UNITED STATES OF AMERICA BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc. submits tariff filing per 35.13(a)(2)(iii): 205: **BSM Capacity Accreditation Market Design Docket No. ER22-772-000** submitted on 1/5/2022 3:18:12 PM, Filing Type code: 10

COMMENTS OF CLEAN ENERGY ADVOCATES

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COMMENTS OF CLEAN ENERGY ADVOCATES

Pursuant to Rule 211 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"),¹ Sierra Club, the Natural Resources Defense Council, Sustainable FERC Project, American Clean Power Association ("ACP"), Advanced Energy Economy ("AEE"), Alliance for Clean Energy New York ("ACE NY"), Cypress Creek Renewables, LLC, Enel North America, Inc., New York Battery and Energy Storage Technology Consortium ("NY-BEST"), Centrica Business Solutions, Tesla, Inc., Borrego Solar, Inc., and Voltus, Inc. (collectively, "Clean Energy Advocates" or "CEAs") submit this Comment in support of the January 5, 2022 filing² submitted by New York Independent System Operator, LLC ("NYISO") under Section 205 of the Federal Power Act ("FPA") in the above-captioned docket.³

I. SUMMARY OF ARGUMENTS

NYISO has put before the Commission a package of revisions to its Market Administration and Control Area Services Tariff ("NYISO tariff" or "tariff") consisting of three separate and distinct tariff rules.⁴ One of NYISO's proposed revisions would limit application of NYISO's buyer-side mitigation ("BSM") to exempt from mitigation resources necessary to comply with New York State's requirement to achieve 100% clean electricity production by 2040 as required by the Climate Leadership and Community Protection Act ("CLCPA"). The second proposal would adopt tariff language marking the NYISO's intent to

¹ 18 C.F.R. § 385.211 (2021).

² New York Independent System Operator, Inc., Excluding Certain Resources from the "Buyer-Side" Capacity Market Power Mitigation Measures, Adopting a Marginal Capacity Accreditation Market Design, and Enhancing Capacity Reference Point Price Translation ("Transmittal Letter") (Jan. 5, 2022), Accession No. 20220105-5146. ³ The views and opinions expressed in this filing do not necessarily reflect the official position of each of the individual members of ACP, AEE, NY-BEST, or ACE-NY.

⁴ Transmittal Letter at 2, 4, 19, 51 ("Each of the proposed tariff provisions. . . includes language specifying its own implementation date.").

implement a future, undefined capacity accreditation methodology, to be based on "factors, set annually by the ISO in accordance with Section 5.12.14.3 and ISO Procedures, that reflect the marginal reliability contribution of the ICAP Suppliers."⁵ The third proposal would adjust the rules governing the ICAP to Unforced Capacity ("UCAP") translation that is done for the peaking plant used to set the ICAP Reference Price for the ICAP Demand Curves in each quadrennial reset.⁶

A. BSM Reform Must Move Forward without Delay.

Clean Energy Advocates urge the Commission to approve NYISO's Section 205 proposal to eliminate application of the BSM rules to resources required to meet state CLCPA targets, which will enable these resources to offer into the capacity market at a price that represents their true costs and put an end to the unjust, unreasonable and unduly discriminatory rates that result from application of the BSM.⁷ If left in place, existing BSM rules will continue to harm consumers at an increasing pace estimated to reach approximately \$460 million per year by 2030. As generation is increasingly driven by state policies in order to meet CLCPA deadlines of a 70% clean energy grid by 2030 and a 100% clean energy grid by 2040, the continued application of BSM rules to state policy resources will rapidly disconnect the ICAP from actual market supply—a result that is not only economically absurd, but fundamentally unreasonable.

⁵ *Id.* at 48.

⁶ Based on the record presented by NYISO, CEAs believe this third proposal is just, reasonable, and not unduly discriminatory, but will not be discussing it further in this filing.

⁷ While differences exist on the how to reform buyer side mitigation policies, a majority of Commissioners have expressed the view that the current application of these policies to impede state authority over generation is unjust and unreasonable. Technical Conference Regarding Resource Adequacy in the Evolving Electricity Sector, at 9 (Comments of Chairman Glick), 22 (Comments of Comm'r Christie), 29–30 (Comments of Comm'r Clements regarding the unworkability of the Expanded MOPR), Docket No. AD21-10-000 (Mar. 23, 2021) ("Tech. Conf. Tr."), Accession No. 20210426-4004.

As described in NYISO's filing and elaborated upon below, the proposed BSM reforms will result in capacity prices that send accurate signals for new capacity resources to enter the market, and for existing ones to exit. It avoids requiring consumers to pay for unnecessary capacity. The reformed BSM rules respect state authority over generation⁸ and end improper use of FERC-jurisdictional markets to attempt to nullify state policy. NYISO's filing will lead to just and reasonable rates by anchoring the capacity market in economic fundamentals, including accommodating legitimate state policy decisions.

Commissioners have stressed the urgent need for reform of NYISO's policies⁹ and Clean Energy Advocates agree with NYISO that the Commission must approve the BSM tariff proposal without delay. CEAs share NYISO's concern that "it is very important that the BSM Reforms . . . be implemented during Class Year 2021 to avoid the risk that resources that serve CLCPA goals will be over-mitigated under the currently effective BSM Rules."¹⁰ The CEAs therefore join NYISO in requesting that the Commission issue an order making NYISO's BSM reforms effective by March 6, 2022.¹¹

B. NYISO's Capacity Accreditation Proposal Lacks Necessary Detail to Meet Section 205 Requirements as Submitted and Requires Further Oversight from FERC.

NYISO's proposed capacity accreditation reforms would impose sweeping changes to the foundational rules for how all resource capacity is credited and compensated in the ICAP market. NYISO's proposal is impermissibly vague and fails to comply with the filed rate

⁸ 16 U.S.C. § 824(b)(1).

⁹ See, e.g., Tech. Conf. Tr. at 9:10-20 (Comments of Chairman Richard Glick); *N.Y. Indep. Sys. Operator, Inc.*, 175 FERC ¶ 61,081 (Apr. 29, 2021) (Glick, Chairman, concurring at P 3) ("I urge NYISO and its stakeholders to move expeditiously to replace these buyer-side market power mitigation rules"); *N.Y. State Pub. Serv. Comm'n, et. al. v. N.Y. Indep. Sys. Operator, Inc.*, 174 FERC ¶ 61,110 (Feb. 18, 2021) (Clements, Comm'r, concurring at P 5) ("I look forward to engaging with my colleagues to work with the State of New York, NYISO, and the stakeholder community to reexamine the current capacity market construct to find a durable solution that yields just and reasonable rates for NYISO customers.").

doctrine and rule of reason. Besides expressing its intent to pursue a capacity accreditation based on a resource's marginal availability, critical questions such as what the methodology will be, who it will affect and how it will affect them, how it will interact with reliability standard requirements, or even when it will go into effect are unspecified. Furthermore, NYISO proposes to keep all of the necessary analysis and implementation details of this core foundation of the market outside of the Commission's oversight. While CEAs support a proceeding to determine whether, what, and when changes to NYISO's capacity accreditation methodology might be necessary in light of New York's future highly decarbonized grid, such a foundational element of the capacity market requires thorough study, accurate analysis, and focused stakeholder input in order to ensure the outcome is just, reasonable, and not unduly discriminatory. None of these efforts preceded NYISO's submitted proposal. NYISO assert that capacity reform is of great urgency in light of BSM reforms are undermined by the number of years before it plans to implement its proposal, years that can and must be spent working closely with stakeholders to take a good long look at its accreditation methodology options before it chooses to leap.

As set forth in greater detail in Section VI., because NYISO's capacity accreditation proposal is incomplete, lacking in substantial evidence to support full approval, and would provide no further opportunity for FERC to review critical design or implementation details, the Commission cannot approve NYISO's capacity accreditation proposal as submitted. This presents the Commission with three potential paths forward pursuant to its 205 authority, all of which are predicated on approval of NYISO BSM reforms by March 6, 2022:

• <u>Approve BSM in Whole: Reject Capacity Accreditation in Whole:</u> The

Commission need not-and should not-tie BSM and Capacity Accreditation

reforms together and NYISO has plenty of time to give such a fundamental market element the focused attention it requires. Given the need for additional modeling, analysis, and decision-making requiring stakeholder approval necessary to remedy these omissions, the Commission should consider returning this issue to NYISO and its stakeholders with direction on elements necessary for approval of a future filing.

- <u>Approve BSM in Whole:</u> Issue a Deficiency Letter or Paper Hearing on Capacity Accreditation: Alternatively, the Commission could issue a deficiency letter or hold a paper hearing to give NYISO the opportunity to complete a thorough market impact and reliability analysis of its proposal and remedy the current filing deficiencies.
- <u>Approve BSM in Whole:</u> Approve the Accreditation Proposal Subject to Further Section 205 Filings: Finally, the Commission could decide to approve the capacity accreditation in part, with minor modifications requiring NYISO to file further tariff revisions setting out those components of its rate that significantly affect rates. This would ensure that development and implementation of the NYISO's proposal is subject to FERC oversight.

II. BACKGROUND

A. New York's Power System Is Undergoing an Unprecedented Energy Transition That Is Driving Reform of NYISO's Capacity Market to Maintain Resource Adequacy.

New York's power system is undergoing an unprecedented transition from a grid where energy is largely produced by central station fossil fuel generation, towards a grid with

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increased renewable intermittent resources and distributed generation.¹² The pace of this transition is driven by public policies as well as technological advancements that are expanding the capabilities and lowering the costs of clean resources.¹³ New York addresses environmental externalities through a range of public policies and regulations that serve as both carrots and sticks.¹⁴

Most notably, New York's landmark Climate Leadership and Community Protection Act¹⁵ is reshaping New York's electricity sector and the composition of its grid. Based on New York's determination that climate change is adversely affecting economic well-being, public health, natural resources, and the environment, the CLCPA sets ambitious climate and clean energy targets that require all sectors of the State's economy to collectively achieve 40% emissions reductions from 1990 levels by 2030 and 85% emissions reductions by 2050,¹⁶ as well as to achieve net-zero greenhouse gas ("GHG") emissions by 2050.¹⁷ Within the electric sector, it requires that 70% of the State's electricity supply come from renewable energy sources by 2030 and that this supply is emissions free by 2040.¹⁸ It also sets technologyspecific goals with respect to offshore wind, storage, distributed solar, and energy efficiency.¹⁹

Critically, the CLCPA includes several important provisions to prioritize equity in fighting climate change, reduce criteria pollutants caused by the burning of fossil fuels, and to

¹² NYISO, *Reliability and Market Considerations for a Grid In Transition*, at 4 (Dec. 20, 2019) ("NYISO Grid In Transition Report"), <u>https://www.nyiso.com/documents/20142/2224547/Reliability-and-Market-Considerations-for-a-Grid-in-Transition-20191220%20Final.pdf/61a69b2e-0ca3-f18c-cc39-88a793469d50.</u>

 $[\]overline{^{13}}$ Id.

¹⁴ A list of major policy drivers affecting the electricity sectors can be found in: NYISO, *Reliability and Market Considerations For A Grid In Transition*, at 8–9, Table 1: Potential NYISO Market Design Enhancements (May 2019),

 $[\]frac{https://www.nyiso.com/documents/20142/6785167/Grid+in+Transition+DRAFT+FOR+POSTING.pdf/74eb0b20}{-6f4c-bdb2-1a23-7d939789ed8c?version=1.1\&t=1558703451381\&download=true.}$

¹⁵ S.B. 6599, 2019–2020 Reg. Sess. (N.Y. 2019) (codified as Ch. 106, L. 2019) ("CLCPA").

 $^{^{16}}$ Id. § 2.

 $^{^{17}}$ Id.

¹⁸ *Id.* §§ 1, 4. ¹⁹ *Id.* § 4.

ensure that disadvantaged communities are not disproportionately burdened in the State's clean energy transition.²⁰

The electric sector targets are the foundation of the CLCPA's comprehensive framework for decarbonizing the State's economy: the transformation of New York's "electricity system is assumed to be the backbone of a decarbonized economy as fossil-fueled end-uses electrify in transportation, buildings, and industry."²¹ The electric sector targets, together with other public policies such as nitrogen oxide emission limits, energy infrastructure siting policy and permitting decisions, New York City's codes to eliminate residual oil and reduce carbon emissions in large and medium-sized New York City buildings, and the Regional Greenhouse Gas Initiative are significantly impacting which resources decide to enter and exit NYISO's markets.²²

New York State laws and regulations are designed to address environmental externalities such as air pollution and result in revenues as well as costs for various energy resources. As NYISO readily acknowledges, the CLCPA—not its markets—is "expected to be the principal driver of changes to the resource mix in New York State over the next two decades."²³ According to NYISO: "It is already apparent . . . that the CLCPA and regulations adopted under it will drive resource investment and retirement decisions and, ultimately, the composition of the overall resource mix in New York."²⁴

²⁰ See id. §§ 2, 7.

²¹ Energy and Environmental Economics, Inc. ("E3"), *Pathways to Deep Decarbonization in New York State*, at 18 (June 24, 2020), <u>https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B9163B892-</u>F852-4074-B3AA-F67D918F7BE0%7D.

²² See NYISO, New York's Clean Energy Grid of the Future, at 19–25 (2021) ("NYISO Power Trends 2021"), https://www.nyiso.com/documents/20142/2223020/2021-Power-Trends-Report.pdf/471a65f8-4f3a-59f9-4f8c-3d9f2754d7de.

²³ Transmittal Letter at 3.

²⁴ *Id.* at 13.

The central question arising from New York's clean energy transition for the NYISO is "how the wholesale markets in New York can continue to provide the pricing and investment signals necessary to reflect system needs and to incent resources capable of resolving those needs."²⁵ This question is especially pertinent for NYISO's capacity market. As NYISO acknowledges, it must enhance the capacity market "to improve the resource adequacy models used to set the Installed Reserve Margin and Locational Capacity Requirements and better align compensation with performance given the changing power grid."²⁶ NYISO's capacity market will need to evolve to rely on an increasing share of emerging resources like utilityscale wind, solar, battery storage, and distributed energy resources ("DERs"), including demand response and energy efficiency resources, which reduce demand for electricity and thereby help maintain resource adequacy.²⁷

B. The Purpose of a Capacity Market Is to Support Reliability at Minimal Cost to Consumers through Price Signals Capable of Guiding the Orderly Entry and Exit of Resources.

Electricity capacity markets are a means to an end, not an end in themselves.²⁸ Their purpose is to protect the public from any excessive costs for maintaining resource adequacy, which is the ability of the electric system to supply electrical demand at all times. In most of the United States, the electric system is considered "adequate" if the system has enough supply available to ensure that an involuntary loss of load (blackout) occurs no more than once every

²⁵ NYISO Grid In Transition Report at 4.

²⁶ Id. at 9.

²⁷ See Kathleen Spees et al., *The Benefits of Energy Efficiency Participation in Capacity Markets*, The Brattle Group, at i (Apr. 2021),

https://www.aee.net/hubfs/The%20Benefits%20of%20Energy%20Efficiency%20Participation%20in%20Capacity %20Markets1.pdf.

²⁸ *NYPSC and New York State Energy Research and Dev. Auth. v. NYISO*, 173 FERC ¶ 61,060 (Oct. 15, 2020) (Glick, Comm'r, dissenting at P 15).

ten years.²⁹ Ensuring adequate resource capacity involves a complex combination of forecasting demand and providing sufficient incentives to ensure future supply will be online to meet that demand.

Capacity markets are just one of several non-exclusive approaches to maintaining resource adequacy. All competitive wholesale markets operated by regional transmission organizations or independent system operators ("RTO/ISOs") employ energy and ancillary service markets to provide electricity to customers on a short-term basis. These short-term markets reflect the marginal cost of system operations at granular locational levels and short time intervals.³⁰ They provide incentives for long-term resource investment (retirement or new entry) by providing a basis for forward price expectations. The revenues from marginal cost pricing, however, are insufficient to cover the costs of resources at a level necessary to meet reliability standards.³¹ RTO/ISOs therefore employ a variety of approaches (including contracting, scarcity pricing, and capacity markets) to supplement the signals provided by the energy and ancillary services markets to facilitate new investment, retirement decisions, and participation by demand response.

Capacity markets employ a market-based approach to address the "missing money" that resources need to remain viable but are unable to earn solely by providing energy and ancillary services. Specifically, they provide price signals through a competitive capacity auction design that sets prices at the intersection of sellers' capacity market supply offers and the administrative demand curve in each transmission-constrained location and system-wide.

²⁹ Johannes P. Pfeifenberger et al., *Resource Adequacy Requirements: Reliability and Economic Implications*, The Brattle Group & Astrape Consulting, at iii (Sept. 2013), <u>https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf</u>.

³⁰ Devin Hartman, *Enhancing Market Signals For Electric Resource Adequacy*, R Street Inst., at 5 (Dec. 2017), Policy Study No. 123.

³¹ *Id*.

Under this framework, the market produces prices consistent with supply-demand conditions. The market produces low prices when there is more than enough supply to meet resource adequacy needs, and it produces high prices when capacity supply is scarce.³² Capacity markets are thus a mechanism for attracting new investments and retaining supply, in which private parties may respond to competitive pricing signals to enter the market when supply is tight (and prices are high) or exit the market when supply is long (and prices are low).

Efficient outcomes in capacity markets rely upon resources competing with each other to require as little capacity market revenue as possible to cover their going-forward costs. For the market to be truly competitive, resources must have the flexibility to reflect and bear the risk of their own expertise, experience, technology, risk tolerance, and whatever else might provide them with a competitive advantage in the quest to provide capacity at the lowest possible cost.³³ Capacity sellers offer their resources into the market at the minimum price they are willing to accept to come online or stay in the market.³⁴ For any given resource, the minimum price they are willing to accept is driven by a number of factors including primarily: (a) costs associated with bringing new supply into the market or maintaining an existing facility that needs re-investment; and (b) minus any anticipated net revenues that could be earned from energy markets, ancillary service markets, or other revenue sources (such as sales of renewable energy credits ("RECs"), steam, or gypsum).³⁵ Many sellers also adjust their capacity offer price based on any bilateral sales agreements for capacity or any co-products they may produce; as well as based on their long-term view of future energy and capacity

³² Protest of Clean Energy Parties, Ex. A, *The Economic Impacts of Buyer-Side Mitigation in New York ISO Capacity Market*, at 9 ("Brattle Testimony") (attached hereto as Ex. A), Accession No. 20201118-5165.
 ³³ NYPSC and New York State Energy Research and Dev. Auth. v. NYISO, 173 FERC ¶ 61,060 (Glick, Comm'r, dissenting at P 5).

³⁴ Brattle Testimony at 9.

³⁵ Id.

prices.³⁶ Sellers that are able to pre-sell most of their capacity or energy through bilateral contracts would typically have their going-forward costs covered by their anticipated revenues and so, using the formula above, would offer into the capacity market at a zero price, as would most sellers that have already come online and have few going-forward capital investments.³⁷

The "correct" capacity price in a competitive and efficient market is the one that accurately reflects underlying fundamentals of supply and demand, and can accurately signal when and where capacity investments are needed (and when high-cost resources can retire).³⁸ When new resources are required to offer capacity at administratively-determined prices (i.e., price offer floors) that negate out-of-market revenues, it creates a systemic bias in favor of existing resources and curtails resources' incentive and ability to compete across all possible dimensions.³⁹ This bias has a chilling effect on the development of new technologies and resources needed to satisfy state or federal public policies and slows the transition to a cleaner, more advanced resource mix. Ignoring out-of-market revenues also undermines the integrity of the capacity market because the set of resources selected in market auctions do not reflect the lowest-cost or most efficient means of ensuring resource adequacy. The capacity market thus becomes a mechanism for propping up prices and protecting incumbent generators that tend to be old, inefficient, and highly polluting. Market rules that establish administratively-determined prices to negate out-of-market revenues are inefficient and anti-competitive.⁴⁰

³⁸ *Id.* at 12.

³⁶ Id.

³⁷ Id.

³⁹ Id.

⁴⁰ Brattle Testimony at 13–16.

C. NYISO's Capacity Market Is Designed to Send Price Signals That Meet Long-Term Resource Adequacy Objectives in the Most Cost-Effective Manner for Consumers.

The NYISO's wholesale market framework is designed to provide reliable service at least cost through complementary markets for energy, ancillary services, and capacity. Each market addresses distinct reliability needs. The energy and ancillary services markets provide least-cost dispatch and ensure short-term operational reliability. The capacity market supplements these markets to help meet long-term resource adequacy objectives in the most cost-effective manner. FERC has consistently held that suppliers in competitive markets must have an opportunity to recover their costs but are not guaranteed cost recovery.⁴¹

NYISO's capacity market framework, the Installed Capacity ("ICAP") market, is designed to maintain reliability of the bulk power system by procuring sufficient resource capability to meet system and locational resource adequacy needs.⁴² Each year, the IRM is computed by the NYSRC, with technical assistance from NYISO.⁴³ The quantity needed for the IRM is first established on an ICAP basis as a reserve margin above peak load, and translated into the amount of MWs of Unforced Capacity ("UCAP") that must be secured from supply resources.⁴⁴ NYISO oversees the qualification of supply resources that are eligible to meet system and local capacity needs, determining the UCAP of supply each resource is eligible to sell in the summer and winter seasons within each capacity market zone. In this filing, NYISO proposes to make a major market design change (discussed in Section IV below)

⁴³ Kathleen Spees, et al., *Qualitative Analysis of Resource Adequacy Structures for New York*, The Brattle Group, at 7 (May 19, 2020) ("Qualitative Analysis of Resource Adequacy Structures for New York"); *see* NYISO, *Manual 4: Installed Capacity Manual*, at 4 (Dec. 2021) ("NYISO Manual 4"), https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338.
 ⁴⁴ NYISO Manual 4 at 4.

 ⁴¹ See, e.g., CXA La Paloma, LLC v. California Indep. Sys. Operator Corp., 165 FERC ¶ 61,148 (citing Bridgeport Energy, LLC, 113 FERC ¶ 61,311, at P 29 (2005)), reh'g denied, 169 FERC ¶ 61,045 (Oct. 17, 2019).
 ⁴² Brattle Testimony at 9.

by introducing a new approach for valuing capacity to more accurately capture ICAP Suppliers' contributions to resource adequacy in NYISO's prompt ICAP market as more duration-limited and intermittent capacity resources are added to the system.

Pursuant to the NYISO's FERC-approved tariff, NYISO determines the amount of capacity that each load-serving entity ("LSE") must procure based on the aggregate consumption of its end-use customers over the peak load hour. LSEs may meet their obligation to procure sufficient capacity by either self-supplying, entering into bilateral contracts with capacity suppliers, or through the NYISO-administered auctions. LSEs are required to purchase sufficient amounts of capacity or pay a deficiency charge.⁴⁵

Each LSE has the flexibility to determine how it will meet the resource adequacy obligation through some combination of self-supply, forward bilateral contracting, voluntary participation in NYISO auctions, or reliance on the final mandatory spot auction.⁴⁶ However, buyer-side mitigation ("BSM") rules (discussed in Section III below) can prevent LSEs from using self-supply or bilaterally-contracted new resources by subjecting them to mitigation and imposing a prohibitive risk that these resources will not clear.⁴⁷

To support and enforce LSEs' ability to fulfill the resource adequacy obligation, NYISO conducts a series of auctions for each delivery year including: (a) voluntary forward 6month strip auctions for UCAP; (b) voluntary monthly forward auctions conducted 1 to 6 months ahead of time; and (c) mandatory non-forward monthly spot auctions that all LSEs and

⁴⁵ See NYISO, Market Administration and Control Area Services Tariff, Sec. 5.14: Installed Capacity Spot Market Auction and Installed Capacity Supplier Deficiencies (filed Mar. 2008), https://www.nyiso.com/documents/20142/6665211/MST+5.14+-+redline.pdf/857c2532-e1ed-b711-eacd-c4645c7e23bd?version=1.1&t=1558097277836&download=true.

⁴⁶ Qualitative Analysis of Resource Adequacy Structures for New York at 7; *see also* NYISO Manual 4 at 4.

⁴⁷ Qualitative Analysis of Resource Adequacy Structures for New York at 7 n.9.

resources must participate in to resolve any remaining shortfalls relative to their capacity obligations and ensure that all supply is offered for sale.⁴⁸

The mandatory final spot auction incorporates an administratively-constructed, downward-sloping demand curve and determines the final quantity of capacity procured with a bias toward over-procurement.⁴⁹ The NYISO establishes a sloped ICAP demand curve for Long Island, New York City, the G-J Locality, and for the New York Control Area ("NYCA") as a whole based on four factors: (1) the projected annual net energy and ancillary services revenues of a peaking plant; (2) the locational minimum installed capacity requirement for the locality, and NYCA minimum installed capacity requirement for NYCA-wide; (3) the point at which the value of additional surplus capacity above the applicable minimum requirement declines to \$0 ("zero-crossing point"); and (4) the levelized embedded cost of a new peaking plant in each locality, as well as the rest of state capacity region.⁵⁰ These separate capacity market prices signal the need for investment in each locality to meet resource adequacy.

D. State Policies Invariably Impact the Costs and Revenues of Supply Resources.

The NYISO capacity market has never operated in a vacuum. New York State policies have real world impacts that have always shaped the investment environment. This has been true since NYISO's inception as demonstrated by NYISO's first Power Trends Report in 2001, which implored New York State to aggressively pursue policies that would facilitate resource development, conservation, improve fuel diversity, and issued warnings about the State's increased reliance on natural gas as the fuel of choice for electricity production.⁵¹

⁵¹ See NYISO, Power Alert: New York's Energy Crossroads (Mar. 2001), https://www.nyiso.com/documents/20142/2223154/2001-Power-Trends.pdf/76414f57-e20d-b17c-142b-5f523fea4afd; Id. at 4, 22 ("As part of its energy policy, the State must consider matters of fuel diversity in

⁴⁸ *Id.* at 7.

⁴⁹ Id.

⁵⁰ See NYISO, 113 FERC ¶ 61,271, 62,066 (Dec. 15, 2005).

New York State has a long history of actively pursuing energy, environmental, and climate policies, including policies that address aspects of resource adequacy. New York's steady long-term march toward aggressive climate and clean energy policies would not have escaped the prudent investor:⁵²

- As early as 2002, the New York State government expressed concern in its State Energy Plan regarding the reliance of the State on gas-fired electricity and established a goal to increase renewable energy by 50% as a percentage of total load served by 2020, aiming to move from 10% of demand met by renewable energy to 15% by 2020.⁵³ In 2004, the NYPSC had adopted the more aggressive Renewable Portfolio Standard ("RPS") goal of 25% renewable energy by 2013.⁵⁴
- In 2010, the RPS goal was amended to achieve 30% renewable energy by 2015.⁵⁵
- In December 2015, through Reforming the Energy Vision ("REV"), Governor Cuomo called for 80% GHG emissions reduction by 2050 and 50% of electricity demand to be met by renewables by 2030.⁵⁶
- On January 25, 2016, the New York State Department of Public Service staff published a white paper regarding what was to become the Clean Energy Standard, which aimed to meet the goals set forth by the Governor in 2015. The white paper discussed the plan to institute a zero-emissions energy credit ("ZEC") in order to support "a smooth emission-free transition from nuclear to non-nuclear resources in the event that energy prices are not able to support the continued financial viability of the plants during their

addition to the issues of economics and adequacy of energy supply ... New York through the auspices of its Energy Planning Board needs to study the state's increased reliance on natural gas as the fuel of choice for electricity production.").

⁵² Brattle Testimony at 20–22.

⁵³ New York State, 2002 New York State Energy Plan, at Section 1–3 (2002), https://energyplan.ny.gov/Plans/2002.aspx.

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⁵⁴ Order Regarding Retail RPS, at 3, Case No. 03-E-0188 (NYPSC Sept. 24, 2004).

⁵⁵ Order Establishing New RPS Goal and Resolving Main Tier Issue, at 7, Case No. 03-E-0188 (NYPSC Jan. 8, 2010).

⁵⁶ New York State, *Reforming Energy Division, REV* (Nov. 13, 2020), https://www.ny.gov/sites/ny.gov/files/atoms/files/REV_WhatYouNeedToKnow2.pdf.

license lives."⁵⁷ The ZEC program was established formally on August 1st, 2016, when the NYPSC adopted the Clean Energy Standard.⁵⁸

- In July 2018, the NYPSC adopted a supplementary goal to contribute toward the overall objective of the Clean Energy Standard whereby LSEs were obligated to obtain, on behalf of their retail customers, the Offshore Wind Renewable Energy Credits associated with the output of 2.4 GW of new offshore wind generation facilities.⁵⁹
- In July 2019, New York State enacted the CLCPA, which mandates a transition to 70% renewable electricity by 2030, 100% clean electricity by 2040, an 85% reduction in economy-wide GHG emissions, and another 15% GHG reduction via offsets to reach net-zero emissions by 2050.⁶⁰ The CLCPA also expands on the Clean Energy Standard objectives requiring the establishment of programs for at least 9 GW of Offshore Wind by 2035, and requires the NYPSC to develop programs to procure 6 GW of distributed solar generation by 2025, and to support 3 GW of energy storage capacity by 2030. Importantly, the CLCPA mandates a just and equitable energy transition by requiring that at least 35% of the benefits of the state's clean energy program accrue to historically marginalized communities disproportionately impacted by pollution and climate change.
- In October 2020, the NYPSC expanded the Clean Energy Standard to include a new "Tier 4" program for projects that can cost effectively and responsibly deliver renewable energy to New York City, an area of the state that relies on aging fossil fuelfired generation.⁶¹ This resulted in the state entering into two transmission projects that

⁵⁷ Staff White Paper on Clean Energy Standard, at 30, Case No. 15-E-0302 (NYPSC Jan. 25, 2016).

⁵⁸ Order Adopting a Clean Energy Standard, Case No. 15-E-0302 (NYPSC Aug. 1, 2016).

⁵⁹ Order Establishing Offshore Wind Standard and Framework for Phase 1 Procurement, at 3–4, Case No. 18-E-0071 (NYPSC July 12, 2018).

⁶⁰ CLCPA § 2.

⁶¹ Order Adopting Modifications To The Clean Energy Standard, Case No. 15-E-0302 (NYPSC Oct. 15, 2020), https://gcc02.safelinks.protection.outlook.com/?url=https%3A%2F%2Fwww.nyserda.ny.gov%2F-%2Fmedia%2FFiles%2FPrograms%2FClean-Energy-Standard%2F2020%2FOctober-15-Order-Adopting-Modifications-to-the-Clean-Energy-

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will deliver solar, wind, and hydroelectric power from upstate New York and Canada to New York City. When combined with New York's deployment of clean energy across the state as well as offshore wind, these projects are expected to reduce New York City's fossil fuel use for electricity by more than 80% in 2030.⁶²

- In September 2021, Governor Hochul announced the expansion of the NY-Sun Program to achieve at least 10 GW of distributed solar energy by 2030.⁶³
- In October 2021, the New York State Department of Environmental Conservation ("DEC") denied the required air permit for two fossil gas plants—1) the Astoria Replacement Project, a proposed new 437 MW simple cycle dual fuel fossil fuel-fired peaking combustion turbine, and 2) the Danskammer Energy Center, a proposed new 536 MW gas-fired combined-cycle power generation facility—based on its determination that the proposed project does not demonstrate compliance with the requirements of the CLCPA.⁶⁴
- In January 2022, Governor Hochul announced several new initiatives in the 2022 State of the State, including: planning for an offshore wind transmission network to deliver at least 6 GW of offshore wind energy directly into New York City;⁶⁵ updating New York State's Energy Storage Roadmap to double deployment, reaching at least 6 GW of energy storage by 2030;⁶⁶ undertaking a series of efforts to make New York State a green hydrogen hub;⁶⁷ and coordinated agency planning to develop a blueprint to guide

⁶⁴ DEC, Notice of Denial of Title V Air Permit, DEC ID: 3-3346-00011/00017, Danskammer Energy Center — Town of Newburgh, Orange County, Title V Air Permit Application (Oct. 27, 2021),

https://www.dec.ny.gov/docs/administration_pdf/danskammer10272021.pdf; DEC, Notice of Denial of Title V Air Permit, DEC ID: 2-6301-00191/00014, Astoria Gas Turbine Power — Astoria, Queens County, Title V Air Permit Application (Oct. 27, 2021),

https://www.dec.ny.gov/docs/administration_pdf/nrgastoriadecision10272021.pdf. ⁶⁵ 2022 State of the State at 145–46.

⁶² New York State, Governor Kathy Hochul, *2022 State of the State*, at 146 (2022) ("2022 State of the State"), https://www.governor.ny.gov/sites/default/files/2022-01/2022StateoftheStateBook.pdf.

⁶³ New York State Office of the Governor, *Governor Hochul Announces Expanded NY-Sun Program to Achieve at Least 10 Gigawatts of Solar Energy by 2030* (Sept. 20, 2021), <u>https://www.governor.ny.gov/news/governor-hochul-announces-expanded-ny-sun-program-achieve-least-10-gigawatts-solar-energy-2030</u>.

⁶⁶ *Id.* at 146.

⁶⁷ *Id.* at 147–49.

the retirement and redevelopment of New York's oldest and most-polluting fossil fuel facilities and their sites by 2030.⁶⁸

Merchant generation investors in New York operate in a market and regulatory context that has always included environmental regulations from which they should not be expected to be indemnified any more than they should be charged when regulations work in their favor.⁶⁹ But even if investors could not have fully anticipated the full extent or particulars of New York's climate and clean energy ambitions, these policies are within the State's mandate to protect public health and are part of the context in which investment choices are made. Investors choose to bear the risks and rewards associated with changing market conditions and regulations, and there is no reason to indemnify them for their choices.⁷⁰ Indeed, doing so is antithetical to one of the main drivers behind introducing competitive wholesale electricity markets, which as NYISO states, is "to shift the risk and cost consequences of investment decisions from consumers to the owners of generation and other resources."⁷¹

E. NYISO's Buyer Side Mitigation Rules.

The original and proper economic purpose of BSM rules is to protect the market from the exercise of buyer market power—schemes where large net buyers or their representatives offer a small amount of uneconomic supply into the market below cost in order to suppress market clearing prices.⁷² Without such a rule, a large net buyer could be in a position to game the capacity markets by bringing a small quantity of incremental capacity supply into the market, offering the supply at a zero price, and producing a low capacity price.⁷³ By taking a

⁶⁸ *Id.* at 150.

⁶⁹ Brattle Testimony at 19.

⁷⁰ Id. at 15.

⁷¹ NYISO Power Trends 2021 at 9.

⁷² NYISO, 122 FERC ¶ 61,211 (Mar. 7, 2008).

⁷³ Brattle Testimony at 10.

loss on that small position, a large net buyer could then benefit from a much larger lower capacity price in the market.⁷⁴

To prevent this manipulative price suppression, the BSM rules seek to restate the offer price from zero to a higher level that reflects an administratively determined offer floor.⁷⁵ The higher offer price prevents this scheme from producing price suppression and makes it less likely that the resource in question would clear the capacity market. When applied to large net buyers and their supported resources, the BSM rules privatize the cost of any potentially uneconomic investments, while holding other parties in the market harmless.⁷⁶ More importantly, the rules are intended to disincentivize the manipulative behavior and associated economic waste from taking place at all.

NYISO's BSM rules were first implemented in 2008.⁷⁷ FERC's order accepting that proposal explained, "[m]arkets require appropriate price signals to alert investors when increased entry is needed" and that uneconomic entry could result in "artificially depressed" capacity prices.⁷⁸ FERC emphasized that, "[u]nder the FPA, the Commission must ensure that rates are just and reasonable. The courts have long held that establishing just and reasonable rates involves a balancing of consumer and investor interests."⁷⁹

Subsequent FERC orders have reiterated that NYISO must implement the BSM rules because "under-mitigation" of uneconomic entry can artificially suppress capacity prices, which ultimately harms long-term consumer interests.⁸⁰ "Under-mitigation" could create

⁷⁴ *Id*. at 10–11.

⁷⁵ *Id*. at 11.

⁷⁶ Id.

⁷⁷ *NYISO*, 122 FERC ¶ 61,211.

⁷⁸ *Id.* at PP 103, 110.

⁷⁹ *Id.* at P 103.

⁸⁰ See, e.g., NYPSC v. NYISO, 154 FERC ¶ 61,088, at PP 11, 31 (Feb. 5, 2016) (reiterating the importance of balancing "the need to mitigate the exercise of buyer-side market power to ensure just and reasonable ICAP

incentives that would undermine the market, result in an over-reliance on cost-based "Reliability Must Run" agreements or transmission expansion to maintain reliability. On the other hand, "over-mitigation" can unnecessarily discourage entry by new resources.⁸¹ To help achieve this balance, the Commission has authorized multiple exemptions from the BSM rules for resources that are shown to have "limited or no incentive and ability to artificially suppress ICAP Market Prices."⁸²

Over the last decade, the scope of the BSM rules has expanded. The rules initially applied only to "net buyers" that subsidized uneconomic entry, but this limitation was removed due in large part to difficulty in establishing who constituted a "net buyer."⁸³ The BSM rules also originally only applied to New York City, but were later expanded to include the G-J locality ("mitigated capacity zones").⁸⁴ This limited application is associated with the original narrow purpose of the rules, which were to prevent manipulative price suppression. The mitigated capacity zones were the only locations within the NYCA in which the market

market prices with the risk of over-mitigating new entrants"); *Consolidated Edison Co. of New York, Inc. v. NYISO*, 150 FERC ¶ 61,139, at P 4 (Feb. 26, 2015); *NYISO*, 143 FERC ¶ 61,217, at P 77 (June 6, 2013) (noting that buyer-side market power mitigation rules must "appropriately balance the need for mitigation of buyer-side market power against the risk of over-mitigation").

⁸¹ Id.

⁸² See, e.g., NYPSC v. NYISO, 153 FERC ¶ 61,022, at P 10 (Oct. 9, 2015) ("October 15 Order"); NYPSC v. NYISO, 154 FERC ¶ 61,088, at P 31 ("We maintain that certain narrowly defined renewable and self-supply resources should not be subject to the buyer-side market power mitigation rules because they have limited or no incentive and ability to exercise buyer-side market power to artificially suppress ICAP market prices.").
⁸³ See NYISO, 124 FERC ¶ 61,301, at PP 29 (Sept. 30, 2008) ("Upon further review, for the reasons set forth in the requests for rehearing, the Commission will grant rehearing on this issue. NYISO will not be required to modify its proposed market power mitigation rules for uneconomic entry so that they only apply to net buyers. We find that all uneconomic entry has the effect of depressing prices below the competitive level and that this is the key element that mitigation of uneconomic entry should address. Parties requesting rehearing have convinced us that defining net buyers raises significant complications and provides undesirable incentives for parties to evade mitigation measures."), 38 ("Nevertheless, the Commission recognizes that the NYPSC may conclude that the procurement of new capacity, even at times when the market-clearing price indicates entry of new capacity is not needed, will further specific legitimate policy goals, such as renewable portfolio standards. We agree that it may be appropriate to exempt such new resources from the price floor proposed by NYISO...").
⁸⁴ See NYISO, 143 FERC ¶ 61,217, 62,440.

structure indicated that any large net buyer might have the incentive and ability to exercise market power.

NYISO's BSM rules currently provide that, unless exempt from mitigation, each new capacity resource must enter the mitigated capacity zones⁸⁵ at a price that is at or above an applicable offer floor until its capacity clears 12 monthly auctions.⁸⁶ The offer floor price excludes certain out-of-market revenue that resources may receive (namely revenue from state programs that support clean resources). NYISO's buyer-side market power mitigation rules do not apply to new resources entering in the broader NYCA footprint.⁸⁷

NYISO will exempt a new entrant from the offer floor if it passes either one of two exemption tests under its buyer-side market power mitigation rules: the Part A test, which assesses market capacity conditions, or the Part B test, which evaluates unit-specific costs.⁸⁸ If a new resource passes either test, it is not required to offer above a floor price in the capacity market. Under the Part A test, NYISO will exempt a new entrant from the offer floor if the forecast of capacity prices in the first year of a new entrant's operation is higher than the default offer floor, which is 75% of the Net Cost of New Entry ("CONE") of the hypothetical unit modeled in the most recent ICAP demand curve reset. This test allows new resources to avoid an offer floor at times when the market is approaching the minimum required level of capacity needed in a given load zone, regardless of whether approaching the minimum required level of capacity is due to load growth or the exit of existing resources. Under the Part B test,

⁸⁵ NYISO's Services Tariff defines "Installed Capacity" as "External or Internal Capacity, in increments of 100 kW, that is made available pursuant to Tariff requirements and ISO Procedures." NYISO MST § 2.9 MST Definitions (27.0.0) (Jan. 5, 2022) ("Services Tariff"), <u>https://nyisoviewer.etariff.biz/ViewerDocLibrary</u> /<u>MasterTariffs/9FullTariffNYISOMST.pdf</u>. The G-J Locality (mitigated capacity zones) consists of Load Zones G, H, I, and J zones "within which a minimum level of Installed Capacity must be maintained…" *Id.* § 2.12 MST Definitions (8.0.0) (defining "Locality").

⁸⁶ NYPSC and New York State Energy Research and Dev. Auth. v. NYISO, 173 FERC ¶ 61,060, at P 3. ⁸⁷ Id.

⁸⁸ Id. at P 4.

NYISO will exempt a new entrant from the offer floor if the forecast of capacity prices in the first three years of a new entrant's operation (three-year mitigation study period), is higher than the Net CONE of the new entrant. A resource may also be exempt from buyer-side market power mitigation rules if it meets the requirements for a competitive entry exemption,⁸⁹ a renewable resources exemption,⁹⁰ or a self-supply exemption.⁹¹

FERC has recently expanded the role of BSM in New York and in other regions to impose a MOPR more broadly to apply to resources that earn policy payments.⁹² The large majority of these resources in New York and other regions are those awarded policy payments in recognition of their contribution toward achieving states' environmental policies.⁹³

Importantly, beyond these significant and unnecessary consumer costs, the application of BSM to state resources will have a disproportionate impact on the health and economic well-being of individuals living in disadvantaged communities in New York. In particular, current BSM rules apply to resources developed in Zones G-J (the Lower Hudson Valley and New York City), a capacity-constrained area of the grid where the continued operation of heavily polluting peaker plants poses significant economic, public health, and environmental hazards to nearby disadvantaged communities.⁹⁴ These peaker plants are some of the oldest and most inefficient generating resources in the state, with significantly higher costs than the

⁸⁹ Services Tariff § 23.4.5.7.9.1.

⁹⁰ See Vineyard Wind LLC, 173 FERC ¶ 61,058 (Oct. 16, 2020).

⁹¹ See October 2015 Order at P 2 (requiring NYISO to revise the rules governing buyer-side market power mitigation in NYISO's Services Tariff to exempt a narrowly defined set of renewable and self-supply resources), *reh'g denied*, 154 FERC ¶ 61,088; *see also NYISO*, 170 FERC ¶ 61,121 (Feb. 20, 2020) (accepting in part, subject to condition, and rejecting in part NYISO's compliance filing to the October 2015 Order and directing NYISO to file a further compliance filing).

⁹² See ibid.; see Calpine Corp. v. PJM Interconnection, LLC, 163 FERC ¶ 61,236 (June 29, 2018).

⁹³ Brattle Testimony at 10; *see NYPSC and New York State Energy Research and Dev. Auth. v. NYISO*, 173 FERC ¶ 61,060 (Glick, Comm'r, dissenting).

⁹⁴ Comments of the New York City Environmental Justice Alliance & Allies, at 8–9, Case No. 19-E-0530 (NYPSC Jan. 31, 2020); *see also* NYC Environmental Justice Alliance et al., *Dirty Energy, Big Money, Peak Coalition Report*, at 5 (May 2020), <u>https://nylpi.org/wp-content/uploads/2020/05/PEAK-report-Dirty-Energy-Clean-Money-May-2020.pdf</u>.

average cost of electricity in New York. These high costs disproportionately impact disadvantaged New Yorkers, many of whom pay over six percent of their annual household income in energy costs.⁹⁵ Brattle's analysis confirms that the inefficiencies of BSM rules will manifest through delayed retirement of uneconomic fossil plants in Zones G-J.⁹⁶

F. NYISO's Capacity Accreditation Rules.

The purpose of NYISO's capacity accreditation rules and procedures is to establish each resource's contribution to reliability (i.e., the IRM), which is measured in UCAP. UCAP is used to quantify the amount of capacity that resources are qualified to offer and the portion of the IRM for which each LSE is responsible. A resource's UCAP is generally based on its historic availability or performance. The UCAP values are then used to meet system resource adequacy requirements (i.e., the IRM). Properly valuing each resource's reliability contribution is critical to ensuring an efficient and well-functioning ICAP Market that supports reliability.

Under current rules, a resource's UCAP is equal to its maximum demonstrated output adjusted for the Capacity Resource Interconnection Service ("CRIS") limit and by its historic availability. UCAP is calculated each month for resources qualified to supply capacity using the following equation: UCAP = Available ICAP x (1-Derating Factor). The Available ICAP value is calculated as the lesser of their Demonstrated Max Net Capability and CRIS. Derating factors are calculated using Equivalent Demand Forced Outage Rate ("EFORd") or equivalent performance factors depending on resource type. EFORd is used for traditional resources to represent the portion of time a unit is in demand but is unavailable due to forced outages and forced derates. A variety of performance factors are used for different intermittent and duration limited resources to measure historical performance and availability. Importantly,

⁹⁵ See id.

⁹⁶ Brattle Testimony at 9–11.

derating factor calculations do not consider how the reliability contribution of a resource may be affected by other resources.

As discussed above, due to technology advancements and public policies New York's resource mix is undergoing a rapid transition from a grid dependent on central-station fossil fuel generation, towards a grid with increased renewable intermittent resources and distributed energy resource. As the resource mix evolves, the reliability contribution of all resources can change over time. For example, intermittent and energy duration limited resources have saturation effects at increasing penetrations that cause their reliability value to decline. However, intermittent and energy duration limited resources also have complementary characteristics that produce the opposite effect: synergistic interactions. As penetrations of intermittent and energy-limited resource grow, the magnitude of these interactive effects will increase to the point where they produce meaningful "diversity benefits" in which the reliability value of the resources together is greater than the sum of each resource type in isolation. The reliability contribution of specific resources will thus become more dependent on the diversity and performance of the overall resource portfolio as New York's energy transition progresses.

Because NYISO's current rules do not consider how the reliability contribution of a resource may be affected by other resources, its current rules may fail to accurately reflect the proper value of each resource's contribution to reliability over time. Accordingly, New York's climate and clean energy policies are driving a need to modernize NYISO's capacity accreditation rules. These rules are the foundation for resource adequacy, and as explained in Section IV, their development should not be rushed or undertaken without sufficient information and stakeholder engagement.

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III. NYISO'S PROPOSED BSM TARIFF IS JUST AND REASONABLE

A. NYISO's Proposed BSM Reforms Put an End to the Unjust, Unreasonable, and Unduly Discriminatory Rates That Result from the Application of BSM to State Policy Resources.

NYISO's proposed Tariff revisions have the potential to finally bring to a close the years of shifting mitigation schemes and litigation between NYISO, its stakeholders, and FERC regarding the inexorable clash of its BSM rules with legitimate state energy policy goals. NYISO CEO Richard Dewey emphasized the critical need to re-evaluate the ways in which mitigation policies impede capacity market goals in an environment where state policies are the primary driver of what resources enter and exit the market. He noted that "the current version of the NYISO's Capacity market, and its mitigation rules, must continue to evolve in response to New York's clean energy mandates," stating:

New York State has established some of the most ambitious clean energy goals in the country. Under the Climate Leadership and Community Protection Act ("CLCPA"), seventy percent of energy consumed in New York State must be produced by renewable resources by 2030, and all energy consumed in the state must be completely emissions free by 2040. A number of other rules and policies aimed at implementing the CLCPA are in active development.⁹⁷

New York uses RECs and ZECs to incentivize resources that meet these state policy goals to enter the market. However, under current BSM rules, these state policy resources are subject to offer floor mitigation. Consequently, "New York State and many NYISO stakeholders, increasingly, see the BSM Rules as imposing unnecessary and unjust costs on consumers, interfering with legitimate state policy choices and, ultimately, doing more harm than good."⁹⁸ Unfortunately, efforts to reform the BSM design have "been complicated by

⁹⁷ Comments of Richard J. Dewey on Behalf of NYISO, at 1, Docket No. AD21-10-000 (Mar. 23, 2021) ("Dewey Comments") (citation omitted), Accession No. 20210324-4004; *see also* Tech. Conf. Tr. at 9 (Comments of Chairman Glick), 22 (Comments of Comm'r Christie), 29–30 (Comments of Comm'r Clements regarding the unworkability of the Expanded MOPR).

⁹⁸ Dewey Comments at 13.

uncertainty surrounding earlier Commission rulings addressing Capacity market power mitigation"—the legal merits of which NYISO, the NYPSC, and other New York stakeholders have questioned.⁹⁹ As Mr. Dewey concluded, "the current version of BSM Rules do not appear to be a lasting, 'durable' solution. A fresh look at potential changes is required."¹⁰⁰

Chairman Glick and Commissioner Clements have been clear in a number of public statements and filings that existing tariffs that apply mitigation policies to state policy resources are unjust and unreasonable, opining that overly broad minimum offer price rules that apply to anything besides the actual exercise of buyer-side market power "*hurts* competition" and "can lead to uneconomic price signals" with results that "distort[] the market-clearing price, and forces customers to pay more than necessary to meet their capacity needs."¹⁰¹ As their most recent concurring opinion in the *ISO New England* decision summarizes:

Such overbroad barriers are the antithesis of market competition, in that they divorce "capacity market clearing prices from the actual net going forward costs of would-be capacity suppliers" and serve "only to prop up capacity prices, protect incumbent generators, and increase the costs of state policies." The end result is "is doubly bad for consumers, as they will be forced to pay for more capacity than is actually needed, and to do so at a higher price than they should, because the MOPR will allow a relatively high-cost resource to set the capacity price for the entire set of resources procured through PJM's capacity market."¹⁰²

In the ISO New England decision, Chair Glick and Commissioner Clements

admonished ISO-New England to "move expeditiously" beyond the MOPR, but noted that it was "prudent to give the ISO an opportunity to replace the existing MOPR with a solution of

⁹⁹ Id.

¹⁰⁰ Id.

¹⁰¹ ISO New England, Inc., 178 FERC ¶ 61,050, at PP 2–3 (Jan. 21, 2022) (Glick & Clements, Chairman & Comm'r, concurring).

 $^{^{102}}$ Id. at P 4 (citations omitted).

its choosing" since "one size need not fit all and different regions of the country may choose different approaches to addressing the problem of actual buyer-side market power."¹⁰³

NYISO's Section 205 filing also offers the Commission a chance to reconsider the unjust, unreasonable, unduly discriminatory rates that have resulted from the string of Commission orders establishing NYISO's current tariff and BSM rules.¹⁰⁴ As the Commission is aware, these orders are on appeal before the D.C. Circuit Court of Appeal and have been held in abeyance until March 7, 2022,¹⁰⁵ in anticipation of this filing by NYISO. Litigation involving certain Clean Energy Advocates ("CEA") members in that matter is linked to the outcome in this case, since adoption of the proposed Tariff would largely moot the issues on appeal.¹⁰⁶ Arguments regarding the unjustness, unreasonableness, and undue discrimination that result from NYISO's BSM have been extensively briefed in the filings in that docket and CEAs will not repeat them all here. Instead, CEAs focus on key issues that demonstrate why

¹⁰³ *Id.* at 5.

¹⁰⁴ N.Y. Indep. Sys. Operator, Inc., 170 FERC ¶ 61,121 (2020), order on reh'g, 172 FERC ¶ 61,058 (2020) (FERC rejected in part the NYISO's April 13, 2016 compliance filing to implement the renewable resources and selfsupply exemptions to NYISO's buyer-side market power mitigation rules); N.Y. Pub. Serv. Comm'n v. N.Y. Indep. Sys. Operator, Inc., 170 FERC ¶ 61,119 (2020), order on reh'g, 173 FERC ¶ 61,060 (2020) (FERC rejected 206 compliant alleging that the application of NYISO's BSM rules is unjust, unreasonable, and unduly discriminatory because the rules limit electric storage resources' entry and participation in NYISO's capacity market and interfere with federal and state policy objectives); N.Y. Pub. Serv. Comm'n v. N.Y. Indep. Sys. Operator, Inc., 158 FERC ¶ 61,137 (2017) (Complaint Order), order on reh'g, 170 FERC ¶ 61,120 (2020) (February 2020 Order) (the Commission granted in part and denied in part the Independent Power Producers of New York's request for rehearing of the Complaint Order, thereby reversing the blanket exemption for Special Case Resources (SCR) from the NYISO's buyer-side market power mitigation rules in NYISO's Market Administration and Control Area Services Tariff); Additionally, there is the pending matter of Cricket Valley (Docket No. EL21-7-000) before the Commission which requests that the existing BSM be expanded that has yet to be decided and which members of the CEAs have opposed, Cricket Valley Energy Center LLC and Empire Generating Company, LLC v. New York Independent System Operator, Inc., Docket No. EL21-7-000. ¹⁰⁵ Order, Case No. 20-1219 (D.C. Cir. Oct. 18, 2021), ECF No. 1918647

¹⁰⁶ CEAs incorporate herein by reference the same expert and legal criticisms leveled against its application in NYISO by the members of Clean Energy Advocates participating in those proceedings, review of which is pending before the D.C. Circuit Court of Appeals. *See, e.g.*, New York State Public Service Commission v. Federal Energy Regulatory Commission, No. 20-1219 (CONSOLIDATED); New York State Public Service Commission v. Federal Energy Regulatory Commission CASE NOS. 20-1218 (CONSOLIDATED).

the economic theory underpinning the BSM has always been irredeemably flawed and why the Commission must decisively reject it.

Although a finding that the BSM does not result in just and reasonable rates is not necessary for the Commission to approve NYISO's Section 205 filing, the reasons why such a finding would be justified are critical to understanding why NYISO's transformative Proposed BSM Tariff will produce just and reasonable rates, and why the Commission must reach determinations that differ from those contained in its recent orders.

1. <u>Application of BSM to CLCPA Resources Is Based on Flawed</u> <u>Economic Logic.</u>

Buyer-Side Mitigation, and the Commission's recent orders approving that market rule, do not reflect sound economic reasoning. The economic theory underpinning the current BSM rules is that states with aggressive clean energy mandates are incenting the development of large quantities of new zero- or low-carbon resources to meet system-wide transition deadlines through a variety of programs and contract solicitations that the Commission describes as "subsidies."¹⁰⁷ Because these activities can sometimes lower near-term capacity market prices and/or displace "non-subsidized" resources, proponents of the BSM rules argue that intervention is necessary to "protect" wholesale capacity market prices. BSM proponents allege that without intervention, market prices will be too low for merchant capacity suppliers (particularly fossil fuel resources) to earn adequate returns on investment and that, over time, these low capacity market prices will lead to insufficient entry of new generating resources and exit of needed resources that ultimately threatens reliability of the whole electric system.¹⁰⁸ The proffered

¹⁰⁷ See, e.g., New York State Pub. Serv. Comm'n & New York State Energy Rsch. & Dev. Auth., 173 FERC ¶ 61,060, at P 9 (2020); Brattle Testimony § B, see generally at 12, 19–20.

¹⁰⁸ Brattle Testimony. at 12–21. Drs. Spees and Newell have done extensive work on both BSM and MOPR in the NYISO and PJM regions. *Id.* at 1–2.

remedy is to offset any incentives provided to state policy resources by applying BSM to all such resources in the NYISO capacity market. This would force resources benefiting from state policies to bid at administratively-determined rates that reflect the higher prices that would prevail in the absence of state clean energy policies.¹⁰⁹

As explained by the Brattle Group—experts routinely employed to advise NYISO and the NYPSC on the economics of its markets—these theories rest on flawed economic logic.¹¹⁰ Simply put, "there is no sensible economic rationale for applying BSM to all policy resources that are developed or maintained to address the harms of climate change or other environmental externalities."¹¹¹ Moreover, applying BSM to policy-supported resources pushes them out of the capacity market, with a number of undesirable consequences, namely: (1) policy resources are deprived of revenues commensurate with the capacity value they provide; (2) incentives are created for retaining and developing uneconomic excess capacity supply that is not needed for reliability; (3) market clearing prices are artificially inflated and disconnected from actual supply-demand conditions, which effectuates a wealth transfer from customers to incumbent suppliers; and (4) these distortions become unsustainable over time as New York's CLCPA requirements and other clean energy policy objectives come into full effect, leaving behind a capacity market totally disconnected from the reality of the resources actually operating on the grid.¹¹²

¹⁰⁹ *Id.* at 12–21.

¹¹⁰ See generally id. § B.

¹¹¹ *Id.* at 4.

¹¹² Id.

a. <u>The State Policies at Issue Address Well-Understood Market</u> <u>Failures Such as Environmental Externality Costs.</u>

The theory that state policy resources receive a "subsidy" that "impede[s] a market's ability to set prices that accurately reflect market forces"¹¹³ is an overly simplistic and incomplete analysis that overlooks a well-understood fact that market forces often fail to account for negative externalities—i.e., a negative side effect of production that adversely affects a party not involved in the transaction who has no influence on whether the transaction occurs, but is nevertheless harmed by it.¹¹⁴ Absent intervention to address them, neither the purchaser nor the seller pays the full costs associated with the negative externality.¹¹⁵ When externalities are at play, markets fail to allocate resources efficiently and current market price of that good is not the economically "correct" one, such that what looks like "market forces" are really market failures.¹¹⁶

Environmental externalities (for example, unregulated pollution emitted as a byproduct of fossil fuel electric generation) are a textbook example of market failures that have grievous harms such as asthma and early deaths, resulting from particulate pollution to the current climate change crisis.¹¹⁷ Market pricing that does not account for such negative externalities would drive resource investments and operations toward an inefficiently large quantity of fossil-fuel-fired power plants, imposing inefficiently large externality costs.¹¹⁸

As explained by Brattle, market externalities can be addressed in one of two ways: command-and-control policies that directly regulate behavior, or market-based policies that align

¹¹³ Compl. and Req. for Fast Track Processing, at 18 n.78, Docket No. EL21-7-000 (Oct. 14, 2020) (citing ER16-1404 Rehearing Order, 172 FERC ¶ 61,058, Concurring Statement at P 2 (Danly, Comm'r, concurring)) ("Cricket Valley Complaint"), Accession No. 20201014-5137; Brattle Testimony at B.1.

¹¹⁴ Brattle Testimony at B.1, 13.

¹¹⁵ Id.

¹¹⁶ *Id.* at B.1.

¹¹⁷ *Id.* at B.1, 13.

¹¹⁸ Id.
private incentives with social efficiency.¹¹⁹ In the case of electricity markets, environmental externalities can be addressed through policy mechanisms such as pollutant pricing mechanisms, carbon pricing, or through clean energy attribute payments paid directly to resources. These policies deliberately reward non-polluters and discourage polluters by forcing generators to internalize the environmental costs of production, and both will have the effect of raising market prices for generators who pollute and lowering it for those who do not.¹²⁰ The Commission's recent line of cases that would nullify state policy actions that it deems to provide a direct benefit (e.g., a ZEC), while expressing policy support for policy actions that impose a direct penalty (e.g., a carbon tax), ignores that these are two sides of the same economic coin with the same end result: higher prices for fossil fuels and lower prices for clean energy.¹²¹

When viewed through the proper lens, these payments are not subsidies in the traditional sense of the term of propping up an "economically inefficient" market player. Rather, the incentives provided by states in this context are more appropriately described as compensation provided for the environmental benefits these resources provide that are necessary to correct a market failure.¹²² Compensation for the environmental value of policy-supported resources should not be considered an illegitimate distortion of markets that must be excluded, but rather a correction that is needed to achieve a more efficient outcome.¹²³

¹¹⁹ Id.

¹²⁰ Brattle Testimony at B.1, 13–14.

¹²¹ Id.

¹²² *Id.* § B, see generally at 12-15.

¹²³ *Id.* at Executive Summary, 4–5.

b. The "Correct" Capacity Price Is the One That Aligns Supply with Demand (Not the Price That Would Prevail in the Absence of State Policies).

Advocates for applying BSM measures to state policy resources inaccurately characterize the lower market prices that prevail with these state policies in place as inappropriate "price suppression" that threatens the long-term capacity market supply.¹²⁴

But compensating non-emitting resources for their environmental value simply lowers their net cost of production and makes them correctly appear more competitive as capacity providers with high energy and ancillary services value.¹²⁵ These resources should therefore be allowed to bid into the capacity market at a price that reflects their true value to the system: forcing them to ignore their environmental value (and associated revenue streams) simply perpetuates the market failure that allows fossil fuel resources to effectively underbid their true costs.¹²⁶

If these lower offers result in lower ICAP clearing prices, this is not a system reliability alarm that needs to be corrected. Instead, the market's current low prices correctly reflect that there is an oversupply of capacity in the market as discussed earlier, and correctly signals that the least valuable resources in the market—in this case, expensive fossil fuel generators that are utilized in the energy market with decreasing frequency—should retire.¹²⁷ The argument, in the face of years of excess supply, that BSM is necessary now to prevent the possibility of insufficient capacity in the future, ignores the fundamental tenets of market theory, namely, that if supply becomes constrained in the face of increased demand, prices will rise to encourage

¹²⁴ *Id.* at B.2, 15–16.

¹²⁵ Id

¹²⁶ Brattle Testimony at B.2, 15–16.

¹²⁷ Id.

greater investment.¹²⁸ The idea that mitigating state policy resources will "correct" the market by artificially raising the prices of the most competitive resources in the system in order to prop up the least valuable generators would stand elemental market economics on its head.

The absurdly inefficient, unreasonable, and unsustainable nature of mitigating state policy resources becomes especially apparent when applied to the NYISO, a single state ISO with a mandate to transition rapidly to 100% clean energy. Even the NYISO acknowledges that entry and exit of resources will be determined primarily by state policy and not the ICAP.¹²⁹ Continued application of the existing BSM rules in NYISO will quickly turn the ICAP into a "multi-billion-dollar-per-year parallel 'shadow market' that exists primarily as a means for customers to make duplicative payments to resources that are not needed for resource adequacy."¹³⁰ Such a result is the height of economic absurdity and paradigmatic of unjust and unreasonable rates.¹³¹

The "correct" price for capacity is one that aligns desired supply with actual demand, not the price and resource mix that would prevail in the absence of state policies. As Drs. Spees and Newell point out:

[T]he [BSM offers] a solution to a non-problem. The grievance from the standpoint of incumbent fossil generators is that their resources will eventually become uneconomic in a region with a significant clean energy mandate. Such resources will not enjoy the same revenues they would in a world where emissions do not matter. However, low prices are not a problem from a more holistic market design, reliability, or economic perspective. Low prices would be produced only when supply is long, new entry is not needed, and retirements can be accommodated. Applying BSM to policy resources creates a fundamental disconnect between market pricing outcomes that deviate from the underlying fundamentals of supply

¹²⁸ Id.

¹²⁹ Id.

¹³⁰ *Id.* at C.2, 19 ¹³¹ *Id.*

(including that associated with state policy resources) and demand (as expressed through resource adequacy requirements).¹³²

c. <u>Capacity Markets with Sloping Demand Curves Cannot</u> <u>Simultaneously Produce Low Prices and Poor Resource Adequacy.</u>

Concerns that low prices in the ICAP resulting from a growth in state policy resources

will threaten reliability by discouraging investment are deeply misguided;¹³³ indeed, this concern

is a mathematical impossibility.¹³⁴ By their very nature, capacity markets with downward sloping

demand curves cannot simultaneously produce low prices and poor resource adequacy, as

reflected in Figure 1 below:¹³⁵

FIGURE 1: CAPACITY MARKETS WITH DOWNWARD-SLOPING DEMAND CURVES CANNOT SIMULTANEOUSLY PRODUCE LOW PRICES AND POOR RESOURCE ADEQUACY



As discussed above, and reflected in this figure, if prices are low due to the entry of policy resources, this means that there is ample supply of capacity on the system. Low capacity prices

¹³² Brattle Testimony at 16.

¹³³ *Id.* at B.3, 17.

¹³⁴ Id.

¹³⁵ *Id.* at Figure 3: Capacity Markets with Down-Ward Sloping demand Curves Cannot Simultaneously Produce Low Prices and Poor Resource Adequacy.

signal that high-cost resources should retire and new entry is not needed; they do not reflect "price suppression" that demands imposition of BSM to state policy resources.¹³⁶

d. <u>Broad Application of Buyer-Side Mitigation to Policy Resources</u> <u>Will Amplify (Not Mitigate) Regulatory Risks.</u>

Some proponents also argue that applying BSM to policy resources is necessary to mitigate regulatory risk surrounding capacity investments.¹³⁷ They assert that these low prices "create significant uncertainty, which may further compromise the market" and lead to "unjust and unreasonable rates, terms, and conditions of service."¹³⁸

While elevated prices from an Expanded BSM would offset some immediate issues, they "should not be conflated with less-risky prices . . . On the contrary, a market whose price is artificially inflated by a rule as controversial and economically inefficient as BSM is unsustainable."¹³⁹ The pressure to eliminate MOPR rules across the ISO/RTO landscape is already well underway and will only increase as the sting of it reaches customers already reeling from the economic downturn. A healthy investment environment is more likely to result from long-term visibility into state policy implementation timelines and steps—as New York has done through its CLCPA and associated planning efforts—than from attempting to counter that state policy.

Analysis by the Brattle Group shows several past, current, and future benefits for merchant investment in the NYISO capacity market without BSM that could complement a future with large amounts of new state resources. These simulated markets retained enough existing capacity and new storage investment to maintain resource adequacy through 2040.¹⁴⁰

¹³⁶ Id.

¹³⁷ See, e.g., Cricket Valley Complaint at 34.

¹³⁸ Id. at 18–19 (citing PJM I, 163 FERC ¶ 61,236 at P 155 (footnotes omitted) n.79).

¹³⁹ Brattle Testimony at B.4, 18.

¹⁴⁰ *Id.* at B.5, 19–20.

As noted repeatedly by Chairman Glick, investor uncertainty that could doom capacity markets is far greater from the imposition of BSM than it is without it. The Governor of New York has described climate change as the "transcendent threat of our times."¹⁴¹ Over eighty percent of New Yorkers believe climate change is real, and recent polling indicates that climate change was the second biggest concern listed by voters in the 2020 election.¹⁴² Should the Commission stay on the path of making the capacity market into an impediment to achieving the State's widely-supported and jurisdictionally permitted resource goals, it is far more likely that New York will leave the ICAP market (as it is currently investigating¹⁴³). This result, while necessary to protect consumers, would engender far greater regulatory upheaval and investor uncertainty, and may be contrary to the purported desire of the Commission to foster and protect market competition.

e. <u>Private Investors Operate in a Context That Includes Environmental</u> <u>Policies from Which They Should Not Be Expected to Be</u> <u>Indemnified.</u>

The lower-than-expected returns on investment that BSM proponents attribute to state policy resources is part of competitive markets.¹⁴⁴ Private investors operate in a market and regulatory context that has always required them to face uncertainties associated with environmental regulations. Participants in a competitive market cannot expect to be indemnified against risks associated with these policies (nor should they be required to return

https://www.greatlakesnow.org/2020/02/state-governors-priorities-climate-change-new-york-michigan/. ¹⁴² Climate Nexus et al., *Poll Toplines* (Feb. 2020), https://newsletter.climatenexus.org/hubfs/Upcoming%20Primary%20State%20Poll%20Toplines%20and%20Cros

¹⁴¹ Gwendolyn Craig, *Survey shows most New Yorkers believe in climate change*, The Post Star (Jan. 16, 2019), https://poststar.com/news/local/survey-shows-most-new-yorkers-believe-in-climate-change/article_4e51ee5ae79c-5def-8813-2e90d95a5318.html; Gary Wilson, *Green Spotlight: New York Gov. Cuomo leads with climate change, restoring nature in annual priorities speech*, GreatLakesNow (Feb. 3, 2020),

https://newsletter.climatenexus.org/hubfs/Upcoming%20Primary%20State%20Poll%20Toplines%20and%20Crossstabs%20Climate%20Nexus.pdf.

¹⁴³ See Proceeding on Mot. of the Commission to Consider Resource Adequacy Matters, NYPSC Case No. 19-E-0530.

¹⁴⁴ Brattle Testimony at B.5, 19–20.

revenues to customers when policy changes favor their investments). And, contrary to its assertions, the zero-emission electricity goals enshrined in New York's CLCPA have been the writing on the wall since 2002.¹⁴⁵ All investors choose to bear the risks and rewards associated with changing market conditions and regulations; there is no reason why some investors should be inured to a risk faced by all private investors. A major purpose and off-cited benefit of capacity markets is to shift the risk burden from consumers to investors, not the reverse.

f. <u>BSM Should Be Applied for Its Narrow Original Purpose of</u> <u>Mitigating Market Power Abuses (Not Repurposed to Undo the</u> <u>Effects of State Policies).</u>

Clean Energy Advocates do not dispute that BSM is an appropriate mechanism for its original purpose: preventing manipulative price suppression by entities with market power. But the valid rationale behind BSM does not apply in the context of policy-supported clean energy investments for a number of reasons: (1) state policies are pursued for the purpose of addressing climate change, not in order to suppress market prices; (2) addressing environmental externalities is not "uneconomic"—it is a necessary market correction; and (3) applying BSM to state policy resources actually *causes* uneconomic behavior by incentivizing the retention of truly uneconomic, unnecessary resources. As explained by Brattle:

There is no sensible economic rationale for applying BSM to resources that are developed or maintained to address the harms of climate change or other environmental externalities. The policy support awarded to such resources reflects their environmental value; these resources are not "uneconomic" and their introduction is not in any way related to schemes of manipulative price suppression with uneconomic entry that the BSM was designed to address. Further, expanding BSM does not "level the playing field" as [its proponents] claim, since it does not privatize the costs of environmental externalities and does not attempt to undo the effects of all local, state, and federal policies that have always shaped the resource mix, including supporting the development of existing fossil plants and reduced the delivered cost of fossil fuels.¹⁴⁶

¹⁴⁵ *Id*. ¹⁴⁶ *Id*. at 4.

In sum, the application of BSM to state policy resources creates a market solution in want of a problem, motivated primarily by a concern that incumbent fossil generation owners may no longer expect to earn a satisfactory return on their investments. While certainly a potential concern for some incumbents, low capacity prices are not a problem from a societal or market design perspective. The real distortions before the Commission come from the ICAP's travels through the economic looking glass, not the presence of state policy resources in NYISO's capacity market.

2. BSM Imposes Uneconomic Costs on Customers and Society as a Whole.

NYISO and the independent market monitoring unit for the NYISO, Potomac Economics, ("MMU") acknowledge that failure to address the BSM rules will harm consumers and the NYISO capacity market.¹⁴⁷ This is consistent with findings by the Brattle Group that analyzed the impact of continued application of BSM to state policy resources and determined that the overall effect excludes policy resources from clearing the capacity market and has several adverse consequences, namely: (1) Existing BSM will keep state policy resources from clearing the capacity market and induce the uneconomic retention of excess capacity resources; (2) BSM rules will impose costs on all NYISO consumers by causing them to pay higher capacity prices than is economically efficient and by requiring customers to "pay twice" for capacity; (3) higher prices would effectuate a wealth transfer from customers to suppliers on the entire volume of capacity transacted in the market; and (4) supporting excess capacity results in excess societal costs or deadweight loss that benefits neither customers nor suppliers who bear the costs of maintaining the uneconomic excess supply.¹⁴⁸ Further, the scale of these

¹⁴⁷ Transmittal Letter at 3–5.

¹⁴⁸ Brattle Testimony at 23–25.

problems would grow along with the scope of the BSM and as NYISO proceeds toward fulfilling its various clean energy mandates.¹⁴⁹

a. <u>Application of BSM to CLCPA Resources Unjustly Disconnects</u> <u>Capacity Market from Its Intended Purpose of Providing Resource</u> <u>Adequacy and Thwarts NY's Clean Energy Transition.</u>

The Brattle Group analyzed the impact of applying BSM to state policy resources and determined that the overall effect excludes policy resources from clearing the capacity market and induces the uneconomic retention of fossil fuel resources, both of which pose a significant barrier to the achievement of the State's mandate under the CLCPA to achieve 100% clean electricity by 2040.¹⁵⁰

b. <u>BSM Inflates Capacity Rates and Requires Redundant Capacity</u> <u>without Benefiting Customers.</u>

Applying BSM to policy resources forces them to bid into the capacity market at administratively set prices designed to offset any benefits they receive as a result of state policies. The result is that capacity market prices increase for consumers and policy resources are pushed out of the capacity market as depicted in Figure 2 below:¹⁵¹







Expansion of BSM would exclude the policy resource from clearing by artificially increasing its price. As a result, the market clearing price would increase.

¹⁴⁹ Id.

¹⁵⁰ *Id.* § C, 22–23.

¹⁵¹ *Id.* § A, 9–12.

In addition to the "price effect" of BSM shown above, because NYISO utilities are also subject to the CLCPA, in addition to paying higher prices to meet ICAP reliability requirements, consumers are still required to purchase (and utilize) state policy resources required to meet clean energy mandates-this is known as the "quantity effect" or "double payment issue," whereby consumers have to "pay twice" for capacity—first, to retain the policy resources required by CLCPA, and second, to pay for the redundant ICAP resources required to meet resource adequacy requirements under the NYISO Tariff.¹⁵²

According to Brattle's analysis, and as set forth in Figure 3 below, continued application of existing BSM rules in the NYISO ICAP would subject approximately 7,200 ICAP MW of policy resources to BSM by 2030. A seasonal average of approximately 3,050 UCAP MW of clean energy resources from the ICAP market would be excluded from the market within 10 years.¹⁵³ Worse yet, as indicated by the fourth column, an average of 3,050 UCAP MW of uneconomic capacity resources would be retained by continuation of BSM rules, constituted primarily of aging, high-emitting gas- and oil-fired plants.¹⁵⁴



FIGURE 3: PROJECTED IMPACTS OF BSM ON CAPACITY MARKET CLEARING **BY 2030**

(Before Exemptions) BSM

¹⁵² Id. at 12; see also Dewey Comments at 13–14; Transmittal Letter.

¹⁵³ Brattle Testimony at C.1, 22.

¹⁵⁴ *Id.* at C.2, 22. This increase in unnecessary capacity would exacerbate NYISO's existing issues with excessive capacity.

According to Brattle, continued application of existing BSM rules will rapidly rise with the increase of policy resources, and will cost consumers *approximately \$460 million per year by 2030*.¹⁵⁵ Part of these costs include the economic waste of keeping the uneconomic and undesired plants referenced in Figure 3 online, which induces excess societal costs amount to about \$450 million per year by 2030. This is because the approximate \$10 million per year in net benefits that would be received by some incumbent generators by 2030 is dwarfed by the \$460 million in costs imposed on consumers.¹⁵⁶

FIGURE 4: CUSTOMER COSTS FROM IMPOSING BSM ON POLICY RESOURCES BY 2030



Just and reasonable rates require a balancing of costs to consumers and benefits to

investors, and consumers must receive something of value in order to justify increased rates.

But again, the context of NYISO being located within a single state with an ambitious clean

¹⁵⁵ *Id.* at D.1, 24. Under alternative assumptions, Brattle estimates that Expanded BSM *could range between \$400 and \$850 million per year* by 2030.

¹⁵⁶ *Id.* at D.1, D.3, 24–25.

energy mandate has a significant impact on the cost-benefit analysis. Here, the cost increases to NYISO customers under the BSM would essentially entail a giant wealth transfer from consumers to fossil fuel investors used to funding uneconomic investments for maintaining aging fossil fuel plants that would otherwise retire (benefitting neither customers nor generators).¹⁵⁷ The continued application of BSM rates is thus egregiously unjust and unreasonable.

B. NYISO's BSM Reforms Will Lead To Just and Reasonable Rates.

1. NYISO's Revisions to Its Buyer-Side Mitigation Rules.

Under NYISO's revised BSM rules, resources that fall within the definition of "Excluded Facilities" would not be subject to evaluation under the BSM rules.¹⁵⁸ Excluded Facilities would automatically include, but not be limited to, wind, solar, storage, hydroelectric technologies (including tidal, ocean, and wave generation), geothermal, fuel cells that do not use fossil fuel, and demand response (whether participating in the capacity as a Special Case Resource ("SCR") or a DER).¹⁵⁹ In addition, resources may be Excluded Facilities if they (1) are a technology type identified by the CLCPA or the New York State as supporting the goals of the CLCPA; (2) have a contract with NYSERDA supporting the goals of the CLCPA; or (3) are eligible to receive a contract with a New York State entity that supports the goals of the CLCPA.¹⁶⁰ Resources potentially eligible based on these criteria must submit a self-certification, whereas those eligible based on resource type are automatically categorized as

¹⁵⁷ *Id.* at D.1–D.3, 24–26.

¹⁵⁸ Transmittal Letter at 19.

¹⁵⁹ Id.

¹⁶⁰ Id.

Excluded Facilities.¹⁶¹ NYISO would also retain the existing exemptions under the BSM

Rules, such as Competitive Entry Exemption and the Self-Supply Exemption .¹⁶²

NYISO stresses that it and

"the MMU will continue to monitor and identify any relevant market behaviors or developments that could constitute abuses of buyer-side market power. If the NYISO were to identify any such exercise of buyer-side market power, it would take all appropriate and timely actions to address such abuse and protect against unreasonable capacity market outcomes. Moreover, the NYISO is proposing to retain the core feature of the existing BSM Rules to protect against potential exercises of buyer-side market power involving resources that are not serving New York State's CLCPA objectives."¹⁶³

2. <u>NYISO's Revised BSM Rules Properly Focus Application of BSM on</u> Actual Exercises of Buyer-Side Market Power.

Buyer-side market power mitigation must apply only where there is an actual exercise of buyer-side market power, not in the broader set of cases where some external factor may result in lower rates for capacity (so-called "price suppression").¹⁶⁴ NYISO's revised BSM rules are just and reasonable because they make this critical shift toward focusing on the actual exercise of buyer-side market power, rather than of undoing the effects of state policy.

When BSM rules are applied outside the context of market power mitigation—as a blunt instrument to negate any policy that has the potential effect of reducing wholesale capacity market prices—the Commission risks making capacity market revenues an end in themselves, rather than a means to ensuring reliability.¹⁶⁵ And once the Commission applies mitigation outside the context of the exercise of buyer-side market power, opportunities for discriminatory application abound. Existing, so-called "buyer-side market power" rules in

¹⁶¹ Id.

¹⁶² *Id.* at 20.

¹⁶³ *Id.* at 25.

 ¹⁶⁴ Cf. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC, 475 F.3d 1277, 1280 (D.C. Cir. 2007) (noting that "FERC's authority generally rests on the public interest in constraining exercises of market power").
 ¹⁶⁵ NYPSC and New York State Energy Research and Dev. Auth. v. NYISO, 173 FERC ¶ 61,060 (Glick, Comm'r.

¹⁶⁵ *NYPSC and New York State Energy Research and Dev. Auth. v. NYISO*, 173 FERC ¶ 61,060 (Glick, Comm'r, dissenting at PP 5–6).

NYISO and elsewhere selectively mitigate against only the feared price suppressive effects of state policies that provide revenues in exchange for environmental attributes or otherwise incentivize the development and retention of generation resources that are essential to meeting state policy objectives. In contrast, federal policies that can benefit certain resources have not triggered mitigation, nor have state policies that reduce the cost of upstream fuel production, ¹⁶⁶ or revenues earned outside of FERC-jurisdictional markets through sales of generation-related products to private actors.¹⁶⁷

When it comes to mandatory capacity markets, the Commission has struggled to articulate when buyers have buyer-side market power, or have exercised it.¹⁶⁸ But this is no excuse to abandon the concept of market power altogether as the basis for imposition of offer floors. Mitigating offers that appears "low" relative to an administratively selected determination of what the offer "should be" is an unacceptably fraught substitute for rigorous assessment of when an offer is affected by actual buyer-side market power. Over-mitigation of perceived or redefined buyer-side market power causes significant harm to competition, and prevents the formation of just and reasonable rates. Suppliers may have legitimate reasons to submit bids below an administratively determined "competitive level," including reasons to

¹⁶⁷ See 2020 Req. for Reh'g of Clean Energy Advocates, at 47–48 (setting out argument that expanded MOPR arbitrarily discriminates between resources receiving benefits under state and federal policies); *id.* at 56–57 (noting lack of justification for treating revenues from sales of coal ash, steam heat, and other generation byproducts different from sales of environmental attributes pursuant to state policy).

¹⁶⁸ As former FERC chairman Norman Bay observed, the label of buyer-side market power "is imprecise and somewhat of a misnomer"; and "while the Commission applies elaborate screens to detect the exercise of seller market power, it does not apply similar screens to detect buyer-side market power in capacity markets. The Commission simply assumes it exists." *ISO New England Inc. and New England Power Pool Participants Comm.*, 158 FERC ¶ 61,138 (Feb. 3, 2017) (Bay, Comm'r, concurring). *See also* Joshua Macey & Robert Ward, *MOPR Madness*, 42 Energy L.J. 67 (Oct. 18, 2020) ("MOPR Madness"), https://www.eba-net.org/assets/1/6/6_ _____%5BMacey_____Ward%5D%5B67-122%5D.pdf; Jay Morrison, *Capacity Markets: A Path Back to Resource*

¹⁶⁶ See generally 2018 Protest of Clean Energy Advocates, at App. B, Koplow Report: Energy Subsidies within PJM: A Review of Key Issues in Light of Capacity Repricing and MOPR-Ex Proposals.

Adequacy, 37 Energy L.J. 1, 23–28 (2016) ("A Path Back to Resource Adequacy"), <u>https://www.eba-</u> net.org/assets/1/6/18-1-60-Morrison_FINAL.pdf.

submit an offer of zero—indeed, "exercises of monopsony power are very difficult to differentiate from competition."¹⁶⁹ Applying BSM outside the confines of actual exercises of buyer-side market power guarantees over-procurement and prices higher than the actual marginal cost of capacity in the market.¹⁷⁰

NYISO's revised BSM rules are therefore appropriately limited to guarding against the exercise of buyer-side market power. The fact that a capacity market seller may receive revenues because of a state or local policy that compensates for environmental attributes does not thereby create a load interest or suggest that the seller is submitting capacity market offers at the "direction of a load interest." That seller does not even have an incentive to lower the capacity market price, but instead benefits from higher prices as any seller would.¹⁷¹ That seller may submit a relatively low offer because those revenues actually change the amount of money they require from the capacity market in order to undertake construction or remain in operation. This is a commercially reasonable offer, reflecting a competitive advantage held by the seller—it does not indicate market manipulation by a buyer, or at the direction of a buyer.

Simply put, in the case of state policies to provide incentives for certain types of generation, there is no buyer seeking to benefit from lower capacity market prices, and able to suppress them. It would be pure fiction to regard such state policies as instruments of buyer-

¹⁶⁹ A Path Back to Resource Adequacy at 32 (noting that "[1]ow bids could also 'reflect the lower cost structure of the alleged predator, and so represent[] competition on the merits."); *see also* MOPR Madness at 107 ("MOPRs fail to reward marginal efficiencies, and that they do not permit resources to submit below-cost bids even when the supplier has a legitimate reason to do so. In ordinary markets, resources compete to reduce their own costs, secure favorable financing arrangements, hire cheap labor, and make accurate predictions about future market prices.").

¹⁷⁰ See, e.g., A Path Back to Resource Adequacy at 33 ("Mitigation of self-supply bids can very easily chill procompetitive legitimate conduct unless very carefully limited to prevent abusive behavior.").

¹⁷¹ See MOPR Madness at 121 ("Unlike capacity offered by net buyers, subsidized resources benefit financially when capacity prices increase."); *id.* at 72 ("[U]nlike price suppression caused by predatory pricing strategies, state subsidies do not threaten to drive independent power producers out of wholesale electricity markets. They simply generate a price signal that affects suppliers' behavior.").

side market power.¹⁷² Even if the state policy were constructed in an unusual manner that does somehow control the resource offer, this says nothing about whether such an offer would actually affect the clearing price or whether any associated load would benefit, on net, from such an effect.¹⁷³

Declining to treat the effects of state policies as exercises of buyer-side market power is consistent with the Commission's obligation to ensure that market-based rates are just and reasonable. To be sure, the Commission cannot unquestioningly accept a market-based rate as just and reasonable without having adequate measures in place to detect and protect against the exercise of market power.¹⁷⁴ But this leaves to the Commission the responsibility to determine what constitutes market power or the exercise thereof, and how to balance the risks of excessive mitigation of market power (false positives), and the risk of under-mitigation (false negatives). Defining the exercise of buyer-side market power without regarding to the involvement of a buyer, or that buyer's incentive and ability to suppress the market price, would be unjust and unreasonable. Likewise, applying mitigation outside the context of buyer-side market power, such as to state policies that address the climate crisis, is inconsistent with the foundations of market-based rates. By committing to apply it to CLCPA resources that do not

¹⁷² See NYPSC v. NYISO, 158 FERC ¶ 61,137 (Feb. 3, 2017) (Bay, Chairman, concurring) ("The MOPR is not applied to the state, which may not actually be a buyer and which is acting on behalf of its citizenry, but to the resource, which is offering to sell capacity to the market and which may be a commercial entity. The theory, in other words, assumes such a congruence of interests between the state and the resource that the resource is mitigated for the conduct of the state."); *see NYISO*, 172 FERC ¶ 61,058 (July 17, 2020) (Glick, Comm'r, dissenting at P 17) (rejecting previously articulated Commission view that states are quasi-buyers because they represent the interests of consumers and noting that "[s]tates regulate for a variety of reasons and acting as if any regulation is an exercise of market power fundamentally misunderstands the role Congress reserved for the states under the FPA. Philosophical market power—as distinguished from actual market power—should have no place in the Commission's regulatory regime.").

¹⁷³ See MOPR Madness at 79–101 (detailing importance and evolution of "incentive" and "ability" in buyer-side market power mitigation schemes).

¹⁷⁴ Tejas Power Corp. v. FERC, 908 F.2d 998, 1004 (D.C. Cir. 1990).

represent exercises of market power, NYISO's revised BSM tariff will result in just and reasonable rates for capacity.

3. <u>NYISO's BSM Reforms Will Restore the Capacity Market to Its</u> <u>Intended Function and Ensure Price Signals Reflect True Reliability</u> <u>Needs.</u>

Clean Energy Advocates agree with NYISO that "[i]t would be arbitrary and capricious for FERC to force the NYISO to ignore market and investment realities driven by CLCPA mandates."¹⁷⁵ Capacity markets are intended to ensure reliability by addressing the "missing money" problem—ensuring generators have adequate income to meet peak energy usage.¹⁷⁶ Even though the ICAP market has a short-term focus, it "works in tandem with the energy and ancillary services markets to help meet long-term resource adequacy objectives in the most cost-effective manner."¹⁷⁷

An efficient outcome to a capacity market auction—a price reflecting the actual marginal cost of providing capacity—is achieved where "resources' capacity market offers [] reflect all relevant costs minus all relevant revenues, including costs and revenues that are not derived directly from Commission-jurisdictional markets."¹⁷⁸ By mitigating only actual exercises of buyer-side market power, NYISO's proposed tariff will allow capacity prices to reflect revenues that resources earn through state policy mechanisms, which in turn leads to

¹⁷⁵ Transmittal Letter at 30.

¹⁷⁶ *Id.* at 7 ("The objective of the capacity markets is to provide adequate revenues to attract new and retain existing resources to meet resource adequacy criteria going forward. As the Commission has repeatedly held, "the capacity market is designed to encourage new investment, retain existing needed capacity, and signal when capacity is sufficient or when additional resources are needed.").

¹⁷⁸ FERC, *Comm'r Richard Glick Dissent Regarding NYPSC v. NYISO*, Statements (Feb. 20, 2020), <u>https://cms.ferc.gov/news-events/news/commissioner-richard-glick-dissent-regarding-new-york-public-service-commission-et</u>.

just and reasonable rates. The economic principles informing NYISO's proposal find broad support in the literature.¹⁷⁹

As Chairman Glick has previously explained "[a] capacity construct that ignores those states' public policies will produce price signals that do not reflect the factors that are actually influencing the development of new resources. Those misleading price signals will encourage the participation of the wrong types of resources or resources that are not needed at all."¹⁸⁰ As the Brattle Group has explained in related proceedings concerning NYISO's capacity market, "the correct capacity price is that which aligns supply and demand, given other policies and/or markets that policymakers have identified as necessary to address the externality."¹⁸¹ These correct price signals reflect "that policy resources will be developed and operate regardless of whether or not they clear the capacity market," and avoid "distort[ing] the capacity market by inducing the procurement of additional capacity to meet reliability objectives."¹⁸²

NYISO's filing reflects this logic, noting that "[o]ver-mitigation of [CLCPA] resources would result in needlessly higher costs to consumers, and market inefficiencies."¹⁸³ NYISO also explains that "[i]t is just, reasonable, and not unduly discriminatory to exclude resources that serve CLCPA objectives from the BSM Rules because the statute, and state programs adopted thereunder, are expected to be the principal driver of changes to the resource mix in New York State over the next two decades."¹⁸⁴ Clean Energy Advocates contend that whether

¹⁷⁹ See, e.g., Todd S. Aagaard & Andrew N. Kleit, *A Road Paved with Good Intentions?: FERC's Illegal War on State Electricity Subsidies*, 33 Elec. J. 1, at 3–4, 6–7 (June 2020) (arguing that MOPR reforms lead to unjust and unreasonable rates), <u>https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3544876</u>; Danny Cullenward & Shelley Welton, *The Quiet Undoing: How Regional Electricity Market Reforms Threaten State Clean Energy Goals*, Yale J. Regul. Bulletin (Nov. 8, 2019), <u>https://www.yalejreg.com/bulletin/the-quiet-undoing-how-regional-electricity-market-reforms-threaten-state-clean-energy-goals</u>/.

¹⁸⁰ See NYISO, 172 FERC ¶ 61,058 (Glick, Comm'r, dissenting at P 14).

¹⁸¹ Brattle Testimony at 15.

¹⁸² *Id.* at 16.

¹⁸³ Transmittal Letter at 3.

¹⁸⁴ *Id*.

or not state policies are the *principal* driver of changes to the resource mix is not the determining factor in whether it is just and reasonable to exclude them from application of buyer-side mitigation rules. Application of BSM to any state policy resources distorts market outcomes, but the resulting inefficiencies, elevated prices, and duplicative procurement, will be more extreme in a market like NYISO's where new entry is driven primarily by state policy.

Finally, NYISO argues that because NYISO is a single-state RTO, concerns about shifting costs to other states do not exist.¹⁸⁵ The Commission should not rely upon such a consideration in its order because the concerns about cost-shifts between states that have been articulated elsewhere are misguided. In a multi-state market, application of BSM to state-supported resources increases the price that consumers in other states pay for capacity in other states. Removing BSM actually benefits consumers in those other states, rather than shifting costs to them. Concerns about alleged cost shifts, when scrutinized, appear to be a façade for concerns about the fate of fossil generation resources in states without clean energy policies, rather than about the consumers in those states.

4. <u>NYISO's BSM Reforms Will Result in Just and Reasonable Rates</u> <u>Regardless of How Its Capacity Accreditation Proposal Develops.</u>

NYISO's revised BSM rules are just and reasonable, not because the resources being excluded from BSM application will not cause price suppression under NYISO's unspecific new accreditation framework,¹⁸⁶ but because the resources being excluded (and their unmitigated offers) do not otherwise represent an exercise of buyer-side market power. NYISO indicates that the BSM reforms "are important, just, reasonable, and not unduly discriminatory improvements in their own right."¹⁸⁷ We agree. However, at other points in its

¹⁸⁵ Id. at 30.

¹⁸⁶ Id.

¹⁸⁷ Id. at 18.

filing, NYISO asserts that "a more robust accreditation design is necessary to justify relieving Excluded Facilities from mitigation."¹⁸⁸ This implies that BSM was never about ensuring that a resource offers at its "true" cost, but instead served to paper over gross inaccuracies in the accreditation framework. As described in Section III.A, BSM is based on a fundamentally flawed view of competition and the purposes of the ICAP market to ensure resource adequacy at reasonable cost to consumers. Because BSM is wrong in theory and exceedingly harmful in practice (as NYISO admits), it could not be sustained on the basis that it incidentally fixes another problem with NYISO's markets (its current accreditation approach). For the same reason, BSM should be fixed regardless of whether the Commission agrees that NYISO's request for blank-check approval of a radically new accreditation approach is just and reasonable.

The Analysis Group ("AGI") study provided as Attachment III-A to NYISO's filing departs in potentially significant ways from the accreditation approach as described by NYISO in this filing. AGI's analysis does not reflect the actual capacity accreditation methodology that NYISO will implement in two years. Indeed, it could not, because major elements of that methodology are unknown. As AGI explains: "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."¹⁸⁹ The GIT Evolution Study itself emphasized that the marginal accreditation approach used "does not

¹⁸⁸ *Id.* at 4.

¹⁸⁹ Transmittal Letter, Attach. III-A at 11.

replace a full probabilistic [ELCC] study" due to the approach's failure to account for variability in conditions across years, and to account for internal transmission constraints.¹⁹⁰ Although NYISO touts the ability of its marginal capacity approach to send locational price signals, AGI's analysis "assume[s] 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."¹⁹¹ Likewise, AGI calculates the UCAP value of "existing non-intermittent, non-storage resources to UCAP values using NERC historical EFORd values," rather than a marginal reliability accreditation approach.¹⁹² AGI asserts that this "represents a reasonable approximation of forward-looking Capacity Accreditation for these resources for the purpose of this analysis."¹⁹³ This unsupported assertion seemingly conflicts with the Mukherji testimony that "the forced outage rates that are used to determine capacity credit do not necessarily align with, or produce credit values that accurately reflect, a Resource's true marginal value for resource adequacy."¹⁹⁴

AGI is hardly to blame for the limitations of its study in accurately reflecting the capacity accreditation factors that will be developed for each resource class two years hence. But the Commission should be cautious in relying *solely* upon the findings of a study that departs in significant ways from the promised features of NYISO's marginal reliability

¹⁹⁰ Roger Lueken et al, *New York's Evolution to a Zero Emission Power System*, Brattle Group, at 109 (June 22, 2020),

 $[\]label{eq:https://www.nyiso.com/documents/20142/13245925/Brattle%20New%20York%20Electric%20Grid%20Evolutionn%20Study%20-%20June%202020.pdf/69397029-ffed-6fa9-cff8-c49240eb6f9d.$

¹⁹¹ Transmittal Letter, Attach. III-A at 11.

¹⁹² *Id.*, Attach. III ¶ 18.

¹⁹³ *Id*.

¹⁹⁴ *Id.*, Attach. IV ¶ 52.

contribution approach to conclude that eliminating the application of BSM to CLCPA resources will result in just and reasonable rates.¹⁹⁵

The Commission should instead base its decision upon the fundamental point that absent an exercise of buyer-side market power, the offers reflected in the supply curve represent market forces and policy reality, and therefore result in rates that are just and reasonable.¹⁹⁶ The Commission may also recognize the importance to just and reasonable rates of getting capacity accreditation right, without accepting NYISO's invitation to conclude, up front and without critical information, that NYISO's vague tariff language regarding marginal reliability contributions will necessarily "get it right."

IV. NYISO'S CAPACITY ACCREDITATION PROPOSAL IS INCOMPLETE AND PREMATURE

NYISO proposes, beginning in 2024, to use a new capacity accreditation design. Though details are scant, NYISO outlines several key features.¹⁹⁷ Each resource class will be assigned a Capacity Accreditation Factor. These Capacity Accreditation Factors will be determined based on NYISO's assessment of the marginal resource adequacy contributions of each resource class, using NYSRC's study model for the applicable Capability Year. Neither the new methods for assessment of the marginal resource adequacy contributions nor the resource classes are specified in NYISO's tariff revisions. NYISO reports that the NYSRC study model closely resembles the actual supply mix.¹⁹⁸

¹⁹⁵ The two-year lag between elimination of BSM and implementation of the marginal reliability approach is another reason that the Commission should not rely upon the eventual implementation of a different accreditation methodology as a necessary component of just and reasonable rates once the existing BSM rules are modified. ¹⁹⁶ *Tejas Power Corp.*, 908 F.2d at 1004.

¹⁹⁷ Services Tariff §§ 5.12.14.2 and 5.12.14.3.

¹⁹⁸ Transmittal Letter at 33.

As discussed in detail below,¹⁹⁹ NYISO's proposed rate does not provide sufficient information to satisfy the Commission's rule of reason nor enable the Commission to determine if the proposed rate is just and reasonable. Additionally, the few specified details of the marginal accreditation approach raise significant risks that the implemented rates would not result in just and reasonable rates or would be unduly discriminatory. As NYISO's marginal accreditation proposal is not inherently linked to the Buyer Side Mitigation proposal, we urge the Commission to reject NYISO's request for unconditioned approval of this portion of NYISO's filing, which is insufficiently developed and would be premature to approve as submitted.

Even the sketch NYISO provides is either gravely flawed or omits components vital to a properly functioning approach. First, NYISO's approach to marginal accreditation inherently miscounts the total value of cleared resources and so requires further adjustments for accuracy.²⁰⁰ Second, the procedure for determining Capacity Accreditation Factors introduces errors that prevent the price signals presented as the approach's primary benefit from functioning properly.²⁰¹ Worse, those errors will always, and predictably, be in the direction of understating the reliability value of storage and intermittent resources,²⁰² making the procedure unduly discriminatory.

The remainder of this section describes the insufficiency of NYISO's filed tariff, how NYISO's marginal accreditation proposal likely runs afoul of just and reasonable rates, and the lack of linkage between this proposal and NYISO's larger BSM proposal.

¹⁹⁹ See infra, Section IV.D.

 ²⁰⁰ Written Testimony of Kevin Carden, Trevor Bellon, & Alex Dombrowsky, *NYISO ELCC Accreditation Analysis*, at 21–22 (Jan. 26, 2022) ("Astrapé Testimony"), (attached hereto as Ex. B).
 ²⁰¹ Id. at 24–25.

²⁰² See id. at 23.

A. NYISO's Tariff Language Is Very Limited and Leaves the Critical Concept of "Marginal Reliability Contribution" Unspecified.

NYISO's proposed changes to its tariff—the <u>only</u> tariff language that NYISO contends is necessary to provide sufficient notice to customers and market participants—are relatively minimal.²⁰³ Moreover, the proposed tariff does not indicate how it will derive the "marginal reliability contribution" of a given resource, despite that concept being central to the ultimate capacity accreditation of a given resource.

NYISO's tariff filing proposes to add two new defined terms, each of which presents further ambiguities: "Capacity Accreditation Factor" and "Capacity Accreditation Resource Class." Capacity Accreditation Factor would be defined as "factors, set annually by the ISO in accordance with Section 5.12.14.3 and ISO Procedures, that reflect the *marginal reliability contribution* of the ICAP Suppliers within each Capacity Accreditation Resource Class toward meeting NYSRC resource adequacy requirements for the upcoming Capability Year."²⁰⁴ Capacity Accreditation Resource Class is defined as the "defined set of Resources and/or Aggregations, as identified in accordance with ISO Procedures, with similar technologies and/or operating characteristics which are expected to have similar *marginal reliability contributions* toward meeting NYSRC resource adequacy requirements for the upcoming Capability Year."²⁰⁵ The term "marginal reliability contribution" is not defined elsewhere.

Despite the centrality of marginal reliability contribution for determining resource capacity, NYISO leaves the question of how that marginal contribution will be determined unexplained. As explained in Section IV.B, there is a wide variety of ways in which the marginal contribution could be ascertained, and other complicating factors that arise with

²⁰³ See Transmittal Letter at 48–49.

²⁰⁴ *Id.* at 48; Transmittal Letter, Att. I § 2.3 at 2.

²⁰⁵ Transmittal Letter at 2–3.

marginal accreditation methods.²⁰⁶ NYISO readily admits that it has not even settled on a single methodology for calculating the capacity factors, suggesting that "Capacity Accreditation Factors will be calculated using a system 'Effective Load Carrying Capability' (ELCC) or equivalent methodology."²⁰⁷ In a footnote, NYISO then acknowledges that NYISO "intends to work with stakeholders during the 'Phase II' process" to "compare the ELCC and MRI methodologies as it develops the tools to perform the annual review of Capacity Accreditation Factors."²⁰⁸ Even assuming that ELCC and MRI methodologies are "equivalent" (a fact that has not been established), there is considerable variation within "marginal ELCC" methodologies²⁰⁹. Moreover, NYISO's proposed tariff revisions do not clearly require NYISO to apply the same methodology for calculating Capacity Accreditation Factors to every resource class. Notably, in the NYISO Capacity Accreditation: Consumer Impact Analysis performed by the MMU, the model assumed that available capacity from conventional suppliers was equal to their existing UCAP.²¹⁰ This implies the MMU considers the current method for these resources an "equivalent methodology" to ELCC. Because NYISO's revised tariff language is essentially an empty vessel for NYISO to fill as it pleases, its proposed tariff does not provide adequate notice to customers and market participants of the proposed rate change or how it will affect them.

NYISO's proposal also offers few specific commitments on how resources will be split into classes, even noting that classes and class assignment will likely change over time.²¹¹

²⁰⁶ See, e.g., Astrapé Testimony at 20–25, 31.

²⁰⁷ Transmittal Letter at 34 & n.109.

²⁰⁸ Id.

²⁰⁹ For a discussion of the many factors considered in designing an ELCC calculation methodology, *see generally* PJM Interconnection LLC, Effective Load Carrying Capability Construct, Attach. C: Aff. of Dr. Patricio Rocha Garrido on Behalf of PJM, at 12–22, 28–32, Docket No. ER21-278 (Oct. 30, 2020), Accession No. 20201030-3075.

²¹⁰ See Transmittal Letter, Attach. VI at 6.

²¹¹ See Transmittal Letter at 35.

Because under many capacity value methods a resource's class assignment can have a major impact on its capacity value allocation, NYISO must²¹² provide much greater detail and predictability regarding class assignment before it can be determined whether its proposed method is just and reasonable.²¹³

B. Accreditation Methodologies Are Too Complex to Be Described in a Term as Simple as "Marginal Reliability Contribution."

1. <u>Effective Load Carrying Capability Methods Vary in How They</u> Quantify the Resource Adequacy Contribution of Various Resources.

NYISO's tariff says its ultimate chosen methodology will use a "marginal reliability

contribution" and its Filing Letter says this means that it will use an "Effective Load Carrying

Capability" ("ELCC") or a similar approach to determine the Capacity Accreditation Factor for

all resources.²¹⁴ ELCC is a statistical method that is particularly well suited to capturing

complexities of modern resource adequacy such as multiple plants sharing a common fuel

supply or the interactions between weather, renewables, and storage. It is rapidly becoming a

standard approach for capacity accreditation at RTOs.²¹⁵

²¹² See PJM, 175 FERC ¶ 61,084, at P 66 (April 30, 2021) ("PJM ELCC Order I") ("we find that the ELCC Classes should be specified in the RAA").

²¹³ Transmittal Letter at 35 ("The NYISO would assign each ICAP Supplier to a Capacity Accreditation Resource Class. All Capacity Accreditation Resource Classes will be evaluated in all relevant ICAP Market locations to determine the applicable Capacity Accreditation Factor to be assigned to ICAP Suppliers of that class in each location. All ICAP Supplier resource types would be assigned a class. Capacity Resource Accreditation Classes may be expanded or contracted as supply mix and technology evolve to reflect new technologies not yet identified or participating in the NYISO's markets. The list of available classes could also change to reflect the complete exit of older technologies through the NYISO's deactivation procedures. Consequently, the NYISO would define Capacity Accreditation Resource Classes each year. Each class will contain a defined set of Resources and/or Aggregations, as identified in accordance with ISO Procedures, with similar technologies or operating characteristics which are expected to make similar marginal reliability contributions toward meeting NYSRC resource adequacy requirements for the upcoming Capability Year.").

²¹⁴ *Id.* at 34. There are several varieties of ELCC, and in footnote 109, NYISO mentions they will also consider an ELCC variant called "MRI". The differences between these approaches are generally in the specifics of calculation algorithms, and they all produce similar results. The discussion herein applies equally to any specific ELCC implementation and MRI. For brevity we refer to this family of approaches generically as "ELCC."
²¹⁵ See generally Comments of the PIOs, at 6–18 (Nov. 20, 2020), Docket No. ER21-278, Accession No. 20201120-5261.

ELCC accreditation methods generally account for correlated output and correlated outages within a specific class of resources in determining the capacity accreditation of that class of resources. ELCC captures two important features of renewable and storage resources: (1) changing marginal value, where the resource adequacy value of a resource category changes with the quantity of that resource (e.g., the contribution of solar resources decreases as reliability risk is shifted away from daylight hours); and (2) portfolio effects, where the combined value of multiple resource types may be different than the sum of them taken separately. For example, solar tends to concentrate resource adequacy risk in a few hours around sunset, which storage is well-suited to handling).

Importantly, conventional resources also have correlated reliability risks. For example, multiple gas-fired plants may rely on a common pipeline, creating a risk of simultaneous outages. As recent events such as Winter Storm Uri have shown, all resource types can be subject to correlated outages, and extension of ELCC to all resources provides valuable information and price signals on which types of capacity are most valuable.²¹⁶

The more a resource class has highly correlated operational characteristics, the more steeply its resource adequacy value declines with increased saturation. A "run" of an ELCC model estimates the resource adequacy value of a new resource under a given set of conditions. By systematically changing those conditions over multiple runs, curves can be produced showing the resource adequacy contribution of a given technology as a function of the amount of that technology installed. Stylized examples of these curves are presented in Figure 5 below.

²¹⁶ Astrapé Testimony at 16.

Resource adequacy value is typically measured in megawatts of unforced capacity, or UCAP, which represents the equivalent of a megawatt of a theoretical perfect resource. Expressing resources in UCAP allows direct comparisons of the resource adequacy value of different technologies and a standard measure for which each LSE is responsible. Despite its name, NYISO's ICAP is a market to buy and sell UCAP²¹⁷.



FIGURE 5: TOTAL AND MARGINAL RESOURCE ADEQUACY VALUE

The total value curve (on left) shows the net UCAP value of a fleet of resources in the same resource class. The example shows the expected relationship for many resource types. The initial megawatts of the technology have a high UCAP value, and so the total UCAP of the fleet increases rapidly. As more is installed, each new increment provides less additional resource adequacy, and the increase in total value slows. Finally, at some point, adding more resources brings no additional resource adequacy benefit, and the curve flattens. The same relationship can be displayed as marginal value (on right), which shows the additional UCAP provided by each new unit of the technology. The marginal value starts high, reflecting the contributions of the initial megawatts, and eventually drops to near zero as the technology

²¹⁷ NYISO Manual 4 at 1.

saturates. These two curves are just different views of the same situation; the same ELCC analysis produces both the total value and marginal value results.

This relationship is not particularly subtle; look no further than the common phrase "couldn't eat another bite," which is technically a statement of the marginal value of the next unit of food, but is understood to mean the total food eaten so far has sated the speaker's hunger. However, it raises an important market design conflict that must be resolved: resource adequacy is a function of the total value, while efficient market clearing depends on the marginal value.²¹⁸ An optimally functioning capacity market would select resources based on their marginal price until the total volume of resource adequacy procured meets the volume necessary to meet reliability requirements. Further complicating matters is the FPA's requirement that rates not be unduly discriminatory,²¹⁹ which suggests that sets of resources providing the same volume of reliability services (i.e., the same total volume of UCAP) should receive the same total payment. This raises a potential conflict between economic efficiency, which would credit resources based on marginal value, and equal value for equal services, which would allocate total resource adequacy value to all resources contributing to that value. NYISO's own experts noted the problematic tradeoffs in choosing a marginal ELCC methodology in Figure 6 below:²²⁰

²¹⁸ See Astrapé Testimony at 12.

²¹⁹ 16 U.S.C. §824d(b).

²²⁰ Arne Olson et al., *ELCC Concepts and Considerations for Implementation*, Energy + Environmental Economics, at 34 ("August 30 E3 Report"), https://www.nyiso.com/documents/20142/24172725/NYISO%20ELCC 210820 August%2030%20Presentation. pdf/8ac7b020-206e-6dff-4e0f-756bc215ecc0, (attached hereto as Ex. C).

FIGURE 6: PRINCIPLES FOR INDIVIDUAL RESOURCE ELCC ACCREDITATION



In addition, any ELCC method should also account for the widely documented synergistic "diversity benefits" among resources with non-correlated output.²²¹ The diversity benefit provided by the interaction between storage and variable resources is particularly noteworthy and becomes more pronounced as greater amounts of renewable resources are added to the portfolio, as shown in the example provided by NYISO's experts in Figure 7 below:²²²

²²¹ See PJM, 176 FERC ¶ 61,056, at P 31 (July 30, 2021) ("We find that PJM's adjusted class average ELCC framework is just and reasonable because...it models all ELCC resources simultaneously, recognizing the possible synergistic and antagonistic interactions between resource classes, and ensures that the sum of resource classes' accredited capacity values is equal to the aggregate reliability value of the ELCC Portfolio...") ("PJM ELCC Order II"). See also E3, Capacity and Reliability Planning in the Era of Decarbonization (Aug. 2020) ("Capacity and Reliability Planning in the Era of Decarbonization"), https://www.ethree.com/wpcontent/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf. ²²² August 30 E3 Study at 50.



FIGURE 7: DIVERSITY BENEFITS OF SOLAR + STORAGE

Multiple studies from the national labs,²²³ think tanks,²²⁴ and academia²²⁵ suggest that the diversity benefits from fleets of complementary resources will play an increasingly important role in maintaining resource adequacy. Failing to account for diversity benefits and credit them to those complementary resources would not be just and reasonable.

2. <u>Method Choices Significantly Affect the Accredited Capacity of Resources.</u>

Importantly, identifying the diversity benefit is a fairly straightforward task for ELCC analysis, but there is no single way to allocate those capacity value benefits to the multiple resources that create them.²²⁶ For example, the PJM IMM has previously discussed at length how different variations of the delta approach,²²⁷ a method for accounting for diversity benefits

²²⁴ See, e.g., Mark Dyson et al., *The Economics of Clean Energy Portfolios*, Rocky Mountain Inst. (2018), http://www.rmi.org/insights/reports/economics-clean-energy-portfolios/.

²²⁶ See PJM ELCC Order II at 37 ("we agree with PJM that there is no single 'correct method to determine how the overall ELCC capacity value of a resource portfolio or resource class should be allocated").

²²³ See, e.g., Gregory Brinkman et al., *The North American Renewable Integration Study: A U.S. Perspective. Golden*, National Renewable Energy Laboratory, § 3.2.2 (June 2021), https://www.nrel.gov/docs/fy21osti/79224.pdf.

²²⁵ See, e.g., Alexander MacDonald et al., *Future cost-competitive electricity systems and their impact on US CO2 emissions*, 6 Nature Climate Change 526, 526–531 (2016), <u>https://doi.org/10.1038/nclimate2921</u>.

²²⁷ Patricio Rocha Garrido, *Delta Method—Step-by-Step Guide*, PJM (Feb. 18, 2021), <u>https://www.pjm.com/-/media/committees-groups/task-forces/ccstf/2021/20210218/20210218-item-02-delta-method.ashx</u>.

among resources,²²⁸ result in different allocation outcomes that may determine whether they are just and reasonable.

Indeed, as was explained to NYISO by its own experts, capacity accreditation frameworks based on ELCC analysis present numerous methodological choices for quantifying the resource adequacy contributions of heterogenous resources.²²⁹ Taken together, the set of ELCC modeling choices and allocation methods can produce significantly different capacity accreditations for an individual resource. It is therefore of utmost importance that any such accreditation framework proposed by an RTO or ISO be clearly described in detailed tariff language.

A variety of capacity accreditation approaches have arisen on the common foundation of ELCC analysis. A 2020 report from Energy & Environmental Economics provides a useful taxonomy of these approaches:²³⁰

- In a **"marginal"** accreditation framework, all resources are credited an ELCC based on their marginal contribution to system resource adequacy needs.
- A 'vintaged marginal' approach is closely related to the marginal approach but locks in the marginal ELCC of each resource at the time it is added to the system. This credit is thereafter retained by the resource, either for its lifetime or for a predetermined period of sufficient duration to enable a degree of revenue certainty. In a "class average" framework, a total ELCC is calculated for a class of resources (e.g. wind, solar) and averaged across all resources within the class.
- **"Adjusted class average"** approaches have been explored as a means of adapting class average approaches to incorporate interactive effects among classes."

²²⁸ Comments of the Independent Market Monitor for PJM, at 15–16, Docket No. ER21-2043 (June 22, 2021), Accession No. 20210623-5007,

https://www.monitoringanalytics.com/filings/2021/IMM Comment Docket No ER21-2043 20210622.pdf.

²²⁹ August 30 E3 Study at 48 ("There are many different "marginal" ELCCs depending on your "base" portfolio.").

²³⁰ Capacity and Reliability Planning in the Era of Decarbonization at 13–14. The same report proposes the use of a "Delta" ELCC, discussed further elsewhere in this filing.

NYISO's expert provided stakeholders a presentation on the pros and cons of these approaches as indicated in the chart in Figure 8 below:²³¹

Framework	Description	Pros	Cons
Vintaged Marginal	Assigns each resource a credit based on the marginal ELCC at the time it is added to the system	Yields correct total ELCC across all resources Provides accurate marginal signal for procurement of new resources	Distinction between otherwise identical resources undermines fair competition and isn't a feature of other electricity market products (even though the same factors apply) ELCC "lock-in" can become intractable based on resource lives and potential for upgrades or partial retirements
Marginal	All resources are attributed an ELCC based on their marginal contribution to resource adequacy	Temporarily provides correct marginal signal for procurement of new resources	Does not appropriately credit a portfolio of resources for its total contribution to resource adequacy
Adjusted Class Average	 Calculate Portfolio ELCC Calculate average¹ ELCC for each group of resources (e.g. wind, solar) Apply uniform adjustment to each class average ELCC so that the sum of all classes matches Portfolio ELCC 	Yields correct total ELCC	Increasingly segmented classes to capture distinctions between resources (renewable geography, storage duration, hybrid resource configuration, etc.) leads to inconsistent treatment in classes of different sizes. Small classes have an ELCC much closer to marginal where larger classes have an average ELCC much different from marginal Uniform adjustments to all resource classes to account for interactive effects does not faithfully capture nature of interactions. In a portfolio with positive synergy, adjustments should only be applied to the resources that are providing that synergy

FIGURE 8: ELCC FRAMEWORK PROS AND CONS

Importantly, NYISO's accreditation proposal departs from precedents in other RTOs. PJM presently uses an adjusted class average ELCC approach, detailed in tariff language now approved by the Commission.²³² MISO also uses a class average approach to calculate ELCC for all wind resources.²³³ SPP's approach is most similar to a vintage marginal approach, with the vintage class determined by the level of transmission service procured by the resource with some discretion given to the utility purchasing the capacity.²³⁴

²³¹ August 30 E3 Report at 51.

²³² See PJM ELCC Order II.

²³³ MISO, *Planning Year 2021–2022 Wind & Solar Capacity Credit* (Jan. 2021), https://cdn.misoenergy.org/2021%20Wind%20&%20Solar%20Capacity%20Credit%20Report503411.pdf.

²³⁴ Southwest Power Pool, *Solar and Wind ELCC Accreditation* (Aug. 2019), https://www.spp.org/documents/61025/elcc%20solar%20and%20wind%20accreditation.pdf.

C. The Incomplete Tariff Information Provided by NYISO Regarding Its ELCC Proposal Appears to Not Result in Just and Reasonable Rates.

1. This Proceeding Is Not a Referendum on Marginal vs Average ELCC.

As the previous section suggests, complex market design questions arise when attempting to integrate declining marginal value into existing capacity market structures, and much ink has been spilled debating the relative merits of average vs. marginal approaches. However, this docket is not a referendum on those issues, but rather on whether NYISO's has met its burden of proof to support acceptance of its capacity accreditation proposal. Regrettably, that is a simple decision: what NYISO has filed is woefully incomplete. Moreover, based on the fragments that are included in NYISO's filing, it appears that NYISO's approach may result in inaccurate resource adequacy determinations and inaccurate price signals. The Commission should reject NYISO's request for unconditioned approval of its capacity accreditation proposal.

2. <u>NYISO's Proposal Fails to Reach Accurate Adequacy Resource</u> <u>Adequacy Outcomes.</u>

For a capacity market to function, it must correctly count the total resource adequacy value (as measured in MW of UCAP) of procured resources. For correlated resources with declining UCAP values, this could be accomplished by calculating the total value of a fleet, or by summing up the marginal value of each resource cleared, accounting for the high value of initial resources and the lower value of later ones. NYISO's proposal does neither, but instead credits all resources in each class based on the UCAP value of an additional megawatt of that class. The result is that the higher resource adequacy value of the initial resources in each class is simply lost. NYISO's proposal results in each resource class receiving a total UCAP equal to the installed quantity times the marginal UCAP value. As the marginal UCAP value of a class falls, so does the total UCAP credited to the entire class. Overlying this result on the

figure from the previous section shows that NYISO's proposal results in substantial "missing MW" as shown in Figure 9 below:



FIGURE 9: MISSING MEGAWATTS UNDER NYISO'S PROPOSAL

This effect is demonstrated in NYISO's filing, where they report that under their model, the addition of 11,613 MW (ICAP) of utility-scale solar between 2026 and 2032 results in the total resource adequacy value (UCAP) of the entire utility-scale solar fleet *decreasing* by 240 MW of UCAP.²³⁵

This result is patently incorrect.²³⁶ The capacity market is solely concerned with if the amount of available generation meets or exceeds the demand for energy. A moment's reflection reveals that adding more solar cannot reduce total resource adequacy, since solar never withdraws power from the grid. At worst, additional solar might produce no power, or

²³⁵ Transmittal Letter at 23, Table 3: NYCA Summer Capacity by Unit Type (MW).

²³⁶ While it is certainly possible that adding additional renewable resources increases the need for ancillary services such as ramping or reserves, those are not considered in NYISO's capacity market.

produce power during a period when resource adequacy is not a concern. Neither of those would increase the need for or reduce the supply of energy. The apparent decrease in capacity value of the solar fleet resulting from NYISO's approach is not an accurate reckoning of resource adequacy in a high-renewables grid, it is simply an error caused by NYISO's proposal to incorrectly ascribe the low marginal value of the last unit of solar power to the entire fleet of utility-scale solar resources. Analysis performed by Astrapé Consulting finds that, based on New York State policy goals, by 2030 NYISO's proposed approach will undercount the value of utility solar resources by 2,060 MW, losing 83% of the solar fleets resource adequacy value, and undercount storage resources by 1,920 MW (38%). ²³⁷ The result of these missing MW will be that the NYISO capacity auctions procure unneeded additional UCAP from redundant resources.

Left unchecked, this error would tend to drive the resource adequacy value credited to highly correlated resources towards zero, leading to ever-increasing over-procurement of other resource types. NYISO briefly mentions the possibility of over-procurement, but does not appear to be discussing the issue identified here.²³⁸ Without elaboration, NYISO states that over-procurement is not a concern because "The supply and demand side of the capacity market are both converted to UCAP using the same derating factor."²³⁹ NYISO offers no explanation of what potential over-procurement problem this derating factor might correct, and does not indicate they are considering the over-procurement problem identified above. The Potomac Presentation²⁴⁰ referenced by NYISO appears to be merely demonstrating that the accounting of ICAP-UCAP conversations does not introduce over-procurement. Neither

²³⁷ Astrapé Testimony at 22, Table 6. 2030 Goals Scenario Capacity Payment Discrepancy Summary.

²³⁸ Transmittal Letter at 38.

²³⁹ Id.

²⁴⁰ *Id.* at 38 n.115 (citing Attachment V at 7–9).
Potomac nor NYISO appear to address the issue of how applying marginal accreditation to all resources in a class understates the class's actual UCAP value

NYISO introduces a similar error by failing to consider portfolio effects. As discussed above,²⁴¹ groupings of multiple resources can have a combined capacity that is more or less than the sum of those resources analyzed individually. The Commission has endorsed recognition of "the synergistic and antagonistic interactions between ELCC resource classes" as a component of a just and reasonable capacity accreditation framework.²⁴² This omission may undervalue some combinations of resource types. In the worst case, because NYISO does not propose to consider correlated failures across different resource classes, such as winter conditions impacting both gas and wind powered units, the omission may create reliability risk.

3. <u>NYISO's Proposal Fails to Send Accurate Price Signals for the</u> <u>Economically Efficient Quantity of Each Resource, and Instead Will</u> <u>Systematically Discriminate against Correlated Resources with</u> <u>Declining ELCC Values in Auction Clearing.</u>

The primary benefit of marginal approaches is accurate price signals that produce efficient market outcomes. When each resource is evaluated according to the resource adequacy value it brings, auction clearing mechanisms can properly compare competing offers and reach an optimal, least-cost resource mix. For this to function, marginal pricing must reflect the change in value as resources clear. For example, consider NYISO's marginal capacity curve for offshore wind (Figure 10 below).²⁴³ The first megawatt of offshore wind has a UCAP value of roughly 35% of its nameplate, which drops to roughly 6% for the 5000th installed megawatt. Thus, when comparing capacity offers from offshore wind with other

²⁴¹ See supra, Figure 2 and note 239.

²⁴² PJM ELCC Order II at 18.

²⁴³ Brattle Group, New Yorks' Evolution to a Zero Emission Power System, at 111 (2020), https://www.nyiso.com/documents/20142/13245925/Brattle%20New%20York%20Electric%20Grid%20Evolutio n%20Study%20-%20June%202020.pdf/69397029-ffed-6fa9-cff8-c49240eb6f9d.

offers, NYISO should be willing to pay roughly six times more for the first megawatt (UCAP) of offshore wind than it is for the 5000th. Properly capturing this change in value is critical to capture the economically efficient quantity of each resource and rejecting inefficient purchases.

FIGURE 10: MARGINAL CAPACITY VALUE OF SOLAR AND WIND



NYISO's proposed method does not properly capture this change in value. NYISO proposes to calculate a static marginal capacity value for each resource class based on the installed supply mix used to determine the IRM base case,²⁴⁴ and use that value for all resources of that class.²⁴⁵ During auction clearing, this undervalues the first²⁴⁶ megawatts of each class, sometimes dramatically, which will lead to incorrect auction results.²⁴⁷ Continuing the offshore wind example, when running an auction after 5000 MW of offshore wind has been installed, NYISO will value the first offshore wind resource at 6%, rather than the correct value of around 35%. Since marginal resource value is almost always declining, this means that

²⁴⁴ Transmittal Letter at 32–33.

²⁴⁵ *Id.* at 34–35.

²⁴⁶ Determining which resource enjoys being "first" may itself be a difficult decision; for this discussion it merely means whichever one the auction clearing engine considers first by whatever criteria it uses. *See also* PJM ELCC Order II at 37.

²⁴⁷ See Astrapé Testimony at 24–25.

resources with higher correlated output will be placed at an artificial disadvantage to others in NYISO's capacity auction. ²⁴⁸ This discrimination is systematic, unidirectional, and arises only because of the decision to calculate a static marginal value in advance of the auction.

Note that the correct basis for calculating marginal reliability value is the pool of cleared resources, not in-service resources, as the purpose of a capacity market is to result in a set of cleared resources that meet resource adequacy criteria. Uncleared resources in no way impact the resource adequacy value of the set of cleared resources, since the uncleared resources are not relied on to serve load. In other words, capacity accreditation rules should not discount the value of a resource based on the total resources in the class if the entire class does not clear the auction.²⁴⁹

4. <u>NYISO's Limited Analysis Is Deeply Flawed and Does Not Provide</u> <u>Meaningful or Sufficient Information Regarding the Tariff's Effect on</u> <u>Rates.</u>

Although none of the key accreditation concepts are described in the tariff, the few details NYISO has provided to stakeholders on its specific modeling methods present significant concerns that the corresponding resource accreditations may not be just and reasonable. NYISO is considering a method that approximates ELCC deterministically using a single set of inputs, rather than standard probabilistic ELCC methods. To our knowledge, this method has never been used before. Not only is there risk that under certain conditions it may

²⁴⁸ While almost all the important aspects of NYISO's methodology have not yet been determined, we do support the fact that, so far, NYISO indicates that it will apply its marginal accreditation methodology to all resources, including thermal generators. This is essential for accurately measuring the capacity value of a portfolio of resources and allocating that value to resources in a way that is just and reasonable. It also minimizes the potential for undue discrimination resources, which can arise where correlated outages at thermal resources are not fully accounted for, as is the case under existing EFORd methods. *See, e.g.*, Sinnott Murphy et al., *A Time-Dependent Model of Generator Failures and Recoveries Captures Correlated Events and Quantifies Temperature Dependencies*, 253 Applied Energy 113513 (Nov. 2019),

https://www.sciencedirect.com/science/article/pii/S0306261919311870; Sinnott Murphy et al., *Resource Adequacy Risks to the Bulk Power System in North America*, 212 Applied Energy 1360, 1366 (Feb. 2018), https://www.sciencedirect.com/science/article/pii/S0306261917318202.

²⁴⁹ See Astrapé Testimony at 26–29.

be less accurate than ELCC or result in capacity accreditation allocations that are not just and reasonable, but the limited analysis NYISO has performed is deficient in multiple ways. We summarize these deficiencies below; more detail can be found in the attached report by Telos Energy.²⁵⁰

First, NYISO's analysis, performed by its MMU, used a simplified deterministic model instead of a probabilistic model typical of resource adequacy analysis. ²⁵¹ The MMU failed to use NYISO's GE MARS application which uses Monte Carlo techniques to calculate reliability metrics such as the Loss of Load Expectation (LOLE) resulting from a market structure change. The MARS application is able to calculate much more accurate expected reliability metrics—evaluating market rule changes across multiple forced outage and weather scenarios. The MMU model did not consider these scenarios. Instead, it locks each generator at its average UCAP value. Accordingly, the MMU's report cautioned readers against "applying capacity credit values outside of [the] specific case from which they were derived."²⁵²

Second, the MMU's modeling did not confirm that NYISO's proposed changes produced acceptable levels of reliability across a range of possible portfolios. ²⁵³ Typically, using the GE MARS application, NYISO estimates a reliability criterion that meets the NYSRC standards—0.1 Loss of Load Days per year ("LOLD").²⁵⁴ In this case, the MMU deterministically set the reliability criterion in their model at a value that translates into a value

²⁵⁰ Michael Welch & Derek Stenclik, *Review of the NYISO Capacity Accreditation Reforms*, Telos Energy, at 3, 10–16 (Nov. 2021) ("Telos Report"), (attached hereto as Ex. C).

²⁵¹ Id. at 11.

²⁵² Transmittal Letter, Attach. IV at 42.

²⁵³ Telos Report at 12–13.

²⁵⁴ Y. Guo, Sensitivity Results (Cases 1-9) - For ICS Review, NYISO (Nov. 3, 2021), https://nysrc.org/PDF/MeetingMaterial/ICSMeetingMaterial/ICS%20Agenda%20253/AI%209.1%20-%202022%20PBC%20Sensitivity%20results.pdf.

greater than 0.1 LOLD. Consequently, the reliability of the system in the MMU's modeling is not sufficient to meet NYSRC standards.

Third, the MMU's analysis only captures the minimum renewable energy and storage buildout required by New York's CLCPA. As indicated by Telos Energy, it is reasonable to expect New York surpasses these goals for offshore wind and storage deployment.²⁵⁵ The MMU did not evaluate any such scenario. Furthermore, they did not consider a scenario with increased renewable capacity resulting in the build out of storage for renewable integration. If storage is built for renewable integration, the marginal accreditation method could lead to an overbuild of capacity.

Fourth, the IMM's transmission model did not account for additional transfer capability from upstate to downstate regions. Though it included recently approved projects, it did not evaluate the impact of the marginal accreditation method if additional projects are constructed pursuant to NYISOs ongoing Public Policy Transmission Planning process.²⁵⁶

Fifth, the IMM's analysis only considered one year of weather data.²⁵⁷ Typical resource adequacy analyses use at least five years of historical weather data to evaluate the output of renewable resources. In its analysis, PJM used 8 years of data. Even IRPs by small utilities use multiple years of data to analyze resource adequacy.²⁵⁸ This deficiency makes the model overly simplistic, and accordingly, it fails to capture the real resource adequacy impacts of NYISO's proposed change.

²⁵⁵ Telos Report at 14.

²⁵⁶ Id.

²⁵⁷ Id. at 15-16.

²⁵⁸ Northern Indiana Pub. Serv. Co., *2021 Integrated Resource Plan*, § 8.5.1 (2021), https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2021-nipsco-integrated-resource-plan.pdf?sfvrsn=6.

Lastly, NYISO has used multiple load shapes in its resource adequacy analyses for years. ²⁵⁹ However, the IMM uses only the three standard shapes from 2002, 2006, and 2007. These shapes are not reflective of current or future load patterns. The IMM's analysis, therefore, fails to reasonably model the expected peak demand in NYISO's market.

For all of these reasons, the limited analysis performed by the IMM is insufficient to substantiate that NYISO's proposed changes are just and reasonable, nor is it sufficient to demonstrate that an average accreditation approach would lead to unjust or unreasonable rates. At the very least, the known analytical deficiencies should lead the Commission to seek more information on the appropriateness of NYISO's marginal accreditation approach.

D. NYISO's Tariff Language Does Not Satisfy the "Rule of Reason."

A tariff that fails to provide adequate notice because it does not include elements that significantly affect jurisdictional rates and charges runs afoul of Federal Power Act Section 205(c), the Commission's regulations, and the well-established "rule of reason."²⁶⁰ The "rule of reason" serves to identify which provisions affect rates and services significantly, and therefore must be included in tariff language, rather than in business practice manuals or other ancillary documentation. Numerous orders establish that core methodological details that affect prices are distinct from mere "implementation procedures" or technical details that can be placed in manuals. In *Midwest Indep. Transmission Sys. Operator, Inc. Pub. Utilities with Grandfathered Agreements in the Midwest ISO Region*, 109 FERC ¶ 61,157, at P 563 (Nov. 8,

²⁵⁹ Telos Report at 17.

²⁶⁰ 16 U.S.C. § 824d(c) (requires rate filings to recite "the . . . practices . . . affecting such rates and charges"); 18 C.F.R. §§ 35.1(a), 35.2(b) (rate schedules must set forth "clearly and specifically" and "all . . . practices . . . which in any manner affect or relate to . . . service, rates, and charges."); *see also* City of Cleveland v. FERC, 773 F.2d 1368, 1376 (D.C. Cir. 1985) (explaining that "statutory directive must reasonably be read to require the recitation of only those practices that affect rates and service *significantly*, that are realistically *susceptible* of specification, and that are not so generally understood in any contractual arrangement as to render recitation superfluous.") (emphasis in original).

2004), the Commission distinguished between auction rules, which must be included in the tariff, and implementation procedures, which can be in business practice manuals.²⁶¹ In *Energy Storage Ass'n*, 162 FERC ¶ 61,296, at P 104 (Mar. 30, 2018), the Commission granted a complaint that the benefits factor curve PJM uses to determine the amount of two different types of regulation services to be procured must be included in PJM's tariff because "it directly affects which Regulation resources clear the market and the market-clearing price, and thus significantly affects the rates, terms, and conditions of Regulation service."

The amount of capacity that each supply resource can offer likewise directly affects which resources clear the market and the market clearing price. This was made clear in a 2019 order where the Commission concluded that PJM's rules for determining the capacity value of energy storage resources (which were then based on a 10-hour minimum run time), must be included in PJM's tariff, rather than its manuals.²⁶² Courts have also found it clear, even on "cursory review" that the methods used to translate between ICAP and UCAP, must be in the tariff. In *Keyspan-Ravenswood, LLC v. FERC*, 474 F.3d 804, 811 (D.C. Cir. 2007), the Court held that the Commission had erred in finding that "NYISO had no need to file its method for translating installed capacity into unforced capacity because requiring such detail in a filing goes beyond the 'rule of reason.'" The court concluded that NYISO's own evidence demonstrated that the method for making this conversion significantly affected the region's compliance with its reliability rules. *Id.* Here, NYISO proposes a vague principle for translating between ICAP and UCAP that even it concedes is just the beginning of a two-year

²⁶¹ This 2004 MISO order helpfully considers arguments that a range of provisions should be included in the tariff. The Commission agreed that the following should be in the tariff: LMP calculations (P 560), requirements for entities to qualify as a market participant (P 558); conditions that require emergency procedures (P 561); and metering standards (P 561). Provisions that did not require tariff language included: procedures for determining whether a Generation Resource or Synchronous Condenser Unit is needed for reliability (P 559); procedures for billing dispute resolution (P 561); and invoicing schedules (P 562).

process to design. *Keyspan-Ravenswood* serves as a stern warning to FERC that the method for converting ICAP to UCAP—as in capacity accreditation processes—must be described in FERC-approved tariffs in sufficient detail to be understood by consumers and market participants, not left unscrutinized in NYISO's manuals.

NYISO prefers to characterize the two-year accreditation rule-design process it will commence as merely filling in "implementation details" like those that FERC has allowed to be described only in manuals.²⁶³ But the gaps in NYISO's filing are not "study assumptions and parameters [that] are likely to change over time," and thus should be left to manuals so as to allow NYISO "to adapt to changing circumstances."²⁶⁴ Clean Energy Advocates do not contend that the specific data inputs to any capacity accreditation model, such as the anticipated system mix, load characteristics, or transmission system details, need to be included in the tariff. But those inputs are different than the basic structure of the methodology and models to be used. This structure significantly affects the amount of capacity that each resource is eligible to sell, and therefore the rates and must be included in the tariff. Without any information as to how NYISO will translate a tariff phrase as vague as "marginal contribution to reliability" to an actionable methodology, FERC cannot determine whether the tariff will result in just and reasonable rates.

NYISO cites several FERC orders to support its position that critical methodological details can be included only in its manuals. Two of these, *Sw. Power Pool, Inc.*, 136 FERC ¶ 61,050 and *ISO New England Inc.*, 137 FERC ¶ 61,112 (Nov. 4, 2011), arose in the transmission planning or interconnection context, and in both orders the Commission refers to prior decisions that established over-arching frameworks for application of the rule of reason in

²⁶³ Transmittal Letter at 5.

²⁶⁴ Sw. Power Pool, Inc., 136 FERC ¶ 61,050, at P 37 (July 21, 2011).

that particular context.²⁶⁵ In *Hecate Energy Greene County 3 LLC v. N.Y. Indep. Sys. Operator, Inc.*, 177 FERC ¶ 61,121, at P 46 (Nov. 18, 2021), the Commission concluded that a NYISO rule regarding when a generator seeking interconnection was "firm" enough to be included in the "Base Case" used in future interconnection studies, did not need to be included in the tariff. The Commission determined that this rule "implements the NYISO OATT provisions that require transmission owners to inform NYISO which projects should be included in the Base Case, and implementation details need not be included in the tariff." *Id.* at P 46.

NYISO also cites *Astoria Generating Co., L.P. v. NYISO*, 139 FERC ¶ 61,244, at P 50 (June 22, 2012), and *Cal. Indep. Sys. Operator*, 156 FERC ¶ 61,152, at P 15 (Sept. 1, 2016) (letter order). But neither of these cases supports NYISO's effort to dodge the Commission's well-established rule of reason. The California Independent System Operator ("CAISO") letter order involved a request by a utility intervenor for the ISO to provide numeric examples—in its business practice manuals—to illustrate locational marginal pricing ("LMP") disaggregation for its Energy Imbalance Market.²⁶⁶ The utility did not contend that CAISO's tariff was incomplete in any way. *CAISO*, 156 FERC ¶ 61,152. CAISO agreed to provide the examples, and FERC issued an order approving CAISO's tariff and acknowledging the agreement to update the business practice manuals according.²⁶⁷ Contrary to NYISO's portrayal, this letter order does not establish that details essential to understanding rates, terms, and conditions, can be omitted from a tariff; it just establishes that where an intervenor seeks clarification of business process manuals, FERC will acknowledge that.

²⁶⁵ See, e.g., Sw. Power Pool, 136 FERC ¶ 61,050, at P 33 (noting that in Order No. 890, "the Commission disagreed with parties who argued that all of a transmission provider's rules, standards, and practices should be incorporated into its OATT, finding that such a requirement would be impractical and potentially administratively burdensome"); *ISO New England*, 137 FERC ¶ 61,112 (noting that Order 2003 did not require ISO-NE to file its interconnection cost details).

²⁶⁶ *CAISO*, 156 FERC ¶ 61,152 at P 11.

²⁶⁷ *Id.* at P 15.

Astoria Generating Co. involved a complaint that NYISO's implementation of its tariff provisions for calculating offer price floors for mitigated resources was insufficiently transparent and should be based on objective tariff provisions.²⁶⁸ The Commission concluded that NYISO's tariff already set forth sufficiently objective criteria to guide NYISO's review, and that NYISO had complied with the relevant tariff provisions requiring disclosure of information.²⁶⁹ However, the Commission went on to conclude that developers would benefit from hypothetical examples of how the offer floors were calculated, to be shared on NYISO's website, and that such examples would balance the need for transparency with the importance of preventing commercially sensitive information from being disclosed.²⁷⁰ Thus, Astoria Generating Co. does not address a situation where the utility's methodology for implementing open-ended and subjective tariff provisions has not yet been established. Instead, the Commission found that the existing tariff provisions were sufficiently objective, and that interests of confidentiality weighed against the kind of detailed disclosure sought by complainants. No such countervailing interests exist here; NYISO instead seeks approval of vague tariff provisions that will give it a blank check to develop a highly consequently accreditation methodology. While the Commission has found that "not all of the details of a methodology must be delineated in a tariff," Astoria Generating Co. v. NYISO, 139 FERC ¶ 61,244 at P 44, this does not mean that none of the details must be delineated. The details missing from NYISO's vague tariff language are not fine points, but the broadest strokes of the accreditation methodology that it will use.

²⁶⁸ Astoria Generating Co. v. NYISO, 139 FERC ¶ 61,244 at P 45.

²⁶⁹ *Id.* at P 46.

²⁷⁰ *Id.* at P 50.

Given the wide variety of paths that a marginal accreditation approach could take (as detailed above)—many of which would lead to consumers paying excessive rates for capacity—the Commission must require that the additional implementation details and technical specifications that will be developed in Phase 2 are submitted as tariff revisions under Section 205 rather than go unexamined in the NYISO manuals and ISO Procedures. Without a future obligation to file tariff revisions at FERC—and to establish that the resulting rates are just and reasonable—NYISO's stakeholder process to develop these methodologies will likely be less transparent and collaborative, and important information and perspectives will go unexamined.

The rule of reason test "requires a case-by-case analysis, comparing what is included in the filed tariff against what is contained in the utility manuals."²⁷¹ Here, NYISO has not even developed the manuals containing the methodology to facilitate a case-by-case assessment. The Commission faced similar circumstances in *CAISO*, 116 FERC ¶ 61,274, 62,303, which also involved the introduction of significant changes to a market design (the Market Redesign and Technology Upgrade) while development of Business Practice Manuals was still underway. In that proceeding, the Commission concluded that it was unable to undertake the case-by-case analysis required for the "rule of reason" test. Instead, the Commission directed CAISO to file any necessary tariff revisions after the manual development was complete, at which time parties would be able to comment, and Commission staff would "convene a technical conference to assist us in the determination of which practices or details remaining in the Business Practice Manuals might appropriately belong in the MRTU Tariff."²⁷²

²⁷¹ ISO New England Inc., 137 FERC ¶ 61,112 at P 20.

²⁷² CAISO, 116 FERC ¶ 61,274 at P 1370.

E. NYISO's Rushed Process Caused Stakeholders to Make a Hasty Decision on Critical Capacity Accreditation Design.

NYISO repeatedly accelerated and condensed its plans for a stakeholder initiative to consider capacity accreditation enhancements. In its presentation to the ICAP working group on April 20, 2021, NYISO presented two distinct initiatives for stakeholders to begin in 2021 for Preparing The Capacity Market For The Grid In Transition.²⁷³ The first initiative was a Plan for Comprehensive Mitigation Review, which consisted of developing BSM reforms starting in that April with the goal of a FERC filing in October.²⁷⁴ The second initiative was a Plan for Capacity Market Improvements, which consisted of three sub-initiatives: (i) Capacity Requirements to Support Reliability, (ii) Methods for Measuring Reliability, and (iii) Capacity Accreditation Measures.²⁷⁵ The NYISO identified the Capacity Accreditation Measures effort as the very last to undertake, beginning in early 2022, aimed for one stakeholder vote on both tariff reforms and the final capacity value study in fall 2023.²⁷⁶

In June, when NYISO eventually circled back to the ICAP working group on BSM reforms, it revealed its updated plan to advance the capacity accreditation initiative to begin in Summer 2021.²⁷⁷ NYISO, however, continued to describe the Improving Capacity Accreditation process as distinct from the BSM reforms.²⁷⁸ The timeline NYISO presented aimed to begin introducing capacity accreditation concepts in late 2021, have discussion of

 ²⁷³ Mike DeSocio, Preparing the Capacity Market for the Grid in Transition, NYISO (Apr. 20 2021), https://www.nyiso.com/documents/20142/20839079/20210420%20NYISO%20 <u>%20Preparing%20the%20Capacity%20Market%20for%20the%20Grid%20in%20Transition.pdf</u>.
²⁷⁴ Id. at 6–8.

 $^{^{275}}$ Id. at 9–11.

 $^{^{276}}$ *Id.* at 12.

 ²⁷⁷ Mike DeSocio, *Buyer Side Mitigation Reform Considerations*, NYISO (June 3, 2021), https://www.nyiso.com/documents/20142/21942500/20210603%20NYISO%20-%20BSM%20Reforms%20Consideration%20vFinal.pdf.
²⁷⁸ Id. at 9.

capacity accreditation design and tariff updates beginning in Spring 2022, and aim for stakeholder approval of capacity accreditation design in summer 2022.²⁷⁹

Later that summer NYISO again accelerated and condensed its plans for stakeholders to consider capacity accreditation. On August 5, NYISO reviewed current capacity accreditation rules with stakeholders. On August 9, NYISO presented its Capacity Accreditation Straw Proposal.²⁸⁰ The presentation also announced NYISO's new intent to review tariff changes related to both BSM and capacity accreditation in September.²⁸¹ NYISO thus repeatedly moved forward and truncated its plans for a stakeholder initiative to consider capacity accreditation enhancements and then put stakeholders in the position of digesting the implications of the key design choices at the same time they were also developing critical reforms to BSM rules that have been a long-standing source of tension.

CEAs were among the stakeholders that objected to NYISO's eleventh hour linkage of BSM and capacity accreditation reforms, especially because the problematic impacts of the two sets of rules occur in very different time frames. BSM rules require resolution before the end of the current class year, which at the time was expected to conclude in early spring 2022, to prevent numerous storage resources from being at risk of mitigation. In contrast, the timing of material impacts caused by the current accreditation rules to account for saturation effects at increasing penetrations of clean resources was more distant and speculative. The CLCPA was only recently enacted, and clean resource development had been slowed by the COVID-19

²⁷⁹ Id.

 ²⁸⁰ Zach T. Smith, *Capacity Accreditation: Straw Proposal* (Aug. 9, 2021), https://www.nyiso.com/documents/20142/23645207/20210809%20NYISO%20-%20Capacity%20Accreditation%20Straw%20Proposal.pdf.
²⁸¹ Id. at 20.

pandemic. Nevertheless, NYISO rejected repeated requests for BSM and capacity accreditation reforms to proceed on their own timelines.

Considering the time constraints that NYISO placed on the process, stakeholder discussion of NYISO's Capacity Accreditation Straw Proposal focused on its most controversial element—whether to use a marginal or average methodology for determining the ELCC value of various resources. The MMU's zealous defense of the marginal approach²⁸² failed to satisfy numerous stakeholders.

Several parties, including CEAs, strongly urged NYISO to undertake a robust modeling analysis of the impact of the status quo, marginal, and average accreditation methods on customer costs net of RECs and on the evolution of the resource mix. NYISO, however, refused to undertake the robust modeling analysis based on time and resource constraints. Instead, NYISO and the MMU agreed to a crude analysis that was performed on an accelerated schedule, which sacrificed technical accuracy.²⁸³ The analysis was performed in two parts, the first study was by the NYISO and focused on 2026 and the second by Potomac Economics focused on 2030.²⁸⁴ Numerous stakeholders expressed concern about the quality of the study and whether it was sufficient to support a decision, as NYISO did not provide stakeholders with the report until November 2, 2021, but had scheduled the first stakeholder vote, at the Business Committee, for November 9, 2021.

The vote count for approval of the tariff package of reforms overstates stakeholder support for capacity accreditation. As NYISO's filing points out, The NYISO's stakeholder

%20Marginal%20vs%20Average%20-%20for%20Aug%2030--08-25-2021.pdf/34bca7db-a576-13be-f29b-317cd7ad438b. ²⁸³ Telos Report at 10.

²⁸² See Pallas Lee VanSchaick et al., *NYISO Capacity Accreditation: Continued Discussion of Marginal and Average Approaches*, Potomac Economics (Aug. 30, 2021), https://www.nyiso.com/documents/20142/24172725/Capacity%20Accreditation%20-

 $^{^{284}}$ Id.

Management Committee approved the NYISO Proposal at its November 17, 2021 meeting, with 82.03% of stakeholders voted in favor (*with abstentions*), which is above the 58% stakeholder vote required for the NYISO to file tariff revisions under Section 205 of the FPA.²⁸⁵ Numerous stakeholders, however, absented because they supported BSM reforms, but had concerns with NYISO's capacity accreditation reforms and how it was being arbitrarily linked to BSM.

Indeed, NYISO put its stakeholders in a position of being forced to choose between: (a) an immediate resolution to the clear and present need to address without further delay buyerside mitigation policies that works to thwart New York State to exercise its FPA jurisdiction over generation and cause considerable harm to investors and consumers, or (b) either extending the known BSM harms for another year or two or potentially losing them altogether in order to conduct in-depth expert analysis and stakeholder debate to decide an extremely complex but not currently pressing issue that might ultimately arrive at roughly the same outcome.

F. NYISO's ELCC Proposal Is Not Essential for NYISO's BSM Proposal.

NYISO asserts that "a more robust accreditation design is necessary to justify relieving Excluded Facilities from mitigation."²⁸⁶ This assertion rests entirely on the Analysis Group (AGI) study and NYISO's own flawed logic.²⁸⁷ The AGI study cannot, by its very design, demonstrate that the accreditation reforms are *necessary*. AGI does not evaluate whether the ICAP market would continue provide appropriate financial signals for entry and exit if the

²⁸⁵ Transmittal Letter at 50.

²⁸⁶ *Id.* at 4.

²⁸⁷ *Id.*, Attach. IV at 49.

status quo capacity accreditation methodology remained unchanged.²⁸⁸ AGI only evaluates future scenarios based on its approximation of NYISO's unspecified future marginal accreditation approach. While AGI concludes that, with these changes in capacity accreditation, the market will continue to provide appropriate financial signals, it does not show that without those changes (but with BSM reform), the financial incentives would be inadequate to retain any needed thermal resources. Thus, the AGI analysis does not demonstrate that BSM reform and capacity accreditation changes must be paired to result in a just and reasonable outcome.

While Section 205 does not require the utility to demonstrate that their tariff revisions are necessary or superior to alternatives, NYISO asserts necessity in urging the Commission to approve this two-part Section 205 filing without any modification or further Section 205 obligations. In fact, the lack of any showing that a marginal accreditation approach is necessary if BSM is to be reformed, reveals that the Commission has considerably more flexibility in how to handle this proceeding given the combined urgency of BSM reform, and its responsibility not to approve tariff language that is so vague as to impede the Commission's ability to assess whether the resulting rates would be is just and reasonable.

Indeed, the two years that will lapse before NYISO and its stakeholders have developed the methodology to determine capacity accreditation factors and resource classes demonstrates that it is not actually necessary for approval of a vague concept regarding accreditation to be approved in the same Section 205 filing as the BSM reforms. If the capacity accreditation

²⁸⁸ Hibbard and Wu describe the results of their analysis as showing that "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." *Id.*, Attach. III-A, at 9; *see also id.* at 24. But Hibbard and Wu never explain what they mean by "competitive market outcomes," a term that has been recognized to be amorphous and connote something more political than economic. Their conclusion that the ICAP market will provide sufficient financial incentives for retention and exit, is more specific and less ambiguous, so we focus on that description for this discussion.

revisions were necessary for just and reasonable rates once CLCPA resources to be exempted from the BSM rules, then those revisions would need to be ready to roll out at the same time as the BSM reforms occur. Instead, the lag between revision of the tariff to allude to marginal reliability contributions and development and implementation of the new accreditation methodology, is consistent with a position that ICAP rates are just and reasonable without the application of BSM to CLPCA resources, even with the status quo accreditation in place.

V. REQUESTED RELIEF

A. In Order to Address Extant and Increasing Harms from Currently Unjust and Unreasonable Tariff Rates, FERC Must Approve the NYISO's BSM Proposal -But in Light of Its Substantial Flaws, FERC Cannot Reasonably Accept the NYISO's Capacity Accreditation Proposal as Submitted.

NYISO has put before the Commission a tariff package consisting of separate and distinct tariff rules. The first of these would reform NYISO's existing BSM tariff rules that are necessary to remedy a fundamentally unjust and unreasonable tariff provision already causing significant and steadily increasing harms to investors and consumers. The second tariff rule would impose sweeping changes to the foundational rules for how all capacity is assessed and compensated in the ICAP market. NYISO explains that these changes would address the potential impacts of CLCPA-driven resource mix changes that will occur several years from now and proposes to keep all of the necessary analysis and implementation details of that tariff provision outside of the Commission's oversight. Evidence to support the BSM reform proposal is and has been thoroughly debated and documented over a number of years, litigated in various proceedings at the NYISO and elsewhere, and was the subject of a series of recent Commission technical conferences. Capacity accreditation in the context of high levels of renewable penetration is an emerging issue that elsewhere has involved 1–2 years of extensive modeling, in-depth scenario-based analysis, and considerable discussion in close partnership

with stakeholders *prior* to choosing a methodology. NYISO's proposed tariff consists of a slapdash, poorly studied, and unacceptably vague accreditation proposal tacked onto an already profoundly complex and time-sensitive proceeding over the objections of many of its stakeholders. The only direct connection between NYISO's proposal to change its BSM rules and its proposal to change the accreditation methodology is NYISO's own decision to put them in the same tariff filing.

While CEAs support a proceeding to determine whether, what, and when changes to NYISO's capacity accreditation methodology might be necessary in light of New York's future highly decarbonized grid, such a foundational element of the capacity market requires thorough study, accurate analysis, and focused stakeholder input in order to ensure the outcome is just, reasonable, and not unduly discriminatory—none of which currently underlie NYISO's submitted proposal. NYISO acknowledges that it has put its choice of accreditation methodology cart before the analytic and evidentiary horse, but promises it will thoroughly model, analyze, and finalize a marginal methodology going forward, after it has received what is effectively advance Commission approval for something it has not yet seen and a blank check for implementation.²⁸⁹

NYISO's intimations that its three separate provisions should be treated as one would put the Commission in the same political bind NYISO put its stakeholders in—of being put in the position of having to support an undeveloped market rule change needed several years down the road in order to obtain reforms to an immediately pressing problem. However, the Commission is neither required nor permitted to make such a Hobson's choice, nor is it necessary for it to do so. Section 205 is emphatically clear that *all* rates and charges in

²⁸⁹ See Transmittal Letter at 33–34 (describing Phase 2 and stating that it intends to work with stakeholders to compare various methodologies for setting the capacity accreditation factors).

connection with the transmission or sale of electric energy and *any* rules or regulations affecting or pertaining to such rates or charges must be just, reasonable, not unduly discriminatory²⁹⁰. And as Section 205 filings originate with the utility, the burden is on NYISO to establish that each of these proposals is just and reasonable.²⁹¹ Moreover, for each tariff provision, Section 205 provides the Commission with the option to approve it in whole or in part, or reject in whole or in part.²⁹²

As further discussed below, the record in this filing establishes that NYISO's proposed BSM reform is just, reasonable, and not unduly discriminatory and the Commission must therefore approve it in whole. But because the capacity accreditation proposal is incomplete and lacking in substantial evidence to support full approval, and would provide no further opportunity for FERC to review critical design details of its methodological approach, the Commission cannot approve it in whole as submitted. Given the need for additional modeling, analysis, and decision-making requiring stakeholder approval necessary to remedy these omissions, the Commission should consider returning this issue to NYISO and its stakeholders with direction on elements necessary for approval of a future filing. Alternatively, the Commission could issue a deficiency letter or hold a paper hearing to give NYISO the opportunity to complete a thorough market impact and reliability analysis of its proposal and remedy the current filing deficiencies. Finally, the Commission could decide to approve the capacity accreditation in part, with minor modifications requiring NYISO to file further tariff revisions setting out those components of its rate that significantly affect rates. This would

²⁹⁰ 15 U.S.C. 824d(a).

²⁹¹ 16 U.S.C. § 824d(e).

²⁹² See, e.g., NYPSC v. FERC, 642 F.2d 1335, 1345 (D.C. Cir. 1980); W. Res., Inc. v. FERC, 9 F.3d 1568, 1574 (D.C. Cir. 1993); Sea Robin Pipeline Co. v. FERC, 795 F.2d 182, 183, 187 (D.C. Cir. 1986); City of Winnfield, La. v. FERC, 744 F.2d 871, 875 (D.C. Cir. 1984) ("In Public Service Commission of New York v. FERC, 642 F.2d 1335 (D.C.Cir.1980), we analyzed the provisions of the Natural Gas Act which, in relevant part, are identical in form to §§ 205 and 206, and have been treated by the courts as identical in substance.").

ensure that development and implementation of the NYISO's proposal is subject to FERC oversight.

1. <u>BSM Reforms Must Move Forward, Regardless of the Choice Made</u> <u>Regarding Capacity Accreditation.</u>

As discussed extensively in Section III.A above, there is substantial evidence that NYISO's existing mitigation rules are unjust, unreasonable, and unduly discriminatory and are imposing ever-increasing harms to consumers, investors, and New York State. Without prompt reform, these harms will continue and CLCPA resources are at risk of being mitigated out of the next ICAP class certification scheduled to occur this summer. As discussed in Section III.B above, the record also establishes that NYISO's proposed revisions to its mitigation rules appropriately accommodate state authority over generation and effectively balance the need to avoid over- or under-mitigation of resources. Although NYISO believes that the other tariff provisions it proposes would "serve to validate" its BSM proposal, it stresses first and foremost that this proposal is an "important, just, reasonable, and not unduly discriminatory improvement[] in [its] own right."²⁹³ CEAs agree and the Commission must approve the BSM tariff proposal without delay. CEAs share NYISO's concern that "it is very important that the BSM Reforms . . . be implemented during Class Year 2021 to avoid the risk that resources that serve CLCPA goals will be over-mitigated under the currently effective BSM Rules."294 The CEAs therefore join NYISO in requesting that the Commission issue an order making NYISO's BSM reforms effective by March 6, 2022.²⁹⁵

²⁹³ Transmittal Letter at 18.

²⁹⁴ *Id.* at 50.

²⁹⁵ *Id.* at 51.

2. NYISO's ELCC Proposal Lacks Necessary Details to Meet Section 205 Requirements as Submitted and Requires Further Oversight From FERC.

CEAs appreciate that the rapid transition of the resource mix that is just beginning will eventually have impacts on the capacity market that require a re-examination of the existing capacity accreditation rules. This re-examination, however, demands a thoroughly analyzed, fully vetted, clearly articulated, and stakeholder-vetted tariff proposal. However, as set forth in Section IV above, because the capacity accreditation proposal NYISO submitted on this issue is incomplete and lacking in substantial evidence to support a finding that it is just, reasonable, and not unduly discriminatory, the record does not support full approval at this juncture. Moreover, NYISO has failed to make the case for urgency to approve a capacity accreditation framework *now*, when it is little more than an abstract concept.

As discussed in Sections IV.A and IV.B supra, capacity accreditation is a foundational element of the entire NYISO market, and any decision to change the methodology of how NYISO will assign value to different resources inevitably has cascading impacts across the entire NYISO market and its stakeholders. Failure to properly credit resources for their actual contributions to resource adequacy and to provide clear rules with proper FERC oversight not only threatens investors with undue discrimination or unjust compensation but can threaten the very reliability of the grid.²⁹⁶ Accordingly, the importance of getting such a decision right cannot be overstated.

NYISO stresses that Section 205 "is intended for the benefit of the utility" and the Commission assumes "an essentially passive and reactive role" ... restrict[ed] ... to the confined proposal."²⁹⁷ Citing to recent Commissioner statements regarding revisions to PJM's

²⁹⁶ See supra, Section IV.A; Astrapé Report at 6–7; Telos Report at 6–7.

²⁹⁷ Transmittal Letter at 18 n.56 (citing *Emerga Maine v. FERC*, 854, F.3d 9, 24 (D.C. Cir. 2017)).

buyer-side mitigation provision, NYISO further suggests that "potential imperfections do not preclude FERC from finding a Section 205 filing to be just, reasonable, and not unduly discriminatory."²⁹⁸ This reading suggests a near helplessness of the Commission in the face of a flawed Section 205 filing not supported by the case law and in conflict with the Commission's statutory duty.

It is therefore useful to properly describe the legal authority of the Commission to act in the Section 205 context. Under Section 205, the rate proposal comes from the utility and it is the utility bears the burden of establishing that the proposed rate is just, reasonable, and not unduly discriminatory.²⁹⁹ However, it is the Commission that must decide whether that proposed rate actually is just, reasonable, and not unduly discriminatory and proposals failing to demonstrate this are unlawful.³⁰⁰ Under Section 205, the Commission has authority to approve a provision in whole or in part or reject it (in whole or in part).³⁰¹ While a full approval or full rejection embodies the kind of passive and reactive role suggested by NYISO, when approving a tariff proposal in part, FERC is also permitted to accept some tariff proposals and reject others within the same filing or make modifications to a proposal to ensure that the rate is just and reasonable.³⁰² When FERC acts on a Section 205 filing "in part," it must be mindful of the difference of its narrower authority to make changes to a tariff proposal submitted under Sections 205 and its more expansive authority to order wholly different relief under Section 206. It is in this space—of what limitations exist when FERC proposes changes to a utility-proposed tariff that it is partially accepting-where cases such as NRG Power

²⁹⁸ Id.

²⁹⁹ *NYPSC*, 642 F.2d at 1345.

³⁰⁰ 16 U.S.C. §824d(a).

³⁰¹ See, e.g., NYPSC, 642 F.2d at 1345; *W. Res., Inc.*, 9 F.3d at 1574; Sea Robin Pipeline Co., 795 F.2d at 183, 187; City of Winnfield, 744 F.2d at 875.

³⁰² See, e.g., NYPSC, 642 F.2d at 1345.

Mktg., LLC v. FERC, 862 F.3d 108 (D.C. Cir. 2017), serve to provide boundaries for FERC action.³⁰³

3. <u>FERC Should Exercise Its Longstanding Authority to Approve the Tariff</u> <u>in Part and Reject It in Part.</u>

While NYISO stresses that the Commission cannot let the perfect be the enemy of the good or let "potential imperfections" preclude FERC from approving its tariff proposal, NYISO omitted the caveat of the Commissioners that it cites that such "potential imperfections" be limited to unnecessary provisions that *could not cause harm*.³⁰⁴ As discussed at length in Section IV, the problems with NYISO's capacity accreditation proposal are not "potential imperfections" but material flaws that cannot be overlooked. Because capacity accreditation has such profound implications for its many stakeholders, NYISO and its stakeholders are in the best position to conduct the significant amount of work necessary to revise the proposal to meet Section 205 requirements. Consequently, while there are multiple options for the Commission to choose from in order to address the inadequacies of the current proposal, the most straightforward and prudent course of action is for the Commission to simply reject NYISO's capacity accreditation proposal with relevant direction on key elements necessary to support such a filing in the future. This course of action is also the one that is the most "passive and reactive" and thus the least likely to blur the lines of FERC authority.

a. <u>NYISO's Capacity Accreditation Proposal Violates the Rule of</u> <u>Reason.</u>

As described in Section IV.D. *supra*, NYISO's proposed tariff rate for the accreditation methodology does not include an actual methodology. Rather, it is a placeholder

 ³⁰³ See also W. Res., Inc. v. FERC, 9 F.3d at 1577; City of Winnfield, 744 F.2d at 875; Constellation Mystic Power, LLC, 172 FERC ¶ 61,043, 61,379 (July 17, 2020); MISO, 172 FERC ¶ 61,132 (Aug. 10, 2020); Old Dominion Elec. Coop., 162 FERC ¶ 61,262 (Mar. 22, 2018); Sea Robin Pipeline, 795 F.2d; NYPSC, 642 F.2d.
³⁰⁴ Statement of Chairman Glick and Comm'r Clements, at P 34, Docket No. ER21-2582 (Oct. 19, 2021), Accession No. 20211019-4001.

for a future methodology that "reflect[s] the marginal reliability contribution of the ICAP Suppliers within each Capacity Accreditation Resource Class toward meeting NYSRC resource adequacy requirements for the upcoming Capability Year."³⁰⁵ NYISO's cover letter further admits that it intends to develop an ELCC "or equivalent" methodology.³⁰⁶ What resources will be considered a Resource Class is defined in similarly vague terms.³⁰⁷ It has no set deadline for when the new methodology will become applicable. Even details of how the study will be conducted, what it will analyze, or how it will ultimately apply are also items to be determined in the future. In sum, NYISO has asked for a blank check on how to accredit resources for their actual contribution to the IRM. As discussed extensively in Section IV.D, this violates FERC's rule of reason, a lesson NYISO might have learned from the D.C. Circuit's rejection of its 2001 attempt to leave fundamental decisions on capacity ratings to asyet drafted business manuals.³⁰⁸ As emphasized by the court in *Keyspan-Ravenswood*, *LLC*. v. FERC, "Commission's regulations require that '[e]very public utility shall file with the Commission ... full and complete rate schedules ... clearly and specifically setting forth all rates and charges ... [and the] practices, rules and regulations affecting such rates and charges."³⁰⁹ The NYISO accreditation proposal before the Commission is an unfortunate echo of NYISO's past failure to properly document key methodologies regarding resource accreditation and shares the same failure to provide clear and specific notice to stakeholders regarding the practices, rules, and regulations that will make up the fundamental building block of the NYISO ICAP. The accreditation proposal thus cannot be adopted.

³⁰⁵ NYISO Tariff Proposal, Appendix I at Section 2.3

³⁰⁶ Transmittal Letter at 34

³⁰⁷ NYISO Tariff Proposal, App. I at Section 2.3 (definition of "Capacity Accreditation Resource Class.").

³⁰⁸ See Keyspan-Ravenswood, LLC, 474 F.3d at 809.

³⁰⁹ *Id.* at 810, *citing* 18 C.F.R. §35.1(a).

b. <u>Unqualified Acceptance of NYISO's Capacity Accreditation</u> Proposal Fails to Protect ISO Governance and Protects Stakeholders.

Unqualified approval of NYISO's capacity accreditation proposal jeopardizes effective stakeholder governance process. The record in this matter demonstrates that NYISO and the MMU did not plan to conduct *any* modeling or scenario-based analysis of the realistic impacts of its preferred marginal accreditation approach prior to its adoption and forced tying the two issues together over widespread stakeholder objections at the outset. ³¹⁰ The inherent unreasonableness of such a position is revealed in the fundamental deficiencies of the proposal it now asks FERC to approve. As discussed in Section IV.E, from the outset, a number of stakeholders across the NYISO sectors rightly objected to NYISO's decision to adopt a marginal approach without precise details on what methodology would be used, or a full understanding of how it would be implemented. Many stakeholders expressed concern about the lack of sufficient time to properly model and thoroughly analyze the expected market and reliability impacts—not just of the MMU's preferred approach, but of all the different potential approaches—in order to make an informed decision. This stakeholder concern was also in line with the NYISO's own Grid in Transition study, which notes the importance of accurate modeling and the problems if there is a lack of transparency.³¹¹ The last-minute estimates thrown together by the MMU/NYISO do not present a realistic picture of what outcomes

³¹⁰ See supra, Section IV.E.

³¹¹ It is of note that in the 2019 *Grid in Transition* Study the NYISO expressed an understanding of the need for thorough modeling prior to making a decision and the dangers of hidden assumptions, stating:

As with all administratively-determined parameters, *ELCC ratings are imperfect and depend upon modeling choices and assumptions*... A benefit of today's resource rating approach is its transparency; dispatchable resources receive ratings reflective of their forced outage rate, and intermittent resources receive ratings reflective of their average output during peak periods. More sophisticated ELCC approaches *run the risk of making the resource ratings more opaque and controversial, with direct implications for supplier revenues*.

See NYISO Grid In Transition Report at 52–54.

would be produced under the different methodologies, did not even include the MRI model methodology, and were not delivered in time for stakeholders to even fully digest, much less debate prior to the required vote on the entire package of proposals.³¹²

NYISO emphasizes repeatedly the structural bias toward approving rates filed under Section 205—including the reactive role assigned to FERC and the ability of a utility to avoid choosing the best option, so long as it is within a zone of reasonableness.³¹³ But good governance is the foremost prerequisite for fair markets and is the cornerstone for achieving just, reasonable, and not unduly discriminatory rates filed under Section 205. And good governance is, as we see daily, a delicate foundation requiring continual reinforcement and FERC can never afford to look away from the need to protect a strong and fair stakeholder process. Rejecting NYISO's half-baked accreditation scheme that at this juncture *does not even include the actual methodology that will be used* sends a strong message to NYISO and any other stakeholder that the use of political might over right does not produce just and reasonable rates within the zone of reasonableness and that the Commission will not "average" out a tariff package tying an unjust tariff provision with a just one.

Requiring NYISO to file its methodology for review and approval serves the important goal of ensuring that tariffs are more durable and less prone to being overturned on appeal. Thoroughly developed and debated records lead not only to just and reasonable rates but durable ones. As the BSM situation has aptly demonstrated, especially where tariffs involve fundamental issues such as the very value of a capacity product, ramming through proposals that might potentially disconnect the capacity market from the actual supply chain and disproportionately impact state-sponsored resources is unlikely to be a durable solution and

³¹² See supra, Section IV.

³¹³ Transmittal Letter at 1, 18.

even stakeholder consent cannot override the lack of reasoned decision-making on appeal, a lesson NYISO might have learned from the D.C. Circuit's rejection of its 2001 attempt to leave fundamental decisions on capacity rating to its business manuals.³¹⁴ As emphasized by the Court, "Commission's regulations require that '[e]very public utility shall file with the Commission … full and complete rate schedules … clearly and specifically setting forth all rates and charges … [and the] practices, rules and regulations affecting such rates and charges.³¹⁵ The D.C. Circuit held that in light of NYISO's failure to file the details of its capacity accreditation methodology with the Commission, it had "no trouble concluding" that NYISO had violated the filed rate doctrine.³¹⁶

Nowhere more than with a cornerstone issue such as capacity is the lack of a thorough, complete, clear, and fair tariff more at risk of overturn on appeal and FERC should not allow further investment of all parties on such a shaky foundation. Instead, FERC should direct NYISO to give the same careful study and in-depth partnership with stakeholders to come up with the right solution for the NYISO market as has been done in every other ISO/RTO to adopt an ELCC or similar accreditation methodology.

c. <u>Recommendations to NYISO on What Elements of an Accreditation</u> <u>Methodology Are Necessary for Just and Reasonable Rates.</u>

Following practice established during PJM's ELCC proceedings³¹⁷, it may prove efficient for the Commission to supplement its rejection of NYISO's capacity accreditation proposal with guidance as to how future filings will be evaluated. Based on prior orders, Clean Energy Advocates believe that a just and reasonable capacity accreditation method must:

³¹⁴ See Keyspan-Ravenswood, LLC, 474 F.3d at 809.

³¹⁵ *Id.* at 810 (citing 18 C.F.R. §35.1(a)).

³¹⁶ *Id*.

³¹⁷ See PJM ELCC Order I at 17–18.

- Be specified in sufficient detail, and include sufficient transparency, so that interested parties can reproduce or verify results to a reasonable degree of accuracy.³¹⁸
- For purposes of meeting resource adequacy targets, correctly account for the full resource adequacy value of all resources, including portfolio effects arising from interactions between resource classes.³¹⁹
- For purposes of market clearing and settlement, describe how identified resource adequacy value will be priced and credited to market participants. These does not prejudice decisions on average vs. marginal approaches, but merely requires transparency on compensation for services provided and allocation of benefits between suppliers and load.
- Demonstrate that the methods used to determine capacity accreditation and auction clearing procedures, taken together, produce just and reasonable outcomes and are not unduly discriminatory.
- Not discriminate between similarly situated resources.³²⁰
- Abide by the Rule of Reason.

4. <u>Alternatively, FERC Should Approve BSM and Issue Deficiency Letter</u> <u>Requiring Further Study or Paper Hearing on ELCC.</u>

Should FERC decide that there is currently an insufficient basis on which to reject

NYISO's accreditation proposal outright, the Commission could issue a deficiency letter or

hold a paper hearing to give NYISO the opportunity to provide further evidence necessary to

fill in current informational gaps and determine whether its proposal is just, reasonable, and not

³¹⁸ See PJM Interconnection L.L.C, Order Accepting Tariff Revisions and Terminating Section 206 Proceeding, 176 FERC ¶ 61,056 ("PJM ELCC Order II") at 63.

³¹⁹ See id. at 31.

³²⁰ See PJM ELCC Order I at 17.

unduly discriminatory.³²¹ While such a proceeding is more time- and resource-intensive for FERC, it would provide a means by which the fundamental deficiencies of the NYISO's current filing could theoretically be addressed within the current proceeding and stakeholders would have an opportunity and venue in which to comment on this information. At a minimum, NYISO should be required to explain how their proposal meets the requiremments of a just and reasonable accreditation method discussed in section 3b, above.

A key limitation of this approach is that many of the details that the Commission may need in order to determine whether NYISO's capacity accreditation approach results in just and reasonable rates are simply not available yet, because NYISO and its stakeholders have not yet undertaken the necessary modeling and analysis to develop the methodology. The time frame for the deficiency letter or paper hearing may not be sufficient for NYISO to provide greater clarity on its approach and resolve the concerns raised herein.

5. <u>Alternatively, the Commission Could Approve NYISO's Subject to</u> <u>Necessary Clarifying Modifications to Its Capacity Accreditation</u> <u>Proposal.</u>

Should the Commission disagree with CEAs that the tariff package proposals can and should be treated independently of each other, then the Commission should approve the tariff with modifications regarding the process going forward. Because NYISO's proposal is essentially little more than a preference for marginal accreditation that will ultimately depend upon further study and analysis, the Commission could approve NYISO's proposal as a general plan for ELCC subject to further requirements, but must issue clarifying modifications to ensure that implementation meets Section 205 requirements and satisfies the requirements of

³²¹ 16 U.S.C. § 824d(e).

the rule of reason. Specifically, the Commission must include in its approval the following clarifying modifications:

(1) FERC must require that NYISO conduct within the stakeholder process the thorough, scenario-based dynamic modeling and analyses that NYISO admits and CEA's expert testimony demonstrates are necessary to properly develop, analyze, and implement its proposed accreditation methodology. In order to ensure accuracy, procure the right amount of capacity, and maximize reliability, NYISO's modeling must analyze and the chosen methodology must clearly account for diversity benefits and saturation effects as well as clearly account for how the IRM will account for changes in capacity accreditation; and

(2) FERC must direct NYISO to include full and final details of the capacity methodology and its application to ICAP resources in its filed tariff, as required by 18 C.F.R. §35.1(a).³²²

Both of these elements are necessary to ensure not only that the final capacity accreditation methodology is reasonable and NYISO's tariff complies with the rule of reason , but to do otherwise would inappropriately give NYISO carte blanche to determine the most fundamental building block of the capacity market.³²³

These necessary clarifications do not run afoul of restrictions set forth in *NRG*. Contrary to common misperception, Section 205 is not a game of freeze tag where a utility rate filing renders FERC immobile and unable to make anything but typographical changes to a proposed rate. Rather, a long and unbroken line of court precedent —including *NRG*— has been consistently clear that FERC has authority to approve a tariff rate in part and to propose

³²² See also Keyspan-Ravenswood.

³²³ *Elec. Consumers Res. Council v. FERC*, 747 F.2d 1511, 1514 (D.C. Cir. 1984) ("Despite our highly deferential standard of review, it bears repeating that "courts have never given regulators carte blanche.")

modifications necessary to ensure that the approved rate is just, reasonable, so long as those modifications are accepted by the utility and insofar as the Commission's proposed modifications *are consistent with the change proposed by the utility. NRG* and *Western Resources,* and numerous other cases policing the boundaries between FERC action under Sections 205 and 206 consistently hold that when approving a rate change under Section 205, FERC is well within its authority to suggest a system of rates "similar to that previously in effect, [so long as] the utility acquiesces."³²⁴ What FERC may not do under Section 205 is fundamentally alter one of the proposed rate changes on the grounds that it is accepting others. Under Section 205, the Commission may not "make modifications to a proposal that transform the proposal into an entirely new rate of FERC's own making", "may not employ a rate design that follows "a completely different strategy" than, or is 'methodologically distinct from a proposed rate."³²⁵

The relief being proposed by CEAs is squarely within FERC's Section 205 authority and is consistent with Commission precedent. For example, in a 2020 MISO decision, the Commission required MISO to put elements of their proposal into the tariff and to clarify other parts of their proposal because the proposal would significantly affect rates, terms, and conditions of service and that some provisions needed "clarification" to ensure implementation would be just and reasonable.³²⁶ In its recent decision in *Constellation Mystic Power*, the

³²⁴

NRG at 231. See also

³²⁵ *NRG* at 226. See also *Western Resources* at 1579 (minor deviations from a proposed rate based on extent of specific cost items would be permitted, but approving 50% of the proposed rate, while also using a different methodology as the basis for doing so, would not). *See* also *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,043, 61,379 (2020), *MISO*, 172 FERC P. 61,132 (2020); *Old Dominion Elec. Coop.*, 162 FERC ¶ 61,262 (2018), *Sea Robin Pipeline v. FERC*, 795 F.2d 182 (1986), and *NYPSC v. FERC*, 642 F.2d 1335 (DC Cir. 1980). ³²⁶ *MISO*, 172 FERC P. 61,132 (2020) at PP. 58, 109.

Commission required the inclusion of a true-up mechanism to the rate which the Commission held "is intended to ensure that the rate proposal is properly implemented."³²⁷

The modifications proposed by CEAs are actually a clarification of what NYISO has already stated it intends to do in subsequent phases of development and implementation of its capacity accreditation authority. To the extent that the Commission also requires that NYISO's ultimate methodology explicitly include accounting for and proper valuation of synergistic effects, this is something that the NYISO itself claims its methodology will do (Filing Letter at 34) but has been insufficiently clear about. As explained by CEAs' experts and NYISO's own experts,³²⁸ an accurate methodology must account for these synergistic effects; requiring that NYISO ultimately account for this is of a piece with the Commission's requirement of a true-up mechanism in *Constellation Mystic*. These modification thus fall squarely within FERC's authority under Section 205.

Datou. January 20, 2022	Dated:	January	26,	2022
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Respectfully submitted,

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³²⁷ Constellation Mystic Power, LLC, 172 FERC ¶ 61,043, 61,379 (2020) at P 45.

³²⁸ See generally, Astrapé Report; Aug 30 E3 Report.

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CERTIFICATE OF SERVICE

I hereby certify that the foregoing has been served in accordance with 18 C.F.R. § 385.2010 upon each party designated on the official service lists in these proceedings listed above, by email.

Dated: January 26, 2022.

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EXHIBIT A

Dr. Kathleen Spees & Dr. Samuel A. Newell, *The Economic Impacts of Buyer-Side Mitigation in New York ISO Capacity Market*, The Brattle Group (Nov. 18, 2020)

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Cricket Valley Energy Center LLC and
Empire Generating Company LLC
v.
New York Independent System
Operator Inc.

Docket No. EL21-7-000

WRITTEN TESTIMONY OF

DR. KATHLEEN SPEES AND DR. SAMUEL A. NEWELL

The Economic Impacts of Buyer-Side Mitigation in New York ISO Capacity Market

Our names are Dr. Kathleen Spees and Dr. Samuel A. Newell. We are employed by The Brattle Group as Principals. On behalf of the Natural Resource Defense Council, the Sustainable FERC Project, Earthjustice, Sierra Club, American Wind Energy Association, Alliance for Clean Energy New York, and Advanced Energy Economy, we submit this affidavit on The Economic Impacts of Buyer Side Mitigation in the New York Independent System Operator (NYISO) Capacity Market.

Our qualifications as experts derive from our extensive experience evaluating capacity markets and related market design questions. Our experience working for system operators across North America and internationally has given us a broad perspective on the practical implications of nuanced capacity market design rules under a range of different economic and policy conditions.¹ In New York, we have conducted analyses on behalf of the New York State Energy Research and Development Authority (NYSERDA) and the New York State Department of Public Service (NYSDPS) to analyze the costs of Buyer Side Mitigation (BSM) and potential expansions thereof, and to evaluate alternatives to BSM. We are also very familiar with the Minimum Offer Price Rule (MOPR) in PJM Interconnection, LLC's (PJM) capacity market that Cricket Valley Energy Center (CVEC) LLC and Empire Generating Company LLC (the "Complainants") seek to

¹ We have worked with regulators, market operators, and market participants on matters related to resource adequacy and investment incentives in PJM Interconnection, ISO New England, New York, Ontario, Alberta, California, Texas, Midcontinent ISO, Italy, Russia, Greece, Singapore, and Western Australia.
emulate. We have supported PJM by conducting every one of its periodic reviews of its capacity market and have developed design recommendations for competitive and self-supply exemptions to MOPR.² Dr. Newell has submitted testimony to the Federal Energy Regulatory Commission (FERC) on behalf of PJM in developing economic estimates of offer floor prices to implement the MOPR rules in that region. Dr. Newell has also submitted testimony on behalf of the Competitive Markets Coalition group of generating companies seeking to strengthen PJM's MOPR in its original purpose to prevent and mitigate the exercise of buyer market power.³

Dr. Spees is an economic consultant with expertise in wholesale electric energy, capacity, and ancillary service market design and analysis. She earned a Ph.D. in Engineering and Public Policy, an M.S. in Electrical and Computer Engineering from Carnegie Mellon University, and a B.S. in Mechanical Engineering and Physics from Iowa State University. Dr. Newell is an economist and engineer with more than 20 years of experience analyzing and modeling electricity wholesale markets, the transmission system, and ISO/RTO market designs. He earned a Ph.D. in Technology Management and Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science and Engineering from Stanford University, and a B.A. in Chemistry and Physics from Harvard College.

² See our four independent reviews of PJM's capacity market and associated design parameters published in 2008, 2011, 2014, and 2018. The most recent of these is: Samuel A. Newell, David Luke Oates, Johannes P. Pfeifenberger, Kathleen Spees, J. Michael Hagerty, John Imon Pedtke, Matthew Witkin, and Emily Shorin, *Fourth Review of PJM's Variable Resource Requirement Curve*, Prepared for PJM Interconnection L.L.C., April 19, 2018.

³ FERC Docket No. ER13-535-000, filed "The Competitive Markets Coalition's Supporting Comments, at Attach. A, Affidavit of Dr. Samuel A. Newell on Behalf of the 'Competitive Markets Coalition' Group Of Generating Companies," supporting PJM's proposed tariff revisions to change certain terms regarding the Minimum Offer Price Rule in the Reliability Pricing Model, December 28, 2012 ("Affidavit of Dr. Samuel A. Newell on Behalf of the Competitive Markets Coalition").

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Executive Summary

The original and proper economic purpose of buyer-side mitigation (BSM) rules is to protect the market from the exercise of buyer market power: schemes where large net buyers or their representatives offer a small amount of uneconomic supply into the market below cost in order to suppress market clearing prices.⁴ By taking a loss on that small position, a large net buyer could then benefit from a much larger short position in the market. The BSM was designed to prevent this behavior. The concept was to ensure that entities with the incentive and ability to engage in manipulative price suppression will be unable to do so by requiring their capacity market offers to reflect their full costs. Thus uneconomic new resources sponsored by large net buyers would fail to clear (or would set the prices at a higher level) and prevent the would-be gaming entity from achieving the benefits of manipulative price suppression. Symmetrical rules are imposed on large net sellers of capacity in order to prevent them from exercising economic or physical withholding.

More recently, the BSM has been inappropriately repurposed to exclude from the capacity market resources that earn revenues for supporting states', communities', or private consumers' clean energy mandates or sustainability goals; and the Complainants want to extend BSM's application even further along these lines. There is no sensible economic rationale for applying BSM to resources that are developed or maintained to address the harms of climate change or other environmental externalities. The policy support awarded to such resources reflects their environmental value; these resources are not "uneconomic" and their introduction is not in any way related to schemes of manipulative price suppression with uneconomic entry that the BSM was designed to address. Further, expanding BSM does not "level the playing field" as Complainants claim, since it does not privatize the costs of environmental externalities and does not attempt to undo the effects of all local, state, and federal policies that have always shaped the resource mix, including supporting the development of existing fossil plants and reduced the delivered cost of fossil fuels.

Applying BSM to clean energy resources may prevent them from clearing the market, with several undesirable effects. First, it will deprive clean energy resources of revenues reflecting the capacity value they provide, which will interfere with the State's fulfillment of its clean energy mandates. Second, it will favor the retention of uneconomic fossil-fired generation that are not needed for reliability, further conflicting with the State's transition. Third, it will produce higher market clearing prices exceeding the level corresponding to actual supply conditions and effectuate a large wealth transfer from customers to incumbent suppliers. And fourth, contrary to the Complainants' claims, BSM's application to policy resources will eventually render the market unsustainable as these distortions become larger over time under New York's statutory mandate to achieve 70% renewable electricity by 2030 and 100% clean electricity by 2040.⁵ The end state of applying BSM to clean energy resources would be a capacity market that excludes a large majority of the fleet, with market clearing outcomes having no relationship to underlying supply and demand fundamentals.

These distortions would be amplified by the Complainant's proposal to expand the applicability of BSM to all policy-supported resources throughout the state and to increase their minimum offer prices in the capacity auctions. Instead, BSM should be changed in the other direction to limit its

⁴ Federal Energy Regulatory Commission (FERC), Docket No. EL07-39-000, "Order Conditionally Approving Proposal" at PP 100–P100106, March 7, 2008.

⁵ State of New York, Senate – Assembly, S. 6599 – A. 8429, "<u>Article 75, Climate Change</u>," June 18, 2019.

applicability to its original purpose. The most appropriate capacity price is the one that will prevail after the elimination of BSM rules from policy resources, such that the capacity market can continue supporting economic entry and exit by providing an accurate reflection of capacity surplus or shortfall.

THE APPLICATION OF BUYER-SIDE MITIGATION TO POLICY RESOURCES IS BASED ON FLAWED ECONOMIC LOGIC

The Complainants in this proceeding and their witness Dr. Roy Shanker claim that BSM should be applied to policy resources in order to protect the capacity market from the effects of state policies.⁶ Similar to prior economic arguments presented to the FERC, the Complainants assert that state-supported resources inappropriately suppress capacity market prices, thus undermining investment signals and ultimately system reliability. Their proposed remedy is to apply BSM to policy resources, thus restoring prices to the levels that would prevail in the absence of state policies.

The Complainants' economic arguments are incomplete and flawed. A corrected economic analysis should consider that:

- State environmental policies address a well-understood market failure to reflect environmental externalities. The environmental value of policy-supported resources should not be considered an illegitimate distortion of markets that must be excluded, but rather a correction that is needed to achieve a more efficient outcome;
- The "correct" price for capacity is one that aligns supply and demand, not the price that would prevail in the absence of state policies as the Complainants' BSM proposal would aim to produce;
- Capacity markets with sloping demand curves cannot simultaneously produce low prices and poor resource adequacy as the Complainants assert;
- Broad application of BSM to policy resources will amplify (not mitigate) the regulatory risks affecting capacity investments; and
- Merchant generation investors operate in a market and regulatory context that has always required them to face uncertainties associated with a wide range of energy and environmental regulations at the federal, state, and local levels; these policies and associated economic subsidies have always influenced the resource mix (some in favor of incumbent fossil resources and others in favor of clean energy resources). Merchant investors should never have expected to be indemnified against risks associated with these policies (nor should they be required to return revenues to customers when policy changes favor their own investments).

Overall, the Complainants aim to solve a problem that doesn't exist. Their primary concern appears to be that as incumbent fossil generation owners, they no longer expect to earn a satisfactory return on their investments. While certainly a concern for incumbents, low capacity prices are not a problem from a societal or market design perspective. Low prices are simply a reflection of market conditions indicating ample capacity supply; they appropriately signal that no

⁶ FERC, Docket No. EL21-7-000, "Complaint and Request for Fast Track Processing," at p. 14, October 14, 2020 ("Complaint").

new capacity is needed and that high-cost existing resources should retire. In fact, prices that are low enough to signal retirement of aging fossil resources will be necessary to achieve an orderly transition from fossil resources and toward clean energy.

The BSM should be maintained only for its narrow original purpose of addressing manipulative price suppression, not applied to clean energy policy resources. That will enable the capacity market to continue offering competitive benefits by producing accurate price signals that align with market fundamentals.

APPLYING BUYER-SIDE MITIGATION TO POLICY RESOURCES WILL INTERFERE WITH NEW YORK'S STATUTORY MANDATE TO TRANSITION TO A 100% CLEAN ELECTRICITY GRID BY 2040

New York's Climate Leadership and Community Protection Act (CLCPA) mandates a transition to 70% renewable electricity by 2030, 100% clean electricity by 2040, an 85% reduction in economy-wide greenhouse gas emissions, and another 15% greenhouse gas reduction via offsets by 2050.⁷ Applying BSM to policy resources will interfere with the State's CLCPA mandates by excluding clean energy resources from clearing in the capacity market and causing the uneconomic retention of high-cost fossil fuel resources that would otherwise retire.⁸ Specifically:

- Under the Status Quo BSM rules, approximately 7,200 MW of installed capacity (ICAP) (3,050 MW, reported as the annual average of summer and winter unforced capacity (UCAP) ratings) of policy resources will be subject to BSM by 2030. We project that none of that capacity will clear the capacity market. Instead, approximately 3,050 UCAP MW annual average of aging steam turbine plants will clear that would otherwise retire.
- Under an Expanded BSM rule with the same primary elements as proposed by the Complainants, approximately 17,700 ICAP MW (10,350 UCAP MW annual average) of policy resources would be subject to BSM by 2030. Approximately 8,250 UCAP MW would fail to clear the capacity market, replaced by approximately 7,025 UCAP MW annual average of primarily gas- and oil-fired power plants.

Overall, the application of BSM to policy resources would interfere with the transition to a 100% clean electricity mix. A more appropriate capacity market design would acknowledge the reality of the clean energy transition, support the orderly retirement of aging fossil plants, and adapt to an increasing reliance on clean energy resources to support resource adequacy.

⁷ State of New York, Senate – Assembly, S. 6599 – A. 8429, "<u>Article 75, Climate Change</u>," June 18, 2019.

⁸ The assumptions and methodology used to develop the analytical results reported here are described in more detail in Exhibit B (Spees, *et al.*, "Quantitative Analysis of Resource Adequacy Structures," Prepared for NYSERDA and NYSDPS, July 1, 2020); the assumptions adopted at the time reflected our expectations regarding how various dockets and appeals would be resolved regarding the "Status Quo BSM" rules and an "Expanded BSM" rules assumptions and associated uncertainties. Those assumptions remain largely consistent with the current NYISO capacity market rules and the Complainants' proposal. These results were originally developed on behalf of the New York State Energy Research and Development Authority, and the New York Department of Public Service. *See* Exhibit B, Spees, *et al.*, "Quantitative Analysis of Resource Adequacy Structures," Prepared for NYSERDA and NYSDPS, July 1, 2020.

APPLYING BUYER-SIDE MITIGATION TO POLICY RESOURCES IMPOSES UNECONOMIC EXCESS COSTS ON CUSTOMERS AND ON SOCIETY AS A WHOLE

Misapplying BSM to policy resources will impose significant excess costs on customers, amounting to approximately \$460 million per year under Status Quo BSM rules or \$1,780 million per year by 2030 under the Expanded BSM rules proposed by the Complainants, as summarized in Figure 1. These excess costs appear in two ways: (1) as an increase in capacity prices affecting all transactions; and (2) as an increase in contract payments to policy resources because they are deprived of capacity market revenues that go instead to unnecessary substitute resources. Excess costs would be imposed immediately upon application of the Expanded BSM rules as approximately 3,100 UCAP MW of nuclear resources would immediately be affected. The costs would grow over time alongside the scope of the clean energy transition; by 2030 the excess customer costs would rise to approximately \$950 million per year from inflated capacity prices plus \$840 million per year in excess contract payments reflect paying capacity to non-policy resources that are not actually needed to meet the reliability targets underlying the capacity market, rather than paying the policy resources for the capacity they provide.



FIGURE 1: CUSTOMER COSTS FROM IMPOSING BSM ON POLICY RESOURCES BY 2030

Sources and Notes: * Energy and AS prices decrease in some cases because excess capacity depresses prices in tight hours; and because higher contract payments (due to lack of capacity payments) cause energy prices to be more negative in over-generation hours. Costs reported in 2030\$. *See* Exhibit B at p.7.

The primary beneficiaries of BSM are incumbent capacity market sellers, who enjoy elevated capacity prices and gain a greater share of capacity market sales. However, the net benefits enjoyed by these incumbent capacity suppliers would be much smaller than the excess costs imposed on consumers. By 2030, Status Quo BSM and Expanded BSM would increase capacity sellers' revenues by \$460 million and \$1,790 million annually; but their costs would also increase to maintain the excess capacity cleared by roughly \$450 million and \$790 million annually.⁹ Hence their producer surplus would increase by only approximately \$10 million and \$1,000 million per year. That increase in producer surplus mostly reflects a wealth transfer from

⁹ These estimates rely entirely upon the public presentation attached hereto as Exhibit B.

customers. The increased costs to maintain unneeded supply represents excess societal expenditure that benefits neither consumers nor producers.

TO CONTINUE OFFERING BROAD BENEFITS TO CONSUMERS, COMPETITIVE MARKETS MUST ALIGN WITH AND SUPPORT ENVIRONMENTAL POLICY GOALS

Far from "protecting" the capacity market, maintaining and expanding the application of BSM to policy resources will erode and eventually eliminate the benefits of the competitive capacity market. With Status Quo BSM and particularly with an Expanded BSM, the disconnect between market fundamentals and market clearing prices will grow as greater quantities of policy-supported clean energy resources come online over the coming years. The consequential growth in excess customer costs, societal costs, and wealth transfers to incumbent fossil plants will rapidly become unsustainable from a policy and economic perspective.

A better path forward is to eliminate the application of BSM to energy policy-supported resources so that the wholesale markets can help meet clean energy and reliability needs at low cost. The wholesale electricity markets are already largely set up to do so, with the energy, ancillary services, and capacity markets (absent BSM) complementing the State programs that reward resources for their environmental attributes. Together, all of these markets can guide the supply mix to cost effectively meet the state's energy and environmental needs, and can do so even more effectively with continued enhancements.

Regulators, the NYISO, and stakeholders in New York and other regions are already considering several enhancements to better align wholesale markets with states' environmental policies, including enhanced carbon pricing, enhanced energy and ancillary service market designs, and more accurate accreditation of storage and intermittent resources in the capacity market.¹⁰ These reforms may take some time but will ultimately support the evolution of toward a fit-for-purpose wholesale market for the decarbonized grid.

¹⁰ For example see NYISO, "<u>Reliability and Market Considerations for a Grid in Transition</u>," December 20, 2019; and NYISO, "<u>IPPTF Carbon Pricing Proposal Prepared for the Integrating Public Policy Task Force</u>," December 2018.

A. Background on Buyer Side Mitigation and its Proposed Expansion in New York

The New York capacity market is a centralized competitive platform within which the market operator procures the quantity of resources needed to meet regional resource adequacy or reliability needs. The NYISO uses an administrative demand curve to procure the quantity of capacity that it estimates will be needed to ensure that bulk system supply shortages are infrequent, occurring no more often than once in ten years in expectations (the "1-in-10" reliability standard). Import-constrained subregions such as New York City are represented by separate demand curves establishing a minimum quantity of capacity that must be located in that subregion.

Capacity sellers offer their resources into the market at the minimum price they are willing to accept to come online or stay in the market. For any given resource, the minimum price they are willing to accept is driven by a number of factors including primarily: (a) costs associated with bringing new supply into the market or maintaining an existing facility that needs re-investment; and (b) minus any anticipated net revenues that could be earned from energy markets, ancillary service markets, or other revenue sources (such as sales of renewable energy credits (RECs), steam, or gypsum). Many sellers would also adjust their capacity offer price based on any bilateral sales agreements for capacity or any co-products they may produce and based on their long-term view of future energy and capacity prices. Sellers that are able to pre-sell most of their capacity or energy through bilateral contracts would typically offer at a zero price, as would most sellers that have already come online and have few going-forward capital investments.

Capacity prices are set at the intersection of sellers' capacity market supply offers and the administrative demand curve in each location and system-wide. Under this framework, the market produces prices consistent with supply-demand conditions. The market produces low prices when the region has more than enough supply to meet resource adequacy needs; it produces high prices when capacity supply is scarce. For the two decades since New York's capacity market was implemented, it has produced competitive prices that signal the need for new entry; attracted new entry from generation, imports, and demand response when needed; and allowed for the orderly retirement or net exports of higher-cost resources when supply was long.¹¹

One of the design elements of the capacity market is a comprehensive framework for mitigating the potential for both supply-side and demand-side market power abuses. The framework consists of a number of inter-related design elements. Chiefly, the monitoring and mitigation framework includes: (a) *sell side mitigation* provisions that impose capacity price offer caps that are intended to limit the ability of large net sellers from manipulative economic or physical withholding that could inflate market prices; (b) largely symmetrical *buy side mitigation* provisions that similarly impose offer floors on large net buyers to prevent manipulative suppression of market prices; and (c) *independent monitoring and mitigation* activities to regularly review market efficiency and competitiveness. Together, these comprehensive monitoring and mitigation rules support price formation that market participants can anticipate will largely reflect economic fundamentals and supply-demand conditions, without being driven by the private interests of a player with large buyor sell-side market share.

¹¹ Potomac Economics, Market Monitoring Unit for the NYISO, "2019 State of the Market Report for the New York <u>ISO Markets</u>," May 2020, at p.57 (Capacity Market Results and Design).

The original purpose of BSM rules in the context of the overall market monitoring and mitigation framework was to prevent manipulative price suppression. The rules were intended to prevent entities with a large net buyer position from exercising buy-side market power. Without such a rule, a large net buyer could be in a position to game the capacity markets by bringing a small quantity of incremental capacity supply into the market, offering the supply at a zero price, and producing a low capacity price. In some cases, a large buyer supporting new entry would not be a problem. For example, if the incremental supply is relatively low cost and thus a better deal than purchasing generalized capacity from the market. However, the purchase can be viewed as manipulative price suppression if the incremental supply is very high cost, higher than the but-for capacity price that would otherwise have materialized. In that circumstance, the buyer would develop uneconomic supply (taking a financial loss on a small quantity of high-cost capacity supply) in order to achieve a lower capacity price (thus benefitting the much larger net buy position). This behavior is, by definition, manipulative because the uneconomic incremental supply resource is not a rational resource to develop when viewed in isolation. The incremental supply is pursued only for the purpose of suppressing market prices below the competitive levels that would prevail from individually rational entry and exit.

To prevent this manipulative price suppression, the BSM would restate the offer price from zero to a higher level based on the minimum offer price rule (MOPR). The higher MOPR price prevents this scheme from producing price suppression and makes it less likely that the resource in question would clear the capacity market. When applied to large net buyers and their supported resources, the BSM rules privatize the cost of any potentially uneconomic investments, while holding other parties in the market harmless. More importantly, the existence of the rule is intended to disincentivize the manipulative behavior and associated economic waste from taking place at all.

In New York, the current or "Status Quo BSM" rules currently apply to the downstate capacity zones G-J, apply only to new resources, and apply a MOPR price at the lesser of $0.75 \times$ Mitigation net Cost of New Entry (CONE) or a resource-specific value.¹² The rules further allow for Part A and Part B exemption tests that allow some resources to avoid the application of the BSM, if a forecast of future market conditions indicates that the supply will be needed or likely to clear the future capacity auctions; if the resources appear likely to clear then they can gain an exemption from BSM. This limited application of BSM is associated with the original narrow purpose of the rule, which was to prevent manipulative price suppression; these capacity zones were the only locations within which the market structure indicated that any large net buyer might have the incentive and ability to exercise market power.

The FERC has recently expanded the role of BSM in New York and in other regions to impose a MOPR more broadly to apply to resources that earn policy payments. The large majority of these resources in New York and other regions are those awarded policy payments in recognition of their contribution toward achieving states' environmental policies. The Complainants propose to expand BSM in New York further through several reforms: (1) to increase the applicable MOPR price to a technology-specific value in all cases (which will typically be much higher than the current default value); (2) to eliminate Part A and Part B exemptions that can allow certain resources to avoid BSM application in the delivery year; (3) to apply BSM broadly across all capacity zones in New York; and (4) to apply BSM to existing as well as new resources, with the

¹² "Mitigation Net CONE" is an administrative estimate of the levelized cost of new supply that could be attracted into the capacity market.

greatest effect being the immediate application of BSM to approximately 3,100 UCAP MW of existing nuclear resources.¹³ Overall these changes will substantially expand the scope of capacity resources affected by BSM.

The mechanics of BSM as applied to policy resources are illustrated in Figure 2. The left panel illustrates clearing outcomes if all capacity resources are allowed to offer at their preferred offer price. Most (though not necessarily all) policy resources will typically offer at a zero. These resources earn the (large) majority of their revenues through energy market and policy payments reflecting their environmental value; thus, these resources will be developed and online regardless of the capacity price. So, they would typically choose to offer at zero in the capacity market. Fossil plants and other capacity resources would offer at the minimum capacity price needed to earn a return on going-forward investments.¹⁴ Clearing prices are set at the intersection of supply and demand.

When BSM is applied to a policy resource, its offer price is increased from zero to a higher level for the purposes of auction clearing. As illustrated in the right panel of Figure 2, the higher BSM-based price will re-order the capacity market offer supply curve, make it less likely for the policy resource to clear the market, and cause higher clearing prices.

When applied to policy resources, the mechanics of the BSM are identical as compared to the application in the context of manipulative price suppression. However, the economic purpose and impact are entirely different. Unlike in the context of manipulative price suppression, BSM, when applied to policy resources, is not intended to prevent the investments from taking place. The policy investments will proceed regardless of BSM because they are developed for the primary purpose of addressing climate change (they are not developed as a means of achieving capacity market price suppression, and would not be a cost-effective means of achieving price suppression). Thus the exclusion of these resources from clearing the market will not prevent such investments from taking place.

Another difference between the contexts of manipulative price suppression and policy resources is the scope and scale of the affected resources. In the context of manipulative price suppression, the typical behavior would be that the buyer would endure a small economic loss from developing a small quantity of uneconomic capacity resources, with that small loss more than offset by the gains to the much larger buy-side position. The scope of BSM tend to cover a small volume of supply. In the context of policy resources, there is no expectation that the quantities of excluded resources will remain small. In fact, regardless of BSM, these resources should be expected to become the large majority of the New York capacity market as the state proceeds toward its 100% clean electricity mandate.

¹³ See Exhibit B at p. 12, consistent with Complaint, at Attach. A, Shanker Affidavit, at p. 6.

¹⁴ In the non-forward New York market, these other resources may also offer at zero but would tend to enter or exit the market in advance based on whether projected clearing prices would be sufficient to earn a return. The effect on realized prices is the same as in our stylized description here if we assume that market participants have perfect foresight of future market conditions.



FIGURE 2: EXPANSION OF BSM WOULD INCREASE THE CLEARING PRICE

B. The Application of Buyer Side Mitigation Rules to Policy Resources is Based on Flawed Economic Logic

result, the market clearing price would increase.

The Complainants present an economic analysis that largely reflects analysis that has previously been presented to the FERC on this same topic. The stated concerns are as follows. States such as New York are attracting large quantities of new resources to meet clean energy goals through a variety of programs and contract solicitations that the Complainants consider to be "subsidies."¹⁵ Because these activities can reduce near-term capacity market prices and/or displace "non-subsidized" resources, BSM advocates argue that it is necessary to protect wholesale capacity markets from the price-suppressive impacts of state policies. They argue that without intervention, market prices will be inappropriately low, merchant capacity suppliers will not earn adequate returns on investment, this would discourage new capacity from entering the market, and thus threaten future reliability. Their proposed remedy is to use BSM on policy resources to restore capacity prices to the "correct" level, *i.e.*, the price that would have prevailed in the absence of the state policies.

The rationale that the Complainants provide for applying BSM to policy resources is based on incomplete and flawed economic logic. A corrected economic analysis reveals a simpler truth: that the "correct" capacity price is the one that accurately reflects underlying fundamentals of supply and demand. This is the accurate price that should signal when and where capacity investments are needed (and when high-cost resources can retire). The logical conclusion under this corrected economic analysis is that BSM should be eliminated from application to policy resources so that capacity prices can be utilized to rationalize supply with demand.

¹⁵ We do not subscribe to the view that such state programs and/or solicitations should be considered "subsidies" in the traditional sense, nor that subsidies are inappropriate or inherently problematic if they are pursued in light of policy goals. Instead, we see the introduction of clean energy policies as generally providing compensation for environmental externalities not otherwise provided for by the market itself.

B.1. State Policies Address Well-Understood Market Failures Such as Environmental Externality Costs

The complaint quotes Commissioner Danly observing, "these [BSM] exemptions will, regardless of the policy objectives they may seek to achieve, impede a market's ability to set prices that accurately reflect market forces." But prices "reflecting market forces" alone do not ensure economic efficiency where major externalities exist, as in this case. A negative externality is a negative side effect of an economic activity that adversely affects a party not involved in the transaction. The adversely affected third party has no influence over whether the transaction takes place, but is nevertheless harmed. Environmental externalities such as those caused by greenhouse gas and air quality emissions from fossil fuel-fired power plants are the classic textbook example of externalities.¹⁶ Once emitted into the air, greenhouse gases cause a number of adverse effects on residents, businesses, and environment in New York, nationally, and globally in the present day and for hundreds of years.¹⁷ Other pollutants such as NO_X, SO_X, and particulates cause even more immediate detrimental health outcomes such as asthma and early death.¹⁸ Absent policies to address these externalities, neither the purchaser of the power (NYISO in this case) nor the producer of the emissions (the power plant owner) pays the full cost associated with these negative externalities.¹⁹ Such unpriced or underpriced externalities will tend to be produced at a quantity that exceeds the economically efficient level from a societal perspective. The consequence of ignoring these environmental externalities is that market pricing alone would drive resource investments and operations toward an inefficiently large quantity of fossil fuel-fired power plants, imposing inefficiently large externality costs.

Externalities are by definition not "market forces," but rather market failures. Under their existence markets fail to allocate the resources efficiently and the current market price would not be the "correct" one. As a general matter, public policies can address externalities and market failures in one of two ways: one is *command-and-control* policies that regulate behavior directly; the other is to develop market-based policies that align private incentives with social efficiency.²⁰

Environmental externalities can be incorporated into electricity markets through policy mechanisms, whether through emissions pricing mechanisms (*e.g.*, carbon pricing) that charge

¹⁶ N. Gregory Mankiw, *Principles of Microeconomics*, 5th ed. Mason, (OH: South-Western Cengage Learning, 2009), p. 204.

¹⁷ United States Environmental Protection Agency, "<u>Climate Change Indicators: Greenhouse Gases</u>," accessed on November 16, 2020.

¹⁸ Michael Guarnieri, John R Balmes, "<u>Outdoor Pollution and Asthma</u>," The Lancet 383 (9928): 1581–1592. doi:10.1016/s0140-6736(14)60617-6 (2014).

¹⁹ The Regional Greenhouse Gas Initiative (RGGI) has imposed some costs on emitters, but the allowance prices are far below the Social Cost of Carbon adopted by the New York Public Service Commission (NYPSC) for setting zero-emissions credit (ZEC) prices and VDER tariffs, and likely further below the State's willingness to pay for carbon reduction as implied by its aggressive decarbonization goals. In setting ZEC prices, the NYPSC adopted a social cost of carbon of \$50.11/short ton (in nominal dollars) for Tranche 3, which runs from April 2021 through March 2023. By comparison, the most recent RGGI auction at the time of this writing cleared at \$6.82/short ton on September 2, 2020 (available at https://www.rggi.org/auctions/auction-results/prices-volumes). See also NYPSC, Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, "Order Adopting a Clean Energy Standard," at 136, August 1, 2016.

²⁰ N. Gregory Mankiw, *Principles of Microeconomics*, 5th ed. Mason, (OH: South-Western Cengage Learning, 2009), p. 154–210.

emitters and indirectly reward non-emitters and/or through clean energy attribute payments that reward non-emitters directly. Carbon pricing can take many forms, from a tax or charge approach that sets a price per ton emitted; to a cap-and-trade approach that sets a cap on emissions and lets the market determine the price of allowances; to a hybrid, such as RGGI that is nominally "cap-and-trade" but that includes adjustable caps to serve as price collars. In all of these cases, carbon pricing raises the cost for emitters to produce, making them less competitive and raising market clearing prices for energy; non-emitters earn the higher prices without being charged. Clean energy attribute payments work more directly by paying non-emitters to produce carbon-free energy. They are usually provided through long-term contracts that support clean energy resources will continue to evolve as the State, NYISO, and stakeholders continue to assess the most effective and efficient opportunities to support the clean energy transition, as discussed in Section E below.

Many economists (and some pro-BSM) advocates argue that a carbon pricing mechanism would be a better way to address these environmental externalities and enable all resources to compete based on market prices for energy (that account for carbon-related externalities), capacity, and ancillary services. For example, FERC recently held a technical conference on carbon pricing; and the Electric Power Supply Association recently sponsored a study by Energy + Environmental Economics (E3) presenting carbon pricing as the most efficient way for states to achieve their environmental objectives.²¹ We agree with many of the arguments in favor of carbon pricing, but caution that electricity sector carbon pricing alone may be an incomplete solution in the context of States' environmental mandates.

We too believe that carbon pricing would help support the state's objectives cost-effectively, through resource-neutral competition that accurately signals where and when clean energy production displaces the most carbon emissions, while also appropriately rewarding storage and higher-efficiency gas-fired generation that partially reduce emissions. The ideal is for a carbon pricing regime to apply uniformly and comprehensively in its geographic scope (across state and national borders) and in its coverage of all economic sectors. However, without this comprehensive scope, carbon pricing could induce unintended effects such as leakage or disincentives to electrify heating and transportation demand. In the case of NYISO's proposal to charge carbon emitting generators in New York for their emissions at a state Commission-determined social cost of carbon, our work showed that proposed border adjustments and allocation of carbon revenues to customers could largely avoid these adverse effects.²² These results are not necessarily generalizable to other ISO markets or if carbon prices become much higher, but carbon pricing should continue to be pursued, especially at a national and economy-wide level in order to achieve carbon abatement in the most cost-effective fashion.

However carbon pricing should not be presented as the only "legitimate" or "efficient" policy option for incorporating carbon externalities into electricity markets. Even if carbon pricing is pursued, the practical reality is that carbon prices alone may not be set high enough to support sufficient investment to meet mandated clean energy targets in the timeframe required by State

²¹ E3, "<u>Least Cost Carbon Reduction Policies in PJM</u>," at p. 9, March 28, 2020.

²² Samuel A. Newell, Roger Lueken, Jürgen Weiss, Kathleen Spees, Pearl Donohoo-Vallet, Tony Lee, The Brattle Group, "Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals," August 10, 2017.

laws.²³ Clean energy attribute payments, competitive clean energy solicitations, and customerbacked contracts for clean energy resources are all alternative approaches that can be pursued for addressing environmental externalities, each with advantages and disadvantages relative to carbon pricing in terms of timing, economic efficiency, risk allocation, and implementation feasibility. Further, different communities and customers (within New York) or state governments (in other regions) will place different values on their deemed cost of carbon emissions and so will not be able to establish a single market-wide carbon price. Overall, we anticipate that a combination of carbon pricing and clean energy attribute payments of some form together will be utilized to achieve New York's 100% clean energy mandate. Given the interplay and partial substitutability between RECs and carbon pricing, it is curious that the BSM advocates would view energy revenues incorporating carbon to be legitimate but RECs and ZECs not to be. While they are not the same mechanism, they both serve to address environmental externality costs by affecting the relative revenues of emitting and non-emitting generators, and they have similar effects on capacity market prices. For example, a high enough carbon price would retain high-cost nuclear plants just like a ZEC payment does, so it is difficult to see why the capacity market treatment should be so radically different if using one mechanism or combination of mechanisms versus another.

A more consistent approach is to acknowledge that states, communities, and customers have a legitimate interest in addressing environmental externalities. As the demand side of wholesale electricity markets, customers and their elected representatives have the proper role of establishing how much they are willing to pay to address environmental externalities and what combination of contracts and policies they wish to use to express that value. An efficient marketplace should aim to assist states and customers by providing options for achieving their environmental goals at the lowest possible cost.

B.2. The "Correct" Capacity Price is the One that Aligns Supply with Demand (Not the Price that would Prevail in the Absence of State Policies)

The efficient outcome in a market, or set of interconnected markets, is that which maximizes social welfare: the sum of consumer and producer surplus. Absent environmental externalities and with market participants acting competitively, this outcome would result at the price where the marginal cost of supply (to producers) is equal to the marginal value of additional consumption (to consumers). However, when environmental externalities are introduced, the intersection of (private) supply and demand *will not represent the efficient outcome*. This inefficient outcome is the one that the complainants seek to re-establish with the expanded MOPR. Instead, the correct capacity price is that which aligns supply and demand, given other policies and/or markets that policymakers have identified as necessary to address the externality.

Compensating non-emitting resources for their environmental value lowers their net cost of providing capacity (regardless of whether that compensation is achieved through carbon pricing or clean energy payments). Clean energy resources correctly appear more competitive as capacity providers, just like resources with high energy and ancillary services value, and they should be

²³ Especially as the emissions target tightens toward zero, the carbon price would have to be very high to continue to favor investment in new clean resources over running existing fossil-fired generators in a small number of hours. For example the finding that "carbon taxes alone are unlikely to produce emissions pathways in line with the net-zero emissions targets by 2050," in Larsen, *et al.*, *Expanding the Reach of a Carbon Tax: Emissions Impacts of Pricing Combined with Additional Climate Actions*, October 2020.

allowed to clear the capacity market and be recognized for the resource adequacy value they contribute to the system.

If the capacity market consequently produces low prices, this is correctly signaling an oversupply of capacity, that no more investments are needed for resource adequacy, and that the least valuable resources should retire. Reliability will not be threatened by replacing traditional capacity with clean capacity, as clean resources will be assigned capacity ratings reflecting only the reliability value they actually provide. In fact, NYISO's resource accreditation for intermittent resources is already a fraction of their nameplate capacity and will decline as their market share increases. Thus, as the clean energy transition proceeds it will take greater quantities of wind, solar, and battery supplies to replace a single retiring gas plant. Through this continuously-adjusting displacement rate, reliability can be maintained over the course of the transition. For the same reasons, the market (absent BSM on policy resources) can provide the right price signals and result in efficient outcomes with the least-cost set of economic retirements, entry, and retention of resources needed to maintain resources adequacy.

Forcing policy resource offers upward through BSM rules would generally prevent them from clearing. It would result in an artificially high capacity clearing price and induce inefficient behaviors and uneconomic incentives: it would retain costly existing supply that would otherwise retire, attract costly new supply that is not needed, and dis-incentivize customers from utilizing more electricity given inflated prices that signal a false scarcity of capacity supply. Thus, the application of BSM to policy resources causes the capacity market to depart from supply-demand fundamentals.

The inefficiency of the outcome is especially apparent considering that policy resources will be developed and operate regardless of whether or not they clear the capacity market. Thus the BSM distorts the capacity market by inducing the procurement of additional capacity to meet reliability objectives. The capacity market would simulate a fictional reality as if the policy resources that help meet demand every hour of the year did not exist. Under that fictional scenario, the reliability value of the policy resource in question would be ignored, would not be paid for, and thus would need to be made up for through the purpose of capacity from other suppliers. This scenario becomes perverse when applied to a state such as New York with a 100% clean electricity mandate. All policy-supported resources that physically supply resource adequacy could be excluded from being counted in the capacity market, while the capacity market would remain a multi-billion-dollar-per-year "shadow market" that exists primarily to pay resources that are not actually needed for resource adequacy.

Overall, the Complainants offer a solution to a non-problem. The grievance from the standpoint of incumbent fossil generators is that their resources will eventually become uneconomic in a region with a significant clean energy mandate. Such resources will not enjoy the same revenues they would in a world where emissions do not matter.

However, low prices are not a problem from a more holistic market design, reliability, or economic perspective. Low prices would be produced only when supply is long, new entry is not needed, and retirements can be accommodated. Applying BSM to policy resources creates a fundamental disconnect between market pricing outcomes that deviate from the underlying fundamentals of supply (including that associated with state policy resources) and demand (as expressed through resource adequacy requirements).

B.3. Capacity Markets with Sloping Demand Curves Cannot Simultaneously Produce Low Prices and Poor Resource Adequacy

The Complainants and other BSM advocates have expressed a misguided concern that the low prices that may prevail due to growth in policy resources will threaten reliability by discouraging investment.

As shown in Figure 3, this concern is illogical in the context of a capacity market with a downwardsloping demand curve that reflects the required reserve margin and the incremental value of additional supply beyond that reserve margin. By its nature, the downward sloping demand curve simply cannot produce market outcomes with low prices and low reliability at the same time. If prices are low due to the entry of policy resources, this means that there is ample supply of capacity on the system. In this long market condition the low capacity prices signal that high-cost resources should retire and new entry is not needed. If the supply-demand balance tightens, prices will rise and signal the need to attract and retain scarce capacity. Thus the Complainants' concern that low prices will produce low reliability is unfounded (and a mathematical impossibility).

This is not to say that reliability is not a concern in the clean energy transition. As noted above, intermittent resources whose unavailability may be correlated across the fleet (*e.g.*, low wind days, or low solar insolation periods such as nighttime) provide less and less incremental resource adequacy value as their penetration increases. Capacity markets must recognize that fact through resource accreditation that accurately reflects resources' contribution to system reliability. Beyond the context of capacity markets discussed in this testimony, other aspects of the wholesale electricity markets including energy, ancillary service, and transmission planning rules may be needed to ensure robust pricing and operations in the context of different resource patterns and capabilities throughout the clean energy transition.

FIGURE 3: CAPACITY MARKETS WITH DOWNWARD-SLOPING DEMAND CURVES CANNOT SIMULTANEOUSLY PRODUCE LOW PRICES AND POOR RESOURCE ADEQUACY



B.4. Broad Application of Buyer-Side Mitigation to Policy Resources will Amplify (Not Mitigate) Regulatory Risks

BSM advocates have argued BSM is necessary to mitigate regulatory risk surrounding capacity investments. We acknowledge that capacity investments do face more regulatory risk in a world with environmental policies than one in which policies never change; and that imposition of increasingly-stringent policies will more usually disadvantage higher-emitting resources. The application of BSM to clean energy policy resources undoes some of that effect, by elevating capacity prices to the level that would prevail absent the policy resources. It would also retain the same capacity as in world without the policy-supported clean energy resources. As long as BSM is maintained, it will benefit incumbent fossil resources and might even attract investment in new gas-fired resources (in both cases, securing more capacity than is needed for reliability).

However, elevated prices should not be conflated with less-risky prices. We do not believe the BSM reduces regulatory risk or provides an efficient basis for attracting new investment. On the contrary, a market whose price is artificially inflated by a rule as controversial and economically inefficient as BSM is unsustainable. Investors will not count on the price premiums produced by such a rule to be sustainable over the long term. They would have to realize that, over time, the pressure to eliminate BSM would only increase as mounting quantities of policy resources are excluded from the market and the BSM-supported price and capacity deviate further from reflecting actual supply and demand conditions. Customers will ask why they are paying so much to support excess capacity, as if it were needed to meet the (already conservative) resource adequacy objectives underlying the capacity market. They will notice that the excess capacity they are supporting is primarily fossil fuel generation that contravenes state clean energy policy goals with wide popular support, and they will demand change. For these reasons, capacity markets that fail to accommodate policies that states are committed to pursuing cannot form the basis for a sustainable market design that supports investment.

Capacity markets can better support merchant investment when needed, with lower regulatory risk, if they do not apply BSM to clean energy policy resources. Such a market reflecting actual supply and demand conditions will send just the right price signals to maintain resource adequacy at least cost. Merchant investors will still face market and regulatory risks, including risks from environmental policies changing in the future. States can mitigate these risks by setting environmental policies on a long-term stable basis, as New York has done through its CLCPA that specifies goals through 2050. Investors can then view these policies as part of the fundamentals against which they can plan their business strategies.²⁴

²⁴ For example, the Grid Evolution study we performed for NYISO did not incorporate BSM, and it showed how merchant investment in capacity could complement a future with large quantities of policy-supported clean energy resources added. The simulated market retained enough existing capacity and attract enough storage investment to maintain resource adequacy through 2040. It showed that, as vast amounts of wind and solar generation are added to meet clean energy goals, they will continue to contribute capacity value but at a declining marginal rate reflecting their correlated intermittency. Other non-intermittent resources will still needed to support system reliability, and market prices should adjust to signal dispatchable capacity to stay online or enter the market. In our central scenario where policy-driven electrification of transportation and heating sectors increases demand, the simulated market even attracted investment in new dispatchable "gas-fired" generation capacity, assuming it could generate using "renewable natural gas" that counts as non-emitting. *See* R. Lueken, et al., "New York's Evolution to a Zero Emission Power System," prepared for NYISO and presented to the NYISO stakeholders, June 22, 2020.

B.5. Merchant Investors Operate Amidst Wide-Ranging Energy and Environmental Policies from which They Never Should have Expected to be Indemnified

The Complainants express concern that certain merchant investments are not earning the return on investment that they anticipated. They assert that "state subsidy issues" are producing "lower than expected capacity prices caused by uneconomic retention of state subsidized generation facilities."²⁵

While poor investment returns are certainly a concern for the particular investors referenced here, this is not a concern from a market design perspective. Merchant generation investors operate in a market and regulatory context that has always included environmental regulations from which they should not expect to be indemnified any more than they should be charged when regulations work in their favor. Favorable policy developments for merchant investors in gas-fired generation such as the Complainants have enjoyed in New York include the finalization of the State's arrangement with Entergy to shut down the Indian Point Energy Center, agreements to retire the state's remaining coal plants, rules to eliminate high-NO_X-emitting peaking plants from Downstate New York, and possible future expansion of electricity demand from policy-driven electrification of the heating and transportation sectors. Natural gas-fired generators also benefit from various tax policies and ratepayer-funded gas transportation infrastructure that have lowered the delivered costs of their fuels.²⁶

New York's decarbonization policies underlying the complaint mostly do not help natural gasfired plants that are major emitters of carbon dioxide. But the state has long discussed its environmental priorities, particularly the need to address climate change. Investors in new power plants should have anticipated policies to effectuate a transition in the generation fleet. It is misleading to suggest, as the Complainants have, that investors in Empire and CVEC could not or should not have foreseen the development of public policies that are unfavorable to the interests of large carbon-emitting power plants. Consider the following record of New York's steady longterm march toward the policies it has now:

- As early as 2002, the New York state government expressed concern in its State Energy Plan regarding the reliance of the state on gas-fired electricity and established a goal to increase renewable energy by 50% as a percentage of total load served by 2020, aiming to move from 10% of demand met by renewable energy to 15% by 2020.²⁷ In 2004, the New York PSC had adopted the more aggressive RPS goal of 25% renewable energy by the end of 2013.²⁸ Investment in Empire Energy was made against this backdrop, wherein New York had clearly displayed its commitment to promoting renewable energy.
- In 2010 the RPS goal was amended to 30% by 2015.²⁹

²⁵ Complaint at p. 33.

²⁶ For example, see Doug Koplow, "Testimony on behalf of Sierra Club in Protest on Behalf of Clean Energy Advocates", in FERC Docket No. ER18-1314, May 7, 2018.

²⁷ New York State, "<u>2002 New York State Energy Plan</u>," at Section 1–3.

²⁸ NYPSC, Case 03-E-0188, Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard, "Order Regarding Retail Renewable Portfolio Standard," September 24, 2004.

²⁹ NYPSC, Case 03-E-0188, Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard, "Order Establishing New RPS Goal and Resolving Main Tier," January 8, 2010.

- In December 2015, Through Reforming the Energy Vision (REV), New York State Government called for 80% GHG emissions reduction by 2050 and 50% of electricity demand to be met by renewables by 2030.³⁰
- On January 25, 2016 the NYSDPS staff published a white paper regarding what was to become the Clean Energy Standard, which aimed to meet the goals set forth by Governor Cuomo in 2015. In this white paper they discussed the plan to institute a ZEC in order to support "a smooth emission-free transition from nuclear to non-nuclear resources in the event that energy prices are not able to support the continued financial viability of the plants during their license lives."³¹ The ZEC program was established formally on August 1, 2016, when the New York PSC adopted the Clean Energy Standard.³² It was not until January 24, 2017, nearly one year after NYSDPS staff published the white paper regarding the ZEC program that CVEC closed on financing for developing its generating facility.³³

But even if the Complainants could not have anticipated the full extent or particulars of the CLCPA, these policies are within the State's mandate to protect public health and are part of the context in which the Complainants chose to invest. They chose to bear the risks and rewards associated with changing market conditions and regulations, and there is no reason to indemnify them through BSM. Doing so would distort the market, as explained above, and impose unnecessary costs on consumers.

B.6. BSM Should Be Applied for Its Narrow Original Purpose of Mitigating Market Power Abuses (Not Repurposed to Undo the Effects of State Policies)

BSM is an appropriate mechanism for its original purpose of preventing manipulative price suppression.³⁴ In that context BSM has a valid economic rationale: to prevent net-short entities and their representatives from sponsoring uneconomic investments to suppress prices, benefit themselves in the short run (at the expense of other market participants), and induce economic deadweight losses.³⁵ Applied for that original purpose, BSM rules work together with many other elements of a comprehensive monitoring and mitigation framework that assures market participants that market outcomes will be competitive, reflecting supply-demand fundamentals.³⁶

³⁰ REV, "<u>What You Need to Know</u>," December, 2015.

³¹ NYSPSC, Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, "Staff White Paper on Clean Energy Standard," at p. 30, January 25, 2016.

³² NYPSC, Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*, "Order Adopting a Clean Energy Standard," August 1, 2016.

³³ See "<u>Advanced Power AG Closes Financing of \$1.584 Billion Energy Center in Dover, New York</u>" Business Wire, January 24, 2017.

³⁴ See: FERC, Docket No. EL07-39-000, "Order Conditionally Approving Proposal" at PP 100–P100106, March 7, 2008.

³⁵ This deadweight loss is the cost of the uneconomic resources in excess of the value they provide. The costs of the resources developed in order to suppress prices exceeds the cost of the resources displaced that would otherwise have cleared the market.

³⁶ See Affidavit of Dr. Samuel A. Newell on Behalf of the Competitive Markets Coalition: FERC, (supporting PJM's proposed tariff revisions to change certain terms regarding the Minimum Offer Price Rule in the Reliability Pricing Model).

This valid economic rationale for BSM does not apply in the context of policy-supported clean energy investments:

- Clean energy policy investments are pursued to address climate change, not as a means to suppress capacity prices.
- State-supported investments in clean energy are not uneconomic just because they need payments beyond what they would earn through wholesale electricity markets alone. These policy incentives correct for the market failure to reflect the costs of environmental externalities associated with climate change and public health.
- Applying BSM to clean energy policy resources does not prevent uneconomic behavior (as it does when applied to mitigate manipulative price suppression schemes); rather, it actually *causes* uneconomic behavior by incentivizing the retention of uneconomic, unneeded resources. And as we show later the greatest impact would be to retain exactly those aging fossil plants that the clean energy investments are intended to displace.

Clean energy policies will have a number of effects in the electricity sector and broader economy. Capacity markets, like all other markets, may inevitably be affected by these policies. The overall outcome of an effective policy to mitigate climate change will be to reduce the amount of greenhouse gas emissions produced and to guide the resource mix away from fossil and toward a mix that meets energy and reliability needs with cleaner resources

C. Applying Buyer Side Mitigation to Policy Resources Will Interfere with New York's Statutory Mandate to Transition to a 100% Clean Electricity Grid by 2040

To evaluate the impacts of applying BSM to policy resources, we conducted a simulation analysis of the New York capacity market in a 2030 study year with three scenarios with "No BSM," "Status Quo BSM," and "Expanded BSM" rules.³⁷ In the No BSM case, we estimated the prices, clearing outcomes, and resulting customer costs under a capacity market design in which BSM is eliminated from application to policy resources. In the Status Quo BSM case, we simulated current BSM rules that are applied only to new policy resources in the downstate G-J region of the NYISO capacity market with an offer floor at the minimum of $0.75 \times$ mitigation Net CONE and a technology-specific value. In the Expanded BSM case, we examined rules consistent with Complainants' proposal to expand BSM to existing and new policy resources throughout New York, and increasing the applicable offer floor to technology-specific MOPR values.

Our analysis shows that the overall effect of applying BSM to state policy resources is to exclude policy resources from clearing the capacity market and induce the uneconomic retention of fossil plants. Both of these outcomes pose barriers to achieving the State's mandate to eliminate carbon emissions from electricity generation by 2040, and interim mandates before then.

³⁷ We conducted this analysis on behalf the New York State Energy Research and Development Authority, and the New York Department of Public Service. The assumptions and methodology used to develop the analytical results reported here are described in more detail in Exhibit B. *See* Spees, *et al.*, "Quantitative Analysis of <u>Resource Adequacy Structures</u>," Prepared for NYSERDA and NYSDPS, July 1, 2020.

C.1. Approximately 8,250 MW of Clean Resources Would be Excluded from Clearing the Capacity Market by 2030

Figure 4 summarizes our estimates of the quantity of policy resources that could be subject to BSM rules in the New York capacity market by 2030 under Status Quo and Expanded BSM rules. We further report the shares of these resources that we estimate would be likely to clear the capacity market and those that would not. Specifically, we estimate that:

- Under the Status Quo BSM rules, approximately 7,200 ICAP MW (3,050 UCAP MW, reported as the annual average of summer and winter capacity ratings) of policy resources will be subject to BSM by 2030. We project that none of that capacity will clear the capacity market because their BSM offer floors would price them out of the market.
- Under an Expanded BSM rule similar to the one proposed by the Complainants, approximately 17,700 ICAP MW (10,350 UCAP MW annual average) of policy resources would be subject to BSM by 2030. Approximately 8,250 UCAP MW annual average would fail to clear the capacity market.

Failing to clear such a large quantity of existing capacity resources will limit progress in the transition to a clean energy grid by reducing the formal role of policy resources to contribute to resource adequacy and reliability needs.



FIGURE 4: PROJECTED IMPACTS OF BSM ON CAPACITY MARKET CLEARING BY 2030

Sources and Notes: See p. 14, Exhibit B.

C.2. Approximately 7,025 MW of Fossil Resources Would be Uneconomically Maintained by an Expanded BSM

As also shown in Figure 4 above, policy resources excluded from clearing the capacity market would likely be replaced primarily by uneconomic fossil plants that would otherwise retire. Under Status Quo BSM assumptions, we estimate that 3,050 UCAP MW annual average of aging, high-emitting gas-fired steam turbine plants would be retained that would otherwise retire. Under Expanded BSM, a full 7,025 UCAP MW annual average of unneeded and uneconomic capacity resources would be retained, including primarily gas- and oil-fired plants, as well as a small amount of demand response.

C.3. In a Region with Significant Clean Electricity Goals, Any Sensible Market Must Recognize Clean Supply While Enabling the Orderly Retirement of Fossil Plants

In a region with significant clean electricity goals, a sensible and sustainable market design would be one that supports and enables the clean energy transition. That means increasing reliance on clean energy resources to provide energy, ancillary, and capacity needs; while enabling the orderly retirement of fossil plants.

Applying BSM to policy resources will impede the State's ability to effectively transition away from carbon-emitting supply and toward a 100% clean electricity grid. It will retain existing fossil plants that would otherwise retire and defer the ability to gain operational experience in relying more heavily on clean energy resources, including non-traditional and intermittent clean energy supply.

D. Applying Buyer Side Mitigation to Policy Resources Imposes Uneconomic Excess Costs on Customers and on Society as a Whole

Applying BSM to policy resources would prevent them from clearing the market and, by removing supply, raise prices in the market. This higher price would induce more non-policy-supported resources to clear and thus support more continued investment in maintaining existing plants (and possibly developing new ones) than needed to maintain reliability. That is, the total amount of capacity available and operating would exceed the amount needed to meet the reliability objectives that the capacity market was designed to meet.

This translates into two types of adverse consequences:

- Higher prices would effectuate a wealth transfer from customers to suppliers on the entire volume of capacity transacted in the market, not just the excess resources; and
- Supporting excess capacity results in excess societal costs or deadweight loss that benefits neither customers nor suppliers (who bear the costs of maintaining the uneconomic excess supply).

The scale of these problems would grow with the scope of BSM application and will grow over time as the State proceeds toward achieving its 100% by 2040 clean electricity mandate.

D.1. Expanded BSM Would Cost Customers Approximately \$1,780 Million per Year by 2030

Imposing BSM on policy resources would impose a significant cost on New York customers. We calculated the extent of this cost for several alternative cases with Status Quo and Expanded BSM rules. The detailed assumptions and results from this analysis are included in Exhibit B. These excess costs appear in two ways: (1) as an increase in capacity prices affecting all transactions; and (2) as an increase in contract payments to policy resources because they are deprived of capacity market revenues that go instead to unnecessary substitute resources.

As summarized in Figure 5 below, we estimate costs as an increase in contract payments, plus an increase in capacity market payments, minus a small offset due to reduced energy and ancillary service (E&AS) prices. We estimate that:

- Under the Status Quo BSM rules, costs imposed on customers are currently low but will grow rapidly with the increase in policy resources, with a total cost rising to approximately \$460 million per year by 2030. We estimate a relatively modest price impact over the long term, primarily due to the offsetting impact of supply elasticity that could keep prices consistent with the costs of retaining aging fossil plants over the long term.
- An Expanded BSM would have a much more immediate effect due primarily to the application of BSM to approximately 3,100 UCAP MW of nuclear plants that earn ZECs. The customer cost of the Expanded BSM would grow over time to approximately \$1,780 million per year by 2030 as the quantity of resources subject to BSM grows. Of this total customer cost, approximately \$950 million is caused by higher capacity prices, \$840 million is caused by higher contract payments, and approximately \$10 million is offset by somewhat lower energy and ancillary service prices.

Our cost estimates account for the offsetting effects of supply elasticity that could reduce price impacts from BSM over the long term. This price mitigation would occur to the extent that excluding policy resources could cause the retention of an almost equivalent amount of replacement capacity and thus results in relatively small net price impact. (Absent supply elasticity, BSM would cause the market to clear at a much higher price along the capacity demand curve and result in much higher customer costs.) We also account for offsetting effects of reductions in the prices of energy and ancillary services due to the excess capacity on the system.



FIGURE 5: CUSTOMER COSTS FROM IMPOSING BSM ON POLICY RESOURCES BY 2030

Like any forward-looking estimate of costs, ours are subject to some uncertainty and would differ with alternative assumptions, but we view the overall magnitude to be robust and likely, conservative. Under alternative assumptions, we estimate that Status Quo BSM could cost \$400 to \$850 million per year by 2030; while expanded BSM could cost \$1,300 to \$2,750 million per year by 2030.

The robustness of our analysis is further supported by the findings of an entirely independent analysis of the same question that was previously conducted by NorthBridge Group on behalf of

Exelon. In that separate analysis, NorthBridge estimated customer costs of Status Quo BSM would begin at zero in 2021 and rise to \$950 million per year by 2025, and that customer costs from an Expanded MOPR would range over \$1,200 million to \$1,650 million per year over 2021 to 2025.³⁸ Though the assumptions, methodology, and study years in this Northbridge study differ significantly from our own, the results are relatively consistent. The customer costs of BSM are very high.

D.2. Expanded BSM Would Induce Economic Inefficiencies of Approximately \$790 Million per Year by 2030

BSM's costs to customers do not only reflect a wealth transfer to suppliers. The costs also reflect the fact that BSM induces economic waste by inducing capacity owners to make investments to attract or retain capacity resources that are not needed. As we estimated in our analysis, the vast majority of these investments are associated with retaining existing fossil plants that require substantial ongoing investments to stay in operation. For example, the gas-fired steam turbines require significant ongoing reinvestments each year to keep them in operation. In total, keeping an excess 3,050 UCAP MW of these resources online induces excess societal costs on the order of \$450 million per year by 2030 under the Status Quo BSM.³⁹

With an Expanded BSM, the economic waste is greater, growing to about \$790 million per year by 2030.⁴⁰ This cost is driven by the same effect of inducing investments to retain resources that are not needed for resource adequacy, though the effect is greater given the larger 7,025 UCAP MW scale of the uneconomic resources.

D.3. Expanded BSM Would Impose Harms to Customers that Significantly Exceed the Benefits to Capacity Sellers

Incumbent capacity sellers are the primary beneficiaries of BSM. However, the approximately \$10 million per year in net benefits that these incumbent players would enjoy from Status Quo BSM are far below the \$460 million per year increases in costs imposed on customers. In

³⁸ Aaron T. Patterson, "Impact of Carbon Pricing on Potential Expanded Buyer-Side Mitigation in the NYISO Markets," The NorthBridge Group, at pp. 6–7, November, 2019.

³⁹ This calculation of \$451 million per year in excess resource costs is based on the observation on p. 14 of Exhibit B that approximately 3,050 UCAP MW of Gas ST is retained under status quo BSM in the summer and winter capacity auctions that would economically retire with no BSM. We assume that the entirety of this retained capacity is in Zone J. The average capacity market price in Zone J is unchanged between the cases with status quo BSM and no BSM, indicating that Gas ST is the marginal resource; hence the clearing price corresponds with the going-forward cost of these resources.

⁴⁰ This calculation of \$793 million per year in excess resource costs is based on the finding shown on p. 14 of Exhibit B that an average of 7,025 UCAP MW of supply is uneconomically retained between the summer and winter capacity auctions in the case with expanded BSM relative to the case with no BSM. We have assumed that 3,050 UCAP MW of Gas ST is retained in Zone J, as in the case with Status Quo BSM; we have further assumed that all the mitigated capacity that does not clear in the summer in Zone K with expanded BSM is replaced by incumbent supply that is uneconomically retained and that the remaining retained supply is upstate (Zones A-F). Uncleared mitigated capacity in Zone K is estimated as 480 UCAP MW of mitigated storage plus about 186 UCAP MW of mitigated offshore wind, based on the total uncleared quantity of offshore wind in the summer (approximately 900 UCAP MW) times the ratio of mitigated offshore wind in Zone K to total mitigated offshore wind. The average going-forward costs of the retained supply in each zone are estimated as the average of the clearing price with no BSM and the clearing price with Expanded BSM.

Expanded BSM, the benefits to incumbent players are larger at around \$1,000 million per year, but still far below the \$1,780 million per year in costs to customers.

The reason for this discrepancy is associated with the economic waste induced by BSM as outlined in the following table. As discussed above, customer costs are increased according to the quantity effect (higher contract payments) and price effect (higher capacity market costs). The higher contract payments are earned by policy resources, making up for lost revenues from the capacity market (resulting in overall no net cost or benefit to policy resources that are subject to BSM).

Other incumbent capacity sellers enjoy significant increases in capacity revenue as driven by higher capacity prices and by gaining a greater market share. This causes approximately \$460 and \$1,790 million per year in increased capacity revenues to incumbent capacity sellers in the Status Quo and Expanded BSM cases, respectively, by 2030. This increase in revenues, however, is offset in large part by a large increase in costs that are incurred to keep uneconomic resources online. Thus, the net benefits to capacity sellers is much lower at approximately \$10 or \$1,000 million per year in the Status Quo and Expanded BSM cases, respectively.

Overall, the net benefits to incumbent capacity sellers from BSM are significantly lower than the net costs to customers. This is because a portion of the customer costs from BSM fund a wealth transfer from customers to capacity sellers (benefitting fossil generators at the expense of customers), while the remainder of customer cost increases are used to fund uneconomic investments to maintain aging fossil plants that would otherwise retire (benefitting neither customers nor generators).

TABLE 1: APPLYING BSM TO POLICY RESOURCES PRODUCES NET BENEFITS TO INCUMBENTCAPACITY SELLERS AND NET COSTS TO CONSUMERS

		Change from No BSM		
	9	Status Quo BSM Expanded BSM		
		2030 \$ millions Per Year	2030 \$ millions Per Year	
Customer Costs				
Increased Capacity Market Costs	[1]	\$25	\$949	
Increased Contract Payments	[2]	\$434	\$842	
Total Customer Cost Increase	[3]	\$458	\$1,784	
Revenues Earned by Policy Resources				
Decrease in Capacity Payments	[4]	\$434	\$842	
Increase in Contract Payments	[5]	\$434	\$842	
Net Benefits to Policy Resources	[6]	\$0	\$0	
Revenues and Costs Earned by Other Resources				
Increase in Capacity Revenues	[7]	\$459	\$1,791	
Increase in Investment and Fixed Costs	[8]	\$451	\$793	
Net Benefits to Capacity Sellers	[9]	\$8	\$998	

Sources and Notes:

[1] – [3]: From Exhibit B, p 15. Note that [3] is slightly less than the sum of [1] and [2] due to small offsets in customer costs due to lower energy and ancillary service prices.

[4] - [6]: Increase in policy resources' contract payments is equal to the decrease in capacity revenues earned by policy resources, given that contract payments are structured to capacity market payments thus keeping policy resources whole with or without BSM. Increase in contract costs in [4] can be found on p. 15 of Exhibit B.

[7]: Increase in capacity payments to non-policy resources is equal to the decrease in capacity payments to policy resources that are excluded from the capacity market (item [4]) plus the total increase in capacity market costs (item [1]).

[8]: Estimated based on Exhibit B, at 12, 14-15, as explained in footnotes 39 and 40.

[9]: Calculated as the increase in capacity revenues to non-policy resources (item [7]) minus the increase in investment and fixed costs of non-policy resources (item [8]).

E. To Continue Offering Broad Benefits to Consumers, Competitive Markets Must Align with and Support Environmental Policy Goals

Competitive wholesale electricity markets, including the NYISO capacity market, have a long history of offering significant benefits to consumers by maintaining reliability at low costs. To continue offering these benefits in the future, the markets will increasingly need to adapt to facilitate and accommodate States' clean energy mandates.

E.1. Expansion of BSM Threatens to Undermine the Future of Competitive Wholesale Electricity Markets

Far from "protecting" capacity markets from the threat of price suppression and policy resources, the application of BSM to policy resources threatens to undermine the benefits and eventually the very existence of competitive capacity markets. The application of BSM to state policy resources erodes the benefits that a competitive capacity market can offer. It imposes unnecessary excess costs on customers and society, interferes with the ability to achieve State policy goals, and effects a wealth transfer from customers to incumbent capacity sellers. These adverse economic outcomes are amplified in any region with a significant environmental policy and will rise quickly as New York proceeds toward achieving its 100% clean energy mandate.

Eventually, the scope and scale of an Expanded BSM would become so great that it would exclude the large majority of all resources from participating. At the same time, the capacity market would continue to produce the high prices that would be necessary to retain excess fossil plants consistent with a fictional scenario as though the State's 100% clean electricity policy did not exist. This outcome is nonsensical and unsustainable. Rather than force customers to endure persistent, growing, and unnecessary excess costs, state policymakers would be forced to exit the capacity market entirely. In fact, state policymakers in New York have initiated a proceeding on the future of resource adequacy in the state for this very reason.⁴¹

The solution to this problem is simple: eliminate the application of BSM on policy resources and allow prices to reflect the intersection of supply with demand.

E.2. Wholesale Electricity Markets Should Offer States and Customers Competitive Solutions for Aligning with and Achieving Environmental Policy Goals

More generally, well-designed competitive markets will greatly aid the cost-effective, reliable transition to a clean electricity grid. To preserve and expand the role of competitive markets in offering broad consumer benefits, they will increasingly need to align with and support states' environmental goals. The FERC has already acknowledged the benefits of supporting state goals through the reflection of enhanced carbon pricing within wholesale electricity markets.⁴² States, ISOs, and stakeholders will increasingly identify opportunities to enhance the markets for a decarbonized grid, such as through enhanced carbon pricing, enhanced energy and ancillary service market designs, and solutions for aligning the capacity market with state policy.⁴³ These reforms may take some time but will ultimately support the evolution of toward a fit-for-purpose wholesale market for the decarbonized grid.

⁴¹ See: NYPSC, Case Number 19-E-0530, "<u>Proceeding on Motion of the Commission to Consider Resource</u> <u>Adequacy Matters</u>."

⁴² FERC, Docket No. AD20-14-000, "Carbon Pricing in Organized Wholesale Electricity Markets," October 15, 2020.

⁴³ See Samuel A. Newell, Roger Lueken, Jürgen Weiss, Kathleen Spees, Pearl Donohoo-Vallet, Tony Lee, The Brattle Group, "Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization <u>Goals</u>," August 10, 2017; Kathleen Spees, Samuel A. Newell, Walter Graf, Emily Shorin, "<u>How States, Cities,</u> and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals: Through a Forward Market For Clean Energy Attributes Expanded Report Including A Detailed Market design Proposal," September 2019; and New York Independent System Operator (NYISO), "<u>Reliability and Market Considerations For A Grid in</u> <u>Transition</u>," December 20, 2019.

F. Certification

We hereby certify that we have read the filing signed and know its contents are true as stated to the best of our knowledge and belief. We possess full power and authority to sign this filing.

Respectfully Submitted,

Kahlungen

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November 18, 2020

Exhibit A.1: Curriculum Vitae of Dr. Kathleen Spees

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Dr. Kathleen Spees is a Principal at The Brattle Group with expertise in wholesale electricity and environmental policy design and analysis. Her work for market operators, regulators, regulated utilities, and market participants focuses on:

- Wholesale Power Market Reform
- Capacity Market Design
- Wholesale Energy and Ancillary Service Market Design
- Carbon and Environmental Policy
- Generation and Transmission Asset Valuation
- Analysis of Emerging Technologies and Specialized Products

Dr. Spees has worked in more than a dozen international jurisdictions supporting the design and enhancement of environmental policies and wholesale power markets. Her clients include electricity system operators in PJM, Midcontinent ISO, New England, Ontario, New York, Alberta, Texas, Italy, and Australia. Electricity market design assignments involve ensuring adequacy of capacity and energy market investment incentives to achieve reliability objectives at least cost; designing carbon and clean energy policies that effectively interact with wholesale electricity markets; enhancing operational reliability and efficiency through energy market, scarcity pricing, and ancillary service market improvements; effectively integrating intermittent renewables, storage, demand response, and other emerging technologies; evaluating benefits and costs of industry reform initiatives; and enhancing efficiency at market interties.

For system operators and regulators, Dr. Spees provides expert support through stakeholder forums, independent public reports, and testimony in regulatory proceedings. For utilities and market participants, her assignments support business strategy, investment decisions, asset transactions, contract negotiation, regulatory proceedings, and litigation. Dr. Spees has developed and applied a wide range of analytical and modeling tools to inform these policy, market design, and business decisions.

Dr. Spees earned her PhD in Engineering and Public Policy within the Carnegie Mellon Electricity Industry Center in 2008 and her MS in Electrical and Computer Engineering from Carnegie Mellon University in 2007. She earned her BS in Physics and Mechanical Engineering from Iowa State University in 2005.

Publications posted at: <u>http://www.brattle.com/experts/kathleen-spees</u>

I. REPRESENTATIVE EXPERIENCE

A. WHOLESALE POWER MARKET REFORM

• Ontario Market Renewal Benefits Case. For the Ontario Independent Electricity System Operator (IESO), developed an analysis evaluating the benefits and implementation costs associated with fundamental reforms to wholesale power markets, including implementing nodal pricing, a day-ahead energy market, enhanced intra-day unit commitment, operability reforms, an enhanced intertie design, and a capacity market. Analysis included: (a) market visioning sessions with IESO staff and stakeholders to identify future market design requirements; (b) identify primary drivers and quantify system efficiency benefits; (c) review lessons learned from other markets' reforms to

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identify opportunities and reform risks; (d) conduct a bottom-up analysis of implementation costs for replacing market systems; and (e) evaluate interactions with existing supply contracts.

- MISO Market Development Vision. For the Midcontinent Independent System Operator (MISO), worked with staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next 2-5 years. Authored a foundational report for that Vision, including: describing the core services MISO must continue to provide to support a well-functioning market; establishing a set of principles for enhancing those services; identifying seven Focus Areas offering the greatest opportunities for improving MISO's electricity market; and proposing criteria for prioritizing initiatives within and across Focus Areas.
- Australia NEM Electricity Market Vision for Enabling Innovation and Clean Energy. On behalf of the Australian Energy Market Operator reviewed electricity market design options for the future of the NEM. Evaluated opportunities for relying on markets, innovation, and new technologies to address a range of challenges in the context of significant increases in customer costs, high gas prices, large clean energy penetration, coal retirements, uncertain carbon policies, and emerging reliability and security concerns.
- Thailand Power Market Reform. Supported market design options and recommendations for potential power market reforms in Thailand, including the introduction of forward, day-ahead, and real-time energy markets, as well as the potential introduction of a bilateral or centralized capacity market. Examined interactions with retail rates, existing contracts, and self-supply arrangements.
- Power Market Reform to Accommodate Decarbonization and Clean Energy Policies. For the system operator in a jurisdiction pursuing significant clean energy and decarbonization policies, assisted in evaluating market design alternatives. Estimated energy price, customer cost, and reliability implications under alternative energy, ancillary service, and capacity market design scenarios. Quantified implications of key uncertainties such as intermittent resource penetration levels and impacts of interties with external regions. Provided research and comparative analysis of design alternatives and lessons learned from other jurisdictions.
- Western Australia Power Market Reform Options. For EnerNOC, developed a whitepaper describing high-level market reform options in the face of escalating customer costs in Western Australia. Described the drivers of capacity payment costs in comparison to other major cost driver. Identified high-level options for pursuing capacity and energy-only market design reforms, comparing advantages and disadvantages.
- Russian Capacity and Natural Gas Market Liberalization. On behalf of a market participant, conducted an assessment of market design, regulatory uncertainty, and

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liberalization success. Focus was on the efficiency of market design rules in the newly introduced system of capacity contracts combined with capacity payments, as well as on the impacts of gas price liberalization delays.

- PJM Review of International Energy-Only, Capacity Market, and Capacity Payment Mechanisms. For PJM Interconnection, conducted a review of energy-only markets, capacity payment systems, and capacity markets on behalf of PJM market operator. Reviewed reliability, volatility, and overall investment outcomes related to details of market designs in bilateral, centralized, and forward commitment markets.
- Options for Reconciling Regulated Planning and Wholesale Power Markets in in MISO. For NRG, developed a whitepaper assessing reliability and economic implications of current capacity market and integrated planning approaches, and the challenges in accommodating retail access and integrated planning within the same market region. Recommended options for enhancing the MISO capacity market and regulated entities' approaches to planning.
- Review of California Planning and Market Mechanisms for Resource Adequacy. For Calpine, evaluated interactions and implications of California's policy, planning, and market mechanisms affecting resource adequacy. Recommended improvements to reconcile inconsistencies and enhance efficiencies in regulated long-term procurements, short term local resource adequacy construct, and CAISO backstop mechanisms.

B. CAPACITY MARKET DESIGN

- PJM Review of Capacity Market Design and Demand Curve Parameters: 2011, 2014, and 2018. For PJM Interconnection, conducted independent periodic reviews of PJM's Reliability Pricing Model. Analyzed market functioning for resource adequacy including uncertainty and volatility of prices, net cost of new entry parameters, impacts of administrative parameters and regulatory uncertainties, locational mechanisms, demand curve shape, incremental auction procedures, and other market mechanisms. Developed a probabilistic simulation model evaluating the price volatility and reliability implications of alternative demand curve shapes and recommended a revised demand curve shape. Provided expert support to stakeholder proceedings, testimony submitted before the Federal Energy Regulatory Commission, and before the Maryland Public Service Commission.
- **MISO Resource Adequacy Construct.** For MISO, conducted a review of MISO's resource adequacy construct. Subsequent assistance to MISO in enhancing the market design for resource adequacy related to market redesign, capacity market seams, and accommodation of both regulated and restructured states. Provided background presentations to stakeholders on the capacity market design provisions of NYISO, PJM, CAISO, and ISO-NE.
- Alberta Energy-Only Market Review for Long-Term Sustainability: 2011 and 2013 Update. For AESO, conducted a review of the ability of the energy-only market to

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attract and retain sufficient levels of capacity for long-term resource adequacy. Evaluation of the outlook for revenue sufficiency under forecasted carbon, gas, and electric prices, potential impact of environmentally-driven retirements, potential federal coal retirement mandate, and provincial energy policies.

- Economic Implications of Resource Adequacy Requirements. For the U.S. Federal Energy Regulatory Commission, reviewed economic and reliability implications of resource adequacy requirements based on traditional reliability criteria as well as alternative standards based on economic criteria. Evaluated total system costs, customer costs, supplier net revenues, and demand response implications under a range of reserve margins as well as under different energy-only and capacity market designs.
- Winter Resource Adequacy and Reliability. For an RTO, analyzed the risk of winter reliability and resource adequacy shortages. Examined the drivers of winter reliability concerns including unavailability of specific resource types, winter fuel supply shortages, and weather-driven outages. Developed a range of potential reforms for addressing identified concerns.
- Alberta Capacity Market Design. Supported the development of a capacity market design in Alberta. Provided expert support to public working groups and AESO staff to review analytical questions, develop and evaluate design alternatives, and draft design documents. Supported on all aspects of market design including establishing reliability requirements, developing demand curve parameters, evaluating seasonal capacity resources, setting capacity ratings, product definition and obligations, and penalty mechanisms.
- European Market Flexibility and Capacity Auction Design. For European client, developed a market-based design for meeting flexible and traditional capacity needs in the context of high levels of intermittent resource penetration, degraded energy and ancillary pricing signals, and ongoing electricity market reforms. Engaged in meetings with industry and European Commission staff to develop and refine design options. Developed a model simulating market clearing results in a two-product auction and projecting prices over time.
- Italian Capacity Market Design. For Italy's transmission system operator Terna, supported development of a locational capacity market design and locational capacity demand curves based on simulation modeling on the value of capacity to customers.
- **Capacity Auction Design for Western Australia**. For Western Australia's Public Utility Office, drafted a whitepaper and advised on the design of its new capacity auction mechanism.
- **IESO Capacity Auction Design.** Provided expert support to IESO staff in support of a new capacity auction design. Provided detailed memos describing options, tradeoffs, and lessons learned on every aspect of capacity auction design. Supported stakeholder engagement, conducted analysis of design alternatives, and developed design proposals.

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- **PJM Seasonal Capacity Market Design.** For the Natural Resources Defense Council, provided testimony and economic analysis in support of improving the capacity market design to better accommodate seasonal capacity resources.
- ISO New England Capacity Demand Curve. For ISO New England, worked with RTO staff and stakeholders to develop a selection of capacity demand curves and evaluate them for their efficiency and reliability performance. Began with a review of lessons learned from other market and an assessment of different potential design objectives. Developed and implemented a statistical simulation model to evaluate probabilistic reliability, price, and reserve margin outcomes in a locational capacity market context under different candidate demand curve shapes. Submitted Testimony before the Federal Energy Regulatory Commission supporting a proposed system-wide demand curve, with ongoing support to develop locational demand curves for individual capacity zones.
- MISO-PJM Capacity Market Seams Analysis. For MISO, evaluated barriers to capacity trade with neighboring capacity markets, including mechanisms for assigning and transferring firm transmission rights and cross-border must-offer requirements. Evaluated economic impacts of addressing the barriers and identified design alternatives for enabling capacity trade.
- **MISO Competitive Retail Choice Solution.** For MISO, evaluated design alternatives for accommodating the differing needs of states relying on competitive retail choice and integrated resource planning. Conducted probabilistic simulations of likely market results under alternative market designs and demand curves. Provided expert support in stakeholder forums and submitted expert testimony before the Federal Energy Regulatory Commission.
- **Capacity Market Manipulation.** For a market participant, supported economic and policy analysis of an alleged instance of capacity market withholding.
- **Demand Curve and Net Cost of New Entry Review.** For an RTO, provided a high-level conceptual review of its approach to establishing demand curve and net cost of new entry parameters. Identified potential reliability and economic efficiency concerns, and recommended enhancements.
- Western Australia Reserve Capacity Mechanism and Transition Mechanism. For EnerNOC, authored two public reports related to the energy market reforms in Western Australia. The first report evaluated the characteristics of the Western Australia Reserve Capacity Mechanism in comparison with international best practices and made recommendations for improvements, whether pursuing a capacity market or energy-only market design.

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• Cost of New Entry Study to Determine PJM Auction Parameters: 2011 and 2014. For PJM Interconnection, partnered with engineering, procurement, and construction firm to develop bottom-up cost estimates for building new gas combined cycles and combustion turbines. Affidavit before the Federal Energy Regulatory Commission and participation in settlement discussions on the same.

C. WHOLESALE ENERGY AND ANCILLARY SERVICE MARKET DESIGN

- Greece Energy and Ancillary Service Market Reform. For the Hellenic Association of Independent Power Producers, provided expert advice and a report on how to reform wholesale power markets to conform with policy mandates and meet system flexibility needs. Analyzed energy and ancillary market pricing and rules to identify opportunities to enhance efficiency, improve participation of emerging resources, achieve market coupling, and better integrate intermittent resources. Proposed high-level design recommendations for implementing forward, day-ahead, intraday, and balancing markets consistent with European Target Model requirements. Developed detailed design recommendations for near-term and long term enhancements to market operations, pricing, dispatch, and settlements. Provided expert support in meetings with European Commission staff.
- Alberta Energy and Ancillary Service Market Enhancements. Supported the development of market design enhancements to better support flexibility needs and align with capacity market implementation. Developed design proposals and evaluated alternatives for immediate and long-term reforms including monitoring and mitigation, enhanced administrative scarcity pricing, ancillary service co-optimization, day-ahead markets,
- **SPP Ramp Product Proposal.** For Golden Spread Electric Cooperative, developed recommendations for the design and implementation of a ramping product to most efficiently and cost-effectively manage intermittency needs. Reviewed opportunities to determine the most appropriate quantity of resources, forward product timeframe, price formation, and interactions with existing pricing and commitment procedures.
- ERCOT Energy Market Design and Investment Incentives Review. For the Electric Reliability Council of Texas (ERCOT), conducted a study to: (a) characterize the factors influencing generation investment decisions; (b) evaluate the energy market's ability to support investment and resource adequacy at the target level; (c) examine efficiency of pricing and incentives for energy and ancillary services, focusing on scarcity events; and (d) evaluate options to enhance long-term resource adequacy while maintaining market efficiency. Performed forward-looking simulation analyses of prices, investment costs, and reliability. Interviewed a broad spectrum of stakeholders; worked with ERCOT staff to understand the relevant aspects of their planning process, operations, and market data. Supported ongoing proceedings with stakeholders and before the Public Utility Commission of Texas.

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- Scarcity and Surplus Event Pricing. For an RTO, examined the efficiency and reliability implications of its pricing mechanisms during scarcity and surplus events, and evaluated potential market reforms. Options reviewed included adjusting the price cap consistent with the value of lost load, adjusting supplier offer caps, imposing administrative scarcity prices at varying levels of emergency events, ancillary service market pricing interactions, and reducing the price floor below zero.
- MISO Wind Curtailment Interactions with Energy Market Pricing and Transmission Interconnection Processes. For MISO, evaluated the efficiency and equity implications of wind curtailment prioritization mechanisms and options for addressing stakeholder concerns, including interconnection agreement types, energy and capacity injection rights, ARR/FTR allocation mechanisms, energy market offers, and market participant hedging needs.
- Survey of Energy Market Seams. For the Alberta Electric System Operator (AESO), assessed the implications of energy market seams inefficiencies between power markets in Canada, the U.S., and Europe for the Alberta Electric System Operator. Evaluation of options for improving seams based on other markets' experiences with inter-regional transmission upgrades, energy market scheduling and dispatch, transmission rights models, and resource adequacy.
- New England Fuel Security Market Design. For NextEra, developed design proposals for using market-based mechanisms to meet regional fuel security needs including through a fuel security reserve product that would enhance pricing and operations for fuel security in the energy and ancillary service markets, and options for a long-term solution through forward auctions for fuel security.
- **Reliability Auctions for the NEM.** For the Australian Electricity Market Operator conducted an international review of the range of approaches to supporting reliability and system security through competitive auctions. Focused on product definition including, various aspects of reliability and system security, auctions focused on enabling non-traditional resource types, options ranging from strategic reserve models to partial needs procurements to capacity markets, and potential for impacts on energy-only market pricing and performance.
- ERCOT Operating Reserves Demand Curve and Economically Optimal Reserve Margin 2014 and 2018. For the Public Utility Commission of Texas and ERCOT, co-authored a report estimating the economically-optimal reserve margin. Compared to various reliability-based reserve margins, and evaluated the cost and uncertainty of energy-only and a potential capacity market in ERCOT. Conducted the study in collaboration with Astrape Consulting to construct a series of economic and reliability modeling simulations that account for uncertain weather patterns, generation and transmission outages, and multi-year load forecasting errors. The simulations also incorporate detailed representation of the Texas power market, including intermittent wind and solar generation, operating reserves, different types of demand response, the full range
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of emergency procedures (such as operating reserve deletion), scarcity pricing provisions, and load-shed events.

• Southern Company Independent Auction Monitor. For Southern Company, developed auction monitoring capability and protocol development for monitoring hourly and daily auctions. Supported functions included daily and annual audits of internal company processes and data inputs related to load forecasting, purchases and sales, and outage declarations. Analyzed company data to develop monitoring protocols and automated tools. Coordinated implementation of data collection and aggregation system required for market oversight and for detailed internal company data audits.

D. CARBON AND ENVIRONMENTAL POLICY

- Integrating Markets and Public Policy in New England. For a coalition of stakeholders, engaged in a collaborative effort to develop market-based approaches for accommodating and achieving state decarbonization objectives. Developed and refined design proposals including carbon pricing and market-based clean energy procurements, while identifying options for reducing regulatory uncertainties, avoiding cross subsidies across states, and mitigating customer cost impacts. Evaluated options for improving interactions with existing energy, capacity, renewable energy credit, and carbon markets. Conducted modeling of price, cost, and emissions outcomes under a range of designs. Engaged in an iterative process to develop, present, and refine design proposals based on input from a broad array of stakeholders. Provided expert support in outreach to state policymakers and industry groups.
- Ontario Market Evolution to Support a 90% Clean Energy System and Increasing Distributed Resources. For the IESO, supported the activities of the non-emitting stakeholder committee to model market reforms necessary to fully enable the 90% clean energy fleet. Supported stakeholder workshops to identify potential futures with many more distributed resources, a range of technology costs, and a variety of market designs. Conducted modeling analysis to analyze market outcomes including cost, reliability, resource curtailment, and resource revenues.
- National Carbon Policy Design and Interactions with Power Markets. For an international regulator, analyzed a range of options for the design of a carbon policy for the electricity sector, considering impacts on the wholesale electricity market and interactions with other sectors. Analyzed a range of alternatives for intensity-based and cap-and-trade based approaches, alternative allocations methods, and interactions with renewables standards. Developed two detailed design alternatives within the specified policy constraints.
- **Review of International Carbon Mechanisms.** For an RTO, conducted a survey of international carbon pricing, cap-and-trade, and rate-based mechanisms, and detailed review of design elements of the mechanisms implemented in Europe, California, Alberta, and the Regional Greenhouse Gas Initiative. Evaluated a range of alternatives

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for implementing the Clean Power Plan across states while effectively integrating with wholesale markets.

- New York ISO Carbon Pricing. For the New York ISO, examined economic implications of a possible carbon pricing proposal within the wholesale electricity market. Developed a whitepaper evaluating interactions with state environmental policies, wholesale power markets, intertie pricing, capacity market, and transmission planning. Estimated energy price and customer cost impacts.
- **Carbon Allowance Allocations Alternatives.** For the National Resources Defense Council, developed a whitepaper examining the advantages and disadvantages of auction-based, customer-based, and generator-based approaches to allocating carbon allowances. Developed recommendations for avoiding the introduction of inefficient investment, retirement, and operational incentives under each type of design, and for mitigating customer cost impacts.
- **Power Market Impacts of Clean Power Plan Alternatives.** Conducted a modeling assessment of price, cost, and emissions implications of different rate-based, subcategory rate-based, and mass-based implementation of the Clean Power Plan in Texas. Estimated energy, emission reduction credit, and carbon prices under each scenario, and net revenue and operating implications for several types of generating plants.
- Review of Hydropower Industry Implications under Clean Air Act 111(d). For the National Hydropower Association, provided members review of the implications for new and existing hydropower resources of proposed EPA Clean Power Plan under Clean Air Act Section 111(d). Analyzed impacts under a variety of potential revisions to the proposed rule, different potential state compliance options, differing plan regulatory statuses, mass-based vs. rate-based compliance, regulated planning vs. market-based compliance, and cooperative vs. stand-alone compliance.
- Enabling Canadian Imports for U.S. Clean Energy Policies. For a coalition of Canadian electricity producers and policymakers, reviewed a range of options for U.S. states to pursue clean energy policies and the Clean Power Plan while enabling contributions from clean energy imports.
- Clean Power Plan Regulatory and Stakeholder Support. For a cooperative entity, provided support in developing internal and external positioning associated with the Clean Power Plan. Analyzed state-wide emissions targets and compliance alternatives. Supported messaging and stakeholder engagement at the state and federal levels. Submitted testimony before the Environmental Protection Agency.
- State Compliance Strategy under the Clean Power Plan. For a regulated utility, evaluated options and feasibility of meeting state standards under 111(d) rate standards under a number of compliance scenarios. Developed an hourly dispatch model covering backcast and forecast years through the interim and final compliance timelines, accounting for impacts of load growth, renewables growth, coal-to-gas redispatch, coal

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minimum dispatch constraints, planned retirements, new generation development, and export commitments. Estimated the ability to meet the standard under various compliance strategies.

- New Gas Combined Cycle Plants Under the Clean Power Plan. For the National Resources Defense Council, developed a whitepaper evaluating the economic implications of Clean Power Plan implementation plans that do or do not cover gas combined cycle plants on a level basis with other fossil-emitting plants. Conducted simulation analyses comparing the economic and emissions implications of alternative approaches.
- **MISO Coal Retrofit Supply Chain Analysis.** For the MISO, analyzed the fleet-wide requirements for retrofitting plants to upgrade for the Mercury and Air Toxics Standard. Reviewed the upstream engineering services, procurement, and construction supply chain to evaluate the ability to upgrade the fleet within the available time window. Analyzed the potential for operational and reliability concerns from simultaneous planned outages needed to support fleet-wide retrofit requirements in the MISO footprint.
- Impact of Environmental Policies on Coal Plant Retirement. For a PJM market participant, conducted a zone-level analysis of PJM market prices and used unit-level data to conduct a virtual dispatch of coal units under a series of long-term capacity, fuel, and carbon price scenarios. Modeled retirement decisions of plants by PJM zone and the effect of the carbon price on the location and aggregate size of these retirement decisions.

E. GENERATION AND TRANSMISSION ASSET VALUATION

- Generation and Transmission Asset Valuations (Multiple Clients). For multiple clients, top-line operating cost and revenues estimation for generation and transmission assets in PJM, ISO-NE, MISO, SPP, and ERCOT; experience with a range of asset types including gas CCs, gas CTs, coal, wind, waste-to-energy, cogeneration, and HVDC lines. Evaluation exercises include forecasting market prices and net revenues from energy, capacity, ancillary service, and (if applicable) renewable energy credit markets. Valuations account for the operational impacts and economic value of existing power purchase agreements and other hedges. Clients typically require qualitative and quantitative analysis of regulatory risks under a range of operational and market scenarios. Valuation efforts often conducted in the context of due diligence for transactions, business decisions, and contract negotiations.
- Executive Education and Investment Opportunities Surveys (Multiple Clients). For multiple clients, provided executive education and detailed survey material to support investments in new markets and strategic decision-making. Educational efforts provided over a range of levels including high-level executive sessions, all-day workshop sessions, and detailed support for analytical teams. Examples of subject matter include: (a) cross-market surveys comparing investment attractiveness in many dimensions based

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on market fundamentals, regulatory structure, and contracting opportunities; and (b) single-market deep-dive educational sessions on capacity, energy, ancillary service, and financial/hedging product functioning and market performance.

- In-House Fundamentals Capability Development (Multiple Clients). For multiple clients, supported the development of in-house capability for market fundamentals analysis. Typically needed in the context of new entrants to a market or system operators expanding the scope of their internal analytical capabilities. Scope of support has included: (a) initial education, backup support, and advisory support for fundamentals teams entering a new market; (b) development and transfer of new purpose-built modeling tools such as capacity market models; and (c) external peer review or independent assessment functions.
- Asset or Fleet Valuation in Support of Litigation and Arbitration Proceedings (Multiple Clients). In litigation and arbitration contexts, provided estimates of economic damages or asset/fleet value estimates that would have applied at the time of a particular business decision. Supported expert testimony, litigation workpapers, and assessment of opposing experts' analysis.
- Economic Analysis of Plant Retrofit and Fuel Contracting Decisions (Multiple Clients). Supported plant operational and investment decisions for enhancing the value of particular assets, including contexts such as: (a) retrofitting plants from oil to gas generation; (b) retrofitting single-cycle to combined cycle with different capacities for duct firing; (c) enhancing ancillary service capability; and (d) and contracting for firm gas capability. Evaluated operational, cost, and revenue impacts of alternatives and compared to present investment costs.
- Financial Implications of Regulatory, Policy, and Market Design Changes (Multiple Clients). Conducted analyses of risks and opportunities associated with regulatory, policy, and market design changes. Examples include an analysis of potential Trump administration policies, implications of potential clean energy and carbon policies, and assessing private risks from changes to ancillary service market rules.

F. EMERGING TECHNOLOGIES AND SPECIALIZED PRODUCTS

• RTO Business Models Analysis for Enabling Customer-Side Disruption and the Clean Energy Future. For a system operator, engaged in an executive strategy analysis to evaluate a range of electricity sector business models under a future with high penetrations of distributed resources and decarbonization. Developed detailed scenario descriptions of the business models envisioned considering different roles and scope of services provided by the RTO, distribution companies, load serving entities, and third-party aggregators. Created an interactive tool for mapping financial flows and energy flows at all points in the electricity value chain under each business model considered, and drew implications for value proposition of each segment of the market.

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- Enabling Market Participation from Non-Emitting and Emerging Technologies. For an Ontario stakeholder group, provided expert support to identify market design enhancements to enable and integrate non-emitting and emerging technologies. Examined participation barriers and design enhancements to unlock full value of resources for supporting energy, flexibility, capacity, and other value streams to the province.
- International Review of Demand Response Integration into Wholesale Electricity Markets. For the Australian Energy Market Commission, authored a report describing the range of approaches and market experience integrated demand response into wholesale energy, ancillary service, and capacity markets. Provided detailed discussion of approaches in Singapore, Alberta, ERCOT, PJM, ISO New England, and Ontario. Summarized lessons learned regarding demand response business models, efficient wholesale pricing signals, and interactions with retail markets.
- Oncor Value of Distributed Storage. For Oncor Electric Delivery Company, conducted a benefit-cost analysis of adding varying levels of distributed storage into the ERCOT market. Value streams considered including market values such as energy and ancillary services, as well as regulated system values including deferred transmission and distribution costs, and avoiding distribution outages. Evaluated value from the perspectives of customers, a merchant storage developer, and society as a whole, as well as evaluating impacts on incumbent suppliers.
- Oncor Distributed Storage Business Models to Supply Customer, Distribution System, and Wholesale Value Streams. For Oncor Electric Delivery Company, conducted a <u>benefit-cost analysis</u> of adding varying levels of distributed storage into the Texas market. Recommended policy changes to enable storage under a range of business models (merchant, utility-owned, customer-owned, and third-party owned), and to allow for the development of resources that could provide multiple value streams. Value streams considered including market values such as energy and ancillary services, distribution-system values including deferred transmission and distribution costs, and customer value streams including avoiding distribution outages. Evaluated value from the perspectives of customers, a merchant storage developer, and society as a whole, as well as evaluating impacts on incumbent suppliers.
- Risk and Financial Analysis of PJM Capacity Performance Product. For a market participant, conducted a probabilistic assessment of the expected value, upside, and downside risks (both market-wide and private) associated with PJM's capacity performance product. Evaluated the likely frequency of scarcity events on average and as concentrated in particular years to estimate the expected value of bonus payments if operating as an energy-only asset, and the net potential bonus/penalty if operating as a capacity performance resource. Estimated risk-neutral and risk-averse capacity price offer levels; characterized the magnitude of risk exposure of poor asset performance coincided with system scarcity events.

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- **Demand Response Auction Design**. For a system operator, assisted in the high-level and detailed designs of a demand response auction. Supported market rule development, auction clearing optimization specification, and quality control testing of auction clearing engine.
- Hedging Products for Wind. For a hedge fund, provided analytical support for the development of a hedging product for wind developers. Evaluated the risk exposure based on day-ahead and real-time participation, locational price differentials, profile and curtailment risks, and discrepancies with exchange-traded hedging products.
- **Tariff Design for Merchant Transmission Upgrades.** For a transmission developer, evaluated tariff design options for capturing market value of wind and transmission for a market participant proposing a large HVDC upgrade to enable wind developments.
- Magnitude and Potential Impact of "Missing Efficiency" in PJM. For the Natural Resources Defense Council, analyzed the potential magnitude of energy efficiency programs in PJM that are not accounted for on either demand side (through load forecast adjustments) or on the supply side (in the capacity market). Estimated potential energy and capacity market customer cost impacts in both the short-run and long-run if adjusting the load forecast to account for the missing efficiency.
- Financial Transmission Right and Virtual Bidding Market Manipulation Litigation for PJM. For PJM Interconnection, analyzed financial transmission rights, energy market, and virtual trading data for expert testimony regarding market manipulation behavior.
- Wind and Storage. For a developer of potential storage assets, simulation analysis modeling combined effects of gas dispatch, wind variability, load variability, and minimum generation conditions to determine the value of electric storage under various levels of wind penetration. Conducted portfolio analysis to determine the optimal level of storage on a systems level to minimize cost as a function of wind penetration levels.
- Market Reforms to Meet Emerging Flexibility Needs. For the Natural Resources Defense Council, authored a report on the electricity market reforms needed in the context of declining needs for baseload resources, increasing levels of intermittent supply, and increasing needs for flexible resources.

II. REPRESENTATIVE PUBLICATIONS

A. PAPERS AND REPORTS

- Brown, Toby, Neil Lessem, Roger Lueken, Kathleen Spees, and Cathy Wang. *High-Impact, Low-Probability Events and the Framework for Reliability in the National Electricity Market.* Prepared for the Australian Energy Market Commission, February 2019.
- Newell, Samuel A., Ariel Kaluzhny, Kathleen Spees, Kevin Carden, Nick Wintermantel, Alex Krasny, and Rebecca Carroll. *Estimation of the Market Equilibrium and Economically Optimal*

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Reserve Margins for the ERCOT Region. Prepared for the Electric Reliability Council of Texas, Inc. December 20, 2018.

- Spees, Kathleen. An Economic Perspective on Reliability: Rethinking System Needs and in a Future Dominated by Renewables, New Tech, and Engaged Consumers. Presented at the Electricity Consumers Resource Council. November 28, 2018.
- Spees, Kathleen. *The Cutting Edge in Resource Planning*. Presented to the Solar Energy Industries Association. November 12, 2018.
- Spees, Kathleen. *Clean Energy Markets: The "Missing Link" to Market Design 3.0.* Presented to the Harvard Electricity Policy Group. October 4, 2018.
- Pfeifenberger, Johannes P., Kathleen Spees, Michael Hagerty, Mike Tolleth, Martha Caulkins, Emily Shorin, Sang H. Gang, Patrick S. Daou, and John Wroble. AESO Cost of New Entry Analysis: Combustion Turbines and Combined-Cycle Plants with November 1, 2021 Online Date. Prepared for Alberta Electric System Operator. September 4, 2018.
- Pfeifenberger, Johannes P., John Tsoukalis, Judy Chang, and Kathleen Spees. *Initial Comments on SPP's Draft Ramp Product Report*. August 30, 2018.
- Spees, Kathleen, Johannes P. Pfeifenberger, Samuel A. Newell, and Judy Chang. *Harmonizing Environmental Policies with Competitive Markets: Using Wholesale Power Markets to Meet State and Customer Demand for a Cleaner Electricity Grid More Cost Effectively.* July 30, 2018.
- Newell, Samuel A., David Luke Oates, Johannes P. Pfeifenberger, Kathleen Spees, Michael Hagerty, John Imon Pedtke, Matthew Witkin, and Emily Shorin. *Fourth Review of PJM's Variable Resource Requirement Curve.* April 19, 2018.
- Newell, Samuel A., Kathleen Spees, Yingxia Yang, Elliott Metzler, and John Imon-Pedtke. *Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM.* April 12, 2018.
- Spees, Kathleen, Samuel A Newell, David Luke Oates, Toby Brown, Neil Lessem, Daniel Jang, and John Imon Pedtke. *Near Term Reliability Auctions in the NEM: Lessons from International Jurisdictions.* Prepared for the Australian Energy Market Operator, August 23, 2017.
- Newell, Samuel A., Roger Lueken, Jürgen Weiss, Kathleen Spees, Pearl Donohoo-Vallett, and Tony Lee. *Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals.* Prepared for the New York Independent System Operator. August 10, 2017.
- Newell, Samuel A., Johannes P. Pfeifenberger, Judy Chang, and Kathleen Spees. "How Wholesale Power Markets and State Environmental Policies Can Work Together," *Utility Dive*, July 10, 2017.
- Chang, Judy, Mariko Geronimo Aydin, Johannes P. Pfeifenberger, Kathleen Spees, and John Imon Pedtke. *Advancing Past "Baseload" to a Flexible Grid: How Grid Planners and Power Markets*

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are Better Defining System Needs to Achieve a Cost-Effective and Reliable Supply Mix. Prepared for the Natural Resources Defense Council. June 26, 2017.

- Pfeifenberger, Johannes P., Kathleen Spees, Judy Chang, Walter Graf, and Mariko Geronimo Aydin. "Reforming Ontario's Wholesale Electricity Market: The Costs and Benefits," *Energy Regulation Quarterly*, Volume 5, Issue 2. June 2017.
- Spees, Kathleen, Yingxia Yang, and Yeray Perez. *Energy and Ancillary Services Market Reforms in Greece: A Path to Enhancing Flexibility and Adopting the European Target Model.* Prepared for the Hellenic Association of Independent Power Producers (HAIPP). May 2017.
- Pfeifenberger, Johannes, Kathleen Spees, Judy Chang, Mariko Geronimo Aydin, Walter Graf Peter Cahill, James Mashal, John Imon Pedtke. *The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project.* Prepared on behalf of the Independent Electricity System Operator. Draft Report March 3, 2017.
- Chang, Judy, Kathleen Spees, and Tony Lee. *CO*₂ *Allowance Allocation Options: Considerations for Policymakers when Developing Mass-Based Compliance Strategies Under the Clean Power Plan.* Prepared on behalf of the National Resources Defense Council. November 2016.
- Chang, Judy, Kathleen Spees, Metin Celebi, and Tony Lee. *Covering New Gas-Fired Combined Cycle Plants under the Clean Power Plan: Implications for Economic Efficiency and Wholesale Electricity Markets.* Prepared on behalf of the Natural Resources Defense Council. November 2016.
- Chang, Judy, Kathleen Spees, and Pearl Donohoo-Vallett. *Enabling Canadian Electricity Imports for Clean Power Plan Compliance: Technical Guidance for U.S. State Policymakers.* Prepared on behalf of the Canadian Electricity Association, Canadian Hydropower Association, Canadian Wind Energy Association, Emera Incorporated, Government of Canada, Government of Québec, Manitoba Hydro, Nalcor Energy, and Powerex Corporation. June 2016.
- Pfeifenberger, Johannes P., Samuel A. Newell, Kathleen Spees, and Roger Lueken. "Open Letter to GAO: Response to U.S. Senators' Capacity Market Questions." Submitted to the U.S. Government Accountability Office. May 5, 2016.
- Spees, Kathleen, Samuel A. Newell, and Colin A. McIntyre. *Western Australia's Transition to Competitive Capacity Auction*. Prepared on behalf of EnerNOC. January 29, 2016.
- Chupka, Metin Celebi, Judy Chang, Ira H. Shavel, Kathleen Spees, Jürgen Weiss, Pearl Donohoo-Vallett, Michael Hagerty, and Michael A. Kline. *The Clean Power Plan: Focus on Implementation and Compliance*. Published by The Brattle Group, Inc. January 2016.
- Newell, Samuel A., Kathleen Spees, and Roger Lueken. *Enhancing the Efficiency of Resource Adequacy Planning and Procurements in the Midcontinent ISO Footprint: Options for MISO, Utilities and States.* Prepared on behalf of NRG. November 2015.

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Demand Response Mechanisms. Prepared for the Australian Energy Market Commission. October 2015.

- Spees, Kathleen, Judy Chang, Johannes P. Pfeifenberger, Matthew K. Davis, Ioanna Karkatsouli, James Mashal, and Lauren Regan. *The Value of Distributed Electricity Storage in Texas Proposed Policy for Enabling Grid-Integrated Storage Investments*. Prepared on behalf of Oncor. March 2015.
- Spees, Kathleen and Samuel A. Newell. *Resource Adequacy in Western Australia: Alternatives to the Reserve Capacity Mechanism.* Prepared on behalf of EnerNOC. August 2014.
- Faruqui, Ahmad, Sanem Sergici, and Kathleen Spees. *Quantifying the Amount and Economic Impacts of Missing Energy Efficiency in PJM's Load Forecast.* Prepared on behalf of the Sustainable FERC Project. September 2014.
- Graves, Frank, and Kathleen Spees. "How will the EPA's Clean Power Plan Impact Renewables?" *North American Windpower*. July 2014.
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- Pfeifenberger, Johannes P., Samuel A. Newell, Kathleen Spees, Ann Murray, and Ioanna Karkatsouli. *Third Triennial Review of PJM's Variable Resource Requirement Curve*. May 15, 2014.
- Newell, Samuel A., Michael Hagerty, Kathleen Spees, Johannes P. Pfeifenberger, Quincy Liao, Christopher D. Ungate, and John Wroble. *Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM*. May 15, 2014.
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- Newell, Samuel A., and Kathleen Spees. *Developing a Market Vision for MISO: Supporting a Reliable and Efficient Electricity System in the Midcontinent*. January 27, 2014.
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California: Options for Improving Efficiency and Effectiveness. Prepared for Calpine. October 2012.

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- Pfeifenberger, Johannes, Kathleen Spees, Attila Hajos, Delphine Hou, and Dan Harris. *Alberta's Intertie Challenges: A Survey of Market Design Options for Seams Between Power Markets.* Prepared for the Alberta Electric System Operator.
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- Spees, Kathleen, and Lester Lave. "Do RTOs Promote Renewables? A Study of State-Level Data over Time." Working Paper CEIC-07-14.
- Spees, Kathleen, and Lester Lave. "Impacts of Responsive Load in PJM: Load Shifting and Real Time Pricing." 2007. *The Energy Journal*. Vol. 29, No. 2. 2008.
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B. TESTIMONY

- Newell, Samuel A., Kathleen Spees, and David Luke Oates. Response on Behalf of Midcontinent Independent System Operator (MISO) regarding the Competitive Retail Solution. Docket No. ER17-284-000. January 13, 2017.
- Newell, Samuel A., Kathleen Spees, and David Luke Oates. Testimony on Behalf of Midcontinent Independent System Operator (MISO) regarding the Competitive Retail Solution. Docket No. ER17-284-000. November 1, 2016.
- Chang, Judy, Kathleen Spees, and David Luke Oates, Comments on the Clean Power Plan Federal Implementation Plan Proposal Sponsored by Wolverine Power Supply Cooperative, Inc. Before the Environmental Protection Agency, Docket No. EPA-HQ-OAR-2015-0199. January 21, 2016.
- Newell, Samuel A. and Kathleen Spees. Affidavit on Behalf of PJM Interconnection, LLC Regarding Variable Resource Requirement Curve, for Use in PJM's Capacity Market, Before the Federal Energy Regulatory Commission, Docket ER14-2940-000. November 5, 2014.
- Newell, Samuel A. and Kathleen Spees. Affidavit on Behalf of PJM Interconnection, LLC Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, Before the Federal Energy Regulatory Commission, Docket ER14-2940-000. September 25, 2014.
- Newell, Samuel A. and Kathleen Spees. Testimony on Behalf of ISO New England Inc. Regarding a Forward Capacity Market Demand Curve. Before the Federal Energy Regulatory Commission, Docket No. ER14-1639-000. April 1, 2014.
- Newell, Samuel A. and Kathleen Spees. Response on Behalf of PJM Interconnection, LLC, Regarding the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model. Before the Federal Energy Regulatory Commission. Docket No. ER12-13-000. January 13, 2012.

Newell, Samuel, Kathleen Spees, and Philip Q. Hanser. Supplemental Comments, Re: Notice of

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Proposed Rulemaking regarding Demand Response Compensation in Organized Wholesale Energy Markets. Before the Federal Energy Regulatory Commission. October 4, 2010. Docket Nos. RM10-17-000 and EL09-68-00.

- Pfeifenberger, Johannes P. and Kathleen Spees. Comments In the Matter of the Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results. Before the State of Maryland Public Service Commission. Administrative Docket PC22. Filed October 1, 2010.
- Newell, Samuel, Kathleen Spees, and Philip Q. Hanser. Comments, Re: Notice of Proposed Rulemaking regarding Demand Response Compensation in Organized Wholesale Energy Markets. Before the Federal Energy Regulatory Commission. May 13, 2010. Docket Nos. RM10-17-000 and EL09-68-00.

C. PRESENTATIONS

- Spees, Kathleen and Matthew Witkin. "Market Design for a Clean Grid: Unlocking the Potential for Non-Emitting and Emerging Technologies," Presented to IESO Non-Emitting Resource Subcommittee. January 22, 2018.
- Spees, Kathleen, Judy Chang, and David Luke Oates. "A Dynamic Clean Energy Market in New England," November 2017. Prepared for Conservation Law Foundation, Brookfield Renewable, NextEra Energy Resources, and National Grid.
- Judy Chang, Kathleen Spees, and Johannes P. Pfeifenberger. "Hello World: Alberta's Capacity Market." Presented at the 2018 IPPSA Conference. November 2017.
- Spees, Kathleen. "Decarbonisation and Tomorrow's Electricity Market," Presented at the 2017 IESO Stakeholder Summit. June 12, 2017.
- Spees, Kathleen, Johannes P. Pfeifenberger, Judy Chang, Yingxia Yang, Rebecca Carroll, Roger Lueken, and Colin McIntyre. "Flexibility Enhancements: Alberta Needs and Experience from Other Jurisdictions," Prepared for the Alberta Electricity System Operator," August 10, 2017.
- Spees, Kathleen. "Rethinking Capacity Mechanisms in the Context of Emerging Flexibility Challenges," Presented at the European Capacity Mechanisms Forum. February 3, 2017.
- Spees, Kathleen. "CO₂e Cap-and-Trade: Interactions with Electricity Markets," Presented to the Associated of Power Producers of Ontario. November 15, 2016.
- Spees, Kathleen, Samuel A. Newell, and Judy Chang. "Using Competitive Markets to Achieve Policy Objectives: How the Systems Built for Fossil Plants Can Evolve to Support the Clean, Distributed Grid of the Future." Presented at the Energy Bar Association 2017 Annual Meeting & Conference. March 29, 2017.
- Chang, Judy, Kathleen Spees, and Pearl Donohoo-Vallett. "Enabling Canadian Imports for Advancing Clean Energy Strategies for the U.S.: Considerations for Policymakers," Presented at the Embassy of Canada and Canadian Electricity Association's Half-day Conference. October 24, 2016.

Spees, Kathleen, Samuel A. Newell, David Luke Oates and James Mashal. "Clean Power Plan in

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Texas: Implications for Renewables and the Electricity Market," Presented at the 2016 Renewable Energy Law Conference. February 9, 2016.

- Pfeifenberger, Johannes P., Judy Chang, Kathleen Spees, and Matthew K. Davis. "Impacts of Distributed Storage on Electricity Markets, Utility Operations, and Customers," 2015 MIT Energy Initiative Associate Member Symposium. May 1, 2015.
- Chang, Judy, Johannes P. Pfeifenberger, Kathleen Spees, and Matthew K. Davis. "The Value of Distributed Electrical Energy Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments," Energy Storage Policy Forum 2015, Washington, D.C. January 29, 2015.
- Spees, Kathleen. "EPA's Clean Power Plan: Potential Impacts on Asset Values," Infocast 7th Annual Projects & Money Summit 2015. January 13, 2015.
- Chang, Judy, Johannes P. Pfeifenberger, Kathleen Spees, and Matthew K. Davis. "The Value of Distributed Electrical Energy Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments," UBS Investment Research Webinar. December 5, 2014.
- Spees, Kathleen and Judy Chang. "Evaluating Cooperation Opportunities under CAA 111(d)," Presented to the Eastern Interconnection States' Planning Council. October 2, 2015.
- Spees, Kathleen. "Implications of EPA's Clean Power Plan under Clean Air Act Section 111(d)," Presented to the Department of Engineering and Public Policy at Carnegie Mellon University. September 18, 2015.
- Spees, Kathleen, Samuel A. Newell, and Johannes P. Pfeifenberger. "ERCOT's Optimal Reserve Margin: As Estimated for the Public Utility Commission of Texas and the Electric Reliability Council of Texas," presented to the 2014 Texas Industrial Energy Consumers Annual Meeting. July 15, 2014.
- Pfeifenberger, Johannes P., Samuel A. Newell, and Kathleen Spees. "Energy and Capacity Markets: Tradeoffs in Reliability, Costs, and Risks," presented at the Harvard Electricity Policy Group Seventy-Fourth Plenary Session. February 27, 2014.
- Spees, Kathleen, Johannes P. Pfeifenberger, and Samuel A. Newell. "ERCOT's Optimal Reserve Margin," presented to UBS Investment Research investor conference call. February 19, 2014.
- Spees, Kathleen. "Capacity Markets: Lessons Learned from the First Decade," presented to EUCI 10th Annual Capacity Markets Conference. November 7, 2013.
- Pfeifenberger, Johannes P, and Kathleen Spees. "Characteristics of Successful Capacity Markets," presented at the APEx Conference 2013, New York. NY. October 31, 2013.
- Spees, Kathleen and Johannes Pfeifenberger. "Outlook on Fundamentals in PJM's Energy and Capacity Markets," presented at the 12th Annual Power and Utility Conference, Hosted by Goldman Sachs. August 8, 2013.
- Newell, Samuel A., and Kathleen Spees. "Get Ready for Much Spikier Energy Prices: The Under-Appreciated Market Impacts of Displacing Generation with Demand Response," presented at the Cadwalader Energy Investor Conference. February 7, 2013.

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- Spees, Kathleen and Johannes P. Pfeifenberger. "PJM Reliability Pricing Model: 2016/17 Planning Period Parameters Update," presented to Barclays North American Utilities Investor Call. February 4, 2013.
- Spees, Kathleen and Johannes P. Pfeifenberger. "Seams Inefficiencies: Problems and Solutions at Energy Market Borders," presented at the EUCI Canadian Transmission Summit. July 17, 2012.
- Spees, Kathleen. "New U.S. Emission Regulations: Electric Industry Impacts," presented at the U.S. Energy 24th Annual Energy Conference. May 11, 2012.
- Spees, Kathleen. "Market Design from a Practitioner's Viewpoint: Wholesale Electric Market Design for Resource Adequacy," presented at Lawrence University Economics Colloquium. April 23, 2012.
- Spees, Kathleen. "Options for Extending Forward certainty in Capacity Markets." Presented at the EUCI Conference on Capacity Markets: Achieving Market Price Equilibrium. November 9, 2011.
- Spees, Kathleen, and Pfeifenberger, Johannes P. "Resource Adequacy: Current Issues in North American Power Markets." Presented at the Alberta Power Summit. November 19, 2011.
- Spees, Kathleen and Samuel Newell. "Capacity Market Designs: Focus on CAISO, NYISO, PJM, and ISO-NE," Presented to the Midwest ISO Supply Adequacy Working Group. July 19, 2010.
- Pfeifenberger, Johannes P., and Kathleen Spees. "Best Practices in Resource Adequacy," presented at the PJM Long Term Capacity Issues Symposium. January 27, 2010.
- Chang, Judy, Kathleen Spees, and Jurgen Weiss. "Using Storage to Capture Renewables: Does Size Matter?" working paper presented at the 15th Annual POWER Research Conference. University of California Energy Institute's Center for the Study of Energy Markets. March 18, 2010.

Exhibit A.2: Curriculum Vitae of Dr. Samuel A. Newell

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Dr. Samuel Newell leads The Brattle Group's Electricity Practice. He has 22 years of experience supporting clients in wholesale market design, generation asset valuation, resource planning, and transmission planning. Much of his work addresses the industry's transition to clean energy. He frequently provides testimony and expert reports to Independent System Operators (ISOs), the Federal Energy Regulatory Commission (FERC), state regulatory commissions, and the American Arbitration Association.

Dr. Newell earned a Ph.D. in Technology Management & Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science & Engineering from Stanford University, and a B.A. in Chemistry & Physics from Harvard College.

Prior to joining The Brattle Group in 2004, Dr. Newell was the Director of the Transmission Service at Cambridge Energy Research Associates. Before that, he was a Manager at A.T. Kearney.

AREAS OF EXPERTISE

- Transmission Planning and Modeling
- Electricity Market Design and Analysis
- Generation and Storage Asset Valuation, and Procurements
- Integrated Resource Planning
- Demand Response (DR) Resource Potential and Market Impact
- Gas-Electric Coordination
- RTO Participation and Configuration
- Energy Litigation
- Tariff and Rate Design
- Business Strategy

EXPERIENCE

Transmission Planning and Modeling

- Economic and Environmental Evaluation of New Transmission to Quebec. For the New Hampshire Attorney General's Office in a proceeding before the state Site Evaluation Committee, co-sponsored testimony on the benefits of the proposed Northern Pass Transmission line. Responded to the applicant's analysis and developed our own, focusing on wholesale market participation, price impacts, and net emissions savings.
- Benefit-Cost Analysis of New York AC Transmission Upgrades. For the New York Department of Public Service (DPS) and NYISO, led a team to evaluate 21 alternative projects to increase transfer capability between Upstate and Southeast NY. Quantified a broad scope of benefits: traditional production cost savings from reduced congestion, using GE-MAPS; additional production cost savings considering non-normal conditions; resource cost savings from being able to retire Downstate capacity, delay new entry, and

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shift the location of future entry Upstate; avoided costs from replacing aging transmission that would have to be refurbished soon; reduced costs of integrating renewable resources Upstate; and tax receipts. Identified projects with greatest and most robust net value. DPS used our analysis to inform its recommendation to the NY Public Service Commission to declare a "Public Policy Need" to build a project such as the best ones identified.

- Evaluation of New York Transmission Projects. For the New York Department of Public Service (DPS), provided a cost-benefit analysis for the "TOTS" transmission projects. Showed net production cost and capacity resource cost savings exceeding the project costs, and the lines were approved. The work involved running GE-MAPS and a capacity market model, and providing insights to DPS staff.
- Benefits of New 765kV Transmission Line. For a utility joint venture between AEP and ComEd, analyzed renewable integration and congestion relief benefits of their proposed \$1.2 billion RITELine project in western PJM. Guided client staff to conduct simulations using PROMOD. Submitted testimony to FERC.
- Benefit-Cost Analysis of a Transmission Project for Offshore Wind. Submitted testimony on the economic benefits of the Atlantic Wind Connection Project, a proposed 2,000 MW DC offshore backbone from New Jersey to Virginia with 7 onshore landing points. Described and quantified the effects on congestion, capacity markets, CO2 emissions, system reliability and operations, jobs and economic stimulus, and the installed cost of offshore wind generation. Directed Ventyx staff to simulate the energy market impacts using the PROMOD model.
- Analysis of Transmission Congestion and Benefits. Analyzed the impacts on transmission congestion, and customer benefits in California and Arizona of a proposed inter-state transmission line. Used the DAYZER model to simulate congestion and power market conditions in the Western Electricity Coordination Council region in 2013 and 2020 considering increased renewable generation requirements and likely changes to market fundamentals.
- Benefit-Cost Analysis of New Transmission. For a transmission developer's application before the California Public Utility Commission (CPUC) to build a new 500 kV line, analyzed the benefits to ratepayers. Analysis included benefits beyond those captured in a production cost model, including the benefits of integrating a pumped storage facility that would allow the system to accommodate a larger amount of intermittent renewable resources at a reduced cost.
- Benefit-Cost Analysis of New Transmission in the Midwest. For the American Transmission Company (ATC), supported Brattle witness evaluating the benefits of a proposed new 345 kV line (Paddock-Rockdale). Advised client on its use of PROMOD IV simulations to quantify energy benefits, and developed metrics to properly account for the effects of changes in congestion, losses, FTR revenues, and LMPs on customer

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costs. Developed and applied new methodologies for analyzing benefits not quantified in PROMOD IV, including competitiveness, long-run resource cost advantages, reliability, and emissions. Testimony was submitted to the Public Service Commission of Wisconsin, which approved the line.

- Transmission Investments and Congestion. Worked with executives and board of an independent transmission company to develop a metric indicating congestion-related benefits provided by its transmission investments and operations.
- Analysis of Transmission Constraints and Solutions. For a large, geographically diverse group of clients, performed an in-depth study identifying the major transmission bottlenecks in the Western and Eastern Interconnections, and evaluating potential solutions to the bottlenecks. Worked with transmission engineers from multiple organizations to refine the data in a load flow model and a security-constrained, unit commitment and dispatch model for each interconnection. Ran 12-year, LMP-based market simulations using GE-MAPS across multiple scenarios and quantified congestion costs on major constraints. Collaborated with engineers to design potential transmission (and generation) solutions. Evaluated the benefits and costs of candidate solutions and identified several highly economic major transmission projects.
- Merchant Transmission Impacts. For a merchant transmission company, used GE-MAPS to analyze the effects of the Cross Sound Cable on energy prices in Connecticut and Long Island.
- Security-Constrained Unit Commitment and Dispatch Model Calibration. For a Midwestern utility, calibrated their PROMOD IV model, focusing on LMPs, unit commitment, flows, and transmission constraints. Helped client to understand their model's shortcomings and identify improvement opportunities. Also assisted with initial assessments of FTRs in preparation for its submission of nominations in MISO's first allocation of FTRs.
- Model Evaluation. Led an internal Brattle evaluation of commercially available transmission and market simulation models. Interviewed vendors and users of PROMOD IV, Gridview, DAYZER, and other models. Intensively tested each model. Evaluated accuracy of model algorithms (e.g., LMP, losses, unit commitment) and ability to calibrate models with backcasts using actual RTO data.

Electricity Market Design and Analysis

• MISO Resource Adequacy Framework for a Transforming Fleet. Currently advising MISO in its Resource Availability and Need initiative to reform its resource adequacy framework to address year-round shortage risks as the fleet transforms. Presenting to stakeholders on resource accreditation, determination of LSE requirements, modifications to the Planning Reserve Auction, and interactions with outage scheduling and with energy and ancillary services markets.

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- Singapore Capacity Market Development. For the Energy Market Authority (EMA) in Singapore, developing a complete forward capacity market design. Worked with EMA in collaboration with other government entities and stakeholders. Published high-level design documents and presented to stakeholders. Currently assisting with detailed design and implementation.
- Electricity Market Transformation Study. For NYISO, led a team to conduct simulation analyses of how prices for energy, ancillary services, capacity, and RECs may have to evolve to support adequate generation/storage investment to maintain reliability and meet the state's mandates for 70% renewable electricity by 2030 and 100% carbon-free electricity by 2040. Used an advanced Brattle-developed capacity expansion model, GridSIM, to model investment and chronological operation with large amounts of intermittent and storage resources, subject to reliability and environmental constraints, under a range of assumptions regarding market design and carbon pricing. Results and insights informed NYISO's 2019 Grid in Transition whitepaper, and subsequent scenario analyses are providing a foundation for NYISO's examination of reliability and market design enhancements.
- New York State Resource Adequacy Constructs. For NYSERDA, evaluating the customer cost impacts of several alternative constructs that differ in whether FERC or the state sets the rules and how buyer-side mitigation is implemented.
- IESO's Market Renewal Program / Energy Market Settlements. For the Ontario Independent Electricity System Operator (IESO), helped develop settlement equations for the new day-ahead and real-time nodal market, including make-whole payments for natural gas-fired combined-cycle plants participating as "pseudo-units" and for cascading hydro systems.
- PJM's Capacity Market Reviews and Parameters. For PJM, conducted all four official reviews of its Reliability Pricing Model (2008, 2011, 2014, and 2018). Analyzed capacity auctions and interviewed stakeholders. Evaluated the demand curve shape, the Cost of New Entry (CONE) parameter, and the methodology for estimating net energy and ancillary services revenues. Recommended improvements to support participation and competition, to avoid excessive price volatility, and to safeguard future reliability performance. In 2020, provided Avoidable Cost Rates for existing resources and Net CONE for new energy efficiency resources, for use in the Minimum Offer Price Rule. Submitted testimonies before FERC.
- Seasonal Capacity in PJM. On behalf of the Natural Resources Defense Council, analyzed the ability of PJM's capacity market to efficiently accommodate seasonal capacity resources and meet seasonal resource adequacy needs. Co-authored a whitepaper proposing a co-optimized two-season auction and estimating the efficiency benefits. Filed and presented report at FERC.

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- Energy Price Formation in PJM. For NextEra Energy, analyzed PJM's integer relaxation proposal and evaluated implications for day-ahead and real-time market prices. Reviewed PJM's Fast-Start pricing proposal and authored report recommending improvements, which NextEra and other parties filed with FERC, and which FERC largely accepted and cited in its April 2019 Order.
- Carbon Pricing to Harmonize NY's Wholesale Market and Environmental Goals. Led a Brattle team to help NYISO: (1) develop and evaluate market design options, including mechanisms for charging emitters and allocating revenues to customers, border adjustments to prevent leakage, and interactions with other market design and policy elements; and (2) develop a model to evaluate how carbon pricing would affect market outcomes, emissions, system costs, and customer costs under a range of assumptions. Whitepaper initiated discussions with NY DPS and stakeholders. Supported NYISO in detailed market design and stakeholder engagement.
- Market Design for Energy Security in ISO-NE. For NextEra Energy, evaluated and developed proposals for meeting winter energy security needs in New England when pipeline gas becomes scarce. Evaluated ISO-NE's proposed multi-day energy market with new day-ahead operating reserves. Developed competing proposal for new operating reserves in both day-ahead and real-time to incent preparedness for fuel shortages; also developed criteria and high-level approach for potentially incorporating energy security into the forward capacity market. Presented evaluations and proposals to the NEPOOL Markets Committee.
- ERCOT's Proposed Future Ancillary Services Design. For the Electric Reliability Council of Texas (ERCOT), evaluated the benefits of its proposal to unbundle ancillary services, enable broader participation by load resources and new technologies, and tune its procurement amounts to system conditions. Worked with ERCOT staff to assess each ancillary service and how generation, load resources, and new technologies could participate. Directed their simulation of the market using PLEXOS, and evaluated other benefits outside of the model.
- Investment Incentives and Resource Adequacy in ERCOT. For ERCOT, led a Brattle team to: (1) interview stakeholders and characterize the factors influencing generation investment decisions; (2) analyze the energy market's ability to support investment and resource adequacy at the target level; and (3) evaluate options to enhance long-term resource adequacy while maintaining market efficiency. Worked with ERCOT staff to understand the relevant aspects of their operations and market data. Performed probabilistic simulation analyses of prices, investment costs, and reliability. Conclusions informed a PUCT proceeding in which I filed comments and presented at several workshops.
- Operating Reserve Demand Curve (ORDC) in ERCOT. For ERCOT, evaluated several alternative ORDCs' effects on real-time price formation and investment incentives. Conducted backcast analyses using interval-level data provided by ERCOT and assuming

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generators rationally modify their commitment and dispatch in response to higher prices under the ORDC. Analysis was used by ERCOT and the PUCT to inform selection of final ORDC parameters.

- Economically Optimal Reserve Margins in ERCOT. For ERCOT, co-led studies (2014 and 2018) estimating the economically-optimal reserve margin, and the market equilibrium reserve margins in its energy-only market. Collaborated with ERCOT staff and Astrape Consulting to construct Monte Carlo economic and reliability simulations. Accounted for uncertainty and correlations in weather-driven load, renewable energy production, generator outages, and load forecasting errors. Incorporated intermittent wind and solar generation profiles, fossil generators' variable costs, operating reserve requirements, various types of demand response, emergency procedures, administrative shortage pricing under ERCOT's ORDC, and criteria for load-shedding. Reported economic and reliability metrics across a range of renewable penetration and other scenarios. Results informed the PUCT's adjustments to the ORDC to support desired reliability outcomes.
- Australian Electricity Market Operator (AEMO) Redesign. Advised AEMO on market design reforms for the National Electricity Market (NEM) to address concerns about operational reliability and resource adequacy as renewable generation displaces traditional resources. Also provided a report on potential auctions to ensure sufficient capabilities in the near-term.
- Response to DOE's "Grid Reliability and Resiliency Pricing" Proposal. For a broad group of stakeholders opposing the rule in a filing before FERC, evaluated DOE's proposed rule: the need (or lack thereof) for bolstering reliability and resilience by supporting resources with a 90-day fuel supply; the likely cost of the rule; and the incompatibility of DOE's proposed solution with the principles and function of competitive wholesale electricity markets.
- Energy Market Power Mitigation in Western Australia. Led a Brattle team to help Western Australia's Public Utilities Office design market power mitigation measures for its newly reformed energy market. Established objectives; interviewed stakeholders; assessed local market characteristics affecting the design; synthesized lessons learned from the existing energy market and from several international markets. Recommended criteria, screens, and mitigation measures for day-ahead and real-time energy and ancillary services markets. The Public Utilities Office posted our whitepaper in support of its conclusions.
- MISO Competitive Retail Choice Solution. For MISO, evaluated design alternatives for accommodating the differing needs of states relying on competitive retail choice and integrated resource planning. Conducted probabilistic simulations of likely market results under alternative market designs and demand curves. Provided expert support in stakeholder forums and submitted expert testimony before FERC.

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- Buyer Market Power Mitigation. On Behalf of the "Competitive Markets Coalition" group of generating companies, helped develop and evaluate proposals for improving PJM's Minimum Offer Price Rule so that it more effectively protects the capacity market from manipulation by buyers while reducing interference with non-manipulative activity. Participated in discussions with other stakeholders. Submitted testimony to FERC supporting tariff revisions that PJM filed.
- Market Development Vision for MISO. For the Midcontinent Independent System Operator (MISO), worked with MISO staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next 2–5 years. Authored a foundational report for that Vision, including: describing the core services MISO must continue to provide to support a well-functioning market; establishing a set of principles for enhancing those services; identifying seven Focus Areas offering the greatest opportunities; and proposing criteria for prioritizing initiatives within and across Focus Areas.
- ISO-NE Capacity Demand Curve Design. For ISO New England (ISO-NE), developed a
 demand curve for its Forward Capacity Market. Solicited staff and stakeholder input,
 then established market design objectives. Provided a range of candidate curves and
 evaluated them against objectives, showing tradeoffs between reliability uncertainty and
 price volatility (using a probabilistic locational capacity market simulation model we
 developed). Worked with Sargent & Lundy to estimate the Net Cost of New Entry to
 which the demand curve prices are indexed. Submitted testimonies before FERC, which
 accepted the proposed curve.
- Offer Review Trigger Prices in ISO-NE. For the Internal Market Monitor in ISO-NE, developed benchmark prices for screening for uncompetitively low offers in the Forward Capacity Market. Worked with Sargent & Lundy to conduct bottom-up analyses of the costs of constructing and operating gas-fired generation technologies and onshore wind; also estimated the costs of energy efficiency and demand response. For each technology, estimated capacity payments needed to make the resource economically viable, given their costs and expected non-capacity revenues. Recommendations were filed with and accepted by the FERC.
- Western Australia Capacity Market Design. For the Public Utilities Office (PUO) of Western Australia, led a Brattle team to advise on the design and implementation of a new forward capacity market. Reviewed the high-level forward capacity market design proposed by the PUO; evaluated options for auction parameters such as the demand curve; recommended supplier-side and buyer-side market power mitigation measures; helped define administrative processes needed to conduct the auction and the governance of such processes.
- Western Australia Reserve Capacity Mechanism. For EnerNOC, evaluated Western Australia's administrative Reserve Capacity Mechanism in comparison with international capacity markets, and made recommendations for improvements to meet

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reliability objectives more cost effectively. Evaluated whether to develop an auctionbased capacity market compared or an energy-only market design. Submitted report and presented recommendations to the Electricity Market Review Steering Committee and other senior government officials.

- Evaluation of Moving to a Forward Capacity Market in NYISO. For NYISO, conducted a benefit-cost analysis of replacing its prompt capacity market with a 4-year forward capacity market. Evaluated options based on stakeholder interviews and the experience of PJM and ISO-NE. Addressed risks to buyers and suppliers, market power mitigation, implementation costs, and long-run costs. Recommendations were used by NYISO and stakeholders to help decide whether to pursue a forward capacity market.
- MISO's Resource Adequacy Construct and Market Design Elements. For MISO, conducted the first major assessment of its resource adequacy construct. Identified several successes and recommended improvements in load forecasting, locational resource adequacy, and the determination of reliability targets. Incorporated extensive stakeholder input and review. Continued to consult with MISO in its work with the Supply Adequacy Working Group on design improvements, including market design elements for its annual locational capacity auctions.
- Demand Response (DR) Integration in MISO. Through a series of assignments, helped MISO incorporate DR into its energy market and resource adequacy construct, including: (1) conducted an independent assessment of MISO's progress in integrating DR into its resource adequacy, energy, and ancillary services markets. Analyzed market participation barriers; (2) wrote a whitepaper evaluating various approaches to incorporating economic DR in energy markets. Identified implementation barriers and recommended improvements to efficiently accommodate curtailment service providers; (3) helped modify MISO's tariff and business practices to accommodate DR in its resource adequacy construct by defining appropriate participation rules. Informed design by surveying the practices of other RTOs and by characterizing the DR resources within the MISO footprint.
- Survey of Demand Response Provision of Energy, Ancillary Services, and Capacity. For the Australian Energy Market Commission (AEMC), co-authored a report on market designs and participation patterns in several international markets. AEMC used the findings to inform its integration of DR into its National Energy Market.
- Integration of DR into ISO-NE's Energy Markets. For ISO-NE, provided analysis and assisted with a stakeholder process to develop economic DR programs to replace the ISO's initial economic DR programs when they expired.
- Compensation Options for DR in ISO-NE's Energy Market. For ISO-NE, analyzed the implications of various DR compensation options on consumption patterns, LMPs, capacity prices, consumer surplus, producer surplus, and economic efficiency. Presented findings in a whitepaper that ISO-NE submitted to FERC.

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- ISO-NE Forward Capacity Market (FCM) Performance. With ISO-NE's internal market monitor, reviewed the performance of the first two forward auctions. Evaluated key design elements regarding demand response participation, capacity zone definition and price formation, an alternative pricing rule for mitigating the effects of buyer market power, the use of the Cost of New Entry in auction parameters, and whether to have an auction price ceiling and floor.
- Evaluation of Tie-Benefits. For ISO-NE, analyzed the implications of different levels of tie-benefits (i.e., assistance from neighbors, reducing installed capacity requirements) for capacity costs and prices, emergency procurement costs, and energy prices. Whitepaper submitted by ISO-NE to the FERC.
- Evaluation of Major Initiatives. With ISO-NE and its stakeholders, developed criteria for identifying "major" market and planning initiatives that trigger the need for the ISO to provide qualitative and quantitative information to help stakeholders evaluate the initiative, as required in ISO-NE's tariff. Developed guidelines on the kinds of information ISO-NE should provide for major initiatives.
- Energy Market Monitoring & Market Power Mitigation. For PJM, co-authored a whitepaper, "Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets."
- Vertical Market Power. Before the NYPSC, examined whether the merger between National Grid and KeySpan could create incentives to exercise vertical market power. Employed a simulation-based approach using the DAYZER model of the NYISO wholesale power market and examined whether outages of National Grid's transmission assets significantly affected KeySpan's generation profits.
- LMP Impacts on Contracts. For a West Coast client, reviewed the California ISO's proposed implementation of locational marginal pricing (LMP) in 2007 and analyzed implications for "seller's choice" supply contracts. Estimated congestion costs ratepayers would face if suppliers financially delivered power to the lowest priced nodes; estimated incremental contract costs using a third party's GE-MAPS market simulations (and helped to improve their model inputs to more accurately reflect the transmission system in California). Applied findings to support the ISO in design modifications of the California market under LMP.
- RTO Accommodation of Retail Access. For MISO, identified business practice improvements to facilitate retail access. Analyzed retail access programs in IL, MI, and OH. Studied retail accommodation practices in other RTOs, focusing on how they modified their procedures surrounding transmission access, qualification of capacity resources, capacity markets, FTR allocations, and settlement.

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Generation and Storage Asset Valuation, and Procurements

- Evaluation of Hydropower Procurement Options. For a potential buyer of new transmission and hydropower from Quebec, evaluated the costs and emissions benefits under a range of contracting approaches. Accounted for the possibility of resource shuffling and backfill of emissions. Considered the value of storage services.
- Valuation of a Gas-Fired Combined-Cycle Plant in New England. For a party to litigation, submitted testimony on the fair market value of the plant. Simulated energy and capacity markets to forecast net revenues, and estimated exposure to capacity performance penalties. Compared the valuation to the transaction prices of similar plants and analyzed the differences. Collaborated with a co-testifying export on project finance to assess whether the estimated value would suffice to cover the plant's debt and certain other obligations.
- Valuation of a Portfolio of Combined-Cycle Plants across the U.S. For a debt holder in a portfolio of plants, estimated the fair market value of each plant in 2018 and the plausible range of values five years hence. Reviewed comparables. Analyzed electricity markets in New England, New York, Texas, Arizona, and California using our own models and reference points from futures markets and publicly available studies. Performed probability-weighted discounted cash flow valuation analyses across a range of scenarios. Provided insights into market and regulatory drivers and how they may evolve.
- Wholesale Market Value of Storage in PJM. For a potential investor in battery storage, estimated the energy, ancillary services, and capacity market revenues their technology could earn in PJM. Reviewed PJM's market participation rules for storage. Forecast capacity market revenues and the risk of performance penalties. Developed a real-time energy and ancillary service bidding algorithm that the asset owner could employ to nearly optimize its operations, given expected prices and operating constraints. Identified changes in real-time bid/offer rules that PJM could implement to improve the efficiency of market participation by storage resources.
- Valuation of a Generation Portfolio in ERCOT. For the owners of a portfolios of gasfired assets (including a cogen plant), estimated the market value of their assets by modeling future cash flows from energy and ancillary services markets over a range of plausible scenarios. Analyzed the effects load growth, entry, retirements, environmental regulations, and gas prices could have on energy prices, including scarcity prices under ERCOT's Operating Reserve Demand Curve. Evaluated how future changes in these drivers could cause the value to shift over time.
- Valuation Methodology for a Coal Plant Transaction in PJM. For a part owner of a very large coal plant being transferred at an assessed value that was yet to be determined by a third party, wrote a manual describing how to conduct a market valuation of the plant. Addressed drivers of energy and capacity value; worked with an engineering

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subcontractor to describe how to determine the remaining life of the plant and CapEx needs going forward. Our manual was used to inform their pre-assessment negotiation strategy.

- Valuation of a Coal Plant in PJM. For the lender to a bidder on a coal plant being auctioned, estimated the market value of the plant. Valuation analysis focused especially on the effects of coal and gas prices on cash flows, and the ongoing fixed O&M costs and CapEx needs of the plant.
- Valuation of a Coal Plant in New England. For a utility, evaluated a coal plant's economic viability and market value. Projected market revenues, operating costs, and capital investments needed to comply with future environmental mandates.
- Valuation of Generation Assets in New England. To inform several potential buyers' valuations of various assets being sold in ISO-NE, provided energy and capacity price forecasts and cash flows under multiple scenarios. Explained the market rules and fundamentals to assess key risks to cash flows.
- Valuation of Generation Asset Bundle in New England. For the lender to the potential buyer of generation assets, provided long-term energy and capacity price forecasts, with multiple scenarios to test whether the plant could be worth less than the debt. Reviewed a broad scope of documents available in the "data room" to identify market, operational, and fuel supply risks.
- Valuation of Generation Asset Bundle in PJM. For a potential buyer, provided energy and capacity price forecasts and reviewed their valuation analysis. Analyzed supply and demand fundamentals of the PJM capacity market. Performed locational market simulations using the DAYZER model to project nodal prices as market fundamentals evolve. Reviewed the client's spark spread options model.
- Wind Power Development. For a developer proposing to build a several hundred megawatt wind farm in Michigan, provided a revenue forecast for energy and capacity. Evaluated the implications of several scenarios around key uncertainties.
- Wind Power Financial Modeling. For an offshore wind developer proposing to build a 350 MW project in PJM off the coast of New Jersey, analyzed market prices for energy, renewable energy certificates, and capacity. Provided a detailed financial model of project funding and cash distributions to various types of investors (including production tax credit). Resulting financial statements were used in an application to the state of New Jersey for project grants.
- Contract Review for Cogeneration Plant. For the owner of a large cogen plant in PJM, analyzed revenues under the terms of a long-term PPA (in renegotiation) vs. potential merchant revenues. Accounted for multiple operating modes of the plant and its sales of energy, capacity, ancillary services, and steam over time.

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- Generation Strategy/Valuation. For an independent power producer, acted for over two years as a key advisor on the implementation of the client's growth strategy. Led a large analytical team to assess the profitability of proposed new power plants and acquisitions of portfolios of plants throughout the U.S. Used the GE-MAPS market simulation model to forecast power prices, transmission congestion, generator dispatch, emissions costs, energy margins for candidate plants; used an ancillary model to forecast capacity value.
- Generation Asset Valuation. For multiple banks and energy companies, provided valuations of financially distressed generating assets. Used GE-MAPS to simulate net energy revenues; a capacity model to estimate capacity revenues; and a financial valuation model to value several natural gas, coal, and nuclear power plants across a range of scenarios. Identified key uncertainties and risks.

Integrated Resource Planning (IRP)

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- Resource Planning in Hawaii. Assisted the Hawaiian Electric Companies in developing its Power Supply Improvement Plan, filed April 2016. Our work addressed how to maintain system security as renewable penetration increases toward 100% and displaces traditional synchronous generation. Solutions involved defining technology-neutral requirements that may be met by demand response, distributed resources, and new technologies as well as traditional resources.
- IRP in Connecticut (for the 2008, 2009, 2010, 2012, and 2014 Plans). For the two major utilities in CT and the CT Dept. of Energy and Environmental Protection (DEEP), led the analysis for five successive integrated resource plans. Plans involved projecting 10-year Base Case outlooks for resource adequacy, customer costs, emissions, and RPS compliance; developing alternative market scenarios; and evaluating resource procurement strategies focused on energy efficiency, renewables, and traditional sources. Used an integrated modeling system that simulated the New England locational energy market (with the DAYZER model), the Forward Capacity Market, REC markets, and suppliers' likely investment/retirement decisions. Addressed electricity supply risks, natural gas supply into New England, RPS standards, environmental regulations, transmission planning, emerging technologies, and energy security. Solicited input from stakeholders. Provided oral testimony before the DEEP.
- Contingency Plan for Indian Point Nuclear Retirement. For the New York Department of Public Service (DPS), assisted in developing contingency plans for maintaining reliability if the Indian Point nuclear plant were to retire. Evaluated generation and transmission proposals along three dimensions: their reliability contribution, viability for completion by 2016, and the net present value of costs. The work involved partnering with engineering sub-contractors, running GE-MAPS and a capacity market model, and providing insights to DPS staff.

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- Analysis of Potential Retirements to Inform Transmission Planning. For a large utility in Eastern PJM, analyzed the potential economic retirement of each coal unit in PJM under a range of scenarios regarding climate legislation, legislation requiring mercury controls, and various capacity price trajectories.
- Resource Planning in Wisconsin. For a utility considering constructing new capacity, demonstrated the need to consider locational marginal pricing, gas price uncertainty, and potential CO2 liabilities. Guided client to look beyond building a large coal plant. Led them to mitigate exposures, preserve options, and achieve nearly the lowest expected cost by pursuing a series of smaller projects, including a promising cogeneration application at a location with persistently high LMPs. Conducted interviews and facilitated discussions with senior executives to help the client gain support internally and begin to prepare for regulatory communications.

Demand Response (DR) Resource Potential and Market Impact

- ERCOT DR Potential Study. For ERCOT, estimated the market size for DR by end-user segment based on interviews with curtailment service providers and utilities and informed by penetration levels achieved in other regions. Presented findings to the Public Utility Commission of Texas at a workshop on resource adequacy.
- DR Potential Study. For an Eastern ISO, analyzed the biggest, most cost-effective opportunities for DR and price responsive demand in the footprint, and what the ISO could do to facilitate them. For each segment of the market, identified the ISO and/or state and utility initiatives that would be needed to develop various levels of capacity and energy market response. Also estimated the potential and cost characteristics for each segment. Interviewed numerous curtailment service providers and ISO personnel.
- Wholesale Market Impacts of Price-Responsive Demand (PRD). For NYISO, evaluated the potential effects of widespread implementation of dynamic retail rates. Utilized the PRISM model to estimate effects on consumption by customer class, applied empirically-based elasticities to hourly differences between flat retail rates and projected dynamic retail rates. Utilized the DAYZER model to estimate the effects of load changes on energy costs and prices.
- Energy Market Impacts of DR. For PJM and the Mid-Atlantic Distributed Resources Initiative (sponsored by five state commissions), quantified the market impacts and customer benefits of DR programs. Used a simulation-based approach to quantify the impact that a three percent reduction of peak loads during the top 20 five-hour blocks would have had in 2005 and under a variety of alternative market conditions. Utilized the DAYZER market simulation model, which we calibrated to represent the PJM market using data provided by PJM and public sources. Results were presented in multiple forums and cited widely, including by several utilities in their filings with state

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commissions regarding investment in advanced metering infrastructure and implementation of DR programs.

• Value of DR Investments. For Pepco Holdings, Inc., evaluated its proposed DR-enabling investments in advanced metering infrastructure and its efficiency programs. Estimated reductions in peak load that would be realized from dynamic pricing, direct load control, and efficiency. Built on the Brattle-PJM-MADRI study to estimate short-term energy market price impacts and addressed long-run equilibrium offsetting effects through supplier response scenarios. Estimated capacity price impacts and resource cost savings over time. Submitted a whitepaper to DE, NJ, MD, and DC commissions. Presented findings to DE Commission.

Gas-Electric Coordination

- Gas Pipeline Investment for Electricity. For the Maine Office of Public Advocate, cosponsored testimony regarding the reliability and economic impacts if the Maine PUC signed long-term contracts for electricity customers to pay for new gas pipeline capacity into New England. Analyzed other experts' reports and provided a framework for evaluating whether such procurements would be in the public interest, considering their costs and benefits vs. alternatives.
- Gas Pipeline Investment for Electricity. For the Massachusetts Attorney General's office, provided input for their comments in the Massachusetts Department of Public Utilities' docket investigating whether and how new natural gas delivery capacity should be added to the New England market.
- Fuel Adequacy and Other Winter Reliability Challenges. For an ISO, co-authored a report assessing the risks of winter reliability events due to inadequate fuel, inadequate weatherization, and other factors affecting resource availability in the winter. Evaluated solutions being pursued by other ISOs. Proposed changes to resource adequacy requirements and energy market design to mitigate the risks.
- Gas-Electric Reliability Challenges in the Midcontinent. For MISO, provided a PowerPoint report assessing future gas-electric challenges as gas reliance increases. Characterized solutions from other ISOs. Provided inputs on the cost of firm pipeline gas vs. the cost and operational characteristics of dual-fuel capability.

RTO Participation and Configuration

• Market Impacts of RTO Seams. For a consortium of utilities, submitted written testimony to the FERC analyzing the financial and operational impact of the MISO-PJM seam on Michigan and Wisconsin. Evaluated economic hurdles across RTO seams and assessed the effectiveness of inter-RTO coordination efforts underway. Collaborated

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with MISO staff to leverage their PROMOD IV model to simulate electricity markets under alternative RTO configurations.

- Analysis of RTO Seams. For a Wisconsin utility in a proceeding before the FERC, assisted expert witness on (1) MISO and PJM's real-time inter-RTO coordination process, and (2) the economic benefit of implementing a full joint-and-common market. Analyzed lack of convergence between MISO's and PJM's energy prices and shadow prices on reciprocal coordinated flow gates.
- RTO Participation. For an integrated Midwest utility, advised client on alternative RTO choices. Used GE-MAPS to model the transmission system and wholesale markets under various scenarios. Presented findings to senior management. Subsequently, in support of testimonies submitted to two state commissions, quantified the benefits and costs of RTO membership on customers, considering energy costs, FTR revenues, and wheeling revenues.

Energy Litigation

- Demand Response Arbitration. Provided expert testimony on behalf of a client that had acquired a demand response company and alleged that the company had overstated its demand response capacity and technical capabilities. Analyzed discovery materials including detailed demand response data to assess the magnitude of alleged overstatements. Calculated damages primarily based on a fair market valuation of the company with and without alleged overstatements. Provided deposition, expert report, and oral testimony before the American Arbitration Association (non-public).
- Contract Damages. For the California Department of Water Resources and the California Attorney General's office, supported expert providing testimony on damages resulting from an electricity supplier's alleged breaches of a power purchase agreement. Analyzed two years of hourly data on energy deliveries, market prices, ISO charges, and invoice charges to identify and evaluate performance violations and invoice overcharges. Assisted counsel in developing the theory of the case and provided general litigation support in preparation for and during arbitration. Resulted in successful award for client.
- Contract Damages. For the same client described above, supported expert providing testimony in arbitration regarding the supplier's alleged breaches in which its scheduled deliveries were not deliverable due to transmission congestion. Quantified damages and demonstrated the predictability of congestion, which the supplier was allegedly supposed to avoid in its choice of delivery points.
- Contract Termination Payment. For an independent power producer, supported expert testimony on damages from the termination of a long-term tolling contract for a gasfired power plant in PJM, involving power market forecasting, financial valuation techniques, and a detailed assessment of the plant's costs and operating characteristics. Prepared witness for arbitration and assisted counsel in deposing and cross-examining opposing experts. Resulted in resounding victory for client.

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Tariff and Rate Design

- Wholesale Rates. On behalf of a G&T co-op in the Western U.S., provided testimony regarding its wholesale rates, which are contested by member co-ops. Analyzed the G&T co-op's cost of service and its marginal cost of meeting customers' energy and peak demand requirements.
- Transmission Tariffs. For a merchant generating company participating in FERC hearings on developing a Long Term Transmission Pricing Structure, helped lead a coalition of stakeholders to develop a position on how to eliminate pancaked transmission rates while allowing transmission owners to continue to earn their allowed rate of return. Analyzed and presented the implications of various transmission pricing proposals on system efficiency, incentives for new investment, and customer rates throughout the MISO-PJM footprint.
- Retail Rate Riders. For a traditionally regulated Midwest utility, helped general counsel to evaluate and support legislation, and propose commission rules addressing rate riders for fuel and purchased power and the costs of complying with environmental regulations. Performed research on rate riders in other states; drafted proposed rules and tariff riders for client.
- Rate Filings. For a traditionally regulated Midwest utility, assisted counsel in preparing for a rate case. Helped draft testimonies regarding off-system sales margins and the cost of fuel.

Business Strategy

- Preparing a Gentailer for a Transformed Wholesale Market Design. Supported a gentailer in Alberta to prepare its generation and retail businesses for the implementation of a capacity market.
- Evaluation of Cogeneration Venture. For an unregulated division of a utility, evaluated a venture to build and operate cogeneration facilities. Estimated the market size and potential pricing, and assessed the client's capabilities for delivering such services. Analyzed the target customer base in detail; performed technical cost analysis for building and operating cogeneration plants; analyzed retail/default rate structures against which new cogeneration would have to compete. Senior management followed our recommendations to shut down the venture.
- Strategic Sourcing. For a large, diversified manufacturer, coordinated a cross-business unit client team to reengineer processes for procuring electricity, natural gas, and demand-side management services. Worked with executives to establish goals. Gathered data on energy usage patterns, costs, and contracts across hundreds of facilities. Interviewed energy managers, plant managers, and executives. Analyzed potential

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suppliers. Helped draft RFPs and develop negotiating strategy. Designed internal organizational structure (incorporating outsourced service providers) for managing energy procurement on an ongoing basis.

- M&A Advisory. For a European utility aiming to enter the U.S. markets and enhance its trading capability, evaluated acquisition targets. Assessed potential targets' capabilities and their value versus stock price. Reviewed experiences of acquirers in other M&A transactions. Advised client against an acquisition, just when the market was peaking (just prior to collapse).
- Marketing Strategy. For a power equipment manufacturer, identified the most attractive target customers and joint-venture candidates for plant maintenance services. Evaluated the cost structure and equipment mix of candidates using FERC data and proprietary data. Estimated the value client could bring to each customer. Worked with company president to translate findings into a marketing strategy.
- Distributed Generation (DG) Market Assessment. For the unregulated division of a major utility, performed a market assessment of DG technologies. Projected future market sizes by market segments in the U.S.
- Fuel Cells. For a European fuel cell component manufacturer, acted as a technology and electricity market advisor for a larger consulting team developing a market entry strategy in the U.S.

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TESTIMONY and REGULATORY FILINGS

Before the FERC, Docket Nos. EL19-58 and ER19-1486, "Supplemental Affidavit of Samuel A. Newell and James A. Read Jr. on Behalf of PJM Interconnection, L.L.C.," regarding the use of forward-looking data to estimate energy and ancillary services revenues for the purposes of determining capacity market parameters, September 17, 2020.

Before the FERC, Docket Nos. EL19-58 and ER19-1486, "Affidavit of Samuel A. Newell, James A. Read Jr., and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," regarding the use of forward-looking data to estimate energy and ancillary services revenues for the purposes of determining capacity market parameters, August 5, 2020.

Before the FERC, Docket Nos. EL16-49, ER18-1314-000, ER18-1314-001, EL18-178-000 (Consolidated), "Supplemental Affidavit of Samuel A. Newell, John M. Hagerty and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," regarding the expansion of the Minimum Offer Price Rule in its forward capacity market, March 23, 2020.

Before the FERC, Docket Nos. EL16-49, ER18-1314-000, ER18-1314-001, EL18-178-000 (Consolidated), "Affidavit of Samuel A. Newell, John M. Hagerty and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," regarding the expansion of the Minimum Offer Price Rule in its forward capacity market, March 17, 2020.

Before the Indiana General Assembly 21st Century Energy Policy Development Task Force, "Electricity Transmission Basics," on behalf of the Indiana Energy Association, October 17, 2019.

Before the FERC, Docket No. ER19-105-000, Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, "Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," regarding the Cost of New Entry, accompanied by report, *PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, October 12, 2018.

Before the FERC, Docket No. ER19-105-000, Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, "Affidavit of Dr. Samuel A. Newell and David Luke Oates on behalf of PJM Interconnection, L.L.C," regarding the Variable Resource Requirement Curve Shape, accompanied by report, *Fourth Review of PJM's Variable Resource Requirement Curve*, October 12, 2018.

Before the FERC, Docket Nos. EL16-49-000, ER18-1314-000, ER18-1314-001, EL18-178-000 (Consolidated), Affidavit of Kathleen Spees and Samuel A. Newell Regarding the Need for a Self-Supply Exemption from Minimum Offer Price and Other Policy Supported Resource Rules on behalf of Dominion Energy Services, Inc. and Virginia Electric and Power Company, October 2, 2018.

Before the FERC, Docket Nos. EL17-32-000 and EL17-36-000, Prefiled Comments of Samuel A. Newell, Kathleen Spees, and Yingxia Yang on behalf on behalf of the Natural Resources Defense Council: "Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM," April 15,

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2018; presented oral testimony on the Seasonality Panel at FERC's Seasonal Capacity Technical Conference on April 24, 2018.

Before the FERC, Docket No. EL18-34-000, Samuel A. Newell, Pablo A. Ruiz, and Rebecca C. Carroll, "Evaluation of PJM's Fast-Start Pricing Proposal," report prepared for NextEra Energy Resources and attached to *Reply Brief of Joint Commenters*, March 14, 2018.

Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, oral testimony and cross examination on the electricity market impacts of the proposed Northern Pass Transmission Project, October 26-27, 2017.

Before the FERC, Docket No. AD17-11-000, Prefiled Comments of Samuel A. Newell re "Reconciling Wholesale Competitive Markets with State Polices," April 25, 2017; and oral testimony on Industry Expert Panel at the Technical Conference on May 2, 2017.

Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, Prefiled Supplemental Testimony of Samuel Newell and Jurgen Weiss on behalf of the New Hampshire Counsel for the Public, with attached report, "Electricity Market Impacts of the Proposed Northern Pass Transmission Project--Supplemental Report," April 17, 2017.

Before the FERC, Docket No. ER17-284-000, filed "Response of Dr. Samuel A. Newell, Dr. Kathleen Spees, and Dr. David Luke Oates on behalf of Midcontinent Independent System Operator Regarding the Competitive Retail Solution," January 13, 2017.

Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, Prefiled Direct Testimony of Samuel Newell and Jurgen Weiss on behalf of the New Hampshire Counsel for the Public, with attached report, "Electricity Market Impacts of the Proposed Northern Pass Transmission Project," December 30, 2016.

Before the FERC, Docket No. ER17-284-000, filed "Testimony of Dr. Samuel A. Newell, Dr. Kathleen Spees, and Dr. David Luke Oates on behalf of Midcontinent Independent System Operator Regarding the Competitive Retail Solution," November 1, 2016.

"Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," Appendix 1 to Comparative Evaluation of Alternating Current Transmission Upgrade Alternatives, Trial Staff Final Report, *Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades*, New York State Department of Public Service, Matter No. 12-02457, Case No. 12-T-0502, September 22, 2015. Presented to NYISO and DPS Staff at the Technical Conference, Albany, NY, October 8, 2015.

Before the Maine Public Utilities Commission, Docket No. 2014-00071, filed "Testimony of Dr. Samuel A. Newell and Matthew P. O'Loughlin on Behalf of the Maine Office of the Public Advocate, Comments on LEI's June 2015 Report and Recommendations for a Regional Analysis," November 18, 2015.

Before the FERC, Docket No. ER14-2940-000, filed "Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC Regarding Variable Resource Requirement Curve," for use in PJM's capacity market, November 5, 2014.

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Before the FERC, Docket No. ER15-68-000, filed "Affidavit of Dr. Samuel A. Newell on behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's Minimum Offer Price Rule, October 9, 2014.

Before the Texas House of Representatives Environmental Regulation Committee, Hearing on the Environmental Protection Agency's Newly Proposed Clean Power Plan and Potential Impact on Texas, invited by Committee Chair to present, "EPA's Clean Power Plan: Basics of the Rule, and Implications for Texas," Austin, TX, September 29, 2014.

Before the FERC, Docket No. ER14-2940-000, filed "Affidavit of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's capacity market, September 25, 2014.

Before the FERC, Docket No. ER14-2940-000, filed "Affidavit of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters," September 25, 2014.

Before the Public Utilities Commission of the State of Colorado, Proceeding No. 13F-0145E, "Answer Testimony and Exhibits of Samuel A. Newell on Behalf of Tri-State Generation and Transmission Association, Inc.," regarding an analysis of complaining parties' responses to Tri-State Generation and Transmission Association, Inc.'s Third Set of Data Requests, Interrogatory, September 10, 2014.

Before the Maine Public Utilities Commission, Docket No. 2014-00071, "Testimony of Dr. Samuel A. Newell and Matthew P. O'Loughlin on Behalf of the Maine Office of the Public Advocate, Analysis of the Maine Energy Cost Reduction Act in New England Gas and Electricity Markets," July 11, 2014.

Before the FERC, Docket No. ER14-1639-000, filed "Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on behalf of ISO New England Inc. Regarding a Forward Capacity Market Demand Curve," April 1, 2014.

Before the FERC, Docket No. ER14-1639-000, filed "Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of ISO New England Inc. Regarding the Net Cost of New Entry for The Forward Capacity Market Demand Curve," April 1, 2014.

Before the FERC, Docket No. ER14-616-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of ISO New England Inc.," and accompanying "2013 Offer Review Trigger Prices Study," regarding the Minimum Offer Price Rule new capacity resources in capacity auctions, December 13, 2013.

Before the American Arbitration Association, provided expert testimony (deposition, written report, and oral testimony at hearing) in a dispute involving the acquisition of a demand response company, July-November, 2013. (Non-public).

Before the Public Utility Commission of Texas, at a workshop on Project No. 40000, presented "Report On ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates Prepared By The Brattle Group," on behalf of The Electric Reliability Council of Texas (ERCOT), June 25,

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2013. Subsequently filed additional comments, "Additional ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates," July 29, 2013.

Before the FERC, Docket No. ER13-535-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of the 'Competitive Markets Coalition' Group Of Generating Companies," supporting PJM's proposed tariff revisions to change certain terms regarding the Minimum Offer Price Rule in the Reliability Pricing Model, December 28, 2012.

Before the FERC, Docket No. ER12-513-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC," in support of PJM's Settlement Agreement regarding the Cost of New Entry for use in PJM's capacity market, November 21, 2012.

Before the Texas House of Representatives State Affairs Committee, Hearing on the issue of resource adequacy in the Texas electricity market, presented "The Resource Adequacy Challenge in ERCOT," on behalf of The Electric Reliability Council of Texas, October 24, 2012.

Before The Public Utility Commission of Texas, at a workshop on Project No. 40480, presented "Resource Adequacy in ERCOT: 'Composite' Policy Options," and "Estimate of DR Potential in ERCOT" on behalf of The Electric Reliability Council of Texas (ERCOT), October 25, 2012.

Before The Public Utility Commission of Texas, at a workshop on Project No. 40480, presented "ERCOT Investment Incentives and Resource Adequacy," September 6, 2012.

Before The Public Utility Commission of Texas, at a workshop on Project No. 40480, presented "Summary of Brattle's Study on ERCOT Investment Incentives and Resource Adequacy," July 27, 2012.

Before the FERC, Docket No. ER12-____000, Affidavit of Dr. Samuel A. Newell on Behalf of SIG Energy, LLLP, March 29, 2012, Confidential Exhibit A in Complaint of Sig Energy, LLLP, SIG Energy, LLLP v. California Independent System Operator Corporation, Docket No. EL 12-____000, filed April 4, 2012 (Public version, confidential information removed).

Before the FERC, Docket No. ER12-13-000, filed "Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's capacity market, January 13, 2012.

Before the FERC, Docket No. ER12-13-000, Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC, re: the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model, filed December 1, 2011.

Before the FERC, Docket Nos. ER11-4069 and ER11-4070, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of the RITELine Companies, re: the public policy, congestion relief, and economic benefits of the RITELine Transmission Project, filed July 18, 2011.

Before the FERC, Docket No. No. EL11-13-000, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of The AWC Companies re: the public policy, reliability, congestion relief, and economic benefits of the Atlantic Wind Connection Project, filed December 20, 2010.
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"Economic Evaluation of Alternative Demand Response Compensation Options," whitepaper filed by ISO-NE in its comments on FERC's Supplemental Notice of Proposed Rulemaking in Docket No. RM10-17-000, October 13, 2010 (with K. Madjarov).

Before the FERC, Docket No. RM10-17-000, Filed Comments re: Supplemental Notice of Proposed Rulemaking and September 13, 2010 Technical Conference, October 5, 2010 (with K. Spees and P. Hanser).

Before the FERC, Docket No. RM10-17-000, Filed Comments re: Notice of Proposed Rulemaking regarding wholesale compensation of demand response, May 13, 2010 (with K. Spees and P. Hanser).

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2010 "Integrated Resource Plan for Connecticut" (see below), June 2010.

2010 "Integrated Resource Plan for Connecticut," report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 4, 2010. Presented to the Connecticut Energy Advisory Board January 8, 2010.

"Dynamic Pricing: Potential Wholesale Market Benefits in New York State," lead authors: Samuel Newell and Ahmad Faruqui at The Brattle Group, with contributors Michael Swider, Christopher Brown, Donna Pratt, Arvind Jaggi and Randy Bowers at the New York Independent System Operator, submitted as "Supplemental Comments of the NYISO Inc. on the Proposed Framework for the Benefit-Cost Analysis of Advanced Metering Infrastructure," in State of New York Public Service Commission Case 09-M-0074, December 17, 2009.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2009 "Integrated Resource Plan for Connecticut" (see below), June 30, 2009.

2009 "Integrated Resource Plan for Connecticut," report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 1, 2009.

"Informational Filing of the Internal Market Monitoring Unit's Report Analyzing the Operations and Effectiveness of the Forward Capacity Market," prepared by Dave LaPlante and Hung-po Chao of ISO-NE with Sam Newell, Metin Celebi, and Attila Hajos of The Brattle Group, filed with FERC on June 5, 2009 under Docket No. ER09-1282-000.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2008 "Integrated Resource Plan for Connecticut" and "Supplemental Reports" (see below), September 22, 2008.

"Integrated Resource Plan for Connecticut," co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board; coauthored with M. Chupka, A. Faruqui, and D. Murphy, January 2, 2008. Supplemental Report cosubmitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Department of Utility Control; co-authored with M. Chupka, August 1, 2008.

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"Market Design for Winter Energy Security in New England: Further Discussion of Options," presented to The New England Power Pool Markets Committee on behalf of NextEra Energy Resources, Westborough, MA, February 6, 2019 (with D.L. Oates and P. Ruiz).

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"System Flexibility and Renewable Energy Integration: Overview of Market Design Approaches," presented to Texas-Germany Bilateral Dialogue on Challenges and Opportunities in the Electricity Market, Austin, TX, February 26, 2018.

"Natural Gas Reliability: Understanding Fact from Fiction," panelist at the NARUC Winter Policy Summit presented to The Committee on Gas, Washington, D.C., February 13, 2018 (with A. Thapa, M. Witkin, and R. Wong).

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"ERCOT's Future: A Look at the Market Using Recent History as a Guide," panelist at the Gulf Coast Power Association's Fall Conference, Austin, TX, October 4, 2016.

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"PJM Capacity Auction Results and Market Fundamentals," presented to Bloomberg Analyst Briefing Webinar, September 18, 2015 (with J. Pfeifenberger and D.L. Oates).

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"Electric Infrastructure Needs to Support Bulk Power Reliability," presented to GEMI Symposium: Reliability and Security across the Energy Value Chain, The University of Houston, Houston, TX, March 11, 2015.

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"Resource Adequacy in New England: Interactions with RPS and RGGI," Energy in the Northeast Law Seminars International Conference, Boston, MA, October 18, 2007.

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EXHIBIT B

Spees, et al., "Quantitative Analysis of Resource Adequacy Structures," Prepared for NYSERDA and NYSDPS, July 1, 2020

Quantitative Analysis of Resource Adequacy Structures

PREPARED FOR NYSERDA and NYSDPS

PREPARED BY Kathleen Spees Sam Newell John Imon Pedtke Mark Tracy

July 1, 2020



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Study Scope

NYSERDA and NYDPS retained Brattle to evaluate several alternative resource adequacy constructs that differ primarily in who administers them and how Buyer-Side Mitigation (BSM) is applied; this deck presents estimates of the differences in customer costs.

Structure		Description	Cost Evaluation	
1	ICAP Market with Status Quo BSM	Current ICAP market with current rules	Compared to #3 to indicate costs of Status Quo BSM	
2	ICAP Market with Expanded BSM	Same as above but with potential expansion to BSM rules corresponding to FERC's December 2019 order for PJM	Compared to #3 to indicate costs of potential Expanded BSM	
3	Centralized Market for Resource Adequacy Credits (RACs), without BSM	Functionally similar to current ICAP market, but with rule-setting by State No BSM, except as applied by PSC to prevent the intentional introduction of uneconomic capacity to profitably suppress capacity prices	Evaluated as "No BSM"	
4	LSE Contracting for RACs	Same as #3, but with no centralized market LSEs must procure sufficient RACs bilaterally	Similar to #3 but difficult to quantify	
5	Co-optimized Capacity and Clean Energy Procurement	Same as #3, but a State entity would procure RACs and RECs for LSEs in a joint, co-optimized auction	Not evaluated (out of scope)	

Summary of RA Structures Corresponding to Brattle Qualitative Analysis Memo

Approach and Key Assumptions

To estimate customer cost impacts, we simulated future wholesale markets (including the application of BSM) in 2030, using Brattle's GridSIM model. Key Assumptions:

- Modeled fleet reflects the Climate Leadership and Community Protection Act (CLCPA) and NYISO CARIS study:
 - 70% of load is met by renewable resources by 2030 (does not include Nuclear generation)
 - Annual gross load, 6,100 MW of offshore wind (OSW), 3,000 MW of storage, and 7,500 MW of behind-the-meter (BTM) solar assumptions consistent with CLCPA targets and 2019 CARIS study assumptions
- Assumptions on BSM applicability were updated to align with NYISO's proposed exemption rule:
 - 1. "Status Quo" applies BSM to new renewables and storage in Zones G-J, except approximately 550 UCAP MW of policy exemptions
 - 2. "Expanded BSM" extends BSM to all zones, incl. nuclear and half of the existing hydro resources (assuming CapEx projects), with exemptions for 160 UCAP MW of OSW in Zone J, 173 UCAP MW of OSW in Zone K, and 41 UCAP MW of PV in Zones G-I
 - 3. Centralized RAC Market w/ "No BSM" does not exclude any resources from the capacity market
- Assumptions on UCAP ratings of intermittent resources affect the magnitude of BSM
 - UCAP value declines with penetration; analyzed output vs. net load to estimate effective load-carrying capability (ELCC)
 - Available output data had low CF% and output diversity, making impact estimates conservative; on the other hand, analysis does not
 recognize that transmission constraints could make the local J/K value fall faster with penetration
- Other key assumptions: resources' fixed and variable costs contributing to capacity prices via supply elasticity
- Sensitivity analyses: explored effects of nuclear retirements; higher load; quantity of BSM policy exemptions

The 2030 system examined here leveraged CARIS 70*30 and otherwise made necessary simplifying assumptions. While the system examined in 2030 does not represent a prediction of the future system, it is a reasonable expectation for the purpose of examining alternative RA structures

Cost estimates are thus indicative; impact will ultimately depend on the year, load, supply mix, UCAP ratings, and capacity supply elasticity, and the details of any changes to BSM rules

Updates to this Quantitative Analysis

We have updated this quantitative analysis based on stakeholder input received and to better reflect NYISO's proposed BSM rules and recent developments

- The most important changes provide a more accurate representation of likely outcomes under the "Status Quo" buyer-side mitigation approach, including:
 - Higher renewables exemption (assuming that NYISO's April 20 filing is accepted)
 - Sensitivity analysis on the quantity of public policy resource exemptions
 - Offer floor at the minimum of 0.75x mitigation Net CONE or resource offer floor
 - Updated representation of resource retirements and winter only status as per the NY DEC "Peaker Rule" Part 227-3 and 2020 Gold Book
 - Updated going-forward cost assumptions for fossil resources that are at risk of retirement (identified as a key study sensitivity)
- Overall Impact of Updates: Estimated customer costs imposed by Status Quo BSM are somewhat lower, but the uncertainty range remains similar at approximately \$0.4-\$0.9 billion per year; Expanded BSM scenario costs remain similar at approximately \$1.3-\$2.8 billion per year

Summary of Conclusions

- By 2030 relative to a No-BSM scenario, estimated customer costs increase by:
 - <u>\$0.4-0.9 billion/year under Status Quo BSM</u> (~12%-20% of statewide capacity costs or ~24%-34% of Zones G-J capacity costs), range depending on load growth and exemptions
 - <u>\$1.3-2.8 billion/year under Expanded BSM</u> (~35%-63% of statewide capacity costs), range depending on load growth and nuclear resource retention
- This reflects costs of over-procuring capacity because mitigated policy resources would not be accounted for in the capacity market, including:
 - <u>Contract costs increase</u> for policy resources, since they are denied capacity payments
 - <u>Capacity market clearing prices rise</u>
- These estimates account for moderating long-term factors:
 - <u>Long-term supply elasticity</u> mitigates capacity price impacts so it is smaller than the "double-payment" quantity effect (showing up as higher contract costs)
 - Lower resource UCAP values at higher penetration of mitigated renewable resources limit the impact of BSM
 - Offsetting E&AS impacts, but these are relatively small
 - <u>Policy resource exemptions</u> can somewhat mitigate costs



Analytical Results

Estimated Customer Costs of BSM in 2030

Net impact of BSM on customers is \$0.5 billion/yr under Status Quo; \$1.8 billion/yr under Expanded BSM.



* Energy and AS prices decrease in some cases because excess capacity depresses prices in tight hours; and because higher contract payments (due to lack of capacity payments) cause energy prices to be more negative in over-generation hours.

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Sensitivity of BSM Costs to Supply-Demand Balance

Customer costs of BSM are sensitive to peak load (higher load driving higher costs)



Increased Annual Customer Costs Relative to No-BSM Structure

Notes: "No-Nuclear Sensitivity" loses all >3 GW of upstate nuclear, largely replaced by retaining gas CCs, so fewer resources to mitigate. "High-Load Sensitivity" results in additions of onshore wind to meet 70% target.

Sensitivity of Status Quo BSM Costs to Policy Resource Exemptions

We evaluated the sensitivity of Status Quo costs to +/- 400 MW of policy resource exemptions

Costs remain similar because:

- Base Case: Gas ST is marginal, so 400 MW policy exemptions displaces 400 MW of gas ST retention
- High Load Case: Generic offer floor is marginal in all cases, so 400 MW exemptions results in +400 MW generic offer floor resources (and vice versa)





Base Case Detailed Results

Base Case Supply Mix

Existing generation is consistent with the 2019 Gold Book, and planned capacity changes are based on signed CES contracts and CARIS study assumptions. The model economically retires old plants and builds new clean ones to meet any remaining gap to reach CLCPA 70% target



Capacity Subject to Mitigation before considering exemptions or clearing

Mitigated Non-Emitting Capacity by Zone (ICAP MW)

Blue shading subject to Status Quo BSM

Expanded BSM applies to blue and teal

	2018	Planned/Assumed 2019-2030 Additions/Retirements			Economic Additions		Total Capacity		
	Capacity		(Fixed Input)		(Determined by Model)		by 2030
		Zone A-E	Zone F	Zone G-I	Zone J	Zone K	Zone A-E	Zone F-K	
Hydro & PS	5,436	0	0	0	0	0	0	0	5,436 **
Onshore Wind	1,739	1,710	0	0	0	0	1,814	0	5,263
Offshore Wind	0	0	0	0	4,320*	1,778	0	0	6,098
Solar	77	2,677	0	284*	0	0	0	0	3,038
Storage	0	660	240	270	1,350	480	0	0	3,000
Nuclear	5,399	0	0	(2,054)	0	0	0	0	3,345
Capacity Import	1,100	0	0	0	1,000	0	0	0	2,100
Total	13,751	5,047	240	(1,500)	6,670	2,258	1,814	0	28,280

Notes: 2018 installed capacity informed by <u>2019 Gold Book</u>. Planned/assumed builds are informed by <u>2019 CARIS study</u> assumptions and signed CES contracts based on <u>2018-2019 CES contract summary document</u> and recent <u>2019 Tier 1 solicitation</u>.

* 816 ICAP MW OSW in Zone J and 880 ICAP MW OSW in Zone K procured in <u>2018 solicitation</u> and 284 MW solar in Zone GHI exempt in both Status Quo and Expanded BSM. See the following slide for assumptions regarding status quo renewable exemptions as assumed consistent with the April 20 NYISO filing.

** Half of existing hydro fleet assumed to be mitigated under Expanded BSM.

Status Quo Exemptions

The quantity of possible public policy resource exemptions under the NYISO's April 20 proposed approach is subject to considerable uncertainty. Our updated analysis assumes ~550 UCAP MW of exemptions (with a sensitivity analysis of +/-400 UCAP MW)

- Given the large uncertainties, our assumed quantity of exemptions is intentionally abstracted from specific predictions such as which resources may be deemed "policy-driven" retirements
- Overall quantity is consistent with outlook for load growth, retirements, and demand curve width
- In "high exemptions" scenario, we further assume that some storage becomes exempt through other means (such as via Part A or Part B tests)

Status Quo Exemptions by Zone

	Zones G-I	Zone J	Zones G-J
Summer UCAP Supply (UCA	PMW)		
Offshore Wind	0	848	848
Storage	270	1,350	1,620
Solar	41	0	41
Capacity Imports	0	1,000	1,000
Exemptions (UCAP MW)			
Public Policy Resources	41	507	548
Remaining Mitigated Resou	irces (UCAP	MW)	
Offshore Wind	0	341	341
Storage	270	1,350	1,620
Solar	0	0	0
Capacity Imports	0	1,000	1,000

Summary of Mitigation and Market Response Quantities (NYCA-Wide)

In Status Quo BSM, essentially all of the ~3,000 summer UCAP MW uncleared mitigated capacity is replaced by retained gas ST

In Expanded BSM, ~1,150 summer UCAP MW of the 8,000 summer UCAP MW uncleared mitigated capacity is *not* replaced (mostly Upstate), resulting in a higher capacity prices and costs



Mitigated capacity in Zones G-J only under Status Quo, mostly OSW and storage in Zone J that is replaced by retained gas ST plants. UCAP values reflect average ELCC. Capacity numbers are approximate. Mitigated capacity in all zones. Mitigated OSW and storage in Zones J and K largely offset by retained gas resources. All UCAP values shown reflect average ELCC. Capacity numbers are approximate.

Prices and Customer Costs

Zone J Capacity prices remain similar across all structures as retiring gas ST resources are marginal. Capacity prices in A-F increase significantly in Expanded BSM as more renewables and nuclear resources are mitigated, thus retaining more thermal plants that would otherwise retire

Wholesale Market Prices

	Capa (20	city Market Pi 30 \$/kW-mon	Delta Above (Below) No BSI (2030 \$/kW-month)		
	2. Expanded				2. Expanded
Zone	1. Status Quo	BSM	3. No BSM	1. Status Quo	BSM
A-E	\$3.65	\$8.13	\$3.69	(\$0.04)	\$4.44
F	\$3.65	\$8.13	\$3.69	(\$0.04)	\$4.44
G-I	\$6.05	\$8.13	\$6.05	(\$0.00)	\$2.08
J (NYC)	\$12.33	\$12.32	\$12.34	(\$0.01)	(\$0.02)
K (LI)	\$13.05	\$13.88	\$13.05	\$0.00	\$0.83

	Energy Market Prices (2030 \$/MWh)			Delta Above (203	e (Below) No BSM 0 \$/MWh)
A-E	\$28.02	\$27.99	\$28.02	\$0.00	(\$0.03)
F	\$30.28	\$30.23	\$30.28	\$0.00	(\$0.05)
G-I	\$30.36	\$30.33	\$30.36	\$0.00	(\$0.03)
J (NYC)	\$30.36	\$30.33	\$30.36	\$0.00	(\$0.03)
K (LI)	\$32.19	\$32.19	\$32.19	\$0.00	(\$0.00)

Cost of BSM Customer Costs Delta Above (Below) No BSM (2030 \$ million) 1. Status Quo 2. Expanded BSM Category Wholesale Market Cost \$25 \$941 Energy \$O (\$7) (\$0) \$0 **Ancillary Services** Capacity \$25 \$949 **Contract Costs** \$434 \$842 **Total Customer Cost** \$458 \$1,784 \$1,622 **Excluding Nuclear Make-Whole** \$457



Modeling Approach and Assumptions

Brattle GridSIM Model



GridSIM Optimization Engine

Objective Function

Minimize NPV of Investment & Operational Costs



Constraints

- Market Design and Co-Optimized Operations
 - Capacity
 - Energy
 - Ancillary Services
- Regulatory & Policy Constraints
- Resource Operational Constraints
- Transmission Constraints



Demand Assumptions

- "Base Load" load assumptions align with 2019 CARIS study input assumptions for 2030
- "Base Load" assumes lower demand than 2019 (156 TWh gross load)
- Modeled "High Load" based on State Team input that assumes greater load than 2019

2030 Demand Assumptions

	Base Load	High Load
Scenarios	Base Case No-Nuclear	High-Load
Annual Gross Load	145 TWh	169 TWh
Gross Peak Load	30 GW	35 GW
Net Peak Load	28 GW	33 GW

Sources and Notes:

"Base Load" annual gross load assumptions are based on 2019 CARIS study. Used ratio of 2019 annual gross load and CARIS annual gross load to convert 2019 gross peak loads to 2030 gross peak loads on zonal level.

"High Load" annual gross load assumptions based on State Team's input. Calculated peak loads based on annual gross load ratio as described above. Netted out assumed 7,542 MW of solar BTM (based on 2019 CARIS study) valued at ~27% summer capacity value from gross peak load to calculate net peak load (similar to Gold Book assumptions).

2019 load data taken from NYISO OASIS data.

Supply Cost Characteristics

Resources' fixed O&M costs affect supply elasticity and BSM price impacts. Sources:

- New Gas CCs, CTs: 2020 costs from Demand Curve Reset (DCR); 2.2% cost inflation rate
- New Gas STs: 2019 costs and cost decline rate from 2019 NREL ATB (0% to -1%/year real)
- New wind, solar, storage: 2019 costs and cost decline rate from 2019 NREL ATB (0% to -7% /year real)
- Existing Nuclear: 2019 costs from NEI (constant real), plus assumed \$280/kW-year refurbishment cost adder in 2030
- Existing CTs, STs: FOM from NYISO 2018 SOM Report
- Other existing thermal: FOM assumed 2x new units
- All other existing: Same FOM as new resources
- Zone J and K: FOM assumed 1.3 2.7x higher than upstate based on DCR zonal cost ratios
- Offshore wind tied to either zone J or K
- Utility-scale PV and onshore wind cannot be built in zones J or K

Sources and Notes:

Includes interconnection and network upgrade costs. <u>NREL 2019 ATB</u>, <u>NYISO DCR Model 2019-2020 and 2020-2021</u>, and <u>NEI Nuclear Costs in Context</u>. VOM for storage resources reflect efficiency losses. Existing FOM for nuclear includes refurbishment costs.

FOM costs for existing STs and CTs were based on average GFC shown in Figure 16 of the <u>2018 State of the Market Report</u>; FOM costs for existing Gas CTs upstate assumed to be half of those for existing Gas CTs in Zone K.

FOM costs for other existing thermal resources were assumed to be 2x that of comparable new ones, informed by EPA Integrated Planning Model document. Nuclear refurbishment costs informed by refurbishment costs for nuclear plants in Ontario.

2030 Resource Cost Assumptions

	Upstate New Resource Capital Cost 2030\$/kW	Upstate New Resource FOM 2030\$/kW-yr	Upstate Existing Resource FOM + Refurb Costs 2030\$/kW-yr	Variable O&M 2030\$/MWh
Natural Gas				
Combined cycle	\$2,300	\$27	\$54	\$2
Combustion turbine	\$1,200	\$14	\$25	\$7
Steam turbine	\$5,000	\$43	\$72	\$11
Battery Storage				
4-hour duration	\$1,100	\$26	\$26	\$6
Solar PV				
Utility scale	\$1,100	\$13	\$13	\$0
Wind				
Offshore (downstate)	\$4,600	\$107	\$107	\$0
Onshore	\$1,600	\$50	\$50	\$0
Nuclear				
Single-unit	N/A	N/A	\$602	\$3
Multi-unit	N/A	N/A	\$491	\$3

ELCC Modeling Approach

Supply Resource	Concept	Methodology
Wind and Solar Resources	Generation of new wind and solar additions is correlated with previously deployed resources. New resources therefore provide less marginal capacity value than previously added resources.	 Across 8760 hours, identify 100 top NYCA net load hours Calculate wind UCAP value as avg. output in those hours Repeatedly change the MW of wind installed, all else equal Each time, find top 100 net load hours and the avg. output Repeat process for offshore wind and solar; for each one, hold other variable technologies at likely 2030 levels
Storage Resources	Energy storage can change the "shape" of peak net load periods, flattening and elongating peak periods. As more storage is deployed, longer discharge durations are therefore required to provide the same capacity value.	 Across 8760 hours, analyze MW of storage required to reduce NYCA net peak load by 1 MW Calculate UCAP value as 1 MW peak reduction / MW storage required Increase amount of storage assumed, holding all else equal. Simulate effect of increased storage on net peak load Repeat steps 1 – 3 across many storage deployment levels Repeat process for storage of different durations

Base Case UCAP Value Curves modeled based on NYCA-wide net load

As the penetration increases, marginal effective load-carrying capability (ELCC) decreases.

Note: this analysis may have conservatively low ELCCs for renewables, based on hourly data with lower output than future installations are likely to achieve (and that does not capture diversity across sites for OSW); on the other hand, this analysis uses NYCA-wide net load without considering how transmission constraints could reduce value more quickly.



Summer UCAP Value

Winter Capacity Value

Note: solar capacity credit curves include assumed 7,542 MW of solar BTM already on the grid (based on CARIS study assumption). brattle.com | 21

Assumptions on BSM Applicability

Resource Type	BSM in Structure 1. Status Quo		BSM in Structure 2.	BSM in Structure 2. Expanded BSM	
	Zones G-J	Rest of System	Zones G-J	Rest of System	
Nuclear	N/A		N/A	3,345 ICAP MW	
osw	1,740 ICAP MW (assumed 507 UCAP MW exemption in Zone J applies to OSW)		3,504 ICAP MW (assume 816 ICAP MW of already signed contracts exempt)	898 ICAP MW (assume 880 ICAP MW of already signed contracts exempt)	
Existing Solar and Onshore Wind	No	N/A	Νο	No	
New Utility Scale Solar and Wind	Any new utility scale solar or onshore wind in Zones G-J		All new utility scale solar and onshore wind		
Bulk Storage	1,620 ICAP MW		1,620 ICAP MW	1,380 ICAP MW	
Existing Hydro	No		50 ICAP MW	2,085 ICAP MW	
Tier 2 Renewables	No		No	No	
New HQ Imports	1,000 MW in Zone J		1,000 MW in Zone J	N/A	
Demand Response	No		No	No	
Fossil Resources	No		No No		

Source: Assumptions on applicability provided by NYSERDA/DPS staff.

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EXHIBIT B

Kevin Carden et al., NYISO ELCC Accreditation Analysis, Astrapé Consulting, LLC (Jan. 26, 2022)

UNITED STATES OF AMERICA **BEFORE THE** FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc. submits tariff filing per 35.13(a)(2)(iii): 205: BSM Capacity Accreditation Market Design submitted on 1/5/2022 3:18:12 PM, Filing Type code: 10

Docket No. ER22-772-000

WRITTEN TESTIMONY OF KEVIN CARDEN, TREVOR BELLON, ALEX

DOMBROWSKY


NYISO ELCC Accreditation Analysis

Final Report

1/26/2022

PREPARED FOR

Alliance for Clean Energy New York (ACE NY) Cypress Creek Renewables, LLC Enel North America, Inc. Natural Resources Defense Council (NRDC) New York Battery and Energy Storage Technology Consortium (NY-BEST) Sierra Club

PREPARED BY

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СТ	Combustion Turbine Generation
EFORd	Equivalent Forced Outage Rate Demand
ELCC	Effective Load Carrying Capability
GW	Gigawatt
ICAP	Installed Capacity
IRM	Installed Reserve Margin
ISO	Independent System Operator
LOLE	Loss of Load Expectation
MC	Marginal Cost
MMU	Market Monitoring Unit
MR	Marginal Revenue
MW	Megawatt
NYISO	New York ISO
PRM	Planning Reserve Margin
SERVM	Strategic Energy & Risk Valuation Model
UCAP	Unforced Capacity
WY	Weather Year

EXECUTIVE SUMMARY

The following report has been produced by Astrapé Consulting in response to the marginal ELCC capacity accreditation proposal put forward by the New York Independent System Operator (NYISO) and supported by their Market Monitoring Unit (MMU) for their forward capacity auctions. Astrapé Consulting principals have several decades of experience providing electric system planning services, resource adequacy studies, and effective load carrying capability (ELCC) studies for many of the largest utilities and regulators in the United States and Europe. Astrapé's client list includes MISO, ERCOT, SPP, AESO, Duke Energy, Progress Energy, Southern Company, TVA, Pacific Gas & Electric, Louisville Gas & Electric, Santee Cooper, CLECO, PNM, FERC, NARUC, EPRI, PJM, and the California Public Utilities Commission. In addition to consulting services, Astrapé owns and licenses the probabilistic simulation tool SERVM (Strategic Energy & Risk Valuation Model), which is the primary resource adequacy tool for a majority of the independent system operators (ISOs) in North America and has been used and vetted by public service commissions across the country for various risk and economic based analyses.

Capacity markets are designed with two key objectives: procure enough capacity to ensure system reliability and provide proper price signals to procure that capacity in an economically efficient manner. Unfortunately, as the composition of electric systems becomes more diverse, capacity market design becomes more challenging. In this context, the NYISO has proposed a marginal accreditation scheme which conflates pricing and reliability objectives. In order to disentangle these concepts, it is critical to introduce reliability planning fundamentals and how they apply to both pricing and reliability aspects of capacity markets. With an understanding of reliability planning in place, it will be clear that the most efficient design will ensure that reliability is procured in aggregate while pricing is set on the margin and that this can only be implemented with average ELCC accreditation.

To demonstrate the importance of proper capacity market design, Astrapé Consulting performed rigorous simulations of potential New York resource mixes on the horizon which provide a quantification of the difference between marginal and average ELCCs. As shown in this work and other work performed by various resource adequacy planning entities, the differences between average and marginal capacity accreditation are expected to be significant at most future penetrations for renewable and storage technologies. Accrediting capacity on the margin would therefore create large disconnects between the reliability contributions expected from specific resource classes and the share of capacity revenues those resources would receive. Given the large differences between marginal and average accreditation, this has potentially significant implications for system reliability. For instance, if NYISO procures enough storage to meet the recently announced New York State's Energy Storage Roadmap goal of 6 GW of storage by 2030 (as identified in the 2022 State of the State Report),¹ the reliability contribution expected from storage will be over 5 GW while the capacity will only be compensated for 3 GW.²

¹ Page 146, https://www.governor.ny.gov/sites/default/files/2022-01/2022StateoftheStateBook.pdf

² Average ELCC of 86% multiplied by 6 GW = 5.15 GW. Marginal ELCC of 53% multiplied by 6 GW = 3.17 GW.



Figure ES1. Average and Marginal ELCCs as a Function of Battery Penetration

In summary, the proposed marginal ELCC accreditation by NYISO is inaccurate and poses potential reliability risks for the following reasons:

- 1. Underpays resources relative to their reliability contribution (i.e., does not accurately compensate variable energy resources for the value they provide towards meeting the capacity volume requirement). This has been incorrectly described as "savings" to consumers but is simply a reduction in compensation towards variable energy resources that does not correlate with any reduction in the actual reliability value being provided in aggregate. This may lead to risk of performance issues due to revenues not being commensurate with reliability value that NYISO is trying to procure.
- 2. Disproportionately selects resources with flat sloping ELCC curves, which are predominantly conventional gas and coal resources, and disadvantages resources with steeper ELCC curves, which are renewable and battery technologies. The marginal accreditation construct provides no technical or economic justification for why one portfolio with 5 GW of contribution to reliability should be paid differently from another portfolio that also provides 5 GW of contribution to reliability.
- Conflates average ELCC accreditation with average ELCC pricing by arguing that average ELCC accreditation sends inefficient market signals. Average ELCC accreditation can be used in conjunction with marginal ELCC pricing to produce proper pricing signals and proper revenue determinations.
- 4. Utilizes an ex ante approach to determine the system resource mix, and therefore uses a static ELCC value for every resource class. This can result in both the wrong type and the wrong

quantity of resources clearing the capacity auction, resulting in economically inefficient and potentially unreliable procurement. While ex ante determinations of resource mixes have been approved in past proposals by other ISOs for capacity markets, this issue is only now becoming critical as the penetration of energy-limited and non-dispatchable resources is becoming significant.

I. EFFECTIVE LOAD CARRYING CAPABILITY

NEED FOR PLANNING RESERVES

Grid operators like NYISO must ensure that there are sufficient energy resources available to power the system at all times, even during times of peak demand, such as on the hottest days of summer and coldest days of winter. However, unexpected events can occur, such as significant weather events that cause widespread generator outages and high temperature days that cause higher than forecasted system load. Therefore, systems must procure more capacity than forecasted load to maintain the industry standard level of reliability known as 0.1 Loss of Load Expectation (LOLE). To do this, planners simulate a range of scenarios to identify the required level of reserves that results in fewer than 1 day with firm load shed in 10 years. This is commonly referred to as the Planning Reserve Margin (PRM). New York uses the synonymous term Installed Reserve Margin (IRM).



Figure 1. LOLE vs. Planning Reserve Margin (%)

RESOURCE ACCREDITATION

The PRM is designed to be technology-agnostic which requires that all resources be put on a comparable basis (or normalized) with regard to their reliability value. To determine the reliability value of conventional dispatchable resources like gas generators and coal plants, the only normalization required is based on forced outage rates associated with unexpected shutdowns or fuel supply constraints. A generator with a 10% forced outage rate provides roughly 90% of the reliability value of a generator with a 0% forced outage rate. This adjusted value (90% in this example) is typically referred to as a unit's Unforced Capacity (UCAP) rating.

The normalization of reliability value is more challenging for resources with energy limitations or resources that cannot always be turned on when needed. Resources like batteries can exhaust their stored energy, and wind and solar are reliant on the wind blowing or the sun shining. The reliability value of these resources is determined via Effective Load Carrying Capacity (ELCC) studies which directly compare their reliability contribution to that of a perfectly available resource.³

If all resource technologies are normalized correctly, the PRM will remain static as the resource mix changes. A system that meets reliability with a 20% PRM with all conventional fossil generation should also meet reliability with a 20% PRM when reliability is served by 90% renewables and batteries. The renewables and batteries in this case will just have much lower ELCCs than 100% and so the system will need to procure more of them in order to accomplish this.

Resource accreditation is often a hotly contested process. Every class of generation often fights for the highest possible accreditation. However, maintaining a flat PRM provides a simple rubric for ensuring correct accreditation. If any resource class is given higher accreditation than appropriate, the PRM will increase as that resource class increases in penetration. If any resource class is given lower accreditation than appropriate, the PRM will decrease as that resource class in penetration.



— PRM with over-valuation (e.g., solar given credit for output during peak load hours or nameplate accreditation)
— PRM with correct average ELCC accounting

------ PRM with under-valuation (e.g., solar given credit for output during late evening hours or marginal ELCC)

Figure 2. PRM Error with Increasing Renewable Penetration

³ ELCC studies classically compare resources to additions of load but comparing to perfect resources is mathematically identical.

DECLINING ELCC

As the penetration of energy-limited and non-dispatchable resources increases, the per unit reliability value decreases. Each incremental MW of storage will be needed for longer duration and each incremental MW of wind or solar will have a smaller contribution to the net load peak.

As shown in Figure 3, the average and marginal ELCCs both decline, but intuitively the marginal ELCC declines faster since the first blocks of the technology supplied higher reliability value.



Figure 3. Declining Marginal ELCC Example (Solar)

The marginal ELCC then is used exclusively for marginal pricing. Vertically integrated utilities use marginal ELCC to normalize for reliability contribution in order to compare pricing among technologies when procuring future resources. Average ELCC is used exclusively for accreditation. Those vertically integrated utilities then calculate the average ELCC of all resources in their system to maintain a static PRM.

APPLICATION OF MARGINAL AND AVERAGE ELCC IN CAPACITY MARKETS

Capacity markets require the application of both marginal ELCC and average ELCC. Utilizing the marginal ELCC to calculate the marginal price signal ensures procurement is economically optimal. Utilizing average ELCC to procure a volume of capacity equal to the PRM ensures system reliability. Since NYISO has confused the application of marginal and average ELCCs, the next section will discuss efficient capacity market design principles as they relate to ELCC accounting.

II. EFFICIENT CAPACITY MARKET DESIGN PRINCIPLES

Capacity markets associated with the bulk electric system are designed to accomplish two primary goals for their service territories:

- 1. **Capacity Price Determination:** determine the price to be paid for each unit of capacity, which is established by the marginal resource price
- 2. **Capacity Volume Determination**: establish the total amount of capacity in aggregate required to meet a system reliability standard, such as 0.1 LOLE, regardless of the resource mix that is used to meet this reliability requirement.

CAPACITY PRICE DETERMINATION: PRICING SET ON THE MARGIN

First, marginal pricing is critical. The pricing signal sent to the market should incentivize the lowest cost marginal resource to participate. This is one of the first principles taught in Economics 101. Each incremental unit costs more to produce. Each additional unit of demand comes at a lower price. A profit maximizing firm will produce up to the point where marginal cost (MC) equals marginal revenue (MR).



Figure 4. Marginal Cost and Marginal Revenue Curves

This is not inherently straightforward in electric systems though where there are many different technologies. Before marginal price can be identified, all technologies have to be normalized for their contribution to reliability. As discussed in the previous sections, resources are normalized for their reliability value utilizing UCAP or ELCC. When determining the price for a variable energy resource, the \$/installed capacity MW would be divided by its marginal ELCC so that it can be compared appropriately as you move up the supply stack (starting with highest marginal ELCC value and descending down the marginal ELCC curve as more and more variable resources of the same

technology class are added). The resource with the lowest effective bid price (\$/installed kW-yr / marginal ELCC) where 0.1 LOLE reliability is satisfied should set the marginal price.

CAPACITY VOLUME DETERMINATION: ACCREDITATION IS DETERMINED IN AGGREGATE

To avoid load shed events, every system needs enough capacity to meet the highest load hour in the year. In systems with high renewable and storage penetration, however, reliability events do not always occur in hours where gross load is the highest. As shown in Figure 5, reliability problems could also be expected after sunset when the net load is the highest.



Figure 5. Gross Load vs. Net Load Peak Example

A critical component of the debate over marginal and average ELCCs is whether the capacity auction procurement volume should be determined based on the net load peak (when reliability events are most likely) or based on the gross load peak. As discussed above and recognized in the NYISO proposal,⁴ accrediting capacity at less than its average ELCC will result in a declining PRM or procurement target. This means that by accrediting capacity with marginal ELCC, the volume of capacity targeted by the NYISO proposal is based on the net load in the late afternoon only. After all, energy produced at 12:00-3:00 PM (the original peak timing) often has limited value; producers sometimes even have to pay load to take the energy during those hours in high renewable systems. But the reduction of the gross load

⁴ <u>https://www.nyiso.com/documents/20142/24130223/20210830%20NYISO%20-</u> %20Capacity%20Accreditation v10%20(002).pdf/b12b55d4-7aa9-644a-d803-05ae8df1877c

peak is still a critical component of supplying reliability and should be recognized in the capacity market design. This principle is easiest to understand in the context of energy storage technology.

Batteries do not necessarily shift the net load peak. Since they can be dispatched to perfectly meet the net load peak, their contribution to reliability has a shaving effect as shown in Figure 6.



Figure 6. Net Load Peak at Various Storage Penetration Levels

A 30 GW battery portfolio reduces the net load peak from 30 GW to approximately 10 GW and nearly flattens the net load shape across the entire day. Reliability events are still concentrated in hours 20-21 since batteries continue to be dispatched until they are exhausted. In this example, since the flat load shape means there is no energy to charge incremental storage resources, the marginal value of 4-hour batteries is close to 0%. In a marginal ELCC accreditation construct then, none of the batteries would receive any capacity credit even though the battery portfolio effectively reduced the net load peak by nearly 70% and they are still producing at that level at the time of the reliability event. The only reason that solar appears to have less reliability value is that it shifts the timing of reliability events, but the same principle applies – any reduction in the peak load to be served should be accredited with capacity value since absent that resource class, there is no other mechanism to provide reliability in that period. Once the peak load has been shifted in the case of solar, further contributions to the gross load peak hour should not be given credit, but the initial contributions must be recognized.

Another implication of utilizing marginal ELCC for accreditation is that batteries (or other classes of resources with similar disconnects) that are expected to supply 70% of the energy during emergencies would receive none of the capacity revenue, and consequently would have minimal incentive to perform. Since capacity market performance obligations are enforced via adjustments to capacity market revenue, if there is no revenue to adjust, there is no mechanism to encourage performance. This concern holds at any level of disconnect between reliability supplied and capacity being paid for.

Therefore, there are reliability risks that stem from accrediting solar and storage at a low marginal ELCC even though in combination they are actually being used to reduce the gross load peak from 50 GW down to 10 GW. In an even more extreme scenario, this example could be extended such that solar and storage meet all reliability requirements. While the installed capacities required would be large, and the marginal ELCCs at target system reliability would be close to 0%, this is technically feasible. Further, this is the direction that many systems are headed. New York has goals of 70% renewable energy by 2030 and 100% zero-emission electricity by 2040. California will have greater than 10 GW of short duration storage by 2025 and greater than 30 GW of installed solar capacity. These edge cases where the resources supplying all, or nearly all, of the system's reliability needs, but receive little or none of the capacity revenue demonstrate that marginal accreditation is fundamentally inaccurate. And this principle applies not just for extreme cases. As soon as marginal and average ELCC curves diverge at all, which begins at modest penetrations, there is an inaccurate appropriation of revenue from that class of resource.

This issue is not simply with renewable or battery technologies. Winter reliability is becoming more challenging to supply in the Northeast due to fuel adequacy concerns. If the gas supply is already constrained with the existing gas portfolio, a new gas resource that bids into a winter season capacity market without firm fuel would provide 0% marginal ELCC. In this case, with the NYISO accreditation proposal, a gas portfolio that serves over half the load (per the NYISO 2021 Gold Book, gas resources make up approximately 57% of total installed capacity in 2030) during the time of peak would receive zero revenue from the capacity market.⁵

In all of these examples, under the proper market design, as the marginal ELCC approaches zero, the effective bid price will move drastically higher so that procurement decisions have the right economic signals. A 100 MW battery resource supplying 1% marginal ELCC has the same capacity contribution as a 1 MW perfectly available resource. The battery's effective bid price would then be 100x its nameplate bid (x\$ bid divided by 1% marginal ELCC = 100x per effective MW). If that resource is going to be selected in the auction, its cost would have to be subsidized by state policies or other means, but it is important that the marginal economic signal accurately reflect its reliability value. This is why it is necessary to properly accredit any contribution to reducing the system peak load.

⁵ Page 130, https://www.nyiso.com/documents/20142/2226333/2021-Gold-Book-Final-Public.pdf/b08606d7-db88-c04b-b260-ab35c300ed64

III. PROJECTED NYISO MARGINAL AND AVERAGE ELCCS

The MMU analyzed the implications of marginal and average accreditation in its Consumer Impact Analysis published on November 2, 2021. Their published technology specific capacity credit results when comparing average to marginal accreditation assumptions were potentially misleading. A snapshot of the results is shown in the table below.

			Capa	city Credit by Case (%		
Zone Technology		e Technology Marginal Av		Status Quo - Summer	Status Quo - Winter	
A-F	Solar	7%	16%	9%	2%	
A-F	Land Based Wind	10%	12%	22%	43%	
A-F	2-Hour Storage	42%	43%	32%	32%	
A-F	4-Hour Storage	64%	71%	64%	64%	
A-F	6-Hour Storage	79%	86%	82%	82%	
A-F	8-Hour Storage	87%	92%	100%	100%	
G-I	Solar	14%	24%	9%	2%	
G-I	2-Hour Storage	22%	31%	32%	32%	
G-I	4-Hour Storage	52%	57%	64%	64%	
G-I	6-Hour Storage	75%	80%	82%	82%	
G-I	8-Hour Storage	90%	94%	100%	100%	

Table 1. Capacity Credit Results from MMU Analysis⁶

The difference in capacity credit values for the storage resources between marginal and average accreditation appear to be small. In reality, this is due to significant differences in the assumed resource penetration values between the marginal and average case studies. For example, the marginal case study included only 1,150 MW of 4-hour battery compared to the average case study with 2,150 MW. If the marginal case study had assumed the same penetration at 2,150 MW, the marginal ELCC capacity credit would be much lower, following the marginal ELCC curve.

The capacity credit results from the MMU's preliminary analysis are also much lower than the values expected by Astrapé based on running solar and storage ELCC studies in a wide range of systems for the past 25 years. The low values purported by the MMU would suggest that solar and storage are unlikely to significantly contribute to reliability in New York and thus the concern over ELCC methodology is inconsequential. However, a more realistic analysis than the one conducted by the MMU demonstrates quite the opposite.

To probe the MMU's findings, Astrapé used the SERVM model to calculate NYISO specific marginal and average ELCCs for a range of solar and storage penetrations for the study year 2030. The SERVM model is a resource adequacy tool used by many of the largest utilities in North America as well as several of the ISOs in the U.S. and Canada. A base portfolio was developed for 2030 and a range of solar and storage penetrations were simulated to understand the magnitude of projected ELCCs as well as the relationships between marginal and average ELCC curves. Unless otherwise noted, the resource mixes

⁶ Slide 42,

https://www.nyiso.com/documents/20142/25835955/MMU%20ICAP%20Accreditation%20Consumer%20Impa ct%20Analysis%2011-02-2021.pdf/637ba21e-db75-a4c1-5b41-f770dd26e529

targeted in the scenarios matched scenarios from the NYISO Gold Book. Table 2 contains the resource mix used for the base case.⁷

Unit Category	2030 Goal Installed Capacity (MW)
Community Solar	8,334
Utility Scale Solar	8,583
BTM Batteries	493
PSH	1,407
Hydro	4,807
Land Based Wind	5,275
Offshore Wind	6,200
Conventional	21,168
EOPs	2,775

Table 2. Base Scenario Resource Mix

The penetration levels studied for storage and solar are defined in Tables 3 and 4 below.

Nameplate Capacity (MW)			
BTM Batteries	Utility Scale Batteries ⁸	Total Batteries	
493	507	1,000	
493	1,507	2,000	
493	2,507	3,000	
493	5,507	6,000	
493	8,507	9,000	

Table 3. Battery Penetrations Studied

Table 4. Solar Penetrations Studied

Utility Solar			
Nameplate Capacity			
(MW)			
1,000			
5,000			
8,583			
9,583			

⁷ The derivation of the values used for community solar, utility scale solar, BTM batteries, PSH, land based wind, and offshore wind can be found in Appendix A1.

⁸ All batteries were modeled with a 4-hour duration.

These ELCC values were used directly in quantifying the issues between marginal and average ELCC accreditation to summarize the actual expected impact to the NYISO capacity market. A summary of the resulting ELCCs is provided in Table 5 below.

Study Technology Capacity (GW)	Storage Average ELCC	Storage Marginal ELCC	Solar Average ELCC	Solar Marginal ELCC
1	100%	100%	50%	47%
2	100%	100%	47%	42%
3	100%	93%	45%	36%
4	96%	78%	42%	30%
5	91%	65%	39%	25%
6	86%	53%	36%	19%
7	80%	41%	33%	14%
8	74%	28%	30%	8%
9	69%	16%	28%	2%

Table 5. Summary ELCC Results

As demonstrated from the ELCC results, the differences between the marginal ELCC and average ELCC can be significant, particularly for resources with steeper declining ELCC curves. In some cases, such as storage at 9 GW, the marginal ELCC drops to 16%, which would lead to minimal capacity revenues for all resources in that class, while the technology class would still be expected to supply 69% reliability value based on the average ELCC.

IV. REVIEW OF NYISO MARGINAL ELCC ACCREDITATION PROPOSAL

SUMMARY OF NYISO CAPACITY ACCREDITATION PROPOSAL

The NYISO marginal ELCC capacity accreditation proposal can be summarized in the following steps:

1. A NYISO wide Installed Reserve Margin (IRM) is determined each year utilizing a probabilistic hourly chronological simulation software based on achieving 0.1 LOLE reliability.

 $IRM = \frac{Installed Capacity Required to Acheive 0.1 LOLE (MW)}{Peak Load (MW)}$

- 2. The installed capacity requirement is then converted to a UCAP requirement by applying specific derating factors depending on the technology class.
 - a. Conventional resources are converted to UCAP based on their equivalent forced outage rate demand (EFORd)
 - b. Variable energy resources (solar, wind, battery, etc.) are converted to a UCAP value based on their marginal ELCC value
 - c. Using the resulting total UCAP value, a system derating factor can be determined

 $UCAP_{Conventional} = ICAP * (1 - EFORd)$ UCAP_{Solar} = ICAP * ELCC%_{Marginal,Solar} $UCAP_{Requirement} = UCAP_{Conventional} + UCAP_{Solar} + \dots + UCAP_{n}$

System Derating Factor = $\frac{ICAP_{Requirement} - UCAP_{Requirement}}{ICAP_{Requirement}}$

- 3. Resources bid into the capacity auction, based on per unit accredited capacity (marginal ELCC rate for variable energy resources, UCAP for conventional resources)
- 4. The amount of cleared resources equals the UCAP requirement established in Step 2, with the marginal unit setting the market clearing price
- 5. Payments are allocated to each resource based on the market clearing price multiplied by their accredited capacity value.

Figure 7 summarizes the NYISO proposal where the total capacity accreditation of the cleared portfolio matches the sum of the conventional capacity and the marginal ELCC capacity to match the total gross load at the time of the net load peak.⁹

⁹ The additional capacity that would be supplied above the gross load peak to meet the PRM is disregarded for simplification of the illustration.



Figure 7. Marginal ELCC Accreditation Visualization

MARGINAL ELCC ACCREDITATION PROPOSAL ISSUES

ISSUE #1: MARGINAL ELCC RESOURCE ACCREDITATION DOES NOT ACCURATELY COMPENSATE RESOURCES RELATIVE TO THEIR RELIABILITY CONTRIBUTION

As established in the background section of this report, a key principle of a fair and efficient capacity market is that no resource that clears the market should be advantaged over another so long as that resource is providing the same value. Value is measured relative to a resource's capacity contribution towards meeting the capacity volume requirement, which is an amount set by maintaining the target system reliability. As such, each MW of perfectly available capacity equivalent that contributes to maintaining 0.1 LOLE reliability should receive the same amount of revenue set by the clearing price of the capacity auction.

Utilizing marginal ELCC to determine the capacity accreditation for variable energy resources unfairly underpays these resources relative to their actual reliability contribution as illustrated in Figure 7. It also results in discrimination between variable energy resources, where those with steeper declining marginal ELCC curves are more underpaid than resources with flatter marginal ELCC curves.

Table 6 below provides a detailed summary of the capacity payment discrepancies that arise in a marginal ELCC accreditation construct for each technology resource class under the 2030 Goals Scenario portfolio assumptions. Battery resources are underpaid 38% relative to their actual reliability

contribution and solar resources are underpaid 83% relative to their actual reliability contribution, yet conventional resource revenues remain commensurate with their reliability contribution.

In developing the case for marginal ELCC accreditation, NYISO and the MMU incorrectly claimed that this underpayment to resources can be considered a cost savings to consumers,¹⁰ when in reality this is an artificial revenue reduction to variable energy resources. When payments to resources are not commensurate with their reliability value, the potential for grid reliability risk can be increased. Further, this underpayment results in a potential cost risk that was not accounted for in the MMU's analysis. Existing variable energy resources that required renewable energy credits (RECs) to be developed were based on previous capacity accreditation assumptions. A drastic change to capacity payments, particularly for steeply declining ELCC resources where the marginal ELCC is much lower than the average, may result in resource owners with existing long-term contracts to provide capacity seeking to be made whole with the state of New York. Ultimately, these funds would come from taxpayers/ratepayers.

	Conventional	Utility Solar	Utility Battery Storage	Formulas
Installed Capacity (MW)	21,168	8,583	6,000	[A]
Average ELCC/ UCAP (%)	95%	29%	86%	[B]
Marginal ELCC (%)	95%	5%	53%	[C]
Capacity Contribution (MW)	20,110	2,489	5,160	[D] = [A] * [B]
Capacity Accredited (MW)	20,110	429	3,180	[E] = [A] * [C]
%Delta - Capacity Payments	0%	-83%	-38%	[F] = ([E] – [D]) / [D]

Table 6. 2030 Goals Scenario Capacity Payment Discrepancy Summary

Table 7 quantifies the impact of the potential discrepancy between capacity accredited and capacity supplied as the battery portfolio is built out over time. Critically, these values are based on SERVM simulations which reflect a larger reliability contribution than the values put forward by the MMU. So in the MMU's implementation, the disconnect would start at a lower penetration and increase more rapidly.

¹⁰<u>https://www.nyiso.com/documents/20142/25835955/MMU%20ICAP%20Accreditation%20Consumer%20Imp</u> act%20Analysis%2011-02-2021.pdf/637ba21e-db75-a4c1-5b41-f770dd26e529

Battery Energy Storage Installed Capacity (MW)	Average ELCC (%)	Marginal ELCC (%)	Actual Fleet Reliability Value (MW)	NYISO Accredited Fleet Value (MW)	% Delta
1,000	100%	100%	1,000	1,000	0%
2,000	100%	100%	2,000	2,000	0%
3,000	100%	93%	3,000	2,790	-7%
4,000	96%	78%	3,840	3,120	-19%
5,000	91%	65%	4,550	3,250	-29%
6,000	86%	53%	5,160	3,180	-38%
7,000	80%	41%	5,600	2,870	-49%
8,000	74%	28%	5,920	2,240	-62%
9,000	69%	16%	6,210	1,440	-77%

Table 7. 2030 Goals Scenario Capacity Accreditation Discrepancy Summary

ISSUE #2: MARGINAL ELCC ACCREDITATION PROVIDES DISPROPORTIONATE ECONOMIC DISINCENTIVES FOR VARIABLE ENERGY RESOURCES

As seen in the Table 6 results above, marginal ELCC accreditation disproportionately underpays resources with steeper ELCC curves (e.g., solar, battery storage) relative to resources with flat sloping ELCC curves (e.g., conventional gas and coal resources) for the same reliability contribution. There is no technical or economic reason why 5 GW of contribution to the capacity volume requirement (i.e., perfectly available capacity equivalent) from conventional resources should get compensated more than 5 GW of contribution from battery and solar resources. In the absence of equal payment for equal contribution, there is a larger economic disincentive for battery and solar resources to participate in the capacity market. This disincentive is likely to lead to a lower selection of these types of resources than would otherwise exist and would work counter to the goals and objectives set forth by the state of New York in increasing overall renewable and storage penetration. This selection pressure would have to be made up for in an increase in REC payments or other market subsidies.

ISSUE #3: MARGINAL ELCC ACCREDITATION PROPOSAL CONFLATES AVERAGE PRICING WITH AVERAGE ACCREDITATION

The NYISO proposal justifies marginal ELCC accreditation by stating that it provides a more appropriate price signal as compared to using average pricing. However, accreditation is a separate issue from the establishment of the marginal pricing as established in the Efficient Capacity Market Design Principles section above. To help further illustrate why average pricing and average ELCC accreditation are not the same, and how marginal pricing and average ELCC accreditation can be used in conjunction to create both appropriate price signals as well as a market that provides compensate in proportion to value, the following analogy borrowed from basic economic theory is provided:

Smith Farms sells blueberries. Due to crop densities and other factors, picking the first blueberry is more efficient than picking the last blueberry. Everyone picks at the same rate, but with each additional worker, everyone's productivity drops. Therefore, the cost of production per gallon of blueberries picked rises as demand for blueberries rises.

Blueberry Demand	Workers	Marginal Cost
(gallons)	Required	(\$/Gallon)
1000	10	\$2.35
1800	20	\$2.75
3000	40	\$4.10
4000	80	\$15.46

Table 8. Smith Farms Supply Curve

An entrepreneur has developed a blueberry picking machine that picks at a constant rate regardless of crop density. He offers Smith Farms to pick at a fixed rate of \$6/gallon. Smith Farms is looking for the most efficient mix of workers and machines to pick 4,000 gallons of blueberries. As such, the market clears at \$6/gallon, with the machine displacing the workers whose cost per gallon is above \$6/gallon, resulting in a mix of workers and machines to pick the fields.

Applying this same logic to capacity markets, NYISO is proposing to set the price according to the clearing logic above. Whatever mix of technologies results in the lowest marginal cost is appropriate. However, the NYISO proposal would then pay that price to a different quantity than the total capacity supplied. Using the analogy above, it can be assumed that the last worker hired reduced everyone's productivity such that total production increased by only 33 gallons. Smith Farms then uses the marginal production rate to calculate the payment to all the workers. So despite the fact that each worker produced 60 gallons, they only get paid for 33 gallons/day because of the effect that the last worker had on total production. Over time, this payment structure would provide strong incentives for all workers to produce less or leave Smith Farms. In the same way, NYISO proposes determining the cost of incremental capacity appropriately, but then proposes paying for a much smaller quantity of capacity than is actually procured, producing signals to produce less or exit the market.

Additional descriptions of how marginal pricing and average accreditation can be used in conjunction in capacity markets is summarized in Section V. Example Auction Design.

ISSUE #4: EX ANTE DETERMINATION OF ELCCS, WHETHER AVERAGE OR MARGINAL, CREATES THE POTENTIAL FOR RELIABILITY PROBLEMS OR OVERPROCUREMENT.

Under the NYISO proposal, the UCAP requirement is determined ex ante using a system derating factor from the installed capacity reserve margin requirement. Because the system derating factor utilizes the marginal ELCC to adjust the capacity contribution of the assumed variable energy resource penetration, the resulting UCAP requirement does not actually represent the true amount of perfectly available capacity equivalent that results in a system at 0.1 LOLE. This can be demonstrated by calculating the NYISO UCAP requirement and the actual quantity of perfectly available capacity equivalent for a system with a resource mix that differs ex ante and ex post. For instance, per the values in Table 7, a capacity auction that cleared 35GW of UCAP capacity would be 2GW short of supplying 0.1 LOLE reliability if the auction clears 0GW of battery storage instead of the 6GW of battery storage assumed in the UCAP requirement development (difference between 5,160 MW of actual reliability contribution and 3,180 MW of NYISO accredited contribution).

NYISO has not provided clear methodologies for how it might deal with such discrepancies. To be clear, ex ante determination of ELCCs raises concerns whether the market uses marginal or average accreditation. An average accreditation framework could also result in reliability issues if the cleared resource mix varies from the modeled assumption. However, because the differences between the ex ante and ex post amounts can be significant, it is critically important that the methodology for reconciling these amounts be specified.

	Average Accreditation	Marginal Accreditation
Higher Renewable Than Assumed	Auction procures inadequate capacity leading to reliability issues	Auction procures too much capacity
Lower Renewable Than Assumed	Auction procures too much capacity	Auction procures inadequate capacity leading to reliability issues

Table 9. Incorrect Ex Ante Resource Mix Assumption Outcomes

V. EXAMPLE AUCTION DESIGN THAT SATSIFIES **EFFICIENT CAPACITY MARKET DESIGN** PRINCIPLES

In arguing against the marginal ELCC capacity accreditation put forth by NYISO, a distinction must be made between two different but related concepts: marginal pricing vs. marginal accreditation. Marginal pricing is the practice of establishing the price of a product based on the cost of producing the next, or marginal, unit of that product. The marginal price has long been utilized in determining the auction clearing price in capacity markets and sets appropriate price signals to resource owners and developers to make retirement/investment decisions for their generating assets. Regardless of how resources are accredited for their contribution towards meeting the capacity volume requirement, marginal pricing can and should be implemented to set the per unit cost of capacity to consumers.

One misconception related to average ELCC accreditation methodology is that the average ELCC must also be used in determining the price signal to the capacity market for a given technology class. To illustrate how marginal pricing can be used in conjunction with average accreditation, the following market clearing example is presented below.

CAPACITY AUCTION EXAMPLE

Suppose that a bulk electric system achieves 0.1 LOLE reliability when it procures the equivalent of 33,000 MW of perfectly available capacity equivalent. A capacity market is constructed where resources must provide bids based on a per unit of perfectly available capacity equivalent basis (i.e., UCAP value for conventional resources, ELCC for variable energy resources). A supply stack can be easily constructed for conventional resources, as their individual UCAP values are known in advance and are not dependent on other resources in the market. The conventional resources are priced according to the chart below.



Figure 8. Conventional Resource Supply Stack

For resources like solar and storage however, their perfectly available capacity equivalent is dependent on their resource class penetration. Because the market is designed to clear the lowest cost resources first, the lowest cost resource of a given technology class would receive the highest marginal ELCC rating to determine its perfectly available capacity equivalent. Subsequent resources would get the next marginal ELCC rating, following a predetermined technology specific declining ELCC curve. This would continue through all bids received for the auction.

The supply curves for solar and battery resources are shown in Figure 9 and Figure 10 below, where 20 GW of solar is initially bid at a flat price of \$20/kW-yr (installed capacity basis) and 10 GW of 4-hour storage is bid at a flat price of \$50/kW-yr (installed capacity basis). These bids are then adjusted for each MW of perfectly available equivalent capacity supplied, following the declining marginal ELCC curve for each technology. As more bids are received and the marginal ELCC decreases, the adjusted price per unit of perfectly available capacity equivalent will increase to reflect its true marginal value to the system.



Figure 9. Adjusted Bid Curve and Marginal ELCC Curve (Solar)



Figure 10. Adjusted Bid Curve and Marginal ELCC Curve (Battery)

With the adjusted bid prices of solar and storage, all resources can then be sorted by their effective bid price to produce the following supply stack. At 33 GW of perfectly available capacity equivalent,

the supply stack yields a clearing price of \$83.38/kW-yr with 29 GW of conventional, 4 GW of solar, and 6 GW of storage cleared (installed capacity).



🗙 Solar 🔹 Storage 🔹 Thermal

Figure 11. Total System Supply Stack

After the volume of capacity to be procured and clearing price are determined, resources must now be accredited based on their reliability contribution. In total, precisely 33 GW of perfectly available equivalent capacity has been procured. While the first solar and first storage resources that cleared had higher marginal ELCC values than subsequent resources, this is simply due to how the resources were sorted according to price and not reflective of how they contribute to reliability in the aggregate. Therefore, all solar and all storage should receive the average ELCC based on the total value of capacity that cleared for each respective technology class. For solar this is 33% and for storage this is 83%.

In summary, 29 GW of conventional resources is accredited at 92% (based on an 8% EFORd), 4 GW of solar is accredited at 33%, and 6 GW of storage is accredited at 83%. The sum product yields 33 GW of effective capacity.

ADDRESSING ARGUMENTS AGAINST AVERAGE ELCC ACCREDITATION

NYISO and the MMU have put forward the following main argument against average ELCC accreditation throughout the stakeholder process of developing the marginal ELCC accreditation proposal: average ELCC accreditation leads to inefficient incentives for investment and leads to excess consumer costs.

If the penetration level of a variable energy resource, and thus its expected average ELCC value, is determined before the capacity auction is cleared, it is possible that over procurement can occur for resources with steep declining ELCC curves (e.g., solar resources). In this case, the capacity price signal

reflects a relatively high average ELCC value, and the incremental contribution is a relatively low marginal ELCC value. However, as demonstrated by the capacity auction example above, this is an inappropriate use of average ELCC accreditation, which should not be determined ex ante. If the proper marginal ELCC values are utilized to adjust bid prices ex post, average accreditation does not impact the marginal price signal.

Even in a case where solar developers are seeking to manipulate their bids to ensure they clear the market and receive full average accreditation, market outcomes are beneficial to consumers. In theory, solar developers looking to guarantee they are not the marginal unit due to very high effective bid prices could all decide to bid \$0/kW-yr. All solar resources would then clear, even those that provide very little marginal value. However, this would only lead to a depression in the market clearing price, and therefore a reduction to consumer costs relative to a scenario where all bidders bid at their true marginal cost. Reliability would not be impacted, and the lower clearing price would reflect a more efficient market. However, this depressed market price may not cover the costs of certain solar developers, even when utilizing the average accreditation method. If solar producers were forced to bid at cost, then the marginal unit would have a very high effective bid price and not clear the market, with its capacity replaced by more efficient resources.

VI. CONCLUSIONS

In conclusion, the proposed marginal ELCC accreditation by NYISO results in inaccurate resource compensation that has potential risks to system reliability for the following reasons:

- 1. Underpays resources relative to their reliability contribution (i.e., does not accurately compensate variable energy resources for the value they provide towards meeting the capacity volume requirement). This has been incorrectly described as "savings" to consumers but is simply a reduction in compensation towards variable energy resources that does not correlate with any actual reduction in the actual reliability value being provided in aggregate. This may lead to risk of performance issues due to revenues not being commensurate with reliability value that NYISO is trying to procure and creates an economic discrepancy between conventional resources and variable energy resources.
- 2. Disproportionately selects resources with flat sloping ELCC curves, which are predominantly conventional gas and coal resources, and disadvantages resources with steeper ELCC curves which are renewable and battery technologies. The marginal accreditation construct provides no technical or economic justification for why one portfolio with 5 GW of contribution to reliability should be paid differently from another portfolio that also provides 5 GW of contribution to reliability.
- Conflates average ELCC accreditation with average ELCC pricing by arguing that average ELCC accreditation sends inefficient market signals. Average ELCC accreditation can be used in conjunction with marginal ELCC pricing to produce proper pricing signals and proper revenue determinations.
- 4. Utilizes an ex ante approach to determine the system resource mix, and therefore uses a static ELCC value for every resource class. This can result in both the wrong type and the wrong quantity of resources clearing the capacity auction, resulting in economically inefficient and potentially unreliable procurement. While ex ante determinations of resource mixes have been approved in past proposals by other ISOs for capacity markets, this issue is only now becoming critical as the penetration of energy-limited and non-dispatchable resources is becoming significant.

VII. CERTIFICATION

We hereby certify that we have read the filing signed and know its contents are true as stated to the best of our knowledge and belief. We possess full power and authority to sign this filing.

Respectfully Submitted,

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January 26, 2022

Exhibit A.1: Appendix

EXHIBIT A.1: APPENDIX – MODELING ASSUMPTIONS

SERVM is a system-reliability planning and production cost model designed to analyze the capabilities of an electric system during a variety of conditions under thousands of different scenarios. SERVM uses a full economic commitment and dispatch model that results in a higher degree of accuracy of system reliability due to more realistic resource operational characteristics. The SERVM model chronologically simulates the economic commitment and dispatch of the system across all pre-defined scenarios, calculating numerous economic and reliability metrics for each. This process provides insight into risks and costs during these periods as well as the expectation of being able to meet peak load under various conditions. Understanding the results of the model helps a user understand and determine the amount of reserves an electric system requires to adequately meet peak demand. The model is also used for many other analyses including ELCC studies, fuel back up studies, Equivalent Forced Outage Rate (EFOR) improvement studies, and capacity valuations for upcoming peak seasons.

STUDY TOPOLOGY

To capture the system reliability, Astrapé modeled the load and generator outage diversity that a system has with its neighbors. For this study, the NYISO system was divided into 11 zones. The neighboring regions modeled included 8 ISO-NE zones, 3 PJM zones, IESO, and Hydro Quebec. All of the zones were simulated at 0.1 LOLE with their expected 2030 resource mix. Figure A1 shows a simplified representation of the topology used in this study.



Figure A1. Study Topology

UNCERTAINTY FRAMEWORK

The two primary load uncertainties that are modeled in SERVM are weather-related uncertainty and economic load growth uncertainty. To model the effects of weather uncertainty, 38 weather years were developed to reflect the impact of weather on load. Based on the 2010 to 2018 historical weather and load, a neural network program was used to develop relationships between weather observations and load. Different relationships were built for each season and for each zone to ensure that proper weather diversity was captured. These relationships were then applied to the last 38 years of temperature profiles to develop 38 load shapes for 2030. Equal probabilities were given to each of the 38 load shapes in the simulations. Figure A2 ranks all weather years by summer peak load and shows variance from normal weather. In the most severe weather conditions, the peak for the NYCA can be as much as 12.9% higher than under normal weather conditions.



Figure A2. 2019 Peak Load Rankings for All Developed Synthetic Loads

Loads for each external region (Hydro Quebec, IESO, PJM (Mid-Atlantic, West, and South), and ISO-NE (CT, ME, NEMASSBOST, NH, RI, SEMASS, VT, and WCMASS)) were developed in a similar manner as the NYISO loads.¹¹ A relationship between hourly weather and publicly available hourly loads was developed based on recent history, and then this relationship was applied to 38 years of temperature data to develop 38 load shapes. Table A1 summarizes the peak load for the NYISO Balancing Authority and the load diversity relative to the interconnected regions.

¹¹ Hydro Quebec hourly load data was not available. The load shapes for IESO were used for HQ but adjusted so HQ demand peaked in the winter. HQ load diversity is not shown since its exports were limited primarily by transmission and not by generation and load balance.

	Peak Load	Load Div	versity
	(MW)	(% below non-coinc	ident 50/50 peak)
	Non-Coincident	At System	At NYISO
	Peak Load	Coincident Peak	Coincident Peak
NYISO	30,639	-8.1%	0.0%
PJM	154,483	-1.4%	-3.7%
ISONE	24,025	-7.9%	-2.5%
IESO	26,618	-7.8%	-16.1%
System	259,276	0.0%	-2.7%

Table A1. Regional Load Diversity

ECONOMIC LOAD FORECAST ERROR

The non-weather drivers of load forecast errors differ from weather-related forecast errors because they increase with the forward planning period, while weather uncertainties remain relatively constant and are in general independent of the forward period.

The non-weather load forecast error multipliers were developed by reviewing the Congressional Budget Office (CBO) GDP forecasts 3 years ahead and comparing those forecasts to actual data. A standard deviation was calculated, and a normal distribution was developed for economic load forecast error. Because electric load grows at a slower rate than GDP, a 40% multiplier was applied to the raw CBO forecast error.

Table A2 shows the economic load forecast multipliers and associated probabilities used in this study. The table shows that 6.1% of the time, it is expected that the load will be under-forecasted by 4% 3 years out. The load forecast multipliers were applied to all regions.

Load Forecast Multiplier	Probability (%)
0.96	6.1
0.98	24.2
1.00	39.4
1.02	24.2
1.04	6.1

Table A2. Economic Load Forecast Error Multipliers Used in SERVM
--

SERVM utilized each of the 38 weather years and applied each of the 5 load forecast error points to create 190 different load scenarios. While the economic load forecast error distribution follows a normal distribution where each point has a different weighting, each weather year was given equal probability of occurrence.

RESOURCE MODELING CONVENTIONAL RESOURCES

Existing resources included in the 2030 study are consistent with the resources listed in the 2021 Load and Capacity Data Gold Book.¹² To accurately reflect the flexibility of the NYISO system, each resource was modeled with detailed unit variables and all operational constraints were respected by SERVM in the simulations. Resources were selectively retired in the analysis in order to achieve 0.1 LOLE for the each of the base cases.

SOLAR RESOURCES

The solar profiles, one for each zone, were developed from data downloaded from the NREL National Solar Radiation Database (NSRDB) Data Viewer.¹³ Data was downloaded for the 11 different locations for the available years, 1998 to 2020. Historical solar data from the NREL NSRDB Data Viewer included variables such as temperature, cloud cover, humidity, dew point, and global solar irradiance. The data obtained from the NSRDB Data Viewer was input into NREL's System Advisory Model (SAM) for each year and location to generate the hourly solar profiles based on the solar weather data for a fixed and tracking solar PV plant.¹⁴ Inputs in SAM included the DC to AC ratio of the inverter module and the tilt and azimuth angle of the PV array. The azimuth was set to maximize project value by having higher output in late afternoon hours. Data was normalized by dividing each point by the input array size. Solar profiles for 1980 to 1998 were selected by using the daily solar profiles from the day that most closely matched the peak load out of all the days +/- 2 days of the source day for the 1998 to 2020 interval. The profiles for the remaining years 1998 to 2017 came directly from the normalized raw data. The previous steps for selecting a profile for utility scale plants for 1980 to 2017 for fixed and 44 show the August average daily solar profiles for utility scale plants for 1980 to 2017 for fixed and tracking technologies.

¹² https://www.nyiso.com/documents/20142/2226333/2021-Gold-Book-Final-Public.pdf/b08606d7-db88-c04bb260-ab35c300ed64

¹³ https://nsrdb.nrel.gov/nsrdb-viewer

¹⁴ https://sam.nrel.gov/


Figure A3. August Daily Fixed Solar Profile

Figure A4. August Daily Tracking Solar Profile



WIND RESOURCES

Wind profiles were produced using hourly data for 2016 to 2018 found for NYISO, ISO-NE, and PJM, found on their respective websites. To construct wind shapes back to 1980, random days were selected from the 2016 to 2018 dataset based on the aggregate NYISO load. To maintain correlation between wind output and load in the different regions, shown in Figure A5, the same day was used for each region being captured. Offshore wind profiles were based off projects found off the New Jersey coast.¹⁵





ENERGY STORAGE RESOURCES

The batteries tested in the study were modeled with 4-hour storage capability, were allowed to charge from the grid, 90% round trip efficiency, used economic commitment and dispatch, and could serve ancillary services.

HYDRO RESOURCES

Available hydro data from 1980 to 2017 was collected from the U.S. Energy Information Administration Form 923. The projects in all of the zones modeled were assigned to their appropriate regions for all 38 weather years. Using the aggregate actual hourly data provided by NYISO from 2016 to 2018, inputs were developed to be used by the proportional load following algorithm for the proper NYISO zones.

The average daily minimum and maximum dispatch levels, the total monthly energy, as well as the monthly maximum dispatch level was identified from the historical hourly data for NYISO. Minimum and maximum daily dispatch levels are monthly maximum dispatch levels were defined as a function of monthly total energy as shown in Figure A6.

¹⁵ https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability



Figure A6. NYISO Hydro Dispatch Levels

The curve fit equations were then used to apply to historical energy from the monthly energies calculated in the EIA form. SERVM optimally schedules the hourly hydro energy while respecting these constraints. The daily maximum and minimum dispatch and monthly maximum dispatch in conjunction with the total monthly energy are parameters that go into the determination of the hourly hydro schedule. The daily minimum hydro dispatch is scheduled at the minimum load hour of the day, and the daily maximum hydro is scheduled at the maximum load hour of the day. The monthly maximum hydro is scheduled at the month.

Scheduled hydro units are modeled with maximum capacity, total energy, daily average energy, and the schedule flow range. The total energy is the total amount of hydro that will be produced in a given month. This value cannot be greater than the total maximum hydro capacity multiplied by the number of hours in the month. The simulation logic will not allow the unit to simply run at the maximum hydro capacity for all hours because the monthly hydro energy constraint will be violated. After the minimum weekly flows are taken into account, the remainder of the month's energy is scheduled as peak shaving.

SOURCES FOR BASE CASE RESOURCES SELECTED IN THE STUDY

Table A3. Base Portfolio Sources

Unit Category	Capacity (MW)	Link	Additional Notes
Offshore Wind	6,200	https://climate.ny.gov/Our-Climate-Act/ Draft-Scoping-Plan	Annex 2
Land Based Wind	5,275	https://climate.ny.gov/Our-Climate-Act/ Draft-Scoping-Plan	Annex 1
PSH	1,407	https://www.nyiso.com/documents/20142/ 2226333/2021-Gold-Book-Final-Public.pdf/ b08606d7-db88-c04b-b260-ab35c300ed64	Base Gold Book
BTM Storage	493	https://www.nyiso.com/documents/20142/ 2226333/2021-Gold-Book-Final-Public.pdf/ b08606d7-db88-c04b-b260-ab35c300ed64	Base Gold Book
Utility Solar	8,583	https://climate.ny.gov/Our-Climate-Act/ Draft-Scoping-Plan	Annex 1
BTM PV	8,333	https://climate.ny.gov/Our-Climate-Act/ Draft-Scoping-Plan	Annex 1

ELCC CALCULATION METHODOLOGY

Table A4 contains the resource mix used for the base case.¹⁶ A base case of the system was first established by calibrating the NYISO to a reliability level of 0.1 Loss of Load Expectation (LOLE) for each system by retiring conventional generation.

Table A4. Base Scenario Installed Capacity

	2030 Goal Installed Capacity (MW)
Community Solar	8,334
Utility Scale Solar	8,583
BTM Batteries	493
PSH	1,407
Hydro	4,807
Land Based Wind	5,275
Offshore Wind	6,200
Conventional*	21,168
EOPs	2,775

* Includes the Conventional Generation Removed to Calibrate the System to 0.1 LOLE

The ELCC of each resource type was then calculated. The battery or solar under study was added to the system, and load was added until the system returned to 0.1 LOLE. The calculation of the ELCC for each study resource was performed as:

¹⁶ The derivation of the values used for community solar, utility scale solar, BTM batteries, PSH, land based wind, and offshore wind can be found in Appendix A1.

$$ELCC = \frac{Perfect \ Load \ Added(MW)}{Study \ Resource \ Added \ (MW)} * 100\%$$

The process is as follows, using illustrative values and a solar as an example:

- 1. Add a 30 MW solar resource to a system calibrated to 0.1 LOLE
 - a. LOLE decreases to 0.08, indicating an improvement in reliability
- 2. Add 10 MW of load every year
 - a. LOLE increases to 0.1, indicating a return to original reliability
- 3. The ELCC is calculated as the ratio of step 2 and step 1
 - a. 10 MW / 30 MW = 33.3% ELCC

After calibrating the system to 0.1, ELCCs were calculated for multiple storage penetrations defined in Table A5.

BTM Batteries (MW)	Utility Scale Batteries (MW)	Total Batteries (MW)
493	507	1,000
493	1,507	2,000
493	2,507	3,000
493	5,507	6,000
493	8,507	9,000

Table A5. Battery Penetrations Studied

Solar ELCCs were calculated at the penetrations defined in Table A6 for the 2030 Goal scenario.

Table A6. Solar Penetrations Studied for the 2030 Goal Scenario

Utility Solar		
Nameplate Capacity		
(MW)		
1,000		
5,000		
8,583		
9,583		

Exhibit A.2: Curriculum Vitae of Kevin Carden

Kevin Carden | Director, Astrapé Consulting, LLC

3000 Riverchase Galleria Suite 575 Hoover, AL 35224 (205) 988-4404 kcarden@astrape.com

With a background in production cost simulations for risk analysis and reliability planning for power supply options, coupled with more than twenty years of diverse utility management experience, Mr. Carden possesses the technical background needed to successfully execute a wide range of resource adequacy studies. Under Kevin's leadership, Astrapé Consulting has provided consulting services to ISOs, RTOs, utilities, regulators, and developers worldwide. For the Southern Company, he led the redevelopment of SERVM, an industry leading Resource Planning tool which is currently owned and licensed by Astrapé. Additional responsibilities have included project financial analysis, RFP independent evaluation, target reserve margin studies, renewable capacity valuation, demand side management program development and contract management for many large capital projects. Kevin holds a B.S. in Industrial Engineering from the University of Alabama.

Experience

Modeling and design for assessment of power supply options Intensive power modeling experience in multiple applications, including software design Developed proprietary generation reliability and dispatch model for electric utilities Demand forecasting, demand-side option management, and optimal reserve margin targets Evaluation, procurement, and administration of long-term power purchase contracts Demand-side options pricing and evaluation Bid preparation for power purchase RFPs Managing Director, Astrapé Consulting, LLC Generation Reliability Manager, Southern Company Services Holds U.S. patent in Generation Reliability Modeling techniques (#7698233)

\lambda Major Clients

Southern California Edison	Portland General Electric Company	Southern Company Services
Duke Energy	SMUD	AESO
LCRA	Tennessee Valley Authority	Tenaga Nasional Berhad
Santee Cooper	ERCOT	CPUC
MISO	Terna	SPP
Pacific Gas & Electric	Public Service Company of New Mexico	

Education

B.S. Industrial Engineering, The University of Alabama

Relevant Experience

Redevelopment of SERVM

Company Name: Southern Company Services - Resource Planning.

Mr. Carden has been responsible for the redevelopment, management, and use of a proprietary dispatch model used by the Southern Company for over two decades. This model is used primarily for reliability risk analysis and provides key insights into the value and need of capacity in both the short-term and long term. Kevin identified the need for the development of market modeling algorithms, new hydro logic, updated transmission modeling, economic dispatch criteria, reliability dispatch rules, and other key factors which contribute to reliability risks. Kevin wrote the majority of the logic for these additions based on his extended experience in resource planning. Using the model to run studies for the Southern Company, Kevin has recommended risk mitigation strategies that balance the cost of new capacity with the reliability benefits of those resources.

Resource Adequacy Assessments

Southern Company Services: Maintain SERVM for Southern Company and assist in all resource adequacy studies. All reserve margin studies have been filed with regulators. Performed Production Costs and LOLE Based Reserve Margin Study in 2007, 2010, 2013; Performed Interruptible Contract evaluation; Performed Various Other Resource Adequacy Assessments and Product Cost Studies.

Tennessee Valley Authority: Performed Various Reliability Planning Studies including Optimal Reserve Margin Analysis, Capacity Benefit Margin Analysis, and Demand Side Resource Evaluations using the Strategic Energy and Risk Valuation Model (SERVM) which is Astrapé Consulting's proprietary reliability planning software. Recommended a new planning target reserve margin for the TVA system and assisted in structuring new demand side option programs in 2010. Performed Production Costs and Resource Adequacy Studies in 2009, 2011, 2013, and 2015.

PPL - Louisville Gas & Electric and Kentucky Utilities: Performed Reliability Studies including Reserve Margin Analysis for its Integrated Resource Planning Process. This study included the probabilistic simulations regarding load uncertainty, generator performance, and weather uncertainty. Planning Reserve Margin to Company based on lowest cost and risk to customers. Reserve margin study was filed with Kentucky State Commission.

CLECO: Performed resource adequacy studies for CLECO to determine optimal reserve margin and assist in other resource adequacy decisions. Performed Production Costs and LOLE Based Reserve Margin Studies. Performed 2016 Reserve Margin Study.

Pacific Gas and Electric (PG&E): Performing flexibility Requirement Study 2015 – 2017. CES Study for Renewable Integration and Flexibility 2015 – 2016.

California Energy Systems for the 21st Century Project: Performed 2016 Flexibility Metrics and Standards Project. Developed new flexibility metrics such as EUE flex and LOLE flex which represent LOLE occurring due to system flexibility constraints and not capacity constraints.

▲ Testimony

Application of Cleco Power LLC Regarding the Costs and Benefits of Continued Participation in the Midcontinent Independent System Operator, Inc. Regional Transmission Organization, Docket No. U-34501, Direct Testimony on behalf of Cleco Power, LLC, June 19, 2017. https://lpscpubvalence.lpsc.louisiana.gov/portal/PSC/ViewFile?fileId=uVo6s1fRmdk%3d

In re: Petition for a Certificate of Convenience and Necessity by Alabama Power Company, Docket No. 32953, Rebuttal Testimony on behalf of Alabama Power Company, January 27, 2020. <u>https://www.pscpublicaccess.alabama.gov/pscpublicaccess/ViewFile.aspx?Id=1c997c6b-7e1d-40c0-b490-c488e26d9250</u>

In re: Application of Public Service Company of Colorado for Approval of its 2021 Electric Resource Plan and Clean Energy Plan, Proceeding No. 21A-0141E, Hearing Exhibit 115, Direct Testimony on behalf of Public Service Company of Colorado, March 31, 2021. https://www.dora.state.co.us/pls/efi/EFI Search UI.search

In re: Application of Public Service Company of Colorado for Approval of its 2021 Electric Resource Plan and Clean Energy Plan, Proceeding No. 21A-0141E, Hearing Exhibit 131, Rebuttal Testimony on behalf of Public Service Company of Colorado, November 12, 2021. https://www.dora.state.co.us/pls/efi/EFI_Search_UI.search

▶ Published Articles

National Association of Regulatory Utility Commissioners 2015, *A Study on Probabilistic Risk Assessment for Transmission and Other Resource Planning*, accessed 16, March 2021, https://pubs.naruc.org/pub.cfm?id=536DCE1C-2354-D714-5175-E568355752DD Exhibit A.3: Curriculum Vitae of Alex Dombrowsky

Alex Krasny Dombrowsky | Consultant, Astrapé Consulting, LLC

3000 Riverchase Galleria Suite 575 Hoover, AL 35224 (205) 988-4404 adombrowsky@astrapé.com

Mrs. Alex Krasny Dombrowksy is a consultant at Astrapé Consulting. As a consultant, Alex has performed and assisted with various reserve margin studies, renewable integration studies, and ELCC studies for clients across the U.S. and internationally. She is an active participant in industry groups concerned with reliability and resource adequacy, including the NERC Probabilistic Working Group and the IEEE Loss of Load Expectation Working Group. Alex holds a B.S. in Chemical Engineering from the University of Alabama.

Experience

Consultant at Astrapé Consulting (2016 to Present) Manage and Assist Resource Adequacy Studies Manage and Assist Renewable Integration Studies Manage and Assist ELCC and Capacity Value Studies Develop and Manage Eastern Interconnection Database SERVM Model Quality Assurance Develop Study and Project Proposals Marketing and Sales of the SERVM Model Redesign and Maintain the SERVM Manual and Supporting Documents

\lambda Major Clients

ERCOT	Duke	TVA
AESO	PGE	Malaysia
Southern Company	CPUC	

Industry Specialization

Resource Adequacy Planning	Capacity Value Analysis	Renewable Shape Development
Renewable Integration		

Education

B.S. Chemical Engineering, The University of Alabama - Cum Laude

A Relevant Experience

California Energy Systems for the 21st Century Project: Assisted Flexibility Metrics and Standards Project (2016).

Malaysia (TNB, Sabah, Sarawak): Assisted in Resource Adequacy Studies for 3 different Malaysian entities (2016 – 2018).

Southern Company: Developed load, solar, wind, and hydro shapes for Southern's neighbor utilities (2016 – 2021).

AESO: Performed Resource Adequacy Study (2018).

ERCOT: Assisted in Economic Optimal Reserve Margin Studies in cooperation with the Brattle Group in 2018. The report examined the total system costs, generator energy margins, reliability metrics, and economics under various market structures. Performed a Probabilistic Risk Assessment for the North American Electric Reliability Corporation (NERC) (2018).

Duke: Assisted in Capacity Value and Ancillary Service Studies (2018).

TVA: Supported Renewable Integration Study (2018).

NYBEST: Assisted Energy Limited Capacity Value Study in NYISO (2019).

US ESA and NRDC: Assisted Capacity Value of Energy Storage in PJM (2019).

TVA: Performed Reserve Margin Study (2019).

AECI: Supported Reserve Margin Study (2020).

PSCO: Assisted in Planning Reserve Margin Study (2020).

CA Joint IOU: Performed 2020 and 2021 Joint IOU ELCC Study (2020 and 2021).

ERCOT: Performed Economic Optimal Reserve Margin Study Update. Performed Probabilistic Risk Assessment for NERC (2020).

California Public Utilities Commission (CPUC): Performed Incremental ELCC Study for Mid-Term Reliability Procurement (2021).

Industry Involvement

Member of the NERC Probabilistic Working Group Member of the IEEE Loss of Load Expectation Working Group Exhibit A.4: Curriculum Vitae of Trevor Bellon

Trevor Bellon | Consultant, Astrapé Consulting, LLC

1547 Brighton Ave Grover Beach, CA 93433 (936) 828-6790 tbellon@astrape.com

Trevor Bellon is a consultant at Astrapé Consulting. He has experience in utility planning activities including Integrated Resource Plan (IRP) development, resource adequacy assessments, and reliability modeling. Prior to joining Astrapé Consulting, Trevor developed on-the-ground industrial experience as the Consulting Department Manager at VaCom Technologies. At VaCom, Trevor successfully managed the development and implementation of several industrial refrigeration energy efficiency projects at large food and beverage manufacturing plants in California, including detailed system design, project economic analyses, and field installation management. Additional experience includes utility planning activities as a supply planning analyst at Entergy Services.

Education

B.S. Nuclear Engineering, Texas A&M University - Summa Cum Laude

\lambda Experience

Consultant at Astrapé Consulting (2021-Present) SERVM reliability modeling Renewable and battery effective load carrying capability (ELCC) assessments Capacity market assessments

Consulting Department Manager at VaCom Technologies (2016-2021) Developed energy simulation models for energy efficiency assessments of industrial systems Performed over 30 commercial and industrial onsite energy audits Managed field installation of industrial equipment at food manufacturing plants Performed load and capacity balance calculations for industrial refrigeration system design Lead technical writer for California Energy Commission grant applications (\$14M awarded)

Supply Planning Analyst at Entergy Services (2015-2016) Project management of integrated resource plan activities Resource adequacy assessments as related to ISO market requirements New generation site selection analyses SERVM reliability modeling

Industry Specialization

Utility Resource Planning	Energy Efficiency Modeling	Project Financial Analysis
Reliability Planning	Mechanical System Design	Technical Writing
Field Project Management		

Relevant Experience

For **Entergy New Orleans:** Project manager of the 2015 Integrated Resource Plan for the City of New Orleans, coordinating financial analysis, resource mix scenario analysis, and report development for required regulatory filings.

For **DTE Electric Company:** Co-author of 2021 ELCC study, calculating the marginal and average ELCC values for wind, solar, and battery storage resources located in MISO LRZ7.

For **Evergy:** Lead reliability model developer, performing planning reserve margin calculations and ELCC values for variable energy resources for the study years 2025 and 2030 in SERVM for Evergy utility service territory.

EXHIBIT C

Michael Welch & Derek Stenclik, *Review of the NYISO Capacity* Accreditation Reforms, Telos Energy (Nov. 12, 2021) Enel X 20220126-5218

Filed Date: 01/26/2022

Review of the NYISO Capacity Accreditation Reforms November 12, 2021

TELOS ENERGY

Review of the NYISO Capacity Accreditation Reforms

Marginal vs. Average ELCC Accreditation Methods

Michael Welch, Derek Stenclik - Telos Energy on behalf of Enel X | November 12, 2021

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EXECUTIVE SUMMARY

In April 2021, the NYISO started a process to reform multiple aspects of the wholesale capacity market, referred to as the Comprehensive Mitigation Reform Process. The objective of this report is threefold: to review the NYISO proposal and summarize recent stakeholder meetings, identify several limitations of the NYISO's Consumer Impact Analysis (CIA), to provide an overview of capacity accreditation methods, and to summarize key recommendations for future consideration by the NYISO and its stakeholders.

While we believe that the "Comprehensive Mitigation Review" proposal is important, we do not believe that it is appropriate to lock into a capacity accreditation methodology without rigorous analysis being performed. We support the usage of Effective Load Carrying Capability (ELCC), but believe it is premature to value resources at their "marginal reliability contribution," which is codified in draft Tariff language. In the NYISO's proposed timeline they indicate that Phase 2 will evaluate how to perform the ELCC analysis and in this phase the NYISO should fully analyze the differences between a marginal and average approach. Specifically, the NYISO has not properly substantiated that a marginal approach will be advantageous over an average ELCC approach. At this time, it would be sufficient to simply commit to implementation of ELCC for capacity accreditation and to perform a more complete analysis of the multiple accreditation options available.

While ELCC can provide an accurate estimate of capacity contributions of a particular resource, there are numerous challenges that were considered in the NYISO capacity accreditation proposal; namely capturing saturation effects and portfolio effects. To address these challenges, two accreditation methods are available, marginal ELCC and portfolio (average) ELCC. Marginal ELCC measures the incremental capacity credit of a resource when evaluated in isolation, and for the next incremental addition of the resource relative to the existing portfolio. It is limited in that the sum of all the marginal ELCC resources is less than the total resource adequacy benefits.

In contrast, portfolio ELCC quantifies the total capacity contribution of a bundle of wind, solar, and storage resources rather than the incremental addition of the last entrant on the system. Portfolio ELCC is also referred to as average ELCC, which is the portfolio ELCC divided by the total quantity of resources in the portfolio. The benefits of using average ELCC for capacity accreditation provides an accurate quantification of the resource adequacy benefits of the entire portfolio.

To compare the differences between marginal and portfolio ELCC accreditation, the NYISO and Potomac Economics conducted a Consumer Impact Analysis. This report highlights six limitations of that study:

- The analysis used an overly simplified deterministic modeling rather than probabilistic analysis typically used for resource adequacy and ELCC calculations,
- The analysis used a reliability criterion that is not used by the NYISO and therefore reliability of different portfolios cannot be confirmed,
- Scenarios were evaluated with limited energy storage buildout and thermal retirements, and thus show limited benefits to a portfolio ELCC approach,

- Capacity accreditation was based on a single weather year of data rather than a long-term meteorological dataset,
- The analysis used 20-year-old load shapes that are no longer representative of the NYISO demand profile,
- The ELCC methodology is discriminatory because it is not applied to thermal resources.

For such a monumental shift in how resources will be valued in the NYISO Installed Capacity Market, more time is needed to determine the finer aspects of the capacity accreditation methodology and the analytical work supporting it. Currently many stakeholders and the NYISO are justifying an accelerated capacity accreditation redesign because REC payments or storage subsidies from NYSERDA would make up the difference. However, FERC cannot make rules with the expectation that it is corrected by supporting programs at the state level. As a result, we recommend that the NYISO pursue stakeholder approval for the elimination of Buyers Side Mitigation and the intent to implement ELCC for capacity accreditation - but exclude any specific determination on marginal or average ELCC accreditation methods.



INTRODUCTION

In April 2021 the NYISO started a process to reform multiple aspects of the wholesale capacity market. This process, referred to as the Comprehensive Mitigation Reform Process included changes to the buyers side mitigation (BSM) rules as well as the capacity accreditation process for variable renewable and energy limited resources. The objective of this report is threefold: to review the NYISO proposal and summarize recent stakeholder meetings, to provide an overview of capacity accreditation methods, identify several limitations of the ISO's Consumer Impact Analysis (CIA), and to summarize key recommendations for future consideration by the NYISO and its stakeholders.

The capacity accreditation proposal could have serious implications for renewable energy, energy storage, and demand response resource development in the state. If conducted hastily it could ultimately disrupt New York's decarbonization efforts and lead to over procurement of capacity resources and increased cost for ratepayers.

NYISO Comprehensive Mitigation Reform Process

The NYISO's Comprehensive Mitigation Reform proposal implements three market designs:¹

- BSM Reforms, to ensure that resources required to meet the State goals established in the CLCPA are not subject to review under the BSM rules or otherwise subject to an offer floor,
- Capacity Accreditation, to establish a new framework for select resource types in the NYISOs ICAP Market,
- ICAP/UCAP Price Translation, to adopt the recommendation of Potomac Economics to utilize an alternative mechanic for converting the ICAP Reference Price to a UCAP Reference Price.

As a complete package, these three items will introduce a significant change, but individually they also can fundamentally change the NYISO ICAP Market. The planned date for implementation is May 1, 2024, which places them as in-effect for the 2024-25 Capability Year. Procedurally NYISO is seeking an affirmative vote on the Comprehensive Mitigation Reform proposal from the Management Committee on November 17, Board Approval in December, and anticipates submitting tariff changes to FERC by the end of the year.

This report specifically addresses the subject of Capacity Accreditation and the NYISO's proposal. They propose using Effective Load Carrying Capability (ELCC) to assign select resource types Capacity Accreditation Factors. In general, the usage of ELCC is a reasonable capacity accreditation metric and it is an appropriate methodology when considered in the context of a study informing a capacity market, such as the NYISO's ICAP Market. However, given the accelerated stakeholder process and limited analysis provided to date on important capacity market changes, the decision of the NYISO to codify a marginal

¹ The following bullets are reproduced from the NYISO's Comprehensive Mitigation Review slides, <u>https://www.nyiso.com/documents/20142/26119798/05%20CMR.pdf/11217ade-152a-74a2-d478-6b5ae5e21207</u>

ELCC approach in their tariff language is unwarranted. Specifically, the NYISO has not properly substantiated that a marginal approach will be advantageous over an average ELCC approach.

When outlining the Comprehensive Mitigation Reform the NYISO identified three projects where:

- Phase 1 will discuss tariff changes for the new framework through Q4 2021,
- Phase 2 will discuss the procedures and details of capacity accreditation and is expected to start after the completion of Phase 1 and continue throughout 2022 as part of the Improving Capacity Accreditation Project,
- Phase 3 will focus on the implementation of the capacity accreditation review as part of the Capacity Value Study project.

At this juncture the NYISO has advanced substantially through Phase 1 and is currently pursuing the approval of the Management Committee for their proposal. In recent meetings the NYISO has expressed substantial interest in determining the specifics of their ELCC analysis, figuring out items such as how to bootstrap their existing databases from the IRM and LCR studies to perform the work and the development or modification of software tools to perform the calculations. We applaud the existence of Phase 2 but express caution that the NYISO will be locked into a marginal ELCC approach and may find during phase 2 that an average ELCC approach is in fact more tenable.

To support the Comprehensive Mitigation Review, the NYISO consulted with several parties for analysis to inform stakeholders how the three items in the proposal would affect the ICAP Market. This was realized through three main analyses:

- "Modifications to the BSM Construct in the NYISO Capacity Market", performed by the Analysis Group,
- A Consumer Impact Analysis of 2026, performed by NYISO Staff,
- A Consumer Impact Analysis of 2030, performed by Potomac Economics.

Despite the comprehensive nature of the package of changes, these studies were all conducted and presented within a short time frame of just a few months, with limited stakeholder involvement. The concept of capacity accreditation was first introduced in August, with tariff changes proposed in October, consumer impact analysis discussed in October, and results of this work presented in November just days before a vote at the BIC and two weeks in advance of an MC vote. While some insights and analysis were borrowed from The Brattle Group's Grid In Transition Evolution study from 2020, this was still a compressed timeline for proposing such a foundational change. Even with a Phase 2 of the project on the horizon, it will be locked into decisions made from incomplete analysis in Phase 1. More time is certainly needed to ensure a sound capacity accreditation process can be developed and tested.

The focus of this report is on the ELCC methodology and how the technique is applied for Capacity Accreditation, and thus primarily reviews the work performed by Potomac Economics. This analysis evaluates how the different accreditation techniques may affect the amount of installed capacity through use of a capacity expansion model.

The NYISO's proposal was approved by the BIC with an affirmative vote of 76.13%, but prior to conducting the vote, several stakeholders made public comments about their voting positions. Within them we observed several key themes:

- 1. Strong support for the BSM Reforms and the ICAP/UCAP Translation Update,
- 2. Feelings that the capacity accreditation proposal was being rushed through and inappropriately linked with the other two proposals,
- 3. General support for the concept of ELCC, but concern with the NYISO defining a marginal approach in the procedure and tariff language without allowing for a full analysis.

Recent comments by Potomac Economics

Potomac Economics, in their role as the NYISO's Market Monitoring Unit, regularly reviews NYISO studies and practices to ensure that the NYISO markets are operating efficiently. Each year these efforts are encapsulated in their State of the Market which not only reviews market operations over the preceding year but offers recommendations for continued efficient market operations.

In the 2020 State of the Market Report², issued on May 18, 2021, one of their recommendations encouraged the NYISO to "revise the capacity accreditation rules to compensate resources in accordance with their marginal reliability value," the full text of this recommendation is reproduced below:

"Capacity markets exist to provide efficient incentives for attracting resources needed to satisfy the planning reliability requirements of the system. Thus, individual capacity suppliers should be compensated in accordance with the incremental reliability value they provide to the system. In an efficient capacity market, two resources that provide the same incremental reliability value should receive the same compensation.

The incremental reliability value of individual resources should vary according to their availability during certain critical hours when capacity margins are tightest. The current capacity rules do not accurately reflect the marginal reliability value of certain classes of resources, including energy storage and other duration-limited resources, intermittent generation, conventional generators with low availability and long start-up lead times, special case (demand response) resources, and large supply contingency resources. In addition, the EFORd-calculation methodology leads to a downward bias in the EFORd values of some generators. Without enhancements to the current capacity accreditation rules, these deficiencies are likely to become more severe as the resource mix evolves over the next two decades."³

After the release of the State of the Market report evidence suggests the NYISO made efforts to incorporate the recommendation into their 2021 work plan. In a presentation to the ICAPWG on April 20, predating the report, the NYISO noted that capacity accreditation work would likely begin in Spring 2022,⁴

² Potomac Economics, *2020 State of the Market Report for the New York ISO Markets*, May 2021, <u>https://www.nyiso.com/documents/20142/2223763/NYISO-2020-SOM-Report-final-5-18-2021.pdf</u> ³ Ibid.

⁴ M. Desocio, *Preparing the Capacity Market for the Grid in Transition*, NYISO, April, 20 2021, <u>https://www.nyiso.com/documents/20142/20839079/20210420%20NYISO%20-</u> %20Preparing%20the%20Capacity%20Market%20for%20the%20Grid%20in%20Transition.pdf

but by a June 3 presentation to the same group the date had advanced to Summer 2021.⁵ The NYISO also noted in this presentation that discussion of tariff changes would occur in Spring 2022; however, in an August 9 presentation to the ICAPWG the NYISO revised the schedule once again to state that tariff changes would be introduced in September.⁶ The change in timeline is reflected in Figure 1.



Figure 1: Review of the NYISO capacity accreditation reforms

Coincident with the shifting timeline, Potomac Economics presented a review of different ELCC frameworks and methodologies to the ICAPWG in August. These methodologies were then studied in their Consumer Impact Analysis. Despite the content, the recommendation from Potomac has steadily been for a marginal product, which is reflected in the NYISO draft tariff language with the phrase "marginal reliability contributions."

Appendix Section VI.I of the State of the Market report details various capacity accreditation approaches, such as the Marginal Reliability Impact (MRI), ELCC, and heuristic approaches similar to existing NYISO procedures. Potomac "recommend[s] using MRI to determine capacity accreditation" which compares the change in LOLE of an increment of a resource against that same increment of perfect capacity and also state "MRI and Marginal ELCC approaches are likely to produce very similar capacity credit results." Where marginal ELCC measures the amount of perfect capacity needed to return the system to the original LOLE when an increment of a resource is removed from the system is iteratively calculated; and an average ELCC would measure the same but for when the full amount of the resource is removed. In the NYISO's proposal, they elect to utilize a marginal ELCC approach.

⁵ M. Desocio, *Buyer Side Mitigation Reform Considerations*, NYISO, June 3, 2021, <u>https://www.nyiso.com/documents/20142/21942500/20210603%20NYISO%20-</u> <u>%20BSM%20Reforms%20Consideration%20vFinal.pdf</u>

⁶ Z. Smith, *Capacity Accreditation: Straw Proposal*, August 9, 2021, <u>https://www.nyiso.com/documents/20142/23645207/20210809%20NYISO%20-</u> <u>%20Capacity%20Accreditation%20Straw%20Proposal.pdf</u>

A Primer on Capacity Accreditation Methods

Underpinning any capacity accreditation mechanism - whether it be a mandatory capacity market auction in Northeast ISOs or integrated resource planning for vertically integrated utilities - is technical resource adequacy analysis and modeling.

Resource adequacy (RA) analysis utilizes modeling conducted to measure whether the system has enough resources to serve load under a wide range of potential future system conditions. RA analysis considers potential variations in system load, fluctuations in weather and corresponding availability of variable renewable energy (VRE) resources like wind and solar, and planned and unplanned generator outages. By utilizing statistical techniques, the analysis measures the probability, or expectation, that the system has insufficient resources (i.e., capacity) to meet load.

When evaluated across many simulated years of various weather and generator outages, the count of days that experienced some level of capacity shortfall is summarized as the Loss of Load Expectation (LOLE). The LOLE metric is commonly utilized as a resource adequacy criterion (e.g., a 1-day-in-10-years LOLE requirement) in the NYISO and many jurisdictions across North America.

Because not all resources have the same expected performance during shortfall events, different resources are accounted for differently. In these cases, a resource is accredited a certain amount of "firm capacity" that counts towards the planning reserve margin. For example, fossil fuel-fired generators may be counted as "unforced capacity" (UCAP) that discounts the firm capacity of the resource by the generator's forced outage rate (unplanned outages). For variable renewable resources, the generators are often discounted based on their availability during likely shortfall events.

The NYISO is currently proposing to accredit resources based on the *marginal* ELCC calculation method because they believe it provides a more accurate *price signal* to the market and necessary to incentivize the appropriate resources to enter or exit the market.

For additional information on capacity accreditation methodologies and concepts, see Appendix A: Overview of Capacity Accreditation.

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TECHNICAL REVIEW OF THE CONSUMER COST IMPACT ANALYSIS

Summary of the Consumer Cost Impact Analysis

To provide insight to stakeholders on the capacity accreditation methods and its impact on the ICAP market, the NYISO performed a Consumer Impact Analysis (CIA) and presented the results at the November 2nd ICAPWG meeting, only one week before the necessary BIC vote. The intent of this analysis was to provide a comparison of how capacity market costs and NYSERDA REC costs could change with a change in the capacity accreditation methodology. This was accomplished by comparing the status quo scenario, in which the current accreditation methodology is applied, to cases where an average ELCC and a marginal ELCC was used in the capacity accreditation methodology. Despite the importance of this analysis, the work was performed on an accelerated schedule which sacrificed technical accuracy. The study assumptions were presented in mid-October, with final results presented to stakeholders mere weeks later in early November, just in time for materials to be posted for the BIC.

The CIA was performed in two parts, the first study was by the NYISO and focused on 2026 and the second by Potomac Economics focused on 2030. The latter analysis benefited from being "dynamic" and using a capacity expansion model to dynamically build new resources through time, achieving slightly different resource portfolios by 2030, indicating how a change in accreditation methodology could change the resource mix. Meanwhile, the NYISO analysis for 2026 was "static" and simply compared the state of the capacity market for identical resource portfolios.

In both studies, the authors concluded that a marginal accreditation approach would result in more savings than using average accreditation. This is not a point to dispute as it is well recognized that marginal ELCC would yield lower procurement costs; however, as noted by PJM "a marginal framework does not generally credit a portfolio of resources for its total contribution to resource adequacy." This behavior is worth exploring.

		Status Quo	Average ELCC	Marginal ELCC
2026	Procurement Cost (\$M)	2,395	2,390	2,277
	Savings (\$M)	0	5	118
2030	Procurement Cost (\$M)	Unknown	Unknown	Unknown
	Savings (\$M)	0	83	176

Table 1: Review of procurement cost and savings from the Customer Impact Analysis



Limitations of the Study and Additional Considerations

After reviewing both studies presented in the CIA, this report identifies six fundamental limitations of the analysis presented thus far by the NYISO. Many of these limitations were also identified by NYISO staff and Potomac Economics. Given the importance of the accreditation methodology for the wholesale energy markets and the effort required for the stakeholder process and ultimately FERC approval, it is important that analytical methods be as robust as possible to inform decisions on accreditation proposals. As a result, it is crucial that the limitations be corrected prior to determining the specific ELCC calculation process.

The analysis used an overly simplified deterministic modeling rather than probabilistic analysis typically used for resource adequacy and ELCC calculations

There are two classical types of resource adequacy studies, deterministic analysis (such as convolution) and probabilistic analysis (such as Monte Carlo). The NYISO licenses the GE MARS application for performing their resource adequacy analysis. This is a commercial software tool used by system planners across the Northeast. This program utilizes Monte Carlo techniques to run a large number of samples⁷ and calculate Reliability Risk Metrics such as Loss of Load Expectation (LOLE) and Expected Unserved Energy (EUE). The reliability criterion in NY is an 0.1 days per year, which is derived from the "1 day in 10 years" standard, because the unit of this metric is "days per year" this document will subsequently use Loss of Load Days (LOLD).⁸ The calculation of LOLD is fairly straightforward, the number of days in each sample (representing one year) is summed and then divided by the number of samples performed.⁹ Recent NYISO resource adequacy studies have been running 2000 or more samples in order for the LOLD to sufficiently converge to a stable value, otherwise the *expected* result may not be indicative of future conditions.

The principal issue is with generator availability. In a typical resource adequacy analysis at the NYISO each sample reflects one possible set of conventional generator forced outages and a one year of renewable output. When repeated multiple times, resource variability is ensured, and this allows the NYISO to understand how the change in generation affects serving load and transmission interchange. In Potomac's analysis they locked each conventional generator at its UCAP rating and used a single year of weather data, this was applied across three load shapes and aggregated for a final result.

Potomac Economics does not license GE MARS, and in their analysis, they used a custom tool developed in-house instead. While running an ELCC analysis in a different tool than the one used to set the Installed Reserve Margin may not be problematic, and has basis at PJM with their ELCC process, the critical issue is how the analysis was performed. By Potomac's admission their results "are not a full replication of NYISO GE-MARS" and warn readers to "use caution [when] applying capacity credit values outside of [the] specific case from which they were derived." The critical problem here is twofold: first, Potomac did not

⁷ Also referred to as "replications"

⁸ This is being done, in part, to raise awareness that other jurisdictions use LOLE but with units of hours per year, which colloquially is referred to as (Loss of Load Hours) or LOLH

⁹ MARS can additionally layer load forecast uncertainty and associate probabilities of occurrence with each uncertainty level, but that is beyond the scope of this document.

perform a probabilistic analysis, and second, they did not utilize the reliability metric used by the NYISO (as discussed in the next section).

Undergoing a full and robust resource adequacy analysis is necessary to fully understand the implications of the proposed market design changes. A detailed probabilistic analysis using Monte Carlo simulation is industry best practice for this type of analysis. However, there was certainly not enough time available to Potomac Economics or internal NYISO staff to perform such work with the accelerated stakeholder process. The intervening months before Phase 2 of the Comprehensive Mitigation Review begins in early 2022 can be used to properly scope modeling methodologies and practices, such as marginal and average ELCC and how to implement them.

The analysis used a reliability criterion that is not used by the NYISO and therefore reliability of different portfolios cannot be confirmed

As discussed in the preceding section, a defensible LOLD is one that has enough samples performed to calculate a stable average. Typically, this consists of over 2000 randomly generated Monte Carlo samples. Under NYSRC Policy 5 the NYISO performs enough samples so the standard error of the mean (SEM) is 0.025, and when combined with an expected LOLD of 0.1, mathematically 95% of all possible LOLD would be between 0.095 and 0.105.¹⁰ Coincident with LOLD, MARS also calculates the EUE¹¹ of the system.

While the NYSRC sets the reliability criterion at 0.1 LOLD, no threshold yet exists for EUE; however, recent work by the NYSRC Resource Adequacy Working Group has explored the relationship between reliability metrics:

Study Name	LOLD	LOLH	EUE	NEUE
	(dy/yr)	(hr/yr)	(MWh/yr)	(% of load)
2020 IRM ¹²	0.1	0.341	235.2	0.000151%
2021 IRM ¹³	0.1	0.365	243.7	0.000162%
2022 IRM PBC ¹⁴	0.1	0.348	223.0	0.000148% ¹⁵

Table 2: Resource Adequacy Metrics from Recent NYISO Studies

¹⁰ This assumes a normal distribution and 2 standard deviations from the mean.

¹¹ Also referred to as Loss of Expected Energy (LOEE)

¹² NYSRC RAWG, *Resource Adequacy Metrics and Their Applications,* March 31, 2021, <u>https://nysrc.org/PDF/Reports/RAWG%20Report%202[16711].pdf</u>

¹³ Ibid.

¹⁴ Y. Guo, Sensitivity Results (Cases 1-9) - For ICS Review, NYISO, Nov 3, 2021, <u>https://nysrc.org/PDF/MeetingMaterial/ICSMeetingMaterial/ICS%20Agenda%20253/AI%209.1%20-</u> <u>%202022%20PBC%20Sensitivity%20results.pdf</u>

¹⁵ Calculated using the NYCA Baseline Energy Forecast from the 2021 Gold Book for 2022 of 150,480 GWh

In Potomac's analysis they selected a NEUE value of 0.003% as a reliability criterion violation. When compared to the NEUE values from Table 2 the selected value is approximately 20 times greater. Translating the NEUE criterion to EUE is approximately 4500 MWh/yr.¹⁶ We do not mean to imply that the LOLD or LOLH would similarly be 20 times larger, because there is not a linear relationship between these metrics, but we suspect that they would be larger and that the LOLD would be higher than the criterion. Mathematically, in order for the system to be at or below 0.1 LOLD but have an EUE of 4500 MWh/yr then either most hours of the day would have a loss of load event, or the capacity shortfall would always be sufficiently large; however, both of these seem unlikely given the nature of the analysis performed.

Despite the above discussion, EUE (and NEUE) is likely the preferred metric for a system with increasing variable renewable energy and energy limited resources. However, it is important when considering a replacement of one metric with another requires in-depth analysis and stakeholder discussions. As a result, we suggest integration of EUE (or NEUE) into existing work and utilizing it alongside LOLD.

At the November 2nd ICAPWG meeting, when asked about the derivation of the 0.003% NEUE criterion, Potomac Economics replied that they believed for a deterministic analysis, such as theirs, that usage of an energy-based metric was appropriate, we agree with this sentiment. Potomac also noted that the magnitude they selected was similar to other entities that used EUE or similar metrics. In our review of other ISO/RTOs we observed two similar criteria:

- At AEMO they utilize a NEUE of 0.002%
- At Nordic ENTSO-E they utilize a NEUE of 0.001%

Both of these values are smaller than the value selected by Potomac, and at least the value of AEMO is regarded by the NYSRC to be less stringent than the LOLD criterion:

"An interesting reason as to why the US and Canada may have more stringent resource adequacy criteria than used in other countries is provided in the Australian Review Panel report, Reliability Standards and Reliability Settings Review, published in April 2010, that proposes that countries that appear to have more stringent standards (than Australia) generally have characteristics, such as larger system size and higher levels of interconnections that would make a higher standard less costly to achieve."¹⁷

On a single sample, using UCAP for conventional resources, perhaps it is not far-fetched that the system is indeed reliable. The only components that are meaningfully changing in each hour are the load, the amount of renewable generation, storage resources, and transmission. Given the amount of EUE required to cause a resource adequacy violation maybe the events are solely occurring when solar and wind output is reduced substantially due to underlying weather conditions. If so, it is another reason to consider performing a more complete analysis that performs multiple samples and calculates proper reliability risk metrics, such as LOLD or EUE.

 ¹⁶ Calculated using the NYCA Baseline Energy Forecast from the 2021 Gold Book for 2030 of 145,960 GWh
¹⁷ NYSRC RAWG, *Resource Adequacy Metrics and Their Applications*, April 20, 2020, https://nysrc.org/PDF/Reports/Resource%20Adequacy%20Metric%20Report%20Final%204-20-2020[6431].pdf

Scenarios were evaluated with limited energy storage buildout and thermal retirements, and thus show limited benefits to a portfolio ELCC approach

With the passage of the Climate Leadership and Community Protection Act (CLCPA) in 2019, New York State codified a series of ambitious policy goals for the energy sector. One of the top-level mandates is the requirement for 70% of energy to be provided by renewable generation in 2030 and this is supported by additional targets for solar (6,000 MW by 2025), energy storage (3,000 MW by 2030), and offshore wind (OSW / 9,000 MW by 2035). In Potomac's analysis, they used these goals to set minimum targets for the capacity expansion. Since their published data focused on 2030 each case exceeded the targeted amount of solar installed capacity. The amount of energy storage capacity was equivalent in each case but the distribution of the 3,000 MW to different duration resources was different. For OSW, the minimum build was set to the recent Tier 4 REC awards from 2020 for a total installed capacity of 4,186 MW, reasonable progress towards the goal but far short of the 9,000 MW 2035 goal. Continued OSW

Potomac's approach is reasonable but has several shortcomings. Using information from existing REC awards to set minimum, or firm, builds is good design because it appropriately captures the current system conditions. Where their analysis falls short is in looking past the goals. We are currently a little over eight years away from 2030 and by then the projection from the capacity expansion model has the State at 46% achievement of the OSW goal. The remaining five years in the period will require a large and accelerated build and it isn't far-fetched to think that at least one more facility could be built by 2030. Analyzing this type of sensitivity would have proved valuable at understanding how the different accreditation methods would function at a higher penetration level. This issue is perhaps compounded by the transmission model utilized, while the network topology reflected impacts of recently approved projects that provide additional transfer capability from upstate to downstate, it does not include any changes to reflect the impact of the Public Policy Transmission Need currently being evaluated by the NYISO, which aims to increase the amount of power that can be delivered by OSW resources to the NYCA. Beyond cost, there is an opportunity that the capacity expansion tool chose not to build additional OSW because the transmission capability needed was not there when surely it will be.

It is similarly interesting that the capacity expansion model chose not to build energy storage resources beyond the State mandate for 3,000 MW. In a power system with high levels of renewable resource penetration the expectation would be that energy storage resources would be built to absorb excess renewable energy and shift it to other parts of the day when the renewables are not available. This would reduce congestion and curtailment risk which was not evaluated in the Potomac analysis. A common example is a battery charging from excess solar generation and then discharging at night. In the A-F region¹⁸ the marginal and average accreditation scenarios, respectively, build 8,482 and 11,982 MW of solar, and 1,850 and 1,450 MW of storage. Interestingly, the marginal accreditation favored 6-hr resources at about a 2-to-1 ratio while the average accreditation case was the opposite, favoring 4-hr resources. A

¹⁸ The only other region to build solar resources was G-I with 500 and 100 MW, respectively, in the marginal and average accreditation cases

scenario with additional energy storage and hybrid resources may have yielded different results and possibly shown more divergent paths between the two accreditation methods.

If storage is built for renewable integration uses - rather than standalone capacity only - the marginal accreditation process could lead to an overbuild of capacity on the system. Alternatively, this approach may diminish the economics of hybrid resources such that developers are unwilling to take on the risk of standalone wind and solar resources. Additional analysis is thus warranted.

One critical note on performing capacity expansion, or even modeling specific setpoints for what the 2030 system could look like, is that multiple scenarios can and should be evaluated to fully understand the impacts of the accreditation methodologies on the market. In his dissent to the order approving the ELCC methodology at PJM, Commissioner Christie quoted David Patton, the President of Potomac Economics, where "in response to a question of whether "it's feasible to design the ELCC based on marginal values, or is it just too hard to do" Dr. Patton stated "I think it's definitely possible… in fact I think you can simulate for what different levels of penetration would give you."¹⁹ In this analysis, Potomac Economics chose not to evaluate different levels of penetration and the analysis suffers for it.

Finally, the Potomac Economics study highlights the benefits of marginal accreditation as yielding a more balanced resource mix. However, this opinion has multiple shortcomings. First, the more balanced resource mix is only in terms of installed capacity and not overall energy. Second, the more balanced resource mix may be less likely to occur given challenges with siting wind resources in the state. Finally, a resource mix with more wind generation may have more congestion and curtailment concerns due to the locations of wind resources, the seasonality of the underlying weather, and less complementary nature of hybrid storage systems. As a result, a more balanced wind and solar *capacity* buildout may not actually be a benefit for New York ratepayers.

Capacity accreditation was based on a single weather year of data rather than a long-term meteorological dataset

Furthermore, in the analysis performed, only a single year of weather was considered, which was based on data the NYISO used in their 70x30 analysis in the 2019 CARIS I and later in the 2020 RNA. In reliability analysis, which ELCC is an offshoot of, it is critical to reflect the impact of multiple years of weather to introduce enough variability into the process for the renewable generators. The Potomac analysis already removed variability from conventional resources by modeling them at their UCAP rating, and then locked wind and solar into one weather pattern, which while good in isolation, is deficient. Typical resource adequacy analyses, such as the RNA and the IRM/LCR studies, rely on 5 years of historical data for nonconventional resources such as wind and solar, this provides an additional degree of variability between samples and overall stability between studies.²⁰ For reference, in PJM's ELCC procedure, they are currently

https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20210730-3055

¹⁹ FERC, FERC Document Accession Number 20210730-3055, July 30, 2021,

²⁰ NYISO, *Multiple Wind Shape Probabilistic Modeling with GE MARS for the IRM Study*, June, 1, 2016, <u>https://www.nysrc.org/pdf/MeetingMaterial/ICSMeetingMaterial/ICS_Agenda184/White_Paper_MWS_Wind_Rel</u> <u>ease_02%20(002).pdf</u>

modeling 8 years of weather data and best practices in the industry utilize over 20-years of time synchronized wind, solar, and load data.²¹

The analysis used 20-year-old load shapes that are no longer representative of the NYISO demand profile

The shape of the load is perhaps the most foundational aspect of reliability analysis. Without a load profile to schedule generation against there would be no analysis to conduct. For several years the NYISO has utilized "multiple load shapes" where they utilize three different historic weather years that are assigned to different levels of load forecast uncertainty. In Potomac's analysis they maintained the usage of the three standard shapes from 2002, 2006, and 2007. While this was done to be consistent with current IRM practice it is well regarded that these shapes may be inappropriate to use because they are no longer reflective of current load patterns, in fact, this is a current item of interest at the NYSRC.

While using historic data is certainly valuable, using the load numbers instead of the weather, econometrics, and consumer patterns that inform the load can be misleading. Adjusting a historic shape to a future forecast can be a valid technique (and this is what Potomac said they did), but not taking the additional step to adjust for the future energy forecast is a misstep as the overall energy of the shape may be wildly different than the forecast. When asked by a member of the Department of Public Service (DPS) about their load shape selection and adjustment procedure, Potomac dismissed concerns because the model only identified unserved energy on select, peak days. While we don't doubt the nature of this claim, mismanagement of the energy forecast would understate the capability of energy storage resources which may either be unable to charge or inappropriately discharged for a load pattern that is no longer reasonable to assume.

Additionally, in 2019 the NYISO published their Climate Change Impacts Phase 1 Study, one of the deliverables of which was a set of hourly load shapes projected to 2050. This data has been used in myriad studies, such as the Climate Change Phase II Study, the 2020 RNA,²² and even the NYISO Consumer Impact Analysis for 2026, which was itself based on work by the Analysis Group that relied on assumptions from the Brattle Group's Grid In Transition Evolution study. It is counterintuitive that the two Consumer Impact Analyses would use load shapes of different vintages in their analysis.

The ELCC methodology is discriminatory because it is not applied to thermal resources

In Potomac's model they made a simplifying assumption that conventional resources are constantly available at their UCAP rating. Compared to a traditional NYISO resource adequacy study a unit will be modeled at the minimum of their seasonal CRIS and seasonal DMNC²³ and the unit will be subject to a forced outage rate which can either derate or take it fully out of service. On average, the unit would be

²¹ D. Stenclik, et al., *Redefining Resource Adequacy for Modern Power Systems*, Energy Systems Integration Group, 2021, <u>https://www.esig.energy/wp-content/uploads/2021/08/ESIG-Redefining-Resource-Adequacy-2021.pdf</u>

²² Although the results of the analysis were not published.

²³ While this is a reasonable assumption for a capacity market analysis, such as the IRM or LCR study, it may not be reasonable for planning studies, such as the RNA or CRP, where units could be expected to provide power up to their DMNC, which may alleviate identification of Reliability Needs.

available at its UCAP rating, this is a mathematical fact, and as such the UCAP assumption isn't necessarily wrong, just misleading. Where it become less correct is the application in NYISO studies of ambient temperature derates²⁴ which reduce the max power output of select conventional resources as a function of temperature,²⁵ whereas the temperature gets warmer the output of the facility drops, this is a known thermodynamic phenomenon.

By only modeling UCAP the Potomac analysis missed how the warmest hours may have less conventional capacity than expected, but something like this could easily be captured with an ELCC analysis and would promote a fairer playing field for all resource types. Specifically, the thermal fleet could be represented in ELCC analysis by including the effects of correlated events that may occur across the fossil fleet due to the following:

- Fuel supply disruptions, specifically on the natural gas system,
- Increased probability of forced outages during extreme weather events,
- Higher than average ambient derates during extreme heat,
- Flexibility constraints that may make the generator unavailable when needed.

While the industry has taken great effort to quantify and measure the capacity accreditation of variable renewable and energy limited resources because they are new entrants, there has been less attention given to measuring capacity contribution of fossil generation which is likely overstated. As a result, any process that is used to accredit variable renewables and energy limited resources should also apply to fossil-fueled resources.

This concept was noted in Commissioner Christie's dissent²⁶ as a shortcoming of PJM's ELCC proposal, where he agreed with stakeholder groups that "ELCC should apply to all resources." ISONE's proposed capacity accreditation redesign process also intends to apply ELCC methods to thermal resources.²⁷ The NYISO's current design does not apply ELCC to conventional resources and is mimicking a "fundamental failure of PJM's ELCC proposal" as a result.

Holistic Cost to Ratepayers

While capacity market efficiency is an important consideration for the accreditation method, it is not the only way ELCC affects ratepayer costs. Cost savings in the capacity market do not necessarily translate directly to ratepayer benefits, but rather shifts renewable plant revenues to REC auctions administered by NYSERDA and has downstream implications for the NYISO energy markets.

- https://www.nysrc.org/PDF/Reports/2021%20IRM%20Study%20Appendices%2012 4 20%20(1).pdf
- ²⁵ This is modeled in MARS by using the load as a proxy for temperature.

²⁴ NYSRC, 2021 IRM Study Appendices, December 4, 2020,

²⁶ FERC, FERC Document Accession Number 20210730-3055, July 30, 2021,

https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20210730-3055

²⁷ V. Chadalavada, ISO New England's Draft 2022 Annual Work Plan, For Discussion at the October 7, 2021, NEPOOL Participants Committee Meeting, ISO New England.

For instance, if New York State is successful in reaching its 70x30 renewable energy goals, it will require substantial investment from NYSERDA. Today, the NYSERDA REC contracts are *Indexed RECs* where generation owners provide a total all-in strike price (revenue requirement) for the plant. If capacity market or energy market revenues fall below expectations, NYSERDA makes up the difference, thus minimizing (some) wholesale market risk for renewable energy asset owners.

The Potomac Economics study included this feedback loop of increased REC payments with a marginal versus average ELCC accreditation process. However, the analysis failed to account for energy market changes that could arise in a high-renewable 2030 grid. Under these conditions, transmission congestion and curtailment is likely, and renewable energy developers may choose to develop hybrid resources to integrate storage as a mitigation. Storage capacity could be added beyond the 3,000 MW assumed by Potomac Economics, creating surplus capacity if marginal ELCC is used instead of average ELCC. An average ELCC approach would properly account for these capacity benefits and reduce the overall need for capacity in the capacity markets. Therefore, the cost impact to be of using marginal instead of average, and that it likely deserves greater scrutiny and study before moving forward with a change of that magnitude.



RECOMMENDATIONS

While we believe that the "Comprehensive Mitigation Review" proposal is important, we do not believe that it is appropriate to lock into a capacity accreditation methodology without rigorous analysis being performed. We support the usage of Effective Load Carrying Capability (ELCC), but believe it is premature to value resources at their "marginal reliability contribution," which is codified in draft Tariff language. In the NYISO's proposed timeline they indicate that Phase 2 will evaluate how to perform the ELCC analysis and in this phase the NYISO should fully analyze the differences between a marginal and average approach. Specifically, the NYISO has not properly substantiated that a marginal approach will be advantageous over an average ELCC approach. Specific recommendations for Phase 2 to correct the study limitations identified in this report as well as the procedural considerations outlined in the Appendix B.

We recommend that the NYISO pursue stakeholder approval for the elimination of Buyers Side Mitigation and the intent to implement ELCC for capacity accreditation - but exclude any specific determination on marginal or average ELCC accreditation methods.

The final determination of a capacity accreditation methodology by the NYISO and its stakeholders has broad implications to capacity accreditation processes currently underway in other jurisdictions. ISONE, MISO, and other ISO/RTOs are currently reviewing ELCC-based accreditation methods for potential FERC approval. While the analytical framework will be similar in these jurisdictions, differences in market design may result in different average vs. marginal ELCC decisions. First, these regions are not single-state markets where forgone capacity revenues can be recovered with in-state REC programs. Second, the ISONE market, for example, is a three-year forward auction instead of NYISO's one-year forward design. As a result, average ELCC may be a more stable metric for markets clearing many years in the future. Finally, in regions like MISO, SPP, and CAISO that do not administer a mandatory capacity auction, measuring a load serving entities portfolio of resources for resource adequacy lends itself to average ELCC accreditation. As a result, it is important to assess these capacity accreditation methods within the unique regulatory and market framework for each region.

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ABOUT TELOS ENERGY

Telos Energy is an analytics and engineering company, headquartered in the Capital District of New York State, specializing in enabling grid technologies and market design for renewable integration. We provide grid analytics and engineering for a cleaner, more efficient, and more reliable power grid.

The Telos Energy team combines an understanding of energy economics and electrical engineering, software tool expertise, and extensive reach across the industry to provide clients with a comprehensive analysis of the impact of new technologies, markets, and policies on power systems. Using highly detailed grid models, we guide our clients through a fast-changing industry to accelerate their clean energy and emerging technology goals.



Mike Welch

Mike Welch is a Senior Analyst at Telos Energy that specializes in resource adequacy analysis and power system planning. Prior to joining Telos Energy, Mike worked at the New York Independent System Operator as a member of the System and Resource Planning Department and, as a Senior Planning Engineer, performed resource adequacy studies to understand the impacts of system changes, such as generator retirements and increased renewable penetration, on statewide reliability. Mike attended Clarkson University where he earned a BS in Electrical Engineering, and later attended the Rochester Institute of Technology where he earned a MS in Sustainable Systems.



Derek Stenclik

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APPENDIX A: OVERVIEW OF CAPACITY ACCREDITATION

Increasing Importance of Capacity Accreditation

Underpinning any capacity accreditation mechanism - whether it be a mandatory capacity market auction in Northeast ISOs or integrated resource planning for vertically integrated utilities - is technical resource adequacy analysis and modeling.

Resource adequacy (RA) analysis utilizes modeling conducted to measure whether the system has enough resources to serve load under a wide range of potential future system conditions. RA analysis considers potential variations in system load, fluctuations in weather and corresponding availability of variable renewable energy (VRE) resources like wind and solar, and planned and unplanned generator outages. By utilizing statistical techniques, the analysis measures the probability, or expectation, that the system has insufficient resources (i.e., capacity) to meet load.

When evaluated across many simulated years of various weather and generator outages, the count of days that experienced some level of capacity shortfall is summarized as the Loss of Load Expectation (LOLE). The LOLE metric is commonly utilized as a resource adequacy criterion (e.g., a 1-day-in-10-years LOLE requirement) by the NYISO and many jurisdictions across North America.

Because not all resources have the same expected performance during shortfall events, different resources are accounted for differently. In these cases, a resource is accredited a certain amount of "firm capacity" that counts towards the planning reserve margin. For example, fossil fuel-fired generators may be counted as "unforced capacity" (UCAP) that discounts the firm capacity of the resource by the generator's forced outage rate (unplanned outages). For variable renewable resources, the generators are often discounted based on their availability during likely shortfall events.

There are multiple ways to accredit wind and solar resources, as shown in the list below, which vary by region. Currently the NYISO utilizes output during predetermined hours for wind and solar resources, and effective load carrying capability (ELCC) for battery storage resources but is proposing to switch these three resources to ELCC. PJM recently switched to an ELCC method for capacity accreditation of renewables and MISO and ISONE are in the process of transitioning to ELCC. Out of the three options listed below, ELCC provides the most accurate accreditation method and inherently updates as the underlying system changes.

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- Output during predetermined hours: resources are measured based on their average or median (or other percentile rank) output during a pre-defined capability period. For example, the NYISO currently accredits wind and solar resources based on hourly production data across a 6- or 8hour window in each Capability Period²⁸ A similar process is done in ISONE.²⁹
- Average output during highest net load hours: rather than determine a predefined time window, this process averages plant output during peak load or peak net load (load minus available wind and solar) hours. For example, SPP accredits wind based on its 60th percentile of production during the top 3% of load hours.³⁰
- Effective load carrying capability: ELCC methods measure the ability of a resource to reduce loss of load events in a probabilistic resource adequacy analysis. Specifically, ELCC measures the amount of load that can be added to a system, after a resource is added, while maintaining the same level of reliability (measured as loss of load expectation or loss of load probability).³¹

Recognizing the shortcomings of accreditation resources based on output during predetermined hours, the market monitor made revisions to the NYISO's capacity accreditation process a top priority in 2020 which recommended the NYISO "revise the capacity accreditation rules to compensate resources in accordance with their marginal reliability value."³²

As the power system further decarbonizes and retires thermal generation, the role of renewable resources, energy storage, and demand response will play an increasing role in the reliability services traditionally served by the fossil fleet. Properly assigning capacity accreditation to these resources is not just a matter of establishing price signals for market entrants - but also to ensure resource adequacy in a decarbonized energy transition. If New York State is set to achieve its decarbonization goals robust resource adequacy and accurate capacity accreditation of the entire resource mix is necessary. First and foremost, resource adequacy analysis - and downstream capacity markets and capacity accreditation - is intended to ensure reliability. A secondary benefit is to provide a stable price signal for long-term investment.

Capacity accreditation is important because variable renewable resources provide capacity benefits sometimes, but not others. Energy limited resources like battery storage and demand response can provide a high degree of availability during peak load conditions but have a limited response duration. Even natural gas resources, as discussed previously, are not as firm as unforced capacity (nameplate minus a forced outage rate adjustment) would indicate due to ambient temperature derates and common mode failures during extreme temperature and fuel supply outages. Even fleets of nuclear plants have suffered

²⁸ Z. Smith, *Capacity Accreditation: Current Rules*, NYISO, August 5, 2021, <u>https://www.nyiso.com/documents/20142/23590734/20210805%20NYISO%20-</u> <u>%20Capacity%20Accreditation%20Current%20Rules%20Final.pdf</u>

 ²⁹ Wholesale Electricity Market Design in North America: Reference Guide: 2020 Review, EPRI, 2021. 3002018647
³⁰ Ibid.

³¹ Ibid.

³² Patton, et al., 2020 State of the Market Report for the New York ISO Markets, Potomac Economics, May 2021.

from drought-induced cooling water loss, and fleets of coal plants have simultaneously experienced frozen coal piles or interruptions in coal deliveries.

This is changing the notion of "firm capacity" as there is no such thing as a perfect resource for resource adequacy. Instead, the definition of capacity is increasingly associated with *the ability of a resource to be available during times of system need and scarcity events.* A given resource therefore does not have to be firm or dispatchable to have high capacity value. However, it also means **the capacity value of a given resource changes with the amount of that resource type, and of other resources, on the system.** These include saturation effects due to positive output correlations within individual resource types, and portfolio benefits due to negative correlations among different types of resources. These effects can make resource accreditation - the value at which a given resource is ascribed capacity value - highly dependent on the region, weather conditions, the load profile, and resource mix. Not only does this vary by region, but it also changes over time as the resource mix evolves.

Saturation effects are common with any resource with correlated output that is only available during certain periods or has energy limitations, as the first "tranche" of the resource added to the system can mitigate certain scarcity events, but subsequent additions are unable to fill in the remainder of events.

Portfolio effects also challenge attempts to assign individual resources a capacity credit. For example, storage capacity value is altered by the amount of solar on the system, as an increase in solar generation increases the availability of surplus energy to charge to storage, and it shortens evening peak load periods. Similar effects are seen with other types of resource diversity (i.e., complementarity between wind and solar output profiles) or changes with the underlying load profile over time.

Marginal vs. Average ELCC

Two options for ELCC calculations

While ELCC can provide an accurate estimate of capacity contributions of a particular resource, there are numerous challenges that were considered in the NYISO capacity accreditation proposal. A first challenge is saturation effects, which cause the ELCC to diminish as the installed capacity of a resource increases and risk shifts to other time periods. Understanding the potential for multi-day weather events with sustained low wind or solar production are also difficult to quantify and the availability of a hybrid resource is dependent not just on its capacity, but also the availability of energy to charge the resource and shift production to later hours. As power systems become more dependent on variable renewable energy and energy limited resources for reliability the system will become less capacity constrained and more energy constrained.³³ The saturation effects are displaced in Figure 2, which shows the marginal capacity contribution of increasing amounts of wind, solar, and storage in New York.³⁴

³³ D. Stenclik, et al., *Redefining Resource Adequacy for Modern Power Systems,* Energy Systems Integration Group, 2021, <u>https://www.esig.energy/wp-content/uploads/2021/08/ESIG-Redefining-Resource-Adequacy-2021.pdf</u>

³⁴ K. Spees, et al., *Quantitative Analysis of Resource Adequacy Structures*, Brattle, July 1, 2020, <u>https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B9D20EBBD-4DF8-4E4E-BEC1-F4452345EBFA%7D</u>



Figure 2: Installed capacity versus marginal capacity credit in New York Source: Brattle

While saturation effects are true of wind, solar, and storage resources *in isolation*, it can be mitigated or even reversed when these resources are combined in a portfolio. According to E3, "while resources with similar operating characteristics yield diminishing returns, combining resources with complementary characteristics can produce the opposite effect, a total ELCC that is greater than the sum of its parts."³⁵ The interactive effects of resources added conjunction to one another can yield additional capacity value benefits that are not captured by an evaluation of the resources interpedently.

Take solar and storage resources as an example. The portfolio effect increases capacity contribution of the joint additions for two reasons. First, the addition of solar makes the system net peak load narrower, improving the ability of an energy limited resource like storage to cover the peak load risk. In addition, the solar adds energy to the system which can be used by the storage resource to charge. As the power system becomes more energy limited rather than short on capacity, this contribution becomes increasingly important. The figure below shows the increasing capacity of 4-hour energy storage relative to the amount to PV on the system.

Another example of the solar and storage portfolio effect is evident from PJM's capacity accreditation results.³⁶ Estimates for energy storage ELCC actually *increase* in future study years despite increasing capacity on the system, and declining portfolio ELCC, due to the change in the underlying resource mix, namely increased renewable energy.

³⁵ N. Schlag, et al., *Capacity and Reliability Planning in the Era of Decarbonization, Practical Application of Effective Load Carrying Capability in Resource Adequacy*. Energy+Environmental Economics (E3), August 2020, <u>https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf</u>

³⁶ PJM, *ELCC Results Report for July 2021*, <u>https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-report-forjuly-2021-results.ashx</u>



Figure 3: Capacity value of storage relative to system solar penetration Source: NREL



Figure 4: Increasing battery storage ELCC at increasing installations in PJM Source: PJM

Recognizing the saturation and portfolio effects of ELCC, there are two methods to calculating ELCC, marginal ELCC and average (portfolio) ELCC. Marginal ELCC measures the incremental capacity credit of a resource when evaluated in isolation, and for the next incremental addition of the resource relative to the existing portfolio. This is a useful metric to quantify the saturation effect of a resource and to compare resources against one another to determine which resource provides the most capacity value for the next addition to the system. As a result, it is a useful metric to serve as an effective price signal and an incentive for new additions. However, it is limited in that the sum of all of the marginal ELCC resources is less than the total resource adequacy benefits.

In contrast, portfolio ELCC quantifies the *total* capacity contribution of a bundle of wind, solar, and storage resources rather than the incremental addition of the last entrant on the system. Portfolio ELCC is also referred to as average ELCC, which is the portfolio ELCC divided by the total quantity of resources in the portfolio (illustrated in Figure 5). The benefits of using average ELCC for capacity accreditation provides an accurate quantification of the resource adequacy benefits of the entire portfolio. A limitation of the average ELCC method is assigning credit to individual resources within the portfolio can be difficult. However, E3 has proposed the "delta method" to split out the total capacity contribution of the portfolio to individual resources.³⁷



Figure 5: Illustration of average vs marginal ELCC Source: E3

The NYISO is currently proposing to accredit resources based on the *marginal* ELCC calculation method because they believe it provides a more accurate *price signal* to the market and necessary to incentivize the appropriate resources to enter or exit the market. In contrast, PJM recently selected an adjusted class average approach which received FERC approval in July 2021. In their filing, PLM explained:

"After thoroughly discussing the benefits and costs of each approach, PJM and its stakeholders ultimately decided to proceed with an adjusted class average approach. This decision was based on several considerations. The purpose of PJM's proposed ELCC is to establish the physical capability of resources in the capacity market. This allows resource providers the opportunity to provide capacity up to the appropriate level, while preventing resources from being offered at a greater level of reliability than they are physically capable of providing. Thus, the ELCC construct is not being established to determine signals for entry and exit to the market—the auction clearing process and Capacity Performance obligations already accomplish that objective. Further, an adjusted class average approach appropriately places ELCC in a reliability "backstop" role, by virtue of the fact that resources cannot offer more in aggregate than their total reliability value as a class. This ensures that reliability will remain the primary objective against which the

³⁷ A. Olsen, *ELCC Concepts and Considerations for Implementation, Prepared for the August 30th, 2021 NYISO ICAPWG,* Energy+Environmental Economics (E3).

enhanced market efficiencies gained from an ELCC construct will be measured. Thus, an adjusted class average approach appropriately allows Capacity Market Sellers to determine the potential risk/reward of offering a certain amount of UCAP into the capacity market, which is consistent with the Commission-approved Capacity Performance construct."³⁸

Recent developments in PJM FERC order

Given that PJM was the first ISO/RTO to recently propose changes to its accreditation process, additional details of the filing and FERC's order are provided to shed light on the potential NYISO filing process. On July 30, 2021 FERC issued an order accepting tariff revisions filed by PJM to establish an ELCC procedure³⁹. This followed an earlier determination from April 30, 2021, that found their initial proposal to be unjust and unreasonable because of a transition mechanic that FERC deemed would be discriminatory. In the final ELCC proposal, PJM defined a process without this mechanic and that was otherwise the same except for defining the resource classes that would be subject to ELCC evaluation.

The new procedure has already been implemented and is in effect for PJM's 2023-24 Base Residual Auction, which will be concluding in December 2021. In the auction, each member of an ELCC Class has been assigned an ELCC Class Rating based on PJM analysis.

The PJM framework for calculating the ELCC Class Ratings is straightforward and thoroughly described in Dr Patricio Rocha Garrido's affidavit attached to the PJM filing. It states the methodology for calculating the ratings is composed of several foundational components of modeling load and resource performance uncertainly. While traditional resource adequacy analysis additionally includes the effect of transmission limitations, PJM does not include this component in their resource adequacy work.

"There are other supplemental assumptions underlying the ELCC methodology proposed by PJM. Transmission limitations are not explicitly modeled in the ELCC simulations. Instead, it is assumed that there are no transmission-related reliability issues within the PJM footprint. This assumption is also used in PJM's main resource adequacy study, the Reserve Requirement Study. The justification for it is the fact that PJM has a Regional Transmission Expansion Process ("RTEP"), with a look-ahead planning horizon of five years, which ensures that specific areas of the PJM footprint have the necessary transmission infrastructure to receive the required level of energy imports. Nevertheless, it is likely that some aspects of this RTEP process will need to change as the penetration level of ELCC Resources increases."⁴⁰

 ³⁸ PJM, *FERC Document Accession Number 20210601-5065*, June 1, 2021, <u>https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20210601-5065</u>
³⁹ FERC, FERC Document Accession Number 20210730-3055, July 30, 2021, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20210730-3055
⁴⁰ PJM, *FERC Document Accession Number 20210601-5065*, June 1, 2021, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20210601-5065

The PJM analysis relies on the calculation of an adjusted class average ELCC, where the amount of perfect capacity is determined against the entire portfolio of ELCC resources, and then prorated by the ELCC Resource Performance Adjustment for Variable Resources, which is calculated based on the resource classes performance in the top 200 load hours of the previous 10 years.

PJM offers additional insight into why their approach to capacity accreditation is valid in their filing:

"In the April 2021 Order, the Commission found PJM's adjusted class average "appropriate because it: (1) applies uniform capacity obligations on similarly situated resources based on their class average contribution to system resource adequacy; and (2) ensures that the sum of resource class's accredited capacity values is equal to the aggregate reliability value of the ELCC Resource portfolio." Further, the Commission recognized that PJM's adjusted class average approach provides "the benefit of informing ELCC Resources of their capacity accreditation prior to the capacity auction, which reduces uncertainty for such resources and gives them better information to construct their capacity supply offers."⁴¹

PJM also states the importance of the underlying resource mix and load shape in their analysis, noting that changes to either could result in changes to the study results. This is a solid justification for periodic review of capacity accreditation factors.

"Because ELCC recognizes the potential diminishing returns associated with greater levels of deployment for most of the ELCC Resource types (as explained below), it will help ensure that the PJM Region does not become over-dependent on a single resource type with inherent limitations, which could contribute to inadequate system reliability. As future installments of these resource types observe the diminishing returns in reliability contribution (and their ability to earn capacity revenues decreases), market forces could induce technological advancements that offset or actually increase their reliability contribution. At the same time, ELCC recognizes the synergistic relationship among distinct resource types, thus potentially facilitating greater provision of reliability from the various resource classes pooled together across the PJM Region than what those same classes could provide in isolation. ELCC also evolves with a changing load shape, which may be a feature of a future grid that could see greater electrification of heating and transportation."⁴²

⁴¹ Ibid. ⁴² Ibid.

Application of Probabilistic Techniques in the PJM ELCC Analysis

PJM's ELCC process incorporates various techniques to produce a sound probabilistic analysis. The bedrock of their process is utilization of multiple historic years of load and weather. Their current analysis uses 8 years of historical data, from 2012 through 2019. For each of these years they used actual or back-casted data to represent the renewable generation profiles, and then layer on a probabilistic load shape and thermal resource availability. The probabilistic layer is represented by applying 1000 Monte Carlo samples on each historical year (for a total of 8000 samples). The LOLD is then calculated for each historic year and then weighted by a probability of occurrence due to a low number of historic years. For their current ELCC analysis, we were able to reproduce an LOLD of 0.1 dy/yr, as shown below. The usage of multiple historic years when overlaid with 1000 Monte Carlo samples creates a robust probabilistic analysis

Year	Weight	LOLD (dy/yr)	Weighted LOLD (dy/yr)
2012	0.157	0.162	0.0254
2013	0.101	0.558	0.0564
2014	0.065	0.027	0.0018
2015	0.289	0.004	0.0012
2016	0.068	0.029	0.0020
2017	0.065	0.037	0.0024
2018	0.068	0.021	0.0014
2019	0.187	0.049	0.0092
Overall	1.000	#N/A	0.0997

Table 3: PJM's Multi-year weighted LOLD⁴³

⁴³ Data in this table is reproduced from the posted results from PJM's July 2021 ELLC Study, https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability

APPENDIX B: CONSIDERATIONS FOR COMPREHENSIVE MITIGATION REFORM PHASE 2

Suggestions for Calculating Capacity Accreditation

This section examines two analytical techniques for calculating a resources capacity accreditation: Effective Load Carrying Capability (ELCC) and Equivalent Firm Capacity (EFC). The intent of this discussion is to inform the NYISO and its stakeholders of these analytic techniques and to serve as a reference for how this analysis could be performed in Phase 2.

For a typical ELCC analysis, a practitioner would be following this workflow:

- 1. Adjust your system to a 0.1 LOLD,
- 2. Add a new resource and measure the LOLD, it will be below 0.1 LOLD,
- 3. Iteratively increase the peak load of the system until the LOLD is found to be 0.1, within a reasonable tolerance.

For a typical EFC analysis, a practitioner would be following this workflow:

- 1. Adjust your system to a 0.1 LOLD,
- 2. Remove an existing resource and measure the LOLD, it will be above 0.1 LOLD,
- 3. Iteratively add firm capacity to the system until the LOLD is found to be 0.1, within a reasonable tolerance.

These techniques are functionally similar with the key difference being the nature of the disturbance applied to the system in Step 2 and how the system is returned to its original state in Step 3. Despite these differences, the two terms are often used interchangeably. It is important to note that in the above workflows a critical assumption was made in the first step where the system was brought to an LOLD of 0.1, the criterion used at the NYISO, but theoretically any reliability metric can be used and at any value.

When performing a capacity accreditation study, careful thought into Step 2 must be taken. Should the analysis evaluate a single resource or a class of resources? Should it function on an increment of generation capability or on an entire facility? The answers to these questions indicate whether a marginal or average methodology is being applied.

Considerations for Performing Analysis with a Marginal Framework

In a marginal analysis, the interest is on the addition of the next unit to the system and determining how much load it can serve. This type of analysis makes intuitive sense, if a new generator is coming online, how well does it perform given the existing generators already on the system? This is also easily expandable to a class of new resources but is trickier when evaluating existing resources.

To evaluate an existing set of resources their capacity would need to be reduced by a small increment to measure their EFC, or alternatively, have their capacity increased by a small amount to measure their ELCC. These values may differ for the same capacity value, but they should be similar. In this analysis, the fundamental component is the increment of capacity, a small value such as 1 MW may be too small to appreciably change the ELCC and a large value such as 500 MW may be too large to keep the "marginal" moniker, values such as 10 or 50 MW may be most appropriate depending on system size.

To implement a marginal framework in GE MARS, the NYISO should consider adjusting the amount of capacity from renewable generators available to the model. This approach requires carefully calculating a new set of penetration factors to adjust the installed capacity of the resources. A simpler approach may be to include a normalized, average resource shape as in input for the class and then scale it to the capacity increment to perform an ELCC analysis. No matter the technique applied, the NYISO's existing iterative tools could be used to iterate to the original LOLD. However, it is worth noting that for units outside of those informed by resource shapes (wind, solar, hydro, LFG) consideration will need to be applied on the appropriate way to adjust unit capacity. Battery units may be able to have their capacity increased proportionally, but certainly caution will need to be exercised for hybrids or other resource combinations under a marginal approach.

Considerations for Performing Analysis with an Average Framework

For the addition of a single, new resource the average framework does not differ from the marginal if in that analysis the entire facility is considered. This same concept applies to a fleet of new resources, but again, only if the entire fleet is considered and not an increment of it.

Where marginal and average diverge is with the treatment of existing resources. In the marginal framework the existing fleet either had its capacity increased or decreased by a small amount to measure its ELCC or EFC. Under an average framework, EFC is a better approach because it is more intuitive to remove the units of interest from service than to duplicate them for an ELCC analysis. This is the fundamental difference, the amount of capacity removed under an average approach is much larger than under a marginal approach, and as such leads to a different valuation because of the underlying LOLE curve.

To implement an average framework in GE MARS, the NYISO should consider an EFC analysis where they retire units in a class from service. This is a simple technique to measure the LOLD of the system and the iterative tools could be used to return the system to its initial state. Under an average approach resource class combination, such as hybrid resources, may be easier to measure.



Procedural Concerns the NYISO Should Consider in Phase 2

The items listed below are outside of the 'marginal vs average ELCC' arena but are items that in review of the NYISO proposal we thought were valuable to opine on and hope the NYISO and its stakeholders find interesting and informative.

Adjusting the System to the Reliability Criterion

The NYISO has indicated that their ELCC analysis will start from the IRM or LCR study and, of these options, we believe the LCR study is a more appropriate starting point. The final LCR case will be at, or near, the reliability criterion of 0.1 LOLD, which is a solid place from which to start a capacity accreditation analysis from. Despite this, to arrive at this LOLD, the amount of installed capacity in each locality and the NYCA has been adjusted to their respective IRM or LCR values, which may differ substantially from the as-found system which would have more capacity available.

Our concern stems from this assumption, because the at-criterion system has been fundamentally altered in how much capacity is available in each locality, is this the appropriate point to start the capacity accreditation work? Or is it more reasonable to start from the as-found system and then increase the peak load uniformly or pro-rata until the statewide LOLD violates the reliability criterion? This is an interesting question that should be evaluated in Phase 2.

How does the ELCC methodology impact the valuation of renewable resources in the IRM/LCR studies?

Another potential concern is the interaction between the IRM and LCR studies and the ELCC of renewable resources. In current analyses, zonal EFORds are used to translate from ICAP to UCAP as capacity is removed or shifted between localities. For conventional, thermal resources the EFORd of each facility is based on GADS data, while for other resource types the "EFORds" used in the calculation are informed by the current capacity accreditation process outlined in the ICAP Manual. This presents an interesting chicken and egg problem, if the IRM and LCR studies are to use ELCC-based accreditation then should these studies use the previous year's capacity accreditation values and then be used to determine the upcoming capacity accreditation values?

Is locational accreditation necessary?

The NYISO capacity accreditation proposal, in its current form, would calculate a value for each resource class in each capacity zone in NY plus the Rest of State region. The granular nature of this approach may be advantageous for certain resource types but disadvantageous for others. For instance, it is intuitive to think about how solar resources behave differently upstate than downstate, but will offshore wind resources differ significantly depending on if they interconnect to NYC or Long Island? We appreciate building the granular approach into the process but wonder if it adds unnecessary complexity.

Is GE MARS the appropriate application to use?

It is also worth asking the question of whether the NYISO's intent to use GE MARS is an appropriate choice. As noted in the report, we believe it is critically important to utilize a probabilistic model for ELCC analysis and GE MARS is certainly not the only application that can perform such feats. Notably, the ELCC analysis performed by PJM is occurring outside of their Reliability Planning Model and still meets the definition of a probabilistic model because variability is being applied to the load shape and unlimited resources.

An alternative commercial tool that may be valuable for capacity accreditation is Energy Exemplar's PLEXOS, which the NYISO licenses.⁴⁴ PLEXOS recently introduced the Reliability module, whose primary function is EFC analysis. This tool may be well worth the NYISO's time to investigate as the EFC process has been fully automated with the PLEXOS desktop application.

⁴⁴ NYISO, *NYISO Capacity Expansion Primer*, October 25, 2021, <u>https://www.nyiso.com/documents/20142/25620932/05 Capacity Expansion Primer REVISED.pdf</u>

EXHIBIT D

Arne Olson et al., *ELCC Concepts and Considerations for Implementation*, Energy + Environmental Economics (Aug. 30, 2021)

ELCC Concepts and Considerations for Implementation

Prepared for the August 30th, 2021 NYISO Installed Capacity Working Group

August 30th, 2021



Energy+Environmental Economics

Arne Olson, Senior Partner Zach Ming, Director Ben Carron, Managing Consultant



Agenda

- **1.** Introduction to the problem of dispatch-limited resource capacity accreditation
- 2. Loss-of-Load Probability modeling basics
- **3.** ELCC computation and application

Introduction





About E3

- + E3 is a San Francisco-based consulting firm founded in 1989 specializing in electricity economics with approximately 75 staff
- + E3 consults extensively for utilities, developers, government agencies, and environmental groups on clean energy issues
- Services for a wide variety of clients made possible through an analytical, unbiased approach
- Our experts provide critical thought leadership, publishing regularly in peer reviewed journals and leading industry publications





Resource adequacy is increasing in complexity – and importance

Transition towards renewables and storage introduces new sources of complexity in resource adequacy planning

- · Planning exclusively for "peak" demand is obsolete
 - This was reasonable when all resources were firm
- Resource adequacy must consider conditions across all hours of the year – as underscored by California's rotating outages during August 2020 "net peak" period
- + Reliable electricity supply is becoming increasingly important to society:
 - Meeting cooling and heating electric demands as extreme weather events become more frequent and severe is increasingly a matter of life or death
 - Economy-wide decarbonization requires electrification of transportation and buildings, making the electric industry the keystone of tomorrow's energy economy



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5



Resource adequacy is no longer only about planning for peak demand

CAISO System Operations on August 14, 2020 (MW of generation & load served)



Energy+Environmental Economics

- Traditional resource adequacy planning focuses on peak demand
- Increasing penetrations of renewables and storage will cause challenges to shift to other periods of the day (and year), requiring innovation in planning approaches

California ISO Final Root Cause Analysis

"In transitioning to a reliable, clean, and affordable resource mix, **resource planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand in the early evening hours**. This made balancing demand and supply more challenging during the extreme heat wave.

"The rotating outages both occurred after the period of gross peak demand, during the "net demand peak," which is the peak of demand net of solar and wind generation resources."



The nature of the resource adequacy challenge is changing

- Resource adequacy is a measure of the ability of the bulk grid (generation) to meet a reliability standard across a wide range of system conditions
 - NY uses a 0.1 day / year standard
- + As renewable penetration grows, planning problems shift from traditional need to meet peak demand hours (e.g., summer) to new questions of meeting net demand (e.g., over multi-day low renewable events)
 - · The timing of these needs will change
 - From summer gross peak to winter net peak
 - To account for unexpected high load and low renewable output during planned outages in the shoulder months
- This new planning problem highlights the need to assess reliability in a time-sequential way over full spectrum of system conditions



Loss of Load Probability Table Identifies the probability of each hour to be deficient





Decarbonization will eventually shift timing of loss of load events into winter months

- Today, reliability events are concentrated in summer "net peak" period – after sunset but while loads remain high
- In a deeply decarbonized grid, reliability events will occur in the winter, during sustained periods of low renewable production
 - With large quantities of solar & storage, summer is no longer the "binding constraint"



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Based on E3's study Long-Run Resource Adequacy under Deep Decarbonization Pathways for California



Evolving grid challenges at increasing renewable penetrations

+ Increasing levels of renewables will cause the timing of reliability challenges to shift to different times of day – and eventually to different times of year





Historical-based capacity accreditation does not accurately reflect reliability value

- Historical output based: credit resource capacity based on historical resource output during peak periods
 - · Can use gross load peaks or net load peaks
 - Typically multiple hours over multiple months (e.g. HE 16-18, Jun-Sept)
 - Can use median, mean, or "exceedance" approach (e.g. 70th percentile)
- Historical output based methods are simple and transparent, but cannot capture load generation correlation, diminishing returns, and interaction between resources
 - The approach works fine at small penetrations but insufficient when the system depends more meaningfully on these resources for reliability





Evolving best practices in resource adequacy

 Best practices in resource adequacy link detailed loss-of-loadprobability modeling with a more simplistic planning reserve margin accounting framework





ELCC has quickly gained traction among ISOs and utilities



Loss of Load Probability Modeling





Loss of Load Probability Modeling Methodologies

- LOLP modeling should contain sufficient information about the probability of certain system conditions occurring, including
 - High and low loads due to weather
 - Renewable conditions across a wide array of high and low generation events
 - · Correlations between load and renewable conditions
 - Dispatch behavior of energy-limited resources such as energy storage and hydro
- + As much data on the distribution of load and renewables should be captured as possible
 - Weather distribution can be based on historical conditions, adjusted for expected climate change impacts
 - Renewable generation can be based on historical conditions, adjusted for climate change impacts
- + E3 recommends at least 10 years of renewable generation conditions and as many load-driven weather years as is reasonable e.g. 30+
 - The accuracy of individual Monte Carlo runs in arriving at the ELCC of a resource-type depends on the data within the run







LOLP analysis produces a range of useful metrics

+ <u>Statistical reliability metrics</u>: measures of the size, duration, and frequency of reliability events

Result	Units	Definition
Expected Unserved Energy (EUE)	MWh/year	Average total quantity of unserved energy (MWh) over a year due to system demand exceeding available generating capacity
Loss of Load Probability (LOLP)	%	Probability of system demand exceeding availability generating capacity during a given time period
Loss of Load Hours (LOLH)	hours/year	Average number of hours per year with loss of load due to system demand exceeding available generating capacity
Loss of Load Expectation (LOLE)	days/year	Average number of days per year in which unserved energy occurs due to system demand exceeding available generating capacity
Loss of Load Events (LOLEV)	events/years	Average number of loss of load events per year, of any duration or magnitude, due to system demand exceeding available generating capacity

+ <u>Derivative metrics</u>: additional useful measurements that can be derived from LOLP analysis

Result	Units	Definition
Planning Reserve Margin Requirement (PRM)	% 1-in-2 peak load	The planning reserve margin needed to achieve a given reliability metric (e.g., 1-day-in-10-years LOLE)
Effective Load-Carrying Capability (ELCC)	MW	Effective "perfect" capacity provided by energy-limited resources such as hydro, renewables, storage, and demand response
Residual Capacity Need	MW	Additional "perfect" capacity needed to achieve a given reliability metric



Capturing the full range of potential electric demands





Planning reserve margin (PRM)

PRM is measured as the quantity of capacity needed above the median year peak load to meet the LOLE standard

- Serves as a simple and intuitive metric that can be utilized broadly in power system planning
- Based on robust LOLP modeling

The integration of increasing levels of renewables and storage does not render the PRM framework obsolete

Does require more advanced techniques for measuring the contribution of different types of resources towards that capacity requirement





Resource accreditation is simple in the traditional planning paradigm

- + PRM defined based on Installed Capacity method (ICAP)
- + Individual resources accredited based on nameplate capacity
 - Small differences in forced outage rate
 - □ No interactions among resources
 - Forced outages also incorporated through performance penalties



Installed Capacity =
$$\sum_{i=1}^{n} G_i$$



Adapting the PRM framework for a high renewable future

- + PRM defined based on Perfect Capacity (PCAP) or Unforced Capacity (UCAP)
- + Individual resources accredited based on ELCC
 - Large differences in availability during peak
 - Significant interactions among resources
 - ELCC values are dynamic based on system conditions



Portfolio $ELCC = f(G_1, G_2, ..., G_n)$

ELCC Computation and Application





ELCC is calculated using loss-of-load-probability modeling



the system in



Measuring ELCC of a Portfolio and Individual Resources

+ ELCC of is a function of the portfolio of resources

- The function is a surface in multiple dimensions
- The Portfolio ELCC is the height of the surface at any given point on the surface

 $Portfolio \ ELCC = f(G_1, G_2, \dots, G_n) \ (MW)$

The Marginal ELCC of any individual resource is the gradient (or slope) of the surface along a single dimension – mathematically, the partial derivative of the surface with respect to that resource

Marginal
$$ELCC_{G_1} = \frac{\partial f}{\partial G_1} (G_1, G_2, \dots, G_n) (\%)$$

- + The functional form of the surface is unknowable
 - Marginal ELCC calculations give us measurements of the contours of the surface at specific points
 - Lt is impractical to map out the entire surface




Portfolio ELCC and Marginal ELCC

+ Portfolio ELCC

- The combined capacity contribution of a combination of intermittent and energy-limited resources
- Inherently captures all interactive effects
- Useful for measuring the total ELCC of an existing portfolio
- + Marginal ELCC
 - The incremental capacity value of a resource (or a combination of resources) measured relative to an existing portfolio
 - Useful for comparing new resource options against one another at the margin





ELCC captures saturation effects at increasing penetrations



Solar and other <u>variable</u> <u>resources</u> (e.g. wind) exhibit declining value due to variability of production profiles

Storage and other <u>energy-limited</u> <u>resources</u> (e.g. DR, hydro) exhibit declining value due to limited ability to generate over sustained periods

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ELCC captures diversity benefits among technologies

- + Resources with complementary characteristics produce the opposite effect, synergistic interactions (also described as a "diversity benefit")
- + As penetrations of intermittent and energy-limited resource grow, the magnitude of these interactive effects will increase and become non-negligible





Resource Interactions: Synergistic or antagonistic pairings





Loss-of-Load Probability Hours and Impact on ELCC

- + ELCC captures the ability of a resource to improve reliability on the system i.e. reduce loss-of-load events
- + The timing of loss of load events can provide a useful indicator of a resource's ability to provide ELCC
- LOLP tables should be based around many potential years of conditions around
 - Load
 - Renewables
 - · Generator Outages
- LOLP conditions correspond with load net of intermittent and energy-limited resources – in a system with ample solar and storage, these net load conditions can shift to the winter





ELCC curves

- Marginal ELCC curves can show the incremental ELCC of individual resources at increasing penetration
- + While marginal ELCC represents the technical value of an additional MW of a technology-type on the system, entities have often implemented average ELCC methodologies for resource planning in order to allocate beneficial interactions between resources
- If this benefit is not allocated to resources via an averaging methodology, the benefit is realized by load



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ELCC application and evolution

+ ELCC modeling applications have evolved

□ In the past, a single ELCC is used value for each resource technology

Many utilities are now using a ELCC curve for each resource technology to reflect diminishing returns

A multi-dimensional surface captures both diminishing returns and interactive effects

+ A computationally useful surface is derived by repeated ELCC calculations at different penetration levels for multiple resource types

E3 uses multi-dimensional surfaces in capacity expansion modeling



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Practical considerations in ELCC calculations

- + An ELCC calculation is a measurement of the gradient at a point that must be specified with the following information:
 - U What resource(s) is being measured? (*Partial derivative with respect to which variable?*)
 - □ How much of that resource(s) is being measured? (Coordinate along that dimension)
 - What resources are in the background system upon which the ELCC is being measured? (Coordinates along other dimensions)
- In theory, each resource is its own dimension, however in practice similar resources will need to be grouped into resource classes
 - □ May be desirable to use heuristics to differentiate among similar but not identical resources

+ Because of interactive effects, the sum of marginal ELCC values will not equal the Portfolio ELCC:

- Marginal ELCCs do not capture diversity benefits among resources
- □ Marginal ELCCs do not capture saturation effects among individual resources
- Difference between Portfolio ELCC and sum of Marginal ELCCs is referred to as the Diversity Benefit



Complicating Factor: Portfolio Diversity Benefit

+ The ELCC of a portfolio of resources is often more than the sum of their parts – creating a diversity benefit that must be allocated between the resources





What is an "Average ELCC"?

+ With only one resource, an Average ELCC can be defined as the Portfolio ELCC divided by the total installed MW

Averge
$$ELCC_{G_1} = \frac{f(G_1)}{G_1} (\%)$$

- Average ELCCs are perceived as useful because the sum of individual ELCCs can be made to be equal to the total Portfolio ELCC
 - This is done by starting with the Portfolio ELCC and allocating it among individual resources
 - Useful for display in a load-resource table
- + Any averaging method requires an allocation of the interactive effects among the various resource types





Challenges with Average ELCC approaches

There are a variety of challenges with the way Average ELCC values have been calculated to date

- Any averaging method requires an allocation of the interactive effects among the various resource types
- + These allocations are by definition arbitrary and can lead to counter-intuitive results
 - If different resource classes are dramatically different in size (e.g., 10,000 MW of solar, 200 MW of storage)
 - CA: average ELCC for solar and wind with marginal diversity benefit allocation calculated on a monthly basis
- + E3 developed the Delta Method as a way to ensure intuitive allocation of interactive effects
 - PJM's application of the Delta Method was recently approved by FERC
 - Average ELCC of a given resources is its Marginal ELCC plus an allocation of the Diversity Benefit based on its contribution to it





Principles for individual resource ELCC accreditation

- The features of ELCC that make it the preferred metric to measure the capacity contributions of resource adequacy needs creates challenges for implementation
- + Centralized capacity markets must assign a ELCC credit to individual resources
- + The following principles are useful to consider in designing an approach
 - · In many ways, these parallel principles that must be balanced in electricity ratemaking
 - · Like with rate design, these principles sometimes conflict with one another
- + The Marginal ELCC approach for resource accreditation in a capacity market context favors the Efficiency principle above all others

Reliability

The sum of all ELCC credits to individual resources should equal the total resource portfolio ELCC

Fairness

ELCC credits should be technology-neutral and properly reward resources for their characteristics

Efficiency

Credits should send signals that encourage economically efficient planning and procurement decisions

Acceptability

Credits should be transparent, tractable, understandable, and implementable for planners and market participants





ELCC of dispatchable resources

+ ELCC calculation can and in theory should also be applied to dispatchable resources such as thermal plants

+ ELCC of thermal resources is determined by two major factors

- Forced outage rates (FOR) of the thermal unit/plant a larger FOR will result in a smaller ELCC of the resource
- □ Unit capacity size of the thermal resource under the same FOR, if the total thermal capacity is the same, a larger plant will have a lower ELCC because its outage will be more likely to cause loss of load

+ If the unit size is small or the system size is large, the ELCC is close to 1 – FOR

□ 1 – FOR can be an acceptable approximation of ELCC





MRI and ELCC

- + On August 9th, the NYISO MMU presented on an approach to capacity accreditation called Marginal Reliability Improvement (MRI)
 - MMU described its methodology as aiming to compensate all resource based on their marginal contribution to meeting the planning reliability metric (e.g. LOLE or expected unserved energy)

+ E3 views MRI as a specific method for calculating an ELCC value

- The MRI approach may have some advantages over other methods, i.e., reduced computational burden
- Reduced computational burden may, in some cases, come at a cost of reduced accuracy
- NYISO should investigate MRI and other alternatives for calculating ELCCs to determine an appropriate method or suite of methods based on accuracy and practicability









Calculating Reliability Statistics



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Calculating Reliability Statistics

Traditional System w/ Dispatchable + Solar Generation





Calculating Reliability Statistics

Traditional System w/ Dispatchable + Solar Generation





E3 Case Study: Net Zero New England







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Key Design Choices

- + Marginal v. Average
- + Unit-specific v. Technology-specific ELCC determination
- + Resource Dispatch Logic
- + Load Shapes
- + Renewable shapes
- + Resource characteristics
 - Resource dispatch logic
 - Storage durations
 - Hydro, DR, hybrids
 - Thermal EFORd
- + ELCC calculation shortcuts



ELCC Allocation Sensitivity Results 4-hr Storage

+ Final ELCC allocation to specific resources will change depending on the methodology – a decision ultimately in the hands of the CPUC

• First-In and Last-In ELCCs are provided for reference but do not sum to portfolio ELCC across all resources





ELCC Allocation Sensitivity Results 4-hr Storage

Final ELCC allocation to specific resources will change depending on the methodology – a decision ultimately in the hands of the CPUC

- · First-In and Last-In ELCCs are provided for reference but do not sum to portfolio ELCC across all resources
- Averaging methodologies sum to portfolio ELCC across all resources but may introduce distortions such as >100% ELCC



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Which capacity value methodology should we use and why should we care?

- Harginal/Incremental ELCC: There are many different "marginal" ELCCs depending on your "base" portfolio. For our purposes, we define two standard types:
 - First-In ELCC:

Incremental capacity contribution for a specific resource relative to a "base" portfolio with <u>no</u> <u>dispatch-limited resources</u>

- Last-In ELCC: Capacity contribution of a specific resource as the <u>last increment</u> to be added to achieve the "full" portfolio with all resources
- + Each marginal ELCC tells a different story









Delta Method: Calculation Approach



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Delta Method captures resource's capacity value and their interactions with the rest of the portfolio





Multiple frameworks have been considered for accreditation of ELCC to individual resources

Framework	Description	Pros	Cons
Vintaged Marginal	Assigns each resource a credit based on the marginal ELCC at the time it is added to the system	Yields correct total ELCC across all resources Provides accurate marginal signal for procurement of new resources	Distinction between otherwise identical resources undermines fair competition and isn't a feature of other electricity market products (even though the same factors apply) ELCC "lock-in" can become intractable based on resource lives and potential for upgrades or partial retirements
Marginal	All resources are attributed an ELCC based on their marginal contribution to resource adequacy	Temporarily provides correct marginal signal for procurement of new resources	Does not appropriately credit a portfolio of resources for its total contribution to resource adequacy
Adjusted Class Average	 Calculate Portfolio ELCC Calculate average¹ ELCC for each group of resources (e.g. wind, solar) Apply uniform adjustment to each class average ELCC so that the sum of all classes matches Portfolio ELCC 	Yields correct total ELCC	Increasingly segmented classes to capture distinctions between resources (renewable geography, storage duration, hybrid resource configuration, etc.) leads to inconsistent treatment in classes of different sizes. Small classes have an ELCC much closer to marginal where larger classes have an average ELCC much different from marginal Uniform adjustments to all resource classes to account for interactive effects does not faithfully capture nature of interactions. In a portfolio with positive synergy, adjustments should only be applied to the resources that are providing that synergy

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Add note about average

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