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Technical Study Report

New York Control Area Installed Capacity Requirement

For the Period May 2021 to April 2022

DRAFT vB 20.7%

December 4, 2020

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 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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NOTE: Appendices A, B, C and D are included in a separate document.

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 year's report covers the period May 1, 2021 through April 30, 2022 (2021 Capability Year). The IRM study described in this report for 2021 Capability Year is referred to as the "2021 IRM Study."

Results of the NYSRC technical study show that the required NYCA IRM for the 2021 Capability Year is 20.7% under base case conditions. This IRM satisfies the NYSRC and Northeast Power Coordinating Council (NPCC) reliability criterion of a Loss of Load Expectation (LOLE) of no greater than 0.1 days per year. The base case, along with other relevant factors, will be considered by the NYSRC Executive Committee on December 4, 2020 for its adoption of the Final NYCA IRM requirement for the 2021 Capability Year.

The NYSRC study procedure used to establish the NYCA IRM[2] also produces corresponding "initial" New York City and Long Island locational capacity requirements (LCRs) necessary to satisfy the NYCA resource adequacy criterion. The 2021 IRM Study determined initial LCRs of 82.6% and 95.1% for the New York City and Long Island localities, respectively. In accordance with its responsibility of setting the LCRs, the New York Independent System Operator, Inc. (NYISO) will calculate and approve *final LCRs* for all NYCA localities using a separate process that utilizes the NYSRC approved Final IRM and adheres to NYSRC Reliability Rules and policies.

The 20.7% IRM base case value for the 2021 Capability Year represents a *1.8% increase* from the 2020 base case IRM of 18.9%. Table 6-1 shows the IRM impacts of individual updated study parameters that result in this change. In summary:

- ✦ There are *five parameter drivers* that in combination *increased* the 2021 IRM from the 2020 base case IRM by 3.1%. Of these five drivers, the most significant are an updated load forecast uncertainty model which increased the IRM by 1.0%, the modeling of Energy Limited Resources (ELRs) which increase the IRM by 0.9%, and the retirement of the second

[1] A Capability Year begins on May 1 and ends on April 30 of the following year.

[2] This procedure is described in Section 3, IRM Study Procedures. This procedure for calculating IRM requirements and initial LCRs is sometimes referred in this report to as the "Tan-45 process."

- Indian Point Energy Center unit (IP3) along with related topology changes which increased the IRM by 0.7%.

- Five parameter drivers in combination decreased the IRM from the 2020 base case by 1.3%. Of these five drivers, the most significant are a reduction in Special Case Resource (SCR) registrations coupled with improved performance (-0.4%) and an updated load forecast (-0.3%). Each of the following three parameter drivers contributed 0.2% to the overall reduction; higher amounts of emergency operating procedure values, improved cable forced outage rates, and more emergency assistance from Outside World Areas.

The complete parametric analysis showing the above and other results can be found in Section 6 in 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. 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 2021. NYSRC Policy 5-15 describes the Executive Committee process for establishing the Final IRM.

In addition, a confidence interval analysis was conducted to demonstrate that there is a high confidence that the base case 20.7% IRM will fully meet NYSRC and NPCC resource adequacy criterion that require a Loss of Load Expectation (LOLE) of no greater than 0.1 days per year.

The 2021 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%, have remained fairly steady since then (see Table 8-1).

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, 2021 through April 30, 2022 (2021 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:

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

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 2021 Capability Year.

The NYISO will implement the Final NYCA IRM as determined by the NYSRC, in accordance with the NYSRC Reliability Rules, NYSRC Policy 5-15, *Procedure for Establishing New York Control Area Installed Capacity Requirement and the Installed Reserve Margin (IRM)*;[3] the NYISO Market Administration and Control Area Services Tariff; and the NYISO Installed Capacity (ICAP) Manual.[4] The NYISO translates the required IRM to a UCAP basis. These values are also used in a Spot Market Auction based on FERC-approved Demand Curves. The schedule for conducting the 2021 IRM Study was based on meeting the NYISO's timetable for conducting this auction.

The study criteria, procedures, and types of assumptions used for the study for establishing the NYCA IRM for the 2021 Capability Year (2021 IRM Study) are set forth in NYSRC Policy 5-15. The primary reliability criterion used in the IRM study requires an LOLE of no greater than 0.1 days per year for the NYCA. This NYSRC resource adequacy criterion is consistent with the Northeast Power Coordinating Council (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 5-15 and discussed in detail later in this report.

The NYSRC procedure for determining the IRM also identifies "initial" corresponding locational capacity requirements (LCRs) for the New York City and Long Island localities[2]. The NYISO, using

[3] http://www.nysrc.org/policies.asp

[4] http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp

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 5-15 – is responsible for setting *final* LCRs for the New York City Long Island and Zones G-J Localities. For its determination of LCRs for the 2021 Capability Year, the NYISO will continue utilizing an economic optimization methodology approved by the Federal Energy Regulatory Commission.

The 2021 IRM Study was managed and conducted by the NYSRC ICS and supported by technical assistance from the NYSRC's technical consultants and the NYISO staff.

Previous IRM Study reports, from year 2000 to year 2020, can be found on the NYSRC website.[5] Appendix C, Table C.1 provides a record of previous NYCA base case and final IRMs for the 2000 through 2020 Capability Years. Figure 8-1 and Appendix C, Table C.2, show UCAP reserve margin trends over previous years. Definitions of certain terms in this report can be found in the Glossary (Appendix D).

A different analysis, separate from the IRM study process covered in this report, is conducted by the NYISO and is called the Reliability Needs Assessment (RNA). This analysis assesses resource adequacy of the NYCA for ten years into the future. This assessment determines whether the NYSRC resource adequacy reliability criterion, as defined in Section 2 below, is 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 Requirements 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 day per 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*.

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

[5] http://www.nysrc.org/reports3.asp

mean that planning reserve margins, or the IRM, needs to be high enough that the probability of an involuntary load shedding due to inadequate resources is limited to only one day in ten years or 0.1 day per 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 day per year has provided an acceptable level of reliability for many years.

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 2021 IRM Study are described in detail in NYSRC Policy 5-15, *Procedure for Establishing New York Control Area Installed Capacity Requirements and the Installed Reserve Margin (IRM)*. Policy 5-15 also describes the computer program used for reliability calculations and the types of input data and models used for the IRM Study.

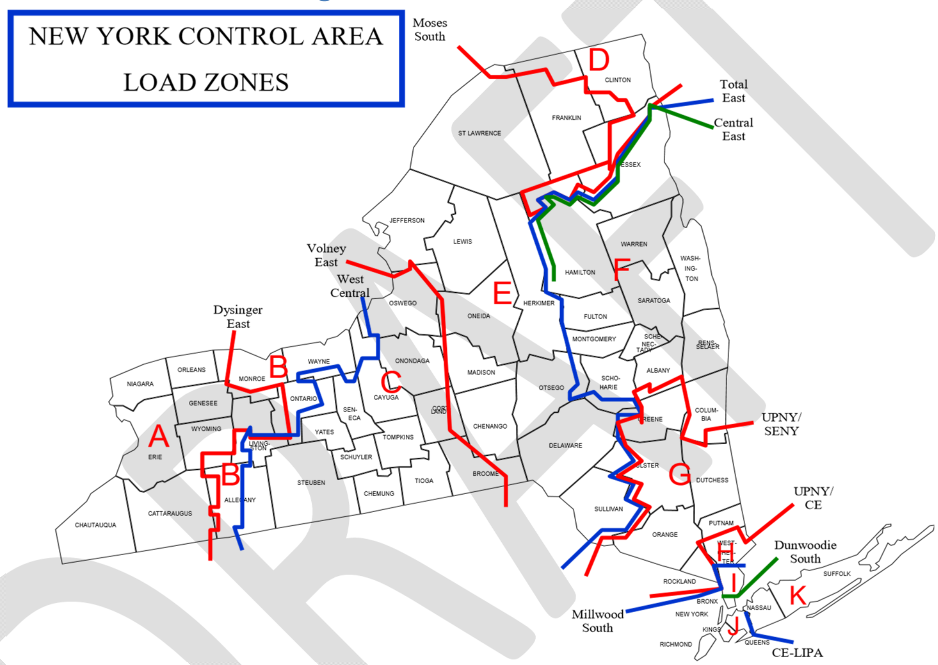
This study utilizes a *probabilistic approach* for determining NYCA IRM requirements. This technique calculates the probabilities of generator unit outages, in conjunction with load and transmission representations, to determine the days per year of expected resource capacity shortages.

General Electric's Multi-Area Reliability Simulation (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 zones are depicted in Figure 3-1. GE-MARS calculates LOLE, expressed in days per 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 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 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 IRM Study and all later studies, including this 2021 IRM Study, were simulated using all hours in the year.

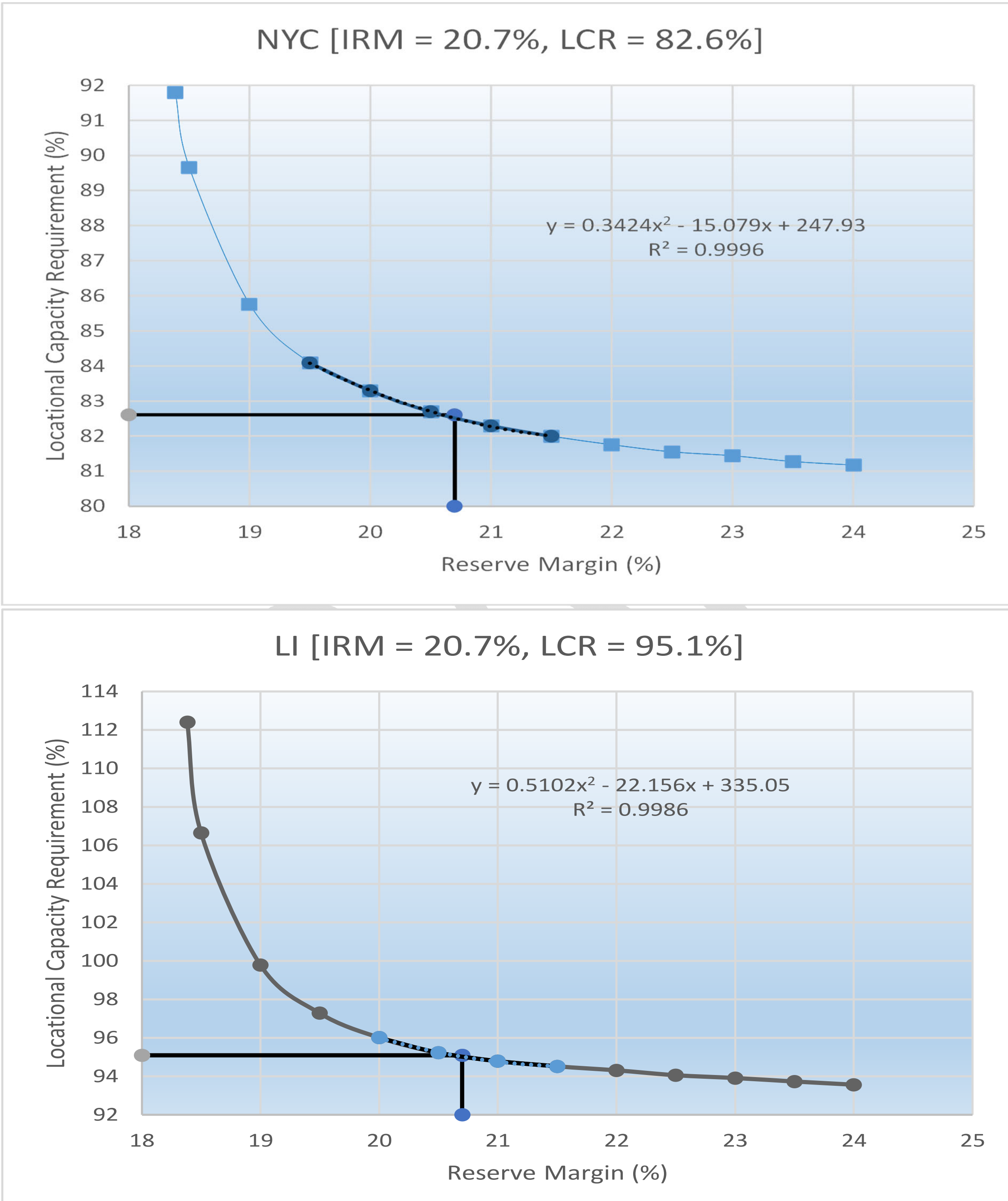
Using the GE-MARS program, a procedure is utilized for establishing NYCA IRM requirements (termed the *Unified Methodology*) which establishes a relationship between NYCA IRM and corresponding initial LCRs, as illustrated in Figure 3-2. All points on these curves meet the NYSRC 0.1 days/year LOLE reliability 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), Zone J; and Long Island (LI), Zone K. Appendix A of NYSRC Policy 5-15 provides a more detailed description of the Unified Methodology.

Figure 3-1 NYCA Load Zones



Base case NYCA IRM requirements and related corresponding Locality reserve margins for 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 (Tan 45) 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 Tan 45-degree inflection point. Appendix B of NYSRC Policy 5-15 provides a more detailed description of the methodology for computing the Tan 45 inflection point.

Figure 3-2 Relationship Between NYCA IRM and Corresponding Initial Locational Capacity Requirements



4. Study Results – Base Case

Results of the NYSRC technical study show that the required NYCA IRM is 20.7% for the 2021 Capability Year under base case conditions. Figure 3-2 on page 8 depicts the relationship between NYCA IRM requirements and corresponding initial LCRs for NYC and LI.

The tangent points on these curves were evaluated using the Tan 45 analysis described in Section 3. Accordingly, maintaining a NYCA IRM of 20.7% for the 2021 Capability Year, together with corresponding initial LCRs of 82.6% and 95.1% for NYC and LI, respectively, will achieve applicable NYSRC and NPCC reliability criteria for the base case study assumptions shown in Appendix A.3.

Comparing the corresponding initial LCRs in this 2021 IRM Study to 2020 IRM Study results (NYC LCR= 83.7%, LI LCR= 101.8%), the corresponding 2021 NYC initial LCR decreased by 1.1%, while the corresponding LI LCR decreased by 6.7%.

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 most recent NYISO LCR study,[6] dated January 8, 2020, determined that for the 2020 Capability Year, the final LCRs for NYC and LI were 86.6% and 103.4%, respectively. An LCR Study for the 2021 Capability Year is scheduled to be completed by the NYISO in January 2021. The NYISO utilizes an economic optimization algorithm for calculating LCRs that minimizes the total cost of NYCA capacity. This study utilizes the same base case database used by the NYSRC for calculating the NYCA IRM[7], while respecting the NYSRC-approved IRM and NYSRC's 0.1 days/year LOLE reliability criterion and required study procedures in NYSRC Policy 5-15.

A Monte Carlo simulation error analysis shows that there is a 95% probability that the above base case result is within a range of 20.6% and 20.8% (see Appendix A.1.1) when obtaining a standard error of 0.025 per unit or less at 2,750 simulated years. This analysis demonstrates that there is a high level of confidence that the base case IRM value of 20.7% is in full compliance with the one day in 10 years LOLE criterion in NYSRC Reliability Rule A.1.

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[6] See *Locational Installed Capacity Requirements Study, http://www.nyiso.com/public/markets_operations/services/planning/planning_studies*

[7] This database may be updated for base case assumption changes that occur after the IRM study is completed.

5. Models and Key Input Assumptions

This section describes the models and related base case input assumptions for the 2021 IRM Study. The models represented in the GE-MARS analysis include a *Load Model, Capacity Model, Transmission Model, and Outside World Model*. A *Database Quality Assurance Review* of the 2021 base case assumptions is also addressed in this section. The input assumptions for the final base case were approved by the Executive Committee on October 8, 2020. Appendix A, Section A.3 provides more details of these models and assumptions and comparisons of several key assumptions with those used for this 2021 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 2021 NYCA summer peak load forecast of 32,243 MW was assumed in the 2021 IRM Study, an increase of 73 MW from the forecast used in the 2020 IRM Study. This "Fall 2021 Summer Load Forecast" was prepared for the 2021 IRM Study by the NYISO staff in collaboration with the NYISO Load Forecasting Task Force and presented to the ICS on October 2, 2020. The 2021 forecast considered actual 2020 summer load conditions.

The "normalized" peak loads[8] shown on Table 5-1 below, indicate a reduction in peak loads in the heavily loaded zones (Zones J and K) while the peak loads for upstate zones (zones A-I) continue to grow. The decrease in Zones J and K load forecast is in part due to the COVID-19 pandemic.

Table 5-1: Comparison of 2020 and 2021 Actual and Forecast Coincident Peak Summer Loads (MW)

	Fall 2020 Forecast	2020 Actual	2020 Normalized	Fall 2021 Forecast	Forecast Change
Zones A-I	15,683	15,416	16,030	16,008	+325
Zones J&K	16,487	15,034	15,562	16,235	-252
NYCA	32,170	30,450	31,592	32,243	+73

[8] The "normalized" 2020 peak load reflects an adjustment of the actual 2020 peak load to account for the load impact of actual weather conditions, demand response programs, and muni self-generation.

Use of the Fall 2021 Load Forecast and an updated load shape in the 2020 IRM Study resulted in an IRM decrease of 0.3% compared to the 2020 IRM Study (Table 6-1). The NYISO will prepare a Final 2021 summer load forecast at the end of 2020 that will be used for the NYISO's calculation of Locality LCRs for the 2021 Capability Year.

5.1.2 Load Forecast Uncertainty

As with all forecasting, uncertainty exists relative to forecasting NYCA loads for any given year. This uncertainty 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 (Zone J), Long Island (Zone K), Westchester (Zones H and I), and two rest of New York State areas (Zones A-E and Zones F-G).

These LFU models are intended to measure the load response to weather at high peak producing temperatures, as well as other factors, such as the economy. However, economic uncertainty is relatively small compared to temperature uncertainty one year ahead. Thus, the LFU is largely based on the slope of load vs. temperature, or the weather response of load. If the weather response of load increases, the slope of load vs. temperature will increase, and the upper-bin LFU multipliers (Bins 1-3) will increase.

The new LFU multipliers included summer 2020 data, which was not included in prior LFU models. In general, the load response to weather in 2020 was greater in magnitude than it was in previous hot summers.

The summer 2020 weekday base load in most areas declined relative to earlier years. This decline was larger than the decline in summer peak load over the same time period. Thus, the slope of load vs. weather has recently increased, resulting in larger LFU multipliers in the upper bins. This change has resulted in higher LFU impacts on the IRM than in previous years.

A sensitivity case shows that the modeling of LFU in the 2021 IRM Study has an effect of increasing IRM requirements by 9.1% (Table 7-1, Case 3), as compared to a range of 7.2% to 9.1% in the previous four 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 IRM study and was again utilized for the 2021 IRM Study. This multiple load shape feature enables a different load shape to be assigned to each of seven load forecast uncertainty bins. ICS has established criteria for selecting the appropriate historical load shapes to use for each of these load forecast uncertainty bins. For this purpose, a combination of load shape years 2002, 2006, and 2007 were selected by ICS as representative years for the 2021 IRM Study. The load shape for the year 2007 was selected to represent a typical system load shape over the 1999 to 2017 period. The load shape for 2002 represents a flatter load shape, *i.e.*, a shape that has numerous daily peaks that are close to the annual peak. The load shape for 2006 represents a load shape with a small number of days with peaks that are significantly above the remaining daily peak loads. The combination of these load shapes on a weighted basis represents an expected probabilistic LOLE result.

The load duration curves were reviewed as part of the 2021 IRM Study. These curves were examined for the period 2002 through 2019. It was observed that the year 2012 was similar to the year 2007, the year 2013 was similar to 2006, and the year 2018 was similar to the year 2002. As a result of this review, the ICS decided to continue using the current three load shapes.

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 2021 IRM Study are shown in Appendix A, Section A.3.2. The rating for each existing and planned resource facility in the capacity model is based on its Dependable Maximum Net Capability (DMNC). In circumstances where the ability to deliver power to the grid is restricted, the value of the resource is limited to its 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.

While there are no new conventional units planned, an existing generator, Sithe Independence, plans to increase its output by 56.6 MW and Hudson Avenue GT3 plans to return to service (16 MW). Also included are the retirements of the West Babylon 4 unit (49 MW), Glenwood GT Unit 1 (15 MW), and the deactivation of the Indian Point Unit No. 3 nuclear facility (1,040 MW).

A behind-the-meter-net-generation (“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. Three BTM:NG resources with a total resource capacity of 147.6 MW and a total host load of 76.7 MW, are included in this 2021 IRM study. The resource capacity of these BTM:NG facilities is included in the NYCA capacity model, while their host loads are included in the NYCA 2021 summer peak load forecast used for this study.

The NYISO has identified several state and federal environmental regulatory programs that could potentially impact operation of NYS Bulk Power System. The NYISO analysis concluded that these environmental initiatives would not result in NYCA capacity reductions or retirements that would impact IRM requirements during the summer of 2021. 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 B, Section B.2.

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 4,750 MW of hydro facilities, will account for a total of 6,749 MW of NYCA renewable resources represented in the 2021 IRM Study.

It is projected that during the 2021 summer period there will be a total wind capacity of 1,859 MW participating in the capacity market in New York State. This represents a decrease in available wind resources of 32 MW and reflects the addition of the Cassadaga Wind Unit (126 MW) and the removal of 158 MW of wind units participating in the capacity market since the 2020 summer Capability Period. All wind farms are presently located in upstate New York in Zones A-E.

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 2021 IRM Study used available wind production data covering the years 2015 through 2019. For any new wind facilities, zonal hourly wind shape averages or the wind shapes of nearby wind units will be modeled.

Overall, inclusion of the projected 1,859 MW of wind capacity in the 2021 IRM Study accounts for 4.9% of the 2021 IRM requirement (Table 7-1, Case 4). This relatively high IRM impact is a direct result of the relatively low capacity factor of wind facilities 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.” A detailed summary of existing and planned wind resources is shown in Appendix A, Table A.7.

Land Fill Gas (LFG) units account for 108 MW and are included in the above total.

For the 2021 study, the newly operational Riverhead Solar plant (20 MW) has been removed as it does not participate in the ICAP market on the NYS Bulk Power System (BPS). The total BPS solar capacity in the IRM Study is 31.5 MW. Actual hourly solar plant output over the 2015-19 period is used to represent the solar shape for existing units, while new solar units are represented by zonal hourly averages or nearby units.

5.2.3 Energy Limited Resources

In 2019 the NYISO filed, and in 2020 FERC approved, tariff changes that became effective May 1, 2021 enhancing the ability of duration limited resources to participate in the NYISO markets. These rules allow output limited resources to participate in the markets consistent with those limitations, and requires owners of those resources to inform the NYISO of their elected energy output duration limitations by August 1st for the upcoming capability year (i.e., August 1, 2020 for the Capability Year beginning on May 1, 2021).

To accommodate this new classification of resources, the NYISO and GE have been working to expand the capabilities of the GE-MARs program to model ELRs. The NYISO and GE work on the new functionality is still proceeding and therefore, previously developed simplified modeling techniques of these resources have been utilized for the 2021 IRM Study. The simplified modeling approach dispatches the ELR units at pre-determined output levels, consistent with the resources' operational capabilities. Resource output is aligned with the NYISO's peak load window, when most loss-of-load events are expected to occur.

While these pre-determined output shapes were aligned with the periods that typically experience the highest loss-of-load risk, the profiles were not dynamic nor optimized. Thus, a more flexible or optimal dispatch schedule for these resources, such as that being developed within the MARS program, will be reviewed by ICS for adoption in future IRM studies.

Due to the confidential nature of these output limitations, the elections made, and the identity of units participating, the hourly representation of each unit was developed by NYISO and several of the NYSRC consultants taking into consideration the elections and operating history, particularly over the peak load conditions.

The introduction of output duration limitations on resources (ELRs) caused a significant increase in the number of times the GE-MARS simulation looked for emergency assistance to resolve a shortage. It is important to note that a "shortage" can be for a duration of an LOLE event as low as 15 minutes, or as little as a single MW necessary to bring the system back to criteria. Making an SCR call is the first step in the EOP process.

Given the inclusion of duration limited resources for 2021, the need for SCR resources increased to 150.5 days (probabilistic expected value) from the 2020 value of 8.2 days (see appendix B, table B.2).

The new modeling resulted in an increase in the IRM of 0.9% (Table 6-1).

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 forced outage rate during demand periods (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 2021 IRM Study covered the 2015-2019 period.

The weighted average five-year EFORd for NYCA thermal and large hydro generating units calculated for the 2015-19 period is slightly lower than the 2014-18 average value used for the 2020 IRM Study. This decrease in average forced outage rates, however, was not sufficient to materially change the IRM (Table 6-1). Appendix A, Figure A.4 depicts NYCA EFORd trends from 2005 to 2019.

5.2.5 Emergency Operating Procedures (EOPs)

(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 when as needed 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. SCRs are modeled with monthly values based on July 2020 registration. For the month of July, the forecast SCR value for the 2021 IRM Study base case assumes that 1,195 MW will be registered, with varying amounts during other months based on historical experience. This is 87 MW lower than that assumed for the 2020 IRM Study.

The number of SCR calls in the 2020 Capability Year for the 2021 IRM base case was limited to five calls per month.

The SCR performance model is based on discounting registered SCR values to reflect historical availability. The SCR model used for the 2021 IRM Study is based on a recent analysis of performance data for the 2012-19 period. This analysis determined a SCR overall performance factor of 68.8%. This is 0.6 % higher than the performance factor used in the 2020 IRM Study (refer to Appendix A, Section A.3.7 for more details). The increased SCR performance factor along with fewer registrations than assumed in the 2020 Study resulted in a net IRM decrease of 0.4% compared to last year's study (Table 6-1).

Incorporation of SCRs in the NYCA capacity model has the effect of increasing the IRM by 2.4% (Table 7-1, Case 5). This increase is because the overall availability of SCRs is lower than the average statewide resource fleet availability.

(2) Other Emergency Operating Procedures

In addition to SCRs, the NYISO will implement several other types of EOPs, such as voltage reductions, as required, to avoid or minimize customer disconnections. Projected 2021 EOP capacity values are based on recent actual data and NYISO forecasts. Refer to Appendix B, Table B.2 for projected EOP frequencies for the 2021 Capability Year assuming the 20.7% 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 benefits. Non-locational capacity, when coupled with a UDR to deliver capacity to a Locality, can be used to satisfy locational capacity requirements. The owners of the UDRs elect whether they will utilize their capacity deliverability rights. This decision determines how this transfer capability will be represented in the 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 2021 IRM Study as having UDR capacity rights: LIPA's 330 MW High Voltage Direct Current (HVDC) Cross Sound Cable, LIPA's 660 MW HVDC Neptune Cable, Hudson Transmission Partners 660 MW HVDC Cable, and the 315 MW Linden Variable Frequency Transformer. 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. The 2021 IRM Study incorporates the confidential elections that these facility owners made for the 2021 Capability Year.

5.3 The Transmission Model

A detailed NYCA transmission system model is represented in the GE-MARS topology. The transmission system topology includes eleven NYCA zones and four Outside World Areas, along with relevant transfer limits, is depicted in Appendix A, Figure A-11. The transfer limits employed for the 2021 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 IRM Study topology.

The transmission model assumptions included in the 2021 IRM Study are listed in Table A.8 in the Appendix which reflects changes from the model used for the 2020 IRM Study. These topology changes are as follows:

Indian Point Deactivation Topology Changes

- UPNY-Con Ed (Zone G to H) limit increased to 7,000 MW (+1,000 MW) from 6,000 MW
- Dunwoodie South (Zone I to Zone J) limit reduced to 4,350 MW (-50 MW)

UPNY-SENY Model Simplification

- Athens (F), Cricket Valley (G), CPV Valley (G) removed from their own zones and placed in indicated zones
- UPNY-SENY, UPNY-SENY1, and CPV+MARCY interface groups combined into one interface group

PJM-SENY Group Interface Removal **(no longer limiting during peak times)**

Updates to Zone K Topology

- Export improvements from Zone K
- Additional East Garden City – Valley Stream 138 kV circuit
- The Zone J to Zone K (Jamaica ties) limit is no longer dependent on the availability of the Barrett generators.

Forced transmission outages based on historic 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 Transmission Owners (TOs) provided updated transition rates for their associated cable interfaces. Updated cable outage rates assumed in the 2021 IRM Study resulted in a 0.2% reduction in the IRM compared with the 2020 IRM Study (Table 6-1).

As in all previous IRM studies, forced outage rates for overhead transmission lines were not represented in the 2021 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 (see www.nysrc.org/reports).

The impact of NYCA transmission constraints on NYCA IRM requirements depends on the level of resource capacity in any of the downstream zones from a constraining interface, especially in NYC (Zone J) and LI (Zone K). To illustrate the impact of transmission constraints on the IRM, if internal NYCA transmission constraints were eliminated, the required 2021 IRM could decrease by 1.9% (Table 7-1, Case 2).

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 2021 IRM Study, two Outside World Areas, New England and PJM, are each represented as multi-area models—*i.e.,* 13 zones for New England and five zones for the PJM Interconnection. 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.

Representing Outside World Area interconnection support in IRM studies significantly reduces IRM requirements. For the previous six IRM studies, EA has reduced IRM requirements in the range of 6.9 to 8.7%.[9]

In 2019, the ICS conducted an analysis of the IRM study's Outside Area Model to review its compliance with a NYSRC Policy 5 objective that "interconnected Outside World Areas shall be modeled to avoid NYCA's overdependence 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 load zone of each Outside World Area to meet the LOLE criterion and the Control Area's minimum IRM requirement. The ICS used this new model in the current study (2021) as well as in the 2020 IRM Study.[10]

During the 2021 Capability Year, Hydro-Quebec is expected to wheel 300 MW of capacity through NYCA to New England. In addition, the 2021 IRM study continues to limit the EA assistance to a maximum of 3,500 MW as applied in the previous three IRM Studies[11].

Utilizing the improved Outside Area Model, while including the Hydro-Quebec wheel to New England and continuing to represent the 3,500 MW EA limit described above, reduces the NYCA IRM by 6.9% (Table 7-1, Case 1). This is 0.6% less than the impact determined in the 2020 IRM Study.

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, General Electric (GE), and two New York TOs 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 TOs for their review. Also, certain confidential data are reviewed by two of the NYSRC consultants as required.

The NYISO, GE, and TO reviews found a few minor data errors, none of which affected IRM requirements in the preliminary base case. The data found to be in error by these

[9] *See* 2015 to 2020 IRM Study reports at www.nysrc.org/reports3.html.

[10] *See Evaluation of External Area Modeling in NYCA IRM Studies*, for a description of this analysis, at http://www.nysrc.org/reports3.html

[11] The 2018 IRM Study report, pages 17-18, describes this EA limit and its derivation. See www.nysrc.org/reports3.html.

reviews were corrected before being used in the final base case studies. A summary of these quality assurance reviews for the 2021 IRM Study input data is shown in Appendix A, Section A.4.

6. Parametric Comparison with 2020 IRM Study Results

The results of this 2021 IRM Study show that the base case IRM result represents a 1.8% increase from the 2020 IRM Study base case value. Table 6-1 compares 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 studies were conducted to test the IRM impact of individual parameters. The IRM impact of each parameter in this analysis was normalized such that the net sum of the -/+ % parameter changes total the 1.8% IRM increase from the 2020 IRM Study. Table 6-1 also provides the reason for the IRM change for each study parameter from the 2020 IRM Study.

There are five parameter drivers that in combination increased the 2021 IRM from the 2020 base case by 3.1%. Of these five drivers, the most significant are an updated load forecast uncertainty model which increased the IRM by 1.0%, a representation of the limited output of certain Energy Limited Resources, which increased the IRM by 0.9%, and the retirement of the second Indian Point Energy Center unit (IP3) coupled with other topology changes which increased the IRM by 0.7%.

Five parameter drivers in combination decreased the IRM from the 2020 base case by 1.3%. Of these five drivers, the most significant are a reduction in SCR registrations coupled with improved performance resulting in a decrease in IRM of 0.4%, and a new load forecast reducing the IRM by 0.3%.

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

Table 6-1: Parametric IRM Impact Comparison – 2020 IRM Study vs. 2021 IRM Study

Parameter	Estimated IRM Change (%)	IRM (%)	Reasons for IRM Changes
2020 IRM Study – Final Base Case		**18.9**	
2021 IRM Study Parameters that increased the IRM			
Load Forecast Uncertainty	1.0		Higher weather uncertainty (see section 5.1.2)
Energy Limited Resources - Simplified	0.9		Limitations on ELRs were introduced using a simplified methodology
Indian Point Unit 3 retirement and Topology	0.7		A material amount of the increase is due to the loss of the Indian Point unit.
New wind facility	0.3		One new wind facility in upstate.
Wind and Run of River shapes (2014 year data replaced with 2019)	0.2		Five-year average lost higher performance years (2014) and added lesser performance years (2019)
Total IRM Increase	**3.1**		
2021 IRM Study Parameters that decreased the IRM			
SCRs	-0.4		Less SCRs than last year with slightly better performance
Load Forecast	-0.3		Relatively less demand in higher load zones potentially due to COVID-19
Outside World Areas	-0.2		More emergency assistance (EA) is available closer to NY load centers
Non-SCR EOPs	-0.2		Higher voltage reduction and voluntary curtailment values
Cable Transition Rates	-0.2		Better cable performance especially in the Long Island territory
Total IRM Decrease	**-1.3**		
2021 IRM Study Parameters that did not change the IRM			
Transition Rates	0		
Gold Book DMNC Generator Ratings	0		
2021 Maintenance	0		
Net Change from 2020 Study		**1.8**	
2021 IRM Study – Final Base Case		**20.7**	

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 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 days/year.

Table 7-1 shows the IRM requirements for 8 sensitivity cases. Because of the lengthy computer run time and personnel needed to perform a full Tan 45 analysis in IRM studies[12], this method was applied for only select cases as noted in the table. It should be recognized that some accuracy is sacrificed when a Tan 45 analysis is not utilized.

Sensitivity Cases 1 through 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. Four of these cases show reasonable results when compared to past results. The fifth, *'No Load Forecast Uncertainty'*, shows a continued rising trend each time the data is renewed. Because of this, the ICS has initiated a study to identify the causes of this trend. These parameters and their IRM impacts are discussed in Sections 5.1.2 and 5.4, respectively.

The next two sensitivity cases, Cases 6 and 7, illustrate the IRM impacts of changing certain base case assumptions. Case 6 shows the impact of using newly developed techniques to model SCRs. It illustrates the impact of incorporating the energy limitation of some SCRs, which is discussed in Section 5.2.3. Case 7 shows the impact of not representing the limitation of ELRs on Non-SCR resources. The resources were modeled in the base case using a simplified representation of the limitations. This allowed a desired representation while a more detailed representation of the ELR limitations is studied over the course of the next six months.

The remaining case, Case 8, is an informational analysis that was performed to analyze the effect on the 2021 IRM of Long Island parameter updates from the 2020 IRM Study. These updates manifested in large decreases in the Long Island's initial locational reserve margin.

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[12] The Tan 45 method is described in Section 3.

A recent NYSRC study examined the IRM impact of a hypothetical addition of a large quantity of intermittent renewable resources.[13] The study indicated that with the addition of 12,000 MW of solar, on-shore wind, and off-shore wind, the IRM would increase to 42.9% from a base case value of 18.6%. This analysis is the first of several that will be needed by the NYSRC to fully understand the impacts of increased renewable resource penetration on system reliability.

Appendix B, Table B-1 includes a more detailed description and explanation of each sensitivity case.

Table 7-1: Sensitivity Cases – 2021 IRM Study

Case	Description	IRM (%)	% Change from Base Case
0	**2021 Final Base Case**	20.7	-
	IRM Impacts of Key MARS Study Parameters		
1	**NYCA Isolated** (no emergency assistance)	27.6	6.9
2	**No Internal NYCA Transmission Constraints** (Free Flow System)	18.8	-1.9
3	**No Load Forecast Uncertainty**	11.6	-9.1
4	**Remove all wind generation**	15.8	-4.9
5	**No SCRs**	18.3	-2.4
	IRM Impacts of Base Case Assumption Changes		
6	**SCR Modeling method update – Energy and Duration Limitations [Tan 45]**	21.4	0.7
7	**Ignore energy limitations of Energy Limited Resources**	19.9	-0.8
	Informational Assessment		
8	**LI LCR Analysis (all three with Tan 45)**	**IRM impacts:** LI LFU (-0.2%), LI unit deactivations (-0.1%), LI cable outage rates (0%)	**LI LCR impacts:** LI LFU (-0.9%), LI unit deactivations (-0.4%), LI cable outage rates (-2.3%)

[13] "The Impacts of High Intermittent Renewable Resources - On the Installed Reserve Margin for New York" available on the NSYRC.org website under Executive Meeting Materials for meeting 252, April 9th, agenda item 4.2a

8. NYISO Implementation of the NYCA Capacity Requirement

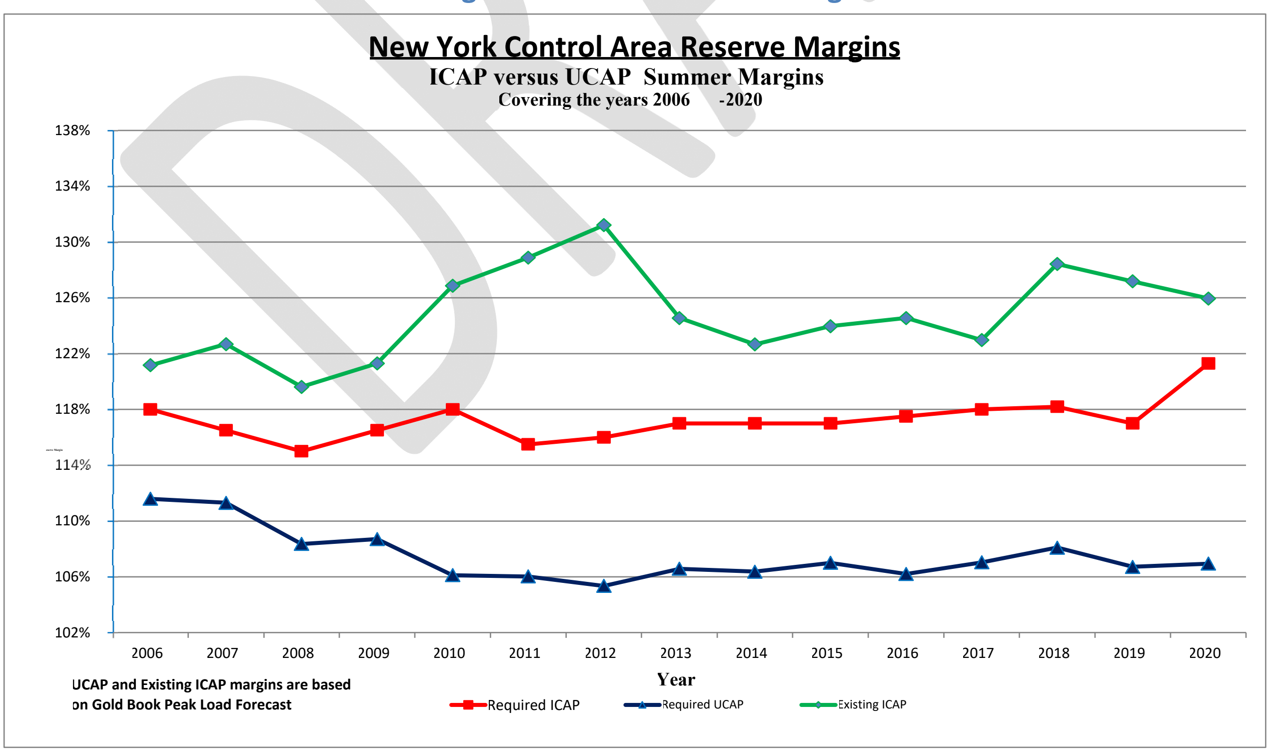
The NYISO values capacity sold and purchased in the market in a manner that considers the forced outage ratings of individual units, whereby generating unit capacity is derated to an unforced capacity basis recognizing the impact of forced outages. This derated capacity is referred to as "UCAP." In the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

Additionally, 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.

The increase in wind resources raises the IRM because wind capacity has a relatively lower peak period capacity factor than traditional resources. On the other hand, there is a negligible impact on the need for UCAP. Figure 8-1 below shows that required UCAP margins, which steadily decreased over the 2006-2012 period to about 5%, and then have remained fairly steady since.

Appendix C provides details of the ICAP to UCAP conversion process used for this analysis

Figure 8-1 NYCA Reserve Margins

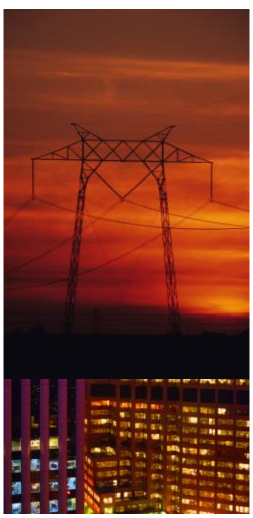


Final Draft of Appendices

New York Control Area Installed Capacity Requirement

For the Period May 2021 To April 2022

Reflects Special Sensitivity Results



December 4, 2020

New York State Reliability Council, LLC
Installed Capacity Subcommittee

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Appendix A

NYCA Installed Capacity Requirement Reliability Calculation Models and Assumptions

Description of the GE MARS Program: Load, Capacity, Transmission, Outside World Model, and Assumptions

A. Reliability Calculation Models and Assumptions

The reliability calculation process for determining the NYCA IRM requirement utilizes a probabilistic approach. This technique calculates the probabilities of outages of generating units, in conjunction with load and transmission models, to determine the number of days per year of expected capacity shortages. The General Electric Multi-Area Reliability Simulation (GE-MARS) is the primary computer program used for this probabilistic analysis. The result of the calculation for "Loss of Load Expectation" (LOLE) provides a consistent measure of system reliability. The various models used in the NYCA IRM calculation process are depicted in Figure A.1 below.

Table A.1 lists the study parameters, the source for the study assumptions, and where the assumptions are described in Appendix A. Finally, section A.3 compares the assumptions used in the 2019 and 2020 IRM reports.

Figure A.1 NYCA ICAP Modeling

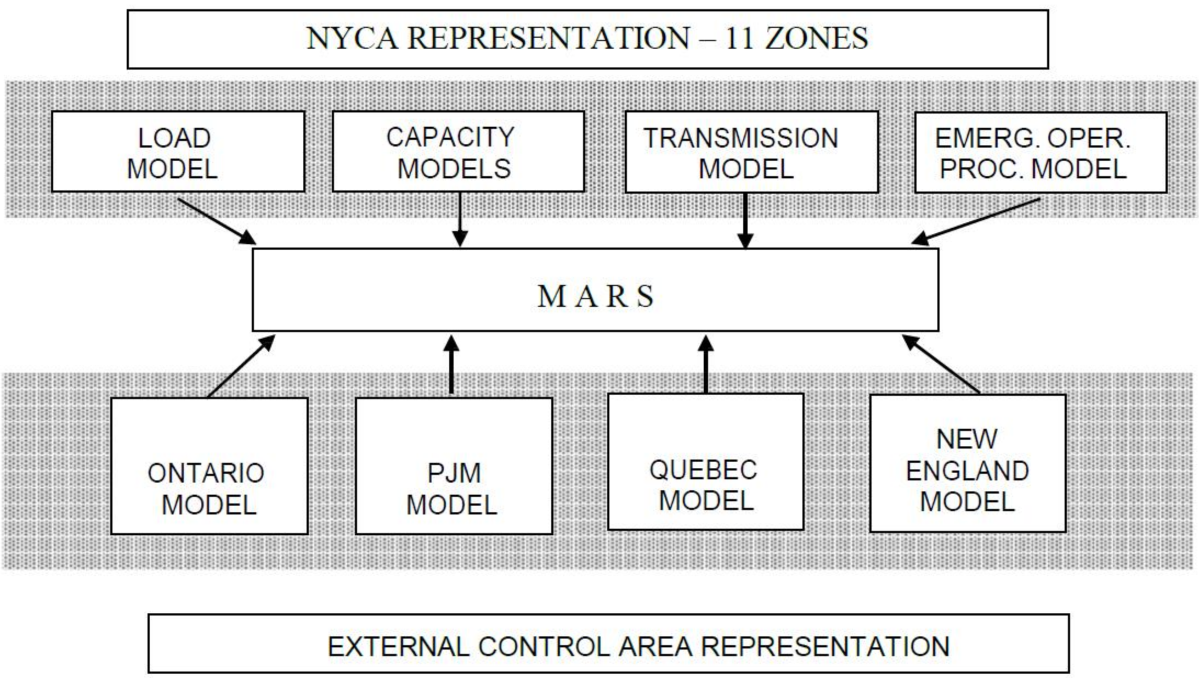


Table A.1 Modeling Details

#	Parameter	Description	Source	Reference
Internal NYCA Modeling				
1	GE MARS	General Electric Multi-Area Reliability Simulation Program		Section A.1
2	11 Zones	Load Areas	Fig A.1	NYISO Accounting & Billing Manual
3	Zone Capacity Models	Generator models for each generating in Zone Generator availability Unit ratings	GADS data 2020 Gold Book[1]	Section A.3.2
4	Emergency Operating Procedures	Reduces load during emergency conditions to maintain operating reserves	NYISO	Section A.3.5
5	Zone Load Models	Hourly loads	NYCA load shape and peak forecasts	Section A.3.1
6	Load Uncertainty Model	Account for forecast uncertainty due to weather conditions	Historical data	Section A.3.1
7	Transmission Capacity Model	Emergency transfer limits of transmission interfaces between Zones	NYISO Transmission Studies	Section A.3.3
External Control Area Modeling				
8	Ontario, Quebec, ISONE, PJM Control Area Parameters	See items 9-12 in this table	Supplied by External Control Area	
9	External Control Area Capacity models	Generator models in neighboring Control Areas	Supplied by External Control Area	Section A.3.4
10	External Control Area Load Models	Hourly loads	Supplied by External Control Area	Section A.3.4
11	External Control Area Load Uncertainty Models	Account for forecast uncertainty due to weather conditions	Supplied by External Control Area	Section A.3.4
12	Interconnection Capacity Models	Emergency transfer limits of transmission interfaces between control areas.	Supplied by External Control Area	Section A.3.3

[1] 2020 Load and Capacity Data Report, http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

A.1 GE MARS

As the primary probabilistic analysis tool used for establishing NYCA IRM requirements, the GE-MARS program includes a detailed load, generation, and transmission representation for 11 NYCA Zones, as well as the four external Control Areas (Outside World Areas) interconnected to the NYCA (see Section A.3 for a description of these Zones and Outside World Areas).

A sequential Monte Carlo simulation forms the basis for GE-MARS. The Monte Carlo method provides a fast, versatile, and easily expandable program that can be used to fully model many different types of generation, transmission, and demand-side options. GE-MARS calculates the standard reliability indices of daily and hourly LOLE (days/year and hours/year) and Loss of Energy Expectation (LOEE in MWh/year). The use of sequential Monte Carlo simulation allows for the calculation of time-correlated measures such as frequency (outages/year) and duration (hours/outage). The program also calculates the need for initiating Emergency Operating Procedures (EOPs), expressed in days/year (see Section A.3.5).

In addition to calculating the expected values for the reliability indices, GE-MARS also produces probability distributions that show the actual yearly variations in reliability that the NYCA could be expected to experience. In determining NYCA reliability, there are several types of randomly occurring events that must be taken into consideration. Among these are the forced outages of generating units and transmission capacity. Monte Carlo simulation models the effects of such random events. Deviations from the forecasted loads are captured using a load forecast uncertainty model.

Monte Carlo simulation approaches can be categorized as "non-sequential" and "sequential". A non-sequential simulation process does not move through time chronologically or sequentially, but rather considers each hour independent of every other hour. Because of this, non-sequential simulation cannot accurately model issues that involve time correlations, such as maintenance outages, and cannot be used to calculate time-related indices such as frequency and duration.

Sequential Monte Carlo simulation (used by GE-MARS) steps through the year chronologically, recognizing the status of equipment is not independent of its status in adjacent hours. Equipment forced outages are modeled by taking the equipment out of service for contiguous hours, with the length of the outage period being determined from the equipment's mean time to repair. Sequential simulation can model issues of concern that involve time correlations and can be used to calculate indices such as frequency and duration. It also models transfer limitations between individual areas.

Because the GE-MARS Program is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time and can be used if one assumes that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in any given hour is dependent on a given state in previous hours and influences its state in future hours. It thus requires additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A (Equation A.1).

Equation A.1 Transition Rate Definition

$$Transition\ (A\ to\ B) = \frac{Number\ of\ Transitions\ from\ A\ to\ B}{Total\ Time\ in\ State\ A}$$

Table A.2 shows the calculation of the state transition rates from historic data for one year. The Time-in-State Data shows the amount of time that the unit spent in each of the available capacity states during the year; the unit was on planned outage for the remaining 760 hours. The Transition Data shows the number of times that the unit transitioned from each state to each other state during the year. The State Transition Rates can be calculated from this data. For example, the transition rate from state 1 to state 2 equals the number of transitions from 1 to 2 divided by the total time spent in state 1 (Equation A.2).

Equation A.2 Transition Rate Calculation Example

$$Transition\ (1\ to\ 2) = \frac{(10\ Transitions)}{5{,}000\ Hours} = 0.0002$$

Table A.2 State Transition Rate Example

Time in State Data				Transition Data			
State	MW	Hours		From State	To State 1	To State 2	To State 3
1	200	5000		1	0	10	5
2	100	2000		2	6	0	12
3	0	1000		3	9	8	0

State Transition Rates			
From State	To State 1	To State 2	To State 3
1	0.000	0.002	0.001
2	0.003	0.000	0.006
3	0.009	0.008	0.000

From the state transition rates for a unit, the program calculates the two important quantities that are needed to model the random forced outages on the unit: the average time that the unit resides in each capacity state, and the probability of the unit transitioning from each state to each other state.

Whenever a unit changes capacity states, two random numbers are generated. The first is used to calculate the amount of time that the unit will spend in the current state; it is assumed that the time in a state is exponentially distributed, with a mean as computed from the transition rates. This time in state is added to the current simulation time to calculate when the next random state change will occur. The second random number is combined with the state transition probabilities to determine the state to which the unit will transition when it leaves its current state. The program thus knows for every unit on the system, its current state, when it will be leaving that state, and the state to which it will go next.

Each time a unit changes state, because of random state changes, the beginning or ending of planned outages, or mid-year installations or retirements, the total capacity available in the unit's area is updated to reflect the change in the unit's available capacity. This total capacity is then used in computing the area margins each hour.

A.1.1 Error Analysis

An important issue in using Monte Carlo simulation programs such as GE-MARS is the number of years of artificial history (or replications) that must be created to achieve an acceptable level of statistical convergence in the expected value of the reliability index of interest. The degree of statistical convergence is measured by the standard deviation of the estimate of the reliability index that is calculated from the simulation data.

The standard deviation has the same physical units (*e.g.,* days/year) as the index being estimated, and thus its magnitude is a function of the type of index being estimated. Because the standard deviation can assume a wide range of values, the degree of convergence is often measured by the standard error, which is the standard deviation of the estimated mean expressed as a per unit of the mean.

Convergence can also be expressed in terms of a confidence interval that defines the range in which you can state, with a given level of confidence that the actual value falls within the interval. For example, a range centered on the mean of two standard deviations in each direction (plus and minus) defines a confidence interval of 95%.

For this analysis, the Base Case required 367 replications to converge to a standard error of 0.05 and required 1,517 replications to converge to a standard error of 0.025. For our cases, the model was run to 2,750 replications at which point the daily LOLE of 0.100 days/year for NYCA was met with a standard error less than 0.025. The confidence interval at this point ranges from 20.6% to 20.8%. It should be recognized that an IRM of 20.7% is in full compliance with the NYSRC Resource Adequacy rules and criteria (see Base Case Study Results section).

A.1.2 Conduct of the GE-MARS analysis

The study was performed using Version 3.31.1546 of the GE-MARS software program. This version has been benchmark tested by the NYISO.

The current base case is the culmination of the individual changes made to last year's base case. Each change, however, is evaluated individually against last year's base case. The LOLE results of each of these pre-base case simulations are reviewed to confirm that the reliability impact of the change is reasonable and explainable.

General Electric was asked to review the input data for errors. They have developed a program called "Data Scrub" which processes the input files and flags data that appears to be out of the ordinary. For example, it can identify a unit with a forced outage rate significantly higher than all the others in that size and type category. If something is found, the ISO reviews the data and either confirms that it is correct as is or institutes a correction. The results of this data scrub are shown in Section A.4.

The top three summer peak loads of all Areas external to NYCA are aligned to be on the same days as that of NYCA, even though they may have historically occurred at different times. This is a conservative approach, using the assumption that peak conditions could be the result of a wide spread heat wave. This would result in reducing the amount of assistance that NYCA could receive from the other Areas.

A.2 Methodology

The 2021 IRM study continues to use the Unified Methodology that simultaneously provides a basis for the NYCA installed reserve requirements and the preliminary locational installed capacity requirements. The IRM/preliminary LCR characteristic consists of a curve function, "a knee of the curve" and straight-line segments at the asymptotes. The curve function is represented by a quadratic (second order) curve which is the basis for the Tan 45 inflection point calculation. Inclusion of IRM/preliminary LCR point pairs remote to the "knee of the curve" may impact the calculation of the quadratic curve function used for the Tan 45 calculation.

The procedure for determining the best fit curve function used for the calculation of the Tan 45 inflection point to define the base case requirement is based on the following methodology:

1) Start with all points on IRM/preliminary LCR Characteristic.
2) Develop regression curve equations for all different point to point segments consisting of at least four consecutive points.
3) Rank all the regression curve equations based on the following:
   - Sort regression equations with highest R2.
   - Remove any equations which show a negative coefficient in the first term. This is the constant labeled 'a' in the quadratic equation: ax2+bx+c
   - Ensure calculated IRM is within the selected point pair range, i.e., if the curve fit was developed between 14% and 18% and the calculated IRM is 13.9%, the calculation is invalid.
   - In addition, there must be at least one statewide reserve margin point to the left and right of the calculated tan 45 point.

- Ensure the calculated IRM and corresponding preliminary LCR do not violate the 0.1 LOLE criteria.
- Check results to ensure they are consistent with visual inspection methodology used in past years' studies.

This approach identifies the quadratic curve functions with highest R^2 correlations as the basis for the Tan 45 calculation. The final IRM is obtained by averaging the Tan 45 IRM points of the NYC and LI curves. The Tan 45 points are determined by solving for the first derivatives of each of the "best fit" quadratic functions as a slope of -1. Lastly, the resulting preliminary LCR values are identified.

A.3 Base Case Modeling Assumptions

A.3.1 Load Model

Table A.3 Load Model

Parameter	2020 Study Assumption	2021 Study Assumption	Explanation
Peak Load	October 1, 2019 NYCA: 32,169 MW NYC: 11,512 MW LI: 5,216 MW G-J: 15,776 MW	October 1, 2020 NYCA: NYCA: 32,243.0 MW NYC: 11,232.3 MW LI: 5,282.0 MW G-J: 15,385.3 MW	Forecast based on examination of 2020 weather normalized peaks, 2021 economic and expected weather projections, and Transmission Owner projections.
Load Shape Model	Multiple Load Shapes Model using years **2002 (Bin 2), 2006 (Bin 1), and 2007 (Bin 3-7)**	Multiple Load Shapes Model using years **2002 (Bin 2), 2006 (Bin 1), and 2007 (Bin 3-7)**	No Change
Load Uncertainty Model	Statewide and zonal models updated to reflect current data	Statewide and zonal models updated to reflect current data	Updated from 2020 IRM. Based on TO and NYISO data and analyses.

(1) Peak Load Forecast Methodology

The procedure for preparing the IRM forecast is very similar to that detailed in the NYISO Load Forecasting Manual for the ICAP forecast. The NYISO's Load Forecasting Task Force had one meeting in September 2020 to review weather-adjusted peaks for the summer of 2020 prepared by the NYISO and the Transmission Owners. Regional load growth factors (RLGFs) for 2021 were reviewed and updated by most Transmission Owners; otherwise the 2021 NYISO RLGFs that were used. The 2021 forecast was produced by applying the RLGFs to each TO's weather-normalized peak for the summer of 2020.

The results of the analysis are shown in Table A-4. The actual peak of 30,450 MW (col. 2) occurred on July 27, 2020 for the hour beginning 17:00. After accounting for the impacts of weather and other factors, the weather-adjusted peak load was determined to be 31,592 MW (col. 6), 704 MW (2.2%) below the 2020 forecast. The 2020 peak load forecast for the Con Edison transmission district was over forecast by 979 MW (7.5%). All other transmission district peaks were under forecast. Most of the forecast error can be attributed to the significant impacts of the COVID-19 pandemic on load during the summer of 2020.

The Regional Load Growth Factors are shown in column 9. The 2021 peak forecast was 32,145 MW (col. 8), prior to adjustments for Behind the Meter Net Generation resources (BTM:NG). The 2020 forecast for the NYCA is 32,243 MW (col. 10). The Locality forecasts are also reported in the second table below.

The LFTF recommended this forecast to the NYSRC for its use in the 2021 IRM study.

Table A.4 2021 Final NYCA Peak Load Forecast

2021 IRM Coincident Peak Forecast by Transmission District for NYSRC

(1)	(2)	(3)	(4)	(5)	(6a)	(6b)	(6c)	(7)	(8)=(6a)*(7)	(9)	(10)=(8)+(9)
Transmission District	2020 Actual MW	Demand Response Estimate MW	2020 Estimated Muni Self-Gen	Total Weather Adjustment MW	2020 Weather Normalized MW	Loss Reallocation MW	2020 WN MW, Adj for Losses	Regional Load Growth Factors	2021 Forecast, Before Adjustments	BTM:NG and Other Adjustments to Load	2021 IRM Final Forecast
Con Edison	11,273	177	0	605	12,055	0	12,055	1.0492	12,649	21.3	12,670.3
Cen Hudson	1,093	0	0	15	1,108	0	1,108	0.9910	1,098		1,098.0
LIPA	5,344	20	7	-181	5,190	0	5,190	0.9948	5,162	42.0	5,204.0
NGrid	6,702	186	48	36	6,972	0	6,972	1.0026	6,991	2.7	6,993.7
NYPA	405	0	0	-1	404	0	404	1.0262	415		415.0
NYSEG	3,178	54	0	-17	3,215	0	3,215	1.0031	3,225	32.0	3,257.0
O&R	1,038	11	0	36	1,085	0	1,085	0.9914	1,076		1,076.0
RG&E	1,417	8	0	137	1,562	0	1,562	0.9785	1,529		1,529.0
Total	30,450	456	55	631	31,592	0	31,592	1.0175	32,145	98.0	32,243.0
				2021 Forecast from 2020 Gold Book					32,129		
				Change from 2020 Gold Book					16		

2021 IRM Locality Peak Forecasts by Transmission District for NYSRC

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)=(8)+(11)
Locality	2020 Actual MW	Demand Response Estimate MW	2020 Estimated Muni Self-Gen	Locality Weather Adjustment MW	2020 Weather Normalized MW	Regional Load Growth Factors	2021 Forecast, Before Adjustments	2021 Forecast from 2020 Gold Book	Change from Gold Book Forecast	BTM:NG and Other Adjustments to Load	2021 IRM Final Forecast
Zone J - NYC	10,061	0	0	624	10,685	1.0492	11,211	11,460	-249	21.3	11,232.3
Zone K - LI	5,428	20	7	-187	5,268	0.9948	5,240	5,139	101	42.0	5,282.0
Zone GHIJ	14,057	0	0	726	14,783	1.0393	15,364	15,660	-296	21.3	15,385.3

(1) Zonal Load Forecast Uncertainty

The 2021 load forecast uncertainty (LFU) models were updated during the spring of 2020, since the weather experienced in 2019 was at or above normal conditions. The NYISO developed models for Zones A through I and reviewed the Zone J and Zone K models prepared by LIPA and Con Ed respectively. NYISO models were compared with independent Con Ed and LIPA models to ensure that the LFU results were consistent. Con Ed and LIPA both agreed with the final LFU models presented at LFTF and ICS; the ICS approved the LFU model results. The results of these models are presented in Table A-5. Each row represents the probability that a given range of load levels will occur, on a per-unit basis, by zone. These results are presented graphically in Figure A.2.

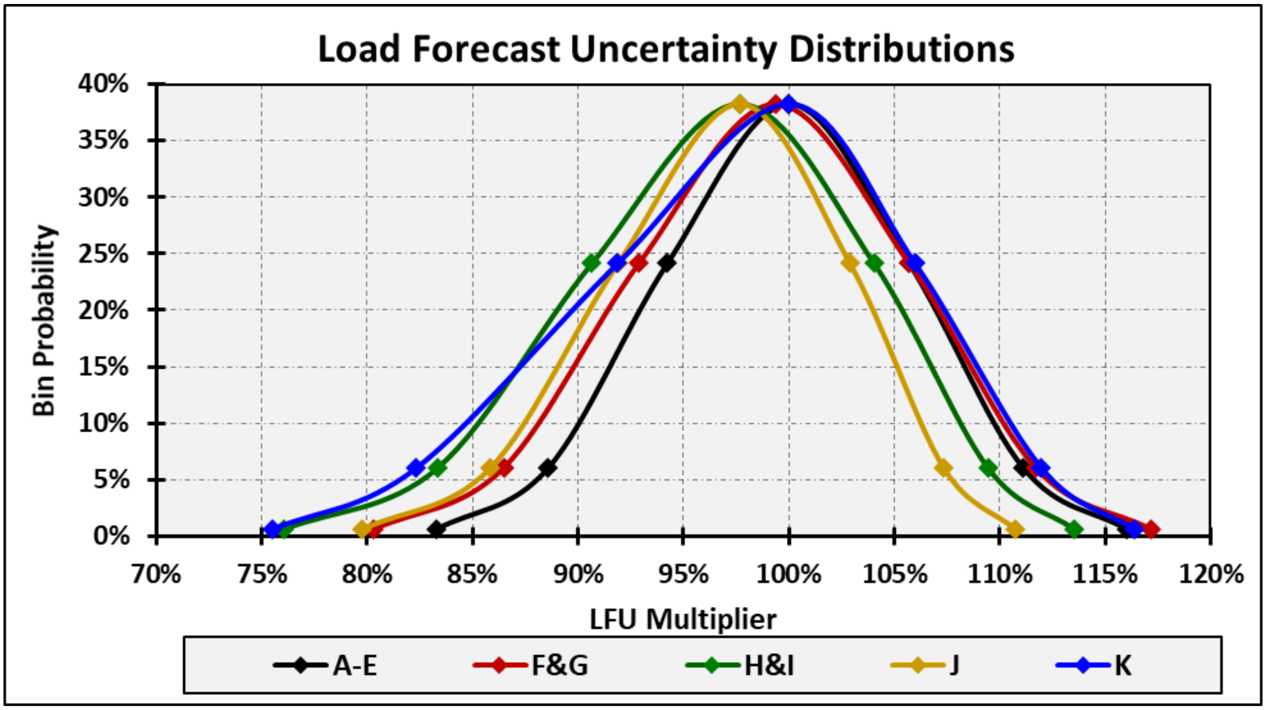
Table A.5 2021 Summer and Winter Load Forecast Uncertainty Models

LFU 2021						
Bin	**Probability**	**A-E**	**F&G**	**H&I**	**J**	**K**
B1	0.62%	116.02%	117.17%	113.56%	110.73%	116.38%
B2	6.06%	111.11%	111.70%	109.46%	107.33%	111.97%
B3	24.17%	105.70%	105.70%	104.06%	102.89%	105.98%
B4	38.30%	100.00%	99.36%	97.68%	97.67%	100.00%
B5	24.17%	94.22%	92.89%	90.66%	91.91%	91.88%
B6	6.06%	88.58%	86.48%	83.35%	85.86%	82.34%
B7	0.62%	83.28%	80.33%	76.06%	79.79%	75.52%

Delta	A-E	F&G	H&I	J	K
B1 - B4	16.02%	17.80%	15.88%	13.06%	16.38%
B4 - B7	16.72%	19.04%	21.62%	17.88%	24.48%
Total Range	32.74%	36.84%	37.50%	30.94%	40.87%

Zones(s): NYCA (Winter)					
Bin	**Probability**	**Wthr**	**MW**	**LFU (2021)**	**LFU (2020)**
B1	0.62%	53.75	25,593	112.22%	111.80%
B2	6.06%	47.98	24,577	107.77%	107.52%
B3	24.17%	42.20	23,648	103.69%	103.59%
B4	38.30%	36.43	22,806	100.00%	100.00%
B5	24.17%	30.66	22,051	96.69%	96.75%
B6	6.06%	24.89	21,383	93.76%	93.85%
B7	0.62%	19.12	20,802	91.22%	91.28%
	Design	36.43	22,806		

Figure A.2 LFU Distributions



The Consolidated Edison models for Zones H, I & J are based on a peak demand with a 1-in-3 probability of occurrence (67th percentile). All other zones are designed at a 1-in-2 probability of occurrence of the peak demand (50th percentile). The methodology and results for determining the 2021 LFU models have been reviewed by the NYISO Load Forecasting Task Force.

Discussion of the 2021 LFU Models

The Load Forecast Uncertainty (LFU) models are meant to measure the load response to weather at high peak-producing temperatures as well as other factors such as the economy. However, economic uncertainty is relatively small compared to temperature uncertainty one year ahead. As a result, the LFTF, the NYISO, and the ICS have agreed that it is sufficient to confine the LFU for the 1-year ahead IRM study only to weather. Thus, the LFU is largely based on the slope of load vs. temperature, or the weather response of load. If the weather response of load increases, the slope of load vs. temperature will increase, and the upper-bin LFU multipliers (Bins 1-3) will increase. The new LFU multipliers included summer 2018 and 2019 data, which was not included in the prior LFU models. In general, the load response to weather in 2018 and 2019 was steeper than it was in previous hot summers.

2018 and 2019 summer weekday base load in most areas declined relative to earlier years. This decline was larger than the decline in summer peak load over the same period. Thus, a contributing factor to increase in slope of load versus weather is due to a downward trend in baseload. This also contributed to larger LFU multipliers in the upper bins.

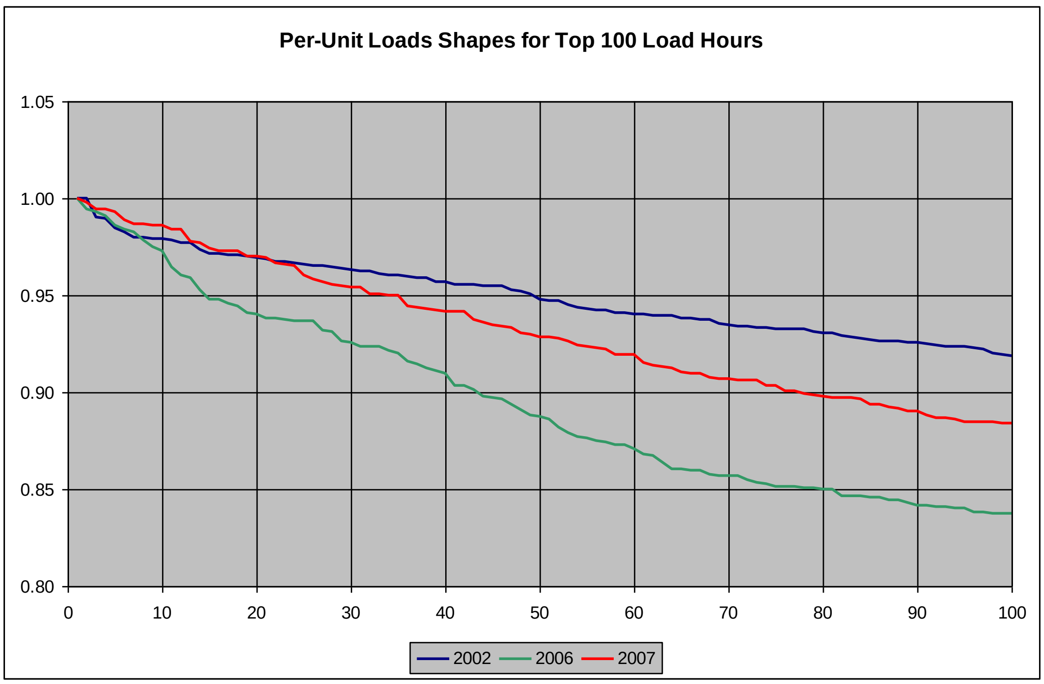
The recent year-over-year decline in the ICAP load forecast is a mitigating factor which somewhat offsets the increase in LFU. Even though the LFU multipliers and the resultant IRM percent will increase, the peak load used as the starting point to calculate the final MW capacity requirement continues to decrease.

(2) Zonal Load Shape Models for Load Bins

Beginning with the 2014 IRM Study, multiple load shapes were used in the load forecast uncertainty bins. Three historic years were selected from those available, as discussed in the NYISO's 2013 report, 'Modeling Multiple Load Shapes in Resource Adequacy Studies'. The year 2007 was assigned to the first five bins (from cumulative probability 0% to 93.32%). The year 2002 was assigned to the next highest bin, with a probability of 6.06%. The year 2006 was assigned to the highest bin, with a probability of 0.62%. The three load shapes for the NYCA as a whole are shown on a per-unit basis for the highest one hundred hours in Figure A.3. The year 2007 represents the load duration pattern of a typical year. The year 2002 represents the load duration pattern of many hours at high load levels. The year 2006 represents the load duration pattern of a heat wave, with a small number of hours at high load levels followed by a sharper decrease in per-unit values than the other two profiles.

The load duration curves were reviewed as part of the 2021 IRM Study. Load duration curves were examined from the period 2002 through 2019. It was observed that the year 2012 was similar to the year 2007, the year 2013 was similar to 2006, and the year 2018 was similar to the year 2002. As a result of this review, the ICS accepted the NYISO's recommendation to continue the use of the current three load shapes.

Figure A.3 Per Unit Load Shapes



A.3.2 Capacity Model

The capacity model includes all NYCA generating units, including new and planned units, as well as units that are physically outside New York State that have met specific criteria to offer capacity in the New York Control Area. The 2020 Load and Capacity Data Report is the primary data source for these resources. Table A.6 provides a summary of the capacity resource assumptions in the 2021 IRM study.

Table A.6 Capacity Resources

Parameter	2020 Study Assumption	2021 Study Assumption	Explanation
Generating Unit Capacities	2019 Gold Book values. Use min (DMNC vs. CRIS) capacity value	2020 Gold Book values. Use min (DMNC vs. CRIS) capacity value	2020 Gold Book publication
Planned Generator Units	1020 MW of new non- wind resources, plus 0 MW of project related re-ratings.	16.0 MW of new Thermal resources, plus 56.6 MW of project related re-ratings.	New resources + Unit rerates
Wind Resources	0 MW of Wind Capacity additions totaling 1891.7 MW of qualifying wind	126.5 MW of Wind Capacity additions totaling 1865.7 MW of qualifying wind	Renewable units based on RPS agreements, interconnection queue, and ICS input.
Wind Shape	Actual hourly plant output over the period 2014-2018. New units will use zonal hourly averages or nearby units.	Actual hourly plant output over the period 2015-2019. New units will use zonal hourly averages or nearby units.	Program randomly selects a wind shape of hourly production over the years 2015-2019 for each model iteration.
Solar Resources (Grid connected)	Total of 51.5 MW of qualifying Solar Capacity.	0 MW of Solar Capacity additions totaling 31.5 MW of qualifying Solar Capacity.	ICAP Resources connected to Bulk Electric System
Solar Shape	Actual hourly plant output over the period 2014-2018. New units will use zonal hourly averages or nearby units.	Actual hourly plant output over the period 2015-2019. New units will use zonal hourly averages or nearby units.	Program randomly selects a solar shape of hourly production over the years 2015-2019 for each model iteration.

Parameter	2020 Study Assumption	2021 Study Assumption	Explanation
BTM- NG Program	No new BTM NG resources Forecast load adjustment of 11.6 MW	One new BTM NG resources Forecast load adjustment of 65.2 MW	Both the load and generation of the BTM:NG Resources are modeled.
Retirements, Mothballed units, and ICAP ineligible units	837.0 MW of retirements, 1023.4 MW of unit deactivations, and 0 MW of IIFO and IR	1,104 MW of unit deactivations and 192.7 MW of unit removals	2020 Gold Book publication and generator notifications
Forced and Partial Outage Rates	Five-year (2014-2018) GADS data for each unit represented. Those units with less than five years – use representative data.	Five-year (2015-2019) GADS data for each unit represented. Those units with less than five years – use representative data.	Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period (2015-2019)
Planned Outages	Based on schedules received by the NYISO	Based on schedules received by the NYISO	Updated schedules
Summer Maintenance	Nominal 50 MWs – divided equally between Zones J & K	Nominal 50 MWs – divided equally between Zones J & K	Review of most recent data
Gas Turbine Ambient De-rate	De-rate based on provided temperature correction curves.	De-rate based on provided temperature correction curves.	Operational history indicates de-rates in line with manufacturer’s curves
Small Hydro Resources	Actual hourly plant output over the period 2014-2018.	Actual hourly plant output over the period 2015-2019.	Program randomly selects a Hydro shape of hourly production over the years 2015-2019 for each model iteration.

Parameter	2020 Study Assumption	2021 Study Assumption	Explanation
Large Hydro	Probabilistic Model based on 5 years of GADS data	Probabilistic Model based on 5 years of GADS data	Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period (2015-2019)
Energy Limited Resources (ELR)	ELR modeled with duration limitation	Based upon elections made by August 1st, 2020. Such an election would override any of the above assumptions.	Existing elections are made by August 1st and will be incorporated into the model.

(1) Generating Unit Capacities

The capacity rating for each thermal generating unit is based on its Dependable Maximum Net Capability (DMNC). The source of DMNC ratings are seasonal tests required by procedures in the NYISO Installed Capacity Manual. Additionally, each generating resource has an associated capacity CRIS (Capacity Resource Interconnection Service) value. When the associated CRIS value is less than the DMNC rating, the CRIS value is modeled.

Wind units are rated at the lower of their CRIS value or their nameplate value in the model. The 2020 NYCA Load and Capacity Report, issued by the NYISO, is the source of those generating units and their ratings included on the capacity model.

(2) Planned Generator Units

Hudson Ave. GT 3 returning from IIFO with a capacity of 16 MW. There was one unit reporting an increased rating of 56.6 MW for the 2021IRM study.

(3) Wind Modeling

Wind generators are modeled as hourly load modifiers using hourly production data over the period 2015-2019. Each calendar production year represents an hourly wind shape for each wind facility from which the GE MARS program will randomly select. New units will use the zonal hourly averages of current units within the same zone. As shown in table A.7, a total of 1,865.7 MW of installed capacity associated with wind generators.

Table A.7 Wind Generation

B1 - Wind Resources				
Wind Resouce	**Zone**	**CRIS (MW)**	**Summer Capability (MW)**	**Summer MARS Model (MW)**
Active Wind Units				
Bliss Wind Power	A	100.5	100.5	100.5
Canandaigua Wind Power	C	125.0	125.0	125.0
High Sheldon Wind Farm	C	112.5	118.1	112.5
Howard Wind	C	57.4	55.4	55.4
Orangeville Wind Farm	C	94.4	93.9	93.9
Wethersfield Wind Power	C	126.0	126.0	126.0
Altona Wind Power	D	97.5	97.5	97.5
Chateaugay Wind Power	D	106.5	106.5	106.5
Clinton Wind Power	D	100.5	100.5	100.5
Ellenburg Wind Power	D	81.0	81.0	81.0
Jericho Rise Wind Farm	D	77.7	77.7	77.7
Marble River Wind	D	215.2	215.2	215.2
Hardscrabble Wind	E	74.0	74.0	74.0
Madison Wind Power	E	11.5	11.6	11.5
Maple Ridge Wind	E	231.0	231.0	231.0
Maple Ridge Wind	E	90.7	90.8	90.7
Munnsville Wind Power	E	34.5	34.5	34.5
		1735.9	**1739.2**	**1733.4**
Proposed Wind Units				
Cassadaga Wind	A	126.0	126.5	126.0
		126.0	**126.5**	**126.0**
Total Wind Resources				
	A	226.5	227.0	226.5
	B	0.0	0.0	0.0
	C	515.3	518.4	512.8
	D	678.4	678.4	678.4
	E	441.7	441.9	441.7
		1861.9	**1865.7**	**1859.4**

(4) Solar Modeling

Solar generators are modeled as hourly load modifiers using hourly production data over the period 2015-2019. Each calendar production year represents an hourly solar shape for each solar facility which the GE MARS program will randomly select from. A total of 31.5 MW of solar capacity was modeled in Zone K.

(5) Retirements/Deactivations/ ICAP Ineligible

There are three units totaling 1104 MW that have become deactivated. In addition, units totaling 192.7 MW have been removed from the 2021 IRM study because they did not participate in the ICAP market.

(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 benefits. Non-locational capacity, when coupled with a UDR to deliver capacity to a Locality, can be used to satisfy locational capacity requirements. The owners of the UDRs elect whether they will utilize their capacity deliverability rights. This decision determines how this transfer capability will be represented in the 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 2021 IRM Study as having UDR capacity rights: LIPA's 330 MW High Voltage Direct Current (HVDC) Cross Sound Cable, LIPA's 660 MW HVDC Neptune Cable, Hudson Transmission Partners 660 MW HVDC Cable, and the 315 MW Linden Variable Frequency Transformer. The 2021 IRM Study incorporates the confidential elections that these facility owners made for the 2021 Capability Year.

(7) Energy Limited Resources

The capacity model now includes Energy Limited resources (ELR). The NYISO filed, and FERC approved, tariff changes that enhance the ability of duration limited resources to participate in the NYISO markets. These rules allow output limited resources to participate in the markets consistent with those limitations and requires owners of those resources to inform the NYISO of their elected energy output duration limitations. Effective May 1, 2021, generation resources may participate in an Energy Limited Resource (ELR) program administered by the NYISO. Under this program, participating generators were required to submit their elected limitations to the NYISO by August 1st for the upcoming capability year (i.e., August 1, 2020 for the Capability Year beginning on May 1, 2021).

(8) Performance Data

Performance data for thermal generating units in the model includes forced and partial outages, which are modeled by inputting a multi-state outage model that is representative of the "equivalent demand forced outage rate" (EFORd) for each unit represented. Generation owners provide outage data to the NYISO using Generating Availability Data System (GADS) data in accordance with the NYISO Installed Capacity Manual. The NYSRC is continuing to use a five-year historical period for the 2021 IRM Study.

Figure A.4 shows a rolling 5-year average of the same data.

Figures A.5 and A.6 show the availability trends of the NYCA broken out by fuel type.

The multi-state model for each unit is derived from five years of historic events if it is available. For units with less than five years of historic events, the available years of event data for the unit is used if it appears to be reasonable. For the remaining years, the unit NERC class-average data is used.

The unit forced outage states for the most of the NYCA units were obtained from the five-year NERC GADS outage data collected by the NYISO for the years 2015 through 2019. This hourly data represents the availability of the units for all hours. From this, full and partial outage states and the frequency of occurrence were calculated and put in the required format for input to the GE-MARS program.

Figures A.6 and A.7 show the unit availabilities of the entire NERC fleet on an annual and 5-year historical basis.

Figure A.4 Five-Year Zonal EFORds

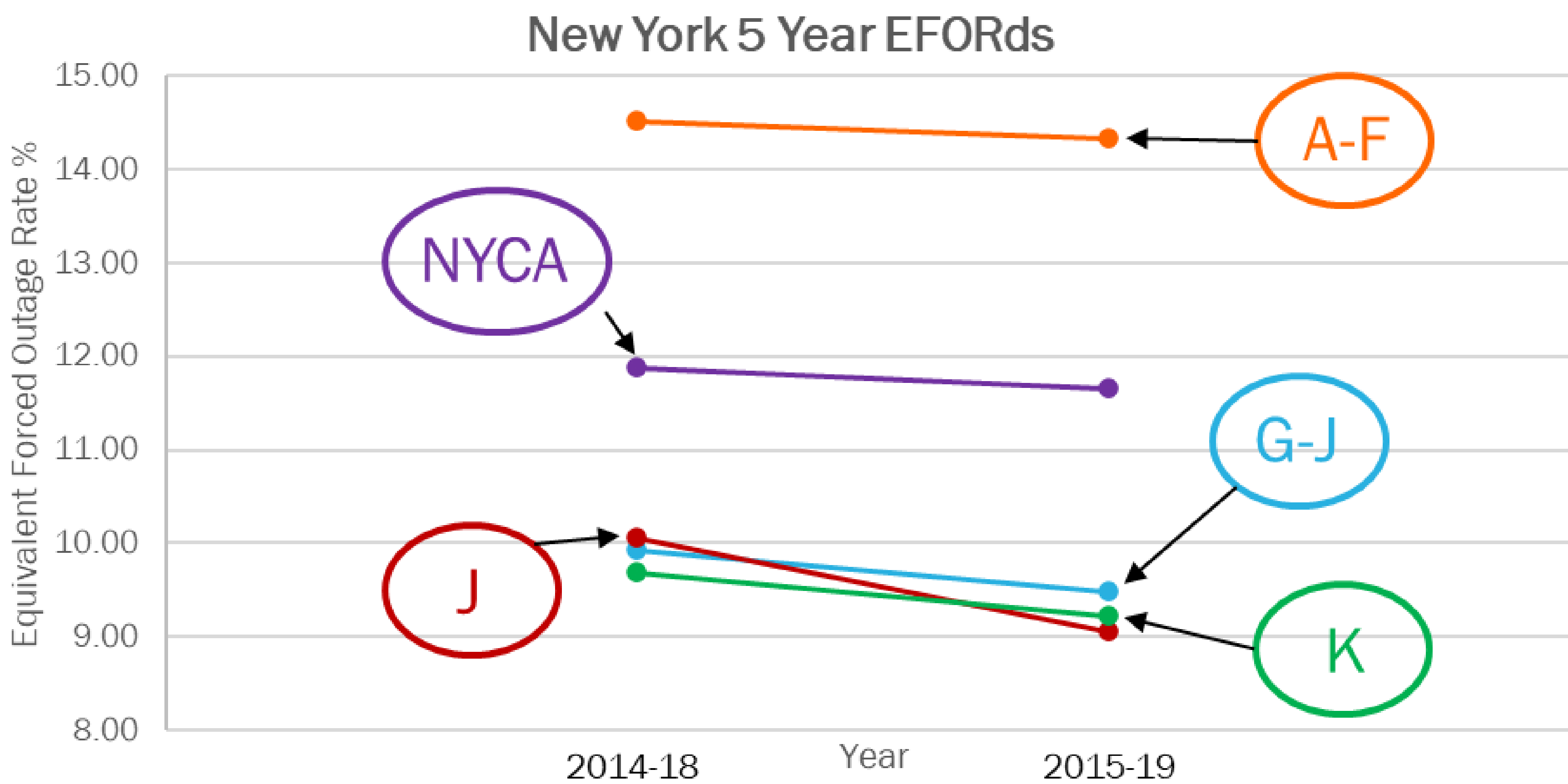


Figure A.5 NYCA Annual Availability by Fuel

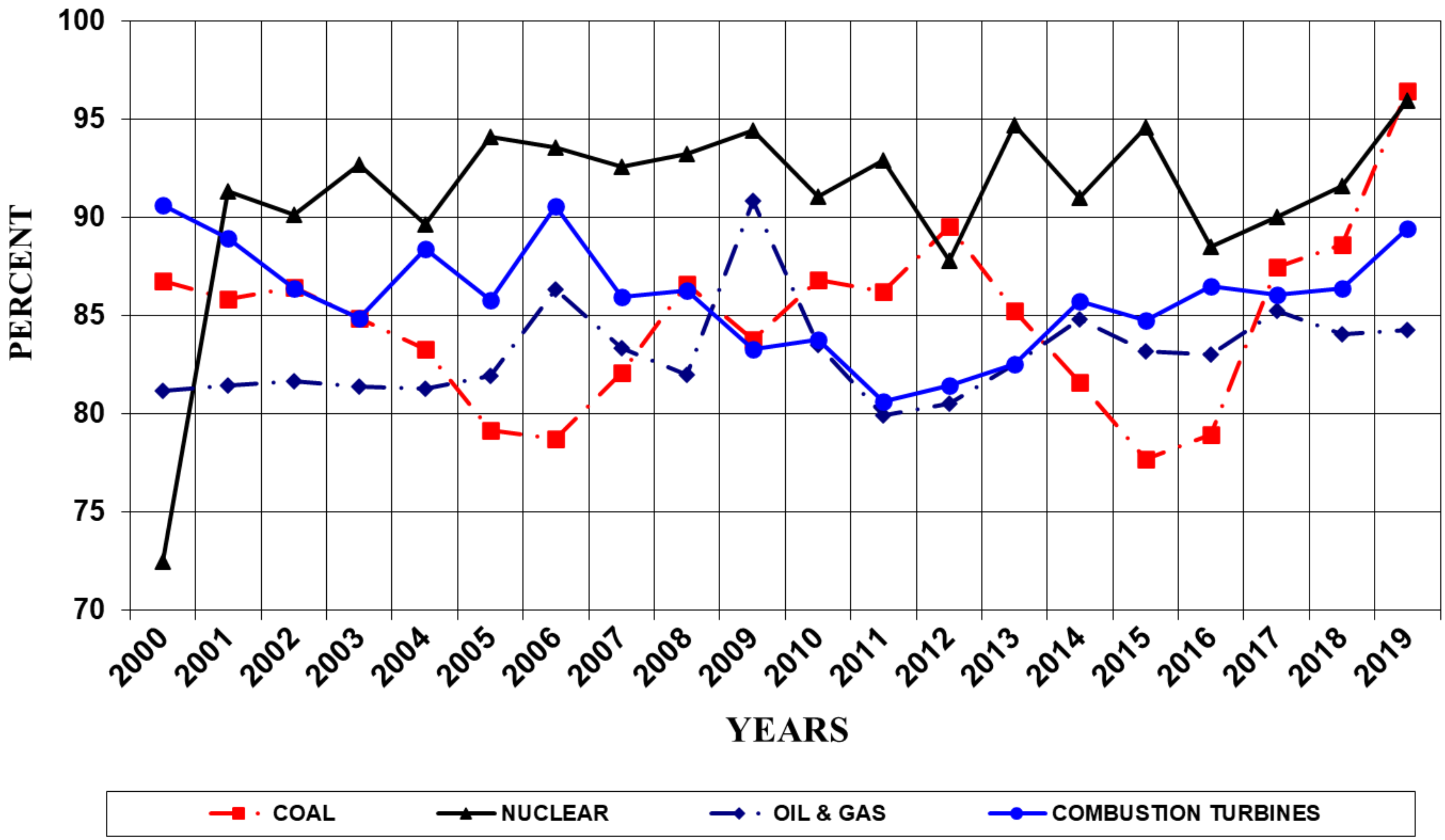


Figure A.6 NYCA Five-Year Availability by Fuel

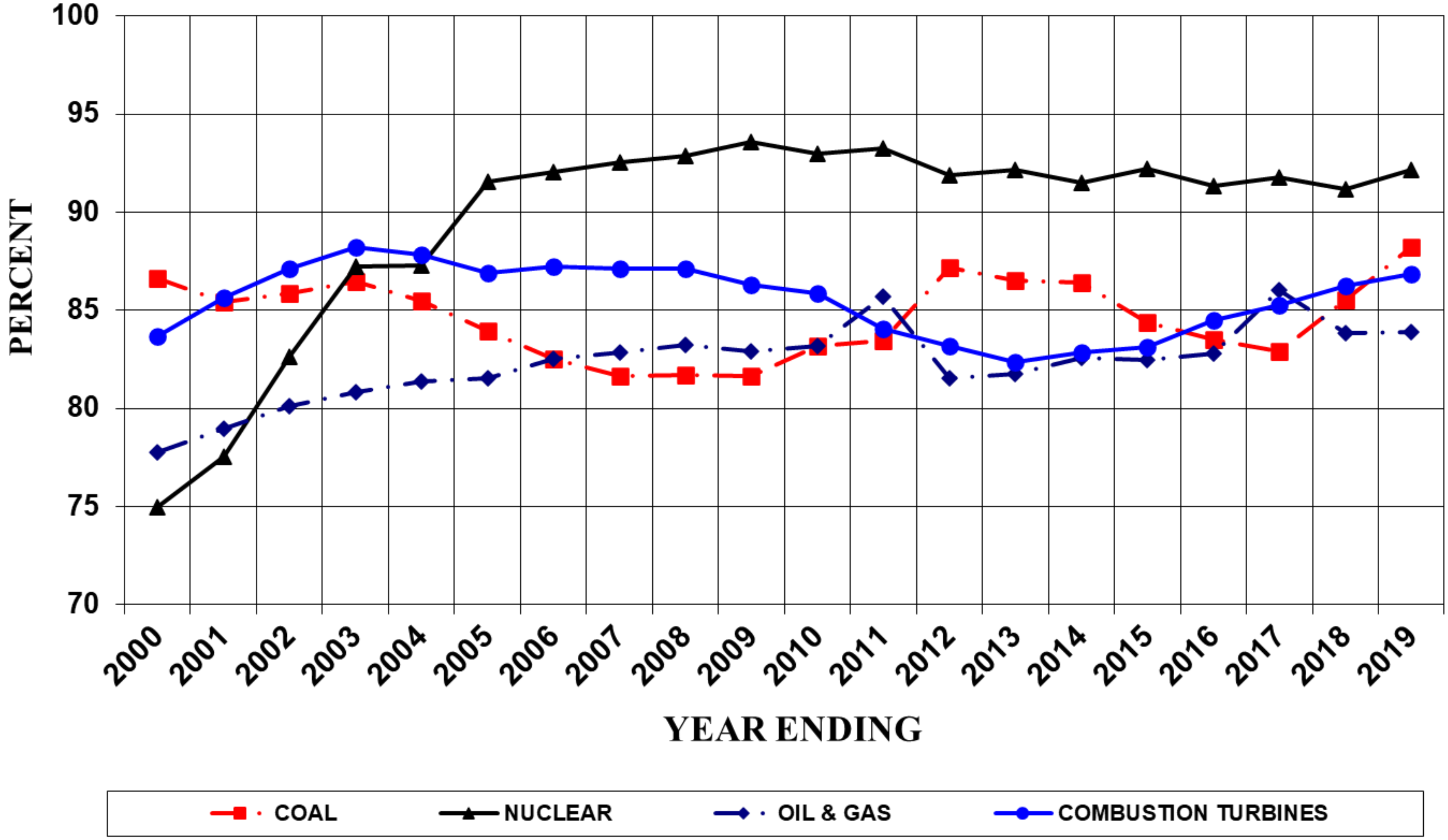


Figure A.7 NERC Annual Availability by Fuel

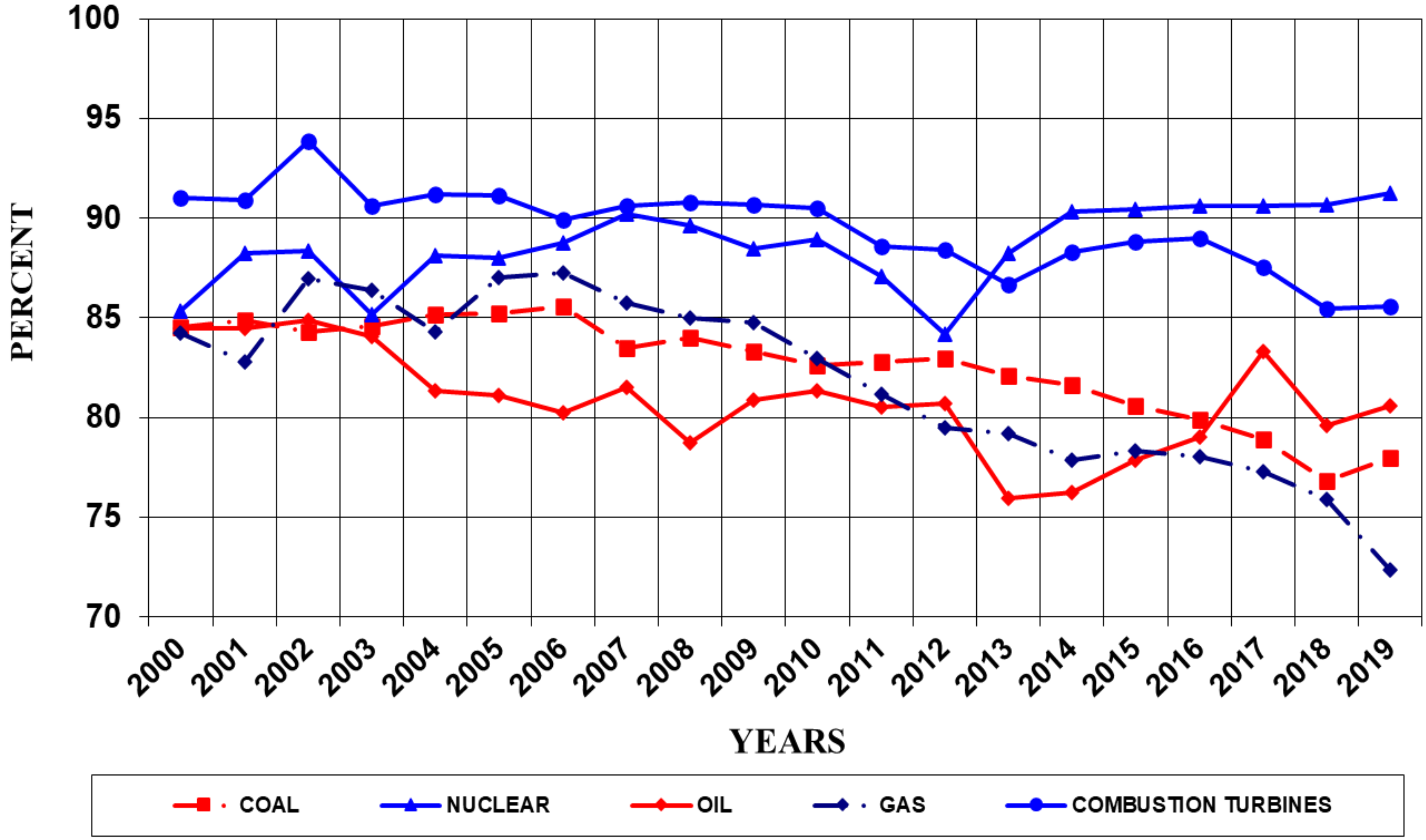
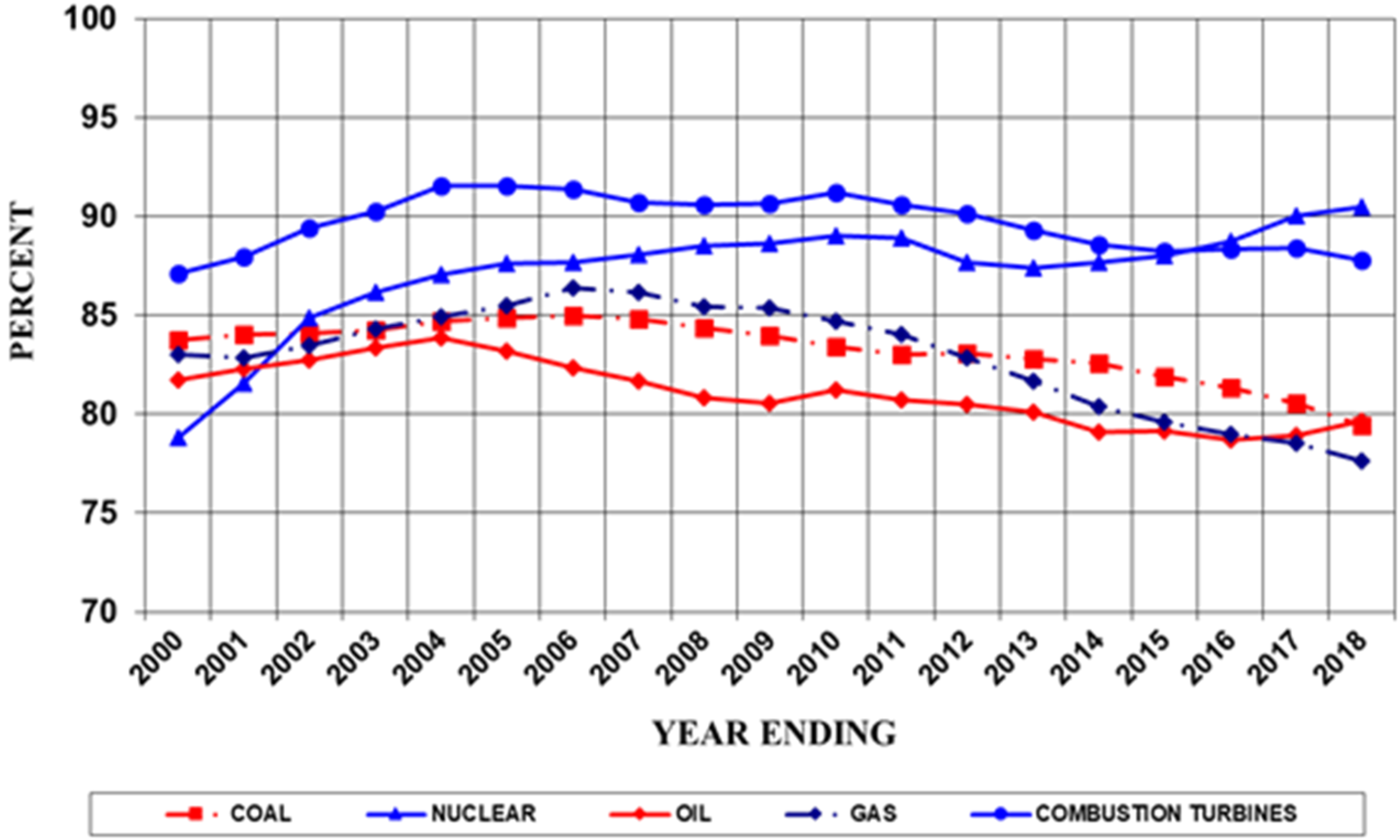


Figure A.8 NERC Five-Year Availability by Fuel



(9) Outages and Summer Maintenance

A second performance parameter to be modeled for each unit is scheduled maintenance. This parameter includes both planned and maintenance outage components. The planned outage (PO) component is obtained from the generator owners. When this information is not available, the unit's historic average planned outage duration is used. Figure A.9 provides a graph of scheduled outage trends over the 2003 through 2019 period for the NYCA generators.

Typically, generator owners do not schedule maintenance during the summer peak period. However, it is highly probable that some units will need to schedule maintenance during this period. Each year, the previous summer capability period is reviewed to determine the scheduled maintenance MW during the previous peak period. An assumption is determined as to how much to model in the current study. For the 2021 IRM Study, a nominal 50 MW of summer maintenance is modeled. The amount is nominally divided equally between Zone J and Zone K. Figure A.10 shows the weekly scheduled maintenance for the 2020 IRM Study compared to this study.

(10) Gas Turbine Ambient De-rate

Operation of combustion turbine units at temperatures above DMNC test temperature results in reduction in output. These reductions in gas turbine and combined cycle capacity output are captured in the GE-MARS model using de-ratings based on ambient temperature correction curves. Based on its review of historical data, the NYISO staff has concluded that the existing combined cycle temperature correction curves are still valid and appropriate. These temperature corrections curves, provided by the Market Monitoring Unit of the NYISO, show unit output versus ambient temperature conditions over a range starting at 60 degrees F to over 100 degrees F. Because generating units are required to report their DMNC output at peak or "design" conditions (an average of temperatures obtained at the time of the transmission district previous four like capability period load peaks), the temperature correction for the combustion turbine units is derived for and applied to temperatures above transmission district peak loads.

(11) Large Hydro De-rates

Hydroelectric projects are modeled as are thermal units, with a probability capacity model based on five years of unit performance. See Capacity Models item 6 above.

Figure A.9 Planned and Maintenance Outage Rates

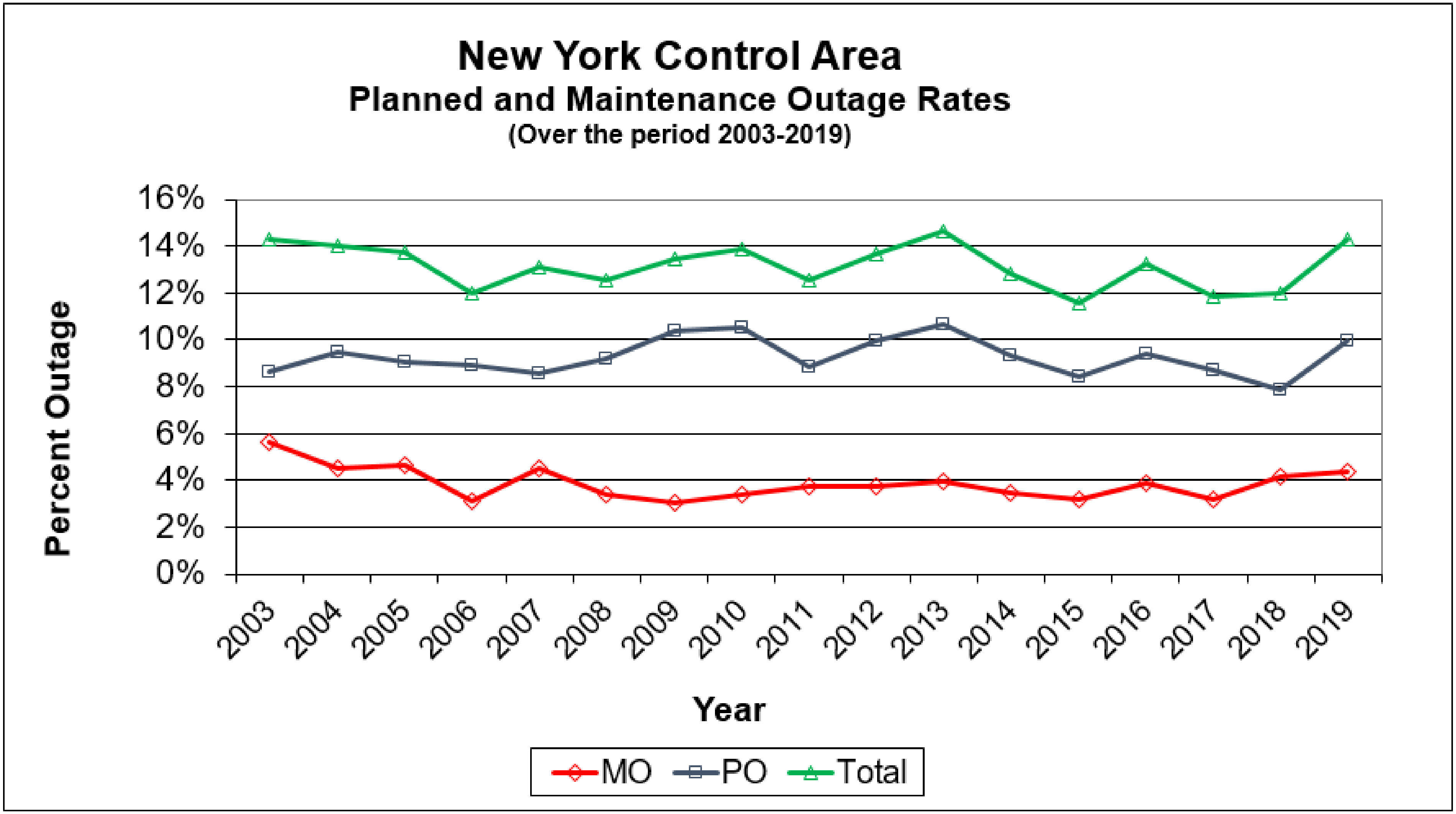
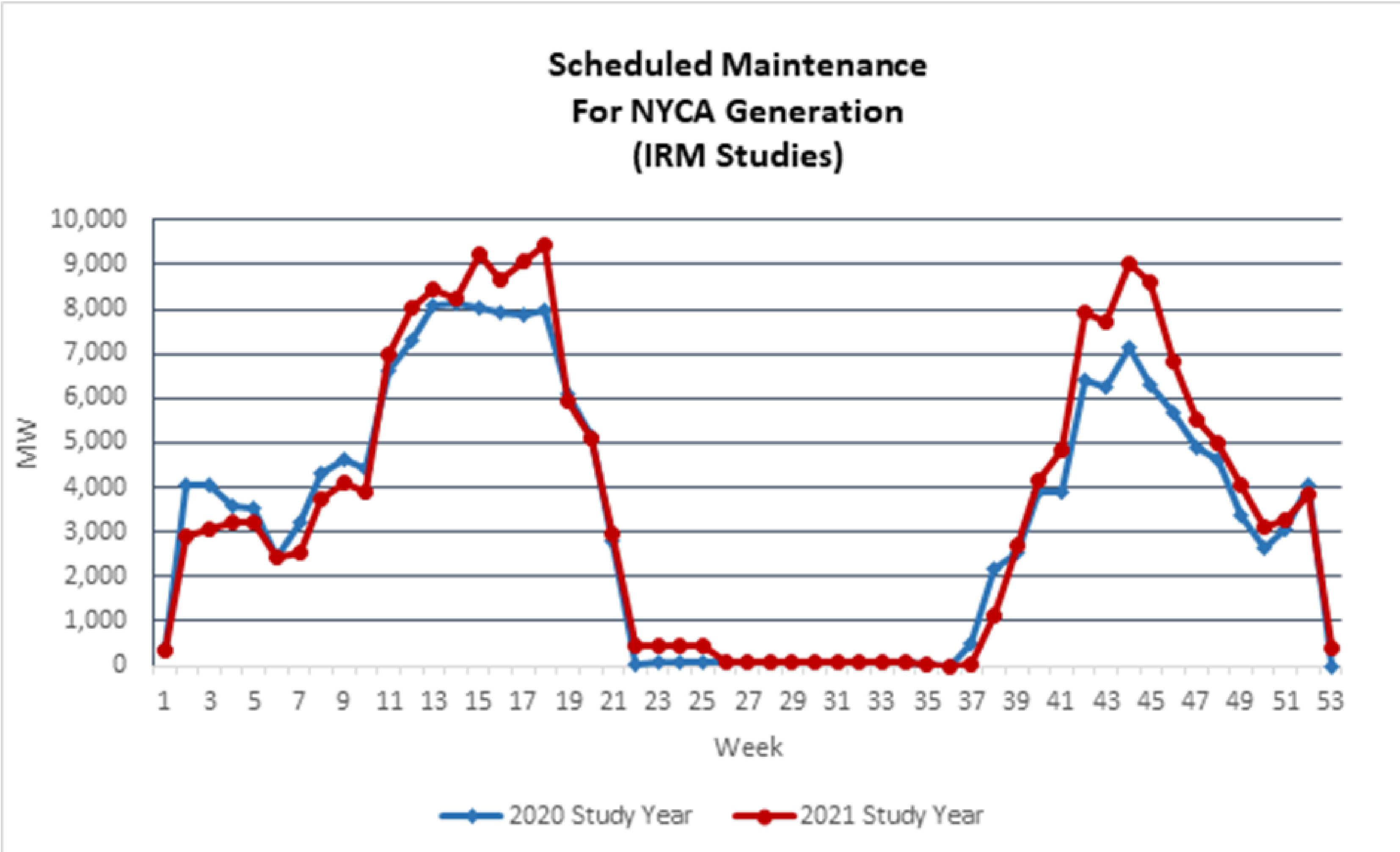


Figure A.10 Scheduled Maintenance



A.3.3 Transmission System Model

A detailed transmission system model is represented in the GE-MARS topology. The transmission system topology, which includes eleven NYCA Zones and four External Control Areas, along with transfer limits, is shown in Figure A.11. The transfer limits employed for the 2021 IRM Study were developed from emergency transfer limit analyses included in various studies performed by the NYISO and based upon input from Transmission Owners and neighboring regions. The NYISO's Transmission Planning and Advisory Subcommittee (TPAS) also reviewed and approved the topology. A list of those studies is shown in Table A.8, below. The transfer limits are further refined by other assessments conducted by the NYISO. The assumptions for the transmission model included in the 2021 IRM Study are listed in Table A.8, which reflects changes from last year's model. The changes that are captured in this year's model are: 1) an update to the UPNY-ConEd (Zone G to Zone H) and Dunwoodie South (Zone I to Zone J) limits as a result of the deactivation of Indian Point; 2) a simplification to the UPNY-SENY group interface; 3) the removal of the PJM-SENY grouped interface; 4) an increased ability to export power from Long Island and the Jamaica ties (J to K) limit is no longer dependent on Barrett availability.

Forced transmission outages are included 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 TOs provided updated transition rates for their associated cable interfaces.

Table A.8 Transmission System Model

Parameter	2020 Model Assumptions	2021 Model Assumptions Recommended	Basis for Recommendation
UPNY-SENY Interface Group	Dual interface groups consisting of one group with a fixed limit of 5600 MW and the other group with a dynamic limit up to 6950 MW	Single interface group with a dynamic limit up to 5350 MW	MARS program functionality was updated that allowed for the translation of the UPNYSENY Dynamic Limit table back to original interface and the removal of dummy bubbles that impacted the limit
Jamaica Ties and Long Island Interface Groups	320 MW of tie capability from Zone J to Zone K, and 1593 MW limit on a grouped interface from Zones I and J into Zone K	320 MW of tie capability from Zone J to Zone K, and 1613 MW limit on a grouped interface from Zones I and J into Zone K	Updated information from PSEG-LI, reduced load forecast for western LI, addition East Garden City – Valley Stream 138 kV circuit
UPNY-ConEd Interface (from G to H)	6000 MW interface limit from Zone G to Zone H	7000 MW interface limit from Zone G to Zone H	Scheduled retirement of Indian Point 3 nuclear unit in year 2021. 71, 72, M51, M52 series reactors assumed bypassed after deactivation of Indian Point
PJM-SENY Group	Interface group was used to limit total imports from PJM into Zones G and Zone J (2000 MW)	Removal of this group limit	Changes in the systems and MARS topology resulted in making this grouped interface no longer limiting in a majority of situations
Interface Limits (other than those identified above)	All changes reviewed and commented on by TPAS	No change from 2019 model assumption	Based on the most recent NYISO studies and processes, such as Operating Study, Operations Engineering Voltage Studies, Comprehensive System Planning Process, and additional analysis including interregional planning initiatives.
Cable Forced Outage Rates	All existing Cable EFORs updated for NYC and LI to reflect most recent five-year history	All existing Cable EFORs updated for NYC and LI to reflect most recent five-year history	Based on TO analysis or NYISO analysis where applicable
UDR line Unavailability	Five-year history of forced outages	Five-year history of forced outages	NYISO/TO review

Figure A.11 shows the transmission system representation for this year's study. Figure A.12 shows the dynamic limits used in the topology.

Figure A.11 2020 IRM Topology

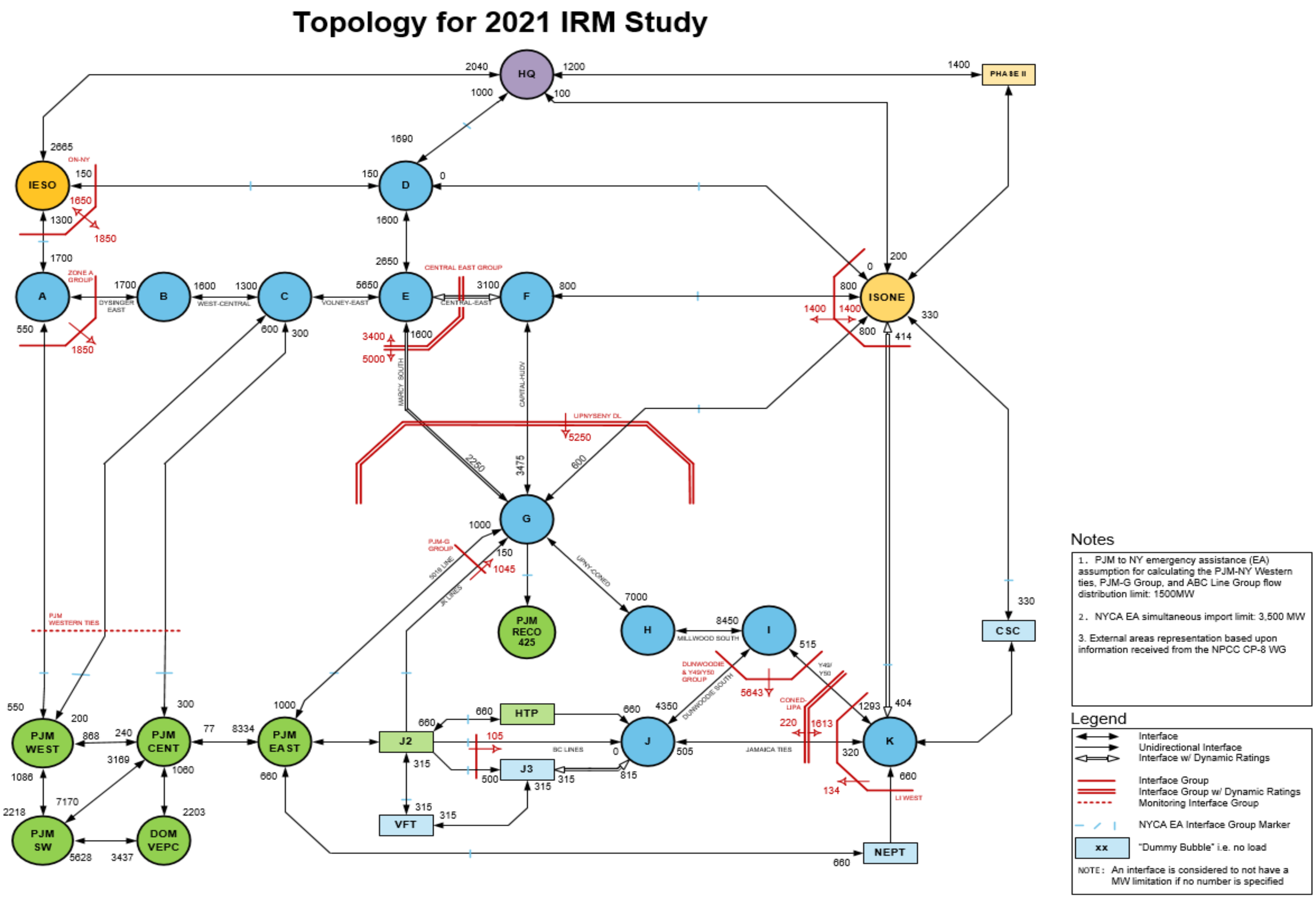


Figure A.12 Dynamic Interface Ratings Information

2021 MARS Topology - Dynamic Limits and Grouping Information

Central East Voltage Limits, Oswego Complex Units								
	IRM2021				IRM2020			
Dependency	9MILP1, 9MILP2, FPNUC1, STHIND, OS05, OS06				9MILP1, 9MILP2, FPNUC1, STHIND, OS05, OS06			
Units Available	E_TO_F		E_TO_FG		E_TO_F		E_TO_FG	
	Forward	Reverse	Forward	Reverse	Forward	Reverse	Forward	Reverse
6	3100	1999	5000	3400	3100	1999	5000	3400
5	3050	1999	4925	3400	3050	1999	4925	3400
4	2990	1999	4840	3400	2990	1999	4840	3400
3	2885	1999	4685	3400	2885	1999	4685	3400
2	2770	1999	4510	3400	2770	1999	4510	3400
All Other Conditions	2645	1999	4310	3400	2645	1999	4310	3400

LI_NE: Northport Units 1-4				
Units Available	IRM2021		IRM2020	
	Norwalk to K	K to Norwalk	Norwalk to K	K to Norwalk
4	260	414	260	414
All Other Conditions	404	414	404	414

ConEd-LIPA: Barrett Units 1 & 2				
Units Available	IRM2021		IRM2020	
	IJ to K	K to IJ	IJ to K	K to IJ
2	1613	220	1593	104
1	1613	200	1593	74
0	1613	130	1593	0

Staten Island Import Limits, AK and Linden CoGen Units							
				IRM2021		IRM2020	
Unit Availability				J_TO_J3		J_TO_J3	
AK02	AK03	LINCOG1	LINCOG2	Forward	Reverse	Forward	Reverse
A	A	A	A	315	200	315	200
U	A	A	A	315	500	315	500
A	U	A	A	315	700	315	700
A	A	U	A	315	500	315	500
A	A	A	U	315	500	315	500
All Other Conditions				315	815	315	815

UPNYSENY					
Units Available					
CPV	Cricket	Athens	IRM2021	IRM2021 (2020 Topology)	IRM2020
2	3	3	5250	5260	6950
2	3	2	5100	5060	6750
1	3	3	5350	5345	6700
2	2	3	5200	5200	6550
2	1	3	5150	5140	6150
1	1	3	5250	5275	5950
2	0	3	5100	5130	5800
All Other Conditions			5350		6600

E to G		
Units Available		
CPV	IRM2021	IRM2020
2	1750	N/A
1	2000	N/A
0	2250	N/A

As can be seen in Table A.9, the following changes were made to NYCA interface limits:

Table A.9 Interface Limits Updates

	2020		2021		Delta	
Interface	**Forward**	**Reverse**	**Forward**	**Reverse**	**Forward**	**Reverse**
UPNY-SENY Interface Group	UPNY-SENY: 6950/6750/6700/6550/6150/5950/5800/6600 UPNYSNY2: 5600	-	UPNY-SENY: 5260/5060/5345/5200/5140/5275/5130/5350 UPNYSNY2: -	-	UPNY-SENY: -1690/-1690/-1355/-1350/-1010/-675/-670/-1250	-
LI West group	-	18	-	134	-	116
UPNY-ConEd Interface	6000	-	7000	-	1000	-
Dunwoodie South Interface	4400	-	4350	-	-50	-
ConEd-LIPA group	1528	104	1613	220	85	116
Y49/Y50 Interface	1293	342	1293	515	0	173

The topology for the 2021 IRM Study features five changes from the topology used in the 2020 IRM Study.

1. <u>Update to the UPNY-ConEd and Dunwoodie South Interfaces</u>

The Indian Point Energy Center deactivation led to the 71, 72, M51, M52 series reactors assuming to be bypassed. This resulted in the increase of 1000 MW in the UPNY-ConEd (Zone G to Zone H) interface. The Dunwoodie South (Zone I to Zone J) also was impacted by this change. The interface was decreased by 50 MW to 4350 MW.

2. <u>Simplification of the UPNY-SENY Group Interface</u>

The MARS program was updated with new functionality which allowed for the translation of the UPNY-SENY Dynamic Limit Table back to the original interface. Units that previously were in dummy bubbles are now modeled in Zones, (Athens (F,) Cricket Valley (G,) CPV Valley (G.)) Since CPV is now directly in Zone G, the E to G grouped interface was removed and replaced with a simple Dynamic Limit Table. The simplifications resulted in minimal LOLE change.

3. <u>Removal of PJM-SENY Group Interface</u>

This interface was traditionally used to limit total imports from PJM into Zones G and J. Due to changes in the system and MARS topology, this interface is no longer limiting in a majority of situations. The 2000 MW limit ran across various interfaces from PJM East and Dummy Bubble J2, into SENY.

4. Updates to Zone K Topology

The NYISO received updated information from PSEG-LI, which resulted in various changes. The load forecast for western Long Island and additional East-Garden City-Valley Stream 138 kV circuit resulted in system changes. Long Island export capability was increased, and the Jamaica ties (Zone J to Zone K) limit is no longer dependent on the Barrett unit availability. The LI West export interface was updated from 18 MW to 134 MW, and the ConEd LIPA export interface changed from 104 to 220 MW. The LI import limit was also increased. The group limit from Zones J and I was 1613 MW. This value was updated to 1613 MW.

Additional topology changes were made to the external area models in accordance with information received through NPCC's CP-8 working group.

A.3.4 External Area Representations

NYCA reliability depends in part on emergency assistance from its interconnected Control Area neighbors (New England, Ontario, Quebec and PJM) based on reserve sharing agreements with these external Control Areas. Load and capacity models of these Areas are therefore represented in the GE-MARS analyses with data received directly from the Areas and through NPCC sources.

The primary consideration for developing the final load and capacity models for the external Control Areas is to avoid over-dependence on the external Control Areas for emergency capacity support.

For this reason, a limit is placed on the amount of emergency capacity support that the NYISO can receive from external Control Areas in the IRM study. The 3,500 MW value of this limit for this IRM study is based on a recommendation from the ICS and the NYISO that considers the amount of ten-minute reserves that are available in the external Control Areas above an Area's required reserve, along with other factors.

In addition, an external Control Area's LOLE assumed in the IRM Study cannot be lower than its LOLE criteria and its Reserve Margin can be no higher than its minimum requirement. If the Area's reserve margin is lower than its requirement and its LOLE is higher than its criterion, pre-emergency Demand Response can be represented. In other words, the neighboring Areas are assumed to be equally or less reliable than NYCA.

Another consideration for developing models for the external Control Areas is to recognize internal transmission constraints within the external Control Areas that may limit emergency assistance to the NYCA. This recognition is considered implicitly for those Areas that have not supplied internal transmission constraint data. Additionally, EOPs are removed from the external Control Area models.

Finally, the top three summer peak load days of an external Control Area should be specified in the load model to be coincident with the NYCA top three peak load days. The purpose of this is to capture the higher likelihood that there will be considerably less load diversity between the NYCA and external Control Areas on the hot summer days.

For this study, both New England and PJM continue to be represented as multi-area models, based on data provided by these Control Areas. Ontario and Quebec are represented as single area models. The load forecast uncertainty model for the outside world model was supplied from the external Control Areas.

Modeling of the neighboring Control Areas in the base case in accordance with Policy 5-10 is as follows:

Table A.10 External Area Representations

Parameter	2020 Study Assumption	2021 Study Assumption	Explanation
Capacity Purchases	Grandfathered amounts: PJM – 1080 MW HQ – 1110 MW All contracts model as equivalent contracts	Grandfathered amounts: PJM – 1080 MW HQ – 1110 MW All contracts model as equivalent contracts	Grandfathered Rights, ETCNL, and other FERC identified rights.
Capacity Sales	Long term firm sales of 281.1 MW	Long term firm sales of 265.9 MW	These are long term federally monitored contracts.
External Area Modeling	Single Area representations for Ontario and Quebec. Five areas modeled for PJM. Thirteen zones modeled for New England	Single Area representations for Ontario and Quebec. Five areas modeled for PJM. Thirteen zones modeled for New England	The load and capacity data are provided by the neighboring Areas. This updated data may then be adjusted as described in Policy 5
Reserve Sharing	All NPCC Control Areas have indicated that they will share reserves equally	All NPCC Control Areas have indicated that they will share reserves equally	Per NPCC CP-8 working group assumption.

Table A.11 shows the final reserve margins and LOLEs for the Control Areas external to NYCA. The 2021 external area model was updated from 2020 but still includes a 3,500 MW limit for emergency assistance (EA) imports during any given hour. As per Table 7-

1 of the IRM study report, the difference in between the isolated case and the final base case was 6.9% in 2021 VS. 7.5% in 2020.

Table A.11 Outside World Reserve Margins

Area	2020 Study Reserve Margin	2021 Study Reserve Margin	2020 Study LOLE (Days/Year)	2021 Study LOLE (Days/Year)
Quebec	38.7%*	38.1%*	0.105	0.108
Ontario	18.1%	21.2%	0.108	0.110
PJM	15.9%	15.1%	0.226	0.177
New England	13.1%	9.8 %	0.112	0.100

*This is the summer margin.

A.3.5 Emergency Operating Procedures (EOPs)

There are many steps that the system operator can take in an emergency to avoid disconnecting load. EOP steps 2 through 10 listed in Table A.13 were provided by the NYISO based on operator experience. Table A.12 lists the assumptions modeled.

The values in Table A.13 are based on a NYISO forecast that incorporates 2020 (summer) operating results. This forecast is applied against a 2021 peak load forecast of 32,243 MW. The table shows the most likely order that these steps will be initiated. The actual order will depend on the type of the emergency. The amount of assistance that is provided by EOPs related to load, such as voltage reduction, will vary with the load level.

Table A.12 Assumptions for Emergency Operating Procedures

Parameter	2020 Study Assumption	2021 Study Assumption	Explanation
Special Case Resources*	July 2019 –1,282 MW based on registrations and modeled as 873 MW of effective capacity. Monthly variation based on historical experience*	July 2020 –1195 MW based on registrations and modeled as 822 MW of effective capacity. Monthly variation based on historical experience	SCRs sold for the program discounted to historic availability. Summer values calculated from July 2020 registrations. Performance calculation updated per ICS presentations on SCR performance.
Other EOPs	692 MW of non-SCR resources	844.4 MW of on-SCR/non-EDRP resources	Based on TO information, measured data, and NYISO forecasts.
EOP Structure	12 EOP Steps Modeled	10 EOP Steps Modeled	Based on agreement with ICS, step 1 and 2 separated, step 3 removed

- The number of SCR calls is limited to 5 per month when calculating LOLE.

Table A.13 Emergency Operating Procedures Values

Step	Procedure	2020 MW Value	2021 MW Value
1	Special Case Resources –Load, Gen	1,282 MW Enrolled/ 873 MW modeled	1,195 MW Enrolled/ 822 MW modeled
2	5% manual voltage Reduction	57 MW	59.64 MW
3	Thirty-minute reserve to zero	655 MW	655 MW
4	5% remote voltage reduction	347 MW	445.42 MW
5	Voluntary industrial curtailment	207 MW	259.36 MW
6	General Public Appeals	80 MW	80 MW
7	Emergency Purchases	Varies	Varies
8	Ten-minute reserves to zero	1,310 MW	1,310 MW
9	Customer disconnections	As needed	As needed
10	Adjustment used if IRM is lower than technical study margin	As needed	As needed

A.3.6 Locational Capacity Requirements

The GE-MARS model used in the IRM study provides an assessment of the adequacy of the NYCA transmission system to deliver assistance from one Zone to another for meeting load requirements. Previous studies have identified transmission constraints into certain Zones that could impact the LOLE of these Zones, as well as the statewide LOLE. To minimize these potential LOLE impacts, these Zones require a minimum portion of their NYCA ICAP requirement, *i.e.,* locational ICAP, which shall be electrically located within the Zone to ensure that enough energy and capacity are available in that Zone and that NYSRC Reliability Rules are met. For the purposes of the IRM study, Locational ICAP requirements are applicable to two transmission-constrained Zones, New York City and Long Island, and are normally expressed as a percentage of each Zone's annual peak load.

These locational ICAP requirements, recognized by NYSRC Reliability Rule A.2 and monitored by the NYISO, supplement the statewide IRM requirement. This report using the unified methodology determines the minimum locational requirements for different levels of installed reserve. The NYSRC chooses the IRM to be used for the coming year and the NYISO chooses the final value of the locational requirements to be met by the LSEs.

A.3.7 Special Case Resources

Special Case Resources (SCRs) are loads capable of being interrupted, and distributed generators, rated at 100 kW or higher, that are not directly telemetered. SCRs are ICAP resources that only provide energy/load curtailment when activated in accordance with the NYISO Emergency Operating Manual. Performance factors for SCRs are shown in Table A.14:

Table A.14 SCR Performance

SCR Performance for 2021 IRM Study						
Super Zones	Enrollments (July 2020)	Forecast (2021)[1]	Performance Factor[2]	UCAP (2021)	Adjustment Factor[3]	Model Value
A-F	622.8	622.8	0.862	537.2	0.949	509.5
G-I	102.0	102.0	0.747	76.2	0.851	64.9
J	427.3	427.3	0.693	296.2	0.752	222.7
K	43.0	43.0	0.706	30.3	0.821	24.9
Totals	1195.1	1195.1		940.0		822.1
					Overall Performance = 68.8%	

Table A.14 note 1: These values represent no growth from July 2020 ICAP based enrollments. Table A.14 note 2: The Performance Factor is based on the average coincident load (ACL) methodology. Table A.14 note 3: The SCR Adjustment factor (3) captures two different performance derates; 1) Calculated Translation Factor (TF) between ACL and customer baseline load (CBL) values, and the Fatigue Factor (FF=1.00)

GE-MARS model accounts for SCRs as a EOP step and will activate this step to minimize the probability of customer load disconnection. Both GE-MARS and NYISO operations only activate EOPs in zones where they are capable of being delivered.

SCRs are modeled with monthly values. For the month of July, the registered value is 1195.1 MW. The effective value of 822.1 MW is used in the model.

A.4 MARS Data Scrub

A.4.1 GE Data Scrub

General Electric (GE) was asked to review the input data for errors. GE has developed a program called “Data Scrub” which processes the input files and flags data that appears to be out of the ordinary. For example, it can identify a unit with a forced outage rate significantly higher than all the others in that size and type category. If something is found, the NYISO reviews the data and either confirms that it is the right value as is or institutes an update. The results of this data scrub are shown in Table A.15 for the preliminary base case.

Table A.15 GE MARS Data Scrub

Item	Description	Disposition	Data Change	Post PBC* Affect
1	Name changes for three units were identified between the 2020 and 2021 study	Name changes were reviewed and accepted	No	N/A
2	Retirement dates for four units have changed	Retirement dates were verified	No	N/A
3	Many units had a change in capacity that exceeded 10 MW	Change in capacity verified	No	N/A
4	14 units changed MARS Areas	Changes were verified, all were related to topology updates	Yes	N/A
5	Two-line ratings were found inconsistent with diagrams previously presented	Diagrams updated to correct values	No	N/A
6	12 units identified with large EFORd change	These units, part of a larger annual review, where confirmed to be correct	No	N/A
7	Fewer EOP Steps than previous study	Verified update to 2021 model	No	N/A
8	Energy, even though not an explicit IRM assumption, appears higher in the model, for the base study year, than gold book forecast	A known effect of growing historical load shapes to meet future peaks. Initiative underway to study alternatives.	No	N/A
9	Changes to shape-based random groups	Change verified in order to align production shape years	No	N/A
10	Penetration factors changed for various units	Penetration factors verified	No	N/A
*Preliminary Base Case				

A.4.2 NYISO Data Scrub

The NYISO also performs a review of the MARS data independently from GE. Table A.16 shows the results of this review for the preliminary base case.

Table A.16 NYISO MARS Data Scrub

Item	Description	Disposition	Data Change	Post PBC* Affect
1	Study Year Change causes unreasonable result	We did not change study year per GE suggestion and ICS approval	N	0
2	UPNYSENY forward limit was incorrect	Corrected for the PBC case	Y	~0.0%
3	IJ to K reverse limit updated	Corrected for the PBC case	Y	~0.0%
4	Dynamic Limit table	Corrected for the PBC case	N	0
5	25 MW of Summer Maintenance for Zone J was assigned to Zone K	Corrected for PBC case	Y	~0.0%
*Preliminary Base Case				

*Preliminary Base Case

A.4.3 Transmission Owner Data Scrub

In addition to the above reviews, two transmission owners scrub the data and assumptions using a masked database provided by the NYISO. All their findings reiterated the previous findings. Table A.17 shows their unique results.

Table A.17 Transmission Owner Data Scrub

Item	Description	Disposition	Data Change	Post PBC* Affect
1	VFT Rating from NYCA to PJM was not correct	Value was updated	Y	0
2	Update to E to G static line rating	Value updated	Y	0
*Preliminary Base Case				

Appendix B

Details of Study Results

B. Details for Study Results

B.1 Results

Table B.1 summarizes the 2021-2022 Capability Year IRM requirements under a range of assumption changes from those used for the base case. The base case utilized the computer simulation, reliability model, and assumptions described in Appendix A. The sensitivity cases determined the extent of how the base case required IRM would change for assumption modifications, either one at a time, or in combination. The methodology used to conduct the sensitivity cases was to start with the preliminary base case 20.1% IRM results then add or remove capacity from all zones in NYCA until the NYCA LOLE approached criterion. The values in Table B.1 on top of next page are the sensitivity results adjusted to the 20.7% final base case.

Table B.1 Sensitivity Case Results

Case	Description	IRM (%)	% Change from Base Case
0	**2021 Final Base Case**	20.7	-
	IRM Impacts of Key MARS Study Parameters		
1	**NYCA Isolated** (no emergency assistance)	27.6	6.9
2	**No Internal NYCA Transmission Constraints** (Free Flow System)	18.8	-1.9
3	**No Load Forecast Uncertainty**	11.6	-9.1
4	**Remove all wind generation**	15.8	-4.9
5	**No SCRs**	18.3	-2.4
	IRM Impacts of Base Case Assumption Changes		
6	**SCR Modeling method update – Energy and Duration Limitations [Tan 45]**	21.4	0.7
7	**Ignore energy limitations of Energy Limited Resources**	19.9	-0.8
	Informational Assessment		
8	**LI LCR Analysis (all three with Tan 45)**	**IRM impacts:** LI LFU (-0.2%), LI unit deactivations (-0.1%), LI cable outage rates (0%)	**LI LCR impacts:** LI LFU (-0.9%), LI unit deactivations (-0.4%), LI cable outage rates (-2.3%)

B.2 Impact of Environmental Regulations

Federal, state, and local government regulatory programs may impact the operation and reliability of New York's bulk power system. Compliance with state and federal regulatory initiatives and permitting requirements may require investment by the owners of New York's existing thermal power plants to continue in operation. If the owners of those plants must make significant investments to comply, the cost of these investments could impact their availability, and therefore new resources may be needed to maintain the reliability of the bulk power system. Other regulatory initiatives being undertaken by the State of New York may preclude certain units from continuing in operation in their current configuration. Prior studies have identified the amounts of capacity that may be negatively impacted by new and developing regulations. Most recently, New York has enacted the Climate Leadership and Community Protection Act (CLCPA) and the Accelerated Renewable Energy Growth and Community Benefit Act (AREGCBA) and promulgated various regulations collectively intended to limit Greenhouse Gas (GHG) emissions and support the development of new renewable energy, energy storage, and energy efficiency resources. This section reviews the status of various regulatory programs.

B.2.1 Combustion Turbine NOx Emission Limits

The New York State Department of Environmental Conservation (DEC) has finalized Part 227-3 which significantly lowers NOx emission limits for simple cycle gas turbines. The proposed rule will require compliance actions for units with approximately 3,300 MW of capacity (nameplate) located predominantly in southeastern New York and requires the owners of affected facilities to file compliance plans by March 2020. The rule will be applicable during the ozone season (May 1- September 30) and establishes lower emission limits in two phases, effective May 1, 2023 and May 1, 2025. The proposed rule also provides for emission averaging plans where the output of the affected facility can be averaged on a daily basis with the output of near-by storage resources or new renewable energy resources under common control. The NYISO used compliance plans submitted by generators under Part 227-3 to develop the assumed outage pattern of the impacted units in the 2020 RNA Base Case starting in May 2023. The plans indicate that approximately 1,100 MW and 1,800 MW of nameplate capacity are proposed to be unavailable during the summers of 2023 and 2025, respectively. The rule provides for the continued operation of facilities necessary for compliance with reliability standards for a period of up to two years with the possibility of another two-year period if permanent solutions have been identified but not completed.

B.2.2 U.S. Clean Water Act: Best Technology Available for Plant Cooling Water Intake

The U.S. Environmental Protection Agency (EPA) has issued a new Clear Water Act Section 316b rule providing standards for the design and operation of power plant cooling systems. This rule is being implemented by the DEC, which has finalized a policy for the implementation of the Best Technology Available (BTA) for plant cooling water intake structures. This policy is activated upon renewal of a plant's water withdrawal and discharge permit. Based upon a review of current information available from the DEC, the NYISO has estimated that 14,000 MW of nameplate capacity is affected by this rule, some of which could be required to undertake major system retrofits, including closed-cycle cooling systems.

Indian Point Energy Center had been involved in an extended renewal of its State Pollution Discharge Elimination System (SPDES) Permit. Entergy retired Unit #2 on April 30, 2020 and plans to retire Unit #3 on April 30, 2021.

Plant	Status as of June 2020
Arthur Kill	BTA in place, verification under review
Astoria	BTA in place, verification under review
Barrett	Permit drafting underway with equipment enhancements, SAPA extended
Bowline	BTA in place, 15% Capacity Factor, BTA Decision made, requested hearings
Brooklyn Navy Yard	BTA Decision pending
Cayuga	Retired
Danskammer	BTA in place
East River	BTA in place
Fitzpatrick	BTA studies being evaluated
Ginna	BTA studies being evaluated
Greenidge	BTA Decision made, installing upgrades, studies being evaluated
Indian Point	BTA in place, limit operations
Nine Mile Pt 1	BTA studies being evaluated
Northport	BTA in place, verification under review
Oswego	Leaning towards Capacity Factor limitation
Port Jefferson	BTA in place, 15% Capacity Factor, verification, SAPA extended
Ravenswood	BTA in place, verification under review
Roseton	BTA in place, studies being evaluated
Somerset	Retired
Wheelabrator Westchester	BTA in place, installing upgrades

B.2.3 Part 251: Carbon Dioxide Emissions Limits

The DEC promulgated a rule establishing an emission limit for CO_2 for existing fossil-fueled generating units. New York's coal-fired generation accounted for less than 1% of the total energy produced in the state in 2019. As of April 2020, all coal-fired generation facilities supplying the New York bulk power system deactivated. NYISO generator deactivation assessments found no reliability needs associated with these deactivations.

B.2.4 New York City Residual Oil Elimination

New York City passed legislation in December 2017 that will prohibit the combustion of fuel oil numbers 6 and 4 in electric generators within New York City by 2020 and 2025, respectively. The rule applies to about 3,000 MW of generation in New York City. Affected generators have filed compliance plans with NYC agencies to switch to compliant fuels. The affected generators are developing new fuel storage and handling equipment necessary to convert their facilities to comply with the law.

B.2.5 Regional Greenhouse Gas Initiative (RGGI)

RGGI is a multi-state carbon dioxide emissions cap-and-trade initiative that requires affected generators to procure emissions allowances authorizing them to emit carbon dioxide. Through a program review, the RGGI states agreed to several program changes, including a 30% cap reduction between 2020 and 2030, essentially ratcheting down the availability of allowances to generators that emit greenhouse gases. The DEC has proposed regulations incorporating these agreed upon program-wide changes and extending RGGI applicability in New York to certain generators of 15 MW (nameplate) or larger. The proposed emission allowance caps are not likely to trigger reliability concerns as the program design provides for mechanisms that consider reliability on various timescales, including multi-year compliance periods, allowance banking provisions, the Cost Containment Reserve, and periodic program reviews. New Jersey rejoined RGGI in 2020 since withdrawing from the program in 2011 and Virginia will begin RGGI participation in 2021. The Governor of Pennsylvania has issued an executive order directing the Pennsylvania Department of Environmental Protection to prepare draft rules for limiting CO_2 emissions from power plants with methods that would allow for the trading of allowances with RGGI.

B.2.6 Distributed Generator NOx Emission Limits

The DEC has adopted Part 222, a rule to limit the NOx emissions from small behind the meter generators that operate as an economic dispatch source in the New York City Metropolitan Area located at facilities with NOx emissions less than 25 tons of NOx per year and driven by reciprocating or rotary internal combustion engines. The proposed emission limits will become effective in two phases, May 1, 2021 and May 1, 2025. The facility must either obtain a registration or permit by March 15, 2021 and must notify the DEC whether the generator will operate as an economic dispatch source subject to the provisions of Part 222. The first emission limitations can be achieved by engines manufactured subsequent to 2000 and some subset of older engines.

B.2.7 Cross-State Air Pollution Rule (CSAPR)

The CSAPR limits emission of SO_2 and NO_X from fossil fuel fired EGUs >25 MW in 27 eastern states by establishing new caps and restricting allowance trading programs. Emissions above the statewide trading limit require additional penalty allowances. NYCA Ozone Season NO_X emissions are highly sensitive to the continued operation of the NYCA nuclear generation fleet. 2020 ozone season NO_X emissions were reportedly 3,561 tons across New York; 30% below the 5,135 ton ozone season budget. The CSAPR ozone season occurs May 1-September 30. The U.SEPA recently proposed a Revised CSAPR Update which proposes to reduce the ozone season NOx budget in 12 of the current CSAPR ozone season states between 2021 and 2024. The proposed budget for New York for 2021 is 3,137 tons dropping to 3,119 tons in 2024.

B.2.8 Climate Leadership and Community Protection Act (CLCPA)

The CLCPA requires, among other things, that 70% of electric energy be generated from renewable resources by 2030 and 100% of electric energy be provided by zero emission resources by 2040. The statute will require the displacement of New York's fossil-fueled generating fleet with renewable resources. During this transition, the NPCC and NYSRC resource adequacy rules will require the New York Control Area to maintain resource adequacy for the New York bulk electric system. In addition, the Greenhouse Gas ("GHG") emission reduction requirements will likely necessitate electrification of the building space and water heating and transportation sectors as an approach to reduce economy-wide emissions. The act builds upon programs and targets already established by the Clean Energy Standard (CES) and in other state policies. The combined set of requirements for new resources are outlined below.

Offshore Wind Development

The CLCPA requires 9,000 MW of offshore wind (OSW) capacity to be developed by 2035. Previously, the New York PSC issued an order directing that NYSERDA, with the involvement of the Long Island Power Authority (LIPA) and the New York Power Authority (NYPA) to procure OSW RECs (ORECs) from developers for up to 2,400 MW of offshore wind. NYSERDA has executed contracts with the winners of the inaugural 2018 OREC solicitation for an initial procurement of two OSW projects totaling nearly 1,700 MW. More recently the PSC gave NYSERDA approval to procure up to the 9,000 MW OSW target without seeking further Commission approval.

Comprehensive Energy Efficiency Initiative

The PSC has approved an order containing utility budgets and targets to accelerate energy efficiency deployment in New York State through 2025. A portion of the 185 TBtu all-fuels energy savings target will come from directed utility programs to expand access to and experience with heat pumps to replace/augment existing conventional heating sources, as well as from increased deployment of more conventional utility energy efficiency programs.

Storage Deployment Target

The CLCPA requires 3,000 MW of energy storage capacity to be developed by 2030. This goal builds on top of the goal to deploy 1,500 MW energy storage capacity by 2025 outlined in NYSERDA's Energy Storage Roadmap.

Distributed Solar Program

The CLCPA requires 6,000 MW of distributed solar capacity by 2025, which is an expansion of the existing 3,000 MW NY-Sun program. The PSC has been charged with developing the regulatory mechanisms to ensure that the incremental 3,000 MW distributed solar comes on line by 2025. Currently, NYSERDA administers the NY-Sun program.

The table below describes the timing and requirements of the major combined clean energy and efficiency policies in New York State.

Year	New York State Policy Mandate
2025	6,000 MW Distributed PV 185 TBtu Energy Efficiency of which 30,000 GWH is attributable to the electricity sector 1,500 MW Energy Storage Resources
2029	Expiration of the Zero Emission Credit Program
2030	3,000 MW Energy Storage Resources 2,400 Off Shore Wind Resources 70% of NY electricity from renewable resources 40% reduction in New York State's GHG emissions compared to 1990
2035	9,000 MW Off Shore Wind Resources
2040	Zero Emissions from the electric power sector
2050	85-100% reduction in New York State's GHG emissions compared to 1990

The PSC issued an Order on October 15 modifying the existing Clean Energy Standard to align with the requirements of the CLCPA. Specifically, the order increased the 2030 Renewable Energy Standard from 50% to 70% and modified the definition of eligible renewable energy resources to align with the CLCPA. This Order authorized the procurement schedules for Tier 1 and Offshore Wind resources needed to achieve the 2030 mandates. The Order also addressed treatment of pre-existing resources by defining criteria for Tier 2 resource solicitations and included a new Tier 4 specifically to recognize incremental renewable energy delivered into Zone J. Notably, controllable HVDC is defined as eligible for Tier 4 Renewable Energy Credits.

Also required by the CLCPA, the DEC has proposed a rule to create an updated GHG Inventory. The rule implements a new approach to accounting for climate impacts of emissions of various GHGs and setting numerical economy wide GHG limits defined in the CLCPA. The proposed inventory and methodology more highly weight the impact of methane emissions relative to the emissions of carbon dioxide among the inventoried GHGs. The 1990 inventory, methodology, and limits will be finalized as regulations during 2020. In addition, proposed natural gas fueled projects potentially face new challenges under the CLCPA, which requires state agencies to consider consistency with the statewide GHG emission limits when issuing permits.

The CLCPA creates a Climate Action Council (CAC) which is tasked with development and approval of a final scoping plan in 2022. The CAC holds meetings to organize the planning process and has convened several advisory panels focused on various sectors of the economy (such as power generation, transportation, and energy efficiency and housing) to perform more detailed evaluations. The work of the advisory panels will inform the CAC scoping plan contents.

To inform policymakers, the NYISO and its consultants completed two studies in 2020 examining the impact of the CLCPA targets on the future supply mix needed to match future expected hourly loads. Both the Brattle *Grid in Transition* and the Analysis Group *Climate Change Phase 2 Study* showed the long-term need for emissions-free dispatchable resources to operate during extended periods of reduced renewable resource output. These studies showed a need for resources with these characteristics even after including the impact of energy storage and load flexibility in the potential supply. The studies also imply increasing ramping demands placed on supply resources primarily to respond to the increased intermittent output of renewable generation.

B.2.9 Accelerated Renewable Energy Growth and Community Benefit Act (AREGCBA)

The AREGCBA was signed into law April 3, 2020 to assist in the achievement of the clean energy and environmental targets outlined in the CLCPA. The Act requires the PSC to establish new planning processes to enable the transmission and distribution expansion to support the CLCPA targets. On May 14, 2020, the PSC commenced a proceeding to implement the Act with respect to utility-based plans for upgrades to local transmission and distribution needed to support the mandates of the CLCPA. Utilities submitted preliminary upgrade proposals by August 1, 2020. On October 15, 2020, the PSC designated the Northern New York transmission projects as priority transmission projects to be carried out by NYPA. The DPS-led working group filed a report at the PSC on November 2, 2021. The report addresses local transmission system needs, proposals for planning transparency, accounting for CLCPA benefits in planning and investment criteria, and cost containment, cost allocation and cost recovery mechanisms for transmission projects. The DPS held a technical conference on the report and recommendations on November 23, 2020.

The AREGCBA also creates an Office of Renewable Energy Siting in the Department of State to speed the permitting timeline of large-scale renewable energy facilities. It also directs the PSC and NYSERDA to advance "Build Ready" projects that package sites and 20-year renewable energy credit contracts in competitive procurements with interested developers. On October 15, 2020, the PSC issued an order to authorize NYSERDA to begin procurement of Build Ready sites and projects as early as 2022.

B.3 Frequency of Implementing Emergency Operating Procedures

In addition to SCRs, the NYISO will implement several other types of EOPs, such as voltage reductions, as required, to avoid or minimize customer disconnections. Projected 2021 EOP capacity values are based on recent actual data and NYISO forecasts. For this year's IRM study, load and generator SCRs were combined into one step and the EDRP was eliminated. SCR calls were limited to 5 per month. Table B.2 below presents the expected EOP frequencies for the 2021 Capability Year assuming the 20.7% base case IRM with ELR modeling. Table B.3 presents SCR calls by months.

Table B.2 Implementation of EOP steps

Step	EOP	Expected Implementation (Days/Year)
1	Require SCRs (Load and Generator)	150.5
2	5% manual voltage reduction	123.5
3	30-minute reserve to zero	120.8
4	5% remote controlled voltage reduction	54.7
5	Voluntary load curtailment	49.3
6	Public appeals	49.1
7	Emergency purchases	49.1
8	10-minute reserve to zero	0.3
9	Customer disconnections	0.1

Note: The expected implementation days per year reported in each EOP step are the expected number of days that MARS calls for that EOP step. If a EOP step has a limitation on the number of days that it can provide load relief such as the 5 days per month limit for SCRs, it will provide no load relief after the 5th day.

Table B.3 SCR Calls Per Month

Month	Days/Month
JAN	13.6
FEB	21.2
MAR	11.4
APR	1.9
MAY	2.8
JUN	11.6
JUL	13.0
AUG	17.8
SEP	8.5
OCT	27.7
NOV	9.9

DEC	11.0

Appendix C

ICAP to UCAP Translations

C. ICAP to UCAP Translation

The NYISO administers the capacity requirements to all loads in the NYCA. In 2002, the NYISO adopted the Unforced Capacity (UCAP) methodology for determining system requirements, unit ratings and market settlements. The UCAP methodology uses individual generating unit data for output and availability to determine an expected level of resources that can be considered for system planning, operation and marketing purposes. EFORd is developed from this process for each generating unit and applied to the units Dependable Maximum Net Capability (DMNC) test value to determine the resulting level of UCAP.

Individual unit EFORd factors are taken in aggregate on both a Statewide and Locational basis and used to effectively "translate" the IRM and LCRs previously determined in the GE-MARS Analysis in terms of ICAP, into an equivalent UCAP basis.

Table C.1 summarizes historical values (since 2000) for NYCA capacity parameters including Base Case IRMs, approved IRMs, UCAP requirements, and NYISO Approved LCRs (for NYC, LI and G-J).

Table C.1 Historical NYCA Capacity Parameters

Capability Year (May - April)	Base Case IRM (%)	EC Approved IRM (%)	NYCA Equivalent UCAP Requirement (%)	NYISO Approved NYC LCR (%)	NYISO Approved LI LCR (%)	NYISO Approved G-J LCR (%)
2000	15.5	18.0		80.0	107.0	
2001	17.1	18.0		80.0	98.0	
2002	18.0	18.0		80.0	93.0	
2003	17.5	18.0		80.0	95.0	
2004	17.1	18.0	11.90	80.0	99.0	
2005	17.6	18.0	12.00	80.0	99.0	
2006	18.0	18.0	11.59	80.0	99.0	
2007	16.0	16.5	11.30	80.0	99.0	
2008	15.0	15.0	8.35	80.0	94.0	
2009	16.2	16.5	7.17	80.0	97.5	
2010	17.9	18.0	6.12	80.0	104.5	
2011	15.5	15.5	6.03	81.0	101.5	
2012	16.1	16.0	5.35	83.0	99.0	
2013	17.1	17.0	6.58	86.0	105.0	
2014	17.0	17.0	6.38	85.0	107.0	88.0
2015	17.3	17.0	7.01	83.5	103.5	90.5
2016	17.4	17.5	6.21	80.5	102.5	90.0
2017	18.1	18.0	7.04	81.5	103.5	91.5
2018	18.2	18.2	8.08	80.5	103.5	94.5
2019	16.8	17.0	6.72	82.8	104.1	92.3
2020	18.9	18.9	9.03	86.6	103.4	90.0

C.1 NYCA and NYC and LI Locational Translations

In the "Installed Capacity" section of the NYISO Web site3, NYISO Staff regularly post summer and winter Capability Period ICAP and UCAP calculations for NYCA Locational Areas and Transmission District Loads. This information has been compiled and posted since 2006.

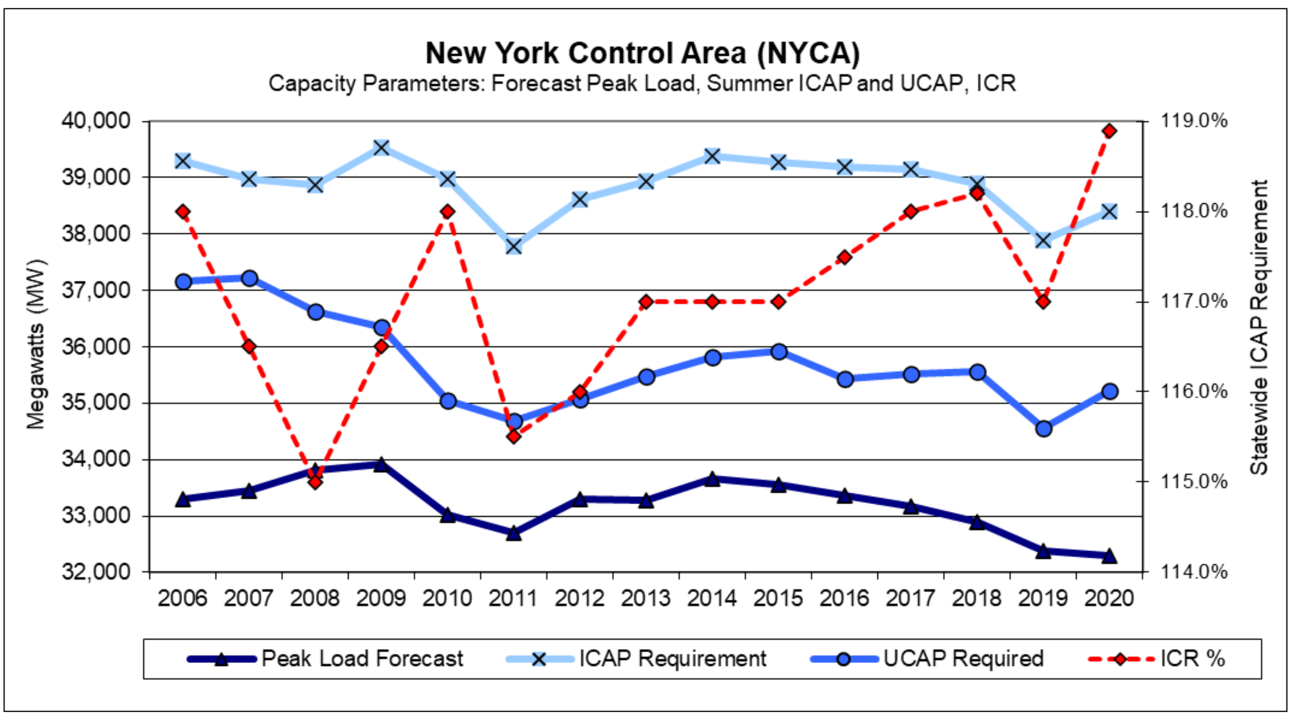
Locational ICAP/UCAP calculations are produced for NYC, LI, G-J Locality and the entire NYCA. Exhibits C.1.1 through C.1.4 summarizes the translation of ICAP requirements to UCAP requirements for these areas. The charts and tables included in these exhibits utilize data from the summer capability periods beginning in 2006.

This data reflects the interaction and relationships between the capacity parameters used this study, including Forecast Peak Load, ICAP Requirements, De-rating Factors, UCAP Requirements, IRMs, and LCRs. Since these parameters are so inextricably linked to each other, the graphical representation also helps one more easily visualize the annual changes in capacity requirements.

C.1.1 New York Control Area ICAP to UCAP Translation

Table C.2 NYCA ICAP to UCAP Translation

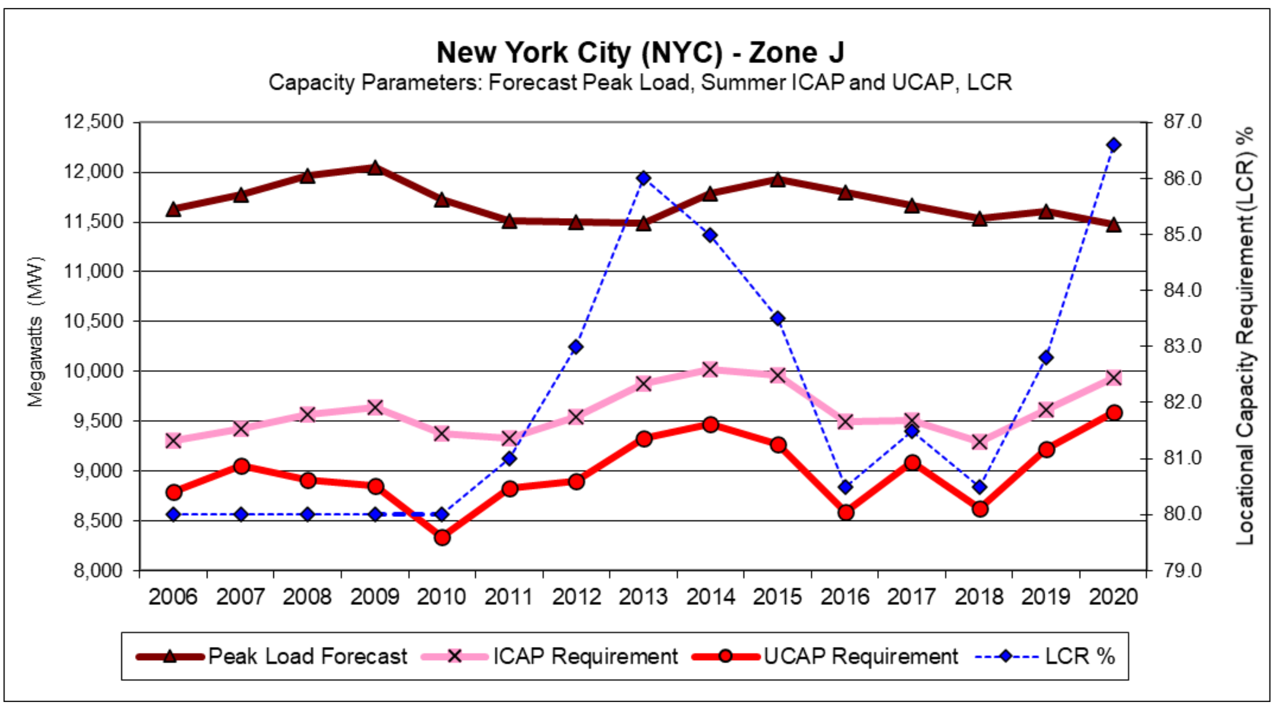
Year	Forecast Peak Load (MW)	Installed Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	33,295	118.0	0.0543	39,288	37,154	111.6
2007	33,447	116.5	0.0446	38,966	37,228	111.3
2008	33,809	115.0	0.0578	38,880	36,633	108.4
2009	33,930	116.5	0.0801	39,529	36,362	107.2
2010	33,025	118.0	0.1007	38,970	35,045	106.1
2011	32,712	115.5	0.0820	37,783	34,684	106.0
2012	33,295	116.0	0.0918	38,622	35,076	105.4
2013	33,279	117.0	0.0891	38,936	35,467	106.6
2014	33,666	117.0	0.0908	39,389	35,812	106.4
2015	33,567	117.0	0.0854	39,274	35,920	107.0
2016	33,359	117.5	0.0961	39,197	35,430	106.2
2017	33,178	118.0	0.0929	39,150	35,513	107.0
2018	32,903	118.2	0.0856	38,891	35,562	108.1
2019	32,383	117.0	0.0879	37,888	34,558	106.7
2020	32,296	118.9	0.0830	38,400	35,213	109.3



C.1.2 New York City ICAP to UCAP Translation

Table C.3 New York City ICAP to UCAP Translation

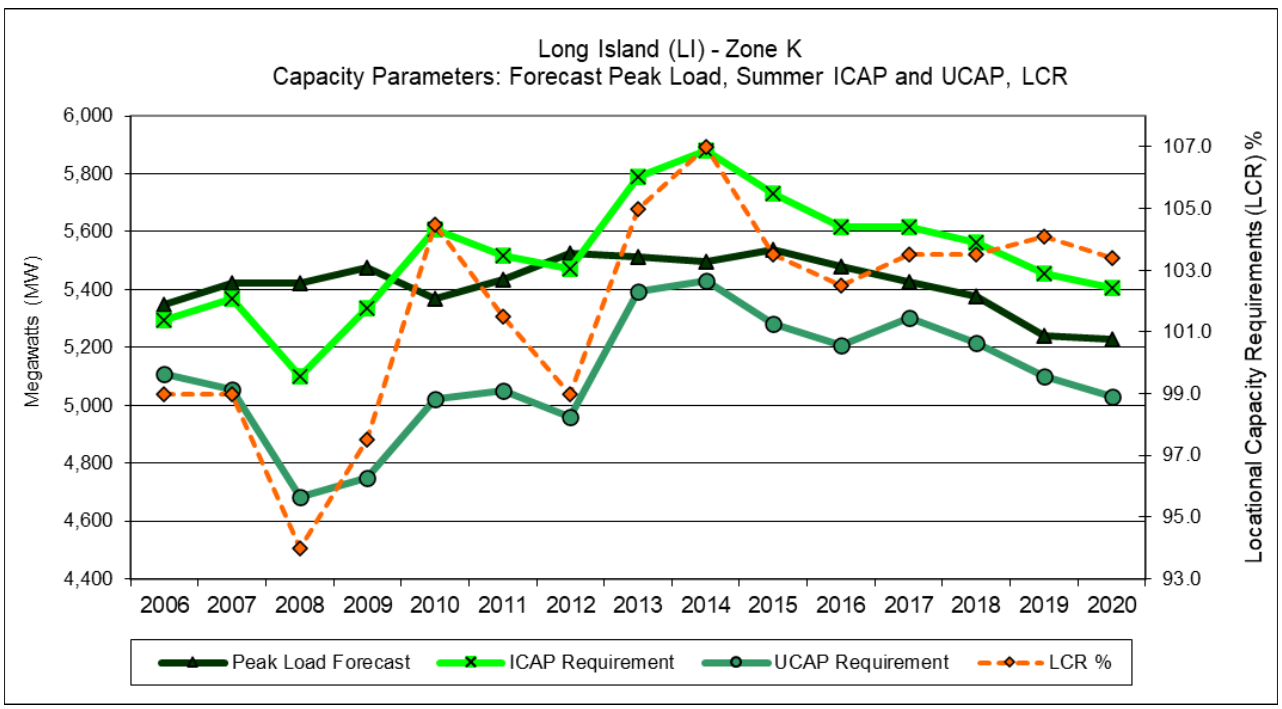
Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	11,628	80.0	0.0542	9,302	8,798	75.7
2007	11,780	80.0	0.0388	9,424	9,058	76.9
2008	11,964	80.0	0.0690	9,571	8,911	74.5
2009	12,050	80.0	0.0814	9,640	8,855	73.5
2010	11,725	80.0	0.1113	9,380	8,336	71.1
2011	11,514	81.0	0.0530	9,326	8,832	76.7
2012	11,500	83.0	0.0679	9,545	8,897	77.4
2013	11,485	86.0	0.0559	9,877	9,325	81.2
2014	11,783	85.0	0.0544	10,015	9,471	80.4
2015	11,929	83.5	0.0692	9,961	9,272	77.7
2016	11,794	80.5	0.0953	9,494	8,589	72.8
2017	11,670	81.5	0.0437	9,511	9,095	77.9
2018	11,539	80.5	0.0709	9,289	8,630	74.8
2019	11,607	82.8	0.0409	9,611	9,217	79.4
2020	11,477	86.6	0.0351	9,939	9,590	83.6



C.1.3 Long Island ICAP to UCAP Translation

Table C.4 Long Island ICAP to UCAP Translation

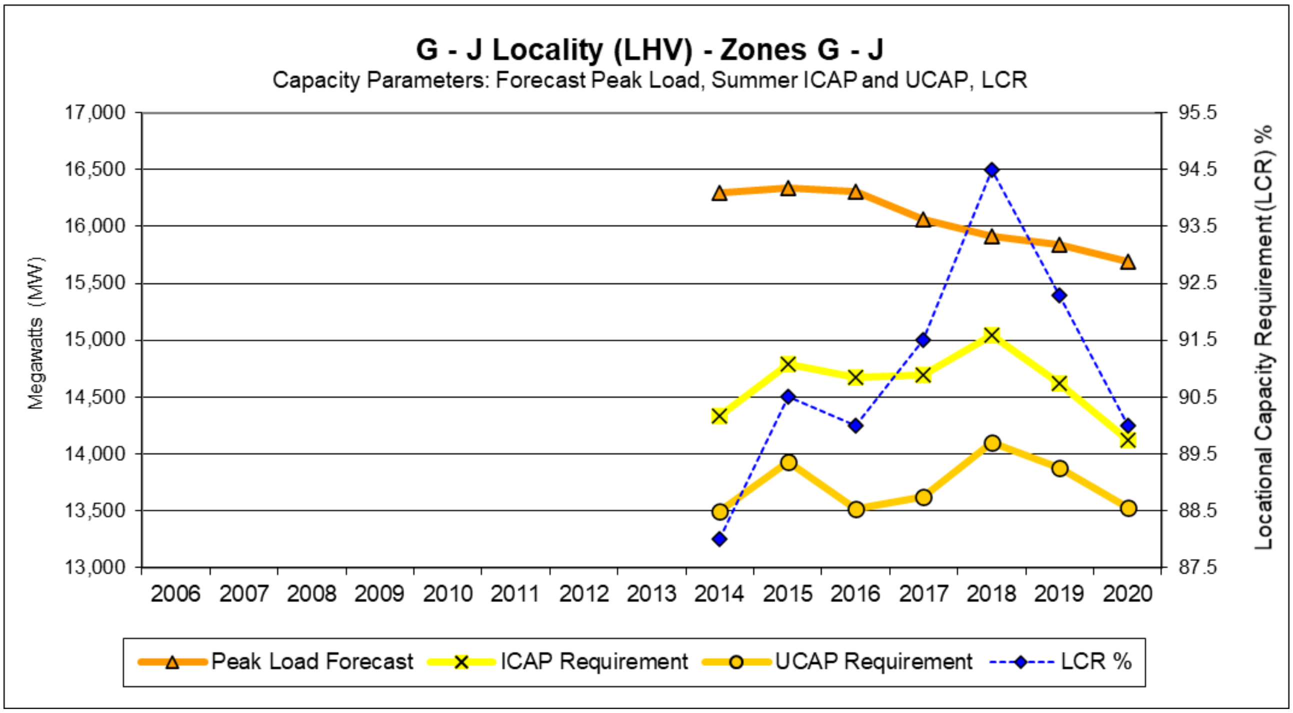
Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	5,348	99.0	0.0348	5,295	5,110	95.6
2007	5,422	99.0	0.0580	5,368	5,056	93.3
2008	5,424	94.0	0.0811	5,098	4,685	86.4
2009	5,474	97.5	0.1103	5,337	4,749	86.8
2010	5,368	104.5	0.1049	5,610	5,021	93.5
2011	5,434	101.5	0.0841	5,516	5,052	93.0
2012	5,526	99.0	0.0931	5,470	4,961	89.8
2013	5,515	105.0	0.0684	5,790	5,394	97.8
2014	5,496	107.0	0.0765	5,880	5,431	98.8
2015	5,539	103.5	0.0783	5,733	5,284	95.4
2016	5,479	102.5	0.0727	5,615	5,207	95.0
2017	5,427	103.5	0.0560	5,617	5,302	97.7
2018	5,376	103.5	0.0628	5,564	5,214	97.0
2019	5,240	104.1	0.0647	5,455	5,102	97.4
2020	5,228	103.4	0.0691	5,405	5,032	96.3



C.1.4 GHIJ ICAP to UCAP Translation

Table C.5 GHIJ ICAP to UCAP Translation

Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2014	16,291	88.0	0.0587	14,336	13,495	82.8
2015	16,340	90.5	0.0577	14,788	13,934	85.3
2016	16,309	90.0	0.0793	14,678	13,514	82.9
2017	16,061	91.5	0.0731	14,696	13,622	84.8
2018	15,918	94.5	0.0626	15,042	14,100	88.6
2019	15,846	92.3	0.0514	14,625	13,874	87.6
2020	15,695	90.0	0.0418	14,124	13,534	86.2

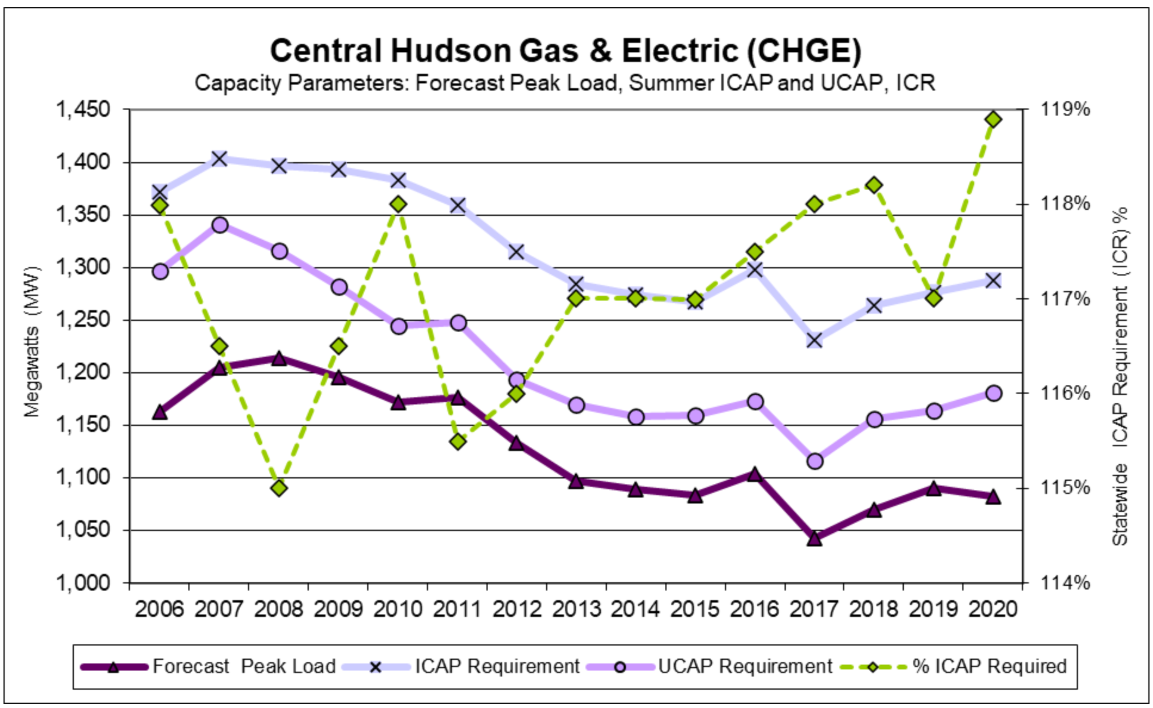


C.2 Transmission Districts ICAP to UCAP Translation

C.2.1 Central Hudson Gas & Electric

Table C.6 Central Hudson Gas & Electric ICAP to UCAP Translation

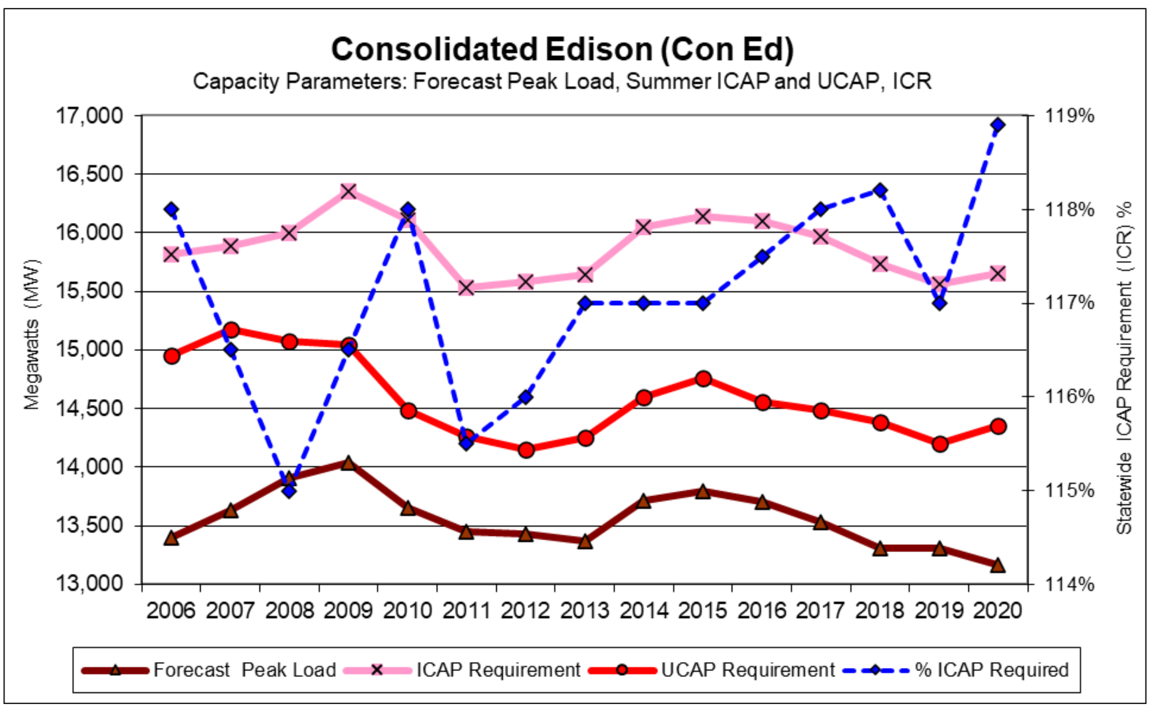
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	1,162.5	1,371.7	1,297.3	118.0%	111.6%
2007	1,205.0	1,403.8	1,341.2	116.5%	111.3%
2008	1,214.1	1,396.2	1,315.5	115.0%	108.4%
2009	1,196.3	1,393.7	1,282.1	116.5%	107.2%
2010	1,172.3	1,383.3	1,244.0	118.0%	106.1%
2011	1,176.9	1,359.3	1,247.9	115.5%	106.0%
2012	1,133.3	1,314.6	1,193.9	116.0%	105.3%
2013	1,097.5	1,284.1	1,169.7	117.0%	106.6%
2014	1,089.2	1,274.4	1,158.7	117.0%	106.4%
2015	1,083.6	1,267.8	1,159.5	117.0%	107.0%
2016	1,104.2	1,297.4	1,172.7	117.5%	106.2%
2017	1,043.1	1,230.9	1,116.5	118.0%	107.0%
2018	1,069.7	1,264.4	1,156.2	118.2%	108.1%
2019	1,090.8	1,276.3	1,164.1	117.0%	106.7%
2020	1,082.7	1,287.3	1,180.5	118.9%	109.0%



C.2.2 Consolidated Edison (Con Ed)

Table C.7 Con Ed ICAP to UCAP Translation

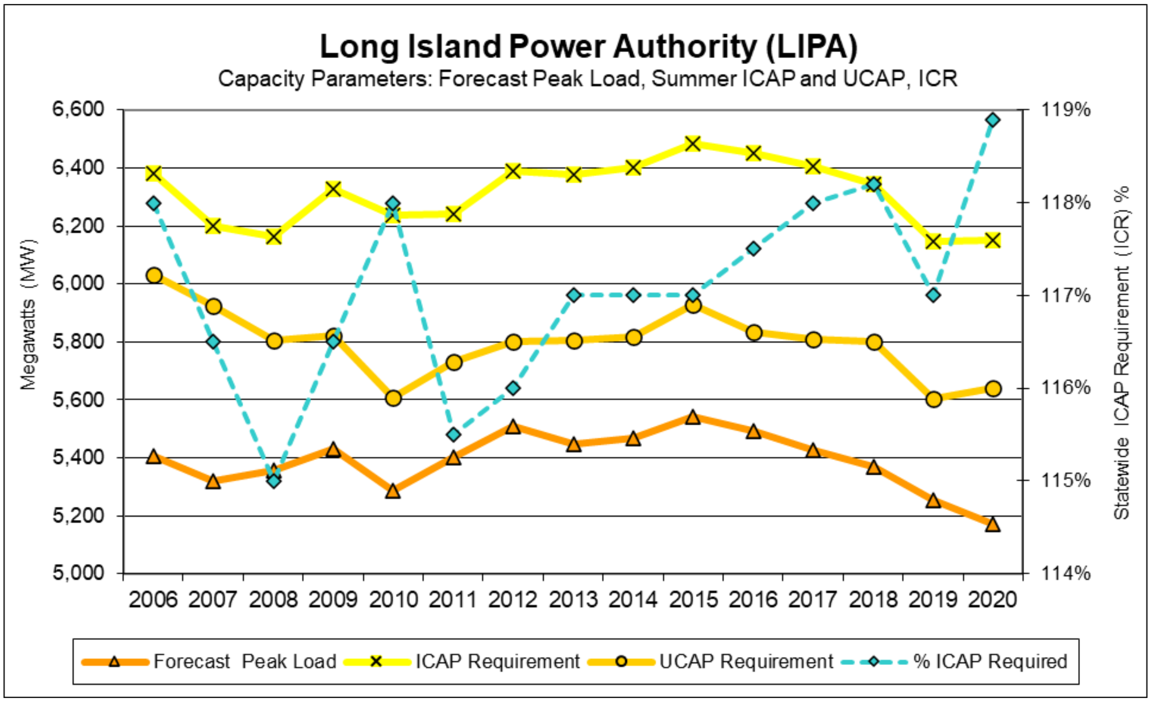
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	13,400.0	15,812.0	14,953.4	118.0%	111.6%
2007	13,633.6	15,883.1	15,174.7	116.5%	111.3%
2008	13,911.1	15,997.8	15,073.1	115.0%	108.4%
2009	14,043.0	16,360.1	15,049.6	116.5%	107.2%
2010	13,654.9	16,112.8	14,490.2	118.0%	106.1%
2011	13,450.5	15,535.3	14,261.4	115.5%	106.0%
2012	13,430.5	15,579.4	14,149.2	116.0%	105.4%
2013	13,370.8	15,643.8	14,250.0	117.0%	106.6%
2014	13,718.7	16,050.9	14,593.5	117.0%	106.4%
2015	13,793.0	16,137.8	14,759.6	117.0%	107.0%
2016	13,704.6	16,102.9	14,555.4	117.5%	106.2%
2017	13,534.0	15,970.1	14,486.5	118.0%	107.0%
2018	13,309.6	15,732.0	14,385.3	118.2%	108.1%
2019	13,305.5	15,567.4	14,199.1	117.0%	106.7%
2020	13,170.0	15,659.1	14,359.4	118.9%	109.0%



C.2.3 Long Island Power Authority (LIPA)

Table C.8 LIPA ICAP to UCAP Translation

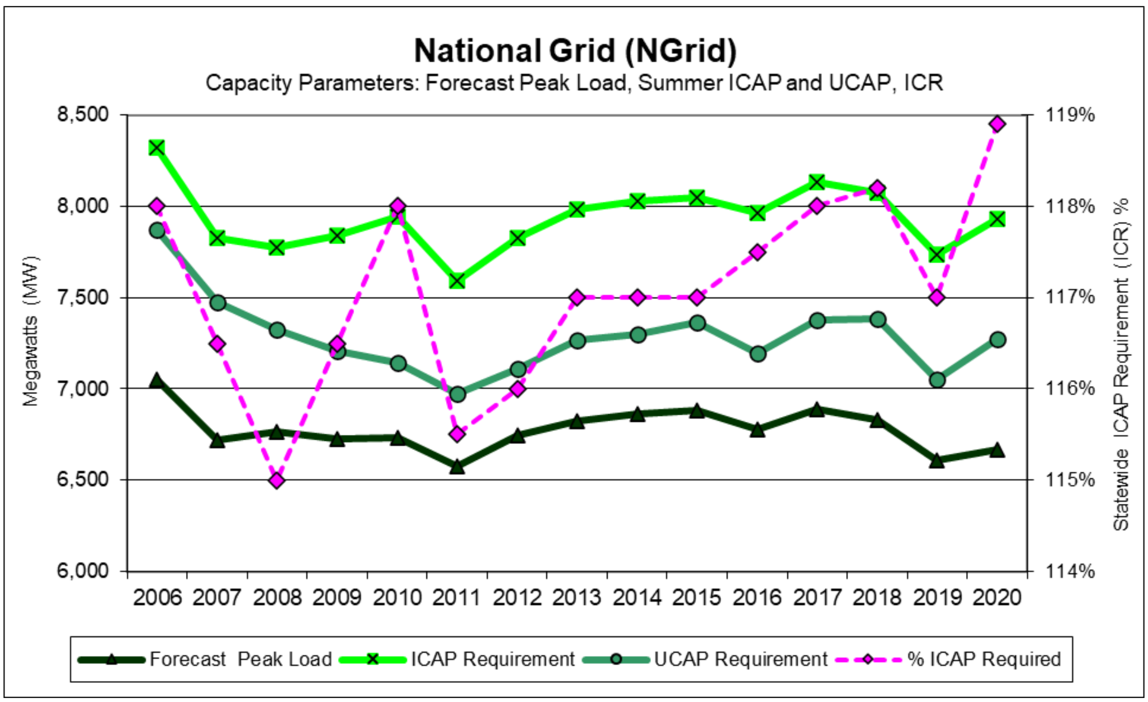
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	5,406.2	6,379.3	6,032.9	118.0%	111.6%
2007	5,321.8	6,199.9	5,923.4	116.5%	111.3%
2008	5,358.9	6,162.7	5,806.5	115.0%	108.4%
2009	5,431.7	6,327.9	5,821.1	116.5%	107.2%
2010	5,286.0	6,237.5	5,609.4	118.0%	106.1%
2011	5,404.3	6,242.0	5,730.1	115.5%	106.0%
2012	5,508.3	6,389.6	5,803.1	116.0%	105.4%
2013	5,448.9	6,375.2	5,807.2	117.0%	106.6%
2014	5,470.1	6,400.0	5,818.9	117.0%	106.4%
2015	5,541.3	6,483.3	5,929.7	117.0%	107.0%
2016	5,491.3	6,452.3	5,832.2	117.5%	106.2%
2017	5,427.2	6,404.1	5,809.1	118.0%	107.0%
2018	5,368.1	6,345.1	5,802.0	118.2%	108.1%
2019	5,253.0	6,146.0	5,605.8	117.0%	106.7%
2020	5,172.9	6,150.6	5,640.1	118.9%	109.0%



C.2.4 National Grid (NGRID)

Table C.9 NGRID ICAP to UCAP Translation

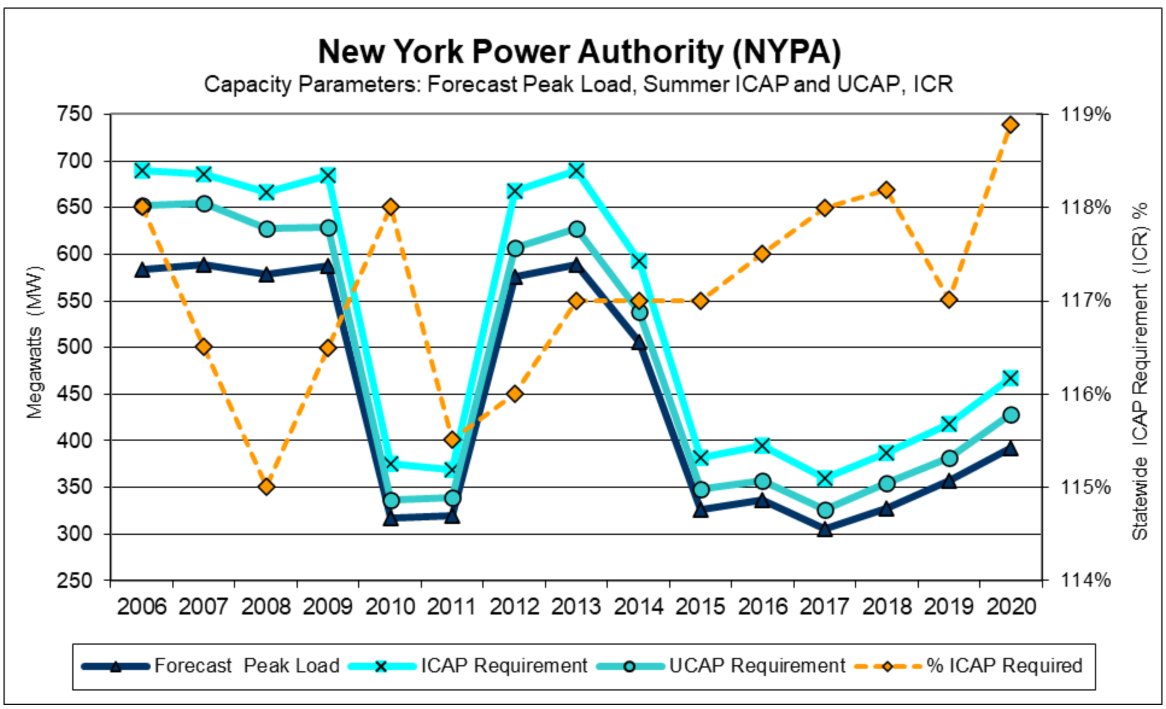
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	7,051.6	8,320.9	7,869.1	118.0%	111.6%
2007	6,718.6	7,827.2	7,478.1	116.5%	111.3%
2008	6,762.5	7,776.9	7,327.3	115.0%	108.4%
2009	6,728.4	7,838.6	7,210.7	116.5%	107.2%
2010	6,732.1	7,943.9	7,144.0	118.0%	106.1%
2011	6,574.7	7,593.8	6,971.1	115.5%	106.0%
2012	6,749.1	7,828.9	7,110.3	116.0%	105.4%
2013	6,821.3	7,980.9	7,269.8	117.0%	106.6%
2014	6,861.9	8,028.4	7,299.4	117.0%	106.4%
2015	6,880.3	8,049.9	7,362.5	117.0%	107.0%
2016	6,776.0	7,961.8	7,196.7	117.5%	106.2%
2017	6,891.4	8,131.9	7,376.4	118.0%	107.0%
2018	6,833.0	8,076.6	7,385.2	118.2%	108.1%
2019	6,608.8	7,732.3	7,052.6	117.0%	106.7%
2020	6,670.2	7,930.9	7,272.6	118.9%	109.0%



C.2.5 New York Power Authority (NYPA)

Table C.10 NYPA ICAP to UCAP Translation

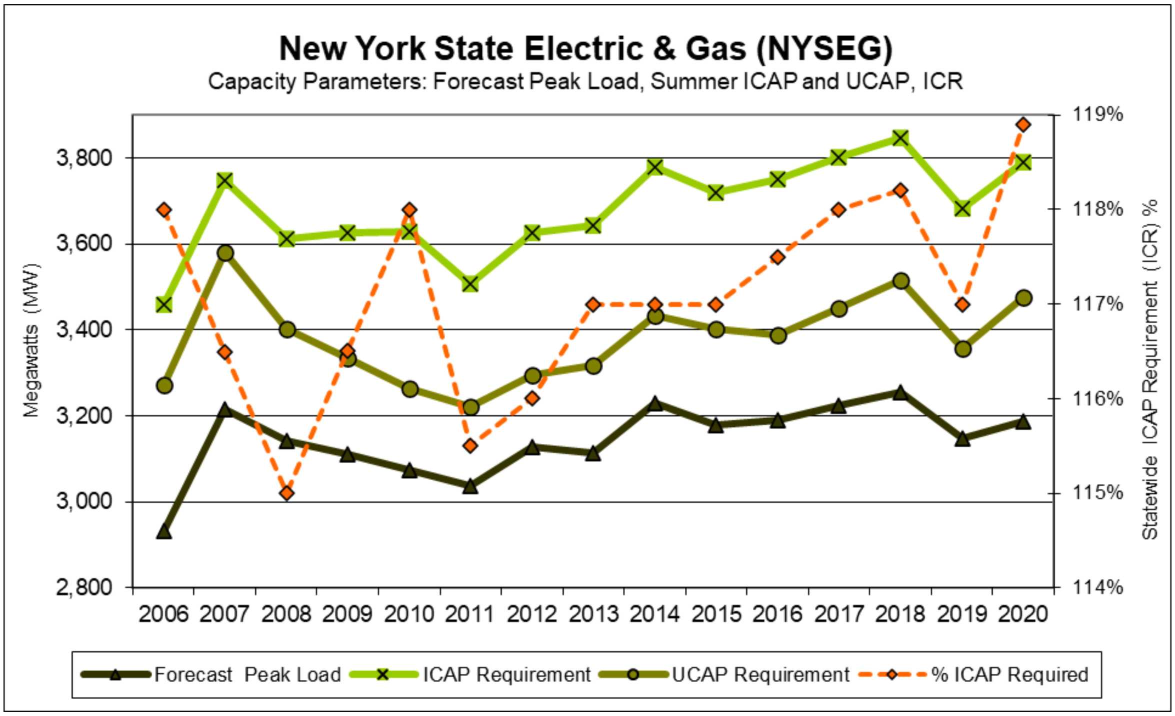
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	584.2	689.4	651.9	118.0%	111.6%
2007	588.2	685.3	654.7	116.5%	111.3%
2008	579.1	666.0	627.5	115.0%	108.4%
2009	587.2	684.1	629.3	116.5%	107.2%
2010	317.6	374.8	337.0	118.0%	106.1%
2011	319.7	369.3	339.0	115.5%	106.0%
2012	576.1	668.3	606.9	116.0%	105.3%
2013	589.3	689.5	628.1	117.0%	106.6%
2014	506.3	592.4	538.6	117.0%	106.4%
2015	325.8	381.2	348.6	117.0%	107.0%
2016	336.0	394.8	356.9	117.5%	106.2%
2017	305.0	359.9	326.5	118.0%	107.0%
2018	327.6	387.2	354.1	118.2%	108.1%
2019	357.5	418.3	381.5	117.0%	106.7%
2020	392.7	466.9	428.2	118.9%	109.0%



C.2.6 New York State Electric & Gas (NYSEG)

Table C.11 NYSEG ICAP to UCAP Translation

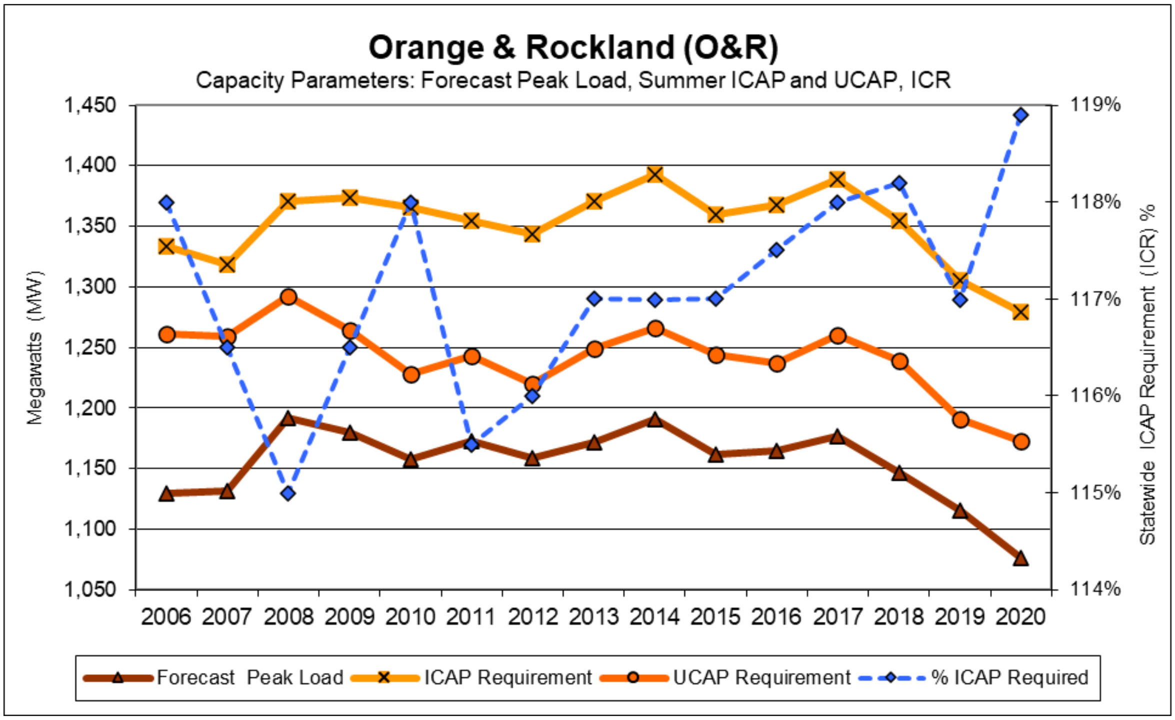
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	2,931.5	3,459.2	3,271.3	118.0%	111.6%
2007	3,216.9	3,747.7	3,580.5	116.5%	111.3%
2008	3,141.1	3,612.3	3,403.5	115.0%	108.4%
2009	3,111.8	3,625.3	3,334.9	116.5%	107.2%
2010	3,075.0	3,628.5	3,263.1	118.0%	106.1%
2011	3,037.0	3,507.7	3,220.1	115.5%	106.0%
2012	3,126.7	3,627.0	3,294.0	116.0%	105.4%
2013	3,113.4	3,642.7	3,318.1	117.0%	106.6%
2014	3,229.1	3,778.1	3,435.0	117.0%	106.4%
2015	3,179.8	3,720.4	3,402.7	117.0%	107.0%
2016	3,191.6	3,750.1	3,389.7	117.5%	106.2%
2017	3,222.9	3,803.0	3,449.7	118.0%	107.0%
2018	3,254.0	3,846.2	3,517.0	118.2%	108.1%
2019	3,146.6	3,681.5	3,357.9	117.0%	106.7%
2020	3,188.4	3,791.0	3,476.3	118.9%	109.0%



C.2.7 Orange & Rockland (O & R)

Table C.12 O & R ICAP to UCAP Translation

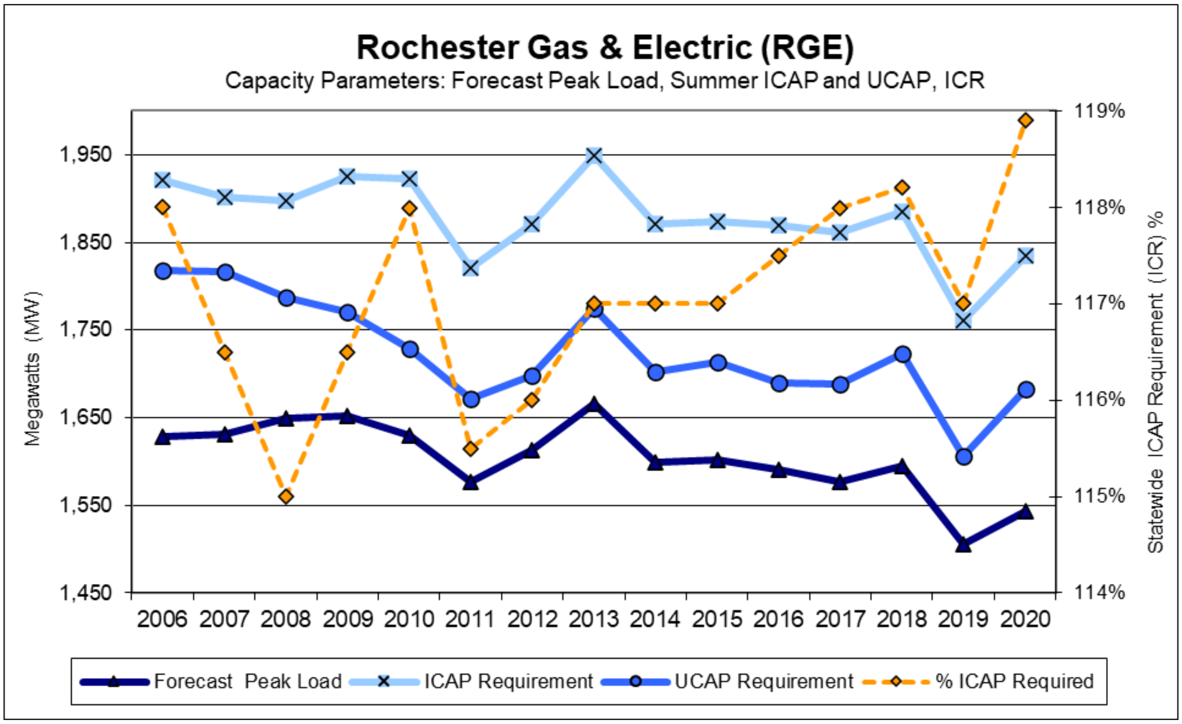
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	1,130.0	1,333.4	1,261.0	118.0%	111.6%
2007	1,131.5	1,318.2	1,259.4	116.5%	111.3%
2008	1,192.3	1,371.1	1,291.9	115.0%	108.4%
2009	1,179.5	1,374.1	1,264.0	116.5%	107.2%
2010	1,157.4	1,365.7	1,228.2	118.0%	106.1%
2011	1,172.7	1,354.5	1,243.4	115.5%	106.0%
2012	1,158.3	1,343.6	1,220.3	116.0%	105.4%
2013	1,171.7	1,370.9	1,248.7	117.0%	106.6%
2014	1,190.8	1,393.2	1,266.7	117.0%	106.4%
2015	1,162.2	1,359.8	1,243.7	117.0%	107.0%
2016	1,164.3	1,368.1	1,236.6	117.5%	106.2%
2017	1,177.3	1,389.2	1,260.2	118.0%	107.0%
2018	1,146.2	1,354.8	1,238.8	118.2%	108.1%
2019	1,115.5	1,305.1	1,190.4	117.0%	106.7%
2020	1,075.9	1,279.3	1,173.1	118.9%	109.0%



C.2.8 Rochester Gas & Electric (RGE)

Table C.13 RGE ICAP to UCAP Translation

Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	1,628.5	1,921.6	1,817.3	118.0%	111.6%
2007	1,631.8	1,901.0	1,816.3	116.5%	111.3%
2008	1,649.4	1,896.8	1,787.2	115.0%	108.4%
2009	1,652.3	1,924.9	1,770.7	116.5%	107.2%
2010	1,629.7	1,923.0	1,729.4	118.0%	106.1%
2011	1,576.4	1,820.7	1,671.4	115.5%	106.0%
2012	1,612.3	1,870.3	1,698.6	116.0%	105.4%
2013	1,665.7	1,948.9	1,775.2	117.0%	106.6%
2014	1,599.6	1,871.5	1,701.6	117.0%	106.4%
2015	1,601.3	1,873.5	1,713.5	117.0%	107.0%
2016	1,590.8	1,869.2	1,689.6	117.5%	106.2%
2017	1,576.9	1,860.7	1,687.9	118.0%	107.0%
2018	1,594.3	1,884.5	1,723.1	118.2%	108.1%
2019	1,505.5	1,761.4	1,606.6	117.0%	106.7%
2020	1,543.3	1,835.0	1,682.7	118.9%	109.0%



C.3 Wind Resource Impact on the NYCA IRM and UCAP Markets

Wind generation is generally classified as an “intermittent" or "variable generation" resource with a limited ability to be dispatched. The effective capacity of wind generation can be quantified and modeled using the GE-MARS program like conventional fossil-fired power plants. There are various modeling techniques to model wind generation in GE-MARS; the method that ICS has adopted uses historical New York hourly wind farm generation outputs for the previous five calendar years. This data can be scaled to create wind profiles for new wind generation facilities.

For a wind farm or turbine, the nameplate capacity is the ICAP while the effective capacity is equal to the UCAP value. Seasonal variability and geographic location are factors that also affect wind resource availability. The effective capacity of wind generation can be either calculated statistically directly from historical hourly wind generation outputs, and/or by using the following information:

- Production hourly wind data.
- Maintenance cycle and duration
- EFOR (not related to fuel)

In general, effective wind capacity depends primarily on the availability of the wind. Wind farms in New York on average have annual capacity factors that are based on their nameplate ratings. A wind plant’s output can range from close to nameplate under favorable wind conditions to zero when the wind does not blow. On average, a wind plant’s output is higher at night, and has higher output on average in the winter versus the summer.

Another measure of a wind generator’s contribution to resource adequacy is its effective capacity which is its expected output during the summer peak hours of 2 p.m. to 6 p.m. for the months of June through August. The effective capacity value for wind generation in New York is based on actual hourly plant output over the previous five-year period – 2015 through 2019 for this year’s study, for new units the zonal hourly averages or averages for nearby units will be used. Wind shapes years are selected randomly from those years for each simulation year.

Appendix D

Glossary of Terms

D. Glossary

Term	Definition
Availability	A measure of time a generating unit, transmission line, or other facility can provide service, whether or not it actually is in service. Typically, this measure is expressed as a percent available for the period under consideration.
Bubble	A symbolic representation introduced for certain purposes in the GE-MARS model as an area that may be an actual zone, multiple areas or a virtual area without actual load.
Capability Period	Six (6) month periods which are established as follows: (1) from May 1 through October 31 of each year ("Summer Capability Period"); and (2) from November 1 of each year through April 30 of the following year ("Winter Capability Period"); or such other periods as may be determined by the Operating Committee of the NYISO. A summer capability period followed by a winter capability period shall be referred to as a "Capability Year." Each capability period shall consist of on-peak and off-peak periods.
Capacity	The rated continuous load-carrying ability, expressed in megawatts ("MW") or megavolt-amperes ("MVA") of generation, transmission or other electrical equipment.
Contingency	An actual or potential unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages.
Control Area (CA)	An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.
Demand	The rate at which energy must be generated or otherwise provided to supply an electric power system.
Emergency	Any abnormal system condition that requires automatic or immediate, manual action to prevent or limit loss of transmission facilities or generation resources that could adversely affect the reliability of an electric system.
Energy Limited Resource (ELR)	Capacity resources, not including BTM:NG Resources, that, due to environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or other non-economic reasons, are unable to operate continuously on a daily basis, but are able to operate for at least four consecutive hours each day.
External Installed Capacity (External ICAP)	Installed capacity from resources located in control areas outside the NYCA that must meet certain NYISO requirements and criteria in order to qualify to supply New York LSEs.
Firm Load	The load of a Market Participant that is not contractually interruptible. Interruptible Load – The load of a Market Participant that is contractually interruptible.
Generation	The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt-hours (kWh) or megawatt-hours (MWh).

Term	Definition
Installed Capacity (ICAP)	Capacity of a facility accessible to the NYS Bulk Power System, that is capable of supplying and/or reducing the demand for energy in the NYCA for the purpose of ensuring that sufficient energy and capacity is available to meet the reliability rules.
Installed Capacity Requirement (ICR)	The annual statewide requirement established by the NYSRC in order to ensure resource adequacy in the NYCA.
Installed Reserve Margin (IRM)	That capacity above firm system demand required to provide for equipment forced and scheduled outages and transmission capability limitations.
Interface	The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.
Load	The electric power used by devices connected to an electrical generating system. (IEEE Power Engineering)
Load Relief	Load reduction accomplished by voltage reduction or load shedding or both. Voltage reduction and load shedding, as defined in this document, are measures by order of the NYISO.
Load Shedding	The process of disconnecting (either manually or automatically) pre-selected customers' load from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages. Load shedding is a measure undertaken by order of the NYISO. If ordered to shed load, transmission owner system dispatchers shall immediately comply with that order. Load shall normally all be shed within 5 minutes of the order.
Load Serving Entity (LSE)	In a wholesale competitive market, Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Power Authority ("LIPA"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange & Rockland Utilities, Inc., and Rochester Gas and Electric Corporation, the current forty-six (46) members of the Municipal Electric Utilities Association of New York State, the City of Jamestown, Rural Electric Cooperatives, the New York Power Authority ("NYPA"), any of their successors, or any entity through regulatory requirement, tariff, or contractual obligation that is responsible for supplying energy, capacity and/or ancillary services to retail customers within New York State.
Locational Capacity Requirement (LCR)	Due to transmission constraints, that portion of the NYCA ICAP requirement that must be electrically located within a zone, in order to ensure that sufficient energy and capacity are available in that zone and that NYSRC Reliability Rules are met. Locational ICAP requirements are currently applicable to three transmission constrained zones, New York City, Long Island, and the Lower Hudson Valley, and are normally expressed as a percentage of each zone's annual peak load.
New York Control Area (NYCA)	The control area located within New York State which is under the control of the NYISO. See Control Area.

Term	Definition
New York Independent System Operator (NYISO)	The NYISO is a not-for-profit organization formed in 1998 as part of the restructuring of New York State's electric power industry. Its mission is to ensure the reliable, safe and efficient operation of the State's major transmission system and to administer an open, competitive and nondiscriminatory wholesale market for electricity in New York State.
New York State Bulk Power System (NYS Bulk Power System or BPS)	The portion of the bulk power system within the New York Control Area, generally comprising generating units 300 MW and larger, and generally comprising transmission facilities 230 kV and above. However, smaller generating units and lower voltage transmission facilities on which faults and disturbances can have a significant adverse impact outside of the local area are also part of the NYS Bulk Power System.
New York State Reliability Council, LLC (NYSRC)	An organization established by agreement (the "NYSRC Agreement") by and among Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., LIPA, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange & Rockland Utilities, Inc., Rochester Gas and Electric Corporation, and the New York Power Authority, to promote and maintain the reliability of the Bulk Power System, and which provides for participation by Representatives of Transmission Owners, sellers in the wholesale electric market, large commercial and industrial consumers of electricity in the NYCA, and municipal systems or cooperatively-owned systems in the NYCA, and by unaffiliated individuals.
New York State (NYS) Transmission System	The entire New York State electric transmission system, which includes: (1) the transmission facilities under NYISO operational control; (2) the transmission facilities requiring NYISO notification, and; (3) all remaining facilities within the NYCA.
Operating Limit	The maximum value of the most critical system operation parameter(s) which meet(s): (a) pre-contingency criteria as determined by equipment loading capability and acceptable voltage conditions; (b) stability criteria; (c) post-contingency loading and voltage criteria.
Operating Procedures	A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.
Operating Reserves	Resource capacity that is available to supply energy, or curtailable load that is willing to stop using energy, in the event of emergency conditions or increased system load, and can do so within a specified time period.
Reserves	In normal usage, reserve is the amount of capacity available in excess of the demand.
Resource	The total contributions provided by supply-side and demand-side facilities and/or actions.
Stability	The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.
Thermal Limit	The maximum power flow through a particular transmission element or interface, considering the application of thermal assessment criteria.
Transfer Capability	The measure of the ability of interconnected electrical systems to reliably move or transfer power from one area to another over all transmission lines (or paths) between those areas under specified system conditions.

Term	Definition
Transmission District	The geographic area served by the NYCA investor-owned transmission owners and LIPA, as well as customers directly interconnected with the transmission facilities of NYPA.
Transmission Owner	Those parties who own, control and operate facilities in New York State used for the transmission of electric energy in interstate commerce. Transmission owners are those who own, individually or jointly, at least 100 circuit miles of 115 kV or above in New York State and have become a signatory to the TO/NYISO Agreement.
Unforced Capacity:	The measure by which Installed Capacity Suppliers will be rated, in accordance with formulae set forth in the ISO Procedures, to quantify the extent of their contribution to satisfy the NYCA Installed Capacity Requirement, and which will be used to measure the portion of that NYCA Installed Capacity Requirement for which each LSE is responsible.
Voltage Limit	The maximum power flow through some particular point in the system considering the application of voltage assessment criteria.
Voltage Reduction	A means of achieving load reduction by reducing customer supply voltage, usually by 3, 5, or 8 percent. If ordered by the NYISO to go into voltage reduction, Transmission Owner system dispatchers shall immediately comply with that order. Quick response voltage reduction shall normally be accomplished within ten (10) minutes of the order.
Zone	A defined portion of the NYCA area that encompasses a set of load and generation buses. Each zone has an associated zonal price that is calculated as a weighted average price based on generator LBMPs and generator bus load distribution factors. A "zone" outside the NY control area is referred to as an external zone. Currently New York State is divided into eleven zones, corresponding to ten major transmission interfaces that can become congested.