

**STATE OF NEW YORK  
PUBLIC SERVICE COMMISSION**

**Proceeding to Implement a Large-Scale Renewable )  
Program and a Clean Energy Standard )           Case 15-E-0302**

**SOLAR + STORAGE PARTIES COMMENTS IN RESPONSE TO DPS STAFF QUESTIONS  
REGARDING UTILITY-OWNED GENERATION**

**I. Introduction**

On May 15, 2025, the Public Service Commission (Commission) issued an *Order Adopting Clean Energy Standard Biennial Review as Final and Making Other Findings* in Case 15-E-0302 (Biennial Review Order). In addition to the actions modifying the Clean Energy Standard and maintaining progress towards the State’s clean energy goals, the Commission sought additional input on two related topics: (1) utility ownership of renewable generation and (2) comprehensive review of the State’s renewable solicitation practices. With respect to utility ownership of renewable generation, the Commission posed a series of questions intended to inform its assessment of whether changes to existing policy might serve the interests of ratepayers.

On July 30, 2025, the Commission issued a Notice Soliciting Comments requesting stakeholder feedback on those questions. Building on that record, on January 27, 2026, the Commission issued a subsequent Notice Soliciting Comments transmitting additional, more detailed questions prepared by Department of Public Service staff. The January 2026 Notice seeks further comment on the potential ratepayer, market, interconnection, siting, solicitation, and regulatory impacts associated with utility ownership of renewable generation, as well as related implications for wholesale energy and capacity market design.

On behalf of the New York Solar Energy Industries Association (“NYSEIA”), New York Battery Energy Storage Technology Consortium (“NY-BEST”), Solar Energy Industries Association (“SEIA”), and the Coalition for Community Solar Access (“CCSA”) (hereafter referred to as the “Solar + Storage Parties” or “SSP”), we respectfully submit the following in response to the Department staff questions on utility ownership of renewable generation as set forth in DPS’ January 2026 Notice.

## II. SSP Responses to the DPS Staff Questions in the January 2026 Notice

### Utility Owned Generation

*Identify the financial impacts and risks to ratepayers of the various options proposed by BMR Energy (build transfer, develop transfer, or milestone-based transfer), Indicated Utilities (build transfer agreement), and New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation (self-build model) as described in response to the July Notice. To the extent possible, include potential ways in which the risks and or impacts could be avoided, mitigated, or managed.*

The SSP's foundational concerns with utility-owned generation and energy storage (UOG) are that: 1) it will cost more for ratepayers; and 2) it will undermine competitive markets and cause financial harm to market participants who are investing significant amounts of private capital into New York's electric sector. The primary reason that UOG will cost more for ratepayers is that regulated utilities earn a guaranteed rate of return on their capital investments, making utility cost overruns a profit center for utility shareholders to the detriment of ratepayers. UOG undermines competitive markets by enabling utilities to leverage information asymmetry, vertical market power, and their cost-plus business model to gain market share and develop projects that would otherwise be developed by competitive market participants. In essence, UOG would enable New York's regulated utilities to "bowl with bumpers" while private industry would not be afforded a similar level of corporate welfare. UOG also introduces material risk that utilities will leverage information asymmetry and other unfair advantages that grant preference to utility-owned projects over market-driven projects.

It's worth noting that utility cost overruns for interconnection work are already negatively impacting distributed energy resource (DER) development in New York. Not only have costs for new DER interconnection skyrocketed in recent years; a growing number of community solar developers in New York are receiving retroactive bills for utility interconnection cost overruns after solar projects are fully operational.<sup>1</sup> These issues highlight the need to strengthen existing regulations and constrain the scope of the utility cost-plus model, not expand it. Rather than expanding the utilities' scope, the SSP urge the Commission to put guardrails in place to ensure utilities are leveraging 21st Century technology and implementing timely and cost-effective work on the transmission and distribution system, which will enable more clean energy projects to come online without imposing new risks on ratepayers or other market participants.

With respect to the various flavors of UOG described in the utilities' and other parties' comments, none of these proposals fully address the inherent risks that UOG imposes on ratepayers and competitive energy market participants.

### **BMR Energy and Indicated Utilities: Transfer-Based Models**

BMR's Build Transfer, Develop Transfer, and Milestone-Based Transfer, along with the Indicated Utilities' Build Transfer Agreements, are existing constructs that are used by developers and long-term owner/operators to support asset development, financing, and construction, including for clean energy

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<sup>1</sup> Case 25-E-0026. Complaint of Altamont Road Solar LLC Against National Grid. January 2025.  
Case 25-E-0469. Complaint of Nexamp Against National Grid. August 2025.

projects in New York State today. All of these proposals would allow regulated utilities to directly compete with other owner/operators to finance and purchase projects. The major distinction is that competitive independent power producers (IPPs), and even unregulated subsidiaries of regulated utilities, raise project finance from banks and investors, and deploy their capital in order to facilitate project development. Risk is borne by their investors and development partners. If the private company is instead replaced by a regulated utility, project risk is transferred from investors to captive ratepayers. Importantly, project risk is not limited to the development and construction period; if new generation assets are owned by a regulated utility, captive customers will also bear performance risk. While competitive companies need to optimize power plant and battery energy storage system (BESS) operations to generate a profit, utilities have no such requirement. Under the cost-of-service model, if a utility-owned asset were to underperform, or if operating expenses were to materially exceed their planned level, these costs would simply be passed along to ratepayers. Utilities are generally entitled to recoup their costs plus a regulated rate of return. Despite best efforts by DPS Staff, it is not always feasible for even a capable and well-resourced regulator to identify instances of imprudent costs, and it is rare for regulators to deny regulated utilities the right to recover such costs from ratepayers. Deregulation eliminates these risks for power plant development, construction, and operation, whereas UOG would bring them back.

### **NYSEG and RG&E: Self-Build Model**

NYSEG and RG&E's Self-Build proposal is the most pure form of UOG, under which regulated utilities would be authorized to construct, own and operate power plants under the cost-of-service model with a guaranteed rate of return. NYSEG and RG&E assert that the "model would enable utilities across the State to deliver additional renewable resources to the system quickly and cost-effectively by providing a stable and durable lane for projects that are feasible"<sup>2</sup> without providing any evidence that this model will deliver projects quickly or cost-effectively. In fact, in the next paragraph, NYSEG and RG&E note that their proposal would "apply the adaptability of the regulated cost-of-service model to building renewable resources even when external factors that have led to recent attrition would otherwise stall development."<sup>3</sup> This is a subtle way of saying that utilities will be able to continue building projects despite cost-overruns, potentially delivering projects at a significantly higher cost to ratepayers.

Importantly, the cost-of-service model *rewards* utility cost overruns; a perverse incentive that may already be contributing to higher-than-necessary delivery prices for New York ratepayers. If the Commission believes that external factors, such as import tariffs and inflation, are risks that should not be borne by clean energy project developers and IPPs and that should instead be borne by ratepayers to ensure project delivery, any such policy should apply uniformly to all projects, operationalized through NYSEDA procurement terms and incentive program designs. It would be inappropriate to provide utilities with the ability to profit from cost overruns on the backs of ratepayers in a regulated "lane" that is parallel to the existing competitive market, in which companies only profit if they can successfully manage their costs. This double standard will impose new risks on ratepayers who are already struggling under the utility cost-of-service model, undermine trust in the market, and chill development in the competitive market.

### **Risk Mitigation**

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<sup>2</sup> Case 15-E-0302. NYSEG and RG&E Comments on Utility Owned Generation. October 2025.

<sup>3</sup> Id.

The SSP's preferred approach is to limit ownership of renewables and energy storage to IPPs and utilities' unregulated affiliates, who bear project risk on the same terms as other market participants. If the Commission were nonetheless to authorize UOG through *regulated* utilities, the following guardrails would be essential – though no set of guardrails can fully protect ratepayers from the structural problems inherent to UOG:

- Requiring that utility shareholders bear 100% of cost overruns, to eliminate the perverse incentive for utilities to underbid for contracts only to recover cost increases from ratepayers over time.
- Prohibiting utilities from adding UOG to their rate base before achieving commercial operation, ensuring shareholders bear all development risk for projects that do not reach commercial operation.
- Appointing a shareholder-funded, DPS-employed project monitor to ensure all costs are properly attributed and that utility-owned projects do not receive preferential treatment in interconnection queues.
- Requiring that UOG projects follow the same interconnection rules as competitive projects, with no ability to jump the queue or avoid upgrade costs.
- Establishing performance-based compensation structures whereby utilities only achieve their target return if assets meet high performance benchmarks, shifting performance risk back to shareholders.

This *partial* list of necessary guardrails illustrates how challenging and ultimately impractical it would be to implement UOG in a manner that genuinely protects ratepayers. The simplest and most effective protection is to maintain existing rules limiting utility ownership of generation.

• What advantages and disadvantages would utilities face overall in terms of siting renewable projects that may not have been considered previously? Identify any potential shortcomings of the advantages described and any remedial action the utilities could take to address any disadvantages described.

The Indicated Utilities and others have argued that utilities possess unique advantages that would enable them to site and develop renewable and storage projects more effectively than private developers. The SSP respectfully disagree. Upon examination, each claimed advantage either applies equally to utilities' unregulated affiliates, constitutes an unfair information asymmetry that should be eliminated rather than institutionalized, or is better addressed through market-wide reforms. Meanwhile, the disadvantages utilities face in siting are real and would apply regardless of ownership structure.

- *Claimed advantage: Community perception.* Utilities argue that their preexisting relationships with municipalities would facilitate siting approvals. While utilities do have established community relationships, this advantage cuts both ways. At a time when members of the public are furious about utility rates that increase far faster than inflation, utility participation may be detrimental to community perception and siting outcomes. A project branded as utility-owned may face greater opposition, not less, in communities that associate the local utility with unaffordable rates. Further, any reputational and relational advantages would logically transfer to their unregulated affiliates, who are already authorized to develop clean energy projects on the

same terms as other market participants.

- *Claimed advantage: Electric system knowledge.* The Indicated Utilities argue that their deep knowledge of the transmission and distribution system would enable them to identify optimal locations for resource integration.<sup>4</sup> The SSP do not dispute that utilities possess valuable system knowledge. However, this is not a reasonable justification for UOG; it is a rationale for surfacing more granular data to clean energy developers so they can also identify these optimal locations and deliver projects using existing competitive and open constructs, such as NYSERDA’s REC procurement for large scale renewables (LSR) and the Value of Distributed Energy Resources (VDER) tariff for distribution-connected solar and energy storage. The Commission has long recognized that there is a trove of underutilized data regarding the electric system that could enable progress toward New York’s energy policy goals. In 2021, NYSERDA published a Charter for the Integrated Energy Data Resource (IEDR) Program, which states that “useful access to useful energy data is essential for achieving New York State’s policy goals to make its electricity system cleaner, more resilient, and more affordable.”<sup>5</sup> To the extent there is data regarding the electric system that could enable optimized resource integration and planning, this data should be made available to inform program and rate design as well as the Coordinated Grid Planning Process. The utilities’ unique knowledge of the system is not justification to allow them to leverage information asymmetry in order to participate in (and distort) the market; instead, it is an issue that should be addressed by increasing access to data through improved hosting capacity maps, transparent capital plans, and through smart improvements to rate design that help target DER deployment to locations where they provide the greater deferral value and deliver the greatest savings. Expanding data access would unlock the same siting benefits across the entire market, without distorting competition or exposing ratepayers to utility cost overruns.

Further, though utilities would have the most insight into where projects could be built at the lowest cost of grid integration, under a cost-of-service model, there is no inherent incentive for them to do so. In fact, utilities are rewarded for building more capital infrastructure on which they may earn a rate of return. Therefore, without additional safeguards, UOG may actually drive projects to locations requiring significant capital upgrades. Given that private developers currently bear the costs of interconnection upgrades, such a pattern could significantly increase costs to ratepayers.

- *Claimed advantage: Experience with project procurement and management.* The utilities have argued that their experience managing large capital projects is a development advantage. However, utility capital project management experience is primarily relating to transmission and distribution infrastructure – a fundamentally different undertaking from renewable energy and energy storage development. Notably, Con Edison’s Shared Solar Pilot Program illustrates this point; authorized by the Commission in 2017, the program was abandoned after four years and at least \$1.6 million in expenses without building a single project, citing common development

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<sup>4</sup> Case 15-E-0302. Indicated Utilities Initial Comments. October 2025.

<sup>5</sup> Case 20-M-0082.

challenges that private developers navigate routinely.<sup>6</sup> Utilities should not be learning development 101 lessons at ratepayers' expense, and Con Edison's failed Shared Solar Pilot Program should serve as a cautionary tale.

The most significant challenges currently facing renewable and energy storage projects relate to permitting and interconnection. Utility ownership does not resolve these challenges; utilities are subject to the same siting and approval processes as private developers, and rising interconnection costs are largely driven by outdated utility practices. The appropriate response is statewide permitting and interconnection reform that benefits all market participants, not a structural shift toward utility ownership that introduces new risks for ratepayers without solving the underlying problems.

• Identify the potential of a utility to exercise vertical or horizontal market power related, but not limited to: (a) property ownership adjacent or in close proximity to beneficial interconnection assets; (b) decisions to build or upgrade facilities that increase hosting capacity or otherwise grow its rate base; (c) impacts on the function or structure of earning adjustment mechanisms; or (d) other traditional utility functions maintained by a utility after the unbundling of generation.

There are myriad opportunities for a regulated utility to exercise vertical or horizontal market power to advantage their projects and maximize their profit while distorting the market and undermining competition. The risks of information asymmetry and inappropriate prioritization/self-dealing are most acute for distributed energy resources (DERs), where the utility company owns, operates and manages the distribution system. The SSP outlined several of these risks in our October 2025 comments in this proceeding, and we maintain that deregulation is the only structure that can truly protect ratepayers and other market participants from these risks. Key risks introduced by UOG include:

- *Control of the interconnection queue.* Utilities can exercise vertical market power through their control of the Standardized Interconnection Requirements (SIR) queue and study process for DERs connecting to their distribution system. If utilities are permitted to own distributed renewables and storage, they would have a direct financial incentive to prioritize interconnection studies, queue positions, and distribution upgrade work for their own projects while slow-walking or deprioritizing third-party DER projects. This risk cannot be eliminated through regulation because the utility's discretion over day-to-day queue management is not fully visible to regulators. This concern is particularly acute given current hosting capacity constraints currently imposed by Con Edison for distributed energy storage, where utility-owned projects could be favored over third-party developers.
- *Prioritization of upgrades that benefit utility-owned projects.* Utilities can accelerate and streamline construction of upgrades needed for their own projects, inherently deprioritizing distribution upgrades required for third-party projects. These factors are especially concerning where hosting capacity is limited, as is the case with the current state of the NY grid.
- *Manipulation of market signals.* Utilities that own energy storage would have the ability to dispatch resources at specific times and places in ways that manipulate market signals and suppress economics for competitive suppliers. Resources that are not formally operating in markets may nonetheless affect market economics, and utility-owned storage dispatched without

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<sup>6</sup> Case 16-E-0622. Consolidated Edison Company of New York, Inc.'s quarterly report for its Shared Solar Pilot Program for the first quarter of 2021. June 2021.

regard to market prices could distort price signals while passing any operating losses to ratepayers.

- *Hosting capacity asymmetry.* Utilities can exercise vertical market power through their control of hosting capacity information. Utilities possess granular, real-time knowledge of where capacity exists on their distribution system, which is critical for identifying optimal sites and dispatch schedules for distributed solar and storage. If permitted to own DERs, utilities could leverage this knowledge to site their own projects in optimal locations while having the incentive and ability to obscure or delay publication of that information to third-party developers.
- *Undermining of Earning Adjustment Mechanisms (EAMs).* EAMs are tools to incentivize utilities to act in the public interest by rewarding progress toward clean energy goals. However, if utilities are permitted to own renewables and storage, these mechanisms could create a perverse market power incentive: a utility could earn EAM rewards for deploying its own utility-owned clean energy resources while simultaneously undermining third-party clean energy projects that would otherwise compete with its own assets, such as by slow-walking interconnection studies or withholding hosting capacity information. This would allow the utility to leverage its control of the electric system to reduce competition, grow its rate base, and collect EAM rewards, all at ratepayer expense. The Commission should carefully consider whether EAMs designed to promote clean energy deployment could inadvertently reward utilities for undermining the market they are meant to support.

Utility-owned property adjacent to electrical infrastructure with favorable interconnection options represents an interesting opportunity for New York. In general, it is challenging to find well-suited land in close proximity to electric infrastructure with significant hosting capacity. These opportunities should be explored with the goal of maximizing ratepayer benefits and public policy goals. However, there is no justification for allowing UOG on such parcels, which would introduce numerous risks for ratepayers and the competitive market.

- How would the utilities provide certainty and transparency to ensure that their renewable energy project(s) are not unduly favored over other non-utility projects that are further along in the Standardized Interconnection Requirements queue and/or in a better position to be built more quickly?

If utilities were allowed to develop, construct and own DERs, they would have material competitive advantage over all other market participants due to information asymmetry and their ability to prioritize their own projects. Not only would allowing regulated utilities to build, own and operate DERs increase costs for ratepayers, introduce the risk of self-dealing and distort the market; it also won't solve any problems. New York has a vibrant DER market, and has achieved state policy goals, such as the Climate Act mandate to deploy six gigawatts of distributed solar by 2025, more than a year ahead of schedule. The major barriers to continued deployment are rising utility interconnection costs and permitting/siting constraints. The major barrier to maximizing the ratepayer benefit of DER deployment is out-of-date rate design for large DERs and the nascent nature of New York's Dynamic Load Management programs.

Utility ownership of DERs does not address any of these problems; permitting, interconnection and rate design reforms are the solutions to address emergent barriers to New York's most successful clean energy

sector. Any arguments that utility direct ownership is necessary to maximize the grid benefits of DERs are unconvincing and unsubstantiated.

The SSP support aligning incentives so utilities are financially successful when more clean distributed energy is deployed; however, we recommend this be accomplished through performance-based ratemaking rather than enabling utilities to build, own, and earn a guaranteed return on DERs, which would distort the market and not address any of the underlying barriers to DER development in NY.

While the SSP strongly oppose UOG, we believe that the Joint Utilities have a critical role to play enabling progress toward state energy policy goals. More than a decade ago, in the Reforming the Energy Vision (REV) proceeding, the Commission initiated New York utilities’ “transition from the historic model of a unidirectional electric system serving inelastic demand, to a dynamic model of a grid that encompasses both sides of the utility meter and relies increasingly on distributed resources and dynamic load management.”<sup>7</sup> This work is unfinished, and significant investments in grid modernization are necessary to unlock the multibillion dollar grid flexibility opportunity that New York recently quantified in the Grid of the Future proceeding.<sup>8</sup> The SSP support investments in expanding Supervisory Control and Data Acquisition (SCADA) coverage so utilities have foundational data necessary to optimize system operations. The SSP support investments in Distributed Energy Resource Management Systems (DERMS) that will enable flexible interconnection and virtual power plant (VPP) programs to operate at-scale. The SSP support proactive planning of the electric distribution system to ensure that investments today support the power system of tomorrow, and to consider DER resource integration in the planning process so investments can be right-sized and performance optimized.

In many respects, REV is unfinished business, and recent load growth and resource adequacy forecasts make it more urgent than ever for New York to advance these grid modernization efforts and lean into the concept of performance-based ratemaking that transitions utilities from “poles and wires” companies to true Distributed System Platforms. There are any number of companies capable of developing, owning and operating clean energy generators and BESS. However, only the regulated utilities are in a position to modernize the electric transmission and distribution system under their jurisdiction. Rather than diverting scarce utility resources to compete with the private market of solar and energy storage developers in New York, the SSP urge the Commission to direct the utilities to invest these resources into system modernization, which will address fundamental barriers to cost-effective clean energy integration that they are uniquely positioned to impact.

- Under the build transfer agreement scenarios presented in comments (Indicated Utilities), the utilities would conduct statewide joint competitive solicitations and then purchase projects after they are successfully completed by developers. How would the utilities ensure that such solicitations would be competitive, and what criteria would be applied to determine if the winning bids were competitive regarding price and other factors?

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<sup>7</sup> Case 14-M-0101. REV Order Adopting Regulatory Policy Framework and Implementation Plan. 2015.

<sup>8</sup> Case 24-E-0165. Brattle Group. New York’s Grid Flexibility Potential. Volume I: Summary Report. January 2025.

Before considering this proposal, the SSP encourage the Commission to consider what, if any, gap this proposal addresses in light of NYSERDA's annual REC procurements and New York Power Authority's recently expanded authority to develop, build and own clean energy assets.

For large-scale energy storage resources, the SSP believe that NYSERDA-run solicitations are generally a more effective way to create a competitive procurement process. NYSERDA's first bulk storage solicitation launched last year was met with robust developer interest and proposed investment. In contrast, the utility bulk storage procurements have not been as successful. Rather than creating a new utility procurement lane for build-transfer, the Commission should continue to reform and enhance NYSERDA's existing procurement program based on lessons learned from the first procurement.

For distributed energy resources, the SSP believe that a competitive marketplace under the VDER tariff is far more effective and scalable than individual bespoke procurements and contracts for each resource. The VDER tariff, coupled with NYSERDA's MW-Block incentive programs, have demonstrated that market-based approaches can mobilize private capital at scale, surpassing the State's 6 GW solar mandate more than a year ahead of schedule and generating significant investment in NYC's retail storage market. Utility-run solicitations for distributed resources are unlikely to be scalable, and would undermine the market frameworks that have made New York's distributed energy resource deployment so successful.

• In response to the questions posed in the July Notice, commenters suggested a Milestone-Based Transfer in which the purchase of the project would occur through a series of milestone-based payments where the developer would be responsible for obtaining the land, interconnection, permits, and developing the energy performance contract prior to the utility transfer, while the utility would be required to make payments at each development milestone. What safeguards could the utility put in place to ensure completion of the project or limit/eliminate risk to ratepayers while making the milestone payments under this model?

The only credible approach to protect ratepayers from the risk of stranded assets and cost overruns is to direct utilities to pursue any such proposal through their unregulated affiliates, who play by the same rules as other clean energy developers and independent power producers (IPPs) and who do not make bets with ratepayer dollars. This would preclude the possibility that such costs would ever be borne by ratepayers.

While the milestone-based transfer model attempts to limit utility risk by tying payments to development progress, it introduces new and serious risks for both ratepayers and developers. Developers who must shoulder early-stage costs without the prospect of long-term ownership will price that risk into their bids, increasing overall project costs for ratepayers and discouraging market participation, which is the opposite of the model's stated intent. The model also undermines the protections that New York's existing procurement framework provides to ratepayers. Today, private developers bear all development risk and are rewarded only upon successful project completion. A milestone-based transfer would expose ratepayers to incremental costs at each payment stage, with no guarantee of a completed project. If costs escalate beyond what a developer can absorb, the project could be abandoned entirely, leaving ratepayers holding the bill for a partially-developed asset with nothing to show for it.

- In its response to the questions posed in the July Notice, the Indicated Utilities (on page 20) stated that “the intermittency of large-scale renewables severely limits any market manipulation risk” and that if the utilities were to own co-sited energy storage in the future, “utilities would develop transparent operating rules in consultation with the Department of Public Service (DPS) that mitigate market power and that it would include rules that optimize providing value to the bulk power and transmission system rather than maximizing market revenues.” Specifically, prior to any DPS consultation, what criteria would be utilized to ensure that the operating rules would result in strategically optimizing the bulk power and transmission system rather than utility revenues.

Regardless of what operating rules are developed, utility-owned storage will affect market economics whether or not it formally participates in wholesale markets. Given that a primary driver for energy storage deployment involves shifting energy from periods of excess generation to periods of peak demand, utility-owned resources performing this function will suppress economics for competitive suppliers. If utility-owned storage operates without regard to market prices, utilities will simply pass any losses to ratepayers while distorting the market signals that private developers rely on to make investment decisions. No set of operating rules developed in consultation with DPS can fully resolve this structural problem.

Rather than creating an extensive regulatory framework to protect ratepayers from market manipulation enabled by utility-owned BESS, the SSP encourage DPS to instead consider what open market frameworks and tariffs could enable the private sector to deploy these same resources without introducing market manipulation risks, which could potentially hurt both ratepayers and generators.

- If Utility Owned generation were to be allowed, what approaches should be considered in order to optimally ensure projects are completed cost-effectively and timely. Identify the role competition should play, and how proposed approaches should be structured to leverage competition to arrive at least cost resources.

The SSP do not believe it is in the public interest for utilities to own generation or BESS. Deregulation fully protects ratepayers from exposure to financial risk associated with project development, construction, and operation. Expanding the scope of the utility’s cost-plus model to include generation and storage reintroduces this risk, as recent Con Edison energy storage projects illustrate. Con Edison’s Fox Hills BESS project (7.5 MW/30 MWh) was completed in 2023<sup>9</sup> at a total cost of \$36.9 million, representing a 69% budget overrun and an annual ratepayer cost approximately three times that of an equivalent privately-owned BESS project operating under the VDER framework.<sup>10</sup> The project then spent

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<sup>9</sup> ConEd 2024 T&D Spending Report (Case 22-E-0064).

<sup>10</sup> The total cost of the project was \$36.9 Mln (\$4,916/kW / \$1,226/kWh), which was 69% over budget resulting in an annual revenue requirement of \$966/kW-yr (based on an annual carrying charge loader of 19.66%. The annual ratepayer cost of \$966/kW-yr represents roughly 3 times the equivalent cost of a BESS project operating under the VDER framework in 2025. This was estimated using the carrying charge loader for substations from Marginal Cost of Service Study (Case 15-E-0751) with an adjustment to depreciation. According to the Embedded Cost of Service Study, “*The Substation function represents the fixed costs associated with Land and Land Rights, Structures and Improvements, Station Equipment, and Storage and Battery Distribution Equipment*”. (Case 25-E-0072, Exhibit \_\_\_(DAC-2), Page 7 of 130). Depreciation modified from 50 years for substation to 15 years based on recommendations in Depreciation Study, (Case 25-E-0072, Exhibit DP-1, page 68). However, Con Edison’s BQDM and REV demo projects are depreciated on a 10-year schedule. (Case 25-E-0072, Joint proposal, Annual

most of 2024 offline due to a design error requiring cable replacement at an additional cost of \$700,000,<sup>11</sup> during which time ratepayers continued to bear the full cost of the project with no grid benefit. Similar trends were observed at Con Edison's Brownsville BESS project, where costs ran 31% over budget and the total revenue requirement was approximately four times that of a comparable privately-owned BESS under the VDER tariff. Notably, the Joint Utilities are currently not required to report on the performance of their BESS assets, meaning ratepayers have no visibility into whether these investments are delivering value.

A major overhaul of utility ratemaking would be needed to mitigate this risk, and to restructure incentives such that the utility would profit from delivering projects on time and under budget, and lose money if the project was delayed and experienced cost overruns. However, this whole exercise would serve no functional purpose, as utilities can already develop, build and own generators and BESS through their unregulated affiliates following the same general rules as other market participants. Additionally, utilities already have the ability to contract for long-term BESS resources through the Utility Dispatch Rights (UDR) solicitation model, providing another avenue to access the benefits of energy storage without exposing ratepayers to the risks of the ratebased cost-of-service model.

### **Energy and Capacity Market Design:**

- In order to better align and improve existing clean energy procurement activities, including a potential utility owned generation approach, with the wholesale energy and capacity market mechanisms, what changes would be necessary with respect to: (1) Market Power Mitigation rules; (2) Bidding Requirements; (3) Capacity Auctions and Capacity Requirements; and (4) Other areas not included above?

While the SSP do not believe that a utility owned generation approach should be considered, as discussed above, we encourage the Commission to consider working with the NYISO to advance reforms to the wholesale energy and capacity market mechanisms that would improve deployment of energy storage.

*Market power mitigation rules.* The SSP support maintaining the current exemption from buyer-side mitigation (BSM) for competitively procured third-party renewable and storage projects, which bear full market risk and were selected through competitive processes. However, if utility-owned storage were to be authorized, BSM exemptions should be reconsidered for those resources. Utility-owned storage backed by ratepayer recovery could offer into capacity markets at artificially low prices, suppressing revenues for private developers and distorting the investment signals that drive new deployments.

*Capacity accreditation.* The SSP urge the NYISO to reconsider its marginal Effective Load Carrying Capacity (ELCC) methodology as applied to bulk energy storage. The current approach systematically undervalues the capacity contribution of installed energy storage, suppressing revenues while increasing financing costs and sending inaccurate price signals that distort investment decisions. The NYISO should

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Depreciation Rate and Life Table, page 231). A 10-year depreciation schedule would result in a carrying charge loader of 25.4%.

<sup>11</sup> Con Edison Report on 2024 Second Quarter Capital Expenditures (pages 28-31) (Case 22-E 0064), Con Edison Report on 2024 Capital Expenditures and 2025 - 2029 Electric Capital Forecast, (Case 22-E-0064).

move toward an accreditation methodology grounded in fleet performance, which would more accurately reflect the reliability contribution of energy storage and improve confidence in the market.

*Capacity auction design.* The NYISO's ICAP market currently clears on monthly and spot auction timescales, providing limited forward price visibility for developers who need multi-year revenue certainty to finance storage projects. The Commission should work with the NYISO to explore longer-term capacity commitment mechanisms. This would give storage developers greater financing certainty and reduce bid prices for State-procured resources.

*Real-time market participation.* The SSP encourage the NYISO to examine whether the current 75-min bid lock window for storage resources can be shortened. Storage is uniquely capable of rapid response to real-time price signals, and a lengthy bid lock window prevents operators from optimizing dispatch in a way that would benefit both project economics and system operations. Other ISOs, including MISO, use significantly shorter bid lock windows that provide operators with greater flexibility while maintaining grid reliability. Shortening the bid lock window for storage would better reflect the operational characteristics of these resources and improve their ability to maximize value to the system.

*Interconnection study assumptions.* Under FERC Order No. 2023, transmission providers are required to study storage resources using operating assumptions that reflect their proposed charging behavior rather than worst-case scenarios. However, this framework has not been extended to distribution-connected bulk storage projects below 100kV, which are instead studied using the unrealistic assumption that the battery charges at the peak hour. This assumption is driven by limitations in utility visibility, modeling capabilities, and operational controls, and results in inflated interconnection upgrade costs that undermine project economics and discourage private investment in resources that could provide significant reliability value. The SSP urge the Commission to direct utilities to develop plans to close this gap, bringing distribution-connected bulk storage interconnection study assumptions in line with the principles established under FERC Order 2023.

• Is an installed capacity product an effective price signal for resource adequacy given the required future generating resource mix? If not, what are potential approaches to ensuring resource adequacy and what would be the attending price signal?

The NYISO adopted a marginal Effective Load Carrying Capability (ELCC) methodology to determine the quantity of capacity a resource can offer into the market. Utilizing a marginal quantity does not accurately account for the capacity that resource provides and ascribes a value that is lower than the actual contribution of the fleet of resources. In addition to ascribing a reduced quantity of capacity to resources, using a marginal ELCC creates substantial risk in the market. A fleet of 4 GW of a resource might have an implied capacity quantity (UCAP) of 3.5GW but if the fleet is doubled to 8 GW the UCAP could drop to less than 3.5GW implying that the addition of resources is actually reducing reliability. This potential extreme reduction in the quantity of capacity a resource is compensated for creates high market risk. Markets generally do use marginal pricing, but it is important to recognize that the marginal ELCC methodology is utilizing a marginal quantity of product that is then combined with marginal pricing. The rationale for this approach was to steer new entry; however, its implementation is creating less than appropriate compensation and high risk and revenue uncertainty has resulted in the need for State

procurements to drive new entry. The SPP recommends that the state work with the NYISO to modify NYISO capacity market rules to accurately reflect the actual resource adequacy contribution of capacity market participants.

- Should alternative approaches be considered to ensure the procurement of generation resources is aligned with State policy goals. If so, which ones? Are there existing or proposed models which might be instructive, such as the State overseeing LSEs' resource adequacy portfolios (e.g., an approach similar to the one used by California) or restructuring New York Independent System Operator, Inc. rules to accommodate State policies?

The SSP believe that the most effective approach to aligning deployment of renewables and storage with State policy goals is to strengthen and reform existing competitive market frameworks, and ensure complementary procurement programs like the Index Storage Credit are adequately coordinated with the NYISO interconnection process, so as to reduce developer risk, improve project financeability and accelerate deployment. New York's competitive market has demonstrated its ability to mobilize private capital at scale; the priority should be removing barriers to that market and improving market rules to better reflect the operational characteristics and reliability contributions of new resources like energy storage.

New York already has the tools necessary to accelerate large-scale clean energy resource deployment. NYSERDA's centralized procurement program, NYPA's recently expanded authority, and a competitive wholesale market can together provide a comprehensive framework for deploying energy storage at scale. The market reforms discussed above would strengthen these existing frameworks without displacing the competitive dynamics that have served New York ratepayers well. Ultimately, the most impactful actions the State can take to accelerate deployment are not changes to utility ownership rules, but permitting and interconnection reforms that reduce development costs and timelines for all market participants.

- What is the State role with respect to resource adequacy matters that best serve New York's electricity customers with safe, adequate, and reliable service at just and reasonable rates in the context of State policies?

The State plays a critical role in ensuring that New York's electricity customers have safe, adequate and reliable service at just and reasonable rates, through a range of bodies including the Governor's Office, the Legislature, DPS, NYSERDA, NYPA, the DEC, and many others. As a general matter, the most equitable and cost-effective approach to add capacity is to leverage competitive markets and to build upon existing frameworks for procurement and rate design. If the Commission, in consultation with the NYISO and Joint Utilities believe there is a resource adequacy need that cannot be met with the current procurement and rate design structures, the SSP recommend that these structures be evaluated to determine how they can be improved to drive new resource addition. To the extent there are regulatory barriers to generator deployment that are under State control, such as unnecessarily high interconnection costs and DEC permitting constraints, the SSP recommend that the Commission work collaboratively with the Governor's Office and relevant state agencies to secure alignment and to address these barriers.

- What, if any, next steps should the Commission take with respect to potential wholesale or energy market reforms?

The Commission should prioritize working with the NYISO to advance the wholesale and energy market reforms discussed above. Beyond market design, permitting and interconnection reforms that reduce development costs and timelines for all market participants are essential. The State must invest in public communications and community engagement to combat misinformation about the need for renewable and energy storage projects and explain to local communities why these investments are critical for energy affordability and grid reliability.

### **III. Conclusion**

The SSP urge the Commission to preserve New York's competitive energy market structure. The record demonstrates that the competitive market has the capacity, expertise, and capital to meet New York's clean energy goals without the risks and costs that utility ownership of renewables and storage would impose on ratepayers. The barriers to deployment are significant but addressable through reform of permitting, interconnection, and market design, all of which would do more to accelerate clean energy deployment than expanding utility ownership.

The Commission's decision more than 25 years ago to restructure New York's energy markets was premised on competition bringing forth efficiencies, technical advancements, and savings that would be unlikely to occur as effectively without a competitive marketplace. The SSP urge the Commission to build upon that foundation rather than walk it back.

We appreciate the opportunity to comment on these matters.