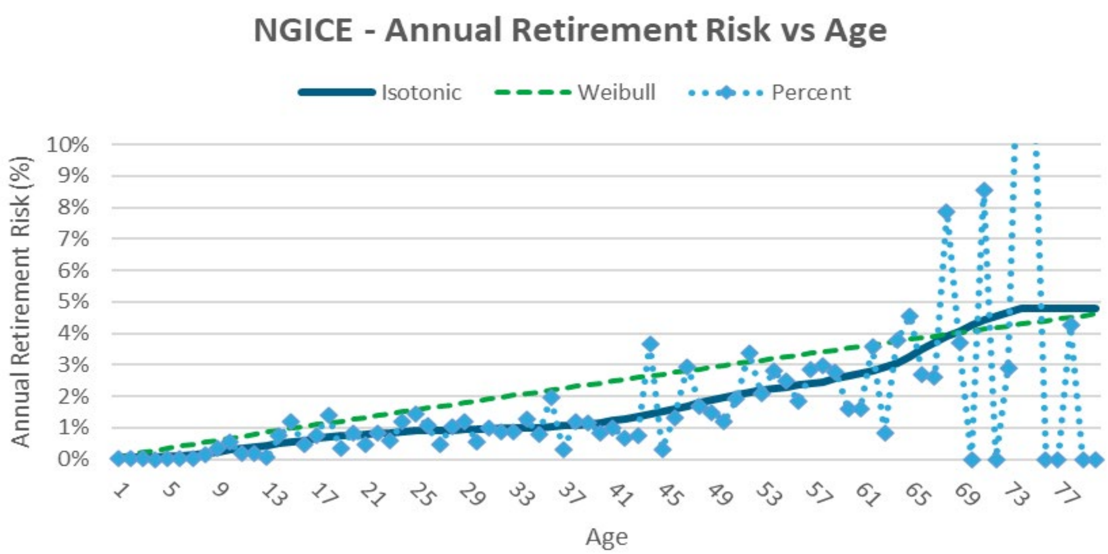
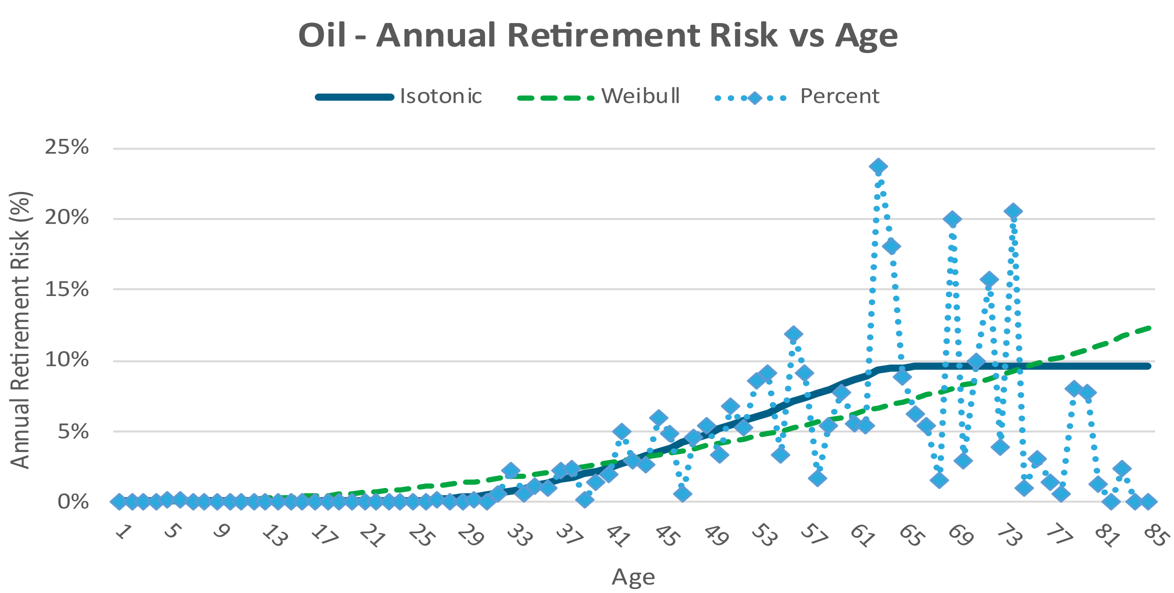


Figure 8: Smoothed Annual Retirement Risk Curves from the EIA-860 dataset: Oil

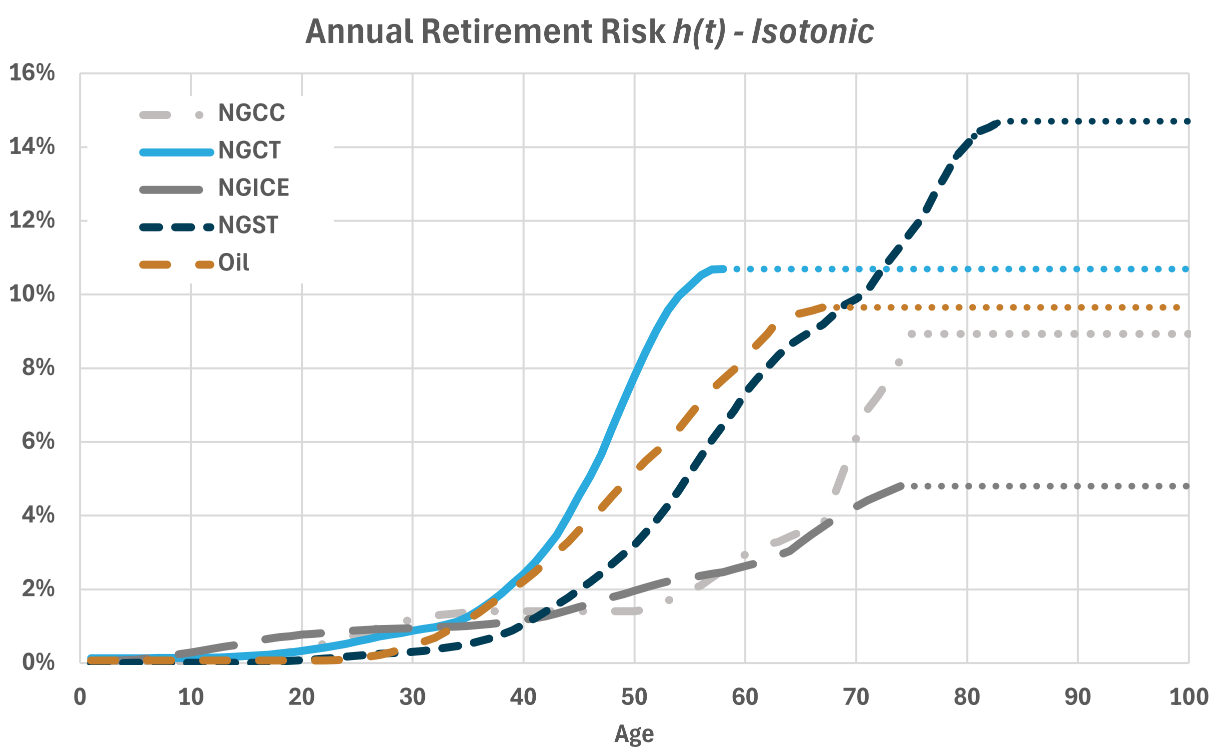


The Weibull Distribution curve does not fit well to the data, as it bends continuously upward. The NYISO selected the use of Isotonic Regression for the smoothing process, as it provides the best fit for "Annual Retirement Risk Curves" and does not assume an unsupported exponential growth at extreme higher range of the curve. The Annual Retirement Risk Curves indicate three stages in predicting unit life cycle, as follows:

- **Early-life**: There are almost no retirements, the annual retirement risk is low.
- **Mid-life**: Retirements gently increase, the annual retirement risk increases.
- **End-of-life**: Older units fall into retirement rapidly; the annual retirement risk stays high.

Figure 9 shows the annual retirement risk for each technology type using Isotonic Regression. The dashed portion at the end of each curve represents an assumed flat retirement risk that extends beyond the unit age where retirement data is not sufficient.

Figure 9: Annual Retirement Risk Curves by Technology Type



Derate Methodology

Using the Observed Retirement Curves (Figure 3) and the Annual Retirement Risk Curves (Figure 9), the NYISO used three steps to compute a derate to account for a retirement risk:

1. Assess which units are older than a threshold age via the Observed Retirement Curves.
2. Calculate the risk of those units retiring via the Annual Retirement Risk Curves.
3. Apply a derate to represent the retirement risk at a given study year.

For the first step, units older than or equal to a threshold are selected. For the CRP scenario analysis, the threshold was chosen as the age where 95% of capacity in the same technology type has retired. These units will get a derate starting from the year in which they cross that age on the Observed Retirement

Curves (Figure 3). Figure 10 shows that age in years for several percentiles. 95% was chosen, meaning the ages in the second column are used as the threshold. For example, NGCT units 57 years or older will have a derate applied. The NYISO recognizes that the New York fleet may not experience exactly the same factors that led to unit retirements represented in the nation-wide statistics. As a result, the NYISO imposed a conservative threshold to apply the derates (e.g., a 95%, threshold) as the primary way to prevent over-forecasting retirement risk.

Figure 10: Retirement Percentiles by Technology Type

Technology		Retirement Percentiles (Years Old)			
		90%	95%	98%	99%
NGCC	Natural Gas Combined Cycle	65	67	73	76
NGCT	Natural Gas Fired Combustion Turbine	55	57	59	60
NGICE	Natural Gas Internal Combustion Engine	70	72	75	79
NGST	Natural Gas Steam Turbine	68	70	73	75
Oil	Petroleum Liquids	60	64	70	75

For the second step, the Annual Retirement Risk Curve is used to assess the risk of retirement on the selected units. The probability of capacity surviving for the planning horizon is the product of one minus the annual retirement risk, h_i, for each of those years. In other words, the probability of a selected unit surviving for years into the future is the combined probability of surviving year i, $i+1$, and so on, all the way up to t years out. This value is provided as S_t in Equation 5.

Equation 5: Survival Probability

$$S_t = \prod_{i=1}^{t} (1 - h_i)$$

$$h_t \in \{h_i\}$$

The survival probability decreases over time. The probability of retirement within t years is one minus the probability of survival. Therefore, the retirement probability t years out is given by F_t in Equation 6.

Equation 6: Retirement Probability

$$F_t = 1 - S_t$$

The retirement probability increases over time. For the third and final step, the retirement probability is used to compute a derate for each selected unit in each planning year. Equation 7 describes the derate.

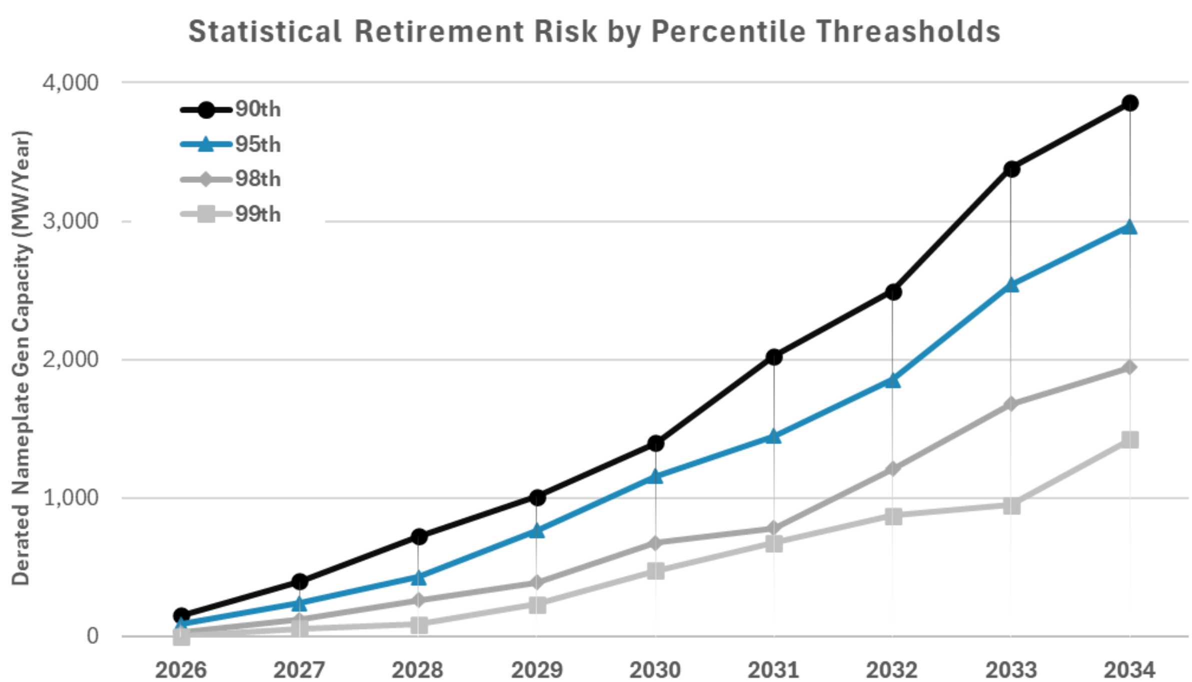
Equation 7: Derate for Statistical Retirement Risk Model

$$If\ Unit\ Age \geq 95th\ Retirement\ Percentile\ in\ year\ t:$$

$$Derate\ (MW) = Unit\ Capacity\ (MW) \cdot F_t$$

To account for the risk of retirement for selected units in a given year, the applied derate is the capacity of each unit multiplied by the probability of that unit retiring on or before that year. This is only applied to the units that will be older than the 95th percentile threshold (Figure 10) in that year. As the years go on, and F_t increases, the derate grows to account for increasing retirement risk. The Unit Capacity in Equation 7 is specific to the type of model for which the derate is applied. Figure 11 shows the total annual derates (NYCA wide) for the next 10 years, based on unit nameplate capacity, for different percentile thresholds.

Figure 11: Derated Nameplate Generation Capacity (MW) vs Planning Year by Percentile Threshold



The example in Figure 12 below shows a 100 MW NGST unit that is 66 years old in 2026. The unit's retirement risk increases annually. As it survives through each study year, the cumulative probability of retirement continues to grow. By 2030, the unit surpasses the 95th percentile retirement age threshold for NGST units. From that point onward, the cumulative retirement risk is applied as a derate to the unit's capacity, reflecting the increasing likelihood that the unit will retire during the study horizon.

Figure 12: 100 MW NGST unit Retirement Risk Example

NGST unit (100 MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034
Current Age	66	67	68	69	70	71	72	73	74
Annual Ret Risk (%)	9%	9%	9%	10%	10%	10%	11%	11%	11%
Cumulative Ret Risk (%)	9%	18%	26%	35%	43%	51%	58%	66%	72%
Derate (MW)	0	0	0	0	43	51	58	66	72

Figure 13 through Figure 15 further breakdown the type and location of derates applied in the statistical retirement risk model to the NYCA generation fleet using the 95th percentile threshold.

Figure 13: Derated Nameplate Generation Capacity (MW) – 95th Percentile Threshold

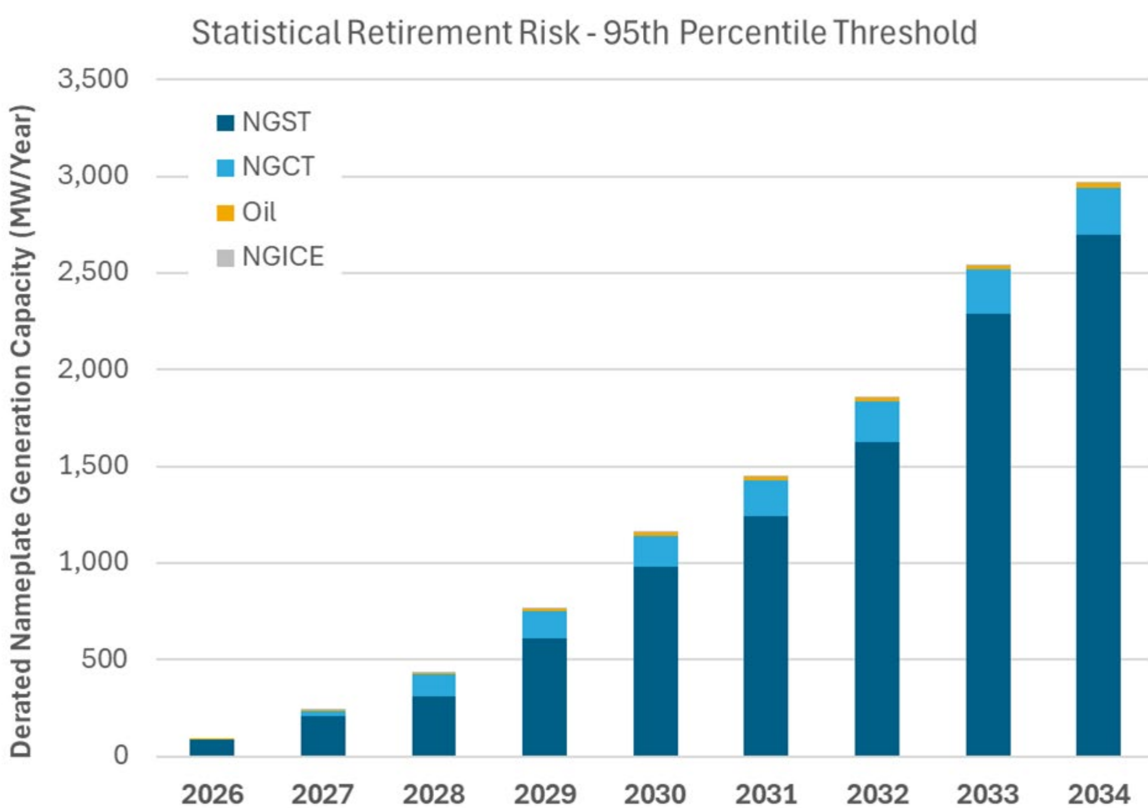


Figure 14: Statistical Retirement Risk as MW derates – 95th Percentile Threshold

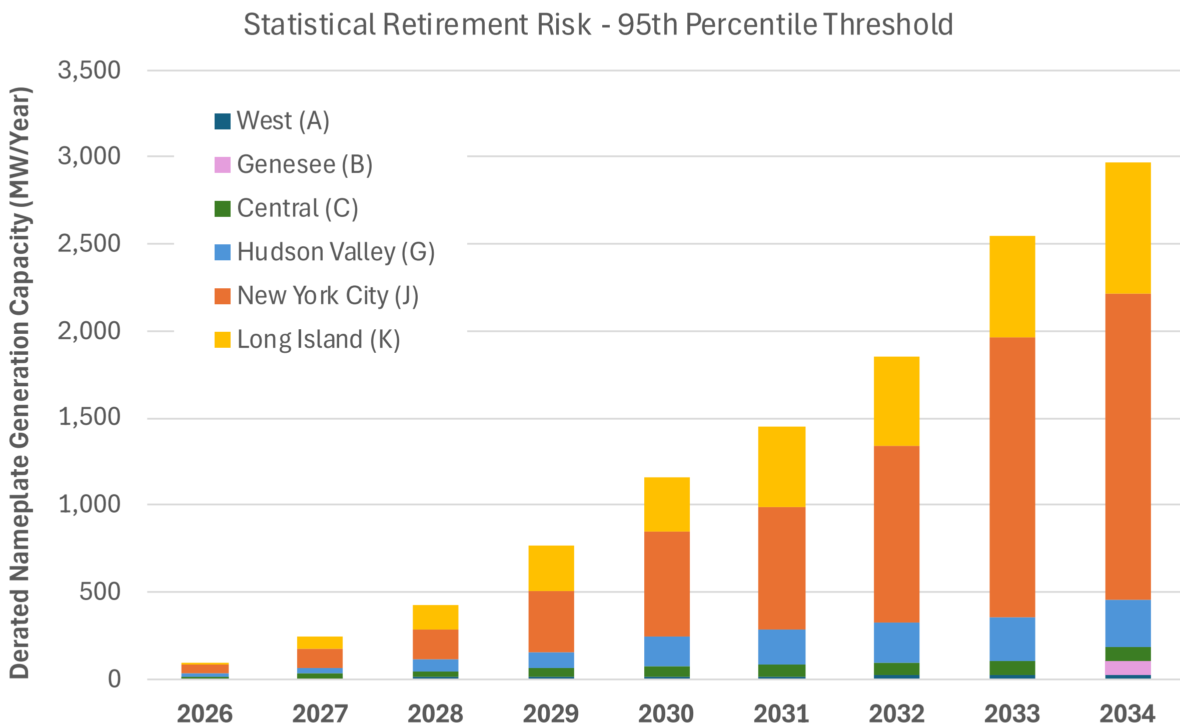
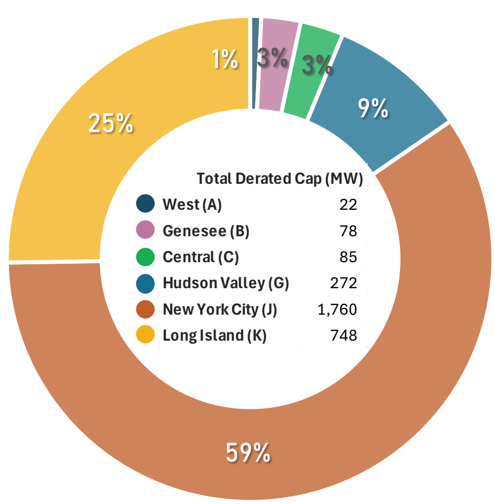
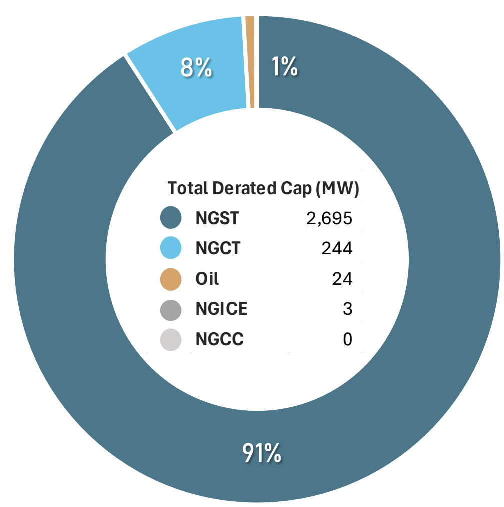


Figure 15: Statistical Retirement Risk by Zone and Technology Type by 2034





Application of Retirement Risk Derates in Reliability Analysis

The cumulative age-based derates shown in the previous figures are based on unit nameplate capability. However, the actual derate applied will be specific to each type of analysis. The NYISO's resource adequacy and transmission security margin analyses have slight differences in modeling unit capability.

- In resource adequacy models, the lesser of the seasonal Dependable Maximum Net Capability (DMNC) and the Capacity Resource Interconnection Service (CRIS) value is used as the seasonal maximum capability for thermal units.
- In transmission security and statewide system margin calculations, the NYISO uses unit seasonal capabilities derated by NERC class average forced outage rates.

Despite this difference, the aging generation derates are applied in a similar manner in both analyses. The calculated derate is applied on a unit-by-unit basis for each natural gas and oil generation plant. No derate is applied when a particular simulation has a unit modeled offline—such as probabilistic forced outage in MARS simulation or when a non-firm gas-only unit is modeled offline in transmission security margin calculations for winter peak conditions.

Appendix D: Impacts of Uncertainties on Margin

The CRP uses scenarios to examine the uncertainty around individual key system factors to assess their influence on system performance. This appendix provides further details on the impacts of each scenario to the statewide system margin and the impacts of relevant scenarios to the New York City and Long Island transmission security margins.

The baseline assumptions used in the statewide system margin and New York City and Long Island transmission security margins are described in the "Future Projects and Assumptions" section of the CRP report. The impact of each key system factor is provided as a delta to the relevant baseline margin result.

Statewide System Margin

Baseline Statewide System Margin

Figure 16: Statewide System Margin – Baseline Summer Peak

Line	Item	Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW)								
		2026	2027	2028	2029	2030	2031	2032	2033	2034
A	NYCA Generation (1)	37,605	40,383	41,687	41,687	41,687	41,233	41,233	41,233	41,233
B	NYCA Generation Derates (2)	(6,380)	(8,813)	(9,982)	(10,008)	(10,033)	(10,012)	(10,037)	(10,037)	(10,063)
C	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
D	External Area Interchanges (3)	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094
E	**Total Resources (A+B+C+D)**	34,319	34,664	34,799	34,774	34,748	34,315	34,289	34,289	34,264
F	Demand Forecast (5)	(31,305)	(31,595)	(31,725)	(31,935)	(32,225)	(32,505)	(32,835)	(33,185)	(33,485)
G	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
H	**Total Capability Requirement (F+G)**	(32,615)	(32,905)	(33,035)	(33,245)	(33,535)	(33,815)	(34,145)	(34,495)	(34,795)
I	**Statewide System Margin (E+H)**	1,704	1,759	1,764	1,529	1,213	500	144	(206)	(531)
J	Higher Demand Impact	(600)	(1,170)	(1,650)	(2,050)	(2,330)	(2,520)	(2,660)	(2,830)	(3,160)
K	**Higher Demand Statewide System Margin (I+J)**	1,104	589	114	(521)	(1,117)	(2,020)	(2,516)	(3,036)	(3,691)
L	SCRs (6), (7)	804	804	804	804	804	804	804	804	804
M	**Statewide System Margin with SCR (K+L)**	1,908	1,393	918	282	(313)	(1,216)	(1,712)	(2,232)	(2,888)
N	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
O	**Statewide System Margin with Full Operating Reserve (M+N) (4)**	598	83	(392)	(1,028)	(1,623)	(2,526)	(3,022)	(3,542)	(4,198)

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 15% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included as well as the Oswego Export limit for all lines in-service. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Interchanges are based on ERAG MMWG values.
4. For informational purposes.
5. Reflects the 2025 Gold Book Forecast.
6. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
7. Includes a derate of 401 MW for SCRs

Figure 17: Statewide System Margin – Baseline Winter Peak

Line	Item	Winter Peak - Baseline Expected Winter Weather, Normal Transfer Criteria (MW)								
		2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
A	NYCA Generation (1)	41,998	43,367	43,747	43,747	43,289	43,289	43,289	43,289	43,289
B	NYCA Generation Derates (2)	(8,253)	(9,437)	(9,817)	(9,817)	(9,817)	(9,817)	(9,817)	(9,817)	(9,817)
C	Unavailability of Non-Firm Gas (6)	(6,328)	(6,328)	(6,328)	(6,328)	(5,870)	(5,870)	(5,870)	(5,870)	(5,870)
D	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
E	External Area Interchanges (3)	735	735	735	735	735	735	735	735	735
F	**Total Resources (A+B+C+D+E)**	28,152	28,337	28,337	28,337	28,338	28,338	28,338	28,338	28,338
G	Demand Forecast (5)	(24,920)	(25,330)	(25,850)	(26,410)	(27,080)	(27,730)	(28,440)	(29,210)	(29,970)
H	Large Load Flexibility	685	685	685	685	685	685	685	685	685
I	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
J	**Total Capability Requirement (G+H+I)**	(25,545)	(25,955)	(26,475)	(27,035)	(27,705)	(28,355)	(29,065)	(29,835)	(30,595)
K	**Statewide System Margin (F+J)**	2,607	2,382	1,862	1,302	633	(17)	(727)	(1,497)	(2,257)
L	SCRs (7), (8)	721	721	721	721	721	721	721	721	721
M	**Statewide System Margin with SCR (K+L)**	3,328	3,103	2,583	2,023	1,353	703	(7)	(777)	(1,537)
N	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
O	**Statewide System Margin with Full Operating Reserve (M+N) (4)**	2,018	1,793	1,273	713	43	(607)	(1,317)	(2,087)	(2,847)

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Interchanges are based on ERAG MMWG values.
4. For informational purposes.
5. Reflects the 2025 Gold Book Forecast.
6. Includes all gas only units that do not have a firm gas contract. Also includes reductions in units with duct burner capabilities.
7. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
8. Includes a derate of 305 MW for SCRs.

Figure 18: Aging Generation Impact to Statewide System Margin

Aging Generation									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Aging Generator Capability Derate Impact	(63)	(178)	(322)	(601)	(927)	(1168)	(1510)	(2075)	(2378)
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
Aging Generator Capability Derate Impact	(33)	(125)	(257)	(515)	(629)	(819)	(1111)	(1634)	(1896)

Figure 19: Demand-Side Uncertainty Impact to Statewide System Margin

Demand-Side Uncertainty									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Higher Demand Impact	(600)	(1170)	(1650)	(2050)	(2330)	(2520)	(2660)	(2830)	(3160)
Lower Demand Impact	640	940	1200	1460	1770	2080	2420	2760	3050
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
Higher Demand Impact	(720)	(1300)	(1910)	(2310)	(2760)	(3360)	(4020)	(5010)	(5830)
Lower Demand Impact	810	1100	1520	1880	2310	2740	3110	3330	3620

Figure 20: Large Loads Impact to Statewide System Margin

Large Loads									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
No New Large Loads Impact	557	863	1034	1252	1539	1707	1870	2018	2063
Planned Large Loads with No Flexibility Impact	(685)	(685)	(685)	(685)	(685)	(685)	(685)	(685)	(685)
All Queue Large Loads with No Flexibility Impact	(120)	(2554)	(3100)	(5000)	(6060)	(8115)	(8115)	(8115)	(8115)
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
No New Large Loads Impact	617	869	1089	1344	1628	1791	1944	2081	2122
Planned Large Loads with No Flexibility Impact	(685)	(685)	(685)	(685)	(685)	(685)	(685)	(685)	(685)
All Queue Large Loads with No Flexibility Impact	(120)	(2554)	(3100)	(5000)	(6060)	(8115)	(8115)	(8115)	(8115)

Figure 21: Weather Variability Impact to Statewide System Margin

Statewide Weather Variability Impact									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Extreme Seasonal Weather:Heatwave (9010) Impact	(1236)	(1256)	(1264)	(1280)	(1300)	(1305)	(1325)	(1347)	(1365)
Mild Seasonal Weather (1090) Impact	2648	2669	2681	2695	2718	2740	2768	2796	2819
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
Extreme Seasonal Weather: Coldsnap (9010) Impact	(351)	(392)	(443)	(519)	(606)	(721)	(844)	(942)	(1079)
Mild Seasonal Weather (1090) Impact	1272	1317	1397	1477	1596	1775	1934	2102	2279

Figure 22: Reliance on Imports Impact to Statewide System Margin

Reliance on Neighbors									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
CHPE Unavailable Impact	(1250)	(1250)	(1250)	(1250)	(1250)	(1250)	(1250)	(1250)	(1250)
Neptune Unavailable	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)
Loss of All Firm Imports Impact	(3094)	(3094)	(3094)	(3094)	(3094)	(3094)	(3094)	(3094)	(3094)
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
CHPE Unavailable Impact	0	0	0	0	0	0	0	0	0
Neptune Unavailable	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)
Loss of All Firm Imports Impact	(735)	(735)	(735)	(735)	(735)	(735)	(735)	(735)	(735)

Figure 23: Nuclear Relicensing Impact to Statewide System Margin

Nuclear Relicensing									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Niclear Generation Not Relicensed Impact	0	0	0	0	(1175)	(1175)	(1175)	(1175)	(1175)
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
Niclear Generation Not Relicensed Impact	0	0	0	(1192)	(1192)	(1192)	(1192)	(1192)	(2031)

Figure 24: Demand Response Impact to Statewide System Margin

Demand Response									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Derated SCR Impact	804	804	804	804	804	804	804	804	804
All Enrolled SCR Impact	1205	1205	1205	1205	1205	1205	1205	1205	1205
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
Derated SCR Impact	721	721	721	721	721	721	721	721	721
All Enrolled SCR Impact	1026	1026	1026	1026	1026	1026	1026	1026	1026

Figure 25: Potential Project Delays Impact to Statewide System Margin

Project Transmission and Generation Project Delays									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Status Quo Impact	(1298)	(1655)	(1796)	(1776)	(1756)	(1736)	(1716)	(1716)	(1696)
CHPE Unavailable Impact	(1250)	(1250)	(1250)	(1250)	(1250)	(1250)	(1250)	(1250)	(1250)
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
Status Quo Impact	(262)	(446)	(446)	(446)	(446)	(446)	(446)	(446)	(446)
CHPE Unavailable Impact	0	0	0	0	0	0	0	0	0

Figure 26: Additional Resources Impact to Statewide System Margin

Additional Resources									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
CBA (Storage Off) Impact	66	181	639	733	691	648	606	606	564
CBA (Storage On) Impact	644	1437	2869	3392	3350	3308	3266	3266	3223
Retain/Replace NYPA GTs Impact	0	0	0	0	0	408	408	408	408
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
CBA (Storage Off) Impact	82	174	174	174	174	174	174	174	174
CBA (Storage On) Impact	1056	2284	2833	2833	2833	2833	2833	2833	2833
Retain/Replace NYPA GTs Impact	0	0	0	0	410	410	410	410	410

New York City Transmission Security Margin

Figure 27: New York City Transmission Security Margin – Baseline Summer Peak

Line	Item	Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW)								
		2026	2027	2028	2029	2030	2031	2032	2033	2034
A	**Zone J Demand Forecast**	(10,790)	(10,820)	(10,840)	(10,860)	(10,880)	(10,930)	(11,010)	(11,080)	(11,170)
B	I+K to J (3)	4,700	4,700	4,700	4,700	4,800	4,800	4,800	4,800	4,800
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	4,689	4,689	4,689	4,689	4,789	4,789	4,789	4,789	4,789
E	Loss of Source Contingency	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)
F	**Resource Need (A+D+E)**	(8,336)	(8,366)	(8,386)	(8,406)	(8,326)	(8,376)	(8,456)	(8,526)	(8,616)
G	J Generation (1)	8,123	8,939	8,939	8,939	8,939	8,529	8,529	8,529	8,529
H	J Generation Derates (2)	(677)	(1,411)	(1,411)	(1,411)	(1,411)	(1,369)	(1,369)	(1,369)	(1,369)
I	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
J	Net ICAP External Imports	1,565	1,565	1,565	1,565	1,565	1,565	1,565	1,565	1,565
K	**Total Resources Available (G+H+I+J)**	9,011	9,093	9,093	9,093	9,093	8,725	8,725	8,725	8,725
L	**Baseline Transmission Security Margin (F+K)**	675	727	707	687	767	349	269	199	109
M	Higher Demand Impact	(130)	(220)	(330)	(470)	(630)	(720)	(790)	(880)	(960)
N	**Higher Demand Transmission Security Margin (L+M)**	545	507	377	217	137	(371)	(521)	(681)	(851)

Notes:
1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Limits for 2026 through 2029 are based on the summer peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on the summer peak 2034 representations evaluated in the 2024 RNA.

Figure 28: New York City Transmission Security Margin – Baseline Winter Peak

Line	Item	Winter Peak - Baseline Expected Weather, Normal Transfer Criteria (MW)								
		2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
A	**Zone J Demand Forecast**	(7,580)	(7,650)	(7,800)	(7,930)	(8,070)	(8,240)	(8,410)	(8,610)	(8,830)
B	I+K to J (3)	3,900	3,900	3,900	3,900	4,900	4,900	4,900	4,900	4,900
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	3,889	3,889	3,889	3,889	4,889	4,889	4,889	4,889	4,889
E	Loss of Source Contingency	(973)	(973)	(973)	(973)	(1,606)	(1,606)	(1,606)	(1,606)	(1,606)
F	**Resource Need (A+D+E)**	(4,664)	(4,734)	(4,884)	(5,014)	(4,787)	(4,957)	(5,127)	(5,327)	(5,547)
G	J Generation (1)	9,433	9,433	9,433	9,433	9,021	9,021	9,021	9,021	9,021
H	J Generation Derates (2)	(1,279)	(1,279)	(1,279)	(1,279)	(1,278)	(1,278)	(1,278)	(1,278)	(1,278)
I	Unavailability of Non-Firm Gas (4)	(2,057)	(2,057)	(2,057)	(2,057)	(1,646)	(1,646)	(1,646)	(1,646)	(1,646)
J	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
K	Net ICAP External Imports	315	315	315	315	315	315	315	315	315
L	**Total Resources Available (G+H+I+J+K)**	6,412	6,412	6,412	6,412	6,412	6,412	6,412	6,412	6,412
M	Transmission Security Margin (F+L)	1,748	1,678	1,528	1,398	1,625	1,455	1,285	1,085	865

Notes:
1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Limits for 2026 through 2029 are based on the winter peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on the winter peak 2034 representations evaluated in the 2024 RNA.
4. Includes all gas only units that do not have a firm gas contract.

Figure 29: Aging Generation Impact to NYC Transmission Security Margin

Zone J - Aging Generation									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Aging Generator Capability Derate Impact	(45)	(91)	(135)	(295)	(502)	(589)	(854)	(1351)	(1475)
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
Aging Generator Capability Derate Impact	(31)	(61)	(92)	(238)	(292)	(343)	(572)	(1040)	(1137)

Figure 30: Demand-Side Uncertainty Impact to NYC Transmission Security Margin

Zone J - Demand-Side Uncertainty									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Higher Demand Impact	(130)	(220)	(330)	(470)	(630)	(720)	(790)	(880)	(960)
Lower Demand Impact	220	350	500	630	730	880	1010	1110	1220
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
Higher Demand Impact	(160)	(230)	(310)	(390)	(490)	(650)	(810)	(1080)	(1220)
Lower Demand Impact	280	400	580	750	950	1090	1230	1270	1360

Figure 31: Reliance on Imports Impact to NYC Transmission Security Margin

Zone J - Reliance on Imports									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
CHPE Unavailable Impact	(800)	(800)	(800)	(800)	(700)	(700)	(700)	(700)	(700)
Neptune Unavailable Impact	0	0	0	0	0	0	0	0	0
Loss of All Firm Imports Impact	(1115)	(1115)	(1115)	(1115)	(1015)	(1015)	(1015)	(1015)	(1015)
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
CHPE Unavailable Impact	0	0	0	0	0	0	0	0	0
Neptune Unavailable Impact	0	0	0	0	0	0	0	0	0
Loss of All Firm Imports Impact	(315)	(315)	(315)	(315)	(315)	(315)	(315)	(315)	(315)

Figure 32: Potential Project Delays Impact to NYC Transmission Security Margin

Zone J - Project Transmission and Generation Project Delays									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Status Quo Impact	(800)	(882)	(882)	(882)	(982)	(982)	(982)	(982)	(982)
CHPE Delay Impact	(800)	(800)	(800)	(800)	(700)	(700)	(700)	(700)	(700)
LIPPTN Delay Impact	0	0	0	0	(100)	(100)	(100)	(100)	(100)
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
Status Quo Impact	(163)	(163)	(163)	(163)	(530)	(530)	(530)	(530)	(530)
CHPE Unavailable Impact	0	0	0	0	0	0	0	0	0
LIPPTN Delay Impact	0	0	0	0	(367)	(367)	(367)	(367)	(367)

Figure 33: Additional Resources Impact to NYC Transmission Security Margin

Zone J - Additional Resources									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
CBA (Storage Off) Impact	0	0	0	0	0	0	0	0	0
CBA (Storage On) Impact	137	343	743	743	743	743	743	743	743
Retain/Replace NYPA GTs Impact	0	0	0	0	0	367	367	367	367
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
CBA (Storage Off) Impact	0	0	0	0	0	0	0	0	0
CBA (Storage On) Impact	187	643	743	743	743	743	743	743	743
Retain/Replace NYPA GTs Impact	0	0	0	0	369	369	369	369	369

Long Island Transmission Security Margin

Figure 34: Long Island Transmission Security Margin – Baseline Summer Peak

Line	Item	Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW)								
		2026	2027	2028	2029	2030	2031	2032	2033	2034
A	**Zone K Demand Forecast**	(4,996)	(5,017)	(5,038)	(5,083)	(5,151)	(5,222)	(5,281)	(5,344)	(5,396)
B	I+J to K (3)	900	900	900	900	2,200	2,200	2,200	2,200	2,200
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	900	900	900	900	2,200	2,200	2,200	2,200	2,200
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	0	0	0	0	0
F	**Resource Need (A+D+E)**	(4,756)	(4,777)	(4,798)	(4,843)	(2,951)	(3,022)	(3,081)	(3,144)	(3,196)
G	K Generation (1)	4,901	4,901	5,825	5,825	5,825	5,780	5,780	5,780	5,780
H	K Generation Derates (2)	(622)	(623)	(1,455)	(1,456)	(1,456)	(1,452)	(1,452)	(1,452)	(1,453)
I	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
J	Net ICAP External Imports	660	660	660	660	660	660	660	660	660
K	**Total Resources Available (G+H+I+J)**	4,939	4,938	5,029	5,029	5,028	4,988	4,987	4,987	4,987
L	**Transmission Security Margin (F+K)**	183	161	231	186	2,077	1,966	1,906	1,843	1,791
M	Higher Demand Impact	(43)	(34)	(30)	(24)	(36)	(47)	(63)	(65)	(110)
N	**Higher Demand Transmission Security Margin (L+M)**	140	127	201	162	2,041	1,919	1,843	1,778	1,681

Notes:
1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2023 https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Limits for 2026 through 2029 are based on the 2024 LIPA Summer Operating Study. Limits for 2030 through 2034 are based on the 2034-2035W winter peak representations evaluated in the 2024 RNA.

Figure 35: Long Island Transmission Security Margin – Baseline Winter Peak

Line	Item	Winter Peak - Baseline Expected Weather, Normal Transfer Criteria (MW)								
		2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
A	**Zone K Demand Forecast**	(3,276)	(3,349)	(3,478)	(3,630)	(3,770)	(3,919)	(4,057)	(4,178)	(4,286)
B	I+J to K (3), (4)	900	900	900	900	2,500	2,500	2,500	2,500	2,500
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	900	900	900	900	2,500	2,500	2,500	2,500	2,500
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(399)	(399)	(399)	(399)	(399)
F	**Resource Need (A+D+E)**	(3,036)	(3,109)	(3,238)	(3,390)	(1,669)	(1,818)	(1,956)	(2,077)	(2,185)
G	K Generation (1)	5,320	6,244	6,244	6,244	6,198	6,198	6,198	6,198	6,198
H	K Generation Derates (2)	(640)	(1,379)	(1,379)	(1,379)	(1,379)	(1,379)	(1,379)	(1,379)	(1,379)
I	Shortage of Gas Fuel Supply (5)	(318)	(318)	(318)	(318)	(272)	(272)	(272)	(272)	(272)
J	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
K	Net ICAP External Imports	660	660	660	660	660	660	660	660	660
L	**Total Resources Available (G+H+I+J+K)**	5,022	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207
M	Transmission Security Margin (F+L)	1,986	2,098	1,969	1,817	3,539	3,390	3,252	3,131	3,023

Notes:
1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. For winter the expected solar PV output at peak is 0 MW. Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Limits for 2026 through 2029 are based on the 2024 LIPA Summer Operating Study. Limits for 2030 through 2034 are based on the 2034-2035W winter peak representations evaluated in the 2024 RNA.
4. As a conservative winter peak assumption these limits utilize the summer values through 2029-2030W.
5. Includes all gas only units that do not have a firm gas contract.

Figure 36: Aging Generation Impact to LI Transmission Security Margin

Zone K - Aging Generation									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Aging Generator Capability Derate Impact	(0)	(52)	(118)	(215)	(262)	(389)	(442)	(489)	(641)
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
Aging Generator Capability Derate Impact	(1)	(59)	(137)	(242)	(294)	(428)	(485)	(536)	(693)

Figure 37: Demand-Side Uncertainty Impact to LI Transmission Security Margin

Zone K - Demand-Side Uncertainty									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Higher Demand Impact	(43)	(34)	(30)	(24)	(36)	(47)	(63)	(65)	(110)
Lower Demand Impact	16	56	92	148	223	297	356	417	466
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
Higher Demand Impact	(20)	(15)	(29)	(88)	(155)	(246)	(348)	(529)	(601)
Lower Demand Impact	47	87	187	256	345	406	477	511	538

Figure 38: Reliance on Imports Impact to LI Transmission Security Margin

Zone K - Reliance on Imports									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
CHPE Unavailable Impact	0	0	0	0	0	0	0	0	0
Neptune Unavailable	(600)	(600)	(600)	(600)	(660)	(660)	(660)	(660)	(660)
Loss of All Firm Imports Impact	(600)	(600)	(600)	(600)	(660)	(660)	(660)	(660)	(660)
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
CHPE Unavailable Impact	0	0	0	0	0	0	0	0	0
Neptune Unavailable	(433)	(439)	(449)	(463)	(660)	(660)	(660)	(660)	(660)
Loss of All Firm Imports Impact	(433)	(439)	(449)	(463)	(660)	(660)	(660)	(660)	(660)

Figure 39: Potential Project Delays Impact to LI Transmission Security Margin

Zone K - Project Transmission and Generation Project Delays									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Status Quo Impact	0	0	(92)	(92)	(2052)	(2052)	(2052)	(2052)	(2052)
CHPE Delay Impact	0	0	0	0	0	0	0	0	0
LIPPTN Delay Impact	0	0	0	0	(1960)	(1960)	(1960)	(1960)	(1960)
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
Status Quo Impact	0	(185)	(185)	(185)	(2046)	(2046)	(2046)	(2046)	(2046)
CHPE Delay Impact	0	0	0	0	0	0	0	0	0
LIPPTN Delay Impact	0	0	0	0	(1861)	(1861)	(1861)	(1861)	(1861)

Figure 40: Additional Resources Impact to LI Transmission Security Margin

Zone K - Additional Resources									
Summer Margin Impacts	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
CBA (Storage Off) Impact	0	6	6	5	5	5	4	4	4
CBA (Storage On) Impact	186	620	860	859	859	859	858	858	858
Retain/Replace NYPA GTs Impact	0	0	0	0	0	40	40	40	40
Winter Margin Impacts	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
CBA (Storage Off) Impact	0	0	0	0	0	0	0	0	0
CBA (Storage On) Impact	487	854	854	854	854	854	854	854	854
Retain/Replace NYPA GTs Impact	0	0	0	0	0	40	40	40	40

Appendix E: Resource Adequacy Background

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

The NYISO conducts its resource adequacy analysis using the GE-MARS software package, which performs probabilistic simulations of outages of capacity and select transmission resources. The program employs a sequential Monte Carlo simulation method and calculates expected values of reliability indices such as LOLE (event-days/year) and includes load, generation, and transmission representation. The NYISO considers several types of randomly occurring events in performing the resource adequacy analysis. Among these are the forced outages of generation and transmission and deviations from the forecasted loads.

Starting with the 2024 RNA[11], planning models reflected several changes highlighted below:

- To account for winter uncertainties:
  - Dynamic LFU: On the demand side, increasing winter peak load forecast uncertainty (throughout the study years) was modeled to account for the impacts of heating electrification, EV charging, and large loads.
  - Winter Gas Unavailability: On the resources side, the risk of gas unavailability mainly related to gas-only plants was implemented.
- **New Data Sources**: Used five years of hourly MW model-based data developed by DNV-GL for land-based and offshore wind, and front of the meter solar.
- **Further Limiting External Reliance**: Modeled the top five (changed from the top three starting with the 2024 RNA as an additional method to further limit reliance) summer and winter peak load days of an external Control Area are modeled as coincident with the NYCA top five peak load days.
- **SCR Model**: Modeled SCRs as duration-limited resources with units being limited to being called once in a day when a loss of load event occurs.
- **Large Loads**: Assumed certain proposed large loads to be flexible and will decrease demand

[11] 2024 RNA: https://www.nyiso.com/documents/20142/48283847/2024-RNA-Appendices.pdf; https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf

on peak days. This was modeled in GE-MARS as an EOP step before the SCR step.

Modeling Assumptions

Generation Model

The NYISO models the generation system in GE-MARS using several types of units. Thermal unit considerations include random forced outages, scheduled and unplanned maintenance, and thermal derates (lesser of CRIS and DMNC MW is used for both summer and winter). Renewable resource units (i.e., both utility and behind the meter solar PV, wind, run-of-river hydro, and landfill gas) are modeled using five years of historical production data. Co-generation units are also modeled using a capacity and load profile for each unit. Starting with the 2024 RNA, the resource adequacy assessments make the following assumptions about 6,400 MW of gas plants (about 5,600 MW located in F through K) during winter to account for cold weather risks:[12] (1) assumes all gas-only units with non-firm gas within the NYCA are unavailable and (2) certain dual-fuel units modeled at their alternate fuel capability. Both assumptions are triggered at the forecasted baseline winter coincident peak. This is a static value applied to all load levels. Therefore, the gas constraint triggers more often at the higher GE-MARS load levels (i.e., bins 1-3).

Load Model

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

Beginning with the 2022 RNA, the NYISO chose to use historical shapes for 2013, 2017, and 2018 based on detailed analysis performed by the NYISO over about 20 years of data.[13] The load bin distribution in MARS is set forth below.

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

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

- 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 and was selected to represent Bins 3 and 4. Bin 4 represents the expected (average) weather and load level.
- Load Bins 5 to 7: 2017
    - 2017 had a cool summer peak day and a relatively flat load shape. 2017 is selected to represent Bins 5 through 7, which represent summers with milder than expected peak weather conditions.

Additionally, starting with the 2024 RNA, the NYISO implemented a winter dynamic load forecast uncertainty[14] to account for forecast uncertainty during winter due to electrification and large loads in the GE-MARS model.

External Areas Model

The NYISO models the four external Control Areas interconnected to the NYCA (ISO-New England, PJM, Ontario, and Quebec). The transfer limits between the NYCA and the external Control Areas are set in collaboration with the NPCC CP-8 Working Group. Additionally, the probabilistic model used in GE-MARS employs a number of methods aimed at preventing the NYISO's overreliance on support from the external Control Areas. These include imposing a limit of 3,500 MW to the total emergency assistance from all neighbors, modeling simultaneous five peak days (changed from three 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 Study Period.

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 GE-MARS model.

Emergency Operating Procedures (EOPs)

The New York model evaluates the need to implement in sequential order a number of emergency operating procedures, such as operating reserves, Special Case Resources (SCRs), manual voltage

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

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

Beginning with the 2024 RNA, the NYISO maintains (i.e., no longer depletes) 350 MW of the 1,310 MW 10-min operating reserves as part of the EOPs in GE-MARS.[15] In the 2024 RNA, the NYISO used an updated value of 400 MW, which was discussed with the NYSRC Installed Capacity Subcommittee.[16] Additionally, the SCR model (a demand response program) was changed starting with the 2024 RNA (additional details in the assumption matrix in Appendix E of the 2024 RNA).

MARS Topology

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

The NYISO used the summer emergency ratings from power flow models to model to represent the internal transfer limits.

Resource Adequacy Results

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 three additional reliability indices for informational purposes—loss of load hours (LOLH in event-hours/year), expected unserved energy (EUE in MWh/year) and normalized expected unserved energy (NEUE in % or parts per million (ppm)).[17] 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.

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

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

[17] NYSRC's "Resource Adequacy Metrics and their Application" is available at: https://www.nysrc.org/wp-content/uploads/2023/03/Resource-Adequacy-Metric-Report-Final-4-20-20206431.pdf .

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.

NEUE is defined as the ratio of EUE to the total NYCA energy forecast. It is typically expressed either in parts per million by multiplying the ratio by 10^6, or as a percentage, by multiplying by 100. Normalizing EUE in this manner provides a consistent measure of reliability performance relative to the size of the system.[18] While currently there is no criteria for New York for EUE, one of the reference points used in industry for normalized EUE is 20 ppm.

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, EUE, NEUE) 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.

Equation 8: Resource Adequacy Metric Definitions

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

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

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

$$\text{NYCA NEUE (ppm)} = \frac{\text{NYCA EUE (MWh/year)} \cdot 10^6}{\text{NYCA Energy Forecast (MWh/year)}}$$

[18] Evolving Planning Criteria for a Sustainable Power Grid: A workshop Report (NERC): https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Evolving_Planning_Criteria_for_a_Sustainable_Power_Grid.pdf

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

Baseline Results

Results using updated GE-MARS models based on the *2025 Gold Book* are below, for various demand forecasts and considering aging generation risks.

The below figure shows the LOLE results for annual versus summer versus winter, as well as LOLH, EUE, and NEUE results. For comparison purposes only (as there is currently no reliability criteria for New York), the value for NYCA year 10 is at 0.43 ppm, which is well below a 20 ppm industry-reference point for NEUE.

Figure 41: 2025 RPP Baseline System with Additional Reliability Indices

Study Year	LOLE (event-days/yr)			LOLH	EUE	NEUE
	Annual	Summer	Winter	hrs/yr	MWh/yr	ppm
2026	0.015	0.015	0.000	0.036	8	0.054
2027	0.007	0.007	0.000	0.016	4	0.028
2028	0.009	0.008	0.000	0.021	5	0.031
2029	0.010	0.010	0.000	0.025	7	0.042
2030	0.008	0.008	0.000	0.016	6	0.040
2031	0.019	0.019	0.000	0.044	22	0.134
2032	0.024	0.024	0.000	0.059	32	0.190
2033	0.029	0.026	0.004	0.073	43	0.249
2034	0.052	0.031	0.021	0.129	75	0.430

The baseline model (with assuming certain large loads as flexible) continues to be below its NYCA annual LOLE criterion of 0.1 event-days/year. When layering aging uncertainties, the baseline model indicates violations starting 2033 (study year 9).

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

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

"Perfect capacity" is capacity that is not derated (*e.g.,* due to ambient temperature or unit unavailability), not subject to energy durations limitations (*i.e.*, available at maximum capacity every hour of the study year), and not tested for transmission security or interface impacts. The results are in Figure 42 below and show that, for instance, for the study year 2034, while the LOLE is at 0.05 event-days/year, if the system loses about 600 perfect MW in any zone, the NYCA will violate the criteria. The ZRAM/Compensatory MW assessment identifies a maximum level of "perfect capacity" that can be removed/added from/to each zone without causing a violation of the NYCA LOLE criterion. However, the impacts of removing (or adding) capacity on the reliability of the transmission system and on transfer capability are highly dependent on location. Thus, removal of lower amounts of real capacity are likely to result in reliability issues at specific transmission locations.

Figure 42: Baseline System - Zonal Resource Adequacy Margin

Study Year	Base Case LOLE event-days/year	Zone A MW	Zone B MW	Zone C MW	Zone D MW	Zone E MW	Zone F MW	Zone G MW	Zone H MW	Zone I MW	Zone J MW	Zone K MW
2026	0.015	1700	1700	2800	1800	2800	2800	2800	2300	2300	1800	500
2027	0.007	1800	1900	3100	1600	3100	3100	3100	2700	2700	2200	700
2028	0.009	1700	1800	2600	1600	2600	2600	2600	2400	2400	2100	700
2029	0.010	1800	1800	2500	1600	2500	2500	2500	2300	2300	2000	600
2030	0.008	1800	1900	2900	1500	2900	2900	2900	2600	2600	2400	1300
2031	0.019	1700	1700	2000	1400	2000	2000	2000	1900	1900	1800	1000
2032	0.024	1500	1500	1700	1400	1700	1700	1700	1600	1600	1500	900
2033	0.029	1200	1200	1200	1100	1200	1200	1200	1200	1200	1200	800
2034	0.052	600	600	600	600	600	600	600	600	600	600	500

When considering the higher demand forecast, NYCA LOLE is above starting 2031 (study year 6). Adding aging generation risks advances the NYCA LOLE violations to 2029 (study year 4).

Figure 43: 2025 RPP Models LOLE Results

Study Year	Baseline	+ Aging	Higher Demand	+ Aging	Lower Demand	+ Aging
2026	0.015	0.016	0.026	0.027	0.011	0.011
2027	0.007	0.009	0.022	0.041	0.003	0.004
2028	0.009	0.013	0.036	0.045	0.004	0.006
2029	0.010	0.025	0.073	0.100	0.003	0.007
2030	0.008	0.019	0.073	0.155	0.000	0.002
2031	0.019	0.049	0.195	0.418	0.002	0.007
2032	0.024	0.083	0.358	1.030	0.001	0.010
2033	0.029	0.170	0.950	3.772	0.001	0.014
2034	0.052	0.415	2.469	7.866	0.001	0.020

Although a violation of the LOLE is not identified, the NYCA LOLE approaches the 0.1 event-days per year criterion in 2034. This indicates that not much surplus power would remain in ten years without further resource development. However, as shown below, this result relies on the use of EOPs (e.g., receiving assistance from neighboring regions) and the assumed flexibility of certain large load facilities (i.e., cryptocurrency mining and hydrogen production) during system peak conditions. The forecasted resource adequacy is also heavily impacted by the assumed unavailability of approximately 6,400 MW of non-firm, gas-only generation during winter peak demand periods.

Figure 44: Baseline and Baseline with Aging NYCA LOLE Results after each EOP

		Baseline - NYCA LOLE (event-days/year) by EOP Step								
Step	EOP	2026	2027	2028	2029	2030	2031	2032	2033	2034
1	No EOP Support	3.202	3.143	3.544	4.073	2.968	4.320	6.540	10.074	12.869
2	Flexible Large Loads	2.630	2.466	2.870	3.394	2.073	3.195	4.981	7.653	9.789
3	Special Case Resources (SCRs) (Load and Generator)	1.912	1.642	2.014	2.480	1.107	1.896	3.154	5.030	6.612
4	5% Manual Voltage Reduction	1.867	1.580	1.945	2.401	1.036	1.794	2.998	4.808	6.346
5	30-Minute Operating Reserve to Zero (655MW)	0.759	0.806	1.139	1.503	0.568	1.037	1.810	3.025	4.268
6	Voluntary Load Curtailment	0.616	0.644	0.944	1.259	0.447	0.840	1.471	2.487	3.653
7	Public Appeals	0.546	0.609	0.905	1.212	0.421	0.794	1.401	2.371	3.518
8	5% Remote Controlled Voltage Reduction	0.396	0.432	0.692	0.927	0.285	0.570	1.006	1.733	2.757
9	Emergency Assistance from External Areas	0.066	0.038	0.041	0.046	0.046	0.075	0.085	0.105	0.167
10	Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero	0.015	0.007	0.009	0.010	0.008	0.019	0.024	0.029	0.052

		Baseline w/Ageing - NYCA LOLE (event-days/year) by EOP Step								
Step	EOP	2026	2027	2028	2029	2030	2031	2032	2033	2034
1	No EOP Support	3.166	3.271	4.008	5.404	4.668	7.912	13.272	27.021	39.740
2	Flexible Large Loads	2.612	2.560	3.242	4.605	3.433	5.984	10.295	20.582	30.313
3	Special Case Resources (SCRs) (Load and Generator)	1.909	1.711	2.299	3.447	1.997	3.827	6.955	14.076	20.872
4	5% Manual Voltage Reduction	1.867	1.648	2.226	3.352	1.894	3.660	6.699	13.584	20.133
5	30-Minute Operating Reserve to Zero (655MW)	0.761	0.805	1.182	1.868	1.069	2.185	4.308	9.130	13.661
6	Voluntary Load Curtailment	0.618	0.638	0.978	1.565	0.860	1.805	3.641	7.910	11.891
7	Public Appeals	0.547	0.594	0.923	1.476	0.807	1.702	3.454	7.576	11.408
8	5% Remote Controlled Voltage Reduction	0.399	0.424	0.699	1.147	0.576	1.267	2.667	6.126	9.463
9	Emergency Assistance from External Areas	0.068	0.043	0.053	0.074	0.078	0.134	0.195	0.379	0.856
10	Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero	0.016	0.009	0.013	0.025	0.019	0.049	0.083	0.170	0.415

Notes:
1. NYCA annual LOLE is at step 10. Red font indicates exceeding NYCA LOLE criterion.
2. Orange font indicates LOLE above 0.1 event-days/year; however, the current NYSRC and NPCC criterion applies only to step 10, NYCA annual LOLE.
3. Figure 50 through Figure 55 in the main report illustrates Step 2 as pre-EOP conditions, rather than Step 1 (no EOP support).

Additional scenarios were performed—such as removing all the proposed generation and certain transmission projects ("status-quo") or removing Champlain Hudson Power Express (CHPE). The results from these two scenarios are shown in the figure below. When removing CHPE—the 1,250MW proposed HVDC line from Quebec to New York City, the NYCA LOLE increases close to criterion in 2034. When removing all the proposed generation and key transmission projects (CHPE and Propel NY Alternate 5), the NYCA LOLE is above criterion starting 2031.

Figure 45: 2025 RPP - Additional Risk Scenarios

Study Year	Baseline	CHPE Off	Status Quo
2026	**0.015**	0.032	0.041
2027	**0.007**	0.017	0.050
2028	**0.009**	0.018	0.048
2029	**0.010**	0.021	0.057
2030	**0.008**	0.022	0.067
2031	**0.019**	0.043	0.104
2032	**0.024**	0.056	0.148
2033	**0.029**	0.064	0.183
2034	**0.052**	0.093	0.272

If there were to be an LOLE criterion violation, the NYISO's next step would be to look to solutions, which may include resources currently under development. The NYISO's interconnection queue[19] is busier than ever with over 400 proposed projects in various interconnection development stages. Of these, about 100 have already completed facilities studies. A portion of these projects have also met the RPP inclusion rules, while others have not. When adding the proposed projects that have met the inclusion rules to the RPP model with the assumed aging generation risk, the system LOLE decreases as shown in the body of the report.

Higher Demand Results

To assess the risk of uncertainties to reliability, the NYISO developed additional MARS models using the Higher and Lower Demand forecasts from the *2025 Gold Book*. These models are intended to provide a well-rounded view of possible system conditions and risks.

[19] NYISO Interconnection Queue: https://www.nyiso.com/documents/20142/1407078/NYISO-Interconnection-Queue.xlsx

Figure 46: 2025 RPP Higher Demand and Higher Demand with Aging with Additional Reliability Indices

Study	Higher Demand LOLE			LOLH	EUE	NEUE
Year	Annual	Summer	Winter	hrs/yr	MWh/yr	ppm
2026	0.026	0.026	0.000	0.066	22	0.136
2027	0.022	0.022	0.000	0.053	23	0.139
2028	0.036	0.033	0.003	0.090	45	0.266
2029	0.073	0.050	0.022	0.186	106	0.601
2030	0.073	0.069	0.004	0.196	140	0.769
2031	0.195	0.171	0.024	0.584	494	2.64
2032	0.358	0.264	0.094	1.118	992	5.143
2033	0.950	0.363	0.587	3.143	3002	15.157
2034	2.469	0.620	1.848	8.171	11285	55.241

Study	Higher Demand w/Aging LOLE			LOLH	EUE	NEUE
Year	Annual	Summer	Winter	hrs/yr	MWh/yr	ppm
2026	0.027	0.027	0.000	0.068	23	0.143
2027	0.041	0.041	0.000	0.110	52	0.313
2028	0.044	0.042	0.003	0.113	60	0.348
2029	0.100	0.080	0.020	0.273	168	0.950
2030	0.153	0.148	0.005	0.446	350	1.923
2031	0.417	0.379	0.038	1.476	1495	7.999
2032	1.030	0.781	0.249	3.630	3847	19.950
2033	3.772	1.914	1.858	13.081	15874	80.135
2034	7.866	4.043	3.823	28.252	47331	231.695

Notes:
1. NYCA annual LOLE is at step 10. Red font indicates exceeding NYCA LOLE criteria.
2. Orange font indicates LOLE above 0.1 event-days/year; however, the current NYSRC and NPCC criterion applies only to step 10, NYCA annual LOLE.

When using the Higher Demand Forecast, NYCA annual LOLE violations can occur as early as 2031. Layering aging generation risks into this scenario, the NYCA LOLE is above criterion starting year 2030. As shown in the figure below, these results rely on the use of EOPs (e.g., receiving assistance from neighboring regions) and the assumed flexibility of certain large load facilities (i.e., cryptocurrency mining and hydrogen production) during system peak conditions. The forecasted resource adequacy is also heavily impacted by the assumed unavailability of approximately 6,400 MW of non-firm, gas-only generation during winter peak demand periods.

Figure 47: Higher Demand and Higher Demand with Aging NYCA LOLE Results after each EOP

		Higher Demand - NYCA LOLE (event-days/year) by EOP Step								
Step		2026	2027	2028	2029	2030	2031	2032	2033	2034
1	No EOP Support	4.23	6.596	7.993	10.729	13.305	24.938	38.44	70.388	106.647
2	Flexible Large Loads	3.471	5.474	6.73	9.059	10.349	18.544	28.789	54.672	85.619
3	Special Case Resources (SCRs) (Load and Generator)	2.504	3.938	5.002	7.073	7.027	12.199	18.886	37.431	61.125
4	5% Manual Voltage Reduction	2.442	3.795	4.849	6.904	6.728	11.661	18.077	35.897	58.688
5	30-Minute Operating Reserve to Zero (655MW)	1.139	2.607	3.604	5.046	4.864	8.112	12.55	24.712	40.918
6	Voluntary Load Curtailment	0.93	2.214	3.175	4.614	4.211	7.079	10.992	21.396	35.275
7	Public Appeals	0.844	2.16	3.113	4.521	4.093	6.846	10.602	20.553	33.869
8	5% Remote Controlled Voltage Reduction	0.633	1.663	2.533	3.889	3.186	5.522	8.77	16.876	27.346
9	Emergency Assistance from External Areas	0.093	0.084	0.121	0.218	0.187	0.382	0.746	1.965	3.796
10	Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero	0.026	0.022	0.036	0.073	0.073	0.195	0.358	0.950	2.469
		Higher Demand w/Ageing - NYCA LOLE (event-days/year) by EOP Step								
Step		2026	2027	2028	2029	2030	2031	2032	2033	2034
1	No EOP Support	4.142	7.804	8.857	13.867	20.545	44.248	77.360	145.946	205.956
2	Flexible Large Loads	3.409	6.308	7.435	11.685	15.599	33.400	59.996	121.252	181.618
3	Special Case Resources (SCRs) (Load and Generator)	2.473	4.436	5.498	9.169	10.478	22.218	41.109	91.112	148.361
4	5% Manual Voltage Reduction	2.411	4.281	5.323	8.969	10.053	21.259	39.408	88.084	144.721
5	30-Minute Operating Reserve to Zero (655MW)	1.119	2.406	3.784	6.121	7.065	14.385	26.844	63.661	113.578
6	Voluntary Load Curtailment	0.918	1.993	3.317	5.515	6.098	12.395	23.175	55.640	102.201
7	Public Appeals	0.831	1.879	3.238	5.343	5.892	11.895	22.234	53.607	99.226
8	5% Remote Controlled Voltage Reduction	0.624	1.412	2.586	4.552	4.646	9.649	18.246	44.669	85.195
9	Emergency Assistance from External Areas	0.092	0.115	0.126	0.259	0.318	0.758	2.043	6.483	12.240
10	Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero	0.027	0.041	0.044	0.100	0.153	0.417	1.030	3.772	7.866

Notes:
1. NYCA annual LOLE is at step 10. Red font indicates exceeding NYCA LOLE.
2. Orange font indicates LOLE above 0.1 event-days/year; however, the current NYSRC and NPCC criterion applies only to step 10, NYCA annual LOLE.

Lower Demand Results

The results for a lower demand forecast are below. The NYCA LOLE is below its criterion throughout the study period, even after layering generation aging risks. As shown in the figure below, these results rely on the use of EOPs (e.g., receiving assistance from neighboring regions) and the assumed flexibility of certain large load facilities (i.e., cryptocurrency mining and hydrogen production) during system peak conditions. The forecasted resource adequacy is also heavily impacted by the assumed unavailability of approximately 6,400 MW of non-firm, gas-only generation during winter peak demand periods.

Figure 48: 2025 RPP Lower Demand and Lower Demand with Aging with Additional Reliability Indices

Study	Lower Demand LOLE			LOLH	EUE	NEUE
Year	Annual	Summer	Winter	hrs/yr	MWh/yr	ppm
2026	**0.011**	0.011	0.000	0.027	5.055	0.034
2027	**0.003**	0.003	0.000	0.007	1.183	0.008
2028	**0.004**	0.004	0.000	0.011	1.643	0.011
2029	**0.003**	0.003	0.000	0.007	1.388	0.009
2030	**0.000**	0.000	0.000	0.001	0.170	0.001
2031	**0.002**	0.002	0.000	0.003	0.722	0.005
2032	**0.001**	0.001	0.000	0.003	0.709	0.005
2033	**0.001**	0.001	0.000	0.002	0.624	0.004
2034	**0.001**	0.001	0.000	0.002	0.640	0.004

Study	Lower Demand w/Aging LOLE			LOLH	EUE	NEUE
Year	Annual	Summer	Winter	hrs/yr	MWh/yr	ppm
2026	**0.011**	0.011	0.000	0.028	5	0.036
2027	**0.004**	0.004	0.000	0.010	2	0.011
2028	**0.006**	0.006	0.000	0.016	3	0.019
2029	**0.007**	0.007	0.000	0.019	3	0.023
2030	**0.002**	0.002	0.000	0.004	1	0.008
2031	**0.007**	0.007	0.000	0.014	5	0.036
2032	**0.010**	0.010	0.000	0.021	8	0.055
2033	**0.014**	0.013	0.000	0.034	16	0.103
2034	**0.020**	0.019	0.001	0.048	23	0.149

Figure 49: Lower Demand and Lower Demand with Aging NYCA LOLE Results after each EOP

		Lower Demand - NYCA LOLE (event-days/year) by EOP Step								
Step	EOP	2026	2027	2028	2029	2030	2031	2032	2033	2034
1	No EOP Support	2.510	1.820	1.680	1.983	0.623	0.922	1.157	1.559	2.259
2	Flexible Large Loads	2.054	1.389	1.271	1.511	0.394	0.614	0.752	1.024	1.522
3	Special Case Resources (SCRs) (Load and Generator)	1.517	0.946	0.874	0.996	0.188	0.313	0.360	0.545	0.835
4	5% Manual Voltage Reduction	1.491	0.916	0.848	0.958	0.176	0.294	0.336	0.513	0.784
5	30-Minute Operating Reserve to Zero (655MW)	0.526	0.326	0.363	0.496	0.077	0.145	0.165	0.272	0.440
6	Voluntary Load Curtailment	0.416	0.244	0.285	0.390	0.058	0.112	0.126	0.211	0.344
7	Public Appeals	0.353	0.212	0.260	0.371	0.053	0.104	0.115	0.197	0.328
8	5% Remote Controlled Voltage Reduction	0.258	0.149	0.189	0.263	0.032	0.069	0.076	0.139	0.229
9	Emergency Assistance from External Areas	0.047	0.017	0.015	0.013	0.008	0.016	0.015	0.013	0.013
10	Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero	**0.011**	**0.003**	**0.004**	**0.003**	**0.000**	**0.002**	**0.001**	**0.001**	**0.001**

		Lower Demand w/Ageing - NYCA LOLE (event-days/year) by EOP Step								
Step	EOP	2026	2027	2028	2029	2030	2031	2032	2033	2034
1	No EOP Support	2.466	1.930	1.910	2.593	1.232	2.037	3.123	6.121	8.501
2	Flexible Large Loads	2.035	1.491	1.499	2.039	0.840	1.448	2.242	4.388	6.493
3	Special Case Resources (SCRs) (Load and Generator)	1.520	1.033	1.077	1.447	0.420	0.799	1.261	2.593	4.220
4	5% Manual Voltage Reduction	1.487	1.008	1.051	1.406	0.396	0.761	1.194	2.455	4.042
5	30-Minute Operating Reserve to Zero (655MW)	0.526	0.338	0.409	0.621	0.190	0.399	0.626	1.315	2.401
6	Voluntary Load Curtailment	0.419	0.258	0.322	0.489	0.147	0.323	0.502	1.046	1.955
7	Public Appeals	0.355	0.221	0.284	0.447	0.133	0.299	0.468	0.980	1.842
8	5% Remote Controlled Voltage Reduction	0.262	0.157	0.210	0.327	0.088	0.213	0.333	0.709	1.371
9	Emergency Assistance from External Areas	0.049	0.022	0.022	0.027	0.021	0.042	0.050	0.066	0.080
10	Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero	**0.011**	**0.004**	**0.006**	**0.007**	**0.002**	**0.007**	**0.010**	**0.014**	**0.020**

Appendix F: 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 fulfilled by the NYISO, as well as the other NPCC and NYSRC planning compliance obligations. While achieving compliance with all NERC, NPCC, and NYSRC obligations is critical to ensuring the continued reliability of the transmission system, this section primarily discusses the planning compliance requirements that closely align with 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.[20]

The purpose of the NERC Reliability Standards is to "define the reliability requirements for planning and operating the North American bulk power system and are developed using a results-based approach that focuses on performance, risk management, and entity capabilities." The objective of NPCC Directory #1 and the NYSRC Reliability Rules and Compliance Manual are to provide a "design-based approach" to design and operate the bulk power system to a level of reliability that will not result in the loss or unintentional separation of a major portion of the system from any of the planning and operations contingencies with the intent of avoiding instability, voltage collapse and widespread cascading outages. Figure 48 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 of 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).[21] The identified data that entities must provide primarily comes from compliance with NERC MOD standards. Most of this data is collected through the annual database update process outlined in the RAD Manual and the annual FERC Form No. 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).

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

Following the completion of the annual database update, these databases are used for study work, such as in the RPP, and for many other compliance obligations, such as those listed in Figure 48. Planning studies similar to the Reliability Planning Process include the NPCC/NYSRC Area Transmission Reviews (ATRs) and the NERC TPL-001 assessments.

Figure 50: List of NERC Standards for Planning Coordinators and Transmission Planners

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

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

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

The 2024 ATR,[22] which is the most recently completed ATR, evaluated study year 2029 and found that the planned system through year 2029 conforms to the reliability criteria described in the NYSRC Reliability Rules and NPCC Directory #1. The next ATR is a Comprehensive ATR and is planned to be completed in the latter part of 2025 or early 2026. 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 RPP, 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 determines 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

[22] 2024 Interim Area Transmission Review of the New York State Bulk Power Transmission System.

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

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

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

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

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

NERC Planning Assessments (TPL-001)

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

The required system conditions to evaluate for this assessment include planned system representations over a 10-year study period for a variety of system conditions. Figure 49 provides a description of the steady state, dynamics, and short circuit cases required to be evaluated in the Planning Assessment.

Figure 51: 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 was completed in July 2025. As this study contains Critical Energy Infrastructure Information (CEII), it is not posted on the NYISO website. Generally, the results of this study are consistent with the ATR studies. The study scope of this assessment is different from the ATR because the ATR evaluates the BPTF while the TPL evaluates the BES. The corrective action plans for criteria violations on the BES are generally addressed in the affected Transmission Owner's LTP and/or the proposed transmission facilities listed in Section 7 of the Load and Capacity Data Report.

Resource Adequacy Compliance Efforts

NPCC's Directory 1 defines a compliance obligation for the NYISO, as Resource Planner and Planning Coordinator, to perform a resource adequacy study evaluating a five-year planning horizon. The NYISO delivers a report every year under this study process to verify the system against the one-day-in-ten-years loss of load expectation (LOLE) criterion, usually based on the results and assumptions from the latest available study in the NYISO's RPP 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[23] 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.*

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

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

Appendix G: Reliability Attributes of Dispatchable Resources

The New York power grid is reliant on several electrical attributes to maintain a reliable power grid. 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 of time, and use multiple fuel sources. However, wind and solar resources have an intermittent fuel that is dependent on the weather. This may result in these resources not being 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 with a larger share of intermittent resources connecting to the grid. Generally speaking, dispatchable resources that provide the reliability attributes of synchronous generation and that 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.

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 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 be reliable. To maintain reliability, new dispatchable resources in the aggregate must also provide 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. As an example, fast frequency response can be provided by resources that can rapidly adjust their output, which can help stabilize system frequency. However, these systems have an inherent time delay required for detection and response and do not entirely offset the need for inertia. New reliability needs may be identified as the grid continues to evolve.

Figure 52 illustrates several potential types of generation technologies and highlights some of their attributes.

Figure 52: Energy and Reliability Attributes of Sample Generation Technologies

		2025 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	25,045	No	Yes[24]	No	Yes	Yes[25]	Yes	Yes	Yes	Yes	Yes
	Hydro	4,264	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Pumped Hydro	1,411	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Hydrogen Fuel Cell	0	Yes	Yes[26]	No	Yes	Yes	Yes	Yes	No	Yes	No
	Hydrogen Combustion	0	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Nuclear	3,326	Yes	Yes	No	No	No	No	No	Yes	Yes	Yes
	Modular Nuclear	0	Yes	Yes	No	No	No	Yes	No	Yes	Yes	Yes
	Battery	17	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	No
	Solar	683	Yes	No	Yes	No[27]	Yes	Yes	Yes	No	Yes	No
	Wind	2,574	Yes	No	Yes	No	Yes	Yes	Yes	No	Yes	No
	Demand Response[28]	1,487	Yes[29]	Yes	Yes	No	No	Yes	No	No	No	No
	Synchronous Condenser[30]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Yes	Yes	Yes	Yes

[24] Firm fuel contract or dual fuel capable

[25] Simple cycle turbines

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

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

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

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

[30] 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.

In May 2023, the PSC issued an order initiating a process to identify technologies that can close the anticipated gap between the capabilities of existing renewable energy technologies and future system reliability needs.[31] The PSC asked stakeholders a series of important questions, including how to define "zero-emissions" for purposes of the zero emissions by 2040 target and whether that definition should include cutting edge technologies such as advanced nuclear, long duration energy storage, green hydrogen, and demand response. The PSC also elicited feedback from stakeholders on how to best design a zero-emissions by 2040 program. Over the next several years, projects undertaken by the NYISO will continue to address the changes needed in the energy and ancillary services, as well as prepare the markets for new resource classes. These efforts will focus on improving signals to drive investment in resources with the characteristics and attributes needed for continued grid reliability.

[31] PSC Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*, Order Initiating Process Regarding Zero Emissions Target (May 18, 2023),