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To: Analysis Group Inc.
1898 and Co.
New York Independent System Operator, Inc.

From: Richard Bratton, Director of Market Policy and Regulatory Affairs

Date: June 28, 2024

Re: **Comments on Proposed ICAP Demand Curve Parameters for the 2025/2026 through 2028/2029 Capability Years – Consultants' Initial Draft Report**

I. INTRODUCTION

Independent Power Producers of New York, Inc. ("IPPNY")[1] submits the following Comments on the *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2025/2026 through 2028/2029 Capability Years – Initial Draft Report* (the "Draft Report") prepared by Analysis Group Inc. ("AG") and 1898 and Co. ("1898" and collectively, the "Consultants") for the instant Demand Curve Reset ("DCR") process.[2] Importantly, as the New York Independent System Operator, Inc. ("NYISO") has established in numerous reports, implementation of New York State's public policy initiatives has driven, and

[1] IPPNY is a trade association representing companies involved in the competitive power supply industry in New York State and in the development of electric generating facilities, the generation, sale, and marketing of electric power, and the development of natural gas and energy storage facilities. IPPNY Member companies produce most of New York's electricity, utilizing hydro, nuclear, wind, natural gas, solar, energy storage, biomass, oil, and waste-to-energy.

[2] IPPNY reserves the right to comment on the net EAS models posted on the NYISO's website on June 27 in the future, given the lack of time to review prior to these comments being submitted.

will continue to drive far into the future, unprecedented system composition changes and associated significant reliability needs requiring a well-orchestrated transition that must include the maintenance of needed existing facilities, and the timely development of new, dispatchable resources. In fact, as reflected in the NYISO's *Draft 2023–2042 System & Resource Outlook Report*,[3] system capacity must grow 300% to meet the Climate Leadership and Community Protection Act ("CLCPA")[4] mandates, and these resources must be available under both peak and normal operating conditions to support reliability with the future resource composition on the system.[5]

New York's capacity market operates to promote this long-term reliability of the system without under- or over-compensating suppliers. Specifically, the Installed Capacity ("ICAP") Demand Curve structure, and correspondingly, the DCR process, if implemented correctly, are the mechanisms expressly designed to support system reliability. To do so, however, reference point prices must be adequate in each capacity Locality to ensure the system maintains sufficient dispatchable resources to address these needs and provide a reliable system over the long term.

Portions of the Draft Report are materially deficient in this regard. The proposed Demand Curves will not produce the necessary price signals to support investment, leading to inadequate levels of new resources being built and the failure to retain the necessary amount of existing resources in the system on a merchant basis until dispatchable zero-emissions resources

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[3] *See Draft 2023–2042 System & Resource Outlook Report*, NYISO (June 27, 2024), https://www nyiso.com/documents/20142/45442281/Draft%20Report_2023-2042_System_Resource_Outlook.pdf/298336ce-7d7e-390a-692e-c6e621c29c7f (approved at June 27, 2024 Management Committee meeting and pending final Board discussion and action at June 27, 2024 meeting) ("2023 Outlook Report").

[4] *See* Climate Leadership and Community Protection Act, 2019 N.Y. Sess. Laws Ch. 106 (McKinney) ("CLCPA").

[5] *See* 2023 Outlook Report.

are innovated and become commercially viable. Therefore, IPPNY requests that the Consultants revise the Draft Report as detailed below.

II. BACKGROUND

It has long been established that the fundamental purpose of ICAP markets is to ensure reliability of the NYISO system.[6] The Federal Energy Regulatory Commission ("FERC") approved demand curve structure, by design, establishes market price signals that provide a level of compensation adequate to attract new resources and retain needed existing resources to promote system reliability over the long term while neither under-compensating nor over-compensating generators.[7] The reference point price signals reflect the net cost of new entry ("CONE") of a proxy peaking plant, *i.e.,* the costs of developing and operating a flexible and dispatchable resource capable of meeting peak load requirements and associated long-term reliability needs.[8]

As reflected by the NYISO's reliability planning process, reliability needs derive both from the failure to meet the requirement of no more than one Loss of Load Event in ten years and the failure to ensure that Localities have sufficient ICAP to avoid Transmission Security violations. To ensure the market addresses the needs reflected in the NYISO's complementary planning processes, the resource chosen to be the proxy unit in each Locality must be capable of meeting both needs as mandated by the MST. To date, the selected proxy peaking plant

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[6] *See New York Independent System Operator, Inc.*, 118 FERC ¶ 61,182 (2007) at P 17 (compensation must be provided to promote long-term reliability of the system).

[7] *See New York Independent System Operator, Inc.*, 103 FERC ¶ 61,201 (2003); *New York Independent System Operator, Inc.,*122 FERC ¶ 61,211 (2008) at P 103.

[8] NYISO Market Administration and Control Area Services Tariff ("MST"), § 5.14.1.2.1.

technology has been a gas turbine facility, in part because its dispatchability is a critical characteristic required to ensure system reliability. In fact, a proposal to utilize demand response resources as the proxy unit in an earlier reset process failed because this resource type could not provide the necessary services to meet the system's reliability needs.[9]

Before deriving costs, the threshold question of what technology characteristics are required to serve these needs and satisfy the tariff requirements must first be addressed by the NYISO. The NYISO must consider the significant developments since the last DCR process for the ICAP Demand Curves to be adequately structured to effectively answer this question and ensure continued system reliability. Specifically, the CLCPA sets requirements of 70% of electric load being served by renewable energy by 2030 and a zero-emission Statewide electric system by 2040. As the NYISO has established, substantial retention of existing generation, combined with the planned generation build out, is required to meet these mandates even before the additional resources required to meet the end state of an 85% reduction in greenhouse gas emissions by 2050 are considered.[10] Once the State is facing the need for an emission-free electric system, the current fossil-based dispatchable generation must be replaced with a roughly equivalent (or greater) amount of non-emitting dispatchable generation ("DEFR")[11] that can run for many hours during periods of low renewable generation. Numerous NYISO studies have

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[9] *See New York Independent System Operator, Inc.*, 134 FERC ¶ 61,058 (2011), at P 25.

[10] *See* 2023 Outlook Report at 38, fig.15.

[11] The 2021 Outlook Report defined DEFRs as "a proxy generator type assumed for generation expansion in the Policy Case to represent a yet unavailable future technology that would be dispatchable and produces emissions-free energy (*e.g.*, hydrogen, RNG, nuclear, other long-term season storage, etc.)." *See 2021–2040 System & Resource Outlook*, NYISO (Sept. 22, 2022), at 48, https://www.nyiso.com/documents/20142/32663964/2021-2040_System_Resource_Outlook_Report_DRAFT_v15_ESPWG_Clean.pdf/99fb4cbf-ed93-f32e-9acf-ecb6a0cf4841 ("2021 Outlook Report").

confirmed that failure to effectively manage the transition to these end states will put system reliability at significant risk.[12]

Pertinent here, the NYISO's Q2 2023 Short-Term Assessment of Reliability ("STAR") Report identified a deficit in meeting Zone J transmission security requirements as large as 446 megawatts ("MW") in New York City ("NYC") for a duration of nine hours beginning in the summer of 2025.[13] Per the Q2 2023 STAR Report, the reliability need deficit is driven primarily by the combination of a forecasted increase in peak demand and the New York State Department of Environmental Conservation's ("DEC") Peaker Rule which directed retirements of certain dispatchable generators that would otherwise be economic with properly set ICAP Demand Curves.[14] On November 20, 2023, the NYISO utilized its expressly established authority under the Peaker Rule to retain the Gowanus 2 & 3 and Narrows 1 & 2 peakers in New York City to address the reliability need.[15] Permanent solutions must be in place in NYC before this temporary solution can be discontinued.[16]

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[12] *Id*. at 5–8 (establishing as a key takeaway that generator additions, including dispatchable, non-renewable resources, and that generator retirements must be staged carefully to ensure an orderly transition to the new system and finding substantial, incremental generation development will be required to meet major demand growth produced by State's electrification mandates).

[13] *Short-Term Assessment of Reliability: 2023 Quarter 2*, NYISO (July 14, 2023), at 5, https://www nyiso.com/documents/20142/16004172/2023-Q2-STAR-Report-Final.pdf/5671e9f7-e996-653a-6a0e-9e12d2e41740 ("Q2 2023 STAR Report").

[14] *Id*. at 4. In 2019, DEC adopted a regulation to limit nitrogen oxides ("NOx") emissions from simple-cycle combustion turbines, referred to as the "Peaker Rule", which has caused more than 1,000 MW of peaking facilities to deactivate or limit their operation. *Id*. at 11; *see also* ECL § 227.3.1 *et seq*.

[15] *Short-Term Reliability Process Report: 2025 Near-Term Reliability Need*, NYISO (Nov. 20, 2023), https://www nyiso.com/documents/20142/15930753/2023-Q2-Short-Term-Reliability-Process-Report.pdf/ccb826e3-e31d-157d-89a0-d2d11f600699 ("2023 STAR Solutions Report").

[16] *Id.*

As the system evolves, the NYISO must also consider that additional reliability needs may well arise throughout the State in the near term. The NYISO's recent quarterly STAR reports have consistently shown the Statewide margins are tightening; in part, due to Upstate needs driven by requirements of new, large-load projects that are the culmination of New York's extensive economic development efforts.[17] Moreover, although the Peaker Rule has forced dispatchable resources to retire, the development of new dispatchable resources that could replace them has been stymied by regulatory hurdles and lack of adequate cost recovery.[18]

Meanwhile, the NYISO's analysis has shown that the Transmission Security reliability needs, such as those identified in the Q2 2023 STAR Report for NYC, persist for several hours, and that limited-duration resources (such as short-duration Battery Energy Storage Systems ("BESS") cannot be utilized effectively given the nature of these needs and the operating capability of this technology.[19] While theoretically several short-duration BESS could be installed to meet these needs, doing so would cause the aggregate costs to multiply to levels that would exceed the costs of other technologies such as the simple cycle gas turbine ("SCGT") that is being considered as the Proxy Unit.

Specifically, the NYISO's own studies have demonstrated the need for approximately three times the amount of capacity on the system now—a significant portion of which must be in

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[17] *See Short Term Assessment of Reliability: 2023 Quarter 3*, NYISO (Oct. 13, 2023), at 5, https://www.nyiso.com/documents/20142/39103148/2023-Q3-STAR-Report.pdf/836a011f-a2a8-2daf-bf5f-bf89ea79c2ff?t=1697223170004.

[18] *See Notice of Denial of Title V Air Permit – Danskammer Energy Center*, No. 3-3346-00011/00017, N.Y. Div. Env't Permits (Oct. 27, 2021) ("Danskammer Denial"); *Notice of Denial of Title V Air Permit – Astoria Gas Turbine Power*, No. 2-6301-00191/00014, N.Y. Div. Env't Permits (Oct. 27, 2021) ("Astoria Denial"). Two Title V air permits for new fossil-fueled generation were denied by the DEC due to the permitting of those facilities being inconsistent with the CLCPA.

[19] 2023 STAR Solutions Report at 7.

the form of new DEFRs, by 2040.[20] These resources must be able to operate for the longer periods of time required to respond to system conditions, such as lulls in the wind for wind generation.[21] Limited-duration resources, such as short-duration BESS, cannot meet the needs that must be satisfied by the DEFRs. The NYISO's analysis indicated that a majority of DEFRs will be needed in NYC and Long Island because of their locational capacity requirements as early as 2035 and continuing through 2040.[22] In one of the scenarios the NYISO studied, the amount of DEFR capacity required in these zones is more than double the fossil generation capacity today.[23]

It is thus clear that reliability remains paramount. Over the past five years since the enactment of the CLCPA, the NYISO has identified the longer-term reliability concerns that drive the need for the substantial build out of DEFRs. Thus, the NYISO must find that a short-

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[20] *See* 2023 Outlook Report at 8–9; *See* Johannes Pfeiffenberger *et al.*, *Initial Report on the Power Grid Study*, The Brattle Group (Jan. 19, 2021), at 102 (projecting that zero emissions could be achieved by 2040 with 17 GW to 23 GW of thermal backstop generation fueled with landfill gas, biogas, or other renewable natural gas), https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/NY-Power-Grid/full-report-NY-power-grid.pdf; 2021 Outlook at 9–11 (concluding 27 GW to 45 GW of DEFRs will be needed to meet reliability needs by 2040"), https://www.nyiso.com/documents/20142/33384099/2021-2040-Outlook-Report.pdf; Paul J. Hibbard *et al.*, *Climate Change Impact Phase II, An Assessment of Climate Change Impacts on Power System Reliability in New York State, Final Report*, Analysis Group (Sep. 2, 2020), at 83–84 (concluding that removal of all the existing fossil-fueled generating resources by 2040 in compliance with the 2040 Zero Emissions Target will require greater than 30 GW of installed capacity of new flexible and dispatchable resources to provide the necessary reliability services that have historically been provided by fossil-fueled generating resources), https://www.nyiso.com/documents/20142/15125528/02%20Climate%20Change%20Impact%20and%20Resilience%20Study%20Phase%202.pdf/89647ae3-6005-70f5-03c0-d4ed33623ce4 ("Phase II Climate Study"). The New York State Climate Action Council's Scoping Plan indicated that its "analysis and current studies show that the 100x40 goal requires 15 GW to 45 GW of electricity from zero-emission, dispatchable resources in 2040 to meet demand and maintain reliability." *New York State Climate Action Council Scoping Plan*, New York State Climate Action Council (Dec. 2022), at 13, https://climate.ny.gov/-/media/Project/Climate/Files/NYS-Climate-Action-Council-Final-Scoping-Plan-2022.pdf ("Scoping Plan").

[21] *Off Shore Wind Data Review – NYSRC Preliminary Findings*, New York State Reliability Council (July 14, 2023), at 5, https://www.nysrc.org/wp-content/uploads/2023/07/NYSRC-Wind-Impacts-Final-07_18_23.pdf.

[22] 2021 Outlook Report at 51.

[23] *Id.*

duration proxy unit cannot meet reliability needs. On this basis alone, the 2-hour BESS must be eliminated from consideration as the technology for the proxy peaking unit. Moreover, based on this first principle, IPPNY has considered the Consultants' recommendations and provides these comments on the Draft Report to identify the deficiencies therein.

Given the investment environment addressed above, the Draft Report establishes aggressively low-balled and inadequate assumptions for material components of the Gross CONE ascribed to the proxy peaking plant technology precisely at the time when it is critical for the Demand Curves to provide sufficient investment signals to new technologies and needed existing dispatchable resources to enable the State's goals to be implemented while meeting impending reliability needs. In large part, the Draft Report's assumptions omit important system composition changes that cannot reasonably be ignored, and the recommendations focus too heavily on theoretical models of how merchant investment should occur and not enough on how the New York system operates, and how the existing laws, regulations, and New York's unique political and regulatory climate have impacted, and can be expected to continue to impact, New York-specific investments.

The Draft Report has defined the Net CONE for this technology in each capacity Locality at a level that is not sufficient to support investment in these facilities. Thus, it cannot be found just and reasonable.

III. DISCUSSION

A. The 2-Hour BESS Cannot Be the Proxy Unit in Any Locality.

The Draft Report recommends a 2-hour BESS as the proxy unit for each Locality for this DCR process. IPPNY strongly opposes the selection of a 2-hour BESS as the proxy unit in any Locality because the limitations of its operating capabilities—specifically, its very limited duration—reflect significant reliability and modeling deficiencies that prohibit its consideration. To be eligible to be deemed a proxy unit, the NYISO tariff states, "[f]or purposes of [the DCR process], *a peaking unit* is defined as the unit with technology that results in the lowest fixed costs and highest variable costs among all other units' technology *that are economically viable*, and a peaking plant is defined as the number of units (whether one or more) that constitute the scale identified in the periodic review."[24]

By tariff, the NYISO's selection of the peaking plant and the calculation of its reference price thus requires two discrete determinations: (i) confirmation that a technology constitutes an eligible peaking plant technology; and, only if (i) can be met, (ii) delineation and quantification of the factors specific to that technology, set accurately, to determine whether it is economically viable (*i.e.*, can it be financed) and, if so, to set Net CONE levels adequate for an investor to have a reasonable opportunity to recover its investment. The Consultants are tasked with satisfying the second requirement alone; they must determine the financial assumptions for each proxy unit *after* the NYISO first determines the technology is eligible to be under consideration. The first step ensures that a technology capable of meeting New York's reliability needs is selected to serve as the proxy unit in each Locality; the second step ensures it can be financed on a merchant basis in New York. Vis-à-vis this second step, the proxy unit chosen for each DCR process must both be economically viable and ascribed a Net CONE that will give an investor a reasonable opportunity to earn a return on and of its investment.

[24] MST § 5.14.1.2.2 (emphasis added).

The 2-hour BESS fails the first step; fails the first part of the second step; and at the Net CONE levels currently proposed in the Draft Report, fails the second part of the second step. The final report must, thus, eliminate the designation of the 2-hour BESS as the proxy unit in every capacity Locality.

1. A 2-Hour BESS Cannot Be Deemed an Eligible Peaking Plant Technology Because It Is Unable to Provide the Requisite Reliability Services Including, But Not Limited to, Meeting Transmission Security Requirements.

For a technology to be an eligible peaking plant, the NYISO must determine that it can operate for a sufficient duration to meet peak conditions. Notably, FERC precedent has long established that a technology cannot be deemed an eligible technology to be the proxy unit in a capacity Locality where, as here, its operating limitations prevent it from being deployed for a sufficient duration or when it cannot support reliable operations.[25] Likewise, the NYISO's limited look-ahead capability, forecast uncertainty, and the inability to utilize a resource when it would be most valuable all must be considered when defining whether a resource can be deemed eligible to serve as the proxy unit for the ICAP Demand Curves relied upon in the NYISO's

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[25] *See New York Independent* System *Operator, Inc.,* 134 FERC ¶ 61,058 (2011) at PP 25, 37 (finding demand response ineligible due to limitations inherent in technology); Docket No. ER11-2224, *New York Independent* System *Operator, Inc.,* Tariff Revisions to Implement Revised ICAP Demand Curves for Capability Years 2011/2012, 2012/2013 and 2013/2014 (Nov. 30, 2010), at 6 (establishing Demand Side Resource technology generally did not have ability to respond to longer deployments under then present market design); *see also New York Independent* System *Operator, Inc.,* 146 FERC ¶ 61,043 (2014), at P 60 (finding to be an eligible proxy plant that is deemed economically viable, technology "must be physically able to supply capacity to the market" as the first prerequisite) ("2014 DCRP Order").

capacity markets to promote the reliability of the system over the long term—factors that have been affirmed by FERC under analogous circumstances.[26]

As a threshold matter, the NYISO's identification of Transmission Security based resource needs underscores the inherent inadequacy of short-duration BESS to serve the reliability needs required of the proxy unit. Both the NYISO and affected Transmission Owners have identified several Transmission Security based reliability needs over the past several years, all of which have had much longer durations than two hours. For example, as discussed above, the 2023 Q2 STAR Report identified a 446 MW New York City deficiency with a duration of nine hours.[27]

The SCGTs chosen as the temporary solution to the Q2 2023 STAR Report need do not have energy duration limitations. Notably, the SCGT proxy unit under review in this DCR process is equally well suited to meet these needs if adequate signals were sent for it to be built in time. In stark contrast, attempting to meet the identified need with 2-hour BESS units would necessarily require many more units to be constructed because of their limited duration. And, as established in more detail below, the Capacity Accreditation Factor ("CAF") for the 2-hour BESS is derived using only Resource Adequacy modeling. Thus, the NYISO cannot rely on CAFs to rectify the 2-Hour BESS's operating deficiencies because the CAF mechanism is not

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[26] *See* Docket No. ER19-2276, *New York Independent System Operator, Inc.*, FPA Section 205 Filing (June 27, 2019), at 80 (specifying forecast uncertainty, limited look-ahead capability and the inability to effectively use 2-hour BESS when they would be most valuable all drive need to limit reliance on resource); *New York Independent System Operator, Inc.,* 170 FERC ¶ 61.033 (2020), at PP 84, 117 (finding appropriate use of GE Energy Study, as modified, to address limitations inherent in 2-hour BESS technology); *see also* 2014 DCRP Order at P 60 (reaffirming past precedent that NYISO Board determination of economically viability is a matter of judgment based on facts and circumstances specific to technology at issue).

[27] 2023 Q3 Star Report at 4.

designed to, and cannot, address this threshold consideration. Because a 2-hour BESS with its inherent limited operating capability cannot meet transmission security-based requirements, it cannot be deemed an eligible peaking plant technology.

If the NYISO were to calculate a CAF equivalent for the 2-hour BESS in meeting Transmission Security needs, the requirement to have many 2-hour BESS units would result in the technology having a higher net CONE than the SCGT based unit. For example, although a 200 MW SCGT could meet a Transmission Security need of 200 MW regardless of the need's duration, if the 200 MW need was eight hours—one hour shorter than the need identified in the NYISO's recent Reliability Need determination for New York—then it would require four 2-hour BESS units to meet the reliability need because each unit could only run for two hours. In this example, the 2-hour BESS unit only provides one quarter the reliability benefit of the SCGT.

Indeed, the New York State Public Service Commission ("PSC") recognized these very inherent limitations in its June 20, 2024, Order Establishing Updated Energy Storage Goal and Deployment Policy[28] issued after a thorough, multi-year vetting of a roadmap and a revised roadmap.[29] The PSC stated that bulk solicitations are expected to attract energy storage durations ranging from four to eight hours, "with the Roadmap recognizing the value that energy storage with an 8-hour or more duration adds in maintaining reliability and integrating large amounts of renewable energy in later years."[30] Finding that implementation of CLCPA mandates

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[28] Case 18-E-0130, *In the Matter of Energy Storage Deployment Program*, Order Establishing Updated Energy Storage Goal and Deployment Policy (June 20, 2024), at 27.

[29] Case 18-E-0130, *supra*, New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage (Mar. 15, 2024) ("Roadmap").

[30] *Id*. at 27.

requires longer duration storage facilities to be a core component of the system, the PSC directed the New York State Energy Research and Development Authority ("NYSERDA") to secure predefined levels of longer duration storage in its Energy Storage Resources ("ESR") based bulk system solicitations.[31] The Roadmap included, and was supported by, a storage expansion analysis and a storage cost analysis, both of which studied and assumed bulk storage procurement of 4-hour and 8-hour durations assets.[32] Notably, neither the Roadmap nor the Storage Goal Order studied or proposed bulk storage procurement of 2-hour BESS. 2-hour BESS was assumed only for residential applications.[33] In that proceeding, the New York State Reliability Council stressed the importance of maintaining reliability, noting that, based on the *2023–24 Installed Reserve Margin Study*, potential reliability events range from 1.2 hours to 9.3 hours, with an average of 3.6 hours—meaning that a 2-hour BESS will not be sufficient to cover even half of the modelled reliability events.[34]

Further, the Hochul Administration recently announced funding through NYSERDA solicitations for BESS with durations from 10 to 100 hours.[35] BESS solicitations issued to date

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[31] *Id.* at 35.

[32] *Id.* at 73, 93

[33] *Id.* at 93. Notably, the associated Final Supplemental Generic Environmental Impact Statement filed on December 14, 2023, in the proceeding accordingly tracked the same scope limited to 4-Hour and 8-Hour BESS units in assessing the environmental impacts of the State's proposed action. Case 18-E-0130, *supra*, Final Supplemental Environmental Impact Statement (Dec. 14, 2023). Without having performed an environmental impact analysis of bulk procurement of 2-hour BESS, the PSC's Storage Goal Order does not provide the requisite legal authority to NYSERDA to procure such resources.

[34] Storage Goal Order, App'x A at 31.

[35] Press Release, *Governor Hochul Announces Over $5 Million is Now Available for Long Duration Energy Storage Projects* (June 12, 2024), https://www.governor.ny.gov/news/governor-hochul-announces-over-5-million-now-available-long-duration-energy-storage-projects.

have also recognized the limitations inherent in this technology as a capacity resource.[36] Setting the ICAP Demand Curves at the much lower 2-hour BESS price, by definition, will ensure that the market will never be able to respond to these identified needs and continued programmatic incentive payments will be required to support their development.

The experience of the PJM Interconnection during Winter Storm Elliot underscores the operational constraints of limited-duration energy storage resources. Over December 23 to December 25, 2022, PJM faced critical system conditions and came within one contingency of having to shed 1,700 MW of load.[37] These conditions were driven by load exceeding forecasts, generation forced outages, and the exhaustion of limited-duration storage resources (particularly, the inability to refill pumped storage hydro ponds). Although PJM currently has minimal BESS participation, it is reasonable to anticipate that BESS, as duration-limited resources, would face similar operational limitations under sustained grid stress. Structuring the capacity market to compensate these resources as the marginal entrant, even if their Net CONE is purportedly lowest, sends an incorrect market signal that undercuts fundamental reliability principle of capacity markets.

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[36] For example, Consolidated Edison Company of New York, Inc. ("Con Edison") solicitations have required proposals for 4-hour ESRs with their associated CRIS capability as capacity resources. *See Bulk Energy Storage Request for Proposals*, Con Edison (2022), https://www.coned.com/en/business-partners/business-opportunities/bulk-energy-storage-request-for-proposals. Other operational limitations also have been recognized truncating the services that could be offered by these resources, such as requiring cycling to be limited to once per day with an overall limitation on the total number of cycles per year.

[37] *Winter Storm Elliot Event Analysis and Recommendations Report*, PJM (July 17, 2023), at 63, https://pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx.

There are currently many large resources throughout the State that provide critical reliability services and rely almost exclusively on the ICAP market for substantial revenues.[38] Price signals based on a 2-hour BESS will indicate a market with very limited value for capacity and may force dispatchable resources to exit. Indeed, ICAP revenues already fall short of covering some generators' operating costs, as shown in Potomac Economics' (the "MMU") most recent State of the Market Report which found that certain steam generators in the Lower Hudson Valley and Long Island did not earn sufficient revenues in 2023 to cover their Going Forward Costs.[39] The exiting resources generally do not have duration limitations and the reliability services they provide cannot be replicated by a similar quantity of short duration BESS or the intermittent resources supported by the State's public policy initiatives. When the NYISO is presented with the exit of these now uneconomic dispatchable resources, especially in areas of load growth, they will be faced with limited choices. One particularly unpalatable choice long disfavored by FERC will be the need for reliability must-run agreements.[40] Thus, the 2-hour BESS is not an eligible peaking plant and should not be considered.

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[38] As reflected in the Potomac Economics 2023 State of the Market Report, the Going Forward Costs for generation on Long Island and the Lower Hudson Valley are estimated to be higher than revenues for the period from 2021 through 2023. Absent adequate price signals, existing units forced to retire could only economically be replaced by 2-hour BESS. (*See 2023 State of the Market Report for the ERCOT Electricity Markets*, Potomac Economics (May 2024), at 5, A-208–A-209, https://www.potomaceconomics.com/wp-content/uploads/2024/05/2023-State-of-the-Market-Report_Final.pdf ("2023 State of the Market Report").

[39] *Id.* at 5, fig.2.

[40] *New York Independent System Operator, Inc.,* 150 FERC ¶ 61,116 (2015), at P 2 (emphasizing "that RMR agreements should be of a limited duration so as to not perpetuate out-of-market solutions that have the potential, if not undertaken in an open and transparent manner, to undermine price formation").

2. The 2-Hour BESS Is Not Economically Viable.

As discussed above, a peaking unit is the unit with the technology that results in the lowest fixed costs and highest variable costs among all other units' technology "that are economically viable."[41] Determining whether a technology is economically viable requires more than producing theoretical costs and calculations. The technology must actually be capable of being developed in New York which, by definition, means it must be able to be financed on a merchant basis. And, in any event, the Net CONE ascribed to it in each Locality must reasonably reflect the costs a merchant developer would face to develop the facility, operate the facility and have a reasonable opportunity to earn a return on and of its interest over the defined amortization period. Assuming, *arguendo*, the NYISO could find a 2-Hour BESS has the operating parameters to accommodate deployment for a sufficient duration to meet peak conditions despite the clear, well-documented evidence to the contrary the NYISO itself has developed, the Draft Report's calculations omit several considerations that eviscerate the technology's economic viability.

i. Demand Curve Parameters Must Consider the Projected Directionality of CAFs

The proposed Demand Curve parameters set forth in the Draft Report significantly understate the Gross CONE of the BESS proxy peaking technologies. Specifically, the financial parameters do not adequately capture the risks associated with developing a 2-hour BESS in New York State. To accurately calculate the gross CONE, the calculations set forth in the final

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[41] NYISO Services Tariff § 5.14.1.2.2.

report must recognize the increased risks inherent in shorter-duration BESS. Doing so will reveal the 2-hour BESS is not an economically viable technology.

It must be recognized that the purpose and structure of the CAF mechanism fundamentally differ from considerations specific to determining whether a technology can be designated the proxy peaking plant in a DCR process; the two cannot be conflated. In contrast to the full scope of considerations that must be considered to designate the proxy unit in the DCR context, the CAF is a subpart of that analysis, a component of the overall Demand Curve design that will indisputably affect a unit's revenue stream. The risk associated with the CAF, thus, must be reflected in the technology's financial parameters.

The NYISO produced the first CAFs in late February of 2024 and the CAF value for all resources will be updated each year by March 1 to set the Demand Curves to be in effect for the upcoming Capability Year. Notably, given its inherent design and concomitant operational limitations, the CAF calculated for a 2-hour BESS in this first cycle is already relatively low from the outset compared to the other potential peaking units studied.

Furthermore, the Draft Report must at least qualitatively address the fact that study results demonstrate the 2-hour BESS will have a precipitously decreasing CAF as the system transitions to more intermittent and non-dispatchable resources.[42] This fact is directly due to its duration limitations.

Arguments that other system changes could occur over time to support a 2-Hour BESS' CAF levels are not probative. First, arguments that BESS co-located with intermittent resources

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[42] *See* 2023 State of the Market Report at A-12–A-13.

retain some level of their CAF ignore the fact that stand alone ESRs are the proposed proxy unit. It cannot simply be assumed that a renewable resource will be coupled with a BESS proxy unit without also accounting for the costs of that companion facility. Likewise, arguments that the NYSRC may revamp its approach to capturing load shapes may necessarily affect any number of factors which must collectively be addressed in a future DCR process once the scope, nature and effects of any such potential change can be known. The potential effects of this change -- which may or may not ever be made, and might result in lowering the CAF instead of raising it -- cannot reasonably be relied upon to counter study results based on known dynamics. Nor is the answer to this problem to set a floor or ceiling on the CAF limits or reference prices for this DCR process as some have proposed —a mechanism that eviscerates the purpose of the CAF itself and would lock in CAF levels that exceed the actual reliability value of this resource. The answer is instead to adequately reflect CAF projections and capture the 2-Hour BESS's documented volatility in its Gross CONE.

In short, given its short duration, the technology is incapable of responding to even a small change in the peak load, thereby driving the certainty that it will have reduced CAFs. That fact must be captured in this DCR process. The exact timing and percentage decline do not need to be calculated. Rather, the fact alone that the CAF decline will occur itself must be incorporated into the gross CONE calculation.

Investors will certainly ascribe a higher risk premium to this technology due to its projected dwindling CAF levels. In addition, investors will also take into account the fact that it is incapable of responding to reliability needs that are driven by extended renewable resource outages in a system where renewables will comprise a much higher percentage of the generation mix. Thus, the financial parameters used for the 2-hour BESS must be increased accordingly.

Given the operational limitations of the 2-hour BESS, it is also the case that the CAF for this technology will drop off more significantly than for other peaking technologies.[43] This is consistent with the 2-hour BESS CAF having the greatest variability in the estimates that the NYISO has provided for all CAFs to date—analyses that, by virtue of having used different base case assumptions, reveals the sensitivity to system change driven directly by this technology's capabilities.[44] It is highly likely that the decline in its CAF rating will outstrip the impact of its lower fixed costs on the reference price calculation well within the 15-year amortization period that the Draft Report has set for the unit. Because the resource will no longer be designated as the peaking plant, it is unlikely it will be able to recover its investment, a fact that investors will also consider in risk premiums.

Unlike the SCGT, which is designed with dual fuel and firm fuel storage capability sufficient to operate for 96 hours at full capacity to maintain 100% CAF value, none of the BESS technologies evaluated come remotely close to this standard—maxing out at eight hours duration. The declining CAF for shorter duration BESS and resulting lower UCAP values captures the lower capacity value of BESS compared to the SCGT, but not the risks inherent in investing in this technology. Given the difference in risk parameters, AG cannot reasonably ascribe the same Weighted Average Cost of Capital ("WACC") across all technologies being studied in this DCRP. The significantly higher economic risk of the BESS proxy unit as compared to the SCGT must be incorporated in its Gross CONE.

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[43] *See* 2023 State of the Market Report.

[44] *See* Tito Onwuzurike, *Final CAFs for the 2024/2025 Capability Year*, NYISO (Feb. 29, 2024), https://www.nyiso.com/documents/20142/43275262/24_02_29_ICAPWG_FinalCAFs.pdf/b1cf7d7f-06eb-ac49-f471-958fa317d90c.

An incorrect accounting for CAF and revenue risk during proxy unit economic evaluation could result in selection of a proxy unit that at best appears economic but on paper only and just for the first four-year reset period, quickly becoming uneconomic over its life. During the initial reset period, investors will be unwilling to invest in this technology on a merchant basis given the overly aggressive assumptions that have been used thereby driving reference prices up along the demand curve towards the maximum clearing price, potentially costing consumers more even over this first reset period than would have been necessary had the proxy unit's Gross CONE been accurately set. Indeed, beyond the initial reset period, investors will recognize that the uneconomic proxy unit would likely continue to be uneconomic and the next DCR process would produce designation of a different proxy unit based with a lower Net CONE. Because these risks are so severe and go to the core value of the 2-hour BESS technology, they irreversibly undermine its economic viability.

ii. Net E&AS Revenues

The 2-hour BESS's Net E&AS revenue assumption is not adequate to support economic viability. The Net E&AS revenues are largely driven by assumed revenues from providing reserves. The assumed operating reserves revenues account for more than two-thirds of the total Net E&AS revenues, when averaged across locations. The reserves market is much smaller than the energy market and, therefore, resources entering the market to secure these revenues are much more at risk of having them eroded by subsequent new entry. The assumed flexibility that results in the BESS appearing to be able to offer reserves in most hours of the year, despite its limited energy stores, also means that, as more BESS are added, the relatively small reserve market will be swamped by these cheap reserve providers, thereby cratering the reserve clearing price.

This dynamic is not reflected in the backward-looking Net E&AS calculation. However, an investor would recognize that severe erosion of projected Net E&AS revenues is likely and, therefore, BESS is unlikely to remain the proxy unit over the long run. Without a high likelihood of remaining the proxy unit for its assumed amortization period, the BESS would not be able to recover its fixed costs.

Moreover, the Draft Report's modeling of Net E&AS revenues over optimizes expected revenues. The Draft Report describes the BESS Net E&AS model as having three steps. The first step determines an optimal Day-Ahead schedule. This is consistent with the NYISO optimizing the BESS schedule in its Day-Ahead Market software which sets optimal schedules for a single day. The second step is described as:

> The models calculate net EAS revenues of maintain energy levels across days by adjoining adjacent cycle-days. For each pair of days, the models create a new set of DAM commitments by eliminating the appropriate number of discharge hours on cycle-day 1 and charge hours on cycle-day 2 in order to maintain the target energy level (i.e., 50% of the battery's capacity) between both days. Net EAS revenues are recalculated based off the new energy levels across both cycle-days. If net EAS revenues are higher with the new set of DAM commitments, then the revised commitments are implemented by the models. Otherwise, the initial DAM commitments are left unchanged. The models pair adjacent cycle-days moving forward day-by-day considering any commitment changes made by the previous pair of cycle-days. This process concludes the DAM commitments made by the models.[45]

What is described in Step two is a multiday optimization based on perfect knowledge of prices that does not exist in the NYISO markets. In the NYISO, each DAM schedule is done without any knowledge of the following day's prices, not the multi-day optimization of end-of-

[45] Draft Report at fn.70.

day charge that the Draft Report describes. While a BESS owner might determine that it is beneficial to end the day with one or two hours of charge, that would be a determination that they would have to make and then they would need to alter their DAM bids to enact the strategy. Most importantly, there would be times when this strategy would have been economic and other times it would not. They would not have the benefit of optimizing over multiple days with perfect knowledge of prices. Allowing the model to optimize in this manner artificially inflates the Net E&AS of short duration BESS more than long duration BESS because its limited storage capacity requires it to make more optimal charging/discharging decisions.

Step 2 of the BESS Net E&AS model should be eliminated. The ability of the BESS owner to optimize its Day 1 DAM commitment based on perfect knowledge of Day 2 DAM prices is complete fiction. Market Participants do not know the prices for Day 2 when their Day 1 DAM schedules are being set. By allowing this optimization based upon perfect knowledge of prices on Day 2, the Draft Report has increased the projected Net E&AS revenues for the BESS units in ways that a BESS operator could not. This issue is likely to overstate the revenues of the 2-hour BESS units even more than for the longer duration BESS units because the 2-hour BESS's shorter duration makes it more sensitive to perfect scheduling.

If the Draft Report is an effort to enact a general strategy where some energy remains in the BESS at the end of the day, then there needs to be an analysis and rules must be established consistent with the NYISO market rules to try to enact that strategy. These would have to be done based on some general analysis of DAM prices rather than any kind of perfect scheduling based on the fictitious assumption that the BESS operator would perfectly know the DAM prices for day 2 before it submits bids for DAM day 1. Since the DAM bids are developed before knowing anything about the schedule, this likely would require bids that assure the BESS charges in the final hour of the DAM as long as there is room to accept the charge. As noted above, this may be beneficial sometimes but also is likely to be a losing strategy at others. It certainly will result in less revenue than the Draft Report's model is currently estimating.

When evaluating the realistic performance of BESS in wholesale electricity markets, it is essential to scrutinize the assumption of perfect optimization across day-ahead and real-time markets, both for energy and ancillary services. Empirical evidence from other ISO markets with more established BESS resources indicates that actual revenues earned by BESS resources are significantly lower than those projected in theoretical backcasts, such as those employed in the Draft Report.

The data analytics company, Orennia, utilizes publicly available data to compare BESS resources' actual performance to theoretical performance in the ERCOT and CAISO markets. Orennia tracks these markets because the BESS fleets are becoming increasingly established, presently totaling 6.4 gigawatts ("GW") in ERCOT and 11.1 GW in CAISO, and because data is publicly available that can be used to discern resources' performance across the ISO-administered energy and ancillary services markets. Orennia calculates a metric—the percentage of perfect foresight ("POPF")—as the ratio of realized merchant revenues to theoretical backcasted revenues, akin to the Draft Report's methodology. Orennia's latest publication estimates 12-month rolling POPFs of 46% for ERCOT and 66% for CAISO.

While no two markets are identical, common factors hinder the optimal performance of BESS resources across different regions. These include operational constraints, imperfect foresight, execution challenges, and increased competition. Together, these factors impede BESS operators from achieving the profits projected in theoretical backcasts. As BESS integration continues, these limitations are becoming more widely recognized among BESS operators, the financial community, and market advisors.

Failing to account for the percentage of perfect foresight, as done in the Draft Report's methodology, materially overstates Net E&AS revenues of all BESS resources and, in turn, understates Net CONE. This factor must be accounted for in the calculation of Net E&AS revenues to render appropriate Demand Curves.

These two errors in modeling drive the Draft Report to produce unattainable reserve price revenues thereby further undercutting any argument that the 2-hour BESS could be deemed economically viable. Considering these risks, taken together, investors would be highly unlikely to invest in this technology on a merchant basis, and, therefore, the 2-hour BESS is not economically viable.

B. The Net CONE of the Technologies Considered in the Draft Report, Including the 2-Hour BESS If It Is Designated as the Proxy Unit for Any Locality in the Final Report, Must Be Increased To Adequately Reflect Their Costs.

1. The WACC Parameters Are Too Low Across Technologies and, Cannot Reasonably Be Set at the Same Level for All Technologies

The WACC for all technologies is unrealistic because it understates the cost of capital required to develop in the New York market on a merchant single asset financed basis. Further, using the same financial parameters for all proxy units, including different duration BESS, is unreasonable. There is no way, considering the difference in CAF volatility for all three capacity accreditation resource classes that the proxy units operate within, that all three classes would be ascribed the same level of risk, and, therefore, cost of capital by investors. The Draft Report continues to weigh corporate debt heavier than project finance debt and does not incorporate the upfront capital cost or ongoing financial carrying costs of energy margin hedges required by lenders. In addition, there is no market currently to implement long tern hedges on either energy or capacity revenue for BESS, especially for the 2-hour duration. Any potential hedges will primarily compensate for expected revenue on a Day Ahead basis and ascribe little value to real time optimization as assumed in the current modelling of Net EAS. The companies reviewed would not invest in a future merchant facility based on being economic at their corporate debt costs, because the merchant generator is riskier than the portfolios of the representative companies.

The Consultants continue, for at least the second reset period in a row, to favor the use of a non-representative sample of corporate debt over project finance debt despite the clear evidence that corporate debt samples do not accurately represent the cost of financing projects in New York. For example, of the four "representative" companies selected by AG to represent the COD, only Vistra, which is a public corporation, owns generation in New York on a merchant basis.[46] On May 7, 2024, Alpha Generation submitted comments to AG providing publicly available information on the COD for six companies representing 40% of the NYISO's capacity supply. The average COD of those companies is 9.27%.[47] The COD, while it was increased to 6.7% from the preliminary recommendation of 6.45%, is still not nearly high enough, and in reality is closer to 9%. Privately held IPPs of comparable credit to what the Consultants based their findings on (BB-, Ba3) in the New York market, have a borrowing cost of SOFR + [350-

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[46] NRG no longer operates power generation in the Northeast, and Constellation and AES operates primarily, if not exclusively, state-supported nuclear and renewable power generation.

[47] *Letter Regarding After-Tax Weighted Average Cost of Capital ("ATWACC") Assumptions Presented at the April 17 Installed Capacity Working Group*, Alpha Generation, LLC (May 7, 2024), https://www nyiso.com/documents/20142/44660396/AlphaGen-Comments-on-ATWACC-Parameters-5-7-24.pdf/13b256e3-8eaa-0627-b5e6-d142d2db8b9c.

450] or around 9-10% on a current pay basis, or around 8-9% on a yield to maturity basis. And even these terms are aggressive as a single asset, merchant project financing will most likely be rated well below Ba3 and will differ by technology as the choice of technology and duration present different risk adjusted revenue streams. It is entirely reasonable for AG to base its COD assumption on the average of factual, publicly available information from single asset financed transactions.

The assumed Cost of Equity ("COE") of 14% is also insufficient. The Draft Report too heavily relies on the average estimated COE of publicly traded IPPs, which primarily invest using balance sheet financing. The COE should be increased to between 16–18%, which is within the range of expected COE for private lenders due to development and construction risk and is a conservatively low assumption even if the Consultants assume a higher COD of ~9%.

Further, the Debt-to-Equity ratio of 55/45 is too aggressive for a merchant project and should instead be 40/60. This more accurately reflects the maximum leverage available in today's lending conditions for the project rating assumed. A failure to provide a hedge that provides zero risk to lenders for a project with more than 50/50 Debt to Equity is unrealistic. An unhedged project will be a riskier loan, have a significant lender risk premium, and likely be unrated. If the debt rate is going to assume rates consistent with BB ratings, a hedge assumption clearly needs to be defined by the Consultants in the final report. The assumptions should define the upfront cost for a revenue put or a discount on forward energy and capacity revenues to reflect a discount to forward energy margins to execute a long term forward energy/capacity hedge.

To date, AG has shrugged off actual COD information presented for more than a third of NYISO market supply as non-representative or incomplete information because the COE and

Debt to Equity ratio for those companies presented is not publicly available, yet this same level of rigor has not been applied to the sample of companies the Draft Report bases its COD and COE recommendations. Should public companies, arguendo, cease to invest altogether in the merchant generation sector, AG would be forced to either conduct a discovery process or develop a new methodology for estimating COE that is not based on publicly available information. Given the evident fact that a very small percentage of merchant capacity market supply is owned by publicly traded companies in New York, AG should initiate this approach in this DCR process. If AG continues to use the current sample and corresponding WACC, it must demonstrate that the sample selected is representative of the developers in NY and captures the risks associated with development of the respective technologies.

The Draft Report also failed to take into account Buyer Side Mitigation ("BSM") rule changes when developing the financial parameters. When the NYISO was reforming its BSM rules which occurred within the 2021-2025 DCR period, there was consensus that no tariff changes were needed to address these additional market risks because the DCRP consultants were already tasked with addressing new factors that were likely to present incremental risks in this reset process. An affidavit submitted by the Analysis Group suggested that addressing the BSM rules would increase the WACC.[48] Additionally, FERC has noted that there needs to be an increase in regulatory risk when developing metrics such as the COE due to BSM rule changes.[49] While the Draft Report stated that BSM rule changes were taken into consideration in a wholistic

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[48] Docket No. ER21-502, *New York Independent System Operator, Inc.*, 2021-2025 ICAP Demand Curve Reset Proposal (Nov. 30, 2020), Att. III, ¶¶ 70–82.

[49] *See New York Independent* System *Operator, Inc.,* 122 FERC ¶ 61,064 (2008), at P 60.

manner, blanket statements are not sufficient, particularly where they directly contradict the same consultants' previous position that the full effects of the rule change need to be measured so that the additional risk is reasonably integrated. Accordingly, IPPNY requests that the Draft Report's COE be increased.

Thus, the reasonable WACC assumptions that the Draft Report should assume include a COE of 18%, a COD of 9%, and a Debt-to-Equity ratio of 40/60. These changes will more accurately reflect the investment metrics for merchant generators developing a standalone project.

2. 2-hour BESS Deviations from Day-Ahead Schedules

Specific to the 2-hour BESS, it will exacerbate a problem inherent in the modeling of Net CONE for batteries due to the failure of real time uses of the battery that deviate from day-ahead schedules to be considered for its impact on the unit's derating factor. If a battery lacks sufficient energy to meet its hourly day-ahead commitment at the beginning of any hour during the peak load window for which it has been scheduled for energy or reserves, its derate factor will be increased in the like capability period starting with the next year and continuing for the following year's capability periods. This, in turn, will reduce the amount of Unforced Capacity ("UCAP") the unit will be qualified to sell. Moreover, increased derates which are likely to continue to accrue in those subsequent periods will be additive, thereby only serving to further erode its derating factor. The shorter the duration of the battery, the greater the potential that real-time decisions to deviate from the day-ahead schedule will result in such a derate given the likelihood that a battery is likely to receive 10-minute reserve schedules for most hours during the peak load window.

The BESS Net E&AS model should track when the BESS does not have the energy to meet its hourly DAM schedule during the peak load window and incorporate the derate into the UCAP rating for the unit.

3. Amortization Period

Specific to the 2-hour BESS, while the Draft Report sets forth a decreased amortization period for all BESS compared to the 20-year amortization period proposed initially, this change is wholly inadequate to address the aforementioned CAF volatility as well as the risk of declining reserve revenues addressed *supra*. Using a static input to account for a dynamic value is not logical. It also means that for an investor to recoup its investment, the 2-hour BESS would have to be the proxy unit for the full 15-year amortization period.

In any event, using a static input vis-à-vis the BESS units to account for a dynamic value is not logical. The Draft Report fails to demonstrate why a 15-year amortization period is appropriate across all durations, rather than a different amortization period for different duration BESS. The Draft Report should demonstrate why a 15-year amortization period is appropriate across all durations, rather than a different amortization period for different duration BESS. Incorporating a 15-year amortization period does not reasonably address the substantial investment risks associated with the strong probability that shorter duration BESS will see its CAF value decline more rapidly than longer duration BESS and other potential future Proxy Units over the assumed 2-hour BESS proxy unit's life.

4. Investment Tax Credits

The Draft Report incorrectly assumes a net Investment Tax Credit ("ITC") benefit of 30% of all BESS capital costs monetized for $1.00 per credit, coincident with each construction expense. As established *infra*, this grossly overestimates the net ITC benefit, which must be corrected to 30% of all eligible capital costs and monetized for $0.92 per credit at commercial operation to reflect the correction of all the errors identified below.

i. Limited ITC Eligibility

The Draft Report fails to recognize that not all such costs would be eligible for the ITC. Under Section 48(a)[50] of U.S. Code Title 26 (the "Code"),[51] "the [ITC] for any taxable year is the energy percentage of the basis of each energy property placed in service during such taxable year." In other words, the ITC amount equals a percentage of the cost basis of any "energy property", as the term is defined under the Code. The term "energy property" means any property which: (i) meets the requirements of Section 48(a)(3)(A) of the Code (in this case, energy storage technology under Section 48(a)(3)(A)(ix)); (ii) which is either constructed or acquired by the taxpayer; (iii) with respect to which depreciation (or amortization in lieu of depreciation) is allowable; and (iv) meets applicable performance as quality standards.[52] Depreciation is addressed in the code primarily under Sections 167 and 168. Section 168 provides rules for determining the appropriate depreciation method, applicable recovery period and applicable convention for the deduction allowed under Section 167(a).[53]

As mentioned above, Section 48 requires "energy property" be subject to depreciation. Under Section 168(e)(3)(B)(vi)(I) of the Code, "any property which is described in [48(a)(3)(A) (i.e., energy property)] is classified as "5-year property" for purposes of the Modified

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[50] Similar rules will apply for Section 48E (the technology neutral ITC) which applies to facilities that begin construction and are placed in service after December 31, 2024.

[51] Unless otherwise stated, all references to "Section" or "Sections" are to the Code, and all references to "Treas. Reg. §" are to the Treasury Regulations promulgated thereunder.

[52] *See* 26 U.S.C. § 48(a)(3)(A).

[53] Section 168(a).

Accelerated Cost Recovery System ("MACRS"). MACRS is used to recover the basis of most business and investment property placed in service after 1986. MACRS consists of two depreciation systems, the General Depreciation System ("GDS") and the Alternative Depreciation System ("ADS"). Generally, these systems provide different methods and recovery periods to use in figuring depreciation deductions. Taxpayers must generally use GDS unless you are specifically required by law to use ADS or you elect to use ADS.

Assuming that the GDS will be used for an ITC project, and assuming that "energy property" is generally the only "5-year property" that is part of an energy project, certain logical conclusions can be drawn. Because "energy property" is classified as "5-year property" under the Modified Cost Recovery System ("MACRS"), the ITC is a percentage of the basis of the qualifying "energy property" of a project, and the "energy property" is generally the only property properly classified as "5-year Property", a projects ITC eligible basis can properly be said to consist of the sum cost of all "5-year property." The allocation of project assets to a specific recovery period is usually completed by a respected accounting firm. Below is a sample from an appraisal conducted by one such firm of the types of property that is generally allocated to the "5-year property" recovery period. The key determination is whether a cost may be properly allocated to the relevant "energy property". The following non exhaustive list of costs will generally not be eligible for inclusion the basis of "energy property": (i) costs related to the transmission line and electrical interconnection; (ii) costs related to the interconnection switchyard; (iii) spare parts; (iv) project development costs; (v) costs of the land and improvements thereto; and (vi) start up and commissioning costs.

ITC Eligibility	Cost Recovery	Tax Category	Depreciation Category
Y	5-Year MACRS	MACRS Class F	Balance of System
	5-Year MACRS	MACRS Class F	Foundations
	5-Year MACRS	MACRS Class F	Monitor & Communication
	5-Year MACRS	MACRS Class F	Inverters
	5-Year MACRS	MACRS Class F	Battery Storage
	5-Year MACRS	MACRS Class F	Substation
	5-Year MACRS	MACRS Class F	Electrical Collection - Project Side
Y Total			
N	7-Year MACRS	MACRS Class A	No Asset Class
	15-Year MACRS	MACRS Class 00.3	Land Improvements
	20-Year MACRS	MACRS Class 49.14	High Side Trans <69kV
	15-Year Straight Line	IRC §197	EPC
	15-Year Straight Line	IRC §197	ESSA
	15-Year Straight Line	IRC §197	IA
	15-Year Straight Line	IRC §197	LTSA
	15-Year Straight Line	IRC §709	Organization
	20-Year Straight Line	IRS Notice 2016-36	Interconnection Facilities Transfer
	25-Year Straight Line	IRC §178	Ground Lease & Easement
	39-Year Straight Line	IRC §1250	Real Prop
	Non-Depreciable	IRC §709	Syndication
	Non-Depreciable	IRC §709	Transaction & Syndication
N Total			

Figure 1: Sample BESS Asset Allocation from an Industry Leading Consulting Firm

Further, the model incorrectly assumes that the project will receive a tax payment when 5-year MACRS is applied. This is factually incorrect, the best outcome on a stand-alone basis with an operating loss in any given year will be that there is zero tax liability. The project will not actually be receiving any payments from the Internal Revenue Service or the State because it has an operating loss with accelerated depreciation.

ii. ITC Monetization

The Draft Report fails to recognize that the ITC will be monetized at a discount directly attributable to: (i) the risk that the buyer will assume which varies by, among other factors, the underlying technology and the creditworthiness of the seller; (ii) tax credit insurance that the tax credit buyer ("TCBs") may require; and (iii) legal and broker fees. Generally, TCBs are purchasing credits at a discount of $0.05 to $0.15 per credit with a price per credit of $0.95 to $0.85 before considering seller's expenses. Credits purchased for less than $10 million traded at $0.89 per credit, whereas purchases exceeding $100 million traded at an average of $0.95 per credit. It is not clear how much of the difference between the credits' sales prices and their maximum values was attributable to liability concerns, the preference for immediately available cash, or other factors.[54] The table below provides a visualization of the price versus risk analysis that TCBs were looking at for calendar year 2023 tax credits.[55]

Risk / Complexity Increases

	Description	Risk mitigation	Pricing*
Current-year PTCs	Proven technologies such as wind or solar	Seller indemnity is typically provided. PTCs do not carry recapture risk	**$0.94 to $0.95** Multi-year or forward PTCs will trade at a discount
De-risked ITCs	Proven technologies such as solar or battery storage. Typically above $10M in volume; larger projects trade at a smaller discount	Assumes tax credit insurance or indemnity from a creditworthy guarantor	**$0.91 to $0.93**
More complex ITCs	Technologies with lower buyer demand such as biogas, or smaller transactions under $10M with any technology	Assumes tax credit insurance or indemnity from a creditworthy guarantor	**$0.88 to $0.91**
Uninsured ITCs	Projects without insurance (e.g. new technologies, very small and / or complex projects)	No insurance. Indemnity is not from a creditworthy guarantor	**Varies by situation**

*Reflects final pricing to buyer, inclusive of marketplace transaction fee and cost of insurance

Figure 2: Buyer Pricing for 2023 Tax Credits

iii. ITC Expenses

The Draft Report fails to assume any cost to monetize the ITC, which is unreasonable. Tax credit insurance premiums are generally between 2% and 3% of the limit purchased, and there will be significant legal costs incurred to enter into the transaction. In line with what was discussed *supra*, the acquisition of ITCs is a costly endeavor because the TCB will often require

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[54] *Tax Credit Transfers and Direct Payments in the Inflation Reduction Act of 2022*, Congressional Research Service (Feb. 26, 2024), https://crsreports.congress.gov/product/pdf/IF/IF12596.

[55] Andy Moon, *What Should Corporations Expect to Pay for Transferable Tax Credits in 2024*, Reunion (Jan. 10, 2024) https://www reunioninfra.com/insights/2024-tax-credit-pricing.

the tax credit seller ("TCS") to pay its legal fees, which can be $250K or more per transaction, as well as procure insurance. Additionally, if a broker is used to connect a TCS and TCB, the broker fee can be between 0.5% and 1% of the amount of credits purchased. These costs are often incorporated into the cost per credit that is presented to the TCB, which effectively lowers the amount realized by the TCS. To illustrate, the cost per credit might be $0.94 per credit, however, after the costs of the transaction are factored in, the price per credit will be driven down closer to $0.91 per credit.

iii. ITC Timing

The Draft Report's BESS DCRP results reflect the flawed assumption that ITC can be monetized coincident with the construction expenses being incurred rather than when the BESS is placed in service. As discussed above, Section 48 of the Code provides an ITC for the basis of energy property that is placed in service during the taxable year for which the taxpayer is claiming the credits.[56] Placed in service is a term of art as is used in the Code and very specific requirements must be met for a project to be deemed placed in service, typically on or just after the commercial operation date. Generally, taxpayers constructing energy projects do not contract to sell the credits until the project is placed in service and the TCS files the tax return on which the credits will be claimed.

5. Net Operating Losses

The Draft Report BESS DCRP results reflect the flawed assumption that net operating losses (NOLs), which occur when allowable deductions exceed taxable income within a tax period, can be monetized in the same year they occur, as if the Federal, NYS, and NYC

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[56] 26 U.S.C. § 48(a).

governments provided a cash payment to the proxy unit in that year. It is incorrect to assume that BESS ownership could utilize the NOLs to offset Federal, NYS, and NYC tax obligations for other businesses, thus significantly underestimating the levelized carrying charge rate. The Draft Report should instead reflect the assumption that deferred tax assets are created from NOL carryforwards and limit them to 80% of the taxable income in any future tax period.

6. BESS Full-Time Employees

The Draft Report assumes that the 2- and 4-hour duration BESS have zero full-time equivalent employees, arguing that the project can be remotely monitored by existing owner staff. When asked about 24/7 operational control of the battery, the Consultants responded that such coverage was not assumed.

Article 8 of NYISO's Standard Large Generator Interconnection Agreement mandates that a developer maintain satisfactory operating communications with the Connecting Transmission Owner and NYISO. This includes providing standard voice line, dedicated voice line, and facsimile communications at its Large Generating Facility control room or central dispatch facility.[57] Moreover, during an emergency Max Gen Pickup, at the NYISO's judgment, generators will be instructed via voice communication to increase output to their upper operating limits as soon as possible until directed otherwise. [58]

The Draft Report does not explain how a properly trained operator could receive a verbal dispatch instruction via a dedicated voice line and take immediate action during normal and

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[57] *See* NYISO Open Access Transmission Tariff ("OATT"), Att. X, § 30.14, App'x 4.

[58] *See Manual 12 Transmission and Dispatch Operations Manual*, NYISO (Apr. 2024), at § 6.7.3, https://www.nyiso.com/documents/20142/2923301/trans_disp.pdf.

emergency conditions in accordance with NERC, NPCC, NYSRC, NYISO, and Connecting Transmission Owner requirements. Additionally, the Draft Report does not provide reasonable explanations for how other operation and maintenance requirements will be adequately managed remotely, such as site security, access control, outage planning, work authorization, balance of plant maintenance, environmental compliance, and emergency response.

Additionally, the Draft Report does not give any consideration to the NYC Fire Code and NYC Fire Department Rules. Per industry feedback, among many requirements exceeding NYS standards that have been implemented by the City of New York, a site of this size would require four FDNY B-28 Certificate of Fitness ("CoF") holders for the supervision of Stationary Energy Storage Systems. A CoF holder is responsible for supervising the commissioning, operations and maintenance, recordkeeping, annual inspections, decommissioning, and emergency management situations. Furthermore, they must be trained and knowledgeable in the operation of the BESS, be reachable by phone immediately and onsite within two hours and be capable of electrically isolating the BESS.

Furthermore, the Draft Report does not account for asset management and energy management costs, again relying on existing owner staff. These assumptions lead to the conclusion that no new hires are needed to run any BESS, regardless of the plant's capacity or the number of plants in a fleet. This assumption effectively shifts project-level expenses to the corporate level, thereby artificially inflating project-level returns. The Draft Report's staffing assumptions must be corrected to ensure 24/7 operational control, capable of responding to verbal dispatch instructions, complying with FDNY requirements, and satisfying other critical operational, maintenance, and compliance tasks. Additionally, the final repot must include allocations for asset management and energy management costs, rather than improperly removing these costs from the project level and thereby artificially inflating project-level returns.

7. Derating Factor and Peak Load Window

The Draft Report incorrectly assumes a 2% Derating Factor for each BESS in perpetuity. This assumption underrepresents the Derating Factor for each Proxy BESS on two accounts.

First, until there are at least three Energy Storage Resources with operational data for all months used in the Unavailability Factor calculation, the initial Unforced Capacity value for an Energy Storage Resource upon entry into the market will be based on the NERC class average EFORd of Pumped Hydro Stations. [59]

Second, the Draft Report must be corrected because it fails to incorporate the Derating Factor caused because of the Net-EAS model's bidding process to subsequent Capability Periods. The NYISO's calculation for an Energy Storage Resource's Derating Factor comprises of three main components during the Peak Load Window: UOL Availability, Storage Availability, and Energy Level Availability.[60] The third component, Energy Level Availability, which considers whether there is sufficient energy in the battery to meet its Day-Ahead Market Commitment at the start of each hour, particularly underscores the significance NYISO places on fulfilling Day-Ahead Market Commitments.

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[59] *See Manual 4 Installed Capacity Manual*, NYISO (May 31, 2024), § 4.5(b), https://www nyiso.com/documents/20142/2923301/icap mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338.

[60] *See Installed Capacity Manual Attachments*, NYISO (May 31, 2024), § 6.7.2, https://www nyiso.com/documents/20142/32280612/Appendix-Attachments-for-ICAP-Manual.pdf/d3501b19-51c4-e511-59df-824dfe0e45b6.

Additionally, the Peak Load Window hours indicated in the Draft Report are incorrect. The Peak Load Window hours must be updated in the final report to match those for the 2024/2025 Capability Year[61] and must be used to determine the Derating Factor resulting from the Net-EAS model's bidding process. A bidding strategy that maximizes Real-Time Market Energy and Ancillary Awards while disregarding an increasing Derating Factor—and consequently reducing UCAP for the next two Capability Periods—represents an irreplicable bidding strategy for any new market entrant. Finally, within the derating factor assumptions, the Consultants must also account for the impact of the initial Unavailability Factor that the NYISO would apply to the BESS proxy upon its entry into the market.

8. RTM Spinning Reserve Awards

The Draft Report also fails to explain how an RTM Spinning Reserve award for the ability to reduce RTM Scheduled Energy withdrawals, which are scheduled for a five-minute interval only, meets NPCC's one-hour Sustainability Requirements for Operating Reserves.[62] Provided that the BESS's state of charge meets the Sustainability Requirements, there are five conceivable ways a BESS could provide Spinning Reserves:

- DAM Reserve award for the ability to convert stored energy to RTM Energy
- DAM Reserve award for the ability to reduce DAM Scheduled Energy withdrawals
- RTD Reserve award for the ability to convert stored energy to RTM Energy

[61] *See Peak Load Window for the 2024/2025 Capability Year*, NYISO (Feb. 22, 2024) https://www nyiso.com/documents/20142/36848677/Peak-Load-Window-for-the-2024-25-Capability-Year.pdf/

[62] *See NPCC Regional Reliability Reference Directory # 5*, Northeast Power Coordinating Council, Inc. (Apr. 26, 2020), https://www.npcc.org/content/docs/public/program-areas/standards-and-criteria/regional-criteria/directories/directory-5-reserve-20200426.pdf.

- RTD Reserve award for the ability to reduce DAM Scheduled Energy withdrawals
- RTD Reserve award for the ability to reduce RTM Scheduled Energy withdrawals

Since DAM Scheduled Energy withdrawals are scheduled for one-hour, DAM & RTD Spinning Reserves based on the ability to reduce DAM Scheduled Energy withdrawals would meet the Sustainability Requirements. However, if the BESS receives a 5-minute RTD Scheduled Energy withdrawal, it is unclear how the ability to reduce that 5-minute RTD Scheduled Energy withdrawal would meet the Sustainability Requirements.[63] When stakeholders requested the Consultants confirm the foregoing, the Consultants directed stakeholders to a section of the Tariff which states that a BESS meeting criteria set forth in the ISO Procedures shall be eligible to supply Spinning Reserve when withdrawing or injecting Energy, and when idle.[64] However, this reference is caveated by the fact a BESS's eligibility to supply Spinning Reserve when withdrawing is limited by the ISO Procedures, such as the Sustainability Requirements. Therefore, the question remains open, and the Consultants must confirm whether the modeled RTD Spinning Reserve awards for the ability to reduce RTD Scheduled Energy withdrawals meet the Sustainability Requirements before they may be incorporated in the revenues delineated in the final report.

9. Fixed O&M

The Draft Report incorrectly assumes that a BESS has the same fixed O&M costs regardless of Locality. When insurance and land leasing costs are removed from the Draft Report's proposed fixed O&M budget, the budgets for each Locality are equal. In addition to the

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[63] *See* NYISO MST § 4.4.2.1.

[64] *See* NYISO MST § 15.4.1.2.1.

previously discussed BESS full-time employee costs, this fails to consider several factors. For example, the Draft Report assumes the benefits of the prevailing wage and apprenticeship ITC bonus; therefore, any construction, alteration, or repair to the BESS within the first five years is also subject to prevailing wage requirements.[65] However, despite the first augmentation occurring in year four, the costs are the same in every Locality. Additionally, the FDNY requires additional fire protection measures, such as an external sprinkler system and means of fire detection, typically infrared flame detectors or thermal imaging, but there are no additional costs in Zone J to account for the associated maintenance. In fact, the costs of owning and operating a business in NYC are more expensive on almost every front. Whether it is high voltage electrical maintenance, relay testing, OT-network cybersecurity, regulatory compliance, employee training, or groundskeeping, the costs in NYC will be higher than in other Localities. Therefore, the final report must be updated to identify fixed O&M assumptions which should be Locality specific and increase those to reflect the realities in that Locality.

10. Discretionary Sales and Mortgage Recording Tax Exemptions

The Draft Report assumed that BESS would receive an as-of-right sales and mortgage recording tax exemptions, but no evidence has been presented to support this assumption. In a 2009 advisory opinion, the New York State Department of Taxation and Finance determined that stand-alone "flywheel" energy storage systems used predominantly for storing and returning electricity to the grid, did not qualify for the sales tax exemption under Section 1115(a)(12) of the Tax Law because it was not directly and predominantly used in the production of electricity

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[65] 26 U.S.C. § 48(a)(10).

for sale by generating. Consequently, the purchase or use of such systems is subject to sales or use tax under Tax Law §§ 1105(a) and 1110.[66] Bills to amend section 1115 of the tax law to include commercial energy storage systems have failed to pass both houses of the New York Legislature as recent as this past legislative session.

As of 2021, the State of New York had 107 active Industrial Development Agencies and Authorities ("IDAs"),[67] which are exempt from paying sales tax on all their purchases under Section 1116(a)(1) of the Tax Law. IDAs may extend sales tax benefits by appointing a business, developer, contractor, or subcontractor as their agent for this purpose. When a project operator or agent is appointed by the IDA to act on its behalf, purchases made within the authority granted by the IDA are deemed to be purchases made by the IDA and are, therefore, exempt from sales tax.[68] In a 1982 advisory opinion, the New York State Department of Taxation and Finance confirmed that an IDA may extend mortgage recording tax exemption, and provided subsequent guidance on certain limitations in a 2017 technical memorandum.[69][70]

However, an IDA's decision to extend these exemptions to a project is discretionary. For example, the New York City Industrial Development Agency's ("NYCIDA") Uniform Tax

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[66] Petition No. S081208B Advisory Opinion, New York State Department of Taxation and Finance (Aug. 21, 2009) https://www.tax.ny.gov/pdf/advisory_opinions/sales/a09_36s.pdf.

[67] *Performance of Industrial Development Agencies in New York State: 2023 Annual Report*, New York State Comptroller (Apr. 2023), at 1, https://www.osc.ny.gov/files/local-government/publications/pdf/ida-performance-report-2023.pdf.

[68] *Sales Tax Reporting and Recordkeeping Requirements for Industrial Development Agencies and Authorities*, New York State Department of Taxation and Finance (Feb. 12, 2014), https://www.tax.ny.gov/pdf/memos/sales/m14_1_1s.pdf.

[69] Petition No. M820512A Advisory Opinion, New York State Department of Taxation and Finance (June 18, 1982) https://www.tax.ny.gov/pdf/advisory_opinions/mortgage/a82_1m.pdf.

[70] *Sales Tax Reporting and Recordkeeping Requirements for Industrial Development Agencies and Authorities*, New York State Department of Taxation and Finance (Feb. 12, 2014), https://www.tax.ny.gov/pdf/memos/sales/m14_1_1s.pdf.

Exemption Policy ("UTEP") states that providing financial assistance is a discretionary act by NYCIDA. This financial assistance is determined based on a multitude of objective eligibility criteria, including, but not limited to, the extent to which the project will create or retain permanent, private-sector jobs, the financial feasibility of the project without financial assistance, the demonstrated public support for the project, and the effect of the project on the environment.

However, the Draft Report assumes that the BESS would not create any permanent, private-sector jobs. Additionally, the very nature of the DCR process solves for the reference price of the BESS which would not require external financial assistance if selected as the proxy unit. Public support for projects can be unpredictable, as shown by past revisions to NYCIDA's UTEP Policy and the numerous moratoria and vocal opposition to BESS projects across the State. Furthermore, it is unclear whether the environmental impacts of the proxy BESS would qualify it for assistance both now and in the future.

Discretionary tax exemption programs are just that, discretionary, meaning there is significant risk that the entity in charge of granting such exemption may choose to deny a request for exemption either in its entirety or otherwise limit it. FERC's precedent on the inclusion of discretionary tax exemption programs is clear, particularly in this case. When considering the inclusion of NYCIDA's property tax abatement during the 2011-2014 DCR process, FERC determined that it was not just and reasonable to assume full or any tax abatement when the granting of the abatement is discretionary under the provisions of the UTEP and not a matter of right. Subsequently, New York State enacted legislation (New York Assembly Bill 7511) that provided an as-of-right NYC SCGT property tax abatement. Following this legislation, FERC found that an as-of-right property tax abatement then existed, alleviating its prior concerns about the discretionary nature of NYCIDA's UTEP program, and concluded that including the tax abatement assumption in calculating the NYC net CONE was appropriate.

The Draft Report must either provide evidence to support the assumptions that as-of-right sales and mortgage recording tax exemptions are available to the BESS unit in each Locality studied or, in accordance with FERC precedent, assume that the BESS will be subject to sales tax. Furthermore, if an as-of-right sales tax exemption is available, the Draft Report must also consider if there are significant costs associated with obtaining the exemption, including legal costs and/or fees. Additionally, the Draft Report must determine if the as-of-right sales tax exemption extends beyond construction completion and whether both the Fixed O&M and VOM costs would be taxable. Finally, the Consultants must determine to what extent any as-of-right mortgage tax exemption is limited by the New York State Department of Taxation and Finance's 2017 technical memorandum.

11. Site Leasing Costs

The Draft Report's recommends site leasing costs for NYC of $644,000 per acre-year, which continues to underestimate NYC site leasing costs. 1898 & Co. developed the site leasing costs using data from the JLL report commissioned by TigerGenCo.[71] While the Draft Report accepts the JLL study's average purchase price of appropriately zoned and sized parcels at roughly $12 million per acre, it ignores the conclusion that the average lease costs for such land would be $871,200 per acre-year. Instead, the Draft Report derives the lease value by applying an arbitrary Cap Rate of 5.5% to JLL's average purchase price of $12 million per acre, resulting

[71] *See New York City's M Zoned Land Value Analysis*, JLL (May 2024), https://www.nyiso.com/documents/20142/44660396/TigerGenCo-New-York-City%20M-Zoned-Land-Value-Analysis.pdf/5198854f-c0ce-db6c-8a17-d1f9eef79dbb ("JLL Report").

in a lease cost of $644,000 per acre-year. The Draft Report relies on an outdated Q3 2023 Cap Rate of 5.7% published by J.P. Morgan, attempted to forecast Federal Reserve rate cuts for 2024, and relying on those rate cuts, settled on a baseless 5.5% Cap Rate. Since then, the Federal Reserve has indicated that they may only cut rates once in 2024, far less than originally expected. Average NYC Industrial Property Cap Rates have increased to 5.9%,[72] not decreased, since the Consultants' forecasted their decline based on Federal Reserve policy. For these reasons, and those discussed further in the JLL comments,[73] the final report must reflect a Cap Rate assumption to no less than 7.2%.

Furthermore, the significant gap between the Draft Report's original NYC industrial land lease assumption and actual costs calls into question the accuracy of their methodology for industrial land lease assumptions in other Localities. The Consultants must perform an assessment on par with the methodology used for NYC for all the Localities.

In addition, the Draft Report's Cap Rate methodology for determining Site Leasing Costs is flawed, as it fails to capture the existing property tax assessed on the land which does not qualify for the exemption, and does not account for landowner expenses, which will be incurred annually over the life of the lease, such as insurance. The Draft Report must also be revised to correct the costs to include existing property taxes and landowner expenses in the Site Leasing Costs.

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[72] *See* JLL Report at 12.

[73] *See* JLL Report.

12. Site Leasing Costs During Construction

The Draft Report fails to account for Site Leasing Costs for all proxy units during construction periods, which range from 30 to 42 months, in the Owner's Costs narrative and the construction budget. Regardless of whether by omission or an intentional assumption, the final report must be corrected to incorporate the costs to include the Site Leasing Costs during construction, as it would be unreasonable to assume that any landowner would provide even one month of free rent.

13. Transmission and Electrical Interconnection Costs

The Draft Report’s transmission and electrical interconnection assumption of $29 million is also underestimated. Consolidated Edison Company of New York Inc. estimates the cost of 345 kV land cables at $47 million per mile, without considering interferences or obstructions that may be encountered.[74] Furthermore, the JLL Report identified the scarcity of appropriately zoned and sized parcels that are not within a Disadvantaged Community. Consequently, the Draft Report’s assumption for the distance between the proxy unit and the interconnecting substation must be revised from one to three miles to avoid locating in a Disadvantaged Community. This adjustment would avoid the otherwise necessary—and likely higher—costs to mitigate the burdens created by locating the proxy unit within Disadvantaged Communities, costs which also would otherwise have to be included in the final report but were absent from the Draft Report.

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[74] Case 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act,* Petition of Consolidated Edison Company of New York, Inc. for Approval to Recover Costs of Brooklyn Clean Energy Hub (Apr. 15, 2022), at 30.

14. SCGT Full-Time Employee Costs

The Draft Report's assumption of seven full-time equivalent employees to run a standalone SCGT is inadequate. To operate an SCGT in Zone J, a minimum of 12 full-time employees is required. This includes five gas turbine operators working rotating eight-hour shifts, one I&C technician, three maintenance mechanics, a facility manager, an O&M manager, and an EH&S supervisor. The justification of the Draft Report's assumption of seven employees is that some plants are operated remotely and thus have only a few employees. However, this reasoning is flawed because the DCR studies the costs of running a standalone plant, which would not have a remote operating center. Labor Unions also agree that assuming only seven full-time employees does not provide the correct market signal to incentivize the retention of existing plants or the creation of new ones. Therefore, the Draft Report must be revised to increase the current assumption to 12 full-time employees for SCGT to better represent operational realities.

C. The Draft Report Correctly Excludes State Public Policy Incentive Payments Which Are Discretionary in Nature from the Net CONE Calculation of Any Proxy Unit.

The Draft Report correctly excludes discretionary State public policy incentive payments from their Net EAS calculations. FERC has expressly held that inputs to the demand curve calculations should not be considered if they result from a discretionary government program.[75] In its 2010 DCR filing, the NYISO proposed that the NYC demand curve should assume full property tax abatement for the NYC peaking plant even though NYC had changed its as-of-right tax abatement program to a discretionary one. FERC rejected the NYISO's proposal because

[75] *New York Independent System Operator, Inc.*, 134 FERC ¶ 61,058 (2011).

NYC had discretion to deny the tax abatement, it was unclear whether NYC peaking units would be eligible for the abatement and, therefore, the NYISO had failed to demonstrate that NYC peaking units will not incur property taxes. After FERC's January 2011 Order, New York enacted legislation that eliminated NYC's discretion to exempt peaking plants from property taxes and returned the property tax abatement to an as-of-right program.[76] FERC granted rehearing of its January 2011 Order, ruling that property taxes should be included in the calculation of the Net CONE of the NYC peaking plant because the legislation had fundamentally changed the structure of the program to an as-of-right one.[77]

Governmental payments to incent the development of new resources to meet public policy goals should not be included in the net EAS calculation where such payments are discretionary. Most of the government incentives paid to grid-connected renewable resources have been made by the New York State Energy Research and Development Authority ("NYSERDA"). Importantly, NYSERDA's payments are discretionary because the only developers that will receive them are ones that NYSERDA has awarded contracts through periodic competitive solicitations and the overall total to be awarded is less than the resources that are being proposed to be developed.[78] Pursuant to the terms of NYSERDA's solicitations, NYSERDA is not obligated to award any contracts. NYSERDA's most recent solicitation for renewable energy credits ("RECs") from Tier 1 renewable resources provides:

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[76] *New York Independent System Operator, Inc.*, 135 FERC ¶ 61,170, at P 16 (2011).

[77] *Id.*

[78] At the time the NYISO froze its interconnection queue to account for the Order No. 2023 tariff modifications, there were approximately 240 renewable resources proposed. *See NYISO Interconnection Queue*, NYISO, https://www.nyiso.com/documents/20142/1407078/NYISO-Interconnection-Queue.xlsx/f615d83e-eea6-ccf6-ec07-b4ecbe78d8ef?t=1718228133245.

> This solicitation does not commit NYSERDA to award a contract, pay any costs incurred in preparing a proposal, or to procure or contract for services or supplies. NYSERDA reserves the right to accept or reject any or all proposals received, to negotiate with all qualified sources, or to cancel in part or in its entirety the solicitation when it is in NYSERDA's best interest.[79]

Most recently, the PSC announced a program to conduct at least three competitive solicitations annually to procure 3 GW of bulk energy storage.[80] The PSC directed NYSERDA to issue the first solicitation no later than June 30, 2025.[81] Like its solicitations for RECs from renewable resources, NYSERDA's solicitations for Index Storage Credits from bulk BESS is discretionary as the only developers that receive the incentive payments will be ones that NYSERDA awards contracts through the competitive solicitations and here, too, the scope of the program is capped.

The consideration of estimations of the value of BESS Investment Tax Credits is appropriate because they are as-of-right payments.

D. The Draft Report's Simple Cycle Gas Turbine Assumptions Are Just and Reasonable.

IPPNY appreciates the Consultant's change of thinking related to the SCGT as opposed to the last DCR.[82] The dual fuel assumption with selective catalytic reduction in all zones

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[79] *Request for Proposals RESRFP24-1*, NYSERDA (June 20, 2024), at 88, https://portal.nyserda ny.gov/servlet/servlet.FileDownload?file=00P8z000004GQksEAG.

[80] Case 18-E-0130, *In re Energy Storage Deployment Program*, Order Establishing Updated Energy Storage Goal and Deployment Policy (June 20, 2024).

[81] *Id.*

[82] The final proxy unit considered, the SCGT with a 20-year amortization period and no net EAS revenues post-2040 did not include a reasonable analysis. Retrofit costs required to operate post-2040 cannot simply be "recast" as variable costs and, as 1898 data has demonstrated, these fixed costs are so high that further review of the fossil fuel SCGT and retrofit option designated in the Scope of Work is no longer warranted.

reflects what investors would expect given DEC regulations and the NYISO's ongoing firm/non-firm fuel gas constraint integration into the capacity market. The most recent results from three separate methodologies being examined by the NYISO on how to calculate CAFs for firm/non-firm fuel resources show a drastic drop off as an increased number of units elect non-firm.[83] In all three methodologies, the CAF drops below 15% in ROS for non-firm units when only 6,000 MW of firm-fuel are elected. Even with 9,000 MW of firm-fuel elected, in all three methodologies the CAF for non-firm fuel for all zones but Zone K hovers around 50%, with Zone K hovering around 75%. This steep drop off in CAF due to a generator not being able to elect firm, the requirements not yet solidified, would result in a generator ensuring that they have enough fuel to elect firm, which is the point of the integration into capacity accreditation. Moreover, the relatively small increase in costs associated with making the SCGT a dual fuel unit is economic, given the risk of a CAF hit to gas only units. Similarly, investors would likely require that the generator be firm in deciding their financing parameters.

Likewise, the final report should adopt the 13-year amortization period for the SCGT correctly established in the Draft Report because it reflects the CLCPA mandate of a zero emissions electric system by 2040. The NYISO proposed a 17-year amortization period in the last DCR to reflect the CLCPA's 2040 zero-emissions requirement. Following a serious of FERC orders and an appellate court decision, FERC ultimately found the NYISO's proposed 17-year

[83] Ryan Carlson, *Modeling Improvements for Capacity Accreditation Support*: *Non-Firm CAFs Methodology*, NYISO (June 4, 2024), at 7, 10, https://www.nyiso.com/documents/20142/45045469/24_06_04_ICAPWG_NonFirmCAFs_Results_FINAL.pdf/f406c731-0f01-5fe7-cc4d-9a9ae23c5f59.

amortization period reasonable and directed the NYISO to implement it for the remainder of the 2021 to 2025 demand curves.[84]

Denying the PSC's petition seeking review of that determination,[85] the Court held earlier this month that, because the CLCPA "provides no clarity about how exactly New York is to achieve the emissions target . . . it makes sense that a rational investor could evaluate all the legal and technological uncertainties and predict that a new fossil-fueled plant would not 'remain commercially viable' past 2039," and, thus, "FERC was therefore obligated to, and rightly did, accept the System Operator's adoption of that reasonable 'reading of the Act.'"[86] As a matter of law, if the NYISO selects a SCGT for the 2025-2029 DCR, its amortization period must be 13 years.

The natural gas hubs related to the supply of this proxy unit should also remain unchanged, as they are reasonable proxies both geographically and economically to what our generators face. Specifically, Load Zone G (Dutchess) having a proxy of Iroquois Zone 2, and Zone G (Rockland) a proxy of Tennessee Zone 6 both have higher LBMP correlations compared to selections in the 2021-2025 DCR. Further, these both pass the 4-part geography test which has been developed to ensure deliverability. Nowhere in the test does it require that a line be unobstructed to the sub-zone by geographical formations such as rivers. Lastly, the AG listened and took heed of the current Consolidated Edison policy of prioritizing natural gas delivery during the winter months, and hence changed Zone J to Iroquois Zone 2 in December and

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[84] *See N.Y. Indep. Sys. Operator, Inc.*, 183 FERC ¶ 61,130 (2023).

[85] *New York State Public Service Commission v. FERC*, No. 23-1192, 2024 WL 2983918 (D.C. Cir. 2024).

[86] *Id*.

January. This reflects real world supply issues from Transco Zone 6 in these winter months, and thus correlates closer to LBMP.

The Draft Report reasonably captures the costs associated with investing in a SCGT in New York with the regulatory environment in place.

IV. CONCLUSION

The NYISO consistently has established through extensive analyses set forth in its reports, as further underscored in additional information provided to policymakers and stakeholders (*e.g.*, fact sheets, podcasts, press releases, etc.), that the electric system needs more, not less, long-duration dispatchable resources to meet system reliability both during the current transition period and as the State's mandates are achieved. If capacity prices do not reflect today's current environment, the CLCPA mandates will put reliability in jeopardy. The PSC and NYSERDA, over the past four years have consistently increased compensation to utilities and generation projects respectively. Utility rate cases[87] and NYSERDA strike prices[88] have both seen increases of around 30%. The assumptions detailed in the Draft Report must reflect today's industrywide economic trends. As AG and 1898 continue to consider the matters raised herein to develop the final report, IPPNY remains available to provide further information or clarification,

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[87] *See e.g.*, Cases 22-E-0317 *et al.*, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service*, Order Adopting Joint Proposal (Oct. 12, 2023), at 1, App'x A (adopting a three-year rate plan with a compounded incremental net base delivery increase of 51.6% and 33.4% for New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation, respectively).

[88] As a result of the most recent NYSERDA solicitation, the Indexed REC Strike Price for the Sunrise Wind project increased from $110/MWh to $146/MWh (32.7%) and the Indexed REC Strike Price for the Empire Wind 1 project increased from $118/MWh to $155/MWh (31.4%). *See* Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable and a Clean Energy Standard*, NYSERDA Comments on Petitions Requesting Price Adjustments to Existing Contracts (Aug. 28, 2023), at 18, tbl.5.

and is committed to engage its members to support such efforts. Thank you for your ongoing consideration of these issues.

Respectfully submitted,

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