ANALYSIS GROUP

Modifications to the BSM Construct in the NYISO Capacity Market

Analysis of Potential Capacity Market Competitiveness and Reliability Outcomes

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Acknowledgments

This is an independent study prepared at the request of the New York Independent System Operator (NYISO) by a team at Analysis Group led by Paul Hibbard and Charles Wu. Our work benefitted significantly from assistance by Scott Ario and Elisa Gan at Analysis Group, and from the input and comment received from the NYISO and its market participants and stakeholders.

About the Authors

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About Analysis Group

Analysis Group is one of the largest international economics consulting firms, with over 1,000 professionals across 14 offices in North America, Europe, and Asia. Since 1981, Analysis Group has provided expertise in economics, finance, analytics, and strategy to top law firms, Fortune Global 500 companies, government agencies, and other clients. The firm's energy and environment practice area is distinguished by its expertise in economics, finance, market modeling and analysis, regulatory and policy analysis, and infrastructure development. Analysis Group's consultants have worked for a wide variety of clients, including energy suppliers, energy consumers, utilities, regulatory commissions, other federal and state agencies, tribal governments, power system operators, foundations, financial institutions, start-up companies, and others.

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I. Executive Summary

Background and Overview

The New York Independent System Operator (NYISO) currently administers Buyer Side Mitigation (BSM) rules that, in part, mitigate the offers of new resources that are supported in whole or in part through out-of-market payments (e.g., contracts or payments/credits for emission or renewable generation attributes). It is increasingly recognized that these BSM rules can frustrate New York State's achievement of its climate policy objectives and requirements as mandated under the 2019 New York State Climate Leadership and Community Protection Act (CLCPA). Consequently, in its Comprehensive Mitigation Review process, NYISO is proposing changes to the BSM rules to better accommodate state objectives while maintaining the function and effectiveness of wholesale capacity markets in efficiently achieving resource adequacy in the state. These changes would exempt state policy resources from BSM offer review, improve the accreditation of capacity from a reliability perspective, and include additional changes to better adapt the NYISO capacity market to the rapidly-changing state climate policy context.

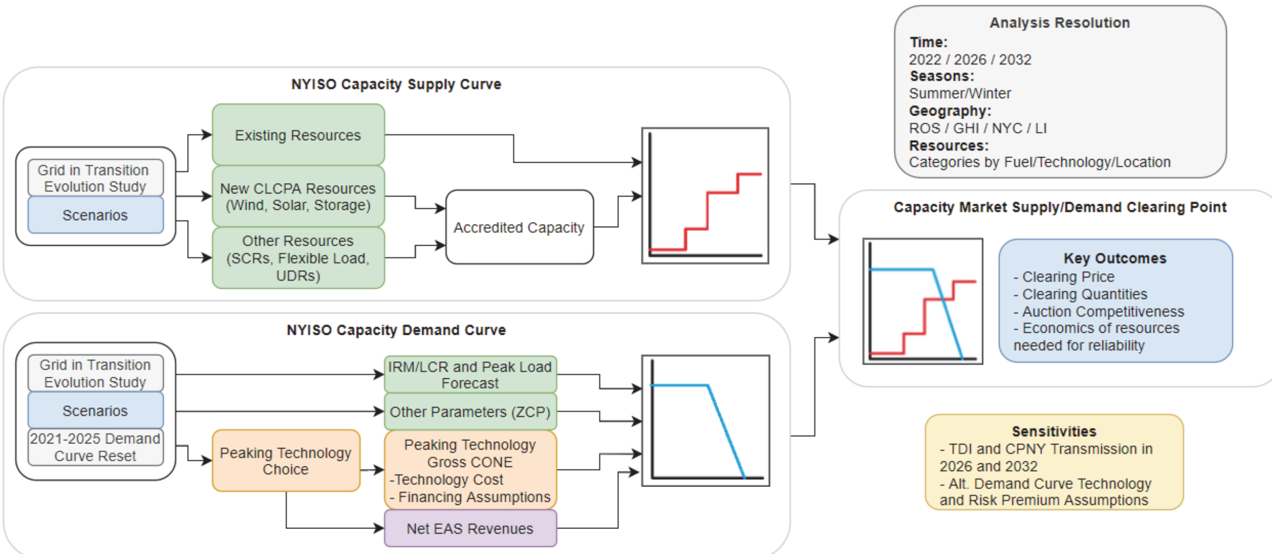
In this report, Analysis Group models the future operation of the NYISO capacity market under conditions consistent with NYISO's implementation of its proposed changes to the BSM rules. The purpose of the analysis is to determine whether the NYISO capacity market will continue to support the achievement of resource adequacy in the state of New York through competitive capacity market auctions administered in concert with the rollout of CLCPA resources. Specifically, we seek to answer two questions:

a) With the proposed BSM Reforms in place, will the NYISO capacity market continue to produce competitive market outcomes?
b) With the proposed BSM Reforms in place, will the NYISO capacity market continue to provide financial incentives for the retention and addition of resources needed to maintain power system reliability?

Analytic Method

The analysis simulates capacity market outcomes against the backdrop of accelerated entry of CLCPA resources, assuming that such resources (a) will be primarily supported through out-of-market state programs, and (b) will participate in the capacity market with unmitigated offers at or near zero price (i.e., reflecting NYISO's proposed BSM Reforms). We then review the results of the simulated auctions with respect to clearing auction quantities, prices, and revenue sufficiency for reliability resources. Figure ES-1 provides a schematic of the analytic method.

Figure ES-1: Summary of Analytic Method



Our focus is on the evolution of the capacity market with BSM Reforms in place in the near to medium term by reviewing market outcomes in year one (2022) and year five (2026). For these years we construct forecasted supply and demand curves starting from current conditions, with adjustments to both based on expected changes in demand, reference technology costs, existing resource going-forward costs, resource entry and exit over these time periods, and the likely magnitude of additional non-mitigated CLCPA resources.[1] In addition, we run a series of sensitivities that reflect changes to the NYISO capacity market supply and demand curves from proposed transmission changes, increases in demand curve risk premiums, and a potential alternative demand curve peaking technology.

The analysis relies on recent analyses completed by and for the NYISO. The recent 2021-2025 Demand Curve Reset is the starting point for demand curves, reference technologies, and certain cost and revenue factors. We also draw from NYISO's 2021 Gold Book and Grid in Transition analyses to forecast future demand, resource entry and exit (including CLCPA resources), changes in technology costs and revenues, and appropriate capacity accreditation factors. The capacity market model clears in nested fashion consistent with the operation of the market, and results are represented in terms of cleared capacity, prices, and revenues earned by resources needed for reliability.

Results

Table ES-1 and Table ES-2 contains the results of the analysis for the New York Control Area (NYCA) as a whole,

[1] Since the CLCPA (and similar laws and policies in neighboring states) will drive a rapidly accelerating pace of change in electricity markets and technologies, we consider analysis beyond the next five to six years as highly uncertain. Nevertheless, we also run various postulated sensitivities ten years out (model year 2032), based on currently available information; these sensitivities are described in Sections III and IV and Appendix A. While such results are highly speculative, they may be useful to help NYISO and stakeholders consider potential longer-term changes to markets.

and for each of the NYISO capacity market localities. The results provide an indication of expected prices in dollars per kilowatt-month ($/kW-mo) and clearing quantities in unforced capacity megawatts (UCAP MW) by year, season, and locality. The results in year one are provided for the baseline model set up, and the results for year five use baseline model assumptions for model year 2026.[2]

Table ES-1: Capacity Market Clearing Prices ($/kW-mo) by Capacity Locality and Season, 2022-2026

Capacity Locality	Summer		Winter	
	2022	2026	2022	2026
NYCA	$4.60	$5.07	$3.33	$4.23
G-J Locality	$7.46	$9.02	$3.87	$5.81
NYC (J)	$7.46	$12.83	$3.87	$7.51
LI (K)	$7.13	$14.61	$3.66	$12.05

Table ES-2: UCAP Clearing Quantities (MW) by Capacity Locality and Season, 2022-2026

Capacity Locality	Summer		Winter	
	2022	2026	2022	2026
NYCA	36,543	34,996	37,540	35,200
G-J Locality	13,791	12,376	14,268	12,868
NYC (J)	9,459	8,638	9,667	9,107
LI (K)	5,817	5,076	5,985	5,286

Changes underlying the results for 2026 include significant changes to the assumed resources on the system compared to 2022. Specifically, in the four years since 2022:

- Fossil fuel ICAP has decreased by 2,834 MW;
- Onshore wind has increased by 244 MW;
- Offshore wind has increased by 1,200 MW;
- Grid-connected solar photovoltaic capacity has increased by 5,000 MW;
- Battery storage resources (two-hour and four-hour) has increased by 1,571 MW.

Despite the significant addition of zero-offer CLCPA resources by 2026, the market retains 31,845 ICAP MW (29,309 UCAP MW) of thermal, hydro and nuclear capacity, and 5,772 ICAP MW (5,650 UCAP MW) of other resources (e.g., biogen, pumped storage, imports, SCRs). In total, the market supply curve includes 42,939 ICAP MW (37,985 UCAP MW) in 2022, and 48,021 MW ICAP (37,283 MW UCAP) in 2026.

Figure ES-2 and Figure ES-3 show graphically how the results of the analysis for the NYCA summer season change between 2022 and 2026. The quantity of UCAP needed to meet reliability requirements and clearing in the market declines from 36.5 gigawatts (GW) in 2022 to 35.0 GW in 2026. At the same time, prices in NYCA

[2] Our baseline results do not presume the presence of TDI transmission into NYC by the year 2026. However, we do include a sensitivity that assumes TDI is in operation in year 2026.

increase from $4.60 per kilowatt-month (kW-mo) in 2022 to $5.07/kW-mo in 2026.

Importantly, while the results for ten years out - 2032 - are necessarily more uncertain, the results of our modeling various scenarios in 2032 are consistent with our observations based on the 2026 model year. Additional results are described in Section IV, and all results by scenario, year, season, and locality are presented graphically and in tabular form in Appendix A.

Many factors affect the results in each year, season, and locality. Exogenous factors lead to a significant amount of resource addition and attrition over the study period. In addition, while we do not build out the supply curves on a specific unit-by-unit basis,[3] it is clear that changing cost and resource factors leads to the retirement of some resources based on market economics. This is not surprising, as the modeling period includes an unprecedented potential for changes in electricity demand, going-forward costs of existing units, cost of the demand curve reference technology, ICAP/UCAP translation factor, CLCPA resource growth, and transmission topology.

Nevertheless, the combination of resource entry/exit - both due to exogenous and market economic factors - and proper accounting for resources' contributions to reliability generally lead to outcomes at capacity market prices reasonably consistent with past market outcomes. The analysis also shows the capacity market can continue to generate competitive market outcomes and provide sufficient financial incentives both for the economic retention of resources needed for reliability and for the economic entry and exit of resources. This result is sustained in all seasons, zones and scenarios over the first five years (i.e., for both model years 2022 and 2026). Moreover, while market conditions and forecasts ten years out - 2032 - are necessarily highly uncertain and speculative, the results for various scenarios completed for that model year also demonstrate continued competitive market outcomes and the retention through the capacity market construct of sufficient resources to meet resource adequacy requirements.

In Section II, we provide a brief overview of the context and purpose of the analysis. Section III provides a comprehensive review of the analytic method, data used, and assumptions that comprise the analysis. Finally, Section IV contains the results of the analysis and observations based on those results. Appendix A contains detailed results for all years, zones, seasons, and scenarios analyzed.

[3] Our resource supply curves are developed on a technology category basis consistent with the resource technology categories applied in the Grid in Transition Evolution Study.

Figure ES-2: Summer Market Capacity Supply and Demand Crossing Points, NYCA 2022

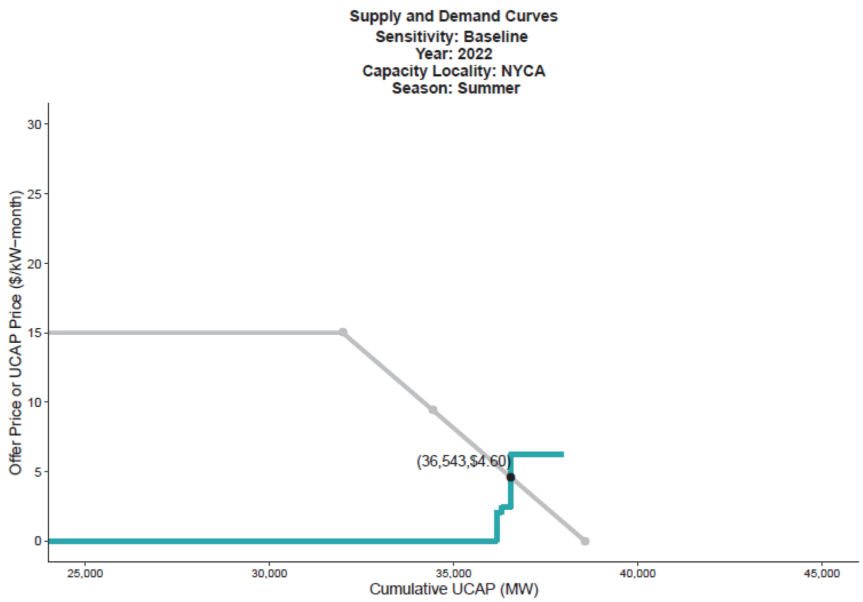
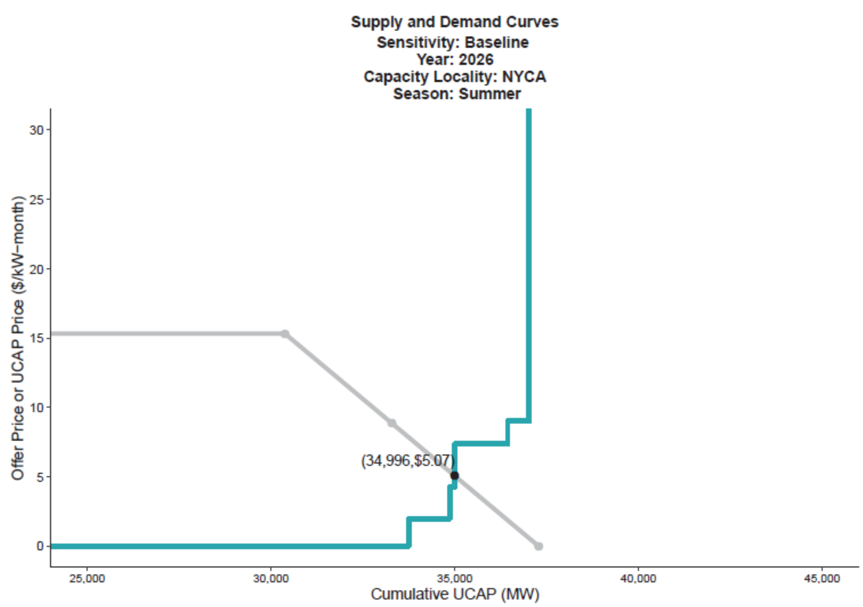


Figure ES-3: Summer Market Capacity Supply and Demand Crossing Points, NYCA 2026



II. Introduction

A. Context: Buyer Side Mitigation Reforms

Currently, pursuant to Sections 5.12 and 23.4.5.7 of the Market Administration and Control Area Services Tariff (MST), the New York Independent System Operator (NYISO) administers Buyer Side Mitigation (BSM) rules that, in part, mitigate the offers of new resources that are supported in whole or in part through out-of-market payments (e.g., contracts or payments/credits for emission or renewable generation attributes).[4] Most often, resources that fall into this category are necessary or important for the state of New York to meet the greenhouse gas (GHG) emission reduction mandates of the 2019 New York State Climate Leadership and Community Protection Act (CLCPA), which requires "…reducing 100% of the electricity sector's greenhouse gas emissions by 2040."[5]

Through its Grid in Transition (GIT) effort, NYISO has been assessing how to best prepare for and respond to a potential rapid transition in the power sector as the state moves towards meeting the CLCPA GHG emission reduction mandates. NYISO's efforts have to date focused on aligning competitive markets with the objectives and mandates of the CLCPA; redesigning markets to better value the reliability benefits of flexible power system resources and strategies; and seeking to improve the valuation of resources in the capacity market to ensure proper accounting for meeting reliability needs in a manner consistent with the transition underway in the New York State power market.[6]

As part of the GIT effort, NYISO is proposing a set of comprehensive changes to the MST's BSM rules as they relate to the potential offer price mitigation of resources considered important to achieve the state's climate change policy objectives. NYISO recognizes that while the application of BSM rules to state-supported resources may result in counterproductive market outcomes, it also recognizes that modifications to the BSM rules must continue to support reasonable and competitive Installed Capacity (ICAP) Market outcomes, and most importantly ensure the market is able to attract and retain resources that are vital to maintain power system reliability objectives.[7]

The NYISO's Comprehensive Mitigation Review effort includes two key elements. The first is a modification of BSM rules to eliminate BSM risk for resources that will be critical to meeting New York's CLCPA mandates (*BSM Reforms*). This requires a more careful accounting of the specific value that all resources have in meeting NYISO's reliability mandates over time. Thus, NYISO is also proposing to change the process by which each resource's installed capacity is valued, or "accredited," to reflect the resource's contribution to resource adequacy (*Capacity Accreditation*). NYISO is also proposing to alter how the capacity market ICAP reference price is translated to an unforced capacity (UCAP) reference price for the peaking unit underlying the capacity market

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[4] NYISO, "NYISO Market Administration and Control Area Services Tariff", October 12, 2021, Sections 5.12 and 23.4.5.7, available at https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf.

[5] The CLCPA defines GHGs as "carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride, and any other substance emitted into the air that may be reasonably anticipated to cause or contribute to anthropogenic climate change." New York Climate Leadership and Community Protection Act (CLCPA), NY State Senate Bill S6599, June 18, 2019, para. 12.d and §75-0101, available at https://www.nysenate.gov/legislation/bills/2019/s6599.

[6] NYISO, "Preparing the Capacity Market for the Grid in Transition," presentation by Mike DeSocio to the NYISO Installed Capacity Market Working Group (ICAPWG), April 20, 2021, pp. 4-5.

[7] NYISO, "Comprehensive Mitigation Review," presentation by Mike DeSocio and Zach T. Smith to the ICAPWG, September 28, 2021 ("September 28, 2021 ICAPWG"), p. 7.

Demand Curve, to better reflect investment risk in the setting of financial parameters of the reference peaking unit technology.[8]

B. Purpose and Approach: Analysis Group Study

As part of their review of potential BSM Reforms, NYISO asked Analysis Group to analyze the operation of the NYISO capacity market under conditions consistent with implementation of its proposed changes to the BSM rules. The purpose of the analysis is to determine whether the NYISO capacity market will continue to support the achievement of resource adequacy in the state of New York through competitive capacity market auctions administered in concert with the rollout of CLCPA resources. This report contains the results of that analysis. Specifically, we seek to answer two questions:

(1) With the proposed BSM Reforms in place, will the NYISO capacity market continue to produce competitive market outcomes?
(2) With the proposed BSM Reforms in place, will the NYISO capacity market continue to provide financial incentives for the retention and addition of resources needed to maintain power system reliability?

To complete the analysis, we simulate capacity market outcomes against the backdrop of accelerated entry of state-supported resources (CLCPA Resources), assuming that such resources (a) will be primarily supported through out-of-market state programs, and (b) will participate in the capacity market with unmitigated offers at or near zero (i.e., reflecting NYISO's proposed BSM Reforms). We then review the results of the simulated auctions with respect to clearing auction quantities, prices, and revenue sufficiency for reliability resources.

Our analytic method (described in detail in Section III) involves forecasting NYISO capacity market supply and demand curves in representative future years (years one (2022) and five (2026)), clearing the market using these curves, and evaluating results. Our focus on evaluation of the BSM Reforms in the capacity market in years one and five recognizes the magnified degree of uncertainty in later years due to accelerating pace of changes in electricity market demand and technology cost and performance needed to meet the CLCPA and similar laws and policies in neighboring states. A five-year focus allows us to draw robust conclusions about the operation of the capacity market under the proposed BSM Reforms over the initial period of market transition. However, we also run sensitivities under postulated condition ten years hence which, while necessarily highly speculative, can be used by NYISO and stakeholders in the coming years to identify future market rule changes (if any) needed between years six and ten. As a result, we also report both baseline and sensitivity results for year ten.

Our analysis relies upon current data and recently completed studies of the New York market as a starting point. We start from the recently completed 2021-2025 Demand Curve Reset (DCR) study completed by Analysis Group,[9] and develop demand curves over time consistent with simplified representations of demand curve inputs (e.g., peak seasonal demand, reference technology costs, and ICAP/UCAP translation factors). In June 2020, the Brattle Group completed a study of the evolution of the New York power system in 2020-2040 on the path to meet

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[8] September 28, 2021 ICAPWG, p. 8.

[9] Analysis Group and Burns & McDonnell, "Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report," September 9, 2020, pp. 108-109, available at https://www.nyiso.com/documents/20142/14526320/Analysis-Group-2019-2020-DCR-Final-Report.pdf/ ("2021-2025 DCR Study").

the CLCPA's carbon requirements ("GIT Evolution Study").[10] We build future supply curves using the GIT Evolution Study's forecasts of CLCPA resources, and for operating and revenue data for technology-centric "groupings" of existing and new resources (e.g., fixed and variable operations and maintenance expenses, and expected energy and ancillary service (EAS) revenues). Finally, we clear the market in future years (in five-year increments) based on these curves, and review market outcomes.

Section III contains detailed descriptions of each component of the analysis (the supply curves, demand curves, and market-clearing logic), presents the sources of data used, identifies key assumptions, and describes the various scenarios analyzed. Section IV presents the key results over the next five years across all zones and discusses observations that flow from the results. In Section IV we also discuss outcomes associated with the various demand and supply scenarios we analyze in year ten. Finally, a comprehensive set of results for all zones and all years is presented in Appendix A.

[10] Brattle Group, "New York's Evolution to a Zero Emission Power System: Modeling Operations and Investment Through 2040 Including Alternative Scenarios," June 22, 2020 ("GIT Evolution Study").

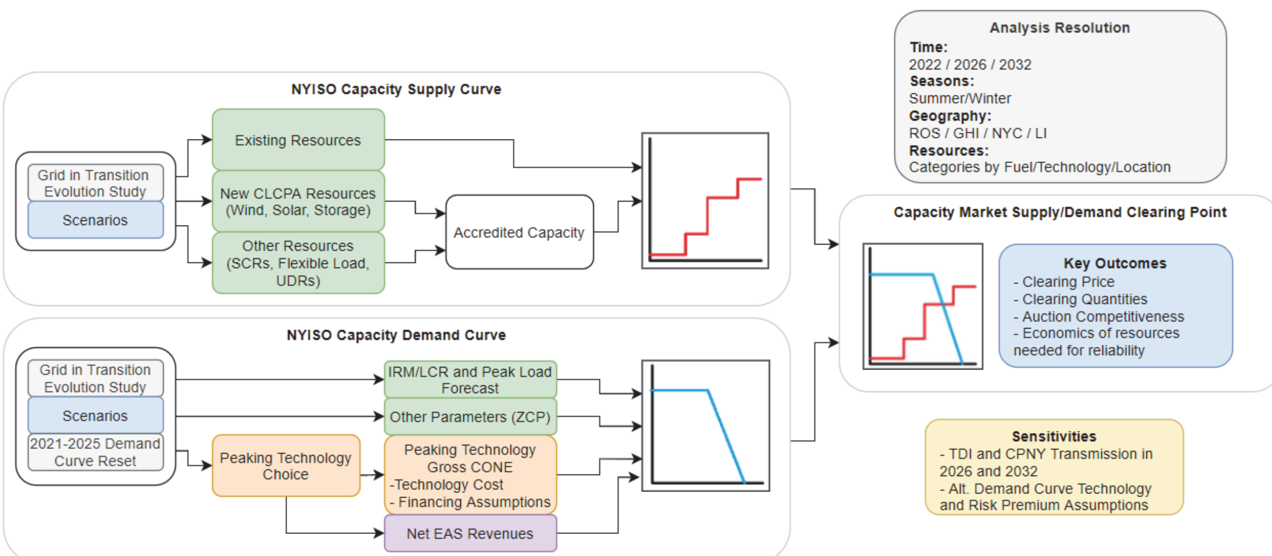
III. Analytic Method

A. Overview

The analysis simulates the clearing of the NYISO capacity market in representative future years. We use a model of the NYISO spot auction to model outcomes of the Installed Capacity market as a whole. We focus primarily on the first five years of capacity market administration with BSM Reforms in place; to do this we simulate the clearing of the NYISO spot market in year one (2022) and year five (2026). While necessarily more speculative, we also model the market clearing under various potential resource and demand scenarios in year ten (2032) to provide some potential longer-term observations to guide market design deliberations in later years.

The model logic and data sources are presented at a high level in Figure 4. For each of the representative years, we construct a supply curve and a demand curve, and use these to "clear" the market.

Figure 4: Summary of Analytic Method



The various elements of the analysis are described in more detail in the sections that follow, but at a high level the elements in each model year consist of the following:

- Supply curves are developed using representative technology categories (e.g., combined cycle, steam turbine, gas turbine, wind, solar, etc.) for existing resources in each year, with the total capacity of each grouped technology category equal to the expected total quantity of resources in that class. CLCPA resources are assumed to offer in at $0 (unmitigated) and remaining resources offering in at their expected going-forward costs (GFC). Resource offers are based on the GIT Evolution Study and supporting documentation, and resources' UCAP quantities reflect an estimate of capacity accreditation values based on the marginal capacity accreditation approach.

- Demand curves are initially based upon the most recent Demand Curve Reset, and in future years are modified to reflect changing expected levels of demand, expected changes in costs of the reference technology, and ICAP/UCAP translation factors based upon the evolving resource mix. Expected energy and ancillary services market revenues are based on the GIT Evolution Study, and curves are constructed for each capacity market zone.
- The market clearing logic is consistent with NYISO capacity market clearing rules using nested capacity market localities and establishes modeled clearing prices and quantities.

B. Supply Curves

The starting point for the analyses on the supply side are a set of winter and summer seasonal supply curves or "supply stacks" for NYCA and each of the capacity market localities, for each of the years 2022, 2026, and 2032. ICAP quantities for supply resources for each year are based on quantities from the Grid in Transition Evolution Study for renewable and nonrenewable generators and storage, and on historical NYISO levels for certain other non-generator resources. The ICAP quantities are further translated into UCAP quantities for the purposes of clearing against the UCAP demand curves, which set the ultimate market clearing prices, based on the procedures in the NYISO ICAP Manual.[11] This section will describe the method used to construct each supply curve.

1. Installed Capacity

The supply curves are constructed at a capacity locality, seasonal, and unit fuel/technology type level. Unit quantities in each fuel/technology type in a capacity locality and season are aggregated and assigned a single fuel/technology type average offer price. For example, the summer 2022 supply curve for Zone J is constructed of quantities for Gas ST units, Gas CT units, Gas CC units, etc., each with a distinct offer price.

Summer ICAP quantities for each generator fuel/technology type in each year and capacity locality were taken from the GIT Evolution Study model output. The GIT Evolution Study modeled economic entry and exit of generators over time from 2020 to 2040, with significant entry of renewable generation and battery storage by 2032, and some exit of fossil fuel and nuclear generation. In each model year, the GIT Evolution Study model provides annual ICAP quantities for each fuel/technology type, which are analogous to summer ICAP values. Winter ICAP values for nonrenewable resources are derived from the GIT Evolution Study ICAP quantities by multiplying by a scaling factor of (Weighted average winter ICAP / Weighted average summer ICAP) by fuel/technology type, calculated from the NYISO 2021 Gold Book.[12] Winter ICAP values for renewable resources are assumed to be identical to summer ICAP values for those resources.

2. Capacity Accreditation

ICAP resource quantities were converted to UCAP quantities using different capacity accreditation methods for each resource type. The ICAP for existing non-intermittent, non-storage resources were converted to UCAP using NERC annual weighted average EFORd values by fuel/technology type from 2016-2020, consistent with the rules

[11] NYISO, "Manual 4: Installed Capacity Manual", May 2021, available at https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/ ("NYISO ICAP Manual").

[12] NYISO, "2021 Load & Capacity Data Gold Book," April 2021, available at https://www.nyiso.com/documents/20142/2226333/2021-Gold-Book-Final-Public.pdf/ ("NYISO 2021 Gold Book").

for nonrenewables in the current ICAP manual.[13] Hydro run-of-river (RoR) resources were converted from ICAP to UCAP using the weighted average capacity factor for all hydro RoR units in the NYISO 2021 Gold Book.

The capacity accreditation methodology for wind, solar, and storage resources varied across the model years studied. In 2022, we assume that the current capacity derating and duration adjustment method described in the ICAP manual would continue to be in effect.[14] This means that onshore wind resources would be assigned a UCAP of 16 percent of ICAP in summer, and 34 percent in winter. Solar resources would be assigned a UCAP of 46 percent of ICAP in summer, and 2 percent in winter. Battery storage units in 2022 would be assigned the duration adjustment factors consistent with the current ICAP manual, 90 percent for 4 hour batteries and 45 percent for 2 hour batteries.

We understand that in future years capacity accreditation values for all resources will be based on a method currently under development in the NYISO stakeholder process. Since this process is not complete, we use a proxy for capacity accreditation for the purpose of our analysis, based on the marginal accreditation value method. Specifically, in 2026 and 2032, we assume that capacity accreditation will depend on the marginal capacity values that were estimated in the GIT Evolution Study. According to its documentation, these values were meant to "approximate the marginal UCAP value of wind, solar, and storage as more are deployed," by varying the amount installed holding all else equal, to assess the capacity value of the last MW added.[15] This "simplified approach" was described as "not replac[ing] a full probabilistic effective load carrying capability study," but nonetheless provides an estimate of incremental capacity value as renewable penetration increases.[16] We assume that, in a given year, all renewable or storage resources of a given type would be assigned the same marginal capacity value based on system-wide penetration of that resource type, regardless of vintage or location. Battery storage units in 2026 and 2032 were assigned marginal capacity values based on the curves from the GIT Evolution Study based on % peak load reduction, with no further duration adjustment.[17,18] Figure 5, Figure 6, and Table 1 show the marginal capacity values by resource type for wind, solar, and storage.

Each supply curve also includes certain non-generator, non-storage resources offered into the market such as net imports, special case resources (SCRs) and unforced deliverability rights (UDRs). UCAP quantities for each of these were taken from historical average quantities from NYISO market reports and the NYISO 2021 Gold Book. We have not modeled changes over time in net imports, SCRs, and UDRs.

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[13] NYISO ICAP Manual, Section 4.5, and NERC, "Generating Unit Statistical Brochure 4 2016-2020 - All Units Reporting", available at https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx.

[14] NYISO ICAP Manual, Sections 4.1.1.

[15] GIT Evolution Study, p. 109.

[16] GIT Evolution Study, p. 109.

[17] 2026 and 2032 storage peak load reduction percentages are calculated as the equivalent 2-hour storage installed capacity divided by the forecasted peak load in 2026 and 2032. The equivalent 2-hour storage ICAP is equal to 2-hour storage ICAP plus two times the 4-hour storage ICAP, based on the longer discharge duration of 4-hour resources. The resulting peak load reduction percentages are then applied to the 2-hour and 4-hour curves from the GIT Evolution Study to calculate the corresponding marginal capacity values for each resource type in each year. The % peak load reductions used in the GIT Evolution Study were based on 2018 historical peak load, but the values used in this study are based on 2026 and 2032 forecasted peak loads from the 2021 NYISO Gold Book (CLCPA load scenario).

[18] SCRs were assigned the same duration adjustment factor in 2022 and the same marginal capacity values in 2026-2032 as 4 hour battery storage resources.

Figure 5: Marginal Capacity Value of Solar and Wind by Season from Grid in Transition Evolution Study[19]

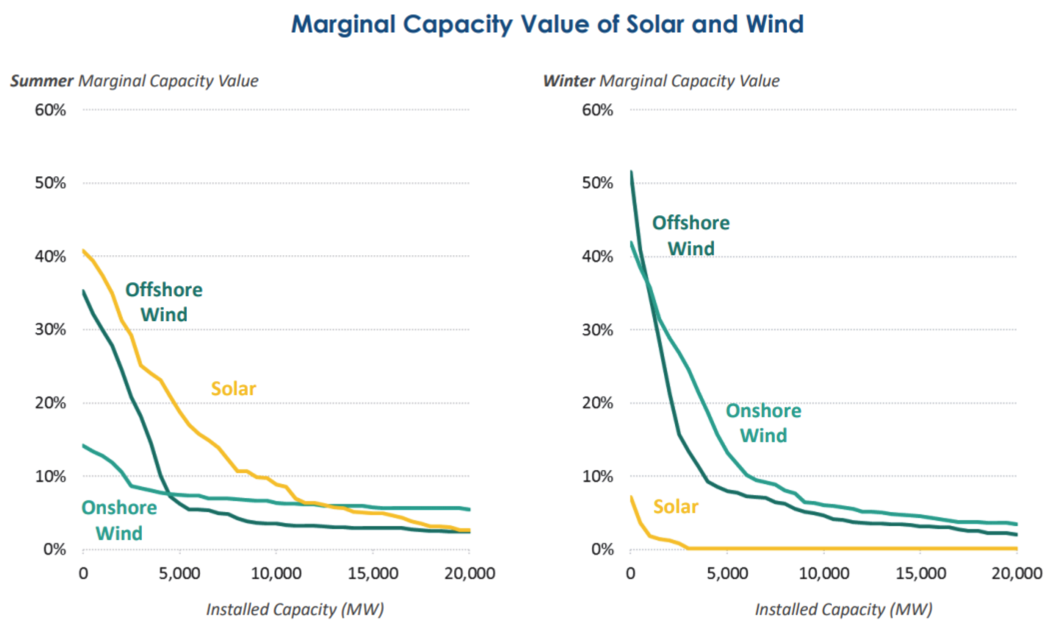
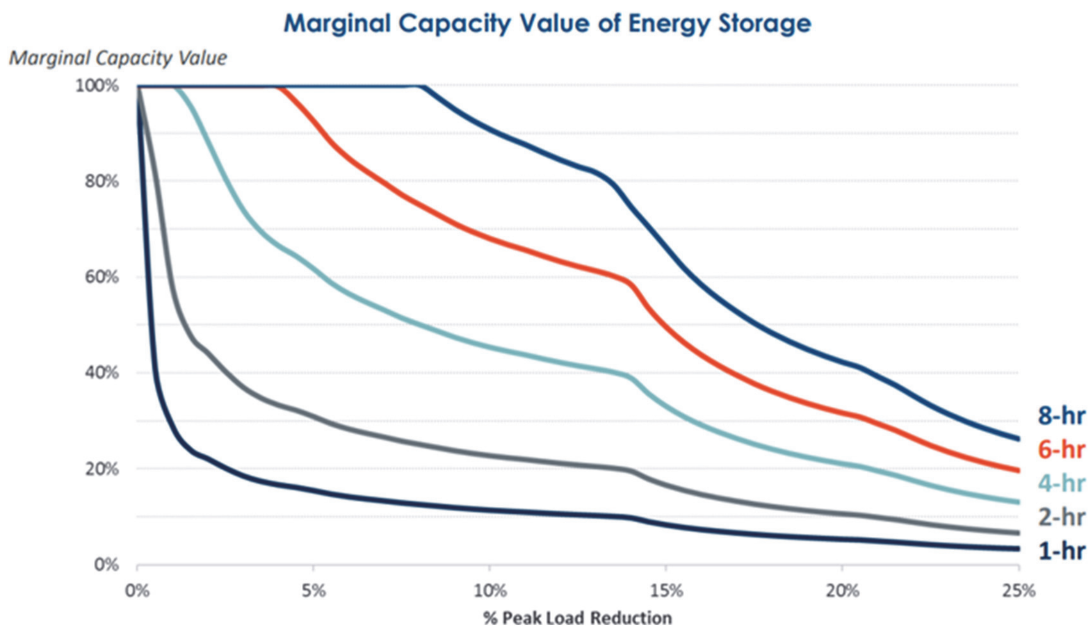


Figure 6: Marginal Capacity Value of Battery Storage from Grid in Transition Evolution Study[20]



[19] GIT Evolution Study, p.111.

[20] GIT Evolution Study, p.112.

Table 1: Summary of Values for UCAP/ICAP Quantity Conversion for CLCPA Resource Types

CLCPA Unit Type	Current ICAP Manual		Marginal Capacity Values			
	2022 Summer	2022 Winter	2026 Summer	2026 Winter	2032 Summer	2032 Winter
Onshore Wind	16.0%	34.0%	10.6%	28.9%	6.5%	6.2%
Offshore Wind	N/A	N/A	29.1%	32.4%	4.8%	6.5%
Utility-Scale Solar	46.0%	2.0%	18.6%	0.2%	4.2%	0.1%
2h Battery Storage	45.0%	45.0%	39.0%	39.0%	30.6%	30.6%
4h Battery Storage	90.0%	90.0%	78.1%	78.1%	61.2%	61.2%

A summary of the ICAP to UCAP conversion method for all resource types is in **Table 2** below:

Table 2: Summary of Method for UCAP/ICAP Quantity Conversion

<table>
<tr><th>Unit Type</th><th>2022</th><th>2026</th><th>2032</th></tr>
<tr><td>Existing Nonrenewable Units (Fossil, Nuclear, Hydro Pondage)</td><td>NERC Weighted average EFORd</td><td>NERC Weighted average EFORd</td><td>NERC Weighted average EFORd</td></tr>
<tr><td>Hydro Run of River</td><td>Capacity factor calculated from 2021 Gold Book</td><td>Capacity factor calculated from 2021 Gold Book</td><td>Capacity factor calculated from 2021 Gold Book</td></tr>
<tr><td>Existing 2021 Wind and Solar</td><td>Derating Factor from NYISO ICAP Manual</td><td rowspan="2">GIT Evolution Study marginal capacity values based on total ICAP by resource type</td><td rowspan="2">GIT Evolution Study marginal capacity values based on total ICAP by resource type</td></tr>
<tr><td>CLCPA Wind and Solar Additions</td><td>N/A</td></tr>
<tr><td>Battery Storage</td><td>Duration Adjustment Factor from NYISO ICAP Manual</td><td>GIT Evolution Study marginal capacity values based on % peak load reduction</td><td>GIT Evolution Study marginal capacity values based on % peak load reduction</td></tr>
</table>

3. *Final UCAP Supply Curve Quantities*

The final set of supply resources in the UCAP supply curves are aggregated for NYCA and capacity market localities G-J, New York City, and Long Island, based on resources in capacity zones A-F, G-I, J, and K. The NYCA aggregate final UCAP and ICAP summer quantities by resource type are detailed in **Table 3** below:

Table 3: NYCA Summer Capacity by Unit Type (MW)

Unit Type	2022		2026		2032	
	ICAP	UCAP	ICAP	UCAP	ICAP	UCAP
Fossil Fuel	26,315	24,322	23,481	21,833	23,485	21,836
Hydro	5,018	4,210	5,018	4,210	5,018	4,210
Nuclear	3,345	3,266	3,345	3,266	2,156	2,105
Onshore Wind	1,739	278	1,983	210	9,698	633
Offshore Wind	0	0	1,200	349	7,591	362
Utility-Scale Solar	56	26	5,056	942	16,669	702
Storage (2-hour)	592	258	2,156	816	4,264	1,266
Storage (4-hour)	2	2	9	7	386	229
Other Resources	2,671	2,541	2,571	2,450	3,251	3,109
SCRs	1,185	1,067	1,185	1,185	1,185	1,185
Net Imports	973	973	973	973	973	973
UDRs	1,042	1,042	1,042	1,042	1,042	1,042
Total	**42,939**	**37,985**	**48,021**	**37,283**	**75,719**	**37,653**

Detailed ICAP and UCAP quantities for each capacity locality and sensitivity are further available in Appendix A.

4. *Resource Offer Prices*

Each resource type in the locational and seasonal supply curves is modeled with a separate offer price in $/kW-mo, with the method for calculation varied across resource types.

Offer prices for nonrenewable resource type in the UCAP supply curve are constructed for each season and year based on costs and revenue outputs from the Grid in Transition Evolution Study. All offer prices are denominated in nominal year dollars, consistent with the cost and revenue assumptions from the Grid in Transition Evolution Study. For each fuel/technology type in each model year, annual going forward costs (GFCs) are aggregated from the Grid in Transition Evolution Study's annual model outputs, using the following formula:

$$\begin{aligned} Annual\ GFC\ (\$) = {} & Fixed\ O\&M\ Costs + Variable\ O\&M\ Costs + Fuel\ Costs + Emissions\ Costs + Startup\ Costs \\ & - (Energy\ Revenues + Ancillary\ Service\ Revenues + ZEC\ Revenues) \end{aligned}$$

The total annual GFCs are then shaped to summer and winter offer prices for each fuel/technology type within each aggregated capacity zone[21] consistent with the following formula, adapted from the existing BSM offer review methodology:

$$Summer\ Offer\ Price\left(\frac{\$}{kWmo}\right) = \frac{Annual\ GFC\ (\$)}{6 * \left(Q_s + Q_w * \frac{ZCP - WSR}{ZCP - 1}\right)}$$

$$Winter\ Offer\ Price\ \left(\frac{\$}{kWmo}\right) = Summer\ GFC\left(\frac{\$}{kWmo}\right) * \frac{ZCP - WSR}{ZCP - 1}$$

- Annual GFC is the going forward cost on a dollar basis for the whole year.
- Summer and Winter ICAP are the aggregated ICAP for a given unit type in a given locality, measured in kW, and denoted by Q_s and Q_w.
- Winter-Summer Ratio (WSR) is the ratio of (total winter ICAP for all unit types in a capacity locality / total summer ICAP in a capacity locality).
- Zero Crossing Point (ZCP) is a parameter from the demand curve formula, varies by capacity locality, and should be >100%.

CLCPA resources are modeled as offering into the capacity market at zero price, consistent with the assumption that these resources will receive partial or full financial support through non-market mechanisms and will not be subject to offer review or mitigation as NYISO has proposed in its BSM Reforms. Net Imports, SCRs, and UDRs are also modeled as offering at zero price, to ensure they clear the market in the model at historical quantities. The method for construction of the capacity supply curves by quantity and offer price is detailed in **Table 4** below:

[21] Each fuel/technology type in the aggregated capacity zones of A-F, G-I, J, and K is assigned a single calculated offer price. For example, Gas CTs in Zones G-I and Zone J are assigned different offer prices, but both types offer into the capacity market in the G-J Locality.

Table 4: Summary of Methodology for Supply Curve Quantities and Offer Prices

Unit Type	Quantity	Offer Price
Fossil Fuel Units	ICAP quantities from GIT Evolution Study model outputs. UCAP conversion methodology described in **Table 2**	GFCs derived from GIT Evolution Study model outputs
Nuclear		GFCs derived from GIT Evolution Study model outputs[22]
Hydro		GFCs derived from GIT Evolution Study model outputs
Wind and Solar		$0
Battery Storage		$0
UDRs	3-year historical UCAP average quantities derived from market reports and Gold Book	$0
Net Imports	5-year historical UCAP average quantities from market reports	$0
SCRs	5-year historical UCAP average quantities from market reports	$0

C. Demand Curves

The demand side of the NYISO spot capacity market is determined by the ICAP demand curves for each capacity locality and season. This study calculates ICAP demand curves in 2022, 2026, and 2032 for both summer and winter, based on assumptions of capacity requirements, demand curve shape, and cost of new entry for a representative peaking unit in each capacity locality. The ICAP demand curves are then translated into UCAP demand curves for the purposes of clearing the market against the UCAP supply curve in each capacity locality. This section will describe the method used to construct each demand curve.

1. Capacity Requirements

One of the key parameters for any ICAP demand curve is the quantity of resources that are to be procured by the installed capacity market in order to meet reliability requirements in each capacity locality. In each year, the NYISO, in conjunction with the New York State Reliability Council (NYSRC), determines the installed reserve margin (IRM) for NYCA as a whole and the Locational Minimum Installed Capacity Requirements (LCRs) for the G-J Locality, New York City, and Long Island.[23] The IRMs and LCRs are calculated as a percent of peak load in each year. The quantities in MW of capacity required in NYCA and each capacity locality are then:

$$Minimum\ ICAP\ Requirement = Forecasted\ Peak\ Load * (1 + IRM\ or\ LCR(\%))$$

[22] Upstate nuclear units are additionally assumed to offer into the capacity market at $0 in 2032.

[23] NYSRC, "NYSRC New York Control Area Installed Capacity Requirement Reports", available at https://www.nysrc.org/NYSRC_NYCA_ICR_Reports.html.

The minimum ICAP requirements in NYCA and each capacity locality are further translated into minimum UCAP requirements using the UCAP/ICAP translation factor applicable to NYCA or the capacity locality in that season/year:

$$Minimum\ UCAP\ Requirement = Minimum\ ICAP\ Requirement * (1 - UCAP/ICAP\ Translation\ Factor)$$

In each historical year, the UCAP Reserve Margin is calculated as the ratio of minimum UCAP requirements to forecasted peak load. The historical average summer UCAP Reserve Margin (URM) from 2016-2021 is shown in Table 5 below:

Table 5: Historical Average Summer UCAP Reserve Margin by Capacity Locality, 2016-2021[24]

NYCA	G-J Locality	NYC	Long Island
107.9%	85.7%	77.8%	96.9%

The historical URMs are then converted into implied IRMs and LCRs using the locality-specific summer UCAP/ICAP translation factor (the ratio of (Total UCAP MW / Total ICAP MW)) from portfolio average capacity values for each modeled future year.[25] The resulting IRMs and LCRs are set across the model years of 2022, 2026, and 2032 to ensure that sufficient quantities of capacity are procured to meet reliability standards under future peak loads.[26] The IRM or LCRs by model year are shown in Table 6 below:

Table 6: IRM and LCR by Model Year, 2022-2032

Year	NYCA	G-J Locality	NYC	Long Island
2022	123.1%	93.2%	84.4%	113.8%
2026	138.9%	93.9%	93.6%	121.7%
2032	209.6%	123.9%	127.5%	161.6%

IRMs and LCRs by model year are then converted into UCAP requirements by year, season, and capacity locality based on the marginal capacity accreditation methodology described in Section B and peak loads from the 2021

[24] Historical averages are calculated from NYISO ICAP data releases available athttp://icap.nyiso.com/ucap/public/ldf_view_icap_calc_detail.do.

[25] UCAP/ICAP translation factors based on portfolio average capacity values are used to calculate IRM and LCRs for each model year so that the capacity contributions of the cumulative NYISO fleet to resource adequacy is properly accounted for.

[26] IRM/LCRs are further modified to reflect changes due to planned transmission topology changes from the AC Public Policy Transmission line, with expected in-service date of December 2023, based on the assumptions used by NYISO in its Buyer Side Mitigation forecasts. These represent a decrease of the LCR by 6.0% in G-J from capability years 2023/24 to 2024/25. NYISO, "Buyer Side Mitigation, ICAP forecast - Class Year 2019 Assumptions and References," December 22, 2020, p. 4, available at https://www.nyiso.com/documents/20142/8363446/ICAP-Buyer-side-Mitigation-Test-Data-Assumptions-Document-Class-Year-2019-December-22-2020/32caa63f-72d8-0258-255d-de201947dca8.

NYISO Gold Book and NYISO Climate Phase I Study under the CLCPA load scenario.[27] The UCAP requirements by year and season are calculated as (rearranging the equations above):

$$\begin{aligned}&Minimum\ UCAP\ Requirement\\ &\qquad = Forecasted\ Peak\ Load * \left(1 + IRM\ or\ LCR(\%)\right) * (1 - \ UCAP/ICAP\ Translation\ Factor)\end{aligned}$$

The UCAP/ICAP Translation Factors are summarized in Table 7 below for the marginal capacity accreditation approach by capacity locality, season and year:

Table 7: UCAP/ICAP Translation Factors by Capacity Locality, Season, and Year

Capacity Locality	Summer			Winter		
	2022	2026	2032	2022	2026	2032
NYCA	12.4%	24.4%	53.2%	11.3%	24.8%	52.8%
G-J Locality	8.0%	15.6%	38.1%	7.8%	14.9%	36.5%
NYC (J)	7.8%	19.1%	43.9%	7.7%	18.0%	41.9%
LI (K)	14.9%	22.8%	45.5%	15.0%	22.2%	44.1%

The final UCAP capacity requirements and UCAP reserve margins under the marginal capacity approach are summarized in Table 8 and Table 9 below:

Table 8: UCAP Capacity Requirements (MW) by Capacity Locality, Season, and Year

Capacity Locality	Summer			Winter		
	2022	2026	2032	2022	2026	2032
NYCA	34,429	33,284	34,733	34,835	33,122	35,055
G-J Locality	12,816	11,689	12,499	12,835	11,792	12,810
NYC (J)	8,397	8,051	8,348	8,405	8,151	8,652
LI (K)	5,237	5,094	5,546	5,229	5,138	5,691

[27] NYISO 2021 Gold Book and Itron, "New York ISO Climate Change Impact Study, Phase 1: Long-Term Load Impact," December 2019, available at https://www.nyiso.com/documents/20142/10773574/NYISO-Climate-Impact-Study-Phase1-Report.pdf ("NYISO Climate Impact Phase 1 Study"), Appendix A-4.

Table 9: UCAP Reserve Margins (%) by Capacity Locality, Season, and Year

Capacity Locality	Summer			Winter		
	2022	2026	2032	2022	2026	2032
NYCA	107.9%	104.9%	98.0%	109.1%	104.4%	98.9%
G-J Locality	85.7%	79.2%	76.8%	85.9%	79.9%	78.7%
NYC (J)	77.8%	75.8%	71.5%	77.9%	76.7%	74.1%
LI (K)	96.9%	93.9%	88.1%	96.7%	94.7%	90.4%

2. Assumptions for ICAP Demand Curves

The reference point price and maximum price parameters in the ICAP demand curve are determined based on the cost of new entry (CONE) of a representative peaking unit, consistent with the quadrennial NYISO Demand Curve Reset process.

Each ICAP Demand Curve is comprised of three portions (each of which is a straight line):[28]

1) Maximum price: A horizontal line with the price equal to 1.5 times the monthly gross CONE value[29] for a representative peaking unit in each capacity region;
2) Sloped segment: A sloped straight-line segment that intersects with number (1) and passes through two points: (a) the point at which the capacity is equal to the NYCA Minimum ICAP Requirement or the Locational Minimum ICAP Requirement, and the price is equal to the NYCA/Locality Reference Point Price, and (b) the zero crossing point (ZCP) at which the price is equal to zero; and
3) Price floor: A horizontal line with the price equal to zero and the quantity includes all quantities greater than the ZCP quantity.

As a baseline assumption, we use the costs for a Gas CT unit as the representative peaking technology in 2022, 2026, and 2032. For capital costs, we use the assumptions from the Grid in Transition Evolution study, which start from a \$900/kW installed cost for a unit in upstate in 2019, then assumes a 1 percent per year real cost decrease through 2040. Using the inflation assumption of 2.1 percent per year from the 2021-2025 DCR study, this equates to a nominal 1.08 percent per year cost increase through 2040.[30] The installed costs are then scaled up for the capacity localities based on the ratio of installed costs of each locality compared to NYCA as seen in the 2021-2025 DCR Study. Table 10 shows the progression of Gas CT installed cost in nominal dollars for each of the model years, for NYCA, and each of the capacity localities.

[28] 2021-2025 DCR Study, pp. 108-109.

[29] ICAP maximum price is calculated as 150 percent of Gross CONE, multiplied by capacity at level of excess conditions (%), multiplied by the applicable winter-to-summer ratio for each locality, following the methodology used in the 2021-2025 DCR Study.

[30] 1.08 percent per year nominal cost increase is calculated as (1 + 2.1% inflation) * (1 - 1% real cost decrease) - 1. 2021-2025 DCR Study, p. 72. GIT Evolution Study, p. 98.

Table 10: Gas CT Installed Cost ($/kW) by Capacity Locality and Model Year

Year	NYCA	G-J Locality	NYC	Long Island
2022	$808	$1,069	$1,316	$1,138
2026	$844	$1,116	$1,373	$1,188
2032	$900	$1,191	$1,465	$1,267

Net EAS Revenues for the peaking technology are assumed to be the same as the revenues used in the 2021-22 ICAP demand curve. Finally, Net CONE and ICAP reference prices are calculated using the same financing and non-capital cost assumptions as the 2021-22 ICAP demand curve.[31] Table 11 summarizes the final ICAP reference prices:

Table 11: ICAP Reference Prices ($/kW-mo) by Capacity Locality and Year

Year	NYCA	G-J Locality	NYC	Long Island
2022	$9.02	$14.47	$22.85	$17.73
2026	$8.49	$14.20	$20.65	$13.72
2032	$8.34	$13.25	$18.85	$12.43

Table 12 shows ICAP maximum prices in each capacity locality and year:

Table 12: ICAP Maximum Prices ($/kW-mo) by Capacity Locality and Year

Year	NYCA	G-J Locality	NYC	Long Island
2022	$14.36	$19.28	$26.50	$21.49
2026	$14.66	$19.82	$26.96	$21.23
2032	$15.33	$20.61	$27.82	$21.98

3. Conversion to UCAP Demand Curves

In each capacity locality and season, the ICAP Demand Curve prices are translated to the UCAP demand curve prices that are used to clear the market against the UCAP supply curve. The ICAP max price and reference price are converted to UCAP $/kW-mo by dividing the ICAP values by (1-peaking unit EFORd), where the peaking unit

[31] This study uses the same modeling assumptions related to taxes, amortization period, etc. as in the 2021-2025 DCR Study.

derating factor is 4.3 percent for the Gas CT peaking technology from the 2021-2025 DCR study.[32,33] The conversion method is detailed in Table 13 below.

Table 13: Translation of ICAP Demand Curve Prices to UCAP Demand Curve Prices

ICAP Demand Curve	UCAP Demand Curve
ICAP Max Price ($/kW-mo)	UCAP Max Price= **ICAP Max Price / (1 - Peaking Unit EFORd)**
ICAP Ref. Price ($/kW-mo)	UCAP Ref. Price= **ICAP Ref. Price / (1 - Peaking Unit EFORd)**

Table 14 and Table 15 summarize the final UCAP reference and maximum prices:

Table 14: UCAP Reference Prices ($/kW-mo) by Capacity Locality and Year

Year	NYCA	G-J Locality	NYC	Long Island
2022	$9.43	$15.12	$23.25	$18.53
2026	$8.87	$14.84	$21.58	$14.33
2032	$8.72	$13.84	$19.70	$12.99

Table 15: UCAP Maximum Prices ($/kW-mo) by Capacity Locality and Year

Year	NYCA	G-J Locality	NYC	Long Island
2022	$15.00	$20.14	$27.69	$22.46
2026	$15.32	$20.71	$28.17	$22.18
2032	$16.02	$21.53	$29.07	$22.96

D. Market Clearing

The NYISO capacity spot market is modeled as clearing at the intersection of the UCAP supply curves and UCAP demand curves in NYCA and each capacity locality. The NYISO capacity market model clears in multiple stages using the logic of nested capacity localities.[34] In the first stage, the market model clears units within the smallest capacity localities, Zones J and K. Any segments of the supply curve that clear in Zone J also clear the market in the G-J Locality, so offer into the G-J Locality supply curve as zero priced resources. In the second stage, the market model clears units within the G-J Locality. Any segments of the supply curve that clear in the G-J Locality

[32] Use of the peaking unit EFORd for ICAP reference price to UCAP reference price conversion is a tariff change suggested in the NYISO stakeholder process. See NYISO, "Capacity Accreditation," presentation by Zach T. Smith, Ryan Patterson and Emily Conway to ICAPWG, August 30, 2021, p.13, available at https://www.nyiso.com/documents/20142/24130223/20210830%20NYISO%20-%20Capacity%20Accreditation_v10%20(002).pdf/.

[33] 2021-2025 DCR Study, p. 59 and Appendix A.

[34] NYISO ICAP Manual, Section 5.15.2.

(including Zone J), or Zone K, then offer into the NYCA supply curve as zero-priced resources. Finally, the market model clears the NYCA supply and demand curves.

The final clearing price in each capacity locality is the highest price for which capacity segments in that locality are eligible. For example, if the initial clearing price in G-J Locality is higher than the initial clearing price in NYC, the final clearing price in NYC is set to that of the G-J Locality. As a result, the Zone J final clearing price is always at least as high as the G-J Locality final clearing price, the G-J Locality final clearing price is always at least as high as the NYCA final clearing price, and the Zone K final clearing price is always at least as high as the NYCA final clearing price. All crossing point prices are denominated in nominal year dollars. Note that the crossing points on the supply and demand curves for each capacity locality in this report and Appendix A show the unadjusted initial clearing prices, which may be lower than the final clearing price.

E. Sensitivities

As noted earlier, we focus primarily on the first five years of market operation with BSM Reforms in place. Across this period of time, several resources are expected to exit or enter the market, load changes are expected to remain relatively modest, and CLCPA resources will increase in importance in NYISO operations and market outcomes as they come into service.

1. Model Year 2032

The later years of the next decade are likely to see far greater change in supply, demand and technological advancement than typically experienced in the electric industry. The introduction of new CLCPA resources will accelerate over this time period. State efforts to drive electrification of the transportation and building sectors will magnify the importance of demand growth and changing demand shape in system operations and market outcomes, and one or more additional major transmission projects could be placed in service. Finally, given the pace of change needed for the Northeast states to meet their climate policy mandates, this time frame may be one of new technological innovation and rapidly changing cost and performance vectors for existing and emerging sources of energy supply.

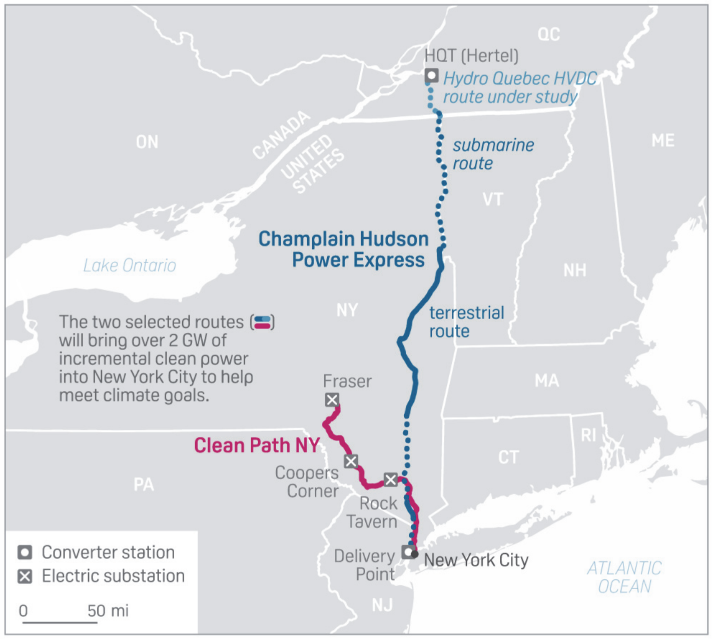
These factors make it very difficult to forecast future market outcomes over this time period with any degree of certainty. However, we carry the analysis forward to model year 2032 to explore the *potential* impacts of changing system conditions over this time under a limited set of scenarios that seem relevant based on current information, and we review the impact of those potential future conditions on the ability of the capacity market to produce competitive and reliable outcomes even beyond the first five years of a capacity market with the BSM Reforms in place.

2. Transmission Addition Sensitivities

In the next ten years, there are a series of large transmission projects proposed or planned in New York that, if or when completed, could change the geographic mix of resources needed to meet New York's overall resource adequacy requirements. In particular, there are two projects that are planned to be built by 2032 that were selected as part of the New York State Energy Research and Development Authority (NYSERDA) Tier 4 Renewable Energy Credit program: 1) Transmission Developer Inc. (TDI) is developing the 1,250 MW Champlain Hudson Power Express transmission line from Quebec into New York City, with a planned in-service date of 2025;

and 2) Forward Power is developing the 1,300 MW Clean Path New York (CPNY) line from Zone E into New York City, with in-service date as early as 2027.[35]

Figure 7: Map of Champlain Hudson Power Express and Clean Path NY Transmission Projects



Source: S&P Global Platts, NYSERDA, individual companies

We model transmission sensitivities which analyze the effect of these transmission projects on both the capacity supply and demand curves. Given the differences in source regions and endpoints of the transmission lines, we model the TDI line as a supply-side increase in resources installed capacity in Zone J, and the CPNY line as a reduction in LCR for both the Zone J and Zone G-J Locality, along with a decrease in IRM.[36] In both cases, we assume a 5 percent derating factor. Consequently, the transmission sensitivities include the following changes to inputs:

[35] Adler, Kevin, IHS Markit, "New York State selects two power transmission projects to deliver 2.55 GW of renewable energy," September 21, 2021, available at https://ihsmarkit.com/research-analysis/new-york-state-selects-two-power-transmission-projects-to-deli.html.

[36] The IRM decrease is modeled to be analogous with the impact of transmission topology changes between 2024/25 and 2025/26 for expedited deliverability studies in 2020-02 based on the assumptions used by NYISO in its Buyer Side Mitigation process. This represents a decrease of IRM by 0.4% in NYCA. NYISO, "BSM Assumptions for EDS - 2020 - 02," presentation by Jonathan Newton to ICAPWG, July 22, 2021, available at https://www.nyiso.com/documents/20142/23240761/IMM_ICAPWG_072621.Final.pdf/.

(1) **TDI only sensitivity**
    (a) 2026: Addition of 1,188 MW UCAP from TDI delivered into Zone J
(2) **CPNY only sensitivity**
    (a) 2032: Reduction of UCAP requirement for both Zone J and G-J Locality by 1,235 MW UCAP, decrease in IRM of 0.4 percent
(3) **TDI and CPNY sensitivity**
    (a) 2026: Addition of 1,188 MW UCAP from TDI delivered into Zone J
    (b) 2032: Reduction of UCAP requirement for both Zone J and G-J Locality by 1,235 MW UCAP, decrease in IRM of 0.4 percent

3. WACC Risk Premium Sensitivity

A possible outcome of the current BSM reform proposal is to change the risk profile for new entrants into the NYISO electricity market. In particular, the CONE of a new generating resource depends on the immediate capital costs for constructing the unit, along with the financial parameters which determine the payback period and return on investment for that unit. One of the key financial inputs is the Weighted Average Cost of Capital (WACC), which comprises the return on equity and cost of debt, along with the debt-to-equity (D/E) ratio used to finance the project. The WACC represents the cost to the new entrant of financing capital and should reflect in part the risk of construction and operations of the resource. In the 2021-2025 DCR, the return on equity was calculated as 13.0 percent, the cost of debt as 6.7 percent, and the D/E ratio as 55 percent, for a nominal after-tax WACC for the NYCA demand curve of 8.52 percent.[37]

Potomac Economics has argued in the context of changes to market rules in ISO-NE that in a capacity market without a mitigation construct, "[r]ising risk associated with future price volatility will raise the CONE for new resources," through increases in financial risk as embodied in the WACC.[38] They argue that new entry supported by out-of-market payments may lead to higher revenue volatility, and require a recalculation of the WACC to reflect the higher investment risk.[39] The results of their calculations in the ISO-NE context were an estimated decrease in cost of debt, from 6.00 percent to 5.06 percent, an increase in cost of equity, from 13.00 percent to 14.58 percent, and a decrease in debt-to-equity ratio, from 55 percent to 42.5 percent.[40]

The risk factors that Potomac has identified in the ISO-NE context have analogues in the NYISO market, in terms of the type and timeframe of market rule changes and new resource additions. Thus, for the purpose of our analysis, and to evaluate the potential impact of elevated risk premiums in capacity market offers, we apply the

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[37] The after-tax WACC used in the demand curve varies by capacity locality due to differences in tax treatment between localities. 2021-2025 DCR Study, pp. 7-8.

[38] Potomac Economics, "Evaluation of Changes in the Minimum Offer Price Rules on Financial Risk," July 26, 2021, p.6, available at https://www.iso-ne.com/static-assets/documents/2021/07/a02b_potomac_economics_presentation_changes_in_mopr_on_financial_risk.pdf.

[39] Potomac Economics, "Evaluation of Changes in the Minimum Offer Price Rules on Financial Risk," July 26, 2021, p. 16, available at https://www.iso-ne.com/static-assets/documents/2021/07/a02b_potomac_economics_presentation_changes_in_mopr_on_financial_risk.pdf..

[40] Potomac Economics, "Evaluation of Changes in the Minimum Offer Price Rules on Financial Risk," September 13, 2021, p. 19 and ISO-NE, "Competitive Capacity Markets without a Minimum Offer Price Rule," September 13-14, 2021, p. 7, available at https://www.iso-ne.com/static-assets/documents/2021/09/2021_09_13_14_mc_a02a_emm_framework_model_initial_input_assumptions_model_results.zip.

WACC adjustments estimated by Potomac to the parameters of the NYISO demand curve. The adjustments are summarized in Table 16 below:

Table 16: Summary of WACC Risk Premium Adjustments

	ISO-NE			**NYISO Risk Premium Sensitivity**		
	Filed Value from Net CONE study	**MOPR adjustment**	**Adjusted Value**	**Filed Value from DCR study**	**Analogous adjustment**	**Adjusted Value**
Cost of Debt	6.00%	-0.94%	5.06%	6.70%	-0.94%	**5.76%**
Cost of Equity	13.00%	1.58%	14.58%	13.00%	1.58%	**14.58%**
D/E Ratio	55%	-12.5%	42.5%	55%	-12.5%	**42.5%**

These adjustments are incremental changes made to the sensitivity which includes TDI and CPNY transmission in service and apply to model years 2026 and 2032 only.

(4) **Additional WACC Risk Premium with TDI and CPNY sensitivity**
   - (a) 2026: Addition of 1,188 MW UCAP from TDI delivered into Zone J
   - (b) 2032: Reduction of UCAP requirement for both Zone J and G-J Locality by 1,235 MW UCAP, decrease in IRM of 0.4%
   - (c) Modified WACC with risk premium used in demand curve construct in 2026 and 2032

4. Alternate Peaking Technology Sensitivity

In future years, advances in technology may change the fuel and technology type chosen by marginal new entrant into the New York market. In particular, advances in battery technology and decreases in costs may make battery energy storage systems (BESS) an economically viable option for consideration as the peaking technology in the Demand Curve Reset process.

The Grid in Transition Evolution Study assumed an installed cost of $1,400/kW installed cost for a 4-hour duration BESS in upstate in 2019, then assumed a real 4 percent per year cost reduction through 2040 (equivalent to a nominal 1.98 percent per year cost reduction once the 2.1 percent inflation rate is taken into account), which means that by 2034, the BESS is assumed to be cheaper on an installed cost basis than a gas combustion turbine unit.[41] The 2021-2025 DCR Study evaluated a 4-hour BESS as a possible peaking technology, using assumptions of a 200 MW capacity, 85 percent storage round-trip efficiency, and 15 year amortization period, among other parameters.[42] In addition, the 2021-2025 DCR Study included calculation of potential Net EAS Revenues for the 4-hour BESS, as part of its Net CONE calculation.

The Alternate Peaking Technology sensitivity combines battery cost inputs from the Grid in Transition Evolution Study with Net EAS Revenues and operational and financing assumptions from the 2021-2025 DCR study to come up with a combined set of inputs to the capacity market model. Since the marginal capacity value for battery storage units is less than 100% in each year, the ICAP Reference Price and ICAP max prices are also divided by

[41] GIT Evolution Study, p.98.

[42] 2021-2025 DCR Study, p.73 and Appendix A.

the marginal capacity value, to account for the discounted capacity that is paid under the capacity accreditation method:

$$ICAP\ Reference\ or\ Max\ Price\ (adj.) = \frac{ICAP\ Reference\ or\ Max\ Price\ (unadj.)}{4\ hour\ Battery\ Storage\ Marginal\ Capacity\ Value}$$

Table 17 and Table 18 show the costs and resulting reference prices under the Alternate Peaking Technology sensitivity.

(5) **Alternate Peaking Technology sensitivity**
   (a) 2026: Demand Curve parameters based on 4 hour BESS as peaking technology
   (b) 2032: Demand Curve parameters based on 4 hour BESS as peaking technology

Table 17: 4-Hour Battery Energy Storage System Installed Cost ($/kW) by Capacity Locality and Model Year

Year	NYCA	G-J Locality	NYC	Long Island
2026	$1,217	$1,281	$1,511	$1,304
2032	$1,079	$1,136	$1,340	$1,156

Table 18: ICAP Reference Prices by Demand Curve Peaking Technology

Gas CT as Peaking Technology				
Year	**NYCA**	**G-J Locality**	**NYC**	**Long Island**
2026	$8.49	$14.20	$20.65	$13.72
2032	$8.34	$13.25	$18.85	$12.43
4 Hour BESS as Peaking Technology				
Year	**NYCA**	**G-J Locality**	**NYC**	**Long Island**
2026	$16.45	$19.24	$25.03	$17.32
2032	$16.59	$18.97	$24.96	$16.78

Table 19: UCAP Reference Prices by Demand Curve Peaking Technology

Gas CT as Peaking Technology				
Year	**NYCA**	**G-J Locality**	**NYC**	**Long Island**
2026	$8.87	$14.84	$21.58	$14.33
2032	$8.72	$13.84	$19.70	$12.99
4 Hour BESS as Peaking Technology				
Year	**NYCA**	**G-J Locality**	**NYC**	**Long Island**
2026	$16.96	$19.83	$25.80	$17.86
2032	$17.10	$19.56	$25.74	$17.30

IV. Results

A. Baseline Model Results: Model Years 2022 and 2026

Under the assumptions described in Section III, the capacity prices for 2022 and 2026 are described in Table 20:

Table 20: Capacity Market Clearing Prices ($/kW-mo) by Capacity Locality and Season, 2022-2026

Capacity Locality	Summer		Winter	
	2022	2026	2022	2026
NYCA	$4.60	$5.07	$3.33	$4.23
G-J Locality	$7.46	$9.02	$3.87	$5.81
NYC (J)	$7.46	$12.83	$3.87	$7.51
LI (K)	$7.13	$14.61	$3.66	$12.05

The quantity of cleared capacity by model year are described in Table 21:

Table 21: UCAP Clearing Quantities (MW) by Capacity Locality and Season, 2022-2026

Capacity Locality	Summer		Winter	
	2022	2026	2022	2026
NYCA	36,543	34,996	37,540	35,200
G-J Locality	13,791	12,376	14,268	12,868
NYC (J)	9,459	8,638	9,667	9,107
LI (K)	5,817	5,076	5,985	5,286

B. Results for Additional Scenarios

1. *Baseline Model Results in Model Year 2032*

Under the assumptions described in Section III, the capacity prices for 2032 are described in Table 22:

Table 22: Capacity Market Clearing Prices ($/kW-mo) by Capacity Locality and Season, 2032

Capacity Locality	Summer 2032	Winter 2032
NYCA	$6.89	$6.28
G-J Locality	$9.58	$7.09
NYC (J)	$13.89	$10.93
LI (K)	$14.52	$13.18

The quantity of cleared capacity by model year are described in Table 23:

Table 23: UCAP Clearing Quantities (MW) by Capacity Locality and Season, 2032

Capacity Locality	Summer 2032	Winter 2032
NYCA	35,607	36,234
G-J Locality	13,076	13,746
NYC (J)	8,792	9,345
LI (K)	5,429	5,676

2. Transmission Addition Sensitivities

With the introduction of the TDI transmission project in 2026 and the CPNY project in 2032, the capacity prices for 2026 and 2032 are described in Table 24:

Table 24: Transmission Sensitivity: Capacity Market Clearing Prices ($/kW-mo) by Capacity Locality and Season, 2026-2032

Clearing Prices ($/kW-mo)	2026 with TDI		2032 with TDI and CPNY	
	Summer	Winter	Summer	Winter
NYCA	$5,07	$4.23	$7.81	$6.40
G-J Locality	$9.02	$5.81	$9.28	$7.09
NYC (J)	$9.02	$6.05	$9.28	$7.36
LI (K)	$14.61	$12.05	$14.52	$13.18

The quantity of cleared capacity by model year are described in Table 25:

Table 25: Transmission Sensitivity: UCAP Clearing Quantities (MW) by Capacity Locality and Season, 2026-2032

Capacity Locality	2026 with TDI		2032 with TDI and CPNY	
	Summer	Winter	Summer	Winter
NYCA	34,996	35,200	35,102	36,103
G-J Locality	12,376	12,868	11,840	12,435
NYC (J)	8,920	9,207	7,808	8,267
LI (K)	5,076	5,286	5,429	5,676

3. *WACC Risk Premium Sensitivity*

Clearing prices under the WACC Risk Premium sensitivity (with TDI and CPNY) in model years 2026 and 2032 are described in Table 26:

Table 26: WACC Risk Premium Sensitivity: Capacity Market Clearing Prices ($/kW-mo) by Capacity Locality and Season, 2026-2032

Clearing Prices ($/kW-mo)	2026 with TDI and Risk Premium		2032 with TDI/CPNY and Risk Premium	
	Summer	Winter	Summer	Winter
NYCA	$5.57	$4.73	$7.81	$7.09
G-J Locality	$9.02	$5.81	$9.58	$7.09
NYC (J)	$9.02	$6.05	$9.58	$7.36
LI (K)	$17.49	$14.41	$17.31	$15.71

The quantity of cleared capacity by model year are described in Table 27:

Table 27: WACC Risk Premium Sensitivity: UCAP Clearing Quantities (MW) by Capacity Locality and Season, 2026-2032

Capacity Locality	2026 with TDI and Risk Premium		2032 with TDI/CPNY and Risk Premium	
	Summer	Winter	Summer	Winter
NYCA	35,152	35,302	35,664	36,286
G-J Locality	12,532	12,970	11,970	12,562
NYC (J)	9,001	9,263	7,889	8,334
LI (K)	5,076	5,286	5,429	5,676

4. Alternate Peaking Technology Sensitivity

Clearing prices under the Alternate Peaking Technology sensitivity in model years 2026 and 2032 are described in Table 28:

Table 28: Alternate Peaking Technology Sensitivity: Capacity Market Clearing Prices ($/kW-mo) by Capacity Locality and Season, 2026-2032

Clearing Prices ($/kW-mo)	2026 with Battery Peaking Tech.		2032 with Battery Peaking Tech.	
	Summer	Winter	Summer	Winter
NYCA	$7.37	$5.13	$7.81	$6.67
G-J Locality	$9.02	$5.81	$12.09	$7.93
NYC (J)	$15.35	$8.98	$18.14	$14.28
LI (K)	$18.21	$15.01	$19.33	$17.55

The quantity of cleared capacity by model year are described in Table 29:

Table 29: Alternate Peaking Technology Sensitivity: UCAP Clearing Quantities (MW) by Capacity Locality and Season, 2026-2032

Capacity Locality	2026 with Battery Peaking Tech.		2032 with Battery Peaking Tech.	
	Summer	Winter	Summer	Winter
NYCA	35,541	35,894	36,998	37,620
G-J Locality	12,644	13,043	13,215	13,952
NYC (J)	8,638	9,107	8,792	9,345
LI (K)	5,076	5,286	5,429	5,676

C. Observations

The results presented above represent a clearing of the NYISO capacity market subject to the BSM Reforms proposed by NYISO, and alongside a major transformation of the electric industry driven by the state's need to meet the obligations of the CLCPA. Specifically, changes underlying the results for 2026 include rapid alteration of the resources on the system compared to 2022. In the years from 2022 to 2026, the following major changes to the system are assumed:

Changes to the system, 2022-2026

- Fossil fuel ICAP capacity has decreased by 2,834 MW;
- Onshore wind has increased by 244 MW;
- Offshore wind has increased by 1,200 MW;
- Grid-connected solar photovoltaic capacity has increased by 5,000 MW;
- Battery storage resources (two-hour and four-hour) has increased by 1,571 MW.

In total, ICAP capacity on the system has increased on net by 5,082 MWs. However, since most of the added capacity is from solar, wind and storage resources, while most of the decrease is associated with thermal generating resources, total UCAP decreases by 702 MW. Despite the significant addition of zero-offer CLCPA resources, the market retains 31,845 MW (ICAP) of thermal, hydro and nuclear capacity, 2,571 MW (ICAP) of pumped storage and other resources, and 3,200 MW (ICAP) of non-generator resources (net imports, SCRs, and UDRs). In total, the market clears 36,543 MW UCAP in summer 2022, and 34,996 MW UCAP in summer 2026.

In the 2026 scenario in which the TDI transmission line is in operation, the changes to the system *also include* the addition of 1,250 MW ICAP of resource capacity injected directly into Zone J. In this case, ICAP capacity in Zone J has increased on net by 1,621 MWs. Given the mix of resources added and leaving Zone J, including peaker rule retirements and new offshore wind, and the injection of high-availability generation through TDI, total UCAP increases by 462 MW. Despite the significant addition of zero-offer CLCPA resources, the Zone J market retains 7,796 MW (ICAP) of thermal capacity, and 781 MW ICAP of other resources (e.g., imports, SCRs). In total, in summer 2026 the market clears 8,920 MW UCAP in Zone J, compared to 8,638 MW UCAP in Zone J without TDI.

The results for the scenarios modeled for ten years out - 2032 - are necessarily less reliable than those observed over the first five years. Changes underlying the scenarios for 2032 include additional major changes to the resources on the system, on top of those summarized above for 2026. Specifically, in the years from 2026 to 2032, the following major changes to the system are assumed in the base model scenario:

Changes to the system, 2026-2032

- Onshore wind has increased by *an additional* 7,715 MW;
- Offshore wind has increased by *an additional* 6,391 MW;
- Grid-connected solar photovoltaic capacity has increased by *an additional* 11,613 MW;
- Battery storage resources (two-hour and four-hour) has increased by *an additional* 2,486 MW.

In total, from 2026-2032 we model and increase of ICAP capacity on the system on net by 27,698 MWs. However, since most of the added capacity is from solar, wind and storage resources, total UCAP increases by only 369 MW. Despite the significant addition of zero-offer CLCPA resources, the market retains 30,659 MW (ICAP) of thermal, hydro and nuclear capacity, 3,251 MW (ICAP) of pumped storage and other resources, and 3,200 MW (ICAP) of non-generator resources (net imports, SCRs, and UDRs). In total, the market clears 35,607 MW UCAP in summer 2032. These general results do not change qualitatively in our assessment of other scenarios (i.e., adding CPNY, adjusting demand curves to add a development risk premium, or the use of battery storage as peaking technology).

Based upon our analysis, we arrive at the following observations associated with continued operation of the capacity market subject to the BSM Reforms proposed by NYISO:

- ***The analysis reflects a rapidly changing system*** - many factors affect the modeling set up and results in each year, season, and locality. Exogenous factors lead to a significant amount of resource addition and attrition over the study period. In addition, while we do not build out the supply curves on a specific unit-by-unit basis (and instead group resources by technology type), it is clear that market dynamics lead to some retirement of resources based on market economics. The modeling period includes an unprecedented potential for changes in electricity demand, going-forward costs of existing units, cost of the demand curve reference technology, ICAP/UCAP translation factor, CLCPA resource growth, and transmission topology.
- ***With BSM reforms in place, the NYISO capacity auction remains competitive*** - the combination of resource entry/exit - both due to exogenous and market economic factors - and proper accounting for resources' contributions to reliability lead to capacity auction results consistent with competitive market outcomes.
- ***With BSM reforms in place, the NYISO capacity auction continues to produce reliable outcomes that meet resource adequacy requirements*** - The analysis shows the capacity market can continue to generate competitive market outcomes, and provide sufficient financial incentives for the economic retention of resources needed for reliability, and for the economic entry and exit of resources. This result is sustained in all seasons, zones and scenarios over the first five years (i.e., for both model years 2022 and 2026).
- ***Scenarios with a longer-term view (2032) and involving other factors yield similar results*** - While the results for ten years out - 2032 - are necessarily more uncertain and speculative, various scenarios completed for that model year also demonstrate continued competitive market outcomes and the retention through the capacity market construct of sufficient resources to meet resource adequacy requirements.