STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission To Implement a Large-Scale Renewable Program and a Clean Energy Standard	)))	Case 15-E-0302

INDICATED UTILITIES' COMMENTS ON COMMISSION'S QUESTIONS REGARDING UTILITY OWNERSHIP OF RENEWABLE GENERATION

The Indicated Utilities of New York (Indicated Utilities)[1] are committed to maintaining a reliable and secure energy system and helping New York State achieve its generation transition objectives through an "all-hands-on-deck" approach that encourages greater deployment of instate generation from clean, renewable energy resources. To that end, the Indicated Utilities comment herein to the Public Service Commission's (Commission) Notice Soliciting Comments (Notice)[2] with responses on utility ownership of renewable generation, elaborating on their September 2024 and October 2025 proposals[3] for utility deployment of a limited amount of regulated large-scale renewable (RLSR)[4] resources to complement the State's broader renewable solution mix.

I. Executive Summary

Utility ownership of RLSR can accelerate deployment of and expand opportunities for competitively procured renewable energy development in New York State (the State) while saving customers money through long-term utility ownership. In prior comments,[5] the Indicated Utilities advanced a framework for utility ownership that includes:

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[1] The Indicated Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Niagara Mohawk Power Corporation d/b/a National Grid, and Orange & Rockland Utilities, Inc.

[2] Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard* (CES Proceeding), Notice Soliciting Comments (issued January 27, 2026).

[3] CES Proceeding, Joint Utilities' Initial Comments on the Department of Public Service Staff and New York State Energy Research and Development Authority Draft Clean Energy Standard Biennial Review (filed September 23, 2024) (September 2024 Utility Comments); CES Proceeding, Indicated Utilities' Initial Comments On Commission Questions Regarding Utility Ownership Of Renewable Generation And The Comprehensive Review Of Renewable Solicitation Practices (filed October 31, 2025) (October 2025 Utility Comments).

[4] Large-scale renewables refer to renewable generation, including wind and solar, of at least tens of megawatts (MW) in size, connected directly to the electric grid. This contrasts with smaller scale behind-the meter renewable generation, which the NY-Sun program has been successful in incentivizing, and which should continue to be developed and owned by third-party developers. CES Proceeding, September 2024 Utility Comments, p. 2.

[5] CES Proceeding, September 2024 Utility Comments and October 2025 Utility Comments.

- A separate procurement lane where utilities have an opportunity to jointly procure projects and own renewables via competitive solicitations;
- A proven business model that may attract additional renewable developers, bring in new capital to spur new projects, and add a stable, complementary path alongside other existing procurements;
- Regulated cost-of-service ownership model—with stable costs for customers underpinned by a Commission-approved capital structure and regulated returns—that has successfully and reliably delivered energy to customers for decades;
- Cost recovery and allocation using the State's existing framework of effectively allocating the net financial costs and benefits of renewable energy to utility supply customers statewide;[6] and
- An initial annual capacity solicitation of up to 1 gigawatt,[7] with an option for each utility to own a portion of RLSR projects based on a volumetric load share basis.[8]

This framework is consistent with the State Energy Plan,[9] which recognized that more must be done to add reliable, clean generation capacity to the State's electric system while being mindful of affordability.

Utility ownership of large-scale renewables benefits customers in several ways. First, utility ownership is cost competitive with third-party developer ownership. In fact, the net cost of utility-owned renewable generation is, under current market conditions, likely lower than that of third-party ownership over the life of the project. Second, competitive procurements—starting with build-transfer agreements that can incorporate milestone-based payments when in the interest of customers—balance risks, costs, and benefits to efficiently increase the timely deployment of renewable generation for the benefit of customers. Among available procurement structures, build-transfer agreements[10] are the appropriate starting point for RLSR procurements, as they offer the lowest risk-adjusted cost for the State's electric customers. Value-based milestone-based payments have the potential to reduce overall project costs by lowering

[6] The Indicated Utilities proposed RLSR program cost allocation and recovery mechanisms that would dovetail with existing regulatory frameworks. The revenue requirement would be determined by using the standard regulated utility cost of service model. Cost recovery would maintain the Commission's policy, presently implemented by the New York State Energy Research and Development Authority (NYSERDA) as the billing agent, of allocating the net financial costs or benefits of renewable energy to utility supply customers statewide (CES Proceeding, October 2025 Utility Comments, pp. 6-7, 12-16).

[7] The Indicated Utilities propose that the annual solicitation amount be adjustable in future RLSR phases. If the first phase proves successful—the utilities execute on cost-effective renewables that bring net benefits to the State's energy system—then the Commission could increase the maximum RLSR solicitation amount. The Commission could also consider an automatic increase based on RLSR success criteria.

[8] In a joint ownership approach, each utility would have an option to either own a share of each asset equivalent to its adjusted share of statewide volumetric load (participating utility) or to opt out (non-participating utility).

[9] 2025 New York State Energy Plan, available at https://energyplan.ny.gov/Plans/2025-Energy-Plan.

[10] A build-transfer agreement (sometimes referred to as a BTA) is a procurement structure under which a third-party developer develops and constructs a renewable generation project and transfers ownership of the completed project to a utility at commercial operation.

developer fees and encouraging bidder diversity. To further manage, mitigate and avoid risks for customers, the utilities would use contractual safeguards, due diligence, and a hands-on approach (leveraging utility's and developer's core capabilities) to facilitate successful and cost-effective project completion. Third, utilities could select projects in locations that maximize system benefits and minimize costs. Finally, market rules and controls would address market power concerns related to RLSR.

The Commission should adopt the Indicated Utilities' competitive, statewide procurement framework. The utilities would design solicitations to provide transparent price discovery and broader market intelligence by accommodating a range of bid structures, including single payment and milestone-based arrangements as well as individual project and portfolio-based submissions. Bid evaluation would emphasize minimizing total risk-adjusted cost to customers, project executability, optimizing electric system performance, and other criteria as appropriate. Evaluation criteria would be developed in consultation with Department of Public Service (DPS) Staff. Solicitations that allow for various bid structures (*e.g.,* single and milestone-based payments) would support competition while allowing procurement design to evolve with market conditions.

Under the proposed build-transfer agreement model, utilities would not site projects but could enhance electric system and community benefits by giving priority in procurements to locations that align with potential Clean Energy Zones referenced in the Clean Energy Standard Biennial Review,[11] with public transmission planning processes, including the Coordinated Grid Planning Process, or with areas with strong community support. Existing Commission requirements, New York Independent System Operator (NYISO) oversight, federal open access rules, and internal separation controls would effectively mitigate the exercise of vertical or horizontal market power,[12] including that utilities cannot favor their own RLSR projects in the interconnection queue. Finally, while the present focus is on renewable generation, if utility ownership of co-located energy storage became a possibility in the future, utilities would prioritize dispatch for system need, and market functions would be walled off from operational functions in accordance with existing rules, including FERC Standards of Conduct.

If the Commission were to approve the framework, the utilities would commence the following next steps:

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[11] CES Proceeding, Order Adopting Clean Energy Standard Biennial Review as Final and Making Other Findings (issued May 15, 2025), (CES Biennial Review Order), pp. 25, 66-68.

[12] Under NYISO rules, renewable generation resources are not subject to Buyer-Side Mitigation (*see* NYISO MST, 23.2.1 Att H Conduct Warranting Mitigation, definition of "*Excluded Facilities*" (*available at*: https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf); *see also New York Independent System Operator, Inc*., 179 FERC ¶ 61,102 (2022)). Intermittent renewable generation, by its nature, lacks the operational flexibility needed to influence market outcomes. NYISO's capacity accreditation and ICAP rules also significantly limit the ability of intermittent resources to affect capacity prices, further reducing any potential incentive or ability to exercise market power.

- Draft the Request for Proposal (RFP) and establish the specific criteria to evaluate projects and portfolios during the first solicitation (DPS Staff input on the RFP and associated evaluation criteria would provide for alignment with State goals and priorities);[13]
- Develop the necessary commercial agreements among them, detailing terms including, but not limited to protocols during the project selection process, operations and maintenance provisions, and ownership rights;
- Begin implementation of the proposed cost recovery and crediting mechanism (as outlined in the Indicated Utilities' September 2025 Comments);[14] and
- File an Implementation Plan in compliance with the Commission approved framework.

The Indicated Utilities estimate that following Commission approval, it would take no more than one year to complete these steps before issuing the first RFP.

II. Customer Impacts and Solicitation Competitiveness

Relevant questions:

- *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.*
- *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?*
- *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*

[13] The Indicated Utilities proposed procurement objectives and the role of the Commission states, "The Commission would define the overall strategic objectives and general utility procurement criteria and regulatory filings for implementation . . . . Prior to commencement of each procurement, the utilities would be directed to consult with DPS Staff to detail the specific evaluation criteria for each procurement that fit with the Commission's objectives" (CES Proceeding, October 2025 Utility Comments, p. 10). The Indicated Utilities proposed that individual solicitations be designed in consultation with DPS Staff to provide oversight while also allowing each solicitation to nimbly adjust to current market conditions.

[14] CES Proceeding, October 2025 Utility Comments, pp. 12-16.

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?

- *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.*

Utility ownership of RLSR could create cost savings for New York State utility customers compared to third party developer ownership under current market conditions. An independent study performed by The Brattle Group (Brattle) in 2024 (conducted at Con Edison's request) compared the customer costs of utility and third-party renewable ownership and found them to be comparable.[15] Con Edison recently updated several assumptions in Brattle's financial analysis to reflect today's market conditions. Updated results show the cost of utility ownership to be approximately five percent lower than third-party ownership on a levelized cost of electricity basis.[16]

Figure 1 shows net costs to New York State electric customers for an illustrative 100 megawatt (MW) solar project.[17] Utility ownership becomes the least cost option within three years (compared to third-party ownership), after a modest extra cost in the early years. Furthermore, utility ownership provides a large cost advantage in the later years of the project's life as the revenue requirement continues to decline as the asset depreciates. Utility ownership over the first twenty years of project life provides approximately $46 million in savings[18] for New York electric customers relative to third-party ownership.[19] Then, because utility ownership will continue in years 21-30, New York State electric customers will receive continuing and additional benefit of the renewable energy production. By contrast, the third-party developer's

[15] *See* The Brattle Group, *Utility Ownership of new renewables in New York State,* available at https://www.brattle.com/wp-content/uploads/2024/09/Utility-Ownership-of-New-Renewables-in-New-York-State.pdf (published September 20, 2024). Brattle's study analyzed the cost of wind and solar projects under utility cost-of-service and third-party ownership, with all non-financial variables held equal. Results showed that utility ownership ranged from approximately 5% more costly to 14% less costly, depending on the use of the Investment Tax Credit or Production Tax Credit, and if the asset is solar or wind generation.

[16] *See* Appendix. The levelized Cost of Electricity (LCOE) under utility ownership is $73.61 per megawatt-hour (MWh) compared $77.97 under developer ownership, or a difference of to $4.36 per MWh.

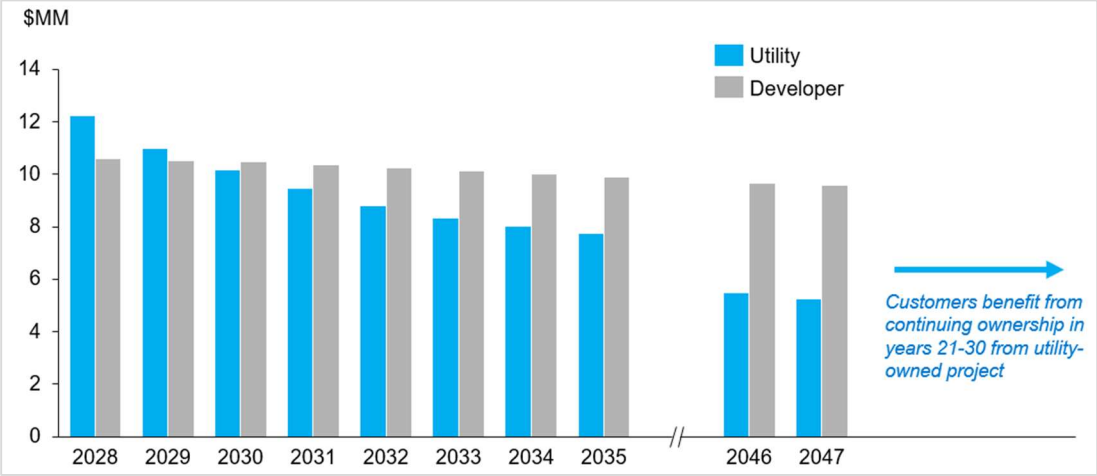
[17] Net costs for utility ownership are the annual revenue requirement minus wholesale market revenues. Net costs for developer ownership are the contract costs (annual sale of energy based on a return on net plant, depreciation, and operations and maintenance costs) minus wholesale market revenues.

[18] Utility ownership provides $27 million on a net present value (NPV) basis. The NPV uses the societal discount rate of 4.04%, per New York State Department of Environmental Conservation.

[19] This analysis models customer net costs over 30 years for utility ownership and 20 years for developer ownership. As of this filing, no renewable energy credit (REC) purchase contracts have been issued with terms greater than 20 years and there is no guarantee that the project RECs will remain in New York State years 21-30. See Appendix for a full description of updates.

Renewable Energy Credit (REC) agreement expires at the end of year 20 with no residual value remaining for customers.

Figure 1. Annual net impact (cost minus revenues) to New York State customers from illustrative 100 MW, $137 million solar project (customer cost in $ millions)



The Notice identified three procurement options for RLSR: build-transfer agreements, develop-transfer agreements, and self-build. Build-transfer agreements entail a third-party developer building a renewable generation project and then transferring ownership of the completed project to a utility at its commercial operation date. The Indicated Utilities are focused on build-transfer agreements. The develop-transfer agreements entail a third-party developer transferring a renewable generation project to a utility prior to completion, with the utility assuming responsibility for construction and project completion following the transfer. Under the self-build model, a utility develops, constructs, owns, and operates a renewable generation project, assuming responsibility for all stages of the project's development and execution. Utilities have tools under each option, including milestone-based payments, to manage cost and risk.[20]

Identifying financial impacts to customers involves assessing the costs and risks associated with each procurement option. Competitive solicitations will enable utilities to gain broad market insight and price discovery and carefully select projects or portfolios that provide the greatest benefits at the lowest cost. Cost consists of both the price customers pay for projects as well as the risks they assume. Like any project, renewable projects bear risks of cost overruns

[20] A milestone-based payment structure is a contractual payment approach under which a utility makes payments to a developer at predefined, verifiable stages of project development or construction rather than providing a single payment at project completion.

and the risk of non-completion (or non-completion risk).[21] When customers assume these risks, they are exposed to the potential for higher project costs. When developers assume these risks, they typically add risk premiums to the prices that customers ultimately pay for the project. These risk premiums can vary based on market conditions at the time of solicitation and contracting. The RLSR framework the Indicated Utilities propose is designed to provide the utilities with the necessary information and evaluation metrics for each RLSR solicitation to yield projects or portfolios structured to have the lowest risk-adjusted costs, *i.e.*, the best balance of the price customers will pay for projects with the level of risk they will bear. The Indicated Utilities intend to achieve this balance through careful assessment of market information pertaining to the developers and the competitive landscape in which they operate in combination with other factors such as the longer-term New York State energy system reliability needs and understanding of the communities where these projects are built.

A. Customer impacts of the RLSR procurement options

The main differentiator among the build-transfer agreement, develop-transfer agreement, and self-build options is timing of acquisition (*i.e.*, when during the development, construction, or completion phase the utilities take ownership). This is a key consideration in the price-risk balance.

Build-transfer agreements are the appropriate point of entry for utility ownership because they provide the lowest risk-adjusted cost for customers when compared to develop-transfer agreements and the self-build model. In the build-transfer agreements model the developer, not the utility, would develop the project all the way through commercial operation date, thereby bearing the development and construction risk. In this way, RLSR procurements would leverage the developer's market capabilities and experience.

Under a single-payment structure, customers avoid non-completion risk (since no payment is made until commercial operation date) as well as the risk of cost overruns outside any limited situations detailed in the build-transfer agreement's terms. The primary risk to customers of a build-transfer agreement is an incomplete project, *i.e.*, a project left unfinished by the developer. An incomplete project does not expose customers to financial risk directly associated with the project but would have cost the time spent by the utility RLSR team working on procuring and contracting with that project. However, this risk could potentially be mitigated by using contracts with step-in-rights that can provide a form of insurance and a path to project completion with a different developer.[22] With milestone-based payments in a build-transfer

[21] In the cost-of-service model, utility costs associated with RLSR would be recovered from New York State supply customers statewide. Details of the proposed cost recovery mechanism are available in the October 2025 Utility Comments (*See* CES Proceeding, October 2025 Utility Comments, pp. 12-16).

agreement, there is similar non-completion risk and potential financial risk, but utilities can mitigate the non-completion risk as described above and the financial risk by limiting milestone payments to not exceed the project value at each milestone (see next section II. B. Milestone-based payment-specific impacts).

The main financial impact to customers with build-transfer agreements is the development fee the developer prices into the project or portfolio cost. The developer fee, however, is counter-balanced by (a) the avoided risks discussed above, and (b) avoiding the costs and additional time of utilities creating a project development organization.

Procurement through develop-transfer agreements introduces execution risk, including construction related execution risk, for utilities and their customers compared to build-transfer agreements. By assuming construction responsibility under a develop-transfer agreement, utility customers would assume construction-related risks such as delays, non-completion, and cost overruns. While the utilities may evaluate the magnitude of such risks and consider mechanisms to manage them in develop-transfer agreements as they gain experience with RLSR, the utilities recommend the build-transfer agreement approach as currently appropriate due to both the reduced risk to customers and the reduced requirement or costs for internal development capability.

At this time, the Indicated Utilities are focused on build-transfer agreements and are not interested in a self-build model.

B. Milestone-based payment-specific impacts

Utilities could use milestone-based payments to reduce the costs of projects or portfolios with minimal additional risk. The main risk is that utilities would make milestone payments and then that the project would not be completed. However, utilities can mitigate this using standard contract terms such as step-in rights, liquidated damages, and claw-backs.[23] Contracts would set clear, objective, measurable, and verifiable milestones[24] to mitigate risk of disputes about milestone achievement. Furthermore, utilities would limit payments not to exceed the value of the project at that milestone, including holding a significant portion of the payment until commercial operation date. This would prevent incurring excess costs in the event of a developer default that requires a replacement developer to complete the project.

Milestone-based payments also may have a positive financial impact on customers. A milestone-based payment structure mitigates developer risk by contributing to developer capital needs throughout the project, while mitigating utility risks because milestone completion is an

[22] The need to complete the project with a different developer may arise in the event of a significant delay, roadblock, or developer insolvency hindering project completion.
[23] See Section II. C for more information on contractual terms.
[24] Examples of clear milestones include executed interconnection agreements or binding equipment contracts.

indication that key project execution risks are being eliminated. Contributing utility capital while carefully mitigating project risks minimizes the need for financing from a third party for the full duration through commercial operation date and reduces cashflow risk for the developer. Thus, using utility capital in place of developer capital once key project risks have been eliminated may lower total project cost, potentially reducing the developer fee and providing lower financing costs (since utilities generally have lower cost of capital). Additionally, lower risk for developers with milestone payments may broaden developer interest in RLSR procurements, which would bring more renewable projects and developers to the State and increase competition (which could have secondary cost benefits).

If milestone payments are employed for RLSR procurements, the Indicated Utilities would follow the practice of traditional utility capital projects where expenditures incurred prior to a project's in-service date typically receive Allowance for Funds Used During Construction (AFUDC). Considering that utilities may make milestone payments prior to the full transfer of ownership of the assets to the utility, such payments would be accorded regulatory asset treatment based on the Commission-approved AFUDC rate applicable to the respective utility until ownership transfers. Upon transfer of ownership and placement of the facilities into service, the cumulative balance of the regulatory assets would be transferred to plant in service and recovered, consistent with standard ratemaking mechanisms.

On balance, while milestone payments do have a cost to customers, the Indicated Utilities would pursue this structure (a) when benefits described above are anticipated to outweigh those costs and (b) in consultation with DPS Staff.

C. General methods to address risks and customer impacts

There are several measures that utilities can use to mitigate, manage, and avoid risks that are broadly applicable across build-transfer agreement and develop-transfer agreement procurement options.

First, contract terms can further allocate risk between parties. Utilities would implement robust contract protections to mitigate risks of both non-completion and cost-overruns. Contract terms could include the following:

- Requirements for security, such as letters of credit and/or security agreements
- Seller performance obligations with penalties to address shortfalls, such as claw-backs and liquidated damages;
- Payment schedules that align with project progress and include holdbacks;
- Detailed default provisions and default and termination related liquidated damages;
- Detailed insurance and indemnification provisions;

- Step-in-rights, enabling the utility to take control of a project before completion to find another developer to complete the project; and
- Limited allowances for price adjustments, including indexed pricing for select materials to account for global energy market and supply chain uncertainty (with potentially symmetrical indexing).[25]

Contract terms such as these are often standard in utility build-transfer agreements in other jurisdictions.[26] Thus, developers (and, if applicable, their capital providers) working with utilities in New York or around the country may already be accustomed to them.

Second, utilities would undertake a thorough due diligence review of developers and material elements of their projects to avoid selecting riskier project developers and to mitigate and manage risks for selected projects. Vetting developers would identify credit worthy partners with track records of renewable development success. Utilities would require access to detailed project information, including costs, timelines, and risk management plans, as well as inspection rights and the right to various representations, warranties, covenants and pre-closing conditions in the build-transfer agreement that minimize customer risk. Due diligence will provide transparency to the Commission and DPS Staff, with whom utilities could share information.

Third, a portfolio approach to RLSR procurement would provide benefits to customers. Procuring portfolios—*e.g.*, multiple projects with a single developer—could help manage non-completion risk by dampening the impact of an incomplete project (in terms of deploying less renewable generation and in terms of cost).[27] Competitively procured and appropriately diversified portfolios can also mitigate execution and financial risk while taking advantages of economies of scale that the developer can bring. Finally, a portfolio of projects could reduce

[25] CES Proceeding, October 2025 Utility Comments, p.18, "For example, utility BTA [build transfer agreement] contracts would circumscribe opportunity for developer price adjustments. Utilities would implement adjustment thresholds and confidential bid ceilings in consultation with DPS Staff, use relevant indices to scrutinize costs, and require developers to share their financials [when requesting a price increase] to demonstrate that their specific project prices increased, not just that a relevant index or interest rate rose."

[26] Other utilities include commercial terms in their build-transfer agreements. These include Evergy (available at https://www.evergy.com/-/media/documents/smart-energy/rfp/evergy-wind-rfp-issued-oct-2021-10-18-2021.pdf and https://www.evergy.com/-/media/documents/smart-energy/rfp/evergy-bta-apa-principal-terms.pdf), Portland General Electric (available at https://portlandgeneral.com/about/who-we-are/resource-planning/procuring-clean-energy), Nevada Energy (available at https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/doing-business-with-us/energy-supply-rfps/2024-AS-RFP-Protocol-rev-1.pdf), Consumers Energy (available at https://www.consumersenergy.com/-/media/CE/Documents/residential/renewable-energy/electric-power-notices/ceco-2022-vgp-rfp-appendix-d3-build-transfer-agreement-bta-term-sheet.ashx), DTE (available at https://dtee-irp-2025allsourcerfp.com), Entergy (available at https://rfp.entergy.com/ENTRFP/SEND/2022ELLRenewablesRFP/Documents/Appendix%20B-1%20(BOT%20Agreement).pdf), and Xcel (available at https://www.prod2.xcelenergy.com/company/rates_and_regulations/resource_plans/sps_2025_rfp).

[27] As discussed earlier in Section II. A, the cost of non-complete project to customers is only the cost of the RLSR team's time.

developer fees associated with procured projects by spreading some fixed common costs over a larger pool of assets.

D. The role of competition for cost-effective and timely project completion

Competitive procurements of RLSR projects from third party developers would support additional cost-effective renewable projects to the State. The utilities will structure each competitive solicitation to gather the necessary market information to determine the procurement model (*e.g.* build-transfer agreement, build-transfer agreement with milestone payments, *etc.*) that optimally balances both customer risk and customer cost based on a set of criteria developed by the utilities in consultation with DPS Staff. Intelligence would include leveraging experience and knowledge from public sources[28] and use of other tools available to utilities, such as market research, developer outreach, and hosting of developer forums, to inform a competitive solicitation design to draw the most interest and participation from multiple developers. The RFP would leverage these insights to request bids under a defined set of commercial structures (*e.g.,* fixed pricing or indexed pricing, and cash flow preferences such as lump sum payments at project completion or milestone payments) to obtain an accurate assessment of the tradeoffs between lower project cost and lower risk under the then existing market conditions. The solicitation would then utilize evaluation criteria that select projects with the lowest risk-adjusted cost to customers.

The bid evaluations would use system specific, economic, and non-economic criteria determined in consultation with DPS Staff. Economic criteria would include an assessment of the net cost to customers, allowing for a quantitative comparison between bids. The net cost would account for expected capital and operations and maintenance costs as well as financial benefits that include projected wholesale market revenues. Electric system and other non-economic criteria would assess customer risk and qualitative customer benefits. Potential system specific and non-economic criteria could include the following:

- Locational benefits (*e.g.*, within a Clean Energy Zone or integrated with Coordinated Grid Planning Process investments)
- Long-term reliability benefits to the State energy system
- Level of customer protections and/or risk (*e.g.*, fixed prices vs. cost adjustors; lump sum vs. milestone payments), including evaluation of the project risk management plan
- Developer financial health (*e.g.*, creditworthiness, cash flow)
- Engineering, Procurement, and Construction (EPC) firm financial health

[28] Including but not limited to NYSERDA, U.S. Energy Information Administration, and National Laboratory of the Rockies, which publish renewable energy project costs.

- Developer and EPC experience, including a preference for State or regional experience
- The current stage of project development
- The expected length of construction time, expected project completion date, and credibility of bid
- Estimated curtailment (both of the subject renewable generation project and of existing renewable projects)
- Consideration of any other Public Service Commission and New York State guidance and policy published prior to the receipt of bids.

Subject to Commission-established objectives and overarching criteria,[29] the Indicated Utilities propose that solicitations be flexible to allow modifications to the specific criteria and scoring values used in individual procurements. Utilities would consult with DPS Staff to finalize these criteria and, for each procurement, determine the specific values or weights depending on market conditions at the time.

Under all procurement structures, Utilities would take a hands-on approach to facilitate timely project completion. With detailed information and engagement throughout the project cycle, developers and utilities can work together to identify and address project challenges proactively. Project progress would benefit from utilities' core capabilities such as project management, equipment procurement (including leveraging long-standing procurement relationships with existing suppliers—for equipment such as for transformers, wire and cable—and establishing new ones that could potentially assist with supply chain constraints), permitting, and relationships with local communities and authorities.[30]

III. Siting

Relevant question:

- *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.*

Under the build-transfer agreement approach, utilities would generally not be responsible for siting projects but rather would procure projects for which a third-party developer has already selected a location. Nonetheless, RLSR procurements could include locational preferences in the evaluation and selection process.

[29] CES Proceeding, October 2025 Utility Comments, p. 10.
[30] CES Proceeding, September 2024 Utility Comments, pp. 11-12; CES Proceeding, October 2025 Utility Comments, pp. 5-6, 18-19.

Including locational preferences in RLSR procurements would allow utilities to prioritize sites that bring system benefits or otherwise align with the State's priorities and are in the best interests of customers. The project selection process could align with public plans for the electric system, for example, by prioritizing projects in Clean Energy Zones (if created), in areas with stronger community support, or in areas with headroom created through the Coordinated Grid Planning Process. Prospective RLSR projects could also be evaluated to minimize nodal or zonal renewable energy curtailment over the project lifetime. A holistic approach to assessing curtailment would promote selection of projects that minimize curtailment, maximizing the renewable energy flowing into the State energy system overall. Utilities could also review projects across their prospective renewable portfolio to consider opportunities to optimize the sizes of interconnections and minimize the total cost of upgrades across all projects together. Other system benefit criteria could be added in consultation with DPS Staff.

A potential shortcoming of the utilities' siting advantage is that prioritizing system benefits may lead to preferencing sites that do not solely maximize wholesale market revenues. Utilities could remedy this by valuing economic, system, and non-economic criteria as discussed above. Trade-offs would be transparent and RLSR would seek to provide the greatest overall benefits to the State's electric customers.

IV. Potential for Market Power

Relevant question:

- *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.*

Existing Commission requirements, NYISO operational control, federal open access rules, and utility codes of conduct protect against utilities exercising vertical or horizontal market power in connection with utility-owned RLSR. These protections were designed to address information asymmetries, planning discretion, and the separation of regulated monopoly functions from competitive activities and remain fully effective here.

A. Property Ownership

The Indicated Utilities do not expect to rely on utility-owned land for RLSR deployment. First, under the proposed build-transfer agreement procurement approach, utilities would be procuring projects from third-party developers that have already selected locations. Second, land already owned by utilities is prioritized for transmission and distribution needs and core system

functions. Interconnection is governed by transparent state and federally-approved non-discrimination rules that apply uniformly to all developers. Utilities do not have exclusive control over bulk-system transmission planning, interconnection queue administration, or network upgrade determinations, all of which are administered by NYISO under its Tariff. Accordingly, utilities lack the ability to leverage property ownership or interconnection proximity for competitive advantage given current market rules and the proposed RLSR procurement approach.

B. Decisions to Build or Upgrade Facilities

RLSR would be procured through a competitive process that evaluates project benefits and costs in a transparent manner based on pre-set criteria determined in consultation with DPS Staff under a framework approved by the Commission. RLSR framework attributes—competition, transparency, and regulatory oversight—will serve to verify that selected projects are meritorious.[31] Further, there already is adequate transparency in decisions to build or upgrade facilities because all interconnection cost estimates for selected projects would already be determined before the utility procures the project and would be disclosed.[32] Because RLSR procurement would require projects that have completed the NYISO interconnection studies and finalized all local and network system upgrade studies, the upgrade obligations associated with a project are fixed before procurement occurs and interconnection and upgrade costs are known. This structure further reduces a utility's ability to influence, expand, or otherwise shape upgrade requirements through its role in a project.

Finally, project siting priorities would be developed in consultation with DPS Staff and consider outputs from the Coordinated Grid Planning Process. For example, if the Coordinated Grid Planning Process has public plans to invest in renewable-enabling system upgrades in a certain region, the RLSR procurement could prioritize that region. This would direct RLSR bids toward locations where planned upgrades already exist, when possible.

C. Impacts on Earnings Adjustment Mechanisms

Utility ownership of RLSR does not interact with earning adjustment mechanisms in a manner that could create market power incentives. Existing earnings adjustment mechanisms do not reward utility ownership or operation of renewable generation.[33] RLSR would be developed

[31] CES Proceeding, Notice Soliciting Comments (issued January 27, 2026).

[32] A summary of interconnection costs is available at the end of the NYISO Phase 1 study.

[33] Orange & Rockland's current rate plan—Case 24-E-0060, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service,* Order Adopting Terms of a Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 20, 2025) — includes an earnings adjustment mechanism (EAM) that targets deployments of distributed energy resources like solar. However, the scope of that EAM is projects less than or equal to 5 MW that are installed and owned by third parties, not the utility. Thus, there is no potential interaction between this EAM and RLSR.

under cost-of-service regulation, with all net wholesale revenues credited to customers, rendering utilities economically indifferent to wholesale price outcomes.

D. Other Traditional Utility Functions

As stated in the Indicated Utilities' October 2025 Comments, utilities maintain existing physical, process, and technology controls, and they remain subject to codes of conduct, functional separation requirements, and Commission oversight.[34] Furthermore, the utilities' bulk facilities remain subject to NYISO operational control. Each of these controls protect against the exercise of undue discrimination or undue preference in competitive activities. The Commission has previously determined that vertical market power concerns associated with utility-affiliated generation can be sufficiently mitigated through established protections, and it has approved such arrangements;[35] similar protections would apply in the RLSR context. In addition, intermittent renewable resources lack the operational characteristics necessary to exercise horizontal market power.

Taken together, the existing Commission-mandated separation requirements, NYISO operational control, competitive procurement design, cost-of-service treatment, and federal open-access rules eliminate any material market power concern associated with RLSR.

V. Interconnection Queue Management

In the RLSR framework, there will be no opportunity for utilities pursuing build-transfer agreements to favor RLSR projects over other projects in the State's Standardized Interconnection Requirements (SIR), utility, or NYISO interconnection processes.

The SIR applies to new DER projects 5 MW and below on the utility distribution system. The utilities seek to develop RLSR projects significantly larger than those that qualify for the SIR process. Because RLSR projects would not be in the SIR queue, there is no possibility of utility favoritism.

For projects proceeding through the NYISO interconnection process and/or the utilities' tariff-based distribution-level interconnection process, the utilities will adhere to controls to prevent any undue preferential treatment during study support. For example, utility employees

[34] CES Proceeding, October 2025 Utility Comments, pp. 19-23.

[35] *See, e.g.*, Case 25-E-0194, *Petition of National Grid Generation LLC for a Declaratory Ruling Regarding the Ownership and Operation of the West Babylon Generation Station*, Order Directing Filings and Making Other Findings (issued October 22, 2025); Case 21-E-0303, *Petition of National Grid PLC and NGV Ventures Emerald, LLC for a Declaratory Ruling Regarding Ownership of a 50 Percent Upstream Interest in the Calverton Solar Project*, Declaratory Ruling on Generation Ownership and Making Other Findings (Issued September 10, 2021); Case 10-E-0497, *Joint Petition of Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Consolidated Edison Solutions, Inc. and Consolidated Edison Development, Inc., Regarding the Development of Renewable Energy Projects owned by the CEI Affiliates*, Declaratory Ruling on the Development of Renewable Generation Facilities and Order Establishing Filing Requirements (issued February 23, 2011).

who support interconnection studies will be prevented from accessing non-public information – including information that indicates whether a particular project has bid into or is under consideration in a RLSR procurement. In addition, in the build-transfer agreement approach utilities would not execute a contract until the developer has completed the study process, thereby eliminating the potential for utilities to have an early informational advantage relative to third-party developers.

Ultimately, the utilities will operate within the confines of confidentiality, including having walled-off procedures such that personnel evaluating potential utility projects do not interact with, or disclose information to, employees providing support to interconnection studies. These internal controls complement the NYISO's own interconnection procedures, which are standardized, FERC-approved, and subject to NYISO oversight, providing a transparent and interest-neutral framework for all market participants. Further, the Commission's existing oversight of utility procurement and planning provides an additional safeguard that utilities cannot favor their own future projects.

Together, these strict measures help ensure that potential utility-owned renewable projects proceed through applicable interconnection processes on an equal basis as third-party owned projects.

VI. Energy Storage

Relevant PSC questions:

- *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.*

The Indicated Utilities are interested in the creation of a pathway for utilities to procure, own, and operate RLSR to promote increased renewable generation deployment in a manner beneficial to customers. Energy Storage is not a focus area of the Indicated Utilities' comments.[36]

But, if, in the future, there is a circumstance where a utility owns (or has the opportunity to own) storage that is co-located with renewable generation connected to the transmission

[36] Transmission & distribution energy storage use cases are a subject in Case 18-E-0130, *In the Matter of Energy Storage Deployment Program*.

system, the Indicated Utilities would use transparent criteria for selecting energy storage locations and for operational protocols that prioritize energy system reliability and customer benefits. When operating in the NYISO market, co-located storage and RLSR projects would be subject to NYISO's independent operational control and security constrained dispatch. Further, the energy storage asset would, if and when needed by the transmission operator, be dispatched to meet the needs of the transmission system. Such energy storage assets would be operated to respond to the transmission system operational need, regardless of the impact on wholesale market revenues.

To create additional transparency, utilities could establish a storage operations manual that is available for review. The manual would define criteria and protocols for dispatch and could include priorities such as:

- Minimizing renewable curtailment
- Responding to certain contingencies (*e.g.*, equipment out of service or a transmission line operating too close to its operating limit)
- Providing reliability value

Moreover, protocols and market functions would be walled off from operational functions in accordance with existing rules, including FERC Standards of Conduct.

In any event, because utilities would operate RLSR under a cost-of-service model, they would seek first to serve transmission system needs prior to generating wholesale market revenues.

VII. Energy and Capacity Market Design

The Indicated Utilities' proposed model of procuring RLSR is compatible with existing energy and capacity market mechanisms. No changes would be needed with respect to market power mitigation rules, bidding requirements, capacity auctions and capacity requirements, or other areas. The full responses by Indicated Utilities, made jointly with New York Transmission Owners, to the Energy and Capacity Market Design questions from the Notice are filed separately.

VIII. Conclusion

The Indicated Utilities are committed to the stability and long-term health of the State's energy system and the communities they serve, maintaining a reliable and secure energy system and helping the State achieve its clean energy goals in a cost-efficient manner. The Commission should determine that utility ownership of regulated large-scale renewables is consistent with Commission policies and brings benefits to the State. Indeed, the proposed RLSR framework

will enable and accelerate the cost-effective deployment of the significant volume of clean energy generation resources that will be needed to meet State objectives. Commission approval would allow the Indicated Utilities to begin next steps to implement RLSR,[37] including developing: commercial agreements, cost allocation and recovery mechanisms, a request for proposals, and an implementation plan that will be filed with the Commission.

Dated: April 24, 2026

Respectfully submitted,

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[37] The Indicated Utilities expect these next steps would take no more than one year to complete.

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APPENDIX: Updates to study by The Brattle Group

A study performed by The Brattle Group (Brattle) in 2024 (conducted at the request of Con Edison) compared the customer costs of utility renewable ownership and developer ownership and found them to be comparable.

Con Edison recently updated several assumptions in Brattle's financial analysis to reflect today's market conditions. These updates included

1. Removal of the Investment Tax Credit (ITC), which terminates at the end of 2027
2. Updating developer and utility costs of capital to reflect current market conditions (utility financing costs have become relatively lower)
3. Adding developer debt origination costs and breaking these costs out for Con Edison as a line item separate from its rate plan cost of debt
4. Greater and/or full discounting of the terminal value of the asset post-Renewable Energy Credit (REC) purchase agreement

The impact of each of these updates is detailed in Figure 2. Details on the rationale for each update are available in Figure 3 and 4 at the end of this appendix.

Figure 2: Cumulative Revisions and Results of Solar Levelized Cost of Electricity (LCOE) to customers ($ per MWh)

Cumulative Results

Assumption	Brattle Value	Revision	Utility	Developer Owner	Developer Owner Delta
Base Case (Brattle 2024 results)			$60.71	$58.43	(-) $2.28
1 ITC	30%	0%	$72.43	$70.33	(-) $2.10
2 Higher Developer WACC[1]	6.99%	8.25%	$72.43	$75.87	(+) $3.44
2 Higher Utility WACC[1, 2]	6.75%	7.03%	$73.54	$75.87	(+) $2.33
3 Effective WACC with Developer Debt Origination Costs of 1.50%	NA	8.40%	$73.54	$76.39	(+) $2.85
3 Effective WACC with Utility Debt Origination Costs of 1.01%	NA	7.05%	$73.61	$76.39	(+) $2.78
4 Modified Discount for TV	7.72%	*See below*	$73.61	*see below*	(+) $3.51 - $4.36
4a *Higher Discount for TV*	*7.72%*	***10.50%***	***$73.61***	***$77.12***	***(+) $3.51***
4b *Full Discount for TV*	*7.72%*	***Discount fully***	***$73.61***	***$77.97***	***(+) $4.36***

1 Not including debt origination fees and Without tax shield of debt

2 4.46% debt and 9.25% ROE revised to 4.90% debt and 9.40% ROE

The removal of the ITC is necessary due to federal tax policy changes enacted in 2025. Wind and solar projects that begin construction after July 4, 2026 need to be placed into service by December 31, 2027 to access the ITC. Given RLSR is not yet authorized, it can be assumed that RLSR projects would begin construction after this cutoff. While the ITC expiry impacts both developer ownership and utility-ownership, the net impact is worse for developers because

utilities were at a disadvantage with the ITC due to challenges passing the tax credit as a benefit to utility customers.

The cost of capital has also increased for developer-owners more than it has for utilities. The sharply curtailed role of tax equity from the ITC phaseout decreased the supply of capital for developer ownership, increasing their cost of capital. Broadly, negative policies and actions at the federal level are also creating challenges for clean energy projects that increase developer and investor risk premiums. Developer capital costs are also higher due to higher equity requirements than modeled in the Brattle analysis. Con Edison has updated these values in line with ranges from Lazard's 2025 levelized cost of electricity report. [38]

The utility rate plan cost of debt used in Brattle's analysis included the cost of utility debt issuances. But the analysis scope did not include these costs for developer ownership. Con Edison updated the analysis to add this to the developer-owner costs and, for clarity, to separate them into their own line item in the utility costs. Debt issuance costs are lower for the utility than the developer-owner because the utility raises debt at scale using highly rated investment grade corporate bonds.

Furthermore, Con Edison also updated the developer-owner cost of capital for discounting project revenues after the expiration of a Tier 1 REC contract. The low end of the range is discounting at the developer owner's cost of equity, recognizing that at this point in the project's lifecycle all debt will have been paid off and only equity will remain. The high end of the range is fully discounting these post-contract cash flows, recognizing that many developers and investors fully discount these uncertain revenues when determining strike price of a REC purchase agreement.[39]

With these updates taken together, the LCOE for a solar project under utility ownership is $4.36 per MW lower than the LCOE under developer ownership ($73.61 vs. $77.97). Table 1 shows the translation of this LCOE difference into the difference in total customer cost over a 30-year project life for a 100 MW solar project. [40]

[38] Lazard, "Lazard's Levelized Cost of Energy+ (LCOE+)" available at https://www.lazard.com/research-insights/levelized-cost-of-energyplus-lcoeplus/

[39] The model assumes a 20-year REC contract life. Con Edison did not modify this assumption, as NYSERDA has not issued any Tier 1 REC contracts for terms greater than 20 years as of the time of this filing.

[40] For comparative purposes, this analysis models customer net costs over the full asset life of 30 years and makes the simplifying assumption that the developer-owner has a 30-year REC purchase contract. As of this filing, no REC purchase contracts have been issued with terms greater than 20 years and there is no guarantee that the project RECs will remain in NYS years 21-30. See appendix for a full description of updates.

Table 1: Total cost to New York State electricity customers ($ millions) of an illustrative 100 MW, $137 million solar project over 20 years

	Nominal	Net Present Value[41]
Utility	$154	$110
Developer	$200	$137
Delta	*- $ 46*	*- $ 27*

Note: because utility ownership will continue in years 21-30, New York State electric customers will receive continuing and additional benefit. By contrast, the third-party developer's Renewable Energy Credit (REC) agreement expires at the end of year 20 with no residual value remaining for customers.

Figure 3. Major Financial Assumptions for Developer

	Category	Brattle Assumption	Commentary	Assumption update
1	ITC	30%	Phased out	0%
2	WACC	6.99% (without tax shield)	Brattle original assumptions (based on NREL) were not what was being experienced in market (too low a WACC and debt rate, too high debt)	8.25%; 8.40% incl. 1.5% debt orig. fee (8-9% without tax shield per market feedback & Lazard 2025 LCOE report)[1]
	Debt/Equity	75%/25%		60%/40% per market feedback & Lazard LCOE
	Debt Rate	5.58%		6.75% (6-8% per market feedback & Lazard LCOE)
	Equity Rate	11.23% (Implied)		10.50% (10-12% per market feedback & Lazard LCOE)
3	Debt origination costs	None	Brattle analysis did not model this next level of detail impacting developer pricing	1.25-1.75% of loan value per market feedback
4	Terminal value – Yrs. 21-30	Discount 7.72%	Brattle assumption incorporating higher post-contract WACC	At a minimum, use ROE as discount rate (capital structure has no debt at year 21.) Also, per market feedback, many project owners entirely discount post-PPA revenue

Impact on relative attractiveness of utility vs. developer-owner economics
Favorable Unfavorable

1 https://www.lazard.com/research-insights/levelized-cost-of-energyplus-lcoeplus . Lazard numbers restated to remove debt tax shield

[41] The net present value (NPV) uses the societal discount rate of 4.04%, per New York State Department of Environmental Conservation.

Figure 4. Major Financial Assumptions for Utility

	Category	Brattle Assumption	Commentary	Assumption update
1	ITC	30% with utility accounting treatment	Phased out	0%. However, this removes accounting disadvantage utility had in passing tax credit as benefit to customers
2	WACC	6.75% (without tax shield)	Last rate plan	7.05% (without tax shield; includes debt origination fees of 1.01%) per Con Edison rate plan RY2
	Debt/Equity	52%/48%	Last rate plan	No change in latest rate plan
	Debt Rate	4.46%		4.90% per Con Edison rate plan RY2
	Equity Rate	9.25%		9.40% per Con Edison rate plan RY2
3	Debt origination costs	None	Already part of rate plan debt interest rate	Broken out for analysis
	WACC – Yrs. 21-30 (terminal Value)	N/A	Utility holds full lifetime on behalf of customers	

Impact on relative attractiveness of utility vs. developer-owner economics

Favorable Unfavorable