Technical Study Report

New York Control Area
Installed Capacity Requirement

For the Period May ~~2026~~ 2027 to April ~~2027~~ 2028

~~December 5~~November 3, ~~2025~~2026

New York State Reliability Council, LLC
Installed Capacity Subcommittee

About the New York State Reliability Council

The New York State Reliability Council (NYSRC) is a not-for-profit corporation responsible for promoting and preserving the reliability of the New York State power system by developing, maintaining and, from time to time, updating the reliability rules which must be complied with by the New York Independent System Operator, Inc. (NYISO) and all entities engaging in electric power transactions on the New York State power system. One of the responsibilities of the NYSRC is the establishment of the annual statewide Installed Capacity Requirement for the New York Control Area.

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EXECUTIVE SUMMARY

A New York Control Area (NYCA) Installed Reserve Margin (IRM) study is conducted annually by the New York State Reliability Council (NYSRC) Installed Capacity Subcommittee (ICS). ICS has the overall responsibility of managing studies for establishing NYCA IRM requirements for the upcoming Capability Year[1] including the development and approval of all modeling and database assumptions to be used in the reliability calculation process. This report covers the period May 1, ~~2026~~ 2027 through April 30, ~~2027~~ 2028 (~~2026-2027~~2027-2028 Capability Year). The IRM study described in this report for the ~~2026-2027~~2027-2028 Capability Year is referred to as the "~~2026-2027~~2027-2028 IRM Study."

The NYSRC technical study was performed pursuant to the NYSRC Policy for setting the IRM.[2] The report shows that the calculated NYCA IRM for the ~~2026-2027~~2027-2028 Capability Year is ~~25.3~~30.9% under final base case assumptions. This IRM satisfies the NYSRC resource adequacy criterion of a Loss of Load Expectation (LOLE) of no greater than 0.1 Event-Days/year. The base case, along with other relevant factors, will be considered by the NYSRC Executive Committee on December ~~5~~4, ~~2025~~2026, for its adoption of the Final NYCA IRM requirement for the ~~2026-2027~~2027-2028 Capability Year. Of note this year is the fact that 14% of the risk occurred in the winter season.

In addition to calculating the LOLE, the analysis also determined that the Hourly Loss of Load Expectation (LOLH) was 0.355~~61~~ hours per year and the Expected Unserved Energy (EUE) was ~~169.506~~178.423 MWh per year. The NYSRC does not have criteria for LOLH or EUE. For comparison to other systems, a Normalized Expected Unserved Energy (NEUE) can also be determined, which divides the EUE by the expected load consumption. Using the NYISO's projected 2026 NYCA forecasted load consumption of ~~155,460~~153,392 GWh/year (from the ~~2025~~ 2026 ~~NYISO Load & Capacity Data report or "Gold Book"~~Fall Forecast) this produces a NEUE of 0.000~~0~~121~~1~~%. Other systems around the world that design to LOLH have a criteria of less than 3 to 8 hours per year. Criteria based on NEUE is typically less than 0.002%. The NYCA results represent a significantly higher level of reliability than either of these criteria.[3]

The NYSRC study procedure used to establish the NYCA IRM[4] also produces corresponding "Minimum Locational Capacity Requirements" (MLCRs) for New York City and Long Island to satisfy the NYCA resource adequacy criterion, along with the calculated NYCA IRM. The ~~2026-2027~~2027-2028 IRM Study determined related MLCRs of ~~79.2~~85.1% and ~~106.7~~110.7% for New York City and Long Island,

[1] A Capability Year begins on May 1 and ends on April 30 of the following year.
[2] Policy No. 5-17; Procedure for Establishing New York Control Area Installed Capacity Requirements.
[3] *See,* Resource Adequacy for a Decarbonized Future *available at:* https://www.epri.com/research/products/000000003002023230
[4] This procedure is described in Section 3, IRM Study Procedures. The procedure for calculating IRM requirements and initial LCRs is sometimes referred to in this report as the "Tan45 process."

respectively. This represents an increase of ~~3.6~~5.2% for NYC and ~~a decrease of 0.6~~3.2% in Long Island from the MLCRs determined as part of the ~~2025~~2026-~~2026~~ 2027 IRM Study. In accordance with its responsibility of setting the Locational Minimum Installed Capacity Requirements (LCRs), the NYISO will calculate and approve *final LCRs* for all NYCA localities using a separate process that utilizes the NYSRC approved Final NYCA IRM and adheres to NYSRC Reliability Rules and policies.

The ~~25.3~~30.9% IRM base case value for the ~~2026-2027~~2027-2028 Capability Year represents a ~~0.9~~5.3% *increase* from the ~~2025~~2026-~~2026~~ 2027 IRM Study base case IRM of ~~24.4~~25.6%. **(Note: Those results were from the Special Sensitivity Case which was adopted as the Final Base Case by the Executive Council at the 2025 December meeting.)** Table 6-1 shows the IRM impacts of individual updated study parameters that result in this change from last year's FBC to this year's PBC. Table 6-2 shows the parametric changes from the PBC Tan45 results through the Final Base Case (FBC). Note, the values in ~~Table 6-1~~these tables have NOT been ratioed up or down in order to "true-up" the parametric results with the resulting Tan45 values. ~~The initial parametric deltas from the 2026-2027 IRM Study preliminary base case (PBC) were off by roughly a factor of two and it was felt that ratioing the numbers would give a false sense of accuracy for the process. One of the goals for the NYISO next year is to investigate potential changes in the parametric process to improve the accuracy.~~ In summary:

- There are ~~sixteen~~ fifteen parameter drivers that in combination *increased* the ~~2026-2027~~2027-2028 IRM from the ~~2025~~2026-~~2026~~ 2027 IRM Study base case IRM by ~~6.29~~7.92%. Of these ~~sixteen~~ fifteen drivers, the most significant was the ~~Winter Fuel Availability Constraints~~New Generator Inclusion which consisted of 1,229 MW of renewable generation and energy storage which only required the removal of 216 MW of ICAP to restore the system to 0.1 event-days/year. This resulted in an increase of over 1,000 MW in the ICAP requirement. The next closest impacts were the Transition Matrix and EFORD Updates (1.12%) and the 2026 Gold Book. DMNC and Behind-the-Meter Net Generation updates (1.01%). All other increases were less than 0.5% each.~~followed closely by the Fall Load Forecast reduction and the explicit modeling of the Behind the Meter (BTM) Solar as supply side resource. Each of these three items increased the IRM by over 1% each. The addition of the Champlain Hudson Power Express (CHPE) with its 1,250 MW transfer capability into Load Zone J *for the summer months only,* resulted in just a 0.317% increase in the IRM but caused significant shifts in the locational requirements. The Load Zone J locational requirement increased by 8.474%, the locational requirement for Load Zone K decreased by 3.397%, and the locational requirement for the G-J Locality increased by 5.272%. Because of the modeled seasonal capability of this line, it also exacerbated the impact of the winter fuel availability constraints.~~
- ~~Twelve~~ Only four parameter drivers in combination *decreased* the IRM from the ~~2025~~2026-~~2026~~ 2027 IRM Study base case by ~~4.66~~1.89%. Of these ~~twelve~~ four drivers, the most significant

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was the Generator Deactivations which caused a 1.23% decrease. All other changes were less than 0.5% each.~~change in the quantity of Special Case Resources (SCRs) modeled for the 2026-2027 IRM Study which decreased the IRM by 1.569%. The Gowanus and Narrows generator deactivations decreased the IRM by 0.686% followed closely by the initial 2025 Gold Book Load Forecast which decreased the IRM by 0.619%. All other modifications, individually, had less than a 0.50% impact each on the IRM.~~

The overall parametric impact from ~~both~~ the PBC ~~and~~ to FBC cases, shown in Table 6-2, was 0.1%~~-~~. The largest impact was the Fall Loads Forecast which resulted in a decrease of 573 MW in the system peak load. Although this caused a decrease in the ICAP MW requirements, because the IRM is expressed as a percentage of the peak load it resulted in a 0.64% increase in IRM. Other changes, most notably updates to the SCR MW, Voluntary Curtailment and Public Appeals MW and Topology changes all decreased the IRM slightly and effectively cancelled out the impact of the Load changes. ~~showed an increase of 1.52%, while the final Tan45 analysis resulted in an increase of only 0.9% from last year's Final Base Case (FBC).~~

The complete parametric analysis showing the above and other results can be found in Section 6 of this report.

This study also evaluated IRM impacts of several sensitivity cases. The results of these sensitivity cases are discussed in Section 7 and summarized in Table 7-1 of this report. The base case IRM and sensitivity case results, along with other relevant factors, will be considered by the NYSRC Executive Committee in adopting the Final NYCA IRM requirement for the ~~2026-2027~~2027-2028 Capability Year. NYSRC Policy 5-19 describes the Executive Committee process for establishing the Final NYCA IRM.

The study also included a confidence interval analysis to demonstrate that there is a high confidence that the base case ~~25.3~~30.9% IRM will fully meet NYSRC and Northeast Power Coordinating Council (NPCC) resource adequacy criterion that require a LOLE of no greater than 0.1 Event-Days/year. For the final parametric case prior to the Tan45, the model was run to ~~8,750~~3,000 replications at which point the daily LOLE of 0.100 Event-Days/year for NYCA was met with a standard error less than 0.~~025~~050. At 3,000 replications the Standard Error was 0.0323. ~~The significant number of replications required to meet the standard error criteria would significantly increase the runtime of the Tan45 case. In order to complete the 2026-2027 IRM study on time, an exception was granted by the Executive Committee to reduce the confidence level to 90% instead of 95% for the Tan45 of the Final Base Case and associated Special Sensitivity Case. Potential longer-term solutions to address the possibility that similar concerns could arise in future IRM study cycles will be reviewed in 2026. The Final Base Case Tan45 was conducted with 3,000 replications, finishing with a standard error of 0.0299 and representing a 94% confidence level.~~

The ~~2026-2027~~2027-2028 IRM Study also evaluated Unforced Capacity (UCAP) trends. The NYISO values capacity sold and purchased in the market in a manner that considers the forced outage ratings of individual units, whereby generating unit capacity is derated to an unforced capacity basis recognizing the impact of forced outages. This derated capacity is referred to as "UCAP." This analysis shows that required UCAP margins, which steadily decreased over the 2006-2012 period to about 5%, remained relatively steady through 2019 but have increased through 2021 (see Figure 8-1). Since then, it has varied between 6% and 10%. Due to lower contributions to reliability, the increase in wind and solar resources lowers the translation factor from required ICAP to required UCAP which reflects the performance of all resources on the system.

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1. Introduction

This report describes a technical study, conducted by the NYSRC Installed Capacity Subcommittee (ICS), for establishing the NYCA Installed Reserve Margin (IRM) for the period of May 1, 2026 through April 30, 2027 (~~2026-2027~~2027-2028 Capability Year). This study is conducted each year in compliance with Section 3.03 of the NYSRC Agreement, which states that the NYSRC shall establish the annual statewide Installed Capacity Requirement (ICR) for the NYCA. The ICR relates to the IRM through the following equation:

$$ICR = \left(1 + \frac{IRM\ Requirement\ (\%)}{100}\right) \times Forecasted\ NYCA\ Peak\ Load$$

~~$$ICR = \left(1 + \frac{\text{IRM Requirement (\%)}}{100}\right) * \text{Forecast NYCA Peak Load}$$~~

The base case and sensitivity case study results, along with other relevant factors, will be considered by the NYSRC Executive Committee for its adoption of the Final NYCA IRM requirement for the ~~2026-2027~~2027-2028 Capability Year.

The NYISO will implement the Final NYCA IRM as determined by the NYSRC, in accordance with the NYSRC Reliability Rules, NYSRC Policy 5-19, *Procedure for Establishing New York Control Area Installed Capacity Requirement and the Installed Reserve Margin (IRM)*; the NYISO Market Administration and Control Area Services Tariff; and the NYISO Installed Capacity (ICAP) Manual. The NYISO translates the required IRM to a UCAP basis. These values are also used in ICAP Spot Market Auctions based on FERC-approved ICAP Demand Curves. The schedule for conducting the ~~2026-2027~~2027-2028 IRM Study was based on meeting the NYISO's timetable for conducting such auctions.

The study criteria, procedures, and types of assumptions used for the study for establishing the NYCA IRM for the ~~2026-2027~~2027-2028 Capability Year are set forth in NYSRC Policy 5-19. The primary reliability criterion used in the IRM study requires a LOLE of no greater than 0.1 Event-Days/year for the NYCA. This NYSRC resource adequacy criterion is consistent with the NPCC resource adequacy criterion. IRM study procedures include the use of two reliability study methodologies: The *Unified Methodology* and the *IRM Anchoring Methodology.* NYSRC reliability criteria and IRM study methodologies and models are described in Policy 5-19 and discussed in detail later in this report.

The NYSRC procedure for determining the IRM also identifies corresponding MLCRs for the New York City and Long Island localities. The NYISO, using a separate process – in accordance with the NYISO tariffs and procedures, while adhering to NYSRC Reliability Rules and NYSRC Sections 3.2 and 3.5 of Policy 5-19 – is responsible for setting *final* LCRs for New York City, Long Island and the G-J Locality.

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For its determination of LCRs for the ~~2026-2027~~2027-2028 Capability Year, the NYISO will continue utilizing an economic optimization methodology approved by the Federal Energy Regulatory Commission (FERC).

The ~~2026-2027~~2027-2028 IRM Study was managed and conducted by the NYSRC ICS and supported by technical assistance from the NYSRC's technical consultants and NYISO staff.

Previous IRM Study reports, from year 2000 to year 2025, can be found on the NYSRC website.[5] Appendix D, Table D.1 provides a record of previous NYCA base case and final IRMs for the 2000-2001 through 2025-2026 Capability Years. Figure 8-1 and Appendix D, Table D.1.1, show UCAP reserve margin trends over previous years. Definitions of certain terms in this report can be found in the Glossary (Appendix E).

Different reliability analyses, separate from the IRM study process covered in this report, are conducted by the NYISO and are called the Reliability Needs Assessment (RNA) and the Short-Term Assessment of Reliability (STAR). These analyses together assess the resource adequacy and transmission security of the NYCA for up to ten years into the future. The RNA is conducted once every two years and examines years four through ten of the study period, while the STAR is conducted quarterly and analyzes years one through five, with a focus on fulfilling any identified reliability needs in years one through three. These assessments determine whether the NYSRC resource adequacy reliability criterion, as defined in Section 2 below, is expected to be maintained over the study period; and if not, identifies reliability needs or compensatory MW of capacity or other measures of solutions required to meet those needs.

2. NYSRC Resource Adequacy Reliability Criterion

The required reliability level used for establishing NYCA IRM is dictated by Requirement 1.1 of NYSRC Reliability Rule A.1, *Establishing NYCA Statewide Installed Reserve Margin Requirements,* which states that the NYSRC shall:

> *Probabilistically establish the IRM requirement for the NYCA such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 Event-Days/year. This evaluation shall make due allowances for demand uncertainty, scheduled outages and de-ratings, forced outages and de-ratings, assistance over interconnections with neighboring control areas, NYS Transmission System emergency transfer capability, and capacity and/or load relief from available operating procedures*.

[5] *See*, NYSRC New York Control Area Installed Capacity Requirement Reports, *available at:* https://www.nysrc.org/documents/reports/nysrc-new-york-control-area-installed-capacity-requirement-reports/

The above NYSRC Reliability Rule is consistent with NPCC's Resource Adequacy criterion in NPCC Directory 1, *Design and Operation of the Bulk Power System*. This criterion is interpreted to mean that planning reserve margins, including the IRM, needs to be high enough that the probability of an involuntary load shedding due to inadequate resources is limited to only one event-day in ten years or 0.1 Event-Days/ year. This criterion has been widely accepted by most electric power systems in North America for reserve capacity planning. In New York, use of the LOLE criterion of 0.1 Event-Days/year has provided an acceptable level of reliability for many years.

In addition to calculating the LOLE reliability metric the calculations shall also include the calculation and reporting of LOLH and EUE reliability metrics in the probabilistic resource capacity assessments.

In accordance with NYSRC Reliability Rule A.2, Establishing Load Serving Entity (LSE) Installed Capacity Requirements, the NYISO is required to establish LSE installed capacity requirements, including LCRs, for meeting the statewide IRM requirement established by the NYSRC in compliance with NYSRC Reliability Rule A.1 above.

3. IRM Study Procedures

The study procedures used for the ~~2026-2027~~2027-2028 IRM Study are described in detail in NYSRC Policy 5-19, *Procedure for Establishing New York Control Area Installed Capacity Requirements and the Installed Reserve Margin (IRM)*. Policy 5-19 also describes the computer program used for reliability calculations and the types of input data and models used for the IRM Study.

This study utilizes a *probabilistic approach* for determining NYCA IRM requirements. This technique calculates the probabilities of generator unit outages, in conjunction with load and transmission representations, to determine the Event-Days per year of expected resource capacity shortages.

General Electric's Multi-Area Reliability Simulation software program (GE-MARS) is the primary computer program used for this probabilistic analysis. This program includes detailed load, generation, and transmission representation for eleven NYCA load zones — plus four Outside World Control Areas (Outside World Areas) directly interconnected to the NYCA. The Outside World Areas are as follows: Ontario, New England, Quebec, and the PJM Interconnection. The eleven NYCA Load Zones are depicted in Figure 3-1. GE-MARS calculates LOLE, expressed in Event-Days/year, to provide a consistent measure of system reliability. The GE-MARS program is described in detail in Appendix A, Section A.1.

Prior to the 2016-2017 IRM Study, the IRM base case and sensitivity analyses were simulated using only weekday peak loads rather than evaluating all 8,760 hours per year in order to reduce computational run times. However, the 2016-2017 IRM Study determined that the difference between study results using the daily peak hour versus the 8,760-hour methodologies would be significant. Therefore, the base case and sensitivity cases in the 2016-2017 IRM Study and all later studies, including this ~~2026-2027~~2027-2028 IRM Study, were simulated using all hours in the year.

Using the GE-MARS program, a procedure is utilized for establishing NYCA IRM requirements (termed the *Unified Methodology*) which establishes a relationship between NYCA IRM and corresponding MLCRs, as illustrated in Figure 3-2. All points on these curves meet the NYSRC 0.1 Event-Days/year LOLE reliability criterion described in Section 2. Note that the area above the curve is more reliable than the criterion, and the area below the curve is less reliable. This methodology develops a pair of curves for two zones with locational capacity requirements, New York City (NYC) or Load Zone J; and Long Island (LI) or Load Zone K. Appendix A of NYSRC Policy 5-19 provides a more detailed description of the Unified Methodology.

Figure 3-1 NYCA Load Zones



Base case NYCA IRM requirements and corresponding initial locality reserve margins for Load Zones J and K are established by a supplemental procedure (termed the *IRM Anchoring Methodology*), which is used to define an *inflection point* on each of these curves. These inflection points are selected by applying a tangent of 45 degrees (Tan45) analysis at the bend (or "knee") of each curve. Mathematically, each curve is fitted using a second order polynomial regression analysis. Setting the derivative of the resulting set of equations to minus one yields the points at which the curves achieve the Tan45 inflection point. Appendix B of NYSRC Policy 5-19 provides a more detailed description of the methodology for computing the Tan45 inflection point.

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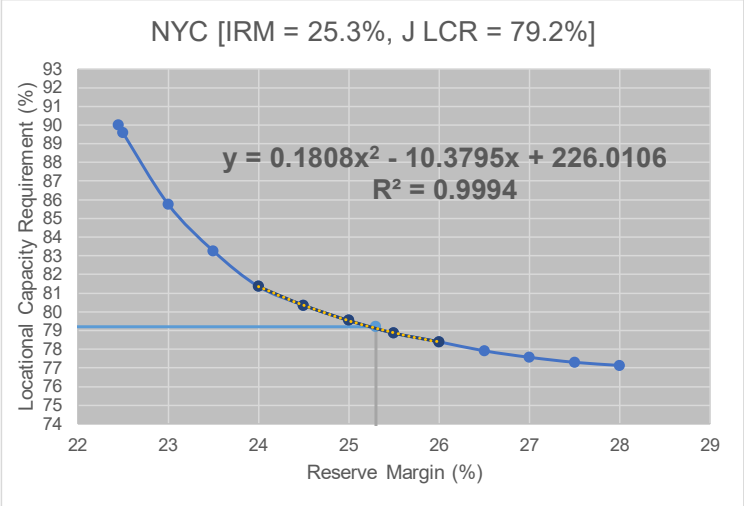
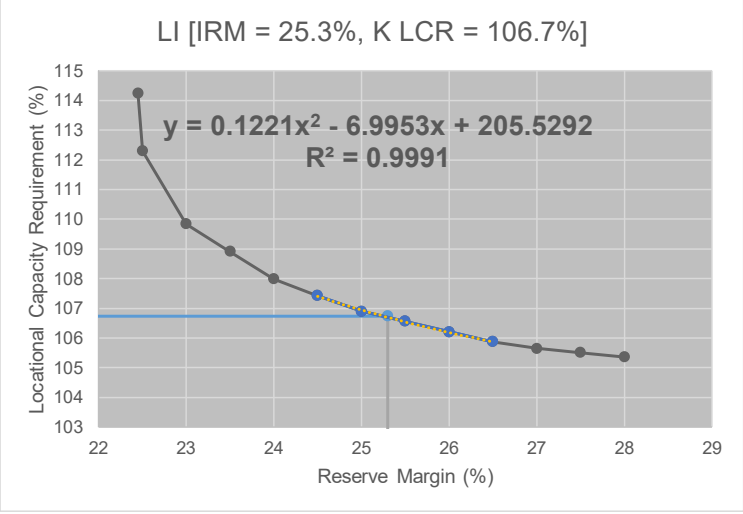
Figure 3-2: Relationship Between NYCA IRM and Corresponding Initial Locational Capacity Requirements for ~~2026-2027~~2027-2028 IRM

IRM ~~2026-2027~~2027-2028 Final Base Case Tan45





4. Study Results – Base Case

Results of the NYSRC technical study show that the calculated NYCA IRM is ~~25.3~~30.9% for the ~~2026-2027~~2027-2028 Capability Year under final base case assumptions. Figure 3-2 on the previous page depicts the relationship between NYCA IRM requirements and corresponding MLCRs for New York City and Long Island.

The tangent points on these curves were evaluated using the Tan45 analysis described in Section 3. Accordingly, maintaining a NYCA IRM of ~~25.3~~30.9% for the ~~2026-2027~~2027-2028 Capability Year, together with corresponding MLCRs of ~~79.2~~85.1 % and ~~106.7~~110.7% for New York City and Long Island, respectively, will achieve applicable NYSRC and NPCC reliability criteria for the base case study assumptions shown in Appendix A.3.

Comparing the corresponding MLCRs in this ~~2026-2027~~2027-2028 IRM Study to 2025-2026 IRM Study results (New York City LCR= ~~75.6~~79.9%, Long Island LCR= 107.~~3~~5%), the corresponding ~~2026-2027~~2027-2028 New York City MLCR increased by ~~3.6~~5.2%, and the corresponding Long Island MLCR ~~decreased~~ increased by ~~0.6~~3.2%. The primary factors driving the increase of the ~~NYC~~ MLCRs was the ~~addition of the CHPE line and its interplay with the winter fuel availability constraints.~~EFORd updates and the new Thermal Transition Matrix.

In accordance with NYSRC Reliability Rule A.2, *Load Serving Entity ICAP Requirements,* the NYISO is responsible for separately calculating and establishing the final LCRs. The NYISO will calculate and approve *final LCRs* for all NYCA localities using a separate process that utilizes the NYSRC approved Final NYCA IRM and adheres to NYSRC Reliability Rules and policies.

These cases were run with 3,000 replications and converged to a confidence interval of only ~~94~~93.5% ~~rather than the~~which exceeds the revised goal of ~~95~~90%. ~~Due to some replications having a higher number of outages it required 8,750 replications to reach the 95% goal for the final base case prior to the Tan45. This situation is being further investigated to isolate the causes. The final rounded Tan45 case run with 3,000 replications reached a 94% confidence interval.~~

Transmission Security limit floor values (TSL Floors) are inputs to the NYISO's LCR study and are not considered in the IRM under the Tan45 process described in NYSRC Policy 5-19. In cases where the TSL floor values are greater than the MLCRs associated with the NYSRC-approved IRM, the resulting LCRs in combination with the NYSRC-approved IRM can potentially result in a system with a loss of load expectation (LOLE) that is lower than the LOLE associated NYSRC-approved IRM. The LCR study is required to maintain the NYSRC-approved IRM and cannot exceed the LOLE associated therewith, while also not exceeding the Locality-specific TSL Floors.

A comparison of the Tan45 MLCRs from the Final Base Case and Special Sensitivity Case to the NYISO's updated ~~2026-2027~~2027-2028 TSL Floors shows that the TSL Floors for Load Zone J (NYC) and Load Zone K (LI) are higher than the MLCRs established through the Tan45 process.

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Impact analysis was conducted to evaluate the LOLE impact by setting the MLCRs to the applicable TSL Floors and the IRM at the applicable Tan45 result to calculate the resulting LOLE. With the MLCRs set equal to the TSL Floors and fixing the IRM at the applicable study value, the LOLE declines to 0.073 for the IRM Final Base Case and 0.074 for the Special Sensitivity.

Impact analysis was also conducted to evaluate the IRM impact by setting the MLCRs to the applicable TSL Floors and allowing the GE MARS program to lower the IRM from the applicable Tan45 result until the LOLE criterion was met. With the MLCRs set equal to the TSL Floors and the IRM adjusted to reflect the value necessary to achieve the LOLE criterion, the IRM could be reduced by 1.6% for both the Final Base Case and the Special Sensitivity.

This additional analysis is presented for informational purposes and does not replace the official Tan45 IRM Final Base Case result of 25.3%.

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	IRM	Load Zone J MLCR	Load Zone K MLCR	G-J Locality MLCR	LOLE (event-days/year)
FBC Tan45	25.3%	79.2%	106.7%	88.8%	0.099
TSL Floors (CHPE-in)	-	85.8%	109.6%	82.1%	
Tan45 IRM w/ TSL Floors	25.3%	85.8%	109.6%	82.1%	0.073
Alternative IRM w/ TSL Floors	23.7%	85.8%	109.6%	82.1%	0.099
	IRM	**Load Zone J MLCR**	**Load Zone K MLCR**	**G-J Locality MLCR**	**LOLE (event-days/year)**
Special Sensitivity Case Tan45	25.6%	79.8%	107.5%	89.2%	0.100
TSL Floors (CHPE-in)	-	86.4%	110.3%	82.5%	
Tan45 IRM w/ TSL Floors	25.6%	86.4%	110.3%	82.5%	0.074
Alternative IRM w/ TSL Floors	24.0%	86.4%	110.3%	82.5%	0.100

5. Models and Key Input Assumptions

This section describes the models and related base case input assumptions for the ~~2026-2027~~2027-2028 IRM Study. The models represented in the GE Multi-Area Reliability Simulation software program (GE-MARS) analysis include a *Load Model, Capacity Model, Transmission Model, and Outside World Model*. A *Database Quality Assurance Review* of the ~~2026-2027~~2027-2028 base case assumptions are also addressed in this section. This year's report introduces Section 5.6, which addresses winter reliability risks identified in the ~~2026-2027~~2027-2028 IRM Study. The input assumptions for the final base case were approved by the Executive Committee on October 9, 2025. Appendix A, Section A.3 provides more details on these models and assumptions and comparisons of several key assumptions with those used for this ~~2026-2027~~2027-2028 IRM Study.

5.1 The Load Model

5.1.1 Peak Load Forecast

The NYCA peak load forecast is based upon a model that incorporates forecasts of economic drivers, end use and technology trends, and normal weather conditions. A 2025 NYCA summer peak load forecast of 31,648.2 MW (including Behind-the-Meter Net Generation (BTM:NG) resource loads) was assumed in the 2026-2027 IRM Study, a decrease of 1.5 MW from the forecast used in the 2025-2026 IRM Study. This load forecast update was prepared for the 2026-2027 IRM Study by NYISO staff in collaboration with the NYISO Load Forecasting Task Force (LFTF) and presented to the ICS on October 1, 2025.[6] The load forecast update considered actual 2025 summer load conditions.

The peak load forecast changes are shown on Table 5-1 below. Relative to the 2025-2026 IRM Study forecast, the load forecast for the 2026-2027 IRM Study has increased in the majority of Load Zones F through K, and decreased in Load Zones A through E. The aggregate NYCA load forecast is nearly identical to the forecast used in the previous IRM study, due to largely offsetting positive and negative load growth drivers. Primary negative load growth drivers include the continued strong load-reducing impacts of state policy incented energy efficiency programs, behind-the-meter (BTM) solar installations, and other distributed energy resources (DER). The BTM:NG resource load projection also decreased. Primary positive load growth drivers include electrification of vehicles and building appliances, "large load" projects, and other sources of economic load growth. These positive drivers are expected to contribute to aggregate load growth in upcoming years.

Table 5-1: Comparison of 2025 and 2026 Actual and Forecast Coincident Peak Summer Load (MW)

	Fall 2025 Forecast*	2025 Actual (7/29/2025)	2025 Normalized	Fall 2026 Forecast*	Forecast Change
	(a)	(b)	(c)	(d)	= (d) – (a)
Zones A-I	15,831.4	15,206.4	15,533.5	15,784.5	-46.9
Zones J&K	15,818.3	15,438.6	15,796.6	15,863.7	45.4
NYCA	31,649.7	30,645.0	31,330.1	31,648.2	-1.5

*BTM:NG resource loads have been incorporated into these numbers.

[6] Load Forecast Update: https://www.nysrc.org/wp-content/uploads/2025/09/2026_IRM_Forecast_ICS_V2.pdf

Following the implementation of the enhanced load modeling (ELM) procedure,[7] where loads in the model are calibrated to annual energy and winter peak forecasts in addition to summer peak forecasts, the Load Forecast Update for the 2026-2027 IRM Study included zonal annual energy and winter peak forecast updates. These forecasts were updated relative to the forecast from the NYISO's 2025 Load & Capacity Data report (Gold Book), solely to account for updates in large load projections and BTM:NG resource load values, in order to maintain consistency with the updates to the summer peak load forecast.

5.1.2 Load Forecast Uncertainty

As with all forecasts, there is uncertainty around the projected NYCA load level for any given year. The uncertainty in the load forecast due to peak day weather is incorporated in the base case model by using a load forecast probability distribution that is sensitive to different weather conditions. Recognizing the unique load forecast uncertainty (LFU) of individual NYCA areas, separate LFU models are prepared for five areas: New York City (Load Zone J), Long Island (Load Zone K), Westchester (Load Zones H and I), and two rest of New York State areas (Load Zones A-E and Load Zones F-G).

These LFU models are intended to measure the load response to weather at high peak producing temperatures. The LFU is based on the slope of load versus temperature, or the weather response of load. If the weather response of load increases, the slope of load versus temperature will increase, and the upper-bin LFU multipliers (Bins 1-3) will increase.

The summer LFU multipliers for the 2026-2027 IRM Study remained unchanged from the 2025-2026 IRM Study. Based on an analysis of the winter 2024-2025 weather data, the NYISO determined that the winter LFU model should be updated. A sensitivity case shows that including LFU in the 2026-2027 IRM Study has an effect of increasing IRM requirements (compared to a case that does not include LFU) by 5.6% (Table 7-1, Case 3), as compared to a range of 5.1% to 9.1% in the previous five IRM studies.

5.1.3 Load Shape Model

The GE-MARS model allows for the representation of multiple load shapes. This feature has been utilized since the 2014-2015 IRM Study and was again utilized for the 2026-2027 IRM Study. This multiple load shape feature enables a different load shape to be assigned to each of seven load forecast uncertainty bins.

Starting with the 2023-2024 IRM Study, a combination of load shapes from the years 2013, 2017, and 2018 were selected by ICS as representative years, as recommended under the LFU

[7] Enhanced Load Modeling: https://www.nysrc.org/wp-content/uploads/2025/04/Enhanced-Load-Modeling-Whitepaper-04022025-ICS.pdf

Phase 2 Study.[8] The LFU Phase 2 Study recommended representing Bin 1 and 2 using the 2013 load shape, representing Bins 3 and 4 using the 2018 load shape, and representing Bins 5, 6, and 7 using the 2017 load shape. The recommendation to change representative load shapes was initially adopted in the base case of the 2023-2024 IRM Study and is also applied in the 2026-2027 IRM Study.

During the 2025-2026 IRM study cycle, the NYISO developed a methodology of modeling BTM solar explicitly as a supply resource in the IRM study.[9] With the new modeling construct, the study is able to better quantify the potential impact of evolving BTM solar resources. This methodology was adopted into the Preliminary Base Case (PBC) for the 2026-2027 IRM Study, increasing the IRM by 1.11% (Table 6-1).

The NYISO developed the ELM methodology as part of the efforts to improve winter load modeling. The load modeling improvement effort focuses on seasonal specific load modeling to reflect summer and winter peak forecasts as well as annual energy requirements. The ELM workflow includes three additional steps, along with the updates to the existing adjustment methodology procedures to ensure that the seasonal peaks align with the target load forecasts, as well as the corresponding annual energy forecasts. This was adopted into the PBC for the 2026-2027 IRM study, decreasing the IRM by 0.15% (Table 6-1).

5.2 The Capacity Model

5.2.1 Conventional Resources: Planned New Capacity, Retirements, Deactivations, and Behind the Meter Generation

Planned conventional generation facilities that are represented in the 2026-2027 IRM Study are shown in Appendix A, Section A.3. The rating for each existing and planned resource facility in the capacity model is based on the lower of its: (1) Dependable Maximum Net Capability (DMNC), or (2) Capacity Resource Interconnection Service (CRIS) value. The source of DMNC ratings for existing facilities is seasonal tests required by procedures in the NYISO Installed Capacity Manual.

There are multiple potential deactivations of thermal units totaling 851.9 MW modeled for the 2026-2027 IRM Study. This includes the Gowanus and Narrows barge units with a combined capacity of 608.7 MW located in Load Zone J,[10] which are assumed to be deactivated in the

[9] https://www.nysrc.org/wp-content/uploads/2023/05/A.I.10-LDC_Recommendation_ICS4098.pdf

[9] BTM Solar Modeling Whitepaper: https://www.nysrc.org/wp-content/uploads/2025/01/BTM-Solar-Modeling-Whitepaper-11122024.pdf

[10] This combined capacity value of all the Narrows and Gowanus barge units (608.7 MW) includes three such units that are assumed to be deactivated in the 2026-2027 IRM Study due to being in ICAP Ineligible Forced Outage (IIFO). The combined capacity of the three IIFO units is 57.7 MW.

2026-2027 IRM Study due to the assumption that the Champlain Hudson Power Express (CHPE) project will be in-service for the study year.

A BTM:NG program resource, for the purpose of this study, contributes its full capacity while its entire host load is exposed to the electric system. Several BTM:NG resources with a total resource capacity of 361.8 MW and a total host load of 96.6 MW, are included in this 2026-2027 IRM Study. The full resource capacity of these BTM:NG resources is included in the NYCA capacity model, while their host loads are included in the load forecast used for this study.

BTM solar resources, which are now modeled as supply side resources starting with the 2026-2027 IRM Study, are represented with a total of 9,339 GWh of total annual energy. For the 2026-2027 IRM Study, BTM solar resources are modeled using shapes covering the years 2020 through 2024, aligning with the other renewable resources.

On April 16, 2024, NYISO implemented its new market participation model for DER. For the 2026-2027 IRM Study, resources modeled as DER in the 2026-2027 IRM Study will be included based on the ICS approved modeling for DER.[11] For the 2026-2027 IRM Study, 480.5 MW of DER are assumed to be available in the study, including some resources that previously participated in the Special Case Resource (SCR) and are transitioning to the DER participation model.

The NYISO has identified several State and Federal environmental regulatory programs that could potentially impact operation of the NYS Bulk Power System. The NYISO's analysis concluded that these environmental initiatives would not result in NYCA capacity reductions or retirements incremental to the deactivations modeled for the 2026-2027 IRM Study that would impact IRM requirements during the summer of 2026. The analysis further identified those regulations that could potentially limit the availability of existing resources, and those that will require the addition of new non-emitting resources. For more details, see Appendix C.

5.2.2 Renewable Resources

Intermittent types of renewable resources, including wind and solar resources, are becoming an increasing component of the NYCA generation mix. These intermittent resources are included in the GE-MARS capacity model as described below. These resources, plus the existing 4,717.3 MW of hydro facilities, will account for a total of 9,138.4 MW of NYCA renewable resources represented in the 2026-2027 IRM Study. This does not include the capacity for any intermittent resources that are installed behind-the-meter (i.e., on the distribution system and not participating in the NYISO wholesale market).

[11] DER Whitepaper: https://www.nysrc.org/wp-content/uploads/2025/03/DER-Modeling-Whitepaper-Phase1-ICS04022025.pdf

It is projected that during the 2026 summer period there will be a total wind capacity of 2,828.3 MW participating in the capacity market in New York State. This includes certain new wind units and an update to the capacity of an existing resource due to the inclusion of a newly constructed phase (totaling 277.6 MW).

GE-MARS allows the input of multiple years of wind data. This multiple wind shape model randomly draws wind shapes from historical wind production data. The 2026-2027 IRM Study used available wind production data covering the years 2020 through 2024. For any new wind facilities, zonal hourly wind shape averages or the wind shapes of nearby wind units will be modeled. The offshore wind resources in the 2026-2027 IRM Study are modeled using synthesized offshore wind production profiles for 2020 through 2024.

Overall, inclusion of the projected 2,828.3 MW of wind capacity in the 2026-2027 IRM Study accounts for 6.8% of the 2026-2027 IRM requirement (Table 7-1, Case 4). This relatively high IRM impact is a direct result of the wind facilities' low capacity factor during the summer peak period. The impact of wind capacity on Unforced Capacity is discussed in Appendix D.2, "Renewable/Intermittent Resources Impact on the NYCA IRM and UCAP Markets." For wind units, a detailed summary of existing and planned wind resources is shown in Appendix A, Table A.9.

Land fill gas (LFG) units account for 97.4 MW of the 2026-2027 IRM Study. For the 2026-2027 IRM Study, this total accounts for one LFG unit modeled as deactivated which reduced available capacity by 4.8 MW.

For the 2026-2027 IRM Study, there are no utility level solar generation additions. The total New York State bulk power system solar capacity in the 2026-2027 IRM Study is 573.4 MW. Actual hourly solar plant output over the 2020-2024 period is used to represent the solar shape for existing units, while new solar units are represented by zonal hourly averages of nearby units.

5.2.3 Energy Limited Resources

The NYISO and GE developed the dynamic energy limited resource (ELR) functionality within the GE-MARS program and the recommended TC4C configuration in the ELR Whitepaper.[12] The recommended modeling would reduce the IRM and lower the SCR program activations as compared to a fixed output profile modeling approach, and it was adopted in the final base case in the 2023-2024 IRM Study. The TC4C configuration contains a static time period limitation for the output from the ELR units. Starting with the 2024-2025 IRM Study, a process

[12] New York State Reliability Council Installed Capacity Subcommittee White Paper on Energy Limited Resources Modeling (Mayb 7, 2021), available at:
https://www.nysrc.org/wp-content/uploads/2023/03/ELR-Modeling-White-Paper-May-2021-FINAL.pdf

to update the time period of the output limitation on an annual basis was implemented, based on the beginning of the 90% LOLE risk period from previous year's Locational Minimum Installed Capacity Requirement study conducted by the NYISO. In the 2025-2026 IRM Study, output from the ELRs was modeled as available starting Hour Beginning (HB) 14, which is the beginning of the 90% LOLE risk window from the NYISO's 2024-2025 Locational Minimum Installed Capacity Requirement study. This process aims to keep the ELR output limitation in close proximity to the period with the highest LOLE risk and the annual update process could have, if any, a small reduction on the IRM on a year-over-year basis.

As ELR capacity continues to grow across the NYCA, the need for more accurate and operationally aligned modeling within the IRM study framework has become critical. A whitepaper was conducted to refine the modeling of ELRs with a particular focus on the start time assumptions for SCRs, as further discussed in Section 5.2.5.

5.2.4 Generating Unit Availability

Generating unit forced and partial outages are modeled in GE-MARS by inputting a multistate outage model that represents an equivalent demand forced outage rate (EFORd) for each unit represented. Outage data used to determine the EFORd is received by the NYISO from generator owners based on outage data reporting requirements established by the NYISO. Capacity unavailability is modeled by considering the average forced and partial outages for each generating unit that have occurred over the most recent five-year time period. The time span considered for the 2026-2027 IRM Study covered the 2020-2024 period.

The weighted average five-year EFORd calculated for generating units in Load Zones A-F is higher, while Load Zones G-J, J and K is lower than the 2019-2023 period, which were used in the 2025-2026 IRM Study. The overall NYCA wide weighted average EFORd in the 2026-2027 IRM Study is higher than the 2025-2026 IRM Study. Appendix A, Figure A.5 depicts NYCA and zonal five-year average EFORd trends from 2017-2024.

5.2.5 Emergency Operating Procedures (EOPs)

As part of the Final Base Case (FBC) for the 2026-2027 IRM Study, a new start time methodology was adopted for SCRs.[13] This decreased the IRM by 0.25% (Table 6-1). For the 2026-2027 IRM Study, Voluntary Curtailments are limited to 3 calls per month which decreased the IRM by 0.30% (Table 6-1). Consistent with the 2025-2026 IRM Study, Public Appeals are limited to 3 calls per year for the 2026-2027 IRM Study.

[13] ELR Whitepaper (SCR Start Times): https://www.nysrc.org/wp-content/uploads/2025/08/ELR-Whitepaper-09032025-ICS.pdf

(1) Special Case Resources (SCRs)

SCRs are loads capable of being interrupted and distributed generators that are rated at 100 kW or higher. SCRs are ICAP resources that provide load curtailment only when activated in accordance with NYISO emergency operating procedures. GE-MARS represents SCRs as an EOP step, which is activated to avoid or to minimize expected loss of load. For the 2026-2027 IRM Study, SCRs are modeled with monthly values based on July 2025 registration data. The modeled capacity also accounts for the transition of resources from the SCR program to the DER participation model. SCRs transitioning to the DER participation model and represented as DER for the 2026-2027 IRM Study have been removed from the SCR values. For the month of July, the forecast SCR value for the 2026-2027 IRM Study FBC assumes that 898 MW will be registered, with varying amounts during other months based on historical experience. This is 589 MW lower than that assumed for the 2025-2026 IRM Study. The SCR model used for the 2026-2027 IRM Study is based on a recent analysis of performance data for the 2012-2024 period. The incorporation of the updated SCR enrollments in the NYCA capacity model has the effect of increasing the IRM by 3.2% (Table 7-1, Case 5).

The "Enhanced SCR Modeling" that was adopted into the PBC of the 2025-2026 IRM Study models SCRs as energy limited resources, using the GE-MARS EL3 unit type. SCRs are modeled as zonal duration limited resources with hourly response rates, subject to a 1 call per day limit. SCRs continue to be deployed as the first EOP step but are not subject to an annual or monthly limit to the maximum number of activations. Performance factors are captured in the hourly response rates rather than in setting the maximum modeled capacities. This enhancement increased the significance of the output window and highlighted the need for differentiated start times based on historical activation data and regional peak load profiles. The "ELR whitepaper"[14] defined a new methodology to define SCR start times based on peak net load for the summer. For the 2026-2027 IRM Study, start times for Load Zones A-E changed from HB14 to HB16 while the Load Zones G-K start time remained at HB14. This methodology was adopted into the FBC for the 2026-2027 IRM Study, decreasing the IRM by 0.25% (Table 6-1).

(2) Other Emergency Operating Procedures

In addition to SCRs, the NYISO will implement several other types of EOP steps, such as voltage reductions, as required, to avoid or minimize customer disconnections. Projected 2026-2027 EOP capacity values are based on recent actual data and NYISO forecasts.

The 2026-2027 IRM Study implements a three call per month limit for Voluntary Curtailments. This decreased the IRM by 0.30% (Table 6-1). The 2026-2027 IRM Study retained the 3 calls per

[14] ELR Whitepaper: https://www.nysrc.org/wp-content/uploads/2025/11/ELR-Phase-2-Whitepaper-ICS11112025-Draft-v2-clean.pdf

year limit adopted for Public Appeals that was implemented as part of the 2025-2026 IRM Study.

Refer to Appendix B, Table B.2 for projected EOP frequencies for the 2026-2027 IRM Study assuming the 25.3% base case IRM.

5.2.6 Unforced Capacity Deliverability Rights (UDRs)

The capacity model includes UDRs, which are capacity rights that allow the owner of an incremental controllable transmission project to provide locational capacity when coupled with a non-locational ICAP Supplier. The owners of the UDRs annually elect whether they will utilize their capacity deliverability rights. This decision helps inform how UDR transfer capability will be represented in the GE-MARS model. The IRM modeling accounts for both the availability of the resource that is identified for each UDR line as well as the availability of the UDR facility itself.

The following facilities are represented in the 2026-2027 IRM Study as having UDR capacity rights: LIPA's 330 MW High Voltage Direct Current (HVDC) Cross Sound Cable (CSC), LIPA's 660 MW HVDC Neptune Cable, the 315 MW Linden Variable Frequency Transformer (VFT), and the 1,250 MW HVDC CHPE project. CHPE is a new addition to the 2026-2027 IRM Study. The owners of these facilities have the option, on an annual basis, of selecting the MW quantity of UDRs they plan on utilizing for capacity contracts over these facilities. Any remaining capability on the cable can be used to support emergency assistance, which may reduce locational and IRM capacity requirements. For CHPE, emergency assistance is not assumed to be available during the winter months (November – April) in the 2026-2027 IRM Study. The 2026-2027 IRM Study incorporates the confidential elections that these facility owners made for the 2026-2027 Capability Year. The Hudson Transmission Partners 660 MW HVDC Cable (HTP) has been granted UDR rights but has lost its right to import capacity and therefore is modeled as being fully available to support emergency assistance.

UDRs, along with other cables captured in the IRM study, are modeled with outage rates based on their historical performance. In the 2026-2027 IRM Study, the cable performance for 2015-2024 was used to develop the cable outage rate assumptions. The aggregated cable outage rate, which covers the facilities of CSC, Neptune, VFT, HTP, Dunwoodie South, Y49/Y50, Norwalk Northport, A Line, and Jamaica Ties, increased from 5.31% (based on the 10-year historical period from 2014-2023) to 5.80% for the 2026-2027 IRM Study compared to the 2025-2026 IRM Study. Given that the CHPE project is a new cable with no historical performance data, the aggregated cable outage rate of 5.80% is being used for its cable outage rate assumption in the 2026-2027 IRM Study.

5.3 The Transmission Model[15]

A detailed NYCA transmission system model is represented in the GE-MARS topology. The transmission system topology which includes eleven NYCA zones and four Outside World Areas, along with relevant transfer limits, is depicted in Appendix A, Figure A-10. The transfer limits employed for the 2026-2027 IRM Study were developed from emergency transfer limit analysis included in various studies performed by the NYISO, and from input from Transmission Owners and neighboring regions. The transfer limits are further refined by additional assessments conducted for this 2026-2027 IRM Study topology.

The transmission model assumptions included in the 2026-2027 IRM Study are listed in Table A.10 in the Appendix which reflects changes from the model used for the 2025-2026 IRM Study. These topology changes are as follows:

Update to Dysinger East Forward Limit

- The Dysinger East Forward Limit decreased from 2,100 MW to 1,925 MW. This change is driven by changes in load pattern in Load Zone A

Update to Central East Forward Limit due to Marcy STATCOM Return to Service

- The Central East voltage collapse limit was increased from 3,810 MW to 3,885 MW; each dynamic limit is also increased by 75 MW. The Central-East Voltage Limit Study (CEVC 2023) provides the voltage collapse limit for the Central East interface under different system conditions. This data identifies a 75 MW derate for an outage of the Marcy STATCOM for all Oswego Complex combinations. The proposed Central East forward transfer limits remove the prior 75 MW derate resulting in dynamic limits that align with the Oswego Complex limits in the 2023 Central-East Voltage Study report with the Marcy STATCOM modeled as in service for the 2026-2027 IRM Study.
- The Central East + Marcy South Group (Total East interface) is not impacted by the STATCOM outage because it is thermally constrained.

Update to Moses South Forward Limit due to Smart Path Connect Project

- The Moses South Forward Limit increased from 2,650 MW to 3,500 MW. The 2025 NYISO Summer Operating Study does not incorporate the Smart Path Connect project, and therefore does not reflect this higher limit. The updated thermal limit was established to more accurately represent the system topology with the Smart

[15] The transmission model is discussed in Appendix A Section 3.5

Path Connect project modeled as in-service, which better aligns with the expected configuration for the 2026–2027 Capability Year.

Update to Sprain-Brook Dunwoodie-South Forward Limit

- The Sprain Brook and Dunwoodie South forward limit decreased from 4,400 MW to 4,225 MW due pre-contingency loading on Dunwoodie-Mott Haven 345kV.

Update to West Central Reverse Limit

- The West Central reverse limit was increased from 2,200 MW to 2,225 MW. This update is driven by redistribution of flows.

Update to Load Zone K- Load Zone I/J Export Limit (Total NYISO Export):

- The export limit from Load Zone K to Load Zones I/J has been reduced from 170 MW to 120 MW under all lines in-service conditions. This update was provided by PSEG Long Island as part of their annual transmission study. The reduction in transfer capability is primarily attributed to a short-term emergency (STE) rating de-rate on the Barrett–Valley Stream circuit and an increase in load in the West of Newbridge region. Additionally, dynamic limits, which vary based on the operational status of the Barrett 1 and 2 generating units, have decreased by approximately 30–60 MW.

Update to Load Zone K- Load Zone J Export Limit (Total Jamaica Export):

- The export limit from Load Zone K to Load Zone J decreased from 505 MW to 485 MW for all lines in-service condition. This update was provided by PSEG Long Island as part of their annual transmission study. The reduction in transfer capability is a result of a STE rating de-rate on the Barrett–Valley Stream circuit. The dynamic limits, which vary based on the operational status of the Barrett 1 and 2 generating units, decreased by 20MW as well.

Update to Zone K- Norwalk Harbor Export Limit (NNC Export):

- The Load Zone K to Norwalk Harbor export limit decreased from 414 MW to 395 MW. This update was provided by PSEG Long Island as part of their annual transmission study. The reduction is due to a NNC phase angle regulatory (PAR) de-rate.

Update to Norwalk Harbor - Zone K Import Limit (NNC Import):

- Norwalk Harbor to Load Zone K import limit decreased from 404 MW to 395 MW. This update was provided by PSEG Long Island as part of their annual transmission study. The reduction is due to a NNC PAR de-rate.

Update to Load Zone I- Load K Export Limit (Y49-Y50):

- The export limit between Load Zone I and Load Zone K decreased from 460 MW to 385 MW. This update was provided by PSEG Long Island as part of their annual transmission study. The reduction in transfer capability is primarily attributed to an STE rating de-rate on the Barrett–Valley Stream circuit and an increase in load in the West of Newbridge region. The NNC PAR de-rate also contributes to this reduction in transfer capability.

Update to Zone K- I/J/PJM Export Limit (Total Export towards West Ties):

- The total export limit towards west ties reduced from 84 MW to 34 MW. This update was provided by PSEG Long Island as part of their annual transmission study.

Forced transmission outages based on historical performance are represented in the GE-MARS model for the underground cables that connect New York City and Long Island to surrounding zones. The GE-MARS model uses transition rates between operating states for each interface, which were calculated based on the probability of occurrence from the historic failure rates and the time to repair. Transition rates into the different operating states for each interface were calculated based on the circuits comprising each interface, including failure rates and repair times for the individual cables, and for any transformer and/or phase angle regulator associated with that cable.

The applicable Transmission Owners provided updated transition rates for their associated cable interfaces. Updated cable outage rates assumed in the 2026-2027 IRM Study resulted in a 0.08% increase to the IRM compared with the 2025-2026 IRM Study (Table 6-1). .The 2025-2026 IRM Study adopted a new methodology, using the annualized average over the past 10 years and the same methodology is used for 2026-2027 IRM Study as well. This change smooths the impact of tail events or years with unusually long cable outages, ensuring more stable and reliable estimates. Additionally, the 10-year average better captures long-term trends in cable performance, providing a more comprehensive understanding of outage patterns.

As in all previous IRM studies, forced outage rates for overhead transmission lines were not represented in the 2026-2027 IRM Study. Historical overhead transmission availability was evaluated in a study conducted by ICS in 2015, *Evaluation of the Representation of Overhead Transmission Outages in IRM Studies*, which concluded that representing overhead

transmission outages in IRM studies would have no material impact on the IRM (www.nysrc.org/reports).

The impact of NYCA transmission constraints on IRM requirements depends on the level of resource capacity in any of the downstream zones from a constraining interface, especially in New York City (Load Zone J) and Long Island (Load Zone K). To illustrate the impact of transmission constraints on the IRM, if internal NYCA transmission constraints were eliminated, the required 2026-2027 IRM would decrease by 2.21% (Table 7-1, Case 2).

The 2026-2027 IRM Study modeled limits on emergency assistance from neighboring jurisdictions during severe and extreme conditions by implementing additional topology limitations between each of the external areas and NYCA. Such topology limitations do not reflect the real constraints on the transmission system, but rather, represent an estimate of the neighboring area's ability to provide support to the NYCA at EOP steps during the GE-MARS simulation. More details on this modeling are discussed in section 5.4.

5.4 The Outside World Model

The Outside World Model consists of four interconnected Outside World Areas contiguous with NYCA: Ontario, Quebec, New England, and the PJM Interconnection (PJM). NYCA reliability is improved and IRM requirements can be reduced by recognizing available emergency assistance (EA) from these neighboring interconnected control areas, in accordance with control area agreements governing emergency operating conditions.

For the 2026-2027 IRM Study, two Outside World Areas, New England and PJM, are each represented as multi-area models— *i.e.,* 14 zones for New England and five zones for PJM. Another consideration for developing models for the four Outside World Areas is to recognize internal transmission constraints within those areas that may limit EA into the NYCA. This recognition is explicitly considered through direct multi-area modeling of well-defined Outside World Area "bubbles" and their internal interface constraints. The model's representation explicitly requires adequate data in order to accurately model transmission interfaces, load areas, resource and demand balances, load shapes, and coincidence of peaks, among the load zones within these Outside World Areas.

In 2019, the ICS conducted an analysis of the IRM study's Outside World Area Model to review its compliance with a NYSRC Policy 5 objective that "interconnected Outside World Areas shall be modeled to avoid NYCA's over dependence on Outside World Areas for emergency assistance." This analysis resulted in a change in the methodology to scale loads proportional to excess capacities in each zone of each Outside World Area to meet the LOLE criterion and the Control Area's minimum IRM requirement, as well as the implementation of global EA limit

of 3,500 MW. For past IRM studies, EA assumptions have reduced IRM requirements by approximately 5.5%.

For the 2024-2025 IRM Study, an EOP whitepaper[16] was conducted and the whitepaper concluded that further refinement of the previous EA assumptions would improve the reasonableness of expectations for the availability of EA. Additional topology limits to constrain EA by LFU bin in the IRM study were recommended. In the 2024-2025 IRM Study, the static EA limit was modified as follows: LFU Bin 1: 1,470 MW; LFU Bin 2: 2,600 MW; LFU Bin 3-7: 3,500 MW. These limits were also implemented on each of the external Control Areas, based on historical extra reserves available in these Control Areas during NYCA peak load periods to better reflect potential support that external Control Areas can provide when New York is in need. For the 2025-2026 IRM Study, the dynamic emergency assistance modeling was expanded to include the HVDC lines to reflect the proportional limits to emergency assistance from the external control areas. For the 2026-2027 IRM Study, the emergency assistance modeling was further updated to reduce the EA from Hydro Quebec to 0 MW in the winter months (November – April).

5.5 Database Quality Assurance Review

It is critical that the database used for IRM studies undergo sufficient review in order to verify its accuracy. The NYISO, GE, and two Transmission Owners conducted independent data quality assurance reviews after the preliminary base case assumptions were developed prior to preparation of the final base case. Masked and encrypted input data was provided by the NYISO to the two Transmission Owners for their review. Also, certain confidential data is reviewed by two of the NYSRC consultants as required.

The NYISO, GE, and Transmission Owner reviews did not identify errors within the assumptions matrix for the 2026-2027 IRM Study PBC. A summary of these quality assurance reviews for the 2026-2027 IRM Study input data is shown in Appendix A, Section A.4. There were no material errors found in the final base case data.

5.6 Winter Reliability Risk

The 2026-2027 IRM Study indicates a notable shift in the seasonal distribution of reliability risk toward winter. While the annual LOLE target of 0.1 loss of load event-days/year is maintained, 14.0% of LOLE events occurred in winter, compared to 0% in the 2025-2026 IRM Study.

[16] See, New York State Reliability Council, EOP Whitepaper, available at: https://www.nysrc.org/wp-content/uploads/2023/10/EOP-Review-Whitepaper-Report_FINAL_For_Posting.pdf

Two key modeling changes contributed to this shift: (1) the inclusion of winter fuel availability constraints, and (2) the inclusion of the CHPE project. The introduction of winter fuel availability constraints results in derating of fossil-fired thermal units in Load Zones F-K during winter peak periods to account for limitations on natural gas and/or oil fuel availability. The introduction of the winter fuel availability constraints modeling leads to LOLE occurring in those peak winter periods. The addition of CHPE does not increase total reliability risk but shifts its seasonal allocation. Because CHPE is modeled in the 2026-2027 IRM Study as a summer-only resource, it only improves summer risk and when capacity is removed annually to achieve the 0.1 loss of load event-days/year criteria, winter modeled capacity is reduced resulting in a higher share of LOLE events occurring in winter.

As seasonal differences in modeled ICAP and reliability risk become more pronounced, the NYISO is evaluating, in collaboration with its stakeholders, a potential transition to establishing seasonal ICAP requirements. In support of this effort, Table 5-6 presents the modeled ICAP values by season, along with the implied IRM and locational capacity values for winter. The winter values are derived from the approved IRM and locational requirements produced by the 2026-2027 IRM Study Final Base Case, while the summer values represent the results of such case. These values are provided for informational purposes only.

Table 5-2: Modeled Capacity by Season 2026-2027

IRM 2026-2027 FBC: Summer				
	Modeled ICAP (MW) (a)	Total ICAP Removals (MW) (b)	Peak Load Forecast (MW) (c)	IRM and Locational Requirements (%) (a-b)/c
NYCA	41,813.92	2,158.73	31,648.2	25.300
Load Zone J	9,979.31	1,196.98	11,088.8	79.200
Load Zone K	5,857.31	384.20	5,127.8	106.734
G-J Locality	14,780.56	1,196.98	15,304.8	88.754
IRM 2026-2027 FBC: Winter				
	Modeled ICAP (MW) (a)	Total ICAP Removals (MW) (b)	Peak Load Forecast (MW) (c)	Effective IRM and Locational Requirements (%) (a-b)/c
NYCA	41,128.92	2,158.73	24,522.6	58.915
Load Zone J	9,081.04	1,196.98	7,647.4	103.095
Load Zone K	6,265.66	384.20	3,327.4	176.758
G-J Locality	14,092.93	1,196.98	10,775.4	119.680
IRM 2026-2027 Special Sensitivity Case: Summer				
	Modeled ICAP (MW) (a)	Total ICAP Removals (MW) (b)	Peak Load Forecast (MW) (c)	IRM and Locational Requirements (%) (a-b)/c
NYCA	42,404.70	2,654.58	31,648.2	25.600
Load Zone J	10,492.21	1,638.36	11,088.8	79.845
Load Zone K	6,061.71	549.22	5,127.8	107.502
G-J Locality	15,293.45	1,638.36	15,304.8	89.221
IRM 2026-2027 Special Sensitivity Case: Winter				
	Modeled ICAP (MW) (a)	Total ICAP Removals (MW) (b)	Peak Load Forecast (MW) (c)	Effective IRM and Locational Requirements (%) (a-b)/c
NYCA	41,895.83	2,654.58	24,522.6	60.021
Load Zone J	9,745.54	1,638.36	7,647.4	106.012
Load Zone K	6,494.56	549.22	3,327.4	178.678
G-J Locality	14,757.43	1,638.36	10,775.4	121.750

6. Parametric Comparison with ~~2025~~2026 ~~-2026~~ 2027 IRM Study Results

The ~~25.3~~30.90% IRM determined for the ~~2026-2027~~2027-2028 IRM Study final base case represents a ~~0.9~~5.3% increase from the ~~2025~~2026 ~~-2026~~ 2027 IRM Study final base case (initially referred to as the Special Sensitivity Case) value of ~~24.4~~25.6%. Note, the final approved IRM value for the ~~2025~~2026 ~~-2026~~ 2027 Capability Year was 24.~~4~~5%. Table~~s~~ 6-1 and 6-2 compare~~s~~ the estimated IRM impacts of updating several key study assumptions and revising models from those used in last year's study. The estimated percentage IRM change for each parameter was calculated from the results of a parametric analysis in which a series of IRM sensitivity runs were conducted to update the underlying IRM model data and test the IRM impact of individual parameters. Table 6-1 shows the transition from last year's FBC to this year's PBC. Table 6-2 then shows the impact of changes from the PBC Tan45 results to the FBC. In practice, the parametric analysis is conducted in a sequential manner and the parametric results can be largely affected by the study sequence and the selected parametric adjustment method. The total parametric change on the IRM from FBC to PBC is ~~roughly 1.5~~5.93%, while the ~~final~~ preliminary base case Tan45 analysis shows that ~~there is only a~~it was a ~~0.9~~5.80% increase from last year's final base case. The increased accuracy of the parametric analysis was the result of changes in the methodology made by the NYISO. ~~Table 6-1 also provides a summary for the IRM changes for some of the study parameters from the 2025-2026 IRM Study.~~

There are fifteen parameter drivers that in combination *increased* the 2027-2028 IRM from the 2026-2027 IRM Study base case IRM by 7.92%. Of these fifteen drivers, the most significant was the New Generator Inclusion which consisted of 1,229 MW of renewable generation and energy storage which only required the removal of 216 MW of ICAP to restore the system to 0.1 event-days/year. This resulted in an increase of over 1,000 MW in the ICAP requirement. The next closest impacts were the Transition Matrix and EFORD Updates (1.12%) and the 2026 Gold Book. DMNC and Behind-the-Meter Net Generation updates (1.01%). All other increases were less than 0.5% each. ~~There are sixteen parameter drivers that in combination a 6.29% increase to the IRM determined for the 2026-2027 IRM Study final base case compared to the 2025-2026 IRM Study final base case. Of these sixteen drivers, the most significant was the Winter Fuel Availability Constraints followed closely by the Fall Load Forecast reduction and the explicit modeling of BTM solar as a supply side resource. Each of these three items increased the IRM by over 1% each. The addition of the CHPE project with its 1,250 MW transfer capability into Load Zone J (assumed in the 2026-2027 IRM Study for the summer months only), resulted in just a 0.317% increase in the IRM but caused significant shifts in the locational requirements. The locational requirement for Load Zone J increased by 8.474%, the Load Zone K locational requirement decreased by 3.397%, and the G-J Locality locational requirement increased by 5.272%. Because of the seasonal capability of this line assumed in the study model, it also exacerbated the impact of the winter fuel availability constraints.~~

Only four parameter drivers in combination *decreased* the IRM from the 2026-2027 IRM Study base case by 1.89%. Of these four drivers, the most significant was the Generator Deactivations which caused a 1.23% decrease. All other changes were less than 0.5% each. ~~Twelve parameter drivers in combination decreased the IRM from the 2025-2026 IRM Study final base case by 4.66%. Of these twelve drivers, the most significant was the change in the quantity of SCR MW modeled for the 2026-2027 IRM Study final base case which decreased the IRM by 1.569%. The assumed Gowanus and Narrows generator deactivations decreased the IRM by 0.686% followed closely by the initial 2025 Gold Book Load Forecast which decreased the IRM by 0.619%. All other modifications, individually, had an impact of less than 0.50% on the IRM.~~

The overall parametric impact from the PBC to FBC cases, shown in Table 6-2, were negligible. The largest impact was the Fall Loads Forecast which resulted in a decrease of 573 MW in the system peak load. Although this caused a decrease in the ICAP MW requirements, because the IRM is expressed as a percentage of the peak load it resulted in a 0.64% increase in IRM. Other changes, most notably updates to the SCR MW, Voluntary Curtailment and Public Appeals MW and Topology changes all decreased the IRM slightly and effectively cancelled out the impact of the Load changes.

The parameters in Table 6-1 and Table 6-2are discussed under *Models and Key Input Assumptions.*

Table 6-1: 2025-2026 FBC vs 2026-2027 PBC Parametric Impact

Material Changes

Number	Adjustment Type	Description	Impact on Margins			
			NYCA	NYC	LI	LHV
		2026-2027 IRM Final Base Case	25.6	79.8	107.5	89.2
1	A-K	2026 Gold Book Load Forecast	0.31	0.66	0.09	-0.01
2	A-K	Run of River Hydro (RoR) Shapes (2021 - 2025)	0.06	0.00	0.00	0.00
3	A-F	Land-Based Wind (LBW) Shapes (2021 - 2025)	-0.22	0.00	0.00	0.00
4	A-K	10-min Operating Reserve Allocation and Level Maintained during Load Shedding	0.24	0.18	0.22	0.19
5	A-K	Preliminary Special Case Resource Modeled MW	0.09	0.00	0.00	0.00
6	A-K	Preliminary Distributed Energy Resources (DER) MW	-0.09	0.06	0.07	0.06
7	A-K	Transition to Power GADS	0.16	0.07	0.16	0.10
8	A-K	Thermal Transition Matrix and EFORd Update (2021-2025)	1.12	1.36	1.85	1.48
9	G-K	Cable Transition Rates	0.09	0.13	0.15	0.13
10	A-K	Load Forecast Uncertainty	0.17	0.13	0.16	0.13
11	A-K	New Generator Inclusion	3.40	0.54	-0.43	0.28
12	A-K	Behind-the-Meter Solar Shapes (BTM PV) Update (2027 BTM PV Forecast for Load and 2021-2025 BTM PV for Generation)	0.39	0.30	0.35	0.29
13	A-K	2026 Gold Book DMNC + Behind-the-Meter Net Generation (BTM:NG) Updates	1.01	1.12	-2.14	1.11
14	A-K	Generator Deactivations	-1.23	0.26	0.30	-2.92
15	A-K	Revised Emergency Assistance Limits for Cables with PJM	0.11	0.17	0.20	0.17
16	A-K	Voluntary Curtailment MW Update	0.11	0.17	0.20	0.17
17	A-K	Firm Transactions Update	0.17	0.13	0.16	0.13
18	A-K	Winter Fuel Availability Constraints Modeling Update	-0.35	-0.27	-0.31	-0.26
19	A-K	External Data + Policy 5 Adjustment	0.49	0.37	0.44	0.37
		Sum of Material Changes	6.03	5.40	1.45	1.41
		Non Material Changes	0.10	0.08	0.06	0.07
		Preliminary Base Case Parametric Results **	31.74	85.32	109.02	90.71

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Non-Material Changes (Less than 0.05% delta on IRM)						
Number	Adjustment Type	Description	Impact on Margins			
			NYCA	NYC	LI	LHV
1	A-K	MARS Version: 5.10.4171	0.00	0.00	0.00	0.00
2	A-F	Landfill Gas (LFG) Shapes (2021 - 2025)	0.02	0.00	0.00	0.00
3	A-K	Solar Shapes (2021 - 2025)	-0.02	-0.01	-0.02	-0.01
4	G-K	Offshore Wind Shapes (2021-2025)	0.01	0.01	0.01	0.01
5	A-F	Topology Update: Limit Update for Dysinger East, Moses South, and Seasonal Limits for West Central Reverse	0.03	0.00	0.00	0.00
6	A-K	External Topology Update	0.02	0.01	0.01	0.01
7	A-K	Database Cleanup	0.01	0.01	0.01	0.01
8	A-K	Maintenance Modeling Update	0.02	0.02	0.02	0.02
9	A-K	Zonal Derating Factors Update (includes intermittent winter performance and seasonal capabilities)	0.02	0.05	0.02	0.04
10	A-K	Standard Error (at 3,000 Replications)	0.00	0.00	0.00	0.00
		Sum of Non-Material Changes	0.10	0.08	0.06	0.07

Table 6-2: 2026-2027 PBC vs 2026-2027 FBC Parametric Impact

Material Changes						
Number	Adjustment Type	Description	Impact on Margins			
			NYCA	NYC	LI	LHV
		2027-2028 IRM Preliminary Base Case	30.80	85.86	109.87	89.33
1	A-K	Special Case Resources (SCR) MW Update	-0.16	0.25	0.19	0.15
2	A-K	Voluntary Curtailment and Public Appeals MW Updates	-0.18	-0.14	-0.16	-0.14
3	A-K	Winter Fuel Allocation Update	-0.07	-0.05	-0.07	-0.05
4	A-K	New Generator Inclusion	0.12	-0.13	0.16	-0.13
5	A-K	Topology Update: Limit Update for UPNY-SENY, UPNY-ConEd, and Seasonal Limits for LI Interfaces	-0.12	-0.09	-0.11	-0.09
6	A-K	Fall Load Forecast	0.64	-0.46	0.00	0.37
7	A-K	Manual and Remote Voltage Reduction	-0.08	-0.06	-0.07	-0.06
		Database Cleanup: Winter Fuel Allocation				
		Sum of Material Changes	0.16	-0.69	-0.06	0.05
		Non Material Changes	-0.12	-0.44	1.18	-0.23
		Final Base Case Parametric Results **	30.83	84.73	110.99	89.15

** The LCR values reported are neither Tan 45 results nor LCR Optimizer results. The actual LCRs will be determined and approved by the NYISO's Operating Committee based upon the EC approved IRM and database model with modifications pursuant to Market Services Tariff Section 5.11.

Non-Material Changes (Less than 0.05% delta on IRM)						
Number	Adjustment Type	Description	Impact on Margins			
			NYCA	NYC	LI	LHV
1	A-K	Distributed Energy Resources (DER) MW Update	-0.04	0.17	0.20	0.17
2	A-K	NERC EFORd: 2021-2025	0.00	0.00	0.00	0.00
3	G-K	Seasonal Unforced Capacity Deliverability Rights (UDR) Elections	-0.04	-0.62	0.98	-0.40
4	A-F	Resource Deactivations	-0.04	0.00	0.00	0.00
5	A-K	Demand-side Management (DSM) Shapes Update	0.00	0.00	0.00	0.00
		Sum of Non-Material Changes	-0.12	-0.44	1.18	-0.23

~~**Table 6-1: 2025-2026 vs 2026-2027 Parametric Impact Comparison**~~

~~Parameter~~	~~Impact on Margins~~		-	-	~~Reason for Change~~
-	~~IRM~~	~~NYC~~	~~LI~~	~~G-J~~	-
~~2025-2026 IRM Final Base Case (FBC)~~	~~24.40%~~	~~75.58%~~	~~107.30%~~	~~86.91%~~	-
~~Study Parameters that Increased the IRM~~					
~~Winter Fuel Availability Constraints~~	~~1.37%~~	~~1.05%~~	~~1.32%~~	~~1.09%~~	~~Adoption of Winter Fuel Availability Constraints modeling~~
~~Fall Load Forecast~~	~~1.29%~~	~~0.86%~~	~~1.04%~~	~~0.63%~~	-
~~Behind the Meter (BTM) Solar~~	~~1.11%~~	~~0.78%~~	~~1.08%~~	~~0.85%~~	~~Modeling BTM Solar explicitly as a supply resource~~
~~New Generator Screening~~	~~0.70%~~	~~0.10%~~	~~0.05%~~	~~0.08%~~	-
~~EFORd Thermal Outage Rate (2020-2024)~~	~~0.37%~~	~~0.27%~~	~~0.33%~~	~~0.30%~~	-
~~Champlain Hudson Power Express (CHPE) Inclusion~~	~~0.32%~~	~~8.47%~~	~~3.40%~~	~~5.27%~~	-
~~2025 BTM Solar Generator Shapes~~	~~0.24%~~	~~0.17%~~	~~0.23%~~	~~0.18%~~	-
~~Generator Deactivations and ICAP Ineligible Forced Outages (IIFOs)~~	~~0.19%~~	~~0.90%~~	~~1.56%~~	~~1.00%~~	-

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Topology Update: Limit Update for Sprain Brook Dunwoodie South	0.17%	0.24%	0.33%	0.26%	-
HQ Imports Modeling Update	0.11%	0.00%	0.00%	0.00%	-
Inclusion of Distributed Energy Resources (DERs)	0.10%	0.00%	0.00%	0.00%	Modeling DER enrollments
Cable Transition Rates	0.08%	0.06%	0.08%	0.06%	-
Load Zone K Topology Update	0.07%	0.11%	0.13%	0.11%	-
Load Forecast Uncertainty	0.05%	0.04%	0.05%	0.04%	-
MARS Version	0.05%	0.04%	0.05%	0.04%	-
Manual & Remote Voltage Reduction MW Update	0.05%	0.04%	0.05%	0.04%	-
Study Parameters that Decreased the IRM					
Special Case Resources (SCR)	-1.57%	-0.03%	0.10%	-0.07%	Updated SCR enrollments
Gowanus 1 & 2 and Narrows 2 & 3 Deactivations	-0.69%	-3.34%	1.53%	-2.03%	-
2025 Gold Book Load Forecast	-0.62%	0.95%	0.98%	0.52%	-
2026 Solar Adjusted Load Shapes	-0.47%	-0.34%	-0.47%	-0.36%	-
Voluntary Curtailment Call Limit Update	-0.30%	-0.22%	-0.28%	-0.23%	3 days/month call limit implemented
Unforced Capacity Deliverability Rights (UDR) Elections	-0.26%	-1.15%	0.55%	-0.69%	-
Revised SCR Start Times	-0.25%	0.00%	0.00%	0.00%	Adoption of new SCR start time methodology
External Data + Policy 5 Adjustment	-0.17%	-0.13%	-0.16%	-0.13%	-
Enhanced Load Modeling (ELM)	-0.15%	-0.11%	-0.15%	-0.12%	Calibrate annual energy and seasonal peak forecasts
NERC EFORd: 2020-2024	-0.07%	-0.06%	-0.07%	-0.06%	-
2025 Gold Book DMNC	-0.06%	0.23%	0.02%	-0.01%	-
Solar Shapes (2020 - 2024)	-0.05%	-0.04%	-0.06%	-0.04%	-
Total Impact/Results					
Sum of Non-Material Changes (FBC&PBC)	**-0.11%**	**-0.06%**	**-0.13%**	**-0.07%**	-
Total Parametric Impact (Sum of FBC&PBC Material and Non-Material Changes)	**1.52%**	**7.12%**	**-0.51%**	**5.40%**	-

~~2026-2027 IRM Parametric Results~~	~~25.92%~~	~~82.70%~~	~~106.79%~~	~~92.31%~~	-
~~2026-2027 IRM FBC Tan45 Results~~	~~25.30%~~	~~79.20%~~	~~106.73%~~	~~88.75%~~	~~Results of FBC Tan45~~
~~Tan45 Delta~~	~~-0.62%~~	~~-3.50%~~	~~-0.06%~~	~~-3.56%~~	~~Delta between the Parametric Results and the Tan45 Results~~

7. Sensitivity Case Study

In addition to calculating the IRM using base case assumptions, sensitivity analyses are run as part of an IRM study to determine IRM outcomes using different assumptions than in the base case. Sensitivity studies provide a mechanism for illustrating "cause and effect" of how some performance and/or operating parameters and study assumptions can impact reliability. Certain sensitivity studies, termed "IRM impacts of base case assumption changes," serve to inform the NYSRC Executive Committee when determining the Final NYCA IRM regarding how the IRM may be affected by reasonable deviations from selected base cases assumptions. The methodology used to conduct sensitivity cases starts with the base case IRM results and adds or removes capacity from all NYCA zones until the NYCA LOLE approaches 0.1 Event-Days/year.

Table 7-1 shows the resulting IRM for the various sensitivity cases. Notably, all of the sensitivities are run on the approved ~~2026-2027~~2027-2028 IRM PBC. It is expected that the relative impact on the PBC remain unchanged on the ~~2026-2027~~2027-2028 IRM Final Base Case (FBC), ~~Table 7-1 is adjusted to show the same relative impact from the approved sensitivity case result on the FBC (Table 7-1, Case 0).~~[17] In addition to showing the IRM requirements for various sensitivity cases, Table 7-1 shows the LOLH and EUE reliability metrics for each case.[18] These two metrics, along with the LOLE metric, are important measures of reliability risk in that together, they describe the frequency, duration, and magnitude of loss of load events.[16] The reliability risk measures provided by these two metrics, in addition to IRM impacts, provide Executive Committee members with different aspects of system risk for selecting the Final NYCA IRM. The data used to calculate LOLH and EUE are collected from GE-MARS output.

Sensitivity Cases 1 through ~~5~~5 in Table 7-1 are annually performed and illustrate how the IRM would be impacted if certain major IRM study parameters were not represented in the IRM base case. The current Case 5, Fuel Availability with Firm Fuel Elections, has now replaced the analysis of SCRs. These parameters and their IRM impacts are discussed in Sections 5.1.2 and 5.4, respectively.

Case 6 looks at the impact ~~of~~ Empire and Sunrise Offshore Wind Farms. Inclusion of these units adds 1,740 MW of ICAP, while removing only 741 MW of ICAP return the system to criteria. This results in a 3.2% increase in the IRM. This sensitivity also has a significant impact on the LCRs in Zones J and K. Zone J LCR increases by 2.6% to 88.5% and Zone K increases by 12.9% to 122.8%.

~~[17] *See*, New York State Reliability Council 2025-2026 Installed Reserve Margin Study – Sensitivity Cases and Case Comparison, *available at:* https://www.nysrc.org/wp-content/uploads/2024/08/IRM25_Sensitivities_Results-09042024-ICS.pdf~~

[18] **LOLH**: The expected number of hours during loss of load events each year when the system's hourly demand is projected to exceed the generating capacity.
EUE: The expected amount of energy (MWh) during loss of load events that cannot be served each year.

Case 7 examined the impact of removing the New Generator Inclusion. This is essentially the reverse of Parametric step 11 and the results are similar. Because the contribution to reliability is much lower with renewable generation removing the new generation results in a reduction in the IRM of 3.2%.

~~removing the Winter Fuel Availability constraints modeling. If there were no limits were included on the availability of the fuel for thermal units in Load Zones F-K in the winter period, the IRM would drop by 1.8% to 23.5%. The final base case assumed that CHPE project was in service and the Gowanus and Narrows barges were removed, resulting in an IRM of 25.3%. Case 7a assumes the reverse – the CHPE line is modeled as out of service and the Gowanus and Narrows barges are modeled as in service. The alternative assumptions would reduce the IRM by 0.8% resulting in a 24.5% value. Case 7b assumes that both CHPE and the Gowanus and Narrows barges are in service. These assumptions increase the IRM by 0.5% to a value of 25.8%.~~

~~*For the 2026-2027 IRM Study, a Special Sensitivity Case (see Case 8 in Table 7-1 below) was conducted to account for the consideration of potential assumption changes that arose following approval of the final base case assumptions matrix, including consideration of potential resource operating status changes that could arise as a result of the findings of the NYISO's 2025 Quarter 3 Short-Term Assessment of Reliability ("STAR") issued on October 13, 2025. The consideration of potential resource operating status changes in consideration of the NYISO's 2025 Quarter 3 STAR recognize that the NYISO's process for solicitation, review, and identification of solutions in response to the near-term reliability needs identified by the 2025 Quarter 3 STAR will not be completed prior to finalizing the 2026-2027 IRM Study and, thus, do not reflect any final determinations by the NYISO for addressing such reliability needs. The Special Sensitivity Case also reflects a change in the assumed operating status of a land-based wind resource that was previously recommended for addition as a new capacity supply resource for inclusion in the 2026-2027 IRM Study. An overview of the resource assumption updates included in the Special Sensitivity Case are as follows:*~~

- ~~*Load Zone J additions (512.9 MW): Gowanus 2-1 – 2-8, Gowanus 3-1 – 3-8 (with exception of Gowanus 3-6), Narrows 1-1 – 1-8, and Narrows 2-1 – 2-8 (with exception of Narrows 2-1 and 2-7)*~~
- ~~*Load Zone K additions (204.4 MW): Far Rockaway GT1 and GT2, Glenwood GT3, and Shoreham IC1*~~
- ~~*Load Zone A removal (126.5 MW): Cassadaga Wind*~~

~~*The Special Sensitivity Case also reflects updates to the winter fuel availability constraint assumptions to align with the changes to the operating status of thermal resources located in Load Zones J and K that are subject to the modeled winter fuel availability constraints.*~~

Table 7-1. ~~2026-2027~~2027-2028 Installed Reserve Margin (IRM) Study - Sensitivity Cases and Special Sensitivity Case

2027-2028 Installed Reserve Margin (IRM) Study - Sensitivity Cases

Note: All results are calculated by adding/removing capacity from Load Zones A - K unless otherwise noted

Case	Description	IRM (%)	NYC (%)	LI (%)	IRM (%) Change from Base	Winter LOLE (%)	Summer LOLE (%)	LOLH (hrs/yr)	EUE (MWh/yr)
0	2027-2028 IRM Preliminary Base Case (PBC)	30.8	85.9	109.9	-	9.15%	90.85%	0.355	178.423
	These are the Base Case technical results derived from knee of the IRM-LCR curve								
1	NYCA Isolated	35.3	89.3	113.9	4.5	5.89%	94.11%	0.301	171.066
	Track Total New York Control Area (NYCA) Emergency Assistance (EA) – NYCA system is isolated and receives no emergency assistance from neighboring control areas (New England, Ontario, Quebec, and PJM). Unforced Capacity Deliverability Rights (UDRs) are allowed								
2	No Internal NYCA transmission constraints	27.7	83.5	107.1	-3.1	14.95%	85.05%	0.357	322.033
	Track level of NYCA congestion with respect to the IRM model – eliminates internal transmission constraints and measures the impact of transmission constraints on statewide IRM requirements								
3	No Load Forecast Uncertainty	24.7	81.2	104.4	-6.1	3.54%	96.46%	0.283	63.989
	Shows sensitivity of IRM to load uncertainty, if the forecast peak loads for NYCA have a 100% probability of occurring								
4	No Wind Capacity	23.1	87.1	108.8	-7.7	14.44%	85.56%	0.354	186.351
	Shows wind impact for both land-based and off-shore wind units and can be used to understand Equivalent Demand Forced Outage Rate (EFORd) sensitivity								
5	Fuel Availability with Firm Fuel Characteristic Elections (Tan45)	29.5	85.9	110.1	-1.3	0.01%	99.99%	0.366	212.574
	Shows the impact of modeling winter fuel availability in each Load Zone based on firm fuel character elections for the 2027-2028 Capability Year								

Case	Description	IRM (%)	NYC (%)	LI (%)	IRM (%) Change from Base	Winter LOLE (%)	Summer LOLE (%)	LOLH (hrs/yr)	EUE (MWh/yr)
6	Empire and Sunrise Wind Included (Tan45)	34.0	88.5	122.8	3.2	10.30%	89.97%	0.361	188.065
	Shows the impact of including the Empire and Sunrise Wind units in the 2027-2028 IRM study. For the PBC, these units are not included in the study.								
7	No New Generator Inclusion (Tan45)	27.6	85.5	110.0	-3.2	8.37%	91.63%	0.353	175.542
	Shows the impact of modeling an alternative assumption in which no new generator additions are included in the 2027 2028 IRM study (i.e., removes the new generator additions modeled as part of the PBC).								
8	2020-2024 Thermal EFORd Data (Tan45)	29.7	83.6	108.4	-1.1	10.01%	89.99%	0.354	186.035
	Shows the impact of modeling thermal generator EFORd values based on the 2020–2024 outage data set instead of the 2021–2025 outage data set used in the PBC.								

~~Case~~	~~Description~~	~~IRM (%)~~	~~NYC (%)~~	~~LI (%)~~	~~IRM (%) Change from Base~~	~~LOLH (hrs/yr)~~	~~EUE (MWh/yr)~~
~~0~~	~~2026-2027 IRM Final Base Case (FBC)~~	~~25.30~~	~~79.20~~	~~106.73~~	~~-~~	~~0.36~~	~~169.51~~
	~~These are the Base Case technical results derived from knee of the IRM LCR curve~~						
~~1~~	~~NYCA Isolated~~	~~30.08~~	~~82.88~~	~~111.33~~	~~4.78~~	~~0.31~~	~~176.64~~
	~~Track Total New York Control Area (NYCA) Emergency Assistance (EA) – NYCA system is isolated and receives no emergency assistance from neighboring control areas (New England, Ontario, Quebec, and PJM). Unforced Capacity Deliverability Rights (UDRs) are allowed~~						
~~2~~	~~No Internal NYCA transmission constraints~~	~~23.09~~	~~77.50~~	~~104.60~~	~~-2.21~~	~~0.33~~	~~256.59~~

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	Track level of NYCA congestion with respect to the IRM model – eliminates internal transmission constraints and measures the impact of transmission constraints on statewide IRM requirements						
3	No Load Forecast Uncertainty	19.71	74.90	101.35	-5.59	0.30	74.15
	Shows sensitivity of IRM to load uncertainty, if the forecast peak loads for NYCA have a 100% probability of occurring						
4	No Wind Capacity	18.53	80.38	105.78	-6.77	0.36	178.73
	Shows wind impact for both land-based and off-shore wind units and can be used to understand Equivalent Demand Forced Outage Rate (EFORd) sensitivity						
5	No SCR Capacity	22.10	75.96	107.50	-3.20	0.36	179.97
	Shows sensitivity of IRM to the Special Case Resource (SCR) program						

Case	Description	IRM (%)	NYC (%)	LI (%)	IRM (%) Change from Base	LOLH (hrs/yr)	EUE (MWh/yr)
6	No Winter Fuel Availability Constraints (Tan45)	23.50	78.14	107.26	-1.80	0.38	217.82
	Shows the level of winter reliability risk due to the winter fuel availability constraints						
7a	Barges + No CHPE (Tan45)	24.50	76.01	108.73	-0.80	0.39	197.86
	Shows impact of modeling alternative assumptions for the status of CHPE and the Gowanus/Narrows barges • With the FBC assuming that CHPE is included and barges are out-of-service, the sensitivity will exclude CHPE and include the barges						

	Barges + CHPE both included (Tan45)	25.80	80.44	106.28	0.50	0.36	163.78
7b	Shows impact of modeling alternative assumptions for the status of CHPE and the Gowanus/Narrows barges • With the FBC assuming that CHPE is included and barges are out-of-service, this sensitivity will include both CHPE and the barges in-service to understand their combined impact						
	Special Sensitivity (Tan45)	25.60	79.85	107.50	0.30	0.36	168.50
8*	Shows impact of modeling certain alternative resource assumptions for the Final Base Case. The alternative resource assumptions are as follows: (1) the removal of Cassadaga Wind in Load Zone A; (2) the inclusion of Gowanus 2-1 – 2-8, Gowanus 3-1 – 3-8 (with exception of Gowanus 3-6), Narrows 1-1 – 1-8, and Narrows 2-1 – 2-8 (with exception of Narrows 2-1 and 2-7) in Load Zone J; and (3) the inclusion of Far Rockaway GT1, Far Rockaway GT2, Glenwood GT3, and Shoreham IC1 in Load Zone K. As part of the generator inclusion updates listed above for Load Zones J and K, the fuel availability constraints modeling assumptions have been updated accordingly.						

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Note: All results are calculated by adding/removing capacity from Load Zones A - K unless otherwise noted

*Case 8 was conducted on the Final Base Case whereas all other cases were run on the Preliminary Base Case and converted to reflect the relative impact on the Final Base Case

8. NYISO Implementation of the NYCA Capacity Requirement

The NYISO values capacity sold and purchased in the market in a manner that considers the forced outage ratings of individual units, whereby generating unit capacity is derated to an unforced capacity basis recognizing the impact of historic unit forced outages. This derated capacity is referred to as "UCAP." In the NYCA, these translations occur twice during the course of each Capability Year, prior to the start of the Summer and Winter Capability Periods.

Additionally, the NYCA installed capacity requirement and LCRs are translated into equivalent UCAP values during these periods. The conversion to UCAP essentially translates from one index to another; it is not a reduction of actual installed resources. Therefore, no degradation in reliability is expected. The NYISO employs a translation methodology that converts ICAP requirements to UCAP in a manner that ensures compliance with NYSRC Resource Adequacy Rule A.1: R1. The conversion to UCAP provides financial incentives to decrease the forced outage rates while improving reliability.

Due to lower contribution to reliability, the increase in wind and solar resources lowers the translation factor from required ICAP to required UCAP which reflects the performance of all resources on the system. Figure 8.1 shows that required UCAP margins decrease slightly through 2024 even though the

required ICAP margins increase slightly. This is due to resources with below average performance being removed from the system and the required UCAP being a function of required ICAP and the weighted average availability of system resources. Last year both the ICAP and UCAP increased slightly.

Appendix D provides details of the ICAP to UCAP conversion.

Figure 8-1 NYCA Reserve Margins

