Consolidated Edison Company of New York, Inc.

New York City
Reliability Contingency Plan

<u>FILED: JULY 17, 2026</u>

<u>CASE 25-E-0764</u>

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1. Executive Summary

Introduction and Procedural History

Providing safe and reliable electric service is one of Con Edison's (the Company's) core responsibilities under the Public Service Law.[1] To meet this obligation, the Company continually studies its electric system so that it can plan for any future reliability needs.

In December 2025, the Company identified the possibility that New York City could experience a transmission security deficiency[2] in the next decade, with the earliest potential need occurring in 2030.[3] The New York Independent System Operator (NYISO), the transmission system operator for New York State, also identified transmission security margin needs affecting New York City (NYISO Zone J).[4] Although these assessments differed in magnitude and timing, both the Company and the NYISO identified the same factors driving the needs: increasing electric demand, the anticipated retirement of aging fossil-fuel generators, and delays in bringing new renewable supply online.

In light of these forecasts, the Public Service Commission ordered the Company to develop an initial reliability contingency plan (Plan) "to guide planning efforts for the next decade, and, if necessary, beyond."[5] The Commission ordered that the Plan be based on the Company's most recent forecasts, consider both market and traditional solutions that are clean and non-emitting, discuss any potential regulatory changes that could increase the effectiveness of available solutions, and include halting mechanisms to defer, delay, or cancel solutions if they ultimately are not required. To obtain information on potential solutions from the market, the Commission ordered the Company to issue a Request for Information (RFI) and host a technical conference. The Company was required to evaluate RFI responses, assess the Company's own potential solutions, and consider any proposals submitted to the NYISO as part of its planning process.[6]

The Commission further ordered the Company to "turn over every stone" to assemble a portfolio of clean and non-emitting solutions, while prioritizing solutions that are cost-effective, are straightforward to deploy with a high level of assurance, and avoid or minimize impacts to disadvantaged communities (DACs).[7] Finally, the Commission directed the Company to evaluate solutions and to develop and submit "a comprehensive implementation framework" with "recommendations for next steps in this proceeding."[8]

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[1] PSL § 65(1).

[2] Transmission security concerns the continued delivery of electricity despite a sudden, violent shock like a lightning strike or short circuit. Transmission security planning evaluates a "worst-case scenario" during the hour of peak electric demand to ensure the system stays reliable.

[3] CECONY's 2025 Local Transmission Plan, *available at* https://www.nyiso.com/documents/20142/55462035/03b_CECONY_2025_LTP.pdf, at 4.

[4] New York Independent System Operator (NYISO), *Short-Term Reliability Process Report: 2026-2030 Generator Deactivation Reliability Needs (2025 Quarter 3 STAR) Solution Section* (Apr. 15, 2026).

[5] Case 25-E-0764, *Proceeding on the Motion of the Commission to Address New York City Reliability Needs* (*Reliability Needs Proceeding*), Order Initiating Proceeding and Directing Reliability Contingency Plan (Order or Order Initiating Proceeding) (Dec. 18, 2025).

[6] *Id.* at 4.

[7] *Id.* at 20.

[8] *Id.* at 19.

Evaluation of Market-Based Solutions

The Company's RFI generated a robust response from the market, yielding 71 timely submissions across several technological categories, including bulk and distributed battery energy storage, district steam-driven technologies, thermal energy networks, and virtual power plants. The Company and the Electric Power Research Institute, Inc. (EPRI), which served as an independent technical advisor to provide objective engineering and market reviews, evaluated these submissions. The Company and EPRI used a comprehensive set of screening criteria to determine the solutions' incremental value, technical and commercial maturity, and ability to deliver firm, verifiable, and measurable load relief during peak hours throughout the six-month summer capability period, as required by transmission planning criteria. While the RFI confirmed a robust market for clean and non-emitting resources, the proposed solutions were non-binding and often did not include clear pricing, clear construction timelines, or clear information related to operational performance guarantees required for transmission security.

Proposed Market-Based Portfolio

To satisfy the identified ten-year reliability needs, the Company proposes soliciting near-term market-based resources while retaining the flexibility to deploy traditional solutions if market-based options are unable to fully address the needs in a timely, cost-effective manner. The Company's proposed portfolio of market-based solutions could fully meet the current identified transmission security needs through 2036. This proposed portfolio, however, faces regulatory, policy, economic, execution, and performance risks. The Company intends to thoroughly evaluate the ability of the market to deliver dependable reliability resources procured through competitive processes and to adjust the portfolio as its needs evolve through the proposed implementation framework.

Transmission-Connected Battery Storage

The Company plans to evaluate the executability and net costs of individual transmission-connected energy storage projects in consultation with DPS Staff through the existing Commission-approved Utility Dispatch Rights (UDR) framework.[9] Beyond projects already under contract, there are more than 1,000 MW of transmission-connected storage projects in the NYISO interconnection queue in Zone J. The Company will procure qualified bids for additional transmission-connected battery energy storage capacity via UDR competitive solicitations. To provide developers with adequate time to finance and build these capital-intensive projects, the Company requests that the Commission extend the bulk storage in-service deadline under the UDR framework to December 31, 2036.

Distribution-Connected Battery Storage and the RADR Program

Developers have applied to interconnect more than 2,700 MW of distribution-connected storage projects in the Company's service territory through the New York State Standardized Interconnection Requirements (SIR) process, with more than 1,000 MW already under executed SIR agreements. Substantial funds have already been committed to support these assets through the Value of Distributed Energy Resources (VDER) tariff; ultimately the Company's customers provide these funds. The current VDER framework, however, is generally not adequate to meet transmission security needs, because VDER developers have no performance obligations, retain complete discretion over when and whether they dispatch their systems, and respond to multiple, oftentimes misaligned, price signals only during non-holiday weekdays over a limited period in the summer. For this class of storage assets to be dependable enough to meet identified transmission security needs, they must instead have enforceable dispatch obligations, firm and full summer availability requirements, and contractual performance obligations.

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[9] Case 18-E-0130, In the Matter of Energy Storage Deployment Program, *Order Establishing Energy Storage Goal and Deployment Policy* (Dec. 13, 2018).

To realize the reliability value of these assets for transmission security and enable their inclusion in the portfolio, the Company proposes a new Reliability Asset Dispatch Rights (RADR) program, modeled in part on the Commission-authorized UDR bulk storage solicitation program. The RADR framework allows eligible distribution-connected storage assets to compete to transition from the VDER tariff framework into a dedicated, reliability-focused program.[10] Participating developers will execute 15-year RADR contracts with the Company, relinquishing their VDER rights and obligations in exchange for predictable, performance-dependent payments. This transition can benefit customers by repurposing batteries seeking to operate under VDER into a reliability-driven RADR framework that can more reliably help address transmission security needs and provide additional economic value that customers do not receive under VDER.

As part of the RADR framework, the Company would reimburse successful bidders for charging costs and, for projects not yet in service, eligible interconnection costs. Additionally, the Company would prioritize the interconnection of contracted RADR assets so they come online in time to meet transmission security needs.

The Company proposes that the Commission authorize the RADR program framework outlined in this filing and allow the Company to administer the RADR program in consultation with Department of Public Service (DPS) Staff. The Company would submit procurement information, including a confidential price ceiling, to DPS Staff and further consult with Staff on final project selections. To mitigate customer bill impacts, the Company proposes to recover all non-capital RADR program and contract costs from all delivery customers as a regulatory asset over 15 years, in addition to recovering capital expenditures as capital.

Other Market-Based Solutions

The Company will also issue a technology-agnostic request for proposals (RFP) for additional clean and non-emitting market-based solutions beyond transmission- and distribution-connected batteries. This solicitation will seek firm proposals for mature alternative technologies to reliably reduce electric peak demand in Zone J in a manner that meets the transmission security criteria and the requirements of the Order. Based on the outcome of the RFP process, the Company will file a petition with the Commission before executing any contracts for potential solutions received through this process.

Infrastructure Solutions

Because the above market-based solutions face policy, permitting, and construction risks, the Company has identified an additional solution to contribute toward meeting the transmission security needs. If the market does not respond as projected, or if the Company requires additional resources to meet reliability needs in a timely, cost-effective manner, the Company can undertake a transmission cooling enhancement project to add refrigeration to the cooling systems of eight existing underground transmission feeders (four 345 kV and four 138 kV lines) to dissipate heat more effectively. These enhancements will increase the transfer capability into Zone J by up to 300 MW. While the Company is not requesting approval or cost recovery to move forward with this solution in this filing, it will engage in preliminary planning efforts should this solution be required to meet identified reliability needs.

Regulatory Framework, Halting Mechanisms, and Requested Authorizations

To successfully implement this Plan while protecting customers from unnecessary costs, the Company has incorporated halting mechanisms into its implementation framework. The Company will continue to update the Commission and the public on its transmission security needs every six months. Consequently,

[10] A similar structure to this program was proposed by one RFI respondent.

the Commission and DPS Staff will have multiple opportunities to review the Company's progress toward meeting its transmission security needs and direct the Company to evolve its plan. In addition, the Company intends to seek Commission approval before executing any contracts for solutions identified through its planned RFP and before implementing any traditional transmission infrastructure solutions. Accordingly, if updated load forecasts show that the needs have been delayed or resolved, the Commission can direct the Company to halt planned solicitations or defer the execution of new contracts.

The Company requests that the Commission approve its Plan and grant the following authorizations:

1. **UDR Deadline Extension:** Extend the bulk storage in-service deadline under the Utility Dispatch Rights program to December 31, 2036.

2. **RADR Program Approval:** Approve the RADR framework and authorize the Company to transition eligible VDER resources into RADR through a competitive procurement process, prioritize their interconnections, and recover non-capital costs as a 15-year regulatory asset and capital costs as typical utility capital investments.

In accordance with the objective of the Order to keep the Commission and stakeholders informed, the Company will provide biannual updates. Each January, the Company will provide an updated needs assessment based on its most recent Local Transmission Plan, including the supporting power flow modeling results. The filing will also contain the Company's proposed adjustments to its portfolio based on the outputs of its most recent needs assessment, progress on market-based solutions, and actions by other parties (e.g., NYISO, NYSERDA).

Each July, the Company will provide progress updates on the individual solutions in the portfolio. It will also identify material changes to available energy supply based on the NYISO FERC 715 database and the NYISO Load & Capacity Data "Gold Book" and their potential implications for the transmission security needs. The Company will also provide an overview of relevant policy and economic changes, as well as material demand changes (e.g., new large loads), and indicate their potential implications for the needs. As part of the July filing, the Company will also provide its annual report on RADR.

2. Updated Reliability Needs

The Commission required the Company to update its ten-year needs assessment in January 2026 and then again every six months.[11] The Company's July 2026 assessment is filed under separate cover contemporaneously with this filing.

The July 2026 assessment uses the same baseline load forecast as the January 2026 assessment, but with updated system topology and resource assumptions described in further detail therein. The report now forecasts that the reliability needs in New York City (i.e., NYISO Zone J) will be smaller and will arrive later than stated in the January 2026 assessment. As shown in Table 1, the July 2026 assessment projects the needs to begin in 2033 at 125 megawatts (MW), a delay of one year compared to the January 2026 assessment, and shows the needs increasing to 675 MW by 2036, a reduction of 75 MW compared to the January 2026 assessment.

[11] *Reliability Needs Proceeding*, Order Initiating Proceeding at 4, 16-17, 22. The Company made its first filing in January. *See Reliability Needs Proceeding*, Con Edison January 2026 Reliability Needs Report (Jan. 20, 2026).

Table 1: New York City (NYISO Zone J) Reliability Needs (as of July 2026)

	2027-2032	2033	2034	2035	2036
Peak MW Need	-	(125)	(250)	(525)	(675)
Hours	-	1	4	6	8
Duration (hours of the day)	-	- - 15-16 - - - - -	- 14-15 15-16 16-17 17-18 - - -	13-14 14-15 15-16 16-17 17-18 18-19 - -	13-14 14-15 15-16 16-17 17-18 18-19 19-20 20-21
~MWh (megawatt hour) by hour	-	- - 15-16: 125 - - - - -	- 14-15: 75 15-16: 250 16-17: 100 17-18: 150 - - -	13-14: 75 14-15: 275 15-16: 475 16-17: 325 17-18: 525 18-19: 300 - -	13-14: 200 14-15: 400 15-16: 625 16-17: 475 17-18: 675 18-19: 450 19-20: 100 20-21: 75
Approx. MWh	-	(125)	(575)	(1,975)	(3,000)

The ten-year needs reflected in the table above are the primary basis for the Company's proposed solutions described in *Section 4: Proposed Portfolio*.

The Company has also projected increasing load in Zone J beyond the initial ten-year planning horizon. Further, the reliability benefits of bidirectional load-shifting resources, such as battery storage, that require electricity on a net basis will become more limited as needs grow over time and the existing generation and delivery infrastructure reach physical and physics-based limits. Absent long-term solutions, the reliability needs will continue to escalate, as estimated in Table 2 below. The long-term solutions that could mitigate these growing needs include new generation assets in Zone J or new generation assets outside Zone J coupled with increased transmission capacity to import the additional electricity into Zone J. As noted in NYISO's 2026 Power Trends report, "New York requires additional new generation and infrastructure, especially resources that are flexible, dependable, and capable of operating through extended periods of high demand."[12]

Table 2: New York City (NYISO Zone J) Reliability Needs, 2037–2045 (as of July 2026)

	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak MW Need	(850)	(1,025)	(1,225)	(1,400)	(1,575)	(1,750)	(1,925)	(2,100)	(2,275)

[12] New York Independent System Operator, 2026 Power Trends: Annual Grid and Market Report (June 9, 2026), at 2, *available at* https://www.nyiso.com/documents/d/guest/2026-power-trends.

3. Evaluation of Market-Based Solutions

The Order directed the Company to undertake a comprehensive process to identify and evaluate potential clean and non-emitting solutions capable of meeting the identified transmission security needs. This process represents an innovative and novel approach to addressing transmission security needs for both the Company and the broader electric utility industry.[13] Adhering to the Commission's directive to "turn over every stone," the Company issued an RFI seeking solutions and examined a diverse suite of market-based resources and policy reforms suggested by respondents. The RFI, however, was non-binding and not anticipated to result in contractual awards, and it did not require respondents to submit firm pricing. Rather, the RFI helped the Company explore the level of market development across different technologies that could address the transmission security needs and informed the Company's proposed plan to address the needs.

3.1 Overview of the RFI Submissions

The Company issued the RFI on January 20, 2026, seeking information from market participants regarding potential clean and non-emitting solutions to address the identified reliability needs.[14] The Company's RFI process included an introductory webinar, two rounds of clarification questions, and a technical conference. This process provided interested stakeholders with multiple opportunities to engage and better understand the needs and the solutions the Company was seeking. The RFI closed on March 15, 2026.

The Company received 71 timely responses to the RFI. Table 3 below provides an overview of the types of solutions identified in those responses.

Table 3: Summary of Responses Received Through the RFI

Response Type	Solution Description	Count
Portfolio	Proposals comprising multiple projects and programs (e.g., multi-technology virtual power plant (VPP))	29
Project	Standalone projects (e.g., building retrofit)	18
Enabling Technologies	Standalone software (e.g., evaluation, measurement and verification platform) and/or hardware solutions	10
Conceptual Proposal	Suggested policy changes, comments, or novel technologies	10
Consulting Services	RFI/implementation support and other advisory services	4

The responses varied in nature and included discrete projects already under development, conceptual ideas, broad discussions of potential policy changes, and offers of advisory services or software products that the respondents believed would help with the reliability needs. The responses from the market covered many technology solutions, including energy storage, energy efficiency (EE) and building

[13] The Company's transmission system must be planned, designed, and operated in accordance with all applicable North American Electric Reliability Corporation, Northeast Power Coordinating Council, and New York State Reliability Council Reliability Rules, including Local Reliability Rules, as well as the Company's Transmission Planning Criteria, which include a strict local zero load-loss criterion for transmission system design. Con Edison Transmission Planning Criteria (TP-7100-19) (effective November 2022), *available at* https://www.coned.com/-/media/files/coned/documents/business-partners/transmission-planning/transmission-planning-criteria.pdf.
[14] Con Edison, Clean and Non-Emitting Reliability Solutions, *at* https://www.coned.com/en/business-partners/business-opportunities/non-emitting-solutions/.

electrification, demand response, distributed generation (DG), thermal storage/thermal energy networks (TENs), managed electric vehicle (EV) charging, and district steam-driven load reduction.

As the RFI was not an RFP, in response to which the Company would make awards, responses generally did not provide a direct path to execution or acquisition by the Company and the responses varied in terms of specificity. Some responses provided adequate technical, financial, and operational information to support a preliminary evaluation, while others were much more limited. While the RFI responses provided valuable insight into potential solution pathways, their assumptions regarding market readiness, costs, performance, and customer participation will need to be validated and refined through subsequent RFPs or authorized acquisition frameworks prior to execution.

3.2 RFI Evaluation Process and Criteria

Each RFI response was subjected to a rigorous evaluation process by internal Company subject matter experts (SMEs) and industry experts from the Electric Power Research Institute, Inc. (EPRI) to determine whether potential solutions met the requirements of the Order and could be included in a portfolio of resources to address the transmission security needs. Each response was independently reviewed and scored by multiple reviewers.

3.2.1. Role of EPRI as a Technical Advisor

The Company engaged EPRI as an independent third-party technical advisor to assist in evaluating responses to the RFI and to advise on the technical characteristics of potential solutions to meet the transmission security needs. EPRI leveraged its industry expertise and knowledge of how other electric utilities address transmission security needs to advise on the technical viability of the various proposed technology pathways. To support this effort, EPRI assembled technical experts across the solution areas and technology types under evaluation to score each proposal and assist the Company in refining its own evaluation of potential solutions. The Company and EPRI collaborated to define the RFI evaluation criteria and scoring approach applied across all potential solutions.

3.2.2. Evaluation Framework

The Company and EPRI evaluated each RFI response through a comprehensive framework designed to progressively narrow the broader set of proposals to an applicable and potentially feasible set of solutions. This framework entailed applying transmission security requirements and evaluating the potential solutions across other operational, financial, community impact, and regulatory dimensions.

The Company first distinguished solutions that could provide actual relief, measured in MW of electric power, and those that could not, such as software programs, consulting/advisory services, or policy proposals. Although these submissions would not provide measurable MW relief, they were still reviewed for informational purposes and provided valuable insights into market capabilities, emerging approaches, and implementation considerations that informed the Company's overall evaluation and portfolio development. But because these submissions did not offer firm relief to address the transmission security needs, the Company did not include them in its proposed portfolio.

Next, reviewers evaluated the remaining submissions to determine whether they aligned with the requirements of the Order and the RFI. These potential solutions included both standalone projects (e.g., transmission-connected batteries) and potential solution concepts (e.g., resources aggregated into a virtual power plant, energy efficiency programs). To qualify for further consideration, a potential solution needed to meet three criteria:

1. Is the solution clean and non-emitting, as required by the Order?
2. Could the solution reasonably be included in a portfolio to relieve the transmission security needs based on the daily performance requirements for the capability period?
3. Is the solution incremental, i.e., a new resource that has not been previously considered and/or differentiated from resources that the Company already assumed, i.e., additionally "firmed up" to meet transmission security criteria, when forecasting the transmission security needs?

Based on these criteria, certain potential solutions did not qualify for inclusion in the portfolio. For example, if a solution was not clean and non-emitting (e.g., a solution that used fuel cell technology or repowered existing generators that might reduce total emissions[15]) or was unable to provide relief during the entire need period (e.g., a demand reduction solution that excluded weekends or had opt-out provisions for participants), the Company determined that it could not provide the required load relief for transmission security needs. Many RFI submissions included novel as well as more established technologies or approaches that may provide value for other purposes but were unable to meet the stringent requirements for transmission security.[16] While these submissions were still reviewed and evaluated, they are not included in the proposed portfolio because the Company determined they could not contribute to meeting the identified reliability needs.

Additionally, if a proposed solution's impacts were already embedded in the Company's load forecasts, it would not provide incremental relief and therefore could not help address the identified transmission security needs. For example, certain submissions included high-confidence solutions with a proven track record for reducing load, such as existing energy efficiency measures. But the impacts of these measures are already reflected in the Company's load forecast and therefore do not provide incremental benefits for transmission security purposes. Additional information on the Company's approach to energy efficiency is provided in *Section 3.3.4: Energy Efficiency/Building Electrification* below.

The third stage of the review process focused on identifying resources with the highest likelihood of successful execution and deliverability. The Company considered a diverse set of criteria, summarized in Table 4 below. EPRI's review focused exclusively on a subset of technical criteria (shown in grey), while Company SMEs also considered other criteria, including financial information, the qualifications of the respondents, and potential impacts on DACs.[17]

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[15] While inconsistent with the clean and non-emitting requirements in the Order, these solutions would help address the identified transmission security needs and potentially provide benefits beyond the ten-year planning horizon.

[16] Transmission security is a deterministic performance requirement that evaluates whether the transmission system can withstand defined contingencies while maintaining applicable thermal, voltage, and stability limits. Accordingly, resources used to address a transmission security need must be sufficiently dependable, measurable, and available before a contingency event, so the system remains within applicable operating limits after the contingency arises. Because the identified reliability needs occur during the summer operating season (i.e., May 1 through October 31), any proposed resource to address them must be dependable, verifiable, and measurable throughout this entire period. Measures that rely on voluntary third-party actions or that cannot be implemented until after a contingency arises do not satisfy transmission security criteria. By contrast, targeted demand-side measures that permanently or contractually reduce load during the relevant need period may reduce net system loading and may be considered where they are firm, verifiable, and available as required.

[17] Due to the confidential nature of RFI responses, the Company is not publicly disclosing submission scoring.

Table 4: Summary of Evaluation Criteria

Category	Criteria	Description
Operational	Availability and Reliability	Certainty the solution will provide firm, dependable load relief or MW during the need period
	Reasonableness of Relief	Reasonableness/completeness of operational data in RFI Attachments B-1 or B-2[18]
	Grid Impacts	Ability to provide ancillary services, create conditions that require ancillary services, or provide additional distribution benefits or impacts
Financial	Reasonableness of Financial Performance	Reasonableness/completeness of financial data in RFI Attachments B-1 or B-2
Portfolio Potential	Solution Maturity	Extent to which the proposed solution is a proven technology through industry studies or provides a reasonable pathway to be measured for load reduction capability
	Customer and/or Land Acquisition	Extent to which the customer and/or land acquisition strategy fits the needs of proposed solution(s) and targeted customer segment(s)
	Execution Risk	Risk associated with project implementation within the timeframe
	Permitting Risk	Extent to which permitting may impact project delivery or implementation
	Business Continuity and Financing Risk	Expectations for whether the respondent will continue operations both during project development/ implementation and throughout the identified period of need
	Respondent Qualifications	Assessment of relevant experience and past successes
	Scalability/Flexibility	Ability to provide relief if the need changes over time
Other Considerations	Community Impacts	Impact on the community in the identified area including, but not limited to, customer experience, environmental impacts, and enhancements or disruptions
	Regulatory Changes Required	Extent the solution depends on regulatory and/or tariff changes and likelihood of enacting the changes
	Proposal Content and Presentation	Completeness and level of clarity/organization of the proposal

While all RFI responses were fully evaluated against the above criteria, many responses lacked sufficient detail to support a comprehensive evaluation.

[18] The RFI required respondents to submit a Financial and Savings Template (Attachment B-1) for all solutions except for dispatchable energy storage systems (ESS). Respondents submitting solutions involving dispatchable ESS were required to submit a Financial and Savings Template - ESS (Attachment B-2). *See* Con Edison, Clean and Non-Emitting Reliability Solutions, *at* https://www.coned.com/en/business-partners/business-opportunities/non-emitting-solutions/.

3.3 Outcome of the RFI

RFI submissions were consolidated into categories of market-based solutions organized by technology type and/or approach to summarize the Company's findings by solution type rather than by each project or respondent. The Company identified eleven potential market-based solutions submitted through the RFI that fall into six broader categories, which are summarized in Table 5 below.

Table 5: Summary of Market-Based Solutions

Category	Solution Type
Battery Energy Storage	Transmission-Connected Batteries
	Distribution-Connected Batteries
	Micro-Storage
District Steam-Driven Reliability Solutions	Steam Chillers
	Small Steam Turbine Generators
Thermal Storage / TENs	Thermal Energy Storage and TENs
Energy Efficiency / Building Electrification	Energy Efficiency and Building Electrification Measures
Managed Electric Vehicle (EV) Charging	Commercial and Residential Managed Charging
Other Distributed Energy Resources (DERs) and Aggregations	Daily Shifting of Load under a VPP
	VPP with (multiple) Behind-the-Meter (BTM) Resources
	Solar and Solar Plus Storage

While the RFI was informational, non-binding, and not a final procurement, the Company determined that certain market-based solutions could meet the requirements for transmission security, while other proposed solutions may not meet the requirements. For example, demand-side management and controlled load reductions are treated differently for the purposes of transmission planning and transmission operations.[19] While some RFI responses included solutions that provide valuable operational benefits, they are not reflected in the proposed portfolio because they did not meet the stricter planning criteria required for transmission security.

The Company's initial assessment of the proposed market-based solutions is described below.

[19] For the purposes of transmission planning, which deals with the long-term design of a future electric system, demand-side measures can only support a solution if they are contractually firm, enforceable, and available pre-contingency. They cannot be considered to address a transmission security need when planning criteria requires the system to withstand a standard contingency without emergency intervention. Transmission planning uses power-flow studies, short-circuit assessments, and transient stability evaluations to model expected load growth, generation shifts, and topology changes. If a modeled design-basis contingency results in a violation, the planning process mandates durable, physical corrective measures, such as line reconductoring, transformer upgrades, or new transmission facilities, rather than relying on operational intervention. In contrast, for the purposes of transmission operations, which involves real-time operation of the grid, qualified demand response programs are front-line resources that can be deployed to help reduce real-time stress. If a severe, multi-element contingency threatens the grid in real time, operators are authorized to implement emergency procedures, including controlled load shedding. In operations, dropping localized customer load serves as the remedy of last resort to prevent cascading impacts and preserve the broader system.

3.3.1. Battery Energy Storage

Transmission-Connected Batteries: Several RFI responses included transmission-connected battery projects in various stages of development. These transmission-connected batteries could provide system reliability benefits and meet the requirements for transmission security if they are sited in the right locations and operated appropriately. Given the complexity of the development process for these projects and the uncertainty of whether these resources will ultimately be placed in service, the NYISO and the Company would typically only include them in the projected resource mix once they reach advanced stages of development. Projects at earlier stages of the development cycle have additional execution risks and greater uncertainty regarding their deliverability. As a larger portfolio of batteries looking to interconnect in Zone J are awaiting the results of the NYISO's transitional cluster study, expected in August 2026, the Company concluded it was reasonable to include transmission-connected batteries within the proposed portfolio to address the identified transmission security needs. Additional details on the Company's assumptions and plan to acquire competitive transmission-connected storage resources are outlined in *Section 4.1: Transmission-Connected Battery Storage*.

Distribution-Connected Batteries: RFI respondents also proposed projects or portfolios that rely on distribution-connected batteries in various stages of development. Additionally, some respondents proposed solution concepts based on distribution-connected batteries that are not yet sited, in development, or in the interconnection process. Respondents also proposed solutions under which they would provide full dispatch rights to the Company so storage could be optimized by the Company for its needs in exchange for compensation under a multi-year contract instead of under the VDER tariff.

Distribution-connected batteries, if sited in the right locations and in the right quantities, and operated to help meet reliability needs, can support transmission security needs. Distribution-connected batteries can help alleviate transmission constraints by flexibly discharging when the grid is constrained during periods of peak demand, provided there is adequate, unconstrained delivery infrastructure (across distribution and transmission) and generation capability to permit charging during non-peak hours. If batteries are built in locations with infrastructure limitations, they can create new peaks from their charging behavior and trigger costly system upgrades that would otherwise not be needed.

Moreover, battery operators relying on market revenues to meet the economic goals of their project are generally responsive to price signals and will manage their assets to maximize the economic return of their investment as opposed to optimizing for reliability. For distribution-connected batteries to meet the stringent requirements of transmission security needs, the regulatory and operational incentive structures must align so these assets are available throughout the entire need period and perform as required to meet the reliability needs. The Company included distribution-connected batteries for which the Company owns full dispatch rights for consideration within the proposed portfolio and outlines its assumptions and requests to transition eligible, competitive resources under the RADR framework in *Section 4.2: Distribution-Connected Battery Storage*.

Micro-Storage: The Company also considered a market-based solution that would rely on daily load shifting using portable plug-in batteries across customer segments. These batteries would provide load relief from appliances that are plugged into them (e.g., window air conditioners, large appliances). RFI respondents proposed dispatch of these batteries under event-based demand response with a limited number of events per year. While micro-storage is promising for future use, the Company did not include this solution in the proposed portfolio because of the lack of locational certainty, unpredictability of customer behavior during the need period, and customer acquisition risk. Specifically, this proposal does not meet transmission security requirements because the resources would not be available during the entire need period and any load relief would depend on repeated customer action. Moreover, as these batteries are not stationary and can be easily unplugged, the Company cannot be certain of their location and operation during the need period. To be effective, the appliance and battery would have to be on and available throughout the hours of need for the entire six-month capability period, which has not been demonstrated at this time. Finally, micro-storage brings high customer acquisition risk to achieve large-scale relief due to the small size of the batteries.

3.3.2. District Steam-Driven Reliability Solutions

Steam Chillers: RFI respondents proposed solutions to deploy steam chillers at several of the Company's large commercial and industrial district steam customers as an alternative to electric chillers. Informed by the market-based solution, a potential program could provide incentives for existing customers to replace electric chillers with new steam-driven chillers and for new customers to install steam chillers. Steam chillers can reduce or eliminate load from electric-powered mechanically driven chillers that are more commonly used in buildings for cooling. By offsetting summer electric load, which is around 3.5-4 MW for some large buildings, this incentive could provide load reductions during the need period. The Company determined that this could help meet transmission security needs if able to be implemented at scale, on time, and cost-effectively.

Small Steam Turbine Generators: Another potential market-based solution could provide an incentive for customers with sufficient steam load to install microturbines. The microturbines are powered by excess steam pressure, which is otherwise reduced mechanically by valves, to generate electricity for on-site use. Every electron generated through these microturbines represents a one-for-one reduction in overall electric demand in Zone J. As this technology can also reduce building electricity usage, the Company determined that this could help meet transmission security needs if able to be implemented at scale, on time, and cost-effectively.

3.3.3. Thermal Storage/TENs

RFI respondents proposed using thermal energy storage measures, including thermal energy networks, to enable demand management and load shifting. Typically, these measures include ice storage tanks, low-temperature chillers, piping systems, advanced controls, heat exchangers, and associated materials required to integrate the technology into a building's cooling infrastructure. Thermal storage systems are better-suited for large commercial and industrial customers with significant cooling demands coincident with summer-peak electric loads. Based on proposals submitted through the RFI and the Company's experience with thermal storage in its Demand Management Program, the Company determined that thermal energy storage systems could meet the requirements for transmission security if able to be implemented at scale, on time, and cost-effectively, and if operated appropriately.

3.3.4. Energy Efficiency/Building Electrification

Several RFI respondents proposed changes to or expansion of the existing energy efficiency and building electrification (EE/BE) portfolio to address the transmission security needs. Energy efficiency is a proven intervention to reduce demand and supports transmission security needs. Over the past ten years, from 2016 through 2025, the Company's energy efficiency programs saved more than 800 MW of peak demand. Additional peak demand savings were, and continue to be, driven by other programmatic offerings administered by the New York Power Authority (NYPA) and New York State Energy Research Development Authority (NYSERDA), and from organic energy efficiency activity spurred by local policies, codes, and standards, as well as broader market transformations. The Company continues to build on its robust energy efficiency experience with $2.1 billion of newly authorized funding for the 2026-2030 period,[20] which is reflected in the Company's load forecast.

The changes suggested by RFI respondents included the reintroduction of non-strategic measures[21] (e.g., lighting upgrades, which now largely happen organically and no longer need incentives to drive adoption except where desired for specific geographic areas or for specific uses), greater incentives for certain measures or customer segments already in the Company's energy efficiency portfolio, and the reintroduction of closed programs. Given the scale of the Company's authorized energy efficiency portfolio and other structures supporting the adoption of energy efficiency measures, which are all reflected in the Company's load forecast, incremental funding in this area will not materially change the outlook or further reduce the transmission security needs. The Company does not propose any changes to the non-Low- and Moderate-Income (non-LMI) and LMI EE/BE frameworks in connection with the Plan. As the EE/BE framework is only authorized through 2030, should the Commission establish a timeframe for a subsequent framework review, similar to the review completed prior to the 2025 EE/BE Orders,[22] the Company would support continued consideration of how the EE/BE framework could drive additional summer electric peak demand reduction in support of transmission security needs.

3.3.5. Managed Electric Vehicle (EV) Charging

Commercial and residential managed EV charging is a market-based solution that can reduce the load of electric vehicle charging during peak conditions. While this type of program could effectively reduce demand, it does not meet the requirements to relieve transmission security needs.

The Company's Residential Managed Charging Program shifts demand at the vehicle level. The vehicles are mobile loads; therefore, the Company cannot know with certainty where or on what days the load shift will occur within the Company's service territory. The program targets reducing load during the system peak window and, for transmission security purposes, would depend on daily customer actions in the summer capability period to realize the potential load relief. In March 2026, the Company first reported an estimated peak load reduction in its Residential Managed Charging Program in the Joint Utilities Managed Charging Comprehensive Report, showing an estimated peak load reduction of 0.31 kW per program participant in the summer.[23] Considering that (i) the EV population is growing in the Company's service territory from a relatively small base, (ii) load reductions per vehicle are small and would require large aggregations to collectively generate larger load impacts, (iii) more study is necessary

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[20] Case 25-M-0248, *In the Matter of the 2026-2030 Non-Low- to Moderate-Income Energy Efficiency and Building Electrification Portfolios*, Order Authorizing Non-Low- to Moderate-Income Energy Efficiency and Building Electrification Portfolios for 2026-2030 (May 15, 2025); Case 25-M-0249, *In the Matter of the 2026-2030 Low- to Moderate-Income Energy Efficiency and Building Electrification Portfolio*, Order Authorizing Low- to Moderate-Income Energy Efficiency and Building Electrification Portfolio for 2026-2030 (May 15, 2025).

[21] Non-strategic measures are defined under the Strategic Framework, which guides EE/BE technology eligibility and is designed to focus ratepayer funding measures that align and advance New York policy objectives. Measures classified as non-strategic are not eligible for EE/BE portfolio funding. Cases 14-M-0094 et al., *Proceeding on Motion of the Commission to Consider a Clean Energy Fund*, Department of Public Service Staff Energy Efficiency and Building Electrification Report (Dec. 20, 2022).

[22] Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative*, Order Initiating the New Efficiency: New York Interim Review and Clean Energy Fund Review (Sept. 15, 2022).

[23] Case 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure*, JU Managed Charging Comprehensive Report (Mar. 16, 2026).

to understand daily EV charging behavior of participating customers and non-participating customers, and (iv) technology is evolving rapidly in both EVs and the means to manage their charging, it is premature to consider residential managed charging as part of the transmission security needs portfolio, even as managed charging presents significant potential as a load flexibility resource as transportation load grows.

The Company's Commercial Managed Charging Program similarly shifts demand at the charger level. The charger locations are fixed in place, so the load shift for this program can be attributed to specific load areas by location. The Company launched this program recently, however, and requires further study to assess the level and consistency of load shift on which it can rely. For this reason, load shift from this program has not been considered for the transmission security needs portfolio. As with residential managed charging above, charger-based managed charging nevertheless has significant potential as a load flexibility resource as transportation load grows.

3.3.6. Other Distributed Energy Resources (DERs) and Aggregations

Daily Shifting of Load Under a VPP: RFI respondents proposed several variations of virtual power plant (VPP) configurations, including Demand Response (DR) and other approaches. These proposed solutions included load reduction and/or shifting of building load, such as HVAC and other electric loads (e.g., appliances) through curtailment or other operational strategies. Several RFI respondents proposed event-based demand response, as opposed to daily load shifting (i.e., demand management), which would not meet the requirements for transmission security because it would not provide relief during the entire summer capability period. Therefore, the Company considered whether load that can be reduced and/or shifted daily could potentially help with transmission security needs.

Based on RFI responses, this type of persistent load reduction or daily shifting, while having the potential to help transmission security needs, does not have a proven track record or operational data to demonstrate that it can deliver the needed load relief, especially when considering building load is variable. This solution would require repeated customer action and adequate daily load to deliver pledged load relief, including on weekends and holidays (in contrast with the Company's existing demand management programs, which are event-based and called on only a subset of summer days). Even when the reduction and/or shifting are automated (e.g., smart thermostats), there is a high risk of customer fatigue, as well as subsequent opt-outs and attrition through the six-month capability period given the need for daily load reduction. As a result, to account for customer fatigue and uncertainty in asset performance, the offering would have to be designed in a way that would sizably derate resource value and require the Company to over-procure resources by a considerable margin to achieve the desired load reduction, thereby reducing the suitability of the potential solution.

The Company and other utilities have used DR for operational purposes successfully on an event-basis on the distribution system, achieving load relief on the hottest days of the year. The Company offers robust demand reduction programs and continues to support them as a valuable resource for load relief and managing distribution system needs. But, as explained above, it is not an appropriate resource for transmission security needs.

VPP with (multiple) behind-the-meter (BTM) Resources: The Company also evaluated an alternative market-based VPP solution that would aggregate exporting and load shifting resources daily throughout the six-month capability period to meet transmission reliability needs. The technologies that would participate would primarily be solar and batteries, either individually or co-located. The Company determined that there are several challenges with leveraging this as a resource to meet the identified transmission security needs: (i) there are very few VPP-like configurations currently in operation in the

Company's service territory with limited performance information; (ii) there is a high degree of execution risk and uncertainty in customer adoption for scaling; and (iii) while the technologies included in this solution (e.g., batteries, solar) are individually mature, the performance of VPPs that combine multiple technologies located fully or partially behind the meter varies based on customer load profiles (e.g., differences between weekdays, weekends, and holidays) and weather conditions (e.g., cloud cover impacting solar production).

As a result, these VPPs are not a consistently dependable resource for the summer capability period for the purposes of transmission security. Further, there is a high degree of execution uncertainty with this potential solution. As BTM batteries have not been installed in New York City at scale, the level of participation (i.e., MW, MWh) is unknown. Additionally, proposals from RFI respondents lacked critical information, including the planned location of installations, how they would meet fire protection and permitting requirements for BTM installations, and robust customer acquisition plans. For these reasons, VPP with BTM resources was not considered for inclusion in the portfolio.

Solar and Solar Plus Storage: In addition to potential VPPs, the Company also evaluated programs and projects for rooftop solar with and without battery storage. Multiple RFI respondents suggested solution concepts or discrete projects within this category. Each response had unique challenges including execution risks such as site location and viability, uncertainty in customer acquisition approach, and/or technology risks. For example, one respondent proposed a non-lithium-ion distribution battery storage system that is not currently permitted by the Fire Department of New York, supported by solar, which creates a high degree of execution risk. Another respondent proposed aggregating solar across hundreds of buildings for an initial pilot, scaling up to several thousand buildings, but did not provide a viable implementation plan with competitive and well-supported financial information or a robust customer acquisition plan. Based on the assessment of the RFI responses, the Company cannot rely on these solutions to address the identified transmission security needs at this time.

3.3.7. Summary of RFI Findings

The Company's RFI generated a robust response from the market with a variety of clean and non-emitting solutions that could potentially alleviate the transmission security needs in Zone J. These include transmission- and distribution-connected battery storage, steam chillers, small steam turbine generators, and thermal energy storage solutions.

The Company determined that certain market-based solutions may not be able to meet the requirements for transmission security based on the maturity of the technology or degree of confidence that it would be available and reliable. But, as discussed above, this does not mean they cannot help with meeting operational and other needs. In addition, as technologies evolve and experience with these technologies increases, solutions that are not viable today may prove to be in the future.

The Company proposes to conduct a technology-agnostic RFP following this filing to further identify potentially viable alternatives. This is further described in *Section 4.3: Other Market-Based Solutions*.

3.4 Details on NYISO Identified Solutions

In addition to the market-based solutions proposed through the RFI, the Order directed the Company to "identify… any NYISO-identified solutions in response to its STAR Q3 Report solicitation that contribute to resolving the NYC needs."[24] The Q3 Report, published on October 12, 2025, detailed the NYISO's assessment of the Bulk Power Transmission Facilities (BPTF) and identified the Short-Term Reliability Process Needs in New York City across the five-year study period (July 15, 2025 through July 15, 2030). On November 10, 2025, the NYISO issued a solicitation for Short-Term Reliability Process Solutions to address the New York City needs identified in the 2025 Q3 Report. Proposed solutions were due to the NYISO on January 9, 2026.

On April 15, 2026, the NYISO published its Short-Term Reliability Process Report: 2026-2030 Generator Deactivation Reliability Needs,[25] which summarizes its evaluation and selection of solutions to address generator deactivation needs in New York City. Below is an overview of the five solutions evaluated by the NYISO, organized by proposing entity. Of these five solutions, four are permanent.

3.4.1. Con Edison Regulated Solutions

1. A conceptual solution comprised of the installation of approximately 16 miles of 345 kV underground cable, construction of a 345 kV switching station, and reconfiguration of two existing 345 kV substations (expected completion in 2035).

Given the 2035 in-service date, the NYISO determined the solution was not viable to meet the identified needs. The NYISO noted that "the conceptual proposed transmission solution would help to improve reliability in the longer-term horizon (2035 and beyond) by increasing the transfer capability into this locality by about 700-800 MW. However, additional transmission capacity into a locality only provides reliability benefit when coupled with sufficient statewide supply to transfer into that locality."[26]

2. Demand response and emergency actions, including the use of emergency operating procedures (e.g., neighboring area emergency imports, voltage reduction, public appeals), as interim solutions to address the need until permanent and sufficient solutions are in-service and have demonstrated their planned capabilities.

The NYISO did not provide any additional details or discussion on the above solution because it is an interim operational action that could be taken to address the reliability needs identified by the NYISO until a permanent solution is in place.

3.4.2. Market-Based Solutions

Both market-based solutions were submitted by Alpha Generation Services, LLC (AlphaGen).

3. Retention of the existing Gowanus and Narrows barges (608 MW nameplate) through May 1, 2029, after which operation is not possible per the New York State Department of Environmental Conservation (DEC) Peaker Rule.[27]

The NYISO submitted a letter to the DEC designating the Gowanus 2 and 3 and Narrows 1 and 2 generators as needed to address ongoing reliability needs until May 1, 2029, the maximum permissible permit

[24] *Reliability Needs Proceeding*, Order Initiating Proceeding, at 18.
[25] NYISO, *Short-Term Reliability Process Report: 2026-2030 Generator Deactivation Reliability Needs (2025 Quarter 3 STAR) Solution Section* (Apr. 15, 2026).
[26] *Id.*
[27] DEC Peaker Rule, 6 N.Y.C.R.R. Part 227-3.

extension date allowed under the Peaker Rule. AlphaGen has also proposed a solution to withdraw the generator deactivation notice for these generators.[28]

4. A conceptual proposal to repower the Gowanus site with three new hydrogen-capable barges. Each barge would be capable of delivering 273 MW of nameplate fast-start, dispatchable capacity for a total of 819 MW of nameplate capacity (earliest potential in-service date is mid-2031).

Given the earliest potential in-service date of 2031 and numerous permitting and financing challenges, the NYISO determined the solution was not viable to meet the identified needs. The NYISO highlighted that "repowering solutions provide significant improvement to reliability margins as well as the additional reliability attributes of dispatchable resources. As such, these types of solutions are critical to achieving policy objectives while maintaining a reliable electric system. The NYISO encourages Developers and State agencies to work collaboratively to establish pathways for these resources to interconnect and supply power to the grid."[29]

3.4.3. Other Proposed Solutions

5. Daroga Power, LLC ("Daroga") proposed a development of up to 200 MW of natural gas-fueled fuel cell or linear generator systems with on-site carbon capture technology. The 200 MW of total capacity would be achieved through up to 40 separate installations of approximately 5 MW each located within the New York City and Long Island service territories.

The NYISO determined the proposed solution to be non-viable due to (i) the lack of information on specific site locations and other data required for the NYISO to assess the viability of the proposal and (ii) Daroga's failure to propose that the resources would be available to participate in NYISO markets. The NYISO "encourages Daroga, and developers of similar solutions, to continue working with Transmission Owners and New York State to advance the development and interconnection of such resources, as they could help offset demand and further support system reliability."[30]

Beyond the four permanent solutions submitted in response to the 2025 Quarter 3 STAR, there are four other projects in New York City that have met the NYISO's reliability planning process inclusion rules:

1. <u>Champlain Hudson Power Express</u>: 1,250 MW High-Voltage Direct Current (HVDC) underground and submarine cable from the Hertel substation in Quebec to the Astoria Annex 345 kV substation in New York City (in-service as of May 2026)
2. <u>Arthur Kill Energy Storage</u>: 15 MW (nameplate) 4-hour battery storage project connecting to the Fresh Kills 13.8 kV substation (planned in-service by winter 2026)
3. <u>Astoria Energy Storage</u>: 100 MW (nameplate) 4-hour battery storage project connecting to the Astoria West 138 kV substation (planned in-service by winter 2026)
4. <u>Empire Wind 1</u>: 816 MW (nameplate) offshore wind project connecting into New York City at the Gowanus 345 kV substation (planned in-service date by winter 2027). The NYISO continues to monitor the status and timeline of this project considering the December 22, 2025 order by the Bureau of Ocean Energy Management to suspend all ongoing activities and the subsequent preliminary injunction granted on January 15, 2026 by the U.S. District Court for the District of

[28] Note 25, *supra.*
[29] *Id.*
[30] *Id.*

Columbia to stay the suspension order while the court considers the merits of Empire Wind's challenge.

Of the nine projects described above, Table 6 below outlines the six proposed solutions that the NYISO deemed viable as of April 15, 2026, to address the identified needs in New York City.

Table 6: Projects Identified by the NYISO to Address New York City Needs[31]

	Queue Position	Project Name	Proposed Solution Developer	Nameplate (MW)	Proposed In-Service
Proposed Solution	N/A	Existing Gowanus and Narrows Retention	AlphaGen	608	In-Service
	Queue Position	**Project Name**	**Developer/ Interconnection Customer**	**Nameplate (MW)**	**Proposed In-Service**
Other Projects (Permanent Solutions)	631/887	NS Power Express	CHPE LLC	1,250	In-Service
	0827	Arthur Kill Energy Storage 1	Lighthouse Arthur Kill, LLC	15	Winter 2026
	0931	Astoria Energy Storage	East River ESS, LLC	100	Winter 2026
	0737	Empire Wind 1	Empire Offshore Wind LLC	816	Winter 2027
	1289	Propel NY Energy – Alternate Solution 5	New York Power Authority/ New York Transco LLC	-	Summer 2030

Due to the factors listed below, the six viable projects identified by the NYISO do not provide incremental MWs of relief for the identified transmission security needs and are therefore not included in the Company's proposed portfolio.

- Retention of Existing Gowanus and Narrows: As per the DEC's current Peaker Rule, these units will not be available after May 1, 2029, and therefore could not be counted toward relief through the entire ten-year need period.
- Propel NY Energy – Alternative Solution 5: This is a policy-driven project originating outside of New York City to increase high-voltage transmission connections between Long Island and Westchester County and does not provide incremental MW to New York City.
- Remaining Four Projects (NS Power Express, Arthur Kill Energy Storage 1, Astoria Energy Storage, and Empire Wind 1): Relief provided by these projects is already accounted for in the Company's July 2026 Reliability Needs Report.

As the NYISO routinely solicits potential solutions to address reliability needs, the Company will continue to monitor these quarterly and bi-annual efforts to determine if potential solutions could provide relief to the identified transmission security needs.

[31] *Id.*

4. Proposed Portfolio

Based on its review of market-based solutions submitted through the RFI, and potential solutions identified by the NYISO, the Company has developed a portfolio of market-based solutions as described below as a contingency plan that could meet the transmission security needs over the ten-year period. The Company is looking to constitute its proposed portfolio of competitively procured market-based solutions through the following three procurement activities:

1. A new UDR solicitation (issued on May 22, 2026)[32] to receive bids for transmission-connected storage under the Commission authorized framework;

2. Establishment and launch of the RADR framework to competitively procure eligible distribution-connected storage dedicated to the transmission security needs (with the full dispatch control to also optimize for other reliability and economic value on behalf of all customers); and

3. A new technology-agnostic RFP for firm clean and non-emitting transmission security resources to solicit other market-based solutions with binding pricing, firm MW of relief, and comprehensive execution plans not provided through the RFI.

Prioritizing the competitive procurement of these resources is intended to put together a cost-effective portfolio and place solutions in service on time to meet the needs.

The elements of this portfolio are intended to operate in a dynamic and interrelated manner to meet the identified reliability needs while delivering the greatest value to customers.[33] As a result, the Company is not providing precise quantities that may be procured for any individual portfolio element. Establishing fixed targets, including specified capacity volumes or price thresholds, would risk undermining competition and could expose customers to higher costs than would otherwise be achieved through flexible, market-responsive procurement processes. The Company will adjust the quantity of capacity procured based on the availability of competitive resources relative to the transmission security needs, which is anticipated to continue to grow beyond the current 10-year period. In addition, the quantity of resources acquired will also be informed by the risk inherent in market-based resource procurements, forecasts, and supply resource changes. The Company, in its biannual reports, will provide transparency to regulators and stakeholders on the evolution of the portfolio, including quantities procured and program expenditures, while filing any commercially sensitive information confidentially.

Should the Company not be able to procure a sufficient quantity of MW via market-based solutions, the Company would seek to pursue traditional infrastructure solutions to contribute toward meeting the needs.

The remainder of this section provides details on the individual market-based solutions in the Company's proposed portfolio–including required regulatory or policy changes and proposed next steps–as well as details on the Company's transmission ratings enhancement project, should it be required to meet the

[32] Con Edison, Request for Proposals: 2026 Bulk Energy Storage Scheduling and Dispatch Rights, *available at* https://cdne-dcxprod-sitecore.azureedge.net/-/media/files/coned/documents/business-partners/business-opportunities/bulk-energy-storage/2026/request-for-proposals.pdf (May 22, 2026).

[33] Due to the timing and existing authorization for a fifth UDR solicitation, this will proceed prior to other market-based procurements. Similarly, if approved by the Commission, the RADR solicitation is likely to proceed before the technology-agnostic RFP process.

needs. This section also outlines how the proposed portfolio was modeled to confirm it could meet the identified needs, overall expected costs, and the potential impacts on DACs. Additional details on the expected next steps and the Company's proposed implementation framework are described in *Section 6: Implementation Framework and Next Steps*.

4.1 Transmission-Connected Battery Storage

The Company's proposed portfolio includes transmission-connected storage projects contracted through previous UDR procurement activities and resources to be procured through existing and future UDR solicitations. Additional details on these projects are provided below.

4.1.1. Bayonne Energy Center III

Scheduled In-service: By March 2028

Description

Of the Company's energy storage projects already procured through the UDR program, the Bayonne Energy Center III (BEC III) battery energy storage system project is the most mature in its development process. The 50 MW/200 MWh transmission-connected BEC III project is currently under construction at the Bayonne Energy Center and will interconnect to the Company's transmission system at the Gowanus 345 kV point of interconnection in Brooklyn. The Company will have full scheduling and dispatch rights of BEC III for the duration of its 15-year contract.

The NYISO's study assumptions for the 2026 Reliability Needs Assessment process[34] recommended BEC III be designated as a firm[35] project.

Assumptions

The BEC III project is expected to commence operation by March 2028 and stay in operation under the contract with the Company until 2043. During this period, the Company will retain full dispatch rights of BEC III and will operate the asset as necessary to help support reliability needs, in addition to optimizing for economic value it can achieve on behalf of customers.

Proposed Next Steps

As this project is currently under construction, the Company will continue to actively monitor its progress.

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[34] New York Independent System Operator (NYISO), *2026 Reliability Needs Assessment (RNA) – Key Assumptions*, ESPWG/TPAS presentation (May 6, 2026).

[35] 2025 NYISO Gold Book, *available at* https://www.nyiso.com/documents/20142/2226333/2025-Gold-Book-Public.pdf. Firm projects are those which have been reported by TOs as being sufficiently firm, and either (1) have an Operating Committee approved System Impact Study (if applicable) and, for projects subject to Article VII, have a determination from New York Public Service Commission that the Article VII application is in compliance with Public Service Law § 122, or (2) is under construction and is scheduled to be in-service prior to June 1 of the current year.

4.1.2. Additional UDR Procurements

Description

In addition to BEC III, the Company has launched its fifth UDR solicitation to seek bids for additional transmission-connected storage capacity.[36] The Company will have full dispatch rights of any contracted asset(s) and will operate those asset(s) as necessary to support reliability needs and deliver any additional system and/or economic value to the benefit of all customers.

Based on data in the NYISO queue, including projects expected to receive interconnection related results as part of the NYISO transitional cluster study beginning in August 2026, there was approximately 1,000 MW of transmission-connected storage capacity that has made interconnection requests in Zone J (see *Section 5: Resources Under Development*) as of May 31, 2026. Though the size of the queue varies based on the addition/removal of projects, 1,000 MW represents the current theoretical potential of transmission-connected storage that could be contracted by the Company under UDR processes. Some of these projects may be interested in participating in the Company's fifth UDR solicitation.

Assumptions

Transmission-connected storage can become part of the portfolio if the Company receives competitive bids. Further, for the transmission-connected storage assets to be considered for inclusion, they will need to be incremental, located in areas where they contribute to solving the transmission security constraint, and capable of being adequately charged and discharged without creating additional congestion or other issues on the system.

Proposed Next Steps

The Company is pursuing potential transmission-connected storage assets through UDR including a currently pending solicitation. The Company's currently pending UDR procurement RFP process closes to bidder entries on July 17, 2026, providing for evaluation of the bids in support of the portfolio.

Furthermore, under the Order Establishing Updated Energy Storage Goal and Deployment Policy in Case 18-E-0130, bulk energy storage assets not projected to be in-service by December 31, 2030, would be ineligible for UDR.[37] This deadline creates financing and development risk for projects currently in the NYISO interconnection study and projects that will participate in future studies. To that end, the Company is requesting the Commission extend the required in-service date for bulk energy storage assets to December 31, 2036. Though the order in Case 18-E-0130 "gives NYSERDA the ability to extend this in-service deadline for projects that have been delayed due to conditions beyond the control of the developer, based on proof that the project construction has commenced on or before December 31, 2030," there is no equivalent provision for the Company. Allowing the Company to enter into contracts with any UDR program participants up to December 31, 2036, will provide the necessary time to develop bulk storage capacity to help meet the Company's transmission security needs.

4.2 Distribution-Connected Battery Storage

The Company's proposed market-based portfolio includes distribution-connected storage projects contracted through a new Reliability Asset Dispatch Rights (RADR) program. Distribution-connected

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[36] Con Edison, Bulk Energy Storage Request for Proposals, *available at* https://www.coned.com/en/business-partners/business-opportunities/bulk-energy-storage-request-for-proposals/.

[37] Case 18-E-0130, *In the Matter of Energy Storage Deployment Program,* Order Establishing Energy Storage Goal and Deployment Policy (Dec. 13, 2018).

battery storage, when sited in the right locations, developed in the right quantities, and subjected to firm commitments, can assist in addressing transmission security needs.

Currently, more than 2,700 MW of third-party storage projects are advancing through the interconnection queue in the Company's service territory, with more than 1,000 MW already under executed SIR agreements. Most are seeking to operate under the existing VDER tariff, which was intended as value-based compensation for solar and then extended to battery storage. But several elements of VDER prevent the Company from being able to dependably rely on these assets to solve transmission security needs. For example, VDER assets operate on fixed, inflexible schedules, and VDER does not create the price signals needed to foster the consistent, daily performance required to address transmission security needs. Simply put, VDER was not designed to attract and manage assets that would operate flexibly to address reliability needs. As a result, there is a gap between the nameplate capability of storage resources in the Company's service territory and the ability of those storage resources to contribute to addressing reliability needs in any given year and over time.

The RADR program is designed to fill that gap by competitively procuring 15-year dispatch rights from distribution-connected battery energy storage projects that are currently (or would otherwise be) compensated under VDER so that they can be counted on to assist in addressing reliability needs. The RADR program is also designed to provide the greatest achievable value to customers, at the lowest achievable net cost, that was not available to them via the VDER tariff. The dispatch rights contract would allow the Company to establish and adjust distribution-connected storage operating requirements, such as the assets' discharge schedules, to support evolving system needs.[38] Program participants would receive periodic performance-dependent compensation in exchange for dispatching storage in compliance with the standardized long-term dispatch rights contract. The Company would reimburse participants for charging costs incurred during program participation and eligible interconnection costs for those that are not yet in operation. Because RADR assets are needed for reliability, they are distinguishable from non-RADR interconnections. Therefore, the Company, with Commission approval, will seek to prioritize interconnections of RADR assets to be ready to serve as reliable capacity for the identified system needs.

Projects enrolled in the RADR program would be contractually prohibited from participating in other programs or tariffs (e.g., the Company's demand response programs, VDER), but the Company would seek to dispatch RADR projects optimally for customer value, including for operational events, demand response, distribution system support and optimization, and/or for economic value, such as wholesale capacity and energy, when not needed for transmission security. Assets could be called upon for distribution and local events as system conditions and transmission planning considerations allow to maximize the benefit to customers. As grid needs evolve throughout the contractual period, dispatch schedules may change annually, seasonally, or as needed due to system conditions. These schedules will be designed to provide optimal value to the grid and customers.

The Company would provide DPS Staff with annual confidential reporting on RADR program costs, including itemized capacity procured via dispatch rights contracts, aggregate procurement totals, and associated program operating costs, to ensure that the program remains within its intended scope and continues to deliver value to customers.

[38] This flexibility may also unlock secondary benefits that would be fully passed on to customers. For example, after meeting reliability needs, there may be additional benefits or other opportunities to capture capacity, energy, or other delivery system value.

In short, RADR is structured to enable the Company to leverage distribution-connected storage to support transmission reliability, with the flexibility to use the assets to optimize for additional system and economic value at the lowest net costs achievable on behalf of customers. The Company's objective is to repurpose eligible VDER assets via a competitive procurement process into a firm RADR reliability program framework that implements these principles:

1. **Deliver Safe and Reliable Service:** RADR participants would be subject to contractual terms so as to deliver safe and reliable service and designed to uphold the Company's reliability criteria so that contracted batteries can be counted as firm capacity for transmission security needs.

2. **Prioritize Customer Affordability:** The RADR framework seeks to deliver on affordability by (i) competitively soliciting the lowest price and (ii) optimizing value by delivering residual system and economic value not otherwise available to customers under VDER.

3. **Support a Sustainable Value-Based Storage Market:** The RADR framework seeks to provide sustainable value to the market by offering developers prioritized interconnections and long-term 15-year revenue predictability without exposure to wholesale market prices or charging cost risks.

4. **Minimize Execution and Performance Risk:** The RADR contracts would include execution and commissioning commitments as well as clear performance requirements to support long-term dependability and minimize risks.

In summary, if approved by the Commission, under the RADR program:

Developers would receive:

(i) 15-year fixed compensation for long-term dispatch rights contracts with the Company
(ii) Prioritized interconnection
(iii) Covered interconnection costs for projects not yet in operation
(iv) Covered charging costs for charging before dispatch

Developers would commit to:

(i) Year-round availability for the 15-year contract term and non-participation in other tariffs or programs
(ii) Performance obligations and financial consequences for non-performance
(iii) Adherence to Company directives on dispatch and outage schedules
(iv) Terms of the standardized RADR program agreement the Company would issue before solicitation

Utility customers would receive (that was not available to them under the VDER tariff):

(i) Full transmission security reliability benefit for the contracted battery capacity
(ii) Residual value from distribution and other system optimization
(iii) Economic value for energy and capacity that can be optimized after reliability is assured
(iv) Year-round availability for reliability and economic needs as the grid evolves

4.2.1. Implementation

If approved by the Commission, the Company would proceed in two phases: (i) the Procurement and Contracting phase and (ii) the Development, Testing, and Operations phase.

Procurement and Contracting Phase

The Company would identify projects eligible to participate in the RADR solicitation. These would be projects at an advanced stage of the interconnection process located in areas where they can meaningfully contribute to meeting the identified transmission security needs. The Company also plans to pre-screen projects to assure they have viable pathways to energization and full-year operation and are not constrained from charging or discharging. By confining participation to projects in eligible locations, the Company would focus RADR procurements on projects that can best address the transmission security needs.

Once the Company has completed eligibility determinations, it plans to issue a RADR solicitation within 60 days, inviting developers with eligible energy storage projects to bid for 15-year "reliability capacity" dispatch rights contracts. Submissions would be evaluated on total price (i.e., the cost at which they are willing to provide full dispatch rights, assuming no wholesale market revenue and charging cost risks but with associated performance guarantees), including consideration of any reimbursable interconnection costs. The Company would also assess projects using qualitative criteria that include technical feasibility, bidder qualifications, constructability, and ability to satisfy reliability requirements. The Company would establish confidential price ceilings in consultation with DPS Staff to assure customers are receiving as much achievable value as possible at the lowest net cost.

Upon evaluation, and in consultation with DPS Staff, the Company would proceed to contracting based on a standardized program agreement. This program agreement would include a new interconnection agreement, or an amendment to a previously executed interconnection agreement, to reflect operating parameters consistent with RADR program requirements. Contracting would be limited to competitive proposals that meet the program and portfolio's evaluation criteria and be based on the confidential price ceiling and system needs. The Company intends to determine the clearing price (i.e., dollars per kilowatt-hour per year) below the ceiling based on the marginal selected RADR project and anticipates issuing awards based on a uniform clearing price. Further, the Company plans to provide periodic compensation for performance and charging costs incurred for operations.

As part of contracting, selected projects would undergo a structured enrollment process into the RADR program. Each participating developer would execute the standardized 15-year dispatch rights contract with the Company, affirming the terms under which the project would provide reliable capacity and the periodic compensation they would receive to provide those services. This contract would effectuate the project's transition to a reliability resource under utility dispatch control and would include performance requirements. As previously noted, a contract condition would require that each enrolled storage project participate solely in the RADR program for the duration of its RADR contract. At the end of the contract term, subject to Commission authorization, RADR assets may be eligible for reenrollment based on system needs.

Development, Testing, and Operations Phase

After contracting, the Company would focus on bringing RADR projects online. Because RADR assets are needed for reliability, they are distinguishable from non-RADR interconnections. Therefore, the Company would seek to prioritize interconnections of RADR assets so they can assist in addressing reliability needs.[39]

Enrolled projects will be required to meet minimum performance standards and, once they are operational, the Company would test their readiness. Performance and readiness standards would include delivering full contracted capacity, adhering to the Company's dispatch schedules, responding to dispatch signals within required timeframes, and adhering to approved outage schedules.

Throughout the administration of the program following initial testing, the Company would actively coordinate with participating developers to smoothly integrate RADR resources as a "reliability plus customer benefit" asset. The Company would also establish a process to provide program participants notice of additional periodic testing and validation, changes in system conditions, or reliability needs that could affect dispatch requirements and coordinate process management with the developer to effectuate Company directives. Assets could be called upon as needed not only for transmission security needs, but also for economic value or for distribution and local events. These additional uses would not detract from the assets' primary purpose of transmission security but would instead provide additional benefits to customers. As grid needs evolve, the Company would maintain the flexibility to change the assets' dispatch schedules to maximize those benefits to customers. The Company would treat all projects that meet their contractual obligations under the standardized agreement as firm capacity contributing toward meeting transmission security needs.

4.2.2. Regulatory Framework

The Commission should approve the RADR framework and authorize the Company to competitively solicit, select, and contract with VDER-eligible distribution-connected storage assets that can help address the transmission security needs. Specifically, the Commission should (i) authorize the Company to conduct a solicitation and establish confidential price ceilings, in consultation with DPS Staff, considering already committed costs under the VDER tariff as well as the value and benefits to customers from RADR, (ii) authorize the Company to enter into 15-year dispatch rights contracts with selected projects, and (iii) authorize the Company to recover costs associated with RADR.

Given the substantial customer funding already committed through VDER, the Company's objective is to repurpose assets to provide reliability and other value at the lowest possible net cost to customers. By introducing targeted obligations, long-term dispatch rights, and enhanced utility control, the RADR program would enable eligible VDER storage projects to transition into longer-term reliability assets capable of providing dependable support to the electric system. This approach prioritizes both reliability and affordability.

The Commission has authorized programs like RADR before. In 2018, as part of its Order Establishing Energy Storage Goal and Deployment Policy, the Commission directed utilities to competitively procure dispatch rights for energy storage (i.e., UDR). Starting in 2019, the Company began conducting competitive solicitations for UDR contracts under which it obtained full operational control of the storage system while

[39] Consistent with the Commission's January 2026 Order on Interconnection Queue Management—which directed utilities to prioritize the interconnection of a defined subset of distributed energy resource projects based on objective eligibility criteria—the Company proposes that prioritization of RADR projects is warranted, as it would accelerate the deployment of storage resources for system reliability needs and thereby serve the public interest. Case 24-E-0621, *Proceeding on Motion of the Commission in Regard to Modifications to the Standardized Interconnection Requirements*, Order on Interconnection Queue Management (Jan. 23, 2026).

developers retained ownership and received long-term compensation. To date, the Company has conducted four solicitations and contracted 185 MW of UDR projects (of which 15 MW of capacity is expected to be energized by the end of 2026).

The RADR framework follows the same dispatch-rights model the Commission authorized in the 2018 Storage Order—competitively procured, utility-dispatched storage—while tailoring programmatic requirements to address specific transmission security needs and optimizing for additional value to benefit customers.[40] The Commission recognized this framework provides a fixed revenue stream to developers while affording utilities the ability to dispatch energy storage systems to maximize benefits.[41]

The Commission should approve a similar approach here. First, RADR relies on competitive solicitations to secure dispatch rights from third-party storage resources, with utility operational control and cost recovery from customers. The main distinction is that RADR specifically targets already committed resources under the VDER tariff for transmission security needs, instead of for new entry to meet policy objectives. Second, the Commission has reaffirmed and refined this model in subsequent orders. In 2021, it confirmed the use of competitive solicitations and authorized longer contract terms.[42] In 2024, the Commission reaffirmed that UDR procurements remain an important component of the State's storage strategy.[43] Third, RADR is a reliability-focused program, and it is appropriate and consistent with Commission precedent that the Company recover RADR costs the same way it recovers costs for capital investments it makes for reliability.

Should the Commission approve the RADR framework, the Company will proceed under DPS Staff oversight, following an approach similar to that for UDR. The Company would engage DPS Staff before issuing solicitations, after receiving bids, and before entering into contracts. Specifically, the Company would submit to DPS Staff proposed procurement information, including confidential price ceilings, and after solicitation, would share results and consult on selection of winning projects before finalizing contractual agreements.[44] This approach balances timely, cost-effective action (by allowing the Company to run competitive procurements) with accountability and compliance (through DPS Staff oversight over the procurement).

4.2.3. Implementation Costs and Cost Recovery for RADR

The Company expects to incur upfront costs to stand up the RADR program and ongoing costs to administer the program and pay program agreement costs, as set forth in Table 7 below. As the costs incurred by the RADR program will benefit all customers, the Company is requesting Commission authorization to recover those costs, as set forth below.

At the outset, the Company expects upfront costs of approximately $3.5 million to facilitate the RADR solicitation, including costs for technical services, evaluation, and contracting with program participants.

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[40] *See* 2018 Storage Order, at 54 (directing utilities to issue RFPs "to competitively procure dispatch rights… based on local needs," including "local reliability services").

[41] *Id.*

[42] Case 18-E-0130, *In the Matter of Energy Storage Deployment Program*, Order Approving Tariff Amendments (Jan. 21, 2021); Order Directing Modifications to Energy Storage Solicitations (Apr. 16, 2021).

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

[44] In the 2018 Storage Order, the Commission directed that the bid ceilings not be released publicly due to the competitive nature of the procurements, and it should do the same here for the same reason.

The Company also expects to incur costs of approximately $1.5 million for an assessment of whether further information technology system enhancements are necessary to capture the full value of the RADR program for the Company's customers, as set forth above. The assessment will evaluate whether additional system investments or enhancements, or acceleration of currently planned capabilities are necessary to support the full implementation of the RADR program, given that administration and operation of the RADR program will require greater planning, coordination, and operational sophistication than is required for resources participating in existing Company programs or under the VDER tariff.

Beyond this initial phase, the Company's ongoing costs will include program implementation and support costs for activities such as enrollment management, planning, operations, measurement, validation, and settlement. The Company forecasts implementation and support costs scaled to the volume of assets enrolled in the program.

In addition to the upfront costs described above, the Company is providing estimates of costs to implement and support the program for the first five years and, considering uncertainty of estimating costs over the long term, anticipates seeking new Commission authorization for subsequent periods. For the first five years of RADR program implementation, the Company forecasts fixed implementation and support costs of $7 million per year, plus variable costs of $1 million per year per 50 MW enrolled in RADR. The Company's fixed costs are related to (i) establishment of program management infrastructure that includes enrollment management, operations, measurement and validation systems for performance management, settlement management and reporting; (ii) establishment of and implementation of processes for optimization of RADR assets for incorporation into forecasting and planning; (iii) establishment of processes and implementation of workflows related to interconnection study management and amendments to allow for flexible operations; and (iv) initial establishment of SCADA or related infrastructure, including secure communications with third-party battery assets. The Company's variable costs are related to (i) efforts necessary to prioritize interconnections of RADR assets; (ii) continued maintenance of SCADA or related infrastructure, including secure communications with third-party battery assets; and (iii) settlement management with more projects onboarding. The first five years represent a significant amount of activity to set up the fundamental infrastructure to manage a fleet of storage assets and optimize it to deliver the best value to customers. While the Company has developed the above estimates, it will further refine its program implementation cost estimates following procurement and report on such expenditures as part of its annual report.

The program's ongoing costs will also include the RADR contract costs, which include the fixed contract payments, battery charging costs, and, for storage systems not yet in service, interconnection infrastructure upgrade costs. The Company's actual expenses for these costs will depend on the market's response to the Company's solicitation, subject to the confidential bid ceiling to be shared with DPS Staff and limited to the resources necessary to satisfy the identified transmission security needs, accounting for uncertainty and the evolving nature of the need.

Finally, once an assessment of the information technology system upgrade needs is completed as described above, the Company will estimate costs for any necessary system upgrades and separately seek Commission authorization for them.

The Company proposes the following cost recovery mechanism for the RADR program, which is consistent with prior authorizations by the Commission for similar programs. This approach ensures that costs are allocated fairly and recovered in a manner that mitigates bill impacts to customers.

First, the Company proposes to defer and recover as a regulatory asset all program costs incurred to launch and implement the RADR program and the costs of battery charging and contract payments to RADR program participants. The Company would amortize these costs over a 15-year period to smooth bill impacts. The Company proposes to recover these costs from all full-service delivery customers, including customers served by the New York Power Authority, through a surcharge mechanism. This cost recovery treatment (i) provides that all customers who benefit from enhanced system reliability contribute to the funding of the program and (ii) aligns the timing of cost recovery with the timing of the long-term reliability benefits provided by the RADR assets. The unamortized net-of-tax balance of the regulatory asset would accrue carrying costs at the Company's pre-tax overall rate of return.

Second, the Company proposes to recover as capital the cost of any internal information technology system upgrades, including the cost of the initial assessment of information technology system upgrade needs. The Company would seek Commission approval, however, to execute any such upgrades following the initial assessment.

All incremental capital costs associated with the RADR program, including costs associated with interconnections, would be recorded as utility capital projects (i.e., as Construction Work in Progress and that accrues Allowance for Funds Used During Construction until the assets are placed in service). Upon being placed in service, these capital costs will be transferred to the appropriate plant-in-service accounts. The associated plant carrying costs, including a return on and of the capital investment (i.e., depreciation), property taxes, and other related costs, would be deferred and collected through the surcharge until such time as these costs are reflected in the Company's base rates in a future rate proceeding.

This ratemaking proposal is just and reasonable, is consistent with Commission precedent, and supports the deployment of cost-effective, market-based solutions to meet the State's reliability needs.

Table 7: Breakdown of RADR Program Costs[45]

<table>
<tr><th>Activity</th><th>Projected Cost</th><th>Recovery</th></tr>
<tr><td colspan="3">Initiation Phase</td></tr>
<tr><td>Procurement Implementation (RFP, technical services, evaluation, contracting)</td><td>$3.5M</td><td>Regulatory Asset</td></tr>
<tr><td>System Upgrade Assessment (contract/consulting)</td><td>$1.5M</td><td>Capital</td></tr>
<tr><td>Total</td><td>$5.0M</td><td></td></tr>
<tr><td colspan="3">Ongoing Costs Following Procurement</td></tr>
<tr><td>Program Implementation and Support</td><td>$7M plus $1M per 50 MW, both annually</td><td>Regulatory Asset</td></tr>
<tr><td>System Upgrades[46]</td><td>Pending Assessment</td><td>Capital</td></tr>
<tr><td>Compensation to RADR program participants (charging and contract payments)</td><td rowspan="2">Determined by Procurement[47]</td><td>Regulatory Asset</td></tr>
<tr><td>Incentives for RADR program participants (interconnection infrastructure upgrades)</td><td>Capital</td></tr>
</table>

4.3 Other Market-Based Solutions

Based on the Company's review of the responses to the RFI, there are other clean and non-emitting market-based solutions that could be leveraged to address the identified reliability needs (e.g., thermal storage/TENs, district steam-driven reliability solutions, or other firm solutions that meet the requirements for transmission security needs). Each solution, however, carries inherent execution risks, including customer or land acquisition, permitting, supply chain constraints, counterparty risk, and evolving market and policy dynamics. The Company's assessment of the RFI responses and potential market-based solutions is outlined in *Section 3: Evaluation of Market-Based Solutions* above. As noted in that section, many RFI responses lacked sufficient detail on project costs, demonstrated operational performance data, clear customer/site acquisition plans, etc. Therefore, the Company plans to issue a technology-agnostic RFP that would solicit binding financial commitments, detailed customer/site acquisition plans, execution timelines, and relevant supporting documentation, which are required to fully evaluate, acquire, and deploy potential non-battery storage solutions. Pending the outcome of the RFP, the Company will file a separate petition as appropriate with the Commission detailing its proposed cost recovery framework to procure any additional market-based solutions before executing any contracts.

4.4 Transmission Ratings Enhancement Projects

If the Company is not able to fully meet the projected ten-year needs with market-based solutions, or is unable to meet the needs in a cost-effective manner, the Company is also prepared to propose a

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[45] All incremental capital costs and total incentive value associated with the RADR program will be finalized when enrollment is complete.

[46] Additional program-related costs outside of program administration for software and technology upgrades will be established following procurement and announcement of winning bidders. The Company will seek authorization from the Commission through a separate petition before proceeding with the execution of any necessary system upgrades and incurring the associated costs.

[47] Determined by quantity of MWs that clear the confidential price ceiling in consultation with Staff, accounting for uncertainty and the evolving nature of the need.

transmission solution to increase the thermal rating of eight existing underground feeders (four 345 kV lines and four 138 kV lines) to enable the transfer of additional power from the rest of New York State into New York City (Zone J). This solution is alone insufficient to meet the full ten-year needs but could supplement the capacity delivered from the other market-based solutions.

The increase in rating would be achieved by adding refrigeration capabilities to existing cooling systems to further dissipate heat, enabling an increase in the maximum current flow while maintaining acceptable conductor temperatures. Increasing the ratings of these feeders is projected to provide approximately 300 MW of relief, 200 MW from the four 345 kV feeders and approximately 100 MW from the four 138 kV feeders. The Company has a long history of using dielectric fluid in feeder pipes to cool High-Pressure Fluid Filled underground cables to increase cable capabilities, including the use of refrigeration to maximize heat dissipation. While some Company feeders were designed with cooling from inception, others have been retrofitted to add or incrementally increase cooling capabilities.

While additional cooling to these feeders is projected to increase the import capacity into Zone J by up to 300 MW, the effectiveness of this solution depends on the availability of generation upstate. As noted by the NYISO in the draft 2025-2034 Comprehensive Reliability Plan, under baseline conditions the State may be short of necessary generation by 2032.[48] Therefore, to realize the benefit of these cooling efforts, at least 300 MW of additional firm generation or compensatory MW[49] is required outside of Zone J.

The Company is not seeking Commission action on the transmission ratings enhancement projects in this filing. As a preliminary step, however, the Company will develop initial plans that outline the expected cost, execution timeline, risks, and mitigations so that these projects can be approved by the Commission and commenced quickly if needed.

4.5 Modeling Results

To determine if the proposed portfolio could fully address the identified ten-year reliability needs identified in the July 2026 update (i.e., 125 MW in 2033, increasing to 675 MW by 2036), the Company performed power flow modeling on a combination of the above solutions across several scenarios to assess their performance in meeting the needs. This analysis was consistent with transmission planning practices and in accordance with the regional regulations, rules, and criteria outlined in *Section 3: Evaluation of Market-Based Solutions*. The modeling was designed to test whether the proposed solutions may meet transmission security needs; it is not dispositive, however, as some of the assumptions underpinning the analysis require action by the market and other parties (e.g., developers, the NYISO).

Based on the modeling results, the Company forecasts that the proposed portfolio could meet the needs in the ten-year horizon through 2036.

4.6 Modeling and Generation Assumptions

The ability of the Company's proposed portfolio to satisfy fully the transmission security needs depends on existing generation resources in the State remaining in-service through the ten-year need period. When modeling the portfolio, the Company assumed that any reduction in output due to generation

[48] NYISO, 2025-2034 Comprehensive Reliability Plan (Oct. 29, 2025), *available at* https://www.nyiso.com/documents/20142/54698854/Draft_2025-2034-Comprehensive-Reliability-Plan_MC.pdf.
[49] Case 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act*, Company Appendices (May 4, 2026).

retirements, derates, or other factors would be replaced with equivalent MWs; as a result, if equivalent MWs do not materialize, the need would likely increase.

The Company expects demand and its transmission security needs to continue to grow in years 11-20, as indicated in the updated reliability needs assessment. Should the needs grow beyond 2036, as anticipated, additional solutions will be required. While certain solutions in the portfolio can flatten the load curve by shifting demand over time (in the case of battery storage and other market-based solutions), they do not increase the supply of electrons. Moreover, if the Company ultimately undertakes the transmission ratings enhancement project discussed in *Section 4.4: Transmission Ratings Enhancement Projects* above, it will require additional generation outside Zone J to take advantage of the increased thermal rating of its transmission feeders.

The NYISO[50] and the State Energy Plan[51] have both indicated that incremental generation is needed within Zone J and/or elsewhere in the state with the capacity for transmission into Zone J. But as the Company is not allowed to develop or own generation assets, the development of these resources falls outside of its control. To that end, the Company assumes that if its transmission security solutions require additional generation, state policy and private market developers will enable the necessary electric supply.

4.7 Non-Binding Estimate of Cost

As the Company's proposed portfolio is composed of market-based solutions that will be procured through competitive solicitations, the Company cannot project the exact incremental investment necessary to address the identified needs. Based on non-binding cost estimates provided via the RFI process, of which only 40 of the 71 submissions provided sufficient financial information, the potential cost to procure market-based solutions ranges from approximately $100,000 per MW to $21.9 million per MW. Given this wide range, and omissions and/or inconsistencies in how financial information was presented in RFI submissions, the Company will leverage competitive solicitation processes to better assess the potential costs of market-based solutions.

To preserve the integrity of procurements associated with market-based solutions, the Company is not providing additional details on the projected costs for each proposed market-based solution in the proposed portfolio. Sharing this information could send unintended price signals to the market that could limit unbiased price discovery and inflate the costs of these solutions for customers. Where possible, the Company will seek to lower costs imposed on customers, including by seeking offsets through wholesale value realization or repurposing committed costs. For example, and consistent with the Company's May filing on VDER and Marginal Cost of Service,[52] the Company seeks to repurpose committed costs that would otherwise be paid through VDER.[53]

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[50] New York Independent System Operator, 2026 Power Trends: Annual Grid and Market Report (June 9, 2026), at 2, *available at* https://www.nyiso.com/documents/d/guest/2026-power-trends.

[51] New York State Energy Planning Board. December 2025. "2025 New York State Energy Plan." energyplan.ny.gov/Plans/2025-Energy-Plan.

[52] *Reliability Needs Proceeding* et al., Con Edison Comments to NY-BEST Petition and Additional Reply Comments to NY-BEST and NYSEIA's Motion for Emergency Rulemaking (May 4, 2026)

[53] Case 15-E-0751 et al., *In the Matter of the Value of Distributed Energy Resources*, Joint Utilities' Comments on DPS Staff Proposal on Updating DRV and LSRV for VDER Compensation, at 4 (Mar. 16, 2026) ("[I]n Con Edison's service area, nearly $2 billion of DRV compensation to energy storage projects has already been committed… if all projects currently in the Con Edison interconnection queue connect, this would grow to a utility customer cost of over $5 billion in DRV compensation alone over ten years….").

The Company is seeking to acquire a least-net-cost portfolio of solutions that accounts for execution and performance risks and can meet the reliability requirements in Zone J. Thus, as technology costs and market dynamics change over time, the Company will continue to evaluate and pursue cost-effective solutions to secure its transmission system.

4.8 Expected Impact on DACs

The Order required that the Company prioritize solutions that avoid or minimize impacts to DACs. As decisions regarding where market-based solutions are developed will be made by developers or building owners rather than the Company, it is possible that some projects will be developed in DACs. For these projects, the Company will defer to local zoning and permitting processes to mitigate the potential impact on these communities. For solutions located within the envelope of either existing buildings or buildings under construction, the Company anticipates little to no impact on DACs. For other potential technologies, to the extent possible, the Company will work with developers, building owners, and other relevant parties to minimize the potential impact on DACs. Moreover, future competitive solicitations will evaluate the long-term positive or negative impacts that proposed solutions may have on communities in the identified area, including customer experience impacts, environmental impacts and emissions, and enhancements or disruptions to the community (e.g., lower energy costs, noise, pollution, support for low-income housing). Preference will be given to solutions that provide benefits to DACs, such as incentives or reduced energy costs.

4.9 Summary of Proposed Portfolio

In developing this Plan, the Company evaluated a variety of market-based and traditional infrastructure solutions. Those included in the Plan meet the criteria for being clean and non-emitting, as well as for transmission security (such as full summer availability), and would be sited in beneficial locations. The Company has included transmission- and distribution-connected storage in the market-based solutions portfolio because the respective programmatic frameworks advance cost-effectiveness and affordability through offsetting customer costs where monetizable value can be realized (such as wholesale capacity and energy) while also considering costs already committed by customers. This portfolio leverages programs already in place and assets in an advanced stage of the interconnection process or beyond.

The Commission first approved UDR in 2018 to further the implementation of battery storage in New York. It is an established mechanism for deploying utility-scale storage that is dispatched by the Company and therefore provides benefits to the bulk system. The program is designed to minimize bill impacts on customers by offsetting customers' costs through wholesale revenues. Leveraging this existing program to competitively procure storage assets provides a straightforward implementation channel to meet reliability needs, benefiting both the grid and customers.

The proposed RADR framework would allow the Company to repurpose distribution-connected storage to deliver transmission security reliability benefits while also optimizing for residual secondary value passed to customers, such as wholesale capacity and energy and other transmission or distribution system relief. The RADR framework is cost-effective because the competitive procurement will consider the most cost-competitive projects, customers' costs are already committed to such storage via the VDER tariff, and the program can secondarily generate value on customers' behalf. Other options identified in the RFI or by the Company that could meet the transmission security needs are not able to leverage existing funds or provide the broader suite of benefits that RADR can.

Complementing these battery storage programs, the technology-agnostic RFP provides an additional path to meeting the need. The competitive RFP would inform the pricing and implementation approach of additional market-based solutions discussed above that can address transmission security needs but that the Company has not already included in its proposed portfolio. It would also provide a vehicle for other technologies to demonstrate that they can contribute to meeting the reliability need in a meaningful, cost-effective manner.

The Company has also identified solutions to increase the transfer capability into Zone J in the event market-based solutions are delayed or the need grows. For the reasons explained above, however, the Company is proceeding first with its proposed market-based portfolio.

While this combination of options faces the risks discussed throughout this Plan, it provides the most appropriate path to meet the identified reliability needs. Through robust planning and biannual updates, the Commission, Staff, and other stakeholders will have visibility into how the reliability needs are changing, how the identified solutions are progressing to meet that need, and whether additional actions by the Company, the Commission, or others may be required to meet the needs.

5. Resources Under Development

The Order also required the Plan to identify and assess "the generation, transmission, and other resources that are currently under development that could, when completed, contribute to meeting the identified reliability need."

For the purposes of this filing, the Company has established the following definitions:

- *Other resources* include transmission- and distribution-connected battery energy storage systems
- *Under development* includes:
    1. Generation, transmission, and transmission-connected storage assets in Zone J[54] included in the NYISO interconnection queue, including cluster projects, as of May 31, 2026,[55] that are not included in the Company's current projections as providing relief for this contingency;[56] and
    2. Distribution-connected storage assets included in the Company's SIR queue, as of June 2026

Below are details on the generation, transmission, and other resources under development, as defined above, that, if completed, may provide relief for this contingency. The Company must undertake additional analysis to determine the extent to which the projects identified below would contribute to meeting the identified needs.

[54] Resources located outside of Zone J could potentially provide relief of the transmission security needs, but further analysis is required.
[55] NYISO, *Interconnection Process*, *at* https://www.nyiso.com/interconnections
[56] Resources included in the NYISO interconnection queue, including cluster projects, as of May 31, 2026, that are included in the Company's projections as providing relief are Empire Wind 1 (generation), and three battery storage projects (Bayonne Energy Center III, Arthur Kill Energy Storage 1, and Astoria Energy Storage).

5.1 Generation

The Bluepoint Wind 1 project represents more than 1,300 MW of offshore wind generation capacity under development that is planned to interconnect in Zone J and could contribute to meeting the identified needs. Offshore wind capacity, however, is derated under the NYISO's transmission security assessment process. As such, 1,300 MW of nameplate capacity would only be counted as 130 MW (across all hours) during summer months. This project has a proposed commercial operation date of December 2033.

The Arthur Kill Unit 2 gas uprate project is also in the queue. Though the projected increase in capacity is not provided, any additional MW generated due to the uprate would contribute to meeting the needs.

5.2 Transmission

There are several transmission expansion projects currently under development in Zone J, with proposed in-service dates between 2029 and 2030. Based on a preliminary assessment by the Company, these projects would not provide any relief toward the identified reliability needs. This determination was based on the following factors: (i) the Propel NY Energy project originating outside of New York City is a policy-driven project designed to increase high-voltage transmission connections between Long Island and Westchester County and does not provide any incremental MW to New York City and (ii) the remaining projects are localized system reconfigurations internal to Zone J.

5.3 Other Resources

As discussed in *Section 4.1.2: Additional UDR Procurements*, there are currently more than 1,000 MW of transmission-connected storage capacity under development in Zone J that could potentially contribute to meeting transmission security needs. These projects range in size from approximately 50 MW to 300 MW and have projected commercial operation dates between 2027 and 2028, representing the current population that could be eligible for UDR procurement (subject to interconnection location and financial considerations).

As described in *Section 4.2: Distribution-Connected Battery Storage*, as of June 2026, there are approximately 1,700 MW of distribution connected battery energy storage systems in the Company's SIR queue, without executed interconnection agreements, in the early stages of development.[57] Should these projects be constructed and interconnected in the right locations, under an appropriate framework, they could contribute to meeting the transmission security needs.

Consistent with current practice, any additional generation, transmission, or other market-based solution type resources (whether identified above or developed in the future) that are confirmed by the NYISO (or, in the case of market-based solutions, by the Company), will be included in updates to the reliability needs assessment as incremental resources to help address the identified reliability needs.

6. Implementation Framework and Next Steps

As directed by the Order, the Company has outlined its recommended implementation framework and next steps for its Reliability Contingency Plan in this section. Specifically, this section addresses:

[57] This number excludes projects located in the transmission-constrained areas of Staten Island and portions of the Bronx and Upper Manhattan.

1. Proposed halting mechanisms
2. Recommended next steps for the proceeding
3. Requested authorizations

6.1 Proposed Halting Mechanisms

The Order requires the Company to incorporate appropriate halting mechanisms[58] into its plan. The Company's plan provides the Commission opportunities to direct the Company to change course on proposed market-based solutions. For example, as market-based solutions will be procured through competitive solicitations, the Commission could direct the Company to limit or not to issue a solicitation or RFP. Following a solicitation, the results will be shared with DPS Staff, with the appropriate follow-on actions identified. In the event a project is halted prior to becoming operable or entering service, the Company should be permitted to recover all prudently incurred costs associated with the project up to the point of halting, with the total costs incurred recorded to a regulatory asset for future recovery.

As described further in the next section, the Company may recommend proceeding, halting, or accelerating in-flight and/or planned solutions in future biannual updates.

6.2 Recommended Next Steps for the Proceeding

In compliance with the Order, the Commission directed the Company to update its reliability needs projection every six months following the first update filing, to provide transparency and increase public understanding of the electric system requirements driving the need for solutions. To achieve the intent of the Order, the Company will continue to provide the Commission updates every six months – with the next update in January 2027. Updates will be provided every January and July, with each update described below.

In the January filings, the Company will provide an updated needs assessment that identifies the reliability needs for the following rolling ten years and projected needs in years 11-20. This needs assessment will be based on the Company's most recent Local Transmission Plan,[59] which is typically completed in mid-November of each year, including the supporting power flow modeling results. The filing will also contain the Company's proposed adjustments to its portfolio based on the outputs of most recent needs assessment, progress on market-based solutions, and actions by other parties (e.g., development of additional generation and storage projects in New York). This filing may also include updates on other solutions should they be required.

In the July filings, the Company will provide progress updates on the individual solutions in the portfolio. It will also identify material changes to available energy supply (e.g., retirement or derating of existing generation, firming of new energy storage resources, etc.) based on the NYISO FERC 715 database and the NYISO Load & Capacity Data "Gold Book," which is available every year on or around April 1, and indicate their potential implications for the transmission security need. To provide additional visibility into potential impacts on customer demand, the Company will also provide an overview of recent policy and economic changes, as well as material demand changes (e.g., data on new large loads) and indicate their

[58] Defined in the Order as, "provisions by which the development of a selected solution may be deferred, delayed, or canceled if it becomes apparent that the solution will not be required. These mechanisms would serve to protect ratepayers from incurring unnecessary costs."
[59] Con Edison, *Transmission Planning*, https://www.coned.com/en/business-partners/transmission-planning/.

potential implications on the needs. As part of this July filing, the Company will also provide its annual report on RADR, as described in *Section 4.2.2. Regulatory Framework*.

Consistent with the Order, the Company will submit its next update in six months, including an updated needs assessment and status updates on each proposed solution.

6.3 Requested Authorizations

To facilitate implementation of the solutions described above, the Company is requesting approval of its Plan to meet the identified transmission security needs, along with the following specific authorizations from the Commission:

1. **UDR Deadline Extension:** Extend the bulk storage in-service deadline under the Utility Dispatch Rights program to December 31, 2036.[60]

2. **RADR Program Approval:** Approve the RADR framework and authorize the Company to transition eligible VDER resources into RADR through a competitive procurement process, prioritize their interconnections, and recover non-capital costs as a 15-year regulatory asset and capital costs as typical utility capital investments.

Commission approval will allow the Company to continue solicitations through UDR beyond the current deadline and launch the RADR program, all with appropriate oversight by DPS Staff and reporting to the Commission and the public, thereby enabling the Company to make progress toward addressing the identified transmission security needs.

7. Conclusion

Con Edison anticipates that the portfolio of market-based solutions in this initial reliability contingency plan will enable it to meet the currently identified ten-year transmission security needs. At the same time, the Company will have to remain flexible to adapt to changing circumstances, including ongoing updates to its needs forecast, the anticipated growth of its transmission security needs beyond the current ten-year window, the potential maturation of new technologies that can help address these needs, and ongoing state and local policy changes that may affect the deployment of reliability resources. For these reasons, the Company anticipates continued coordination with the Commission, Department Staff, market participants, and other stakeholders as it implements the solutions for which it now seeks Commission approval.

[60] If approved, the Company would continue its current practice of engaging with Department of Public Service Staff before initiating efforts to procure additional transmission-connected storage.

Appendix – List of Acronyms

BEC – Bayonne Energy Center
BTM – Behind-the-Meter
DAC – Disadvantaged Communities
DEC – Department of Environmental Conservation
DERs – Distributed Energy Resources
DPS – Department of Public Service
EPRI – Electric Power Research Institute, Inc.
EE – Energy Efficiency
EE/BE – Energy Efficiency/Building Electrification
EV – Electric Vehicle
FDNY – Fire Department of New York
kV – Kilovolt
MW – Megawatt
MWh – Megawatt Hour
NPCC - Northeast Power Coordinating Council
NYISO – New York Independent System Operator
NYSERDA – New York State Energy Research Development Authority
RADR – Reliability Asset Dispatch Rights
RFI – Request for Information
RFP – Request for Proposals
Q3 – Third Quarter
SME – Subject Matter Expert
STAR – Short-Term Assessment of Reliability (published by the NYISO)
TENs – Thermal Energy Networks
VPP – Virtual Power Plant
UDR – Utility Dispatch Rights