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NOTICE¹

IN THE MATTER OF ADVANCING VIRTUAL POWER PLANT (VPP) PROGRAM IN THE STATE OF NEW JERSEY

IN THE MATTER OF THE GARDEN STATE ENERGY STORAGE PROGRAM—PHASE 2 DISTRIBUTED STORAGE

IN THE MATTER OF NEW JERSEY’S DISTRIBUTED ENERGY RESOURCE PARTICIPATION IN REGIONAL WHOLESALE ELECTRICITY MARKETS

IN THE MATTER OF DEVELOPING GRID FLEXIBILITY SERVICES FOR AGGREGATED DER PARTICIPATION IN NEW JERSEY’S MODERNIZED ELECTRIC GRID

IN THE MATTER OF DEVELOPING INTEGRATED DISTRIBUTED ENERGY RESOURCE PLANS TO MODERNIZE NEW JERSEY’S ELECTRIC GRID

REQUEST FOR INFORMATION

Docket Nos. [QO26030099](#), [QO26040116](#), [QO24020116](#), [QO26030059](#), [QO24030199](#)

Staff of the New Jersey Board of Public Utilities (“NJBPU” or “Board”) hereby invites all interested parties and members of the public—especially third-party distributed energy resource (“DER”) aggregators; energy storage developers, owners, and operators; and the four Electric Distribution Companies (“EDC”): Atlantic City Electric, Jersey Central Power & Light, Public Service Electric & Gas, and Rockland Electric Company—to provide written responses to this Request for Information (“RFI”) on the evaluation and development of distributed energy resource programs across two coordinated program areas: the Virtual Power Plant (“VPP”) Program and Phase 2 (Distributed Storage Segment) of the Garden State Energy Storage Program (“GSESP”).

¹ Not a paid legal advertisement.

This RFI is issued pursuant to Governor Mikie Sherrill's Executive Order No. 2 ("EO2"),² which directed the Board, within 180 days of January 20, 2026, to commence the development of a VPP program in New Jersey to be administered by electric distribution utilities and third-party suppliers,³ and, within 90 days, to launch Phase 2 of the GSESP, accelerating the deployment of distribution-scale battery storage incentives while the Phase 1 transmission-scale program continues.⁴ Because Phase 2 resources—distributed battery storage systems—are part of the foundational assets for future VPPs, the Board is issuing this RFI to solicit information on both programs to ensure that the programs are coordinated.

The Board is accepting written and/or electronic responses regarding this Request for Information. All public responses should be filed under Docket No. [QO26030099](#); responses will be available in the other dockets after all filings are received.

The deadline for responses on this matter is 5 p.m. on May 20, 2026.

Please submit responses directly to the specific docket using the "Post Comments" button on the Board's [Public Document Search tool](#).

Comments are considered "public documents" for purposes of the State's Open Public Records Act, and commenters may identify any information that they seek to keep confidential by submitting them in accordance with the procedures set forth in N.J.A.C. 14:1-12.3. In addition to hard copy submissions, confidential information may also be filed electronically via the Board's e-filing system or by email to the Secretary of the Board. Please include "Confidential Information" in the subject line of any email. Instructions for confidential e-filing are found on the Board's webpage, <https://www.nj.gov/bpu/agenda/efiling/>

Written comments may also be submitted to:

Sherri L. Lewis
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Staff look forward to receiving and reviewing stakeholder responses.

Sherri L. Lewis

Sherri L. Lewis
Secretary of the Board
Dated: April 20, 2026

² Exec. Order No. 2 (Jan. 20, 2026), 58 N.J.R. 1041(a) (Feb. 17, 2026) ("EO2").

³ Id. § 4.

⁴ Id. § 3.

Respondents are invited to submit written comments addressing one or more of the following topics:

Section 1. Virtual Power Plant Program (VPP Program):

- A. Assessing the DER assets in the State of New Jersey
- B. Exploring opportunities to strategically design DER aggregations in the State of New Jersey
- C. Examining compensation mechanisms for an effective DER aggregation market
- D. Defining the roles of utilities, third-party aggregators, and the system operator for the VPP Program

Section 2. Phase 2 (Distributed Storage Segment) of the GSESP

- A. Current Technical Capabilities and Limitations
- B. Distribution System Impacts and Operational Constraints
- C. Measurement, Data, and Verification Readiness
- D. Dispatch, Overrides, and Operational Priority
- E. Pathway to Future Aggregation / VPP Participation
- F. Customer Participation, Equity, and Adoption Impacts
- G. Cost Effectiveness and Ratepayer Impacts
- H. Incentive Levels for Distributed Storage Projects
- I. Program Administration and Scalability Inputs
- J. Front-of-the-Meter (FOM) Eligibility

Section 3. Additional Comments

- A. Comments on VPP Program and Phase 2 (Distributed Storage Segment) of the GSESP

BACKGROUND AND PROCEDURAL HISTORY

On January 20, 2026, Governor Mikie Sherrill issued EO2, declaring a statewide energy emergency and affirming the urgent need to strengthen grid reliability and resiliency in light of rapidly rising electricity demand and mounting affordability challenges in New Jersey. EO2 identified a widening gap between electricity supply and demand in the PJM Interconnection, L.L.C. (“PJM”) regional market and recognized that this imbalance is a significant driver of New Jersey’s electricity affordability crisis. Absent timely action to accelerate new generation, expand distributed energy resources, and cost-effectively manage load growth, the PJM region faces elevated risks of involuntary load shedding, brownouts, and blackouts during periods of peak demand, with serious attendant threats to public health, safety, and welfare.

To address these reliability and affordability challenges, EO2 established two complementary directives that together form the basis for this RFI. First, EO2 directs the Board to, “within 180 days, commence the development of a ‘virtual power plant’ program in the State to be administered by electric distribution

utilities and third-party suppliers to drive down peak demand by aggregating behind-the-meter distributed energy resources.”⁵ For the purpose of this RFI, VPP is defined as “aggregations of DERs that can balance electrical loads and provide utility-scale and utility-grade grid services like a traditional power plant;”⁶ DER has the same meaning as defined in N.J.A.C. 14:8-5.1 which is defined as “the equipment used by an interconnection customer to generate and/or store electricity that operates in parallel with the electric distribution system. A DER may include, but is not limited to, an electric generator and/or energy storage system, a prime mover, or combination of technologies with the capability of injecting power and energy into the electric distribution system, which also includes the interconnection equipment required to safely interconnect the facility with the distribution system.”⁷ Furthermore, EO2 directs the Board to launch “Phase 2 of [the GSESP]” within 90 days of EO2, accelerating the deployment of distribution-scale storage incentives by establishing a dedicated tranche of capacity to support the interconnection of distributed energy resources and grid stability. Phase 2 is designed to consist of two incentive components: a fixed incentive provided via capacity blocks released on a periodic basis, and a performance incentive paid to projects in proportion to the value they provide—such as the value associated with reducing on-site load and/or injecting power into the distribution system during designated performance hours over a period of 10 years.

The Board’s engagement on DER aggregation policy also reflects federal policy under FERC Order No. 2222 (“Order 2222”), which required regional transmission organizations (“RTO”) and independent system operators (“ISO”) to lower barriers to participation in wholesale markets for DERs and DER aggregators.⁸ Under Order 2222, aggregators participate directly in regional wholesale markets on behalf of ratepayers who possess or utilize DERs, enabling aggregated DERs to provide meaningful capacity, energy, and ancillary services to the grid. As of the date of this RFI, PJM has enabled DER aggregation participation in the capacity market beginning with the 2028/2029 delivery year Base Residual Auction (“BRA”), and in the energy and ancillary services markets beginning February 1, 2028.⁹ These timelines underscore the urgency for the Board to ensure New Jersey DERs are positioned to participate in wholesale markets, especially since under PJM rules a DER aggregation will need to submit a notice of intent to PJM by June 12, 2026, to participate in the 2029/2030 BRA and by December 1, 2026, to participate in the 2030/2031 BRA.¹⁰ Building on this federal framework, the Board has undertaken a series of actions to advance DER aggregation and storage deployment in New Jersey, including an initial RFI specifically addressing Order 2222 in March 2024 and a technical conference in January 2025.¹¹

In parallel, the Board has advanced the GSESP, New Jersey’s primary vehicle for accelerating energy

⁵ Id. § 4.

⁶ Jennifer Downing, Loan Program Office et al., U.S. Dep’t of Energy, Pathways to Commercial Liftoff: Virtual Power Plants (2023), https://climateprogramportal.org/wp-content/uploads/2025/06/LIFTOFF_DOE_VPP_2023.pdf.

⁷ N.J.A.C. § 14:8-5.1, New Jersey Register, Vol. 58 No. 7, April 6, 2026.

⁸ Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, 86 Fed. Reg. 33853 (June 28, 2021) (codified at 18 C.F.R. pt 385).

⁹ Andrea Yeaton, Lead Operations Analyst, PJM, Order 2222 Registration Process 7 (Apr. 6, 2026), <https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/disrs/2026/20260406/20260406-item-03-1--ferc-order-2222-timeline-and-registration-process---presentation.pdf>.

¹⁰ See Auction Schedule, PJM, <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/rpm-auction-schedule.xlsx> (last visited Apr. 12, 2026); PJM Open Access Transmission Tariff, Attach. DD, § 5.5.

¹¹ In re New Jersey’s Distributed Energy Resource Participation in Regional Wholesale Electricity Markets, Notice of Request for Information, BPU Docket No. EO24020116, Notice dated Mar. 7, 2024; Notice of Technical Conference, In re New Jersey’s Distributed Energy Resource Participation in Regional Wholesale Electricity Markets, BPU Docket No. EO24020116, Notice dated Jan. 7, 2025.

storage deployment across the state. On June 18, 2025, the GSESP was launched, following a 2-year period of extensive stakeholder engagement. The GSESP's 2025 launch opened its first tranche of Phase 1, which solicited 350-750 MW of transmission-scale storage projects ("Tranche 1"). While stakeholdering has been previously conducted on Phase 2, this RFI will seek to solicit additional information on Phase 2 design in light of the Board's efforts to also develop and deploy a VPP program to ensure both programs are effectively and efficiently coordinated to the greatest extent possible. Phase 2 is intended to consist of two incentives paid to each project, including: a fixed incentive provided via capacity blocks released on a periodic basis, and a performance incentive. Performance incentives will be paid to projects in accordance with the value they provide, such as the value associated with the reduction of on-site load and/or injection of power into the distribution system when called upon during certain performance hours.

Furthermore, the Board's demand flexibility work provides important context for this RFI. On November 25, 2025, the Board issued a straw proposal for the Third Triennium of the Energy Efficiency and Peak Demand Reduction Programs,¹² which included a demand flexibility roadmap describing the evolution from existing direct load control programs toward open grid flexibility services markets across retail, wholesale, and non-wires solutions. Stakeholder comments were broadly supportive of capturing the full value stack across wholesale and retail markets.

The Board has also advanced managed EV charging which EO2 cites as a foundational VPP use case:¹³ a 2020 Order established light-duty EV charging programs, and an October 2024 Order established Minimum Filing Requirements ("MFR") for medium- and heavy-duty EV charging,¹⁴ requiring EDCs to propose managed charging programs that reduce peak demand and share charging data with the Board. The Board also called for the EDCs to utilize this information in order to propose more robust programs that "incent EV owners to use charging services in a manner that has the least impact on the reliability and costs of [an EDC's] distribution system."¹⁵ The data that has been collected from the residential chargers in particular can serve as a ready resource when creating VPPs to effectuate EO2.

The Board is also advancing AMI data access standards that are foundational to VPP operations. In September 2025, the Board proposed new rules under N.J.A.C. 14:5-10 establishing customer ownership of Advanced Metering Infrastructure ("AMI") meter data, standardized data sharing through the Green Button Standard, and non-discriminatory third-party access to that data.¹⁶ By enabling aggregators and VPP platforms to access granular, interval-level usage data with customer authorization, these rules directly support the enrollment, dispatch, and measurement and verification functions that an effective VPP Program will require.

Additionally, the Board has developed the Grid Modernization Forum ("GMF"), a collection of expert stakeholder workgroups focused on increasing DER hosting capacity and grid flexibility in New Jersey.

¹² In re the Implementation of P.L. 2018, c. 17, the New Jersey Clean Energy Act of 2018, Regarding the Third Triennium of Energy Efficiency and Peak Demand Reduction Programs, Notice of Straw Proposal, BPU Docket No. QO25050300, Notice dated Nov. 25, 2025.

¹³ Ibid.; EO2.

¹⁴ In re of Minimum Filing Requirements for Light-Duty, Publicly-Accessible Electric Vehicle Charging, BPU Docket No. QO20050357, Order dated Oct. 20, 2020; In re Medium and Heavy-Duty Electric Vehicle Charging Ecosystem, BPU Docket No. QO21060946, Order dated Oct. 28, 2024.

¹⁵ In re the Petition of Atlantic City Electric Company for Approval of a Voluntary Program for Plug-In Vehicle Charging, BPU Docket No. EO18020190, Order dated Feb. 17, 2021.

¹⁶ 57 N.J.R. 1949(a) (Sept. 2, 2025).

To date, the GMF has launched two workgroups: the Integrated Distributed DER workgroup (“IDDER”),¹⁷ whose goal is to develop an MFR for EDCs to file Proactive System Upgrade Plans (“PSUPs”) that outline how each EDC will proactively evolve its distribution grid into a more adaptive, flexible system with higher DER hosting capacity. The second workgroup is the Grid Flexibility Services workgroup (“GridFlex”),¹⁸ with the goal to develop tariffs that enable interoperable DERs to provide distribution-level services—such as energy generation and voltage response—to EDCs and be compensated for them. Because the PSUP MFR has not yet been finalized, the Board expects VPP Program design to be revisited as needed to remain consistent with the distribution plans EDCs ultimately file.

This RFI is issued by the Board to solicit stakeholder input on the design and implementation of both the VPP Program and Phase 2 of the GSESP, with the goal of ensuring these two programs are developed in a coordinated and mutually reinforcing manner. The VPP Program will be enabled by EDC-filed PSUP capabilities, and its implementation will be aligned to the grid flexibility service architectures, both of which are the result of GMF. The Board is committed to developing a regulatory structure that recognizes the full value of aggregating DERs—reducing peak demand, enabling market competitiveness among third-party aggregators, and enabling full participation in PJM wholesale energy markets. The responses received will inform Board staff’s policy recommendations on establishing the VPP Program and launching Phase 2 of the GSESP, with the goals of facilitating DER interconnection and peak electricity demand reduction, increasing market competition, improving grid reliability and resiliency, and ensuring energy affordability for New Jersey ratepayers.

QUESTIONS

Respondents are encouraged to answer any of the following questions they consider relevant to the best of their ability. These questions are intended to help the NJBPU formulate sound policies and programs around key aspects of VPP and GSESP implementation in the State of New Jersey. Respondents are not required to answer all questions for their submission to be considered. Answers are understood to be preliminary and non-binding. Respondents may expand beyond the scope of these questions and/or structure responses as necessary to increase clarity and efficiency. Additional information deemed relevant may also be submitted, including past responses to relevant Board proceedings. The Board is particularly interested in non-proprietary results obtained from programs implemented in other state jurisdictions, as these can support data-driven policy decisions, as well as legislative proposals in other states. *For 3rd-party DER aggregators and other service providers responding to this RFI, please specify the type of aggregation services, if any, your organization provides. Please also identify which role or roles your organization fulfills in the DER ecosystem, for example, but not limited to: original equipment manufacturer (OEM), project developers, system integrator, hardware provider, software or DER Management Systems (DERMS) platform provider (including aggregator-edge or grid DERMS), retail energy provider, curtailment service provider (CSP), or a combination of these roles.*

When answering the following questions, please include the section letter and the question number (e.g., *Answer 1.a.* and *Answer 3.b.i.*).

¹⁷ In re Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey’s Electric Grid, BPU Docket No. QO24030199, Notice dated Jun. 5, 2024.

¹⁸ In re Developing Grid Flexibility Services for Aggregated DER Participation in New Jersey’s Modernized Electric Grid, BPU Docket No. QO26030059, Notice dated Apr. 8, 2026.

Section 1. Virtual Power Plant Program (VPP Program)

A. Assessing the DER assets in the State of New Jersey

1. **For EDCs and 3rd-party aggregators:** What types of DER (e.g., solar, battery storage, EVs, load control devices, smart appliances, and service panels) and associated infrastructure have been deployed and integrated within your service or program territory?
 - a. Please provide information on the number of available DER by type, average capacity of each type of DER, and DER Type locational data (by New Jersey Counties). Example table:

DER Types	Number	Average Capacity (kW)	Top Three New Jersey Counties
Behind the Meter Battery Storage			
Electric Vehicles (EVs)			
Solar			
(Please expand with other relevant DER assets as necessary)			

2. **For EDCs and 3rd-party aggregators:** Are existing interconnection, telemetry, metering, and grid-visibility requirements, as outlined in both the BPU’s proposed AMI rule proceedings and PJM’s Order 2222 compliance filings,¹⁹ sufficient to support reliable DER aggregation and VPP operations at scale? If not, what specific enhancements (e.g., data granularity, signal response times, DER registry functionality) should the Board consider?
 - a. What is the anticipated timeline for implementing these enhancements?
 - b. What is the anticipated cost to implement the infrastructure upgrades?
 - c. Please describe the requirements that are being met/planned to meet.
 - d. Are there any technology specific (i.e. EV, thermostat, storage) requirements that must be met beyond those described above? If so, what are the anticipated timelines and costs to meet those requirements?

*For purposes of Question 3, the Board distinguishes between two functional layers of DER management systems (DERMS): the **Grid DERMS** is the utility-operated platform that manages DERs from the grid operator’s perspective—providing system-wide visibility, integrating with distribution operations infrastructure (e.g., ADMS, AMI, SCADA), and issuing or executing dispatch signals at the distribution grid level. The **Edge (customer-side) DERMS** is the platform—operated by an EDC or a third-party aggregator—that communicates directly with individual BTM devices, manages customer devices, and*

¹⁹ In re a Rulemaking Proceeding to Establish AMI Data Access Standards, Notice of Proposed Rulemaking, BPU Docket No. EX24090717, Notice dated Sep. 17, 2024; 30-Day Compliance Filing to Re-Date eTariff Records for PJM’s Order No. 2222 Participation Model, FERC Docket No. ER22-962-008, (May 29, 2025).

aggregates smaller resources into dispatchable portfolios. Both layers must function and interoperate effectively for the VPP Program and GSESP Phase 2 to succeed.

3. **For EDCs and 3rd-party aggregators:** Please describe the current and planned status, technology, and capabilities of your DERMS, distinguishing between coordinating grid DERMS and edge DERMS.
 - a. **Grid DERMS**—What coordinating grid DERMS platform(s) do you provide, operate or have under procurement? Describe how the platform integrates with Advanced Distribution Management System (“ADMS”), Advanced Metering Infrastructure (“AMI”), SCADA systems, and other distribution grid management platforms.
 - b. **Edge (customer-side) DERMS**—What edge DERMS platform(s) do you provide, currently operate or have under procurement for managing BTM assets such as battery storage, solar, EVs, smart appliances and service panels?
 - i. Identify which customer classes (residential, commercial, industrial) each platform supports, and are these open or proprietary standards?
 - ii. What technical, contractual, or cybersecurity barriers currently limit the platform’s ability to support device-agnostic aggregation of heterogeneous BTM assets into a coordinated VPP portfolio?
 - c. **Interoperability between coordinating grid DERMS and edge DERMS**—What is the current level of two-way data exchange between your grid-DERMS and edge-DERMS? What communication protocols and interoperability standards (e.g., OpenADR, IEEE 2030.5) does the platform rely on to send control, measurement, and verification signals to BTM devices?
 - d. **Coordinated Dispatching Signals**—How does, or how will, your grid and/or edge DERMS manage potential conflicts between competing market signals (e.g., retail, wholesale, or customer opt-out signals)?
4. **For EDCs and 3rd-party aggregators:** What upgrades, timelines, and costs are needed for scalable bidirectional DERs, including bidirectional EVs, for the standalone management of these assets?
 - a. What is the relative cost increment to enable bi-directional power flow (e.g., infrastructure upgrades)?
 - b. What is the incremental cost of allowing DERs to export energy?
 - c. Please detail your plans to expand the presence of bidirectional EVs and describe the anticipated timeline for implementation through February 1, 2028.
5. **For EDCs and 3rd-party aggregators:** What are the technical and programmatic barriers between unidirectional load management and bidirectional power flow DERs as part of the configuration and orchestration of the VPP (e.g., V1G compared to V2G)?
 - a. Are there substantial differences in the control method and metering requirements for these resources?
 - b. Are the impacts of these resources on the electric distribution system fundamentally different? If so, how?
 - c. Is a limitation on exporting energy permanent, or can it be lifted flexibly?

- d. Please describe what Measurement & Verification (“M&V”) methodologies you utilize to account for EVs.
6. **For EDCs:** Please describe your plans to utilize the DOE’s Green Button Connect initiative.
 - a. If you have not, what intention do you have to utilize the Green Button Connect initiative?
 - b. What is the expected cost of making the necessary infrastructure upgrades to participate in the DOE’s Green Button Connect initiative?
 - c. What is your anticipated timeline to incorporate the Green Button Connect initiative?
7. **For EDCs:** Please describe the current AMI meter capabilities within your service territory and your readiness to meet PJM's telemetry and data transmission requirements for DER aggregation participation under Order No. 2222:
 - a. What percentage of AMI meters deployed in your service territory are currently capable of transmitting interval data at five-minute resolution or less? To the extent your current deployment does not meet PJM's data interval requirements for DER aggregation's participation in the capacity market, please describe what upgrades are needed, the estimated cost, and your planned timeline for achieving compliance.
 - b. Please identify the smart meter OEM(s) and product model(s) currently deployed or under contract as part of your AMI deployment plan, and describe how meters are procured (e.g., competitive procurement, sole-source contract, framework agreement).
 - c. What percentage of your deployed smart meters support near-real-time bidirectional data transmission at sub-minute intervals sufficient to enable participation in PJM's frequency regulation market by aggregated DERs? What technical, contractual, or regulatory barriers would need to be resolved to expand that capability, and what is your plan to address them?
8. **For EDCs:** How will this response align with your future Proactive System Upgrade Plan (PSUP) filing? Please explain how your response aligns with your future PSUP filing and help further enable DERs in more advanced VPPs along that long-term planning horizon.

B. Exploring opportunities to strategically design DER aggregations in the State of New Jersey

9. **For all stakeholders:** What specific state-level VPP minimum viable products (“MVP”) and market structures (e.g., programs, tariffs, procurement mechanisms, monitoring, a DER Registry) would most effectively enable DERs to participate competitively in New Jersey? While the Board’s desired timeline is to establish the initial MVP structures within one year, respondents are encouraged to propose longer-term approaches, including models from other jurisdictions, where near-term implementation is not feasible or will require additional later steps.
 - a. What additional market structures or regulatory frameworks are needed to enable a retail distribution-level market that are not covered in FERC Order No. 2222?
 - b. What percentage of an EDC’s Peak Load Share should be used as a goal for reducing peak energy demand through the orchestration of DER aggregators? Please specify which percentage value you feel is feasible to achieve by February 1, 2028.

- i. Should such goals include technology specific subgoals? If so, please propose such goals.
- 10. **For all stakeholders:** Should New Jersey adopt state-level eligibility criteria or aggregation thresholds for DER participation that differ from PJM's minimum 100 kW aggregation size for retail markets or local programs, and if so, how and why?
 - a. Should New Jersey adopt maximum aggregation thresholds that differ from PJM's maximum MW?
- 11. **For EDCs and 3rd-party aggregators:** What forms of data and operational infrastructure (e.g., DER registries, scheduling/dispatch platforms, forecasting tools, and grid needs assessment) are needed to organize, track, and dispatch DER aggregations?
 - a. Should any DER registry be managed at the state level or separately by each EDC?
- 12. **For EDCs and 3rd-party aggregators:** Do your current or planned DER aggregation programs support device-agnostic aggregations that have the ability to combine heterogeneous DER assets from different manufacturers (e.g. EV, smart thermostats, battery storage, smart appliances) into a single, coordinated portfolio to provide distribution grid services?
 - a. Please describe what communication protocols or interoperability standards enable this multi-device aggregation. Are these proprietary or open system?
 - b. What technical or regulatory barriers must be addressed to support device-agnostic DER Aggregation participation at scale in New Jersey?
- 13. **For 3rd-party aggregators:** What do third party aggregators need to allow them to enroll non-storage assets that are seeking to add storage via a distributed storage program? Are there specific grid configurations that should be required to allow for participation in aggregation models?

C. Examining compensation mechanisms for an effective DER aggregation market

- 14. **For all stakeholders:** What distribution-level grid services (e.g., local peak demand reduction, feeder-level congestion relief, reverse power flow) should the Board define and prioritize for future programs?
 - a. What methodology should be used to determine values of those distribution grid services?
 - b. Should there be a phased approach to developing a distribution-level grid services market (e.g., starting with closed pilot program in the distribution-constrained areas before transitioning to an open competitive market) in New Jersey? What performance metrics should the Board develop to govern such a transition?
- 15. **For all stakeholders:** What compensation and tariff designs (e.g., value-stacking, pay-for-performance, dynamic or time-varying rates) would best align DER and aggregator incentives with system needs and customer value?

16. **For all stakeholders:** What technical, regulatory, or economic barriers limit DER adoption and aggregation for New Jersey customers, particularly in low- and moderate-income (LMI) communities, and what specific strategies or programs do you recommend to address these barriers?

D. Defining the roles of utilities, third-party aggregators, and the system operator for the VPP Program

17. **For EDCs:** Please describe how you currently use, or plan to use, third-party aggregators and contractors to enroll, organize, and dispatch DER aggregations to support grid reliability and resiliency, and identify any issues encountered to date. Please describe in detail how dispatch events are determined, response rates, dispatch goals, response goals etc.

18. **For EDCs:** With existing (or planned) VPP and/or Demand Response programs, please summarize:

- a. What is the current (planned) status and scale of your program (e.g., DER types, MW enrolled, number of participating customers, customer segments), and what share of this portfolio is managed by 3rd-party aggregators versus directly by the EDC?
- b. How are portfolio management and performance measurement responsibilities currently divided between the EDC and 3rd-party aggregators, and what metrics are used to evaluate program performance?
- c. What key challenges and lessons learned to date (e.g., technical, operational, customer-related, or regulatory) are shaping your near-term plans for program expansion or modification?
- d. To what extent does a resource's location—such as proximity to hosting capacity constraints or congested feeders—influence enrollment priority or the value assigned to its participation in your program?

19. **For EDCs:** Please describe the incentive structure for the programs described in response to question 18:

- a. Does your program provide upfront or performance-based incentives to encourage customers to install and enroll assets (e.g., battery storage, smart thermostats, EV chargers)? Please describe:
 - i. the incentive structure (e.g., upfront payment, annual performance payment, per-event payment, or combination); and
 - ii. the methodology used to determine the incentive level, including what grid services or avoided costs the incentive is intended to reflect.
- b. What are the terms and conditions governing incentivized assets, including:
 - i. who owns the asset and for how long the EDC retains dispatch rights;
 - ii. what infrastructure investments (e.g., grid DERMS, edge DERMS, telemetry, hardware) have you made or contracted for to coordinate these assets, and how those costs are recovered;
 - iii. would any projects receiving existing incentives need additional performance incentives/payments under future GSESP or VPP programs; and

- iv. how do you ensure incentivized assets continue to perform over the program term, and what remedies apply in cases of non-performance?
20. **For EDCs and 3rd-party aggregators:** Do your current or planned VPP and/or Demand Response services/programs support technology neutral aggregation—that is, the ability to combine heterogeneous DER assets from different manufacturers (e.g., EV, smart thermostats, battery storage, smart appliances) into a single, coordinated portfolio?
- What communication protocols or interoperability standards enable this multi-device aggregation, and what technical or regulatory barriers must be addressed to support device-agnostic VPP participation at scale in New Jersey?
21. **For EDCs and 3rd-party aggregators:** What coordination mechanisms (e.g., data-sharing protocols, operational agreements, scheduling/redispach processes) are needed between EDCs, Original Equipment Manufacturers (OEMs) and 3rd-party aggregators to maximize distribution-level operations and planning of DER aggregator participation and assure flexibility for all participants?
22. **For all stakeholders:** What VPP program designs, market structures, or operational models deployed in other jurisdictions should the Board consider as it develops New Jersey's VPP Program? EDCs may reference their response to Question 18 and focus on supplementary examples not already described there. Respondents are encouraged to address any or all of the following dimensions:
- State-level program and market design**—are there state regulatory frameworks, distribution-level market rules or utility procurement models that New Jersey could study and tailor to local conditions?
 - Technical and operational models**—Are there specific utility VPP program designs—including enrollment practices, dispatch protocols, DERMS architectures, or performance measurement approaches – that have demonstrated measurable results in New Jersey?
 - Wholesale market integration**—Are there models that have successfully coordinated retail VPP programs with wholesale market participation under FERC Order No. 2222 or comparable frameworks that New Jersey should examine as it prepares for PJM market integration?
23. **For all stakeholders:** What roles and responsibilities should aggregators, EDCs, other stakeholders, and the Board take on to ensure data security and enforce DER Aggregation standards in practice?
24. **For all stakeholders:** What role(s) do you envision your organization playing with respect to DER aggregations and VPPs in wholesale and retail markets over the next five years (e.g., program administrator, aggregator, platform provider, customer outreach, technology provider)?

Section 2. Phase 2 (Distributed Storage Segment) of the GSESP

A. Current Technical Capabilities and Limitations

The Board acknowledges that DERMS will be a necessary investment for long-term implementation control and guidance around such investment will be included in future PSUP proceedings. While those proceedings continue, VPPs and Distributed Storage implementation can begin utilizing a Simple Dispatch mechanism (i.e. day-ahead voluntary response charge/discharge windows, the utilization of an edge-DERMS provider, etc.). The Board seeks a greater understanding of what level of controllability is necessary to facilitate a behind-the-meter (BTM) DER calling mechanism that can be implemented in the very near term at minimal cost.

25. **For EDCs:** What telemetry and communications capabilities with BTM DERs does each EDC have today?
26. **For EDCs:** What levels of controllability for BTM energy storage systems are technically feasible today, at scale? What are the costs of implementing such systems?
27. **For EDCs, 3rd-party aggregators, developers:** What level of controllability for BTM energy storage systems is necessary to administer a distributed energy storage performance incentive program?
28. **For EDCs, 3rd-party aggregators, developers:** What limitations—technical, customer behavioral, contractual, or cybersecurity related—restrict the greatest levels of controllability for BTM storage resources? Can such limitations be mitigated, and if so, how?
29. **For EDCs, 3rd-party aggregators, developers:** Should telemetry and communications capabilities differ depending on the customer class (e.g., residential, industrial, commercial). Would the costs of these telemetry systems differ depending on the customer class?

B. Distribution System Impacts and Operational Constraints

30. **For EDCs:** What steps are needed for EDCs to develop a locational value methodology for distributed storage and/or other DER services.
31. **For EDCs:** What are sources of value that should be considered when determining locational benefits of energy storage? What data sources and calculations are necessary to determine or quantify a storage resource's locational value?
32. **For EDCs:** Where are the areas or circuits of New Jersey's distribution system that experience persistent congestion issues?
33. **For all stakeholders:** Should EDCs be allowed to develop and operate storage systems to relieve congestion in those areas?

34. **For all stakeholders:** Please describe and quantify, if possible, if and how storage and VPPs could be utilized to increase hosting capacity on the constrained/worst performing/priority circuits identified in the responses to the RFI published on February 3, 2026.²⁰
35. **For all stakeholders:** How does BTM energy storage charging behavior affect the following:
- Distribution system peak load,
 - Minimum load conditions,
 - Voltage
36. **For all stakeholders:** Under what circumstances should EDCs retain authority to override or curtail the operation of BTM storage resources for safety or reliability reasons?
37. **For all stakeholders:** What interconnection risks and costs exist that are specific to distributed energy storage systems that could limit the benefits of the program?

C. Measurement, Data, and Verification Readiness

38. **For all stakeholders:** How should data access, cybersecurity, and customer privacy considerations be addressed to enable future coordinated dispatch?

D. Dispatch, Overrides, and Operational Priority

39. **For EDCs and 3rd-party aggregators:** What guidelines or best practices should guide the alignment and coordination of GSESP Phase 2 events with any future VPP-related events or dispatch signals?

E. Pathway to Future Aggregation / VPP Participation

40. **For 3rd-party aggregators:** What technical capabilities should a system enrolled under GSESP Phase 2 have in order to be forward-compatible with a VPP in the future?
41. **For 3rd-party aggregators:** Should GSESP Phase 2 include a voluntary designation or certification for resources capable of future aggregation? Who should administer that certification process?
42. **For all stakeholders:** Should GSESP Phase 2-eligible systems be able to participate in any NJBPU VPP program in the future? Why or why not?
43. **For all stakeholders:** If an energy storage system participates in the GSESP Phase 2 program and is both allowed to and chooses to participate in any future NJBPU VPP program, how should the Board prevent them from being compensated for the same service more than once? For

²⁰ In re Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid, BPU Docket No. QO24030199, Notice dated Feb. 3, 2026.

example, should the Board require that any energy storage system receiving GSESP Phase 2 performance incentives give up its ability to continue receiving those incentives as a condition of joining the VPP program or agree to a 1:1 reduction?

44. **For all stakeholders:** How should the Board coordinate with PJM to ensure that New Jersey's distributed storage and VPP resources are positioned to participate in new and emerging PJM market mechanisms—including proposals currently under consideration within PJM's Reliability Backstop Procurement ("RBP") process—and that PJM's load and resource adequacy forecasts are updated to properly reflect the contribution of aggregated demand-side resources to meeting New Jersey's capacity needs?
 - a. What specific actions should the Board take in PJM stakeholder proceedings to advocate for demand-side resource inclusion in new market auction designs, and what program design features in the VPP Program or GSESP Phase 2 would best support that advocacy?
 - b. How should NJ-administered VPP and distributed storage programs report enrollment, performance, and dispatch data to PJM in a standardized way that allows those resources to be accurately reflected in PJM's planning and load forecasting?
45. **For all stakeholders:** To what extent could EDC-directed dispatch for local distribution reliability conflict with a distributed energy storage resource's obligations or performance expectation in the PJM capacity market? What program design features could mitigate these conflicts? For example, would it be preferable to have distributed energy storage resources not bid into the capacity market as supply side resources and instead act as "load reducers" that lower PJM load forecasts and the amount of capacity PJM determines needs to be procured to serve New Jersey?
46. **For all stakeholders:** What technical, contractual, or regulatory barriers would prevent GSESP Phase 2 resources from participating in a future VPP program, and how could those barriers be addressed prospectively through program design?
47. **For EDCs and 3rd-party aggregators:** What charging related controls, limits, or operational rules would be necessary to ensure incentivized Phase 2 eligible storage remains compatible with future aggregation programs including but not limited to VPP operations?
48. **For EDCs and 3rd-party aggregators:** What telemetry, metering, and data granularity are necessary to verify Phase 2 storage performance in a manner consistent with future VPP participation? Do the requirements vary between BTM and front-of-meter (FOM) resources?
49. **For all stakeholders:** How can Phase 2 be structured to facilitate a smooth transition of resources into future aggregation frameworks?

F. Customer Participation, Equity, and Adoption Impacts

50. **For all stakeholders:** What barriers limit participation in BTM energy storage programs for residential, low and moderate income, and small commercial customers? Does net metering create any barriers to unlocking the value of residential distributed storage?

51. **For all stakeholders:** How do controllability, telemetry, or charging management requirements affect participation feasibility for different customer classes?
52. **For 3rd-party aggregators and developers:** Should there be a prequalification process for aggregators that plan to participate in Phase 2 of the GSESP? If yes, what information should the prequalification process request?
53. **For EDCs:** What are the use cases for EDC ownership that need to be considered regardless of FOM or BTM metering?
54. **For all stakeholders:** What are the benefits/drawbacks of allowing EDC owned and operated distributed energy storage systems?
55. **For all stakeholders:** If the Board allows EDCs to own distributed energy storage systems, should there be a specific MW procurement target for EDC-owned distributed energy storage systems? If so, what should that MW target be?

G. Cost Effectiveness and Ratepayer Impacts

56. **For all stakeholders:** How should the Board evaluate the cost effectiveness of incentivizing distribution-connected storage (BTM or FOM)? Should cost savings to ratepayers be the sole criterion, or should the Board also consider improved reliability and/or emissions reductions?

H. Incentive Levels for Distributed Storage Projects

57. **For all stakeholders:** Which benefits provided and value streams (e.g., avoided capacity costs, avoided energy costs, avoided transmission and distribution costs, improved reliability, emissions reductions, etc.) provided by distributed energy storage should be included in the calculation of Phase 2 performance incentives? Are there benefits or value streams that should only be monetizable by distributed storage projects but not VPP projects or vice versa?
58. **For all stakeholders:** What portion of estimated or actual savings should appropriately be included in the derivation of the performance incentive payment?
59. **For all stakeholders:** Should incentive levels differ by FOM or BTM project? If so, should FOM incentives be generally higher or lower than BTM incentives, assuming otherwise comparable projects? Why?
60. **For all stakeholders:** Should a separate or alternative tariff structure be used for FOM projects? What considerations regarding revenue streams or other costs should be considered for FOM projects?

61. **For all stakeholders:** With what frequency should performance incentive rates be reevaluated by the NJBPU? What criteria will be used to reevaluate EDC savings that should appropriately be captured in the setting of performance incentive rates?
62. **For all stakeholders:** Should Phase 2 of the GSESP allow for participation in multiple incentive programs to encourage new development and deployment of storage programs (e.g., VPP)? What incentives should be allowed, and what incentives should be disallowed from being stacked with GSESP Phase 2 incentives?
63. **For all stakeholders:** Should the Board launch the fixed incentive component of Phase 2 first to provide some incentives as quickly as possible, or wait until the performance incentives design and implementation infrastructure has been fully developed first? What impacts to participation or other factors should the NJBPU consider with a potential staggered roll out of a fixed incentive program followed by performance incentives within the following year?

I. Program Administration and Scalability Inputs

64. **For all stakeholders:** What are the proper performance criteria (e.g. critical hours, number of dispatches, events) that GSESP Phase 2 performance incentive payments should be based upon? Should the critical hours window be uniform across all EDCs or EDC specific?
65. **For all stakeholders:** What is a reasonable length of time for the performance call hours for GSESP or VPP programs? Should three hours, four hours, or some other period of time be the maximum duration for the performance call hours?
66. **For all stakeholders:** Should Phase 2 eligibility or incentive levels vary based on whether storage charging behavior can be constrained during system critical periods?
67. **For all stakeholders:** What safeguards should the Board consider to prevent over incentivizing storage installations that may prove to be incompatible with future aggregation (such as in a VPP)?
68. **For all stakeholders:** What tradeoffs should the Board consider between maximizing participation and ensuring operationally capable resources?
69. **For all stakeholders:** What are the advantages/disadvantages of having EDCs determine the details of performance incentive implementation through filings in response to a Minimum Filing Requirement (“MFR”) Order? How specific should the requirements and level of guidance in the MFRs be in order to provide sufficient direction to the EDCs while also allowing for an appropriate level of flexibility in implementation?
70. **For all stakeholders:** What performance reporting cadence is reasonable in order to true-up payments to awarded projects (e.g., monthly, quarterly, bi-annually)?

71. **For all stakeholders:** Should standardized agreements be developed that establish a framework for data sharing agreements between EDCs and developers of energy storage projects? If so, what information should these standardized agreements include and cover?

72. **For EDCs:** Describe the specific elements of GSESP Phase 2 administration that impose costs. Where applicable, please describe classification and functionalization of such costs (e.g., O&M, A&G) and the feasibility, advantages, and disadvantages of recovering such costs through the creation of GSESP Phase 2 program fees instead of recovering them from all ratepayers.

J. Front-of-the-Meter (FOM) Eligibility

73. **For all stakeholders:** What are the advantages and disadvantages of allowing distribution-connected FOM storage resources to be eligible for Phase 2?

74. **For all stakeholders:** What program design considerations are necessary to allow for optimal participation of FOM resources in Phase 2?

Section 3: Additional Comments

A. Comments on VPP Program and Phase 2 (Distributed Storage Segment) of the GSESP

75. **For all stakeholders:** Please add additional comments that you wish to make that were not addressed above.