5. Models and Key Input Assumptions

This section describes the models and related base case input assumptions for the 2026-2027 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 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 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 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[1]. 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

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

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 Loads (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.

Following the implementation of the enhanced load modeling (ELM) procedure,[2] 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).

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

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 Phase 2 Study.[3] 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.[4] 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

[9] https://www.nysrc.org/wp-content/uploads/2023/05/A.I.10-LDC_Recommendation_ICS4098.pdf
[4] BTM Solar Modeling Whitepaper: https://www.nysrc.org/wp-content/uploads/2025/01/BTM-Solar-Modeling-Whitepaper-11122024.pdf

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 preliminary base case (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,[5] which are assumed to be deactivated in the 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

[5] 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.

be included based on the ICS approved modeling for DER.[6] 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).

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.

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

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 C.3, "Wind Resource 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.[7] 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 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.

[7] 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

As ELR capacity continues to grow across the New York Control Area (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.[8] 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.

(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

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

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"[9] 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).

Commented [LC1]: TBD - Update footnote below

(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 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.

[9] Placeholder for link to "ELR whitepaper"

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[10]

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

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

system topology with the Smart 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[11] 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 and 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

[11] 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

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.

Commented [BP2]: TBD

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.

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

	Summer			Winter		
	Modeled ICAP (MW)	Peak Load Forecast (MW)	IRM and LCRs (%)	Modeled ICAP (MW)	Peak Load Forecast (MW)	Implied IRM and LCRs (%)
NYCA	39,655.2	31,648.2	25.3	38,989.3	24,522.6	58.99
Zones G-J	13,583.6	13,583.6	88.75	12,904.0	10,775.4	119.75
Zone J	8,782.3	11,088.8	79.2	7,891.71	7,647.4	103.19