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May 20, 2026

Via Electronic Mail
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Re: 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
BPU Docket Nos: QO26030099, QO26040116, QO24020116, QO26030059, QO24030199

Dear Secretary Lewis:

The Division of Rate Counsel ("Rate Counsel") is pleased to provide these comments to the Board of Public Utilities (the "Board" or "BPU") pursuant to the April 20, 2026 Request for Information ("RFI"), BPU Docket Nos. QO26030099, QO26040116, QO24020116, QO26030059, QO24030199.

The responses to the RFI provided herein are offered solely for the purpose of addressing the Board Staff's questions and facilitating its review of issues related to virtual power plant ("VPP") program concepts. These responses should not be misinterpreted as an endorsement or

acceptance of any specific VPP program, framework, or policy proposal. Nothing in these answers should be interpreted as indicating Rate Counsel's agreement with, or commitment to, any particular VPP design, operational model, or regulatory approach. Rate Counsel expressly reserves all rights to evaluate, comment on, or oppose any future VPP proposal that may be advanced in this proceeding or in any related forum. In light of the foregoing, Rate Counsel responds to specific stakeholder process questions identified below.

Section 1. Virtual Power Plant ("VPP") Program
B. Exploring opportunities to strategically design distributed energy resources ("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 electric distribution company ("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.

Rate Counsel recommends aligning VPP program structures with existing PJM frameworks to promote consistency and avoid customer confusion. PJM's DER aggregation rules were developed through an extensive, multi-year stakeholder process and reflect carefully negotiated compromises among market access, operational reliability, and interconnection requirements. Creating a new state-level structure that departs from these frameworks would fragment regulation, raise compliance costs, and confuse customers who participate across state

lines.

a. Any additional frameworks should align closely with existing PJM structures. Beyond FERC Order No. 2222, New Jersey should adopt only those state-level requirements that ensure DER participation delivers net benefits to customers and does not shift costs or operational risks to non-participants. Any VPP program must be supported by a quantitative, forward-looking cost-benefit analysis demonstrating net benefits under multiple scenarios (peak demand reduction, avoided capacity costs, avoided T&D investments, and wholesale market revenues).

A retail, distribution-level market should include the following safeguards:

- Clear cost-causation rules
- Protections against double compensation
- Transparent distribution planning
- Consumer protection standards for aggregators
- Utility operational review
- Data privacy requirements
- Benefit-cost reporting
- Participant and non-participant impact analysis

These safeguards are essential to ensure that a distribution-level market benefits customers broadly, rather than primarily rewarding aggregators and participating DER owners while shifting costs, complexity, or reliability risks to other ratepayers.

b. Establishing quantitative targets before the Board has assessed actual peak demand deficiencies, the cost-effectiveness of DER solutions relative to alternatives, and ratepayer

impacts would be arbitrary and could drive procurement obligations untethered to demonstrated need.

i) Rate Counsel opposes technology-specific subgoals. Such mandates risk distorting markets and increasing costs. Any decision should instead be grounded in clear benefit-cost reporting and cost-causation principles, rather than technology-specific requirements.

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?

To maintain consistency, avoid complication for aggregators, and prevent possible confusion for customers who have operations in multiple states, Rate Counsel advises that it is sensible to adopt the minimum aggregation size and maximum single component cap established by PJM. The PJM size limits were adopted after a multi-year stakeholder process and were designed to create balance between allowing market access for small load participation and meeting interconnection requirements for large loads.

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?

Since the value of distribution-level grid services are geographically and problem specific, there may be little value in categorizing these services into specific program buckets. Rather, utilities should be required to identify distribution-level problems along with the traditional "wires" approach to correct the issue and calculate that estimated cost. The project(s) can then be presented to VPP providers to bid on potential solutions for the particular problems identified.

a. The value of each distribution grid service is likely unique to the local distribution problem being corrected. The value of the service would be the avoided cost of whatever the traditional wires solution would be (transformers, relays, substations, powerlines, etc.).

b. Non-wire alternatives and VPPs have been piloted in jurisdictions across the country providing many examples from which to draw lessons learned and best practices for successful deployment. These examples, and what New Jersey can learn from those experiences, can inform and make any pilot programs more focused. However, utilities may not have the real-time distribution telemetry, advanced distribution management systems, and DER management tools in place to successfully deploy these types of solutions. For this reason, it would be sensible to begin a pilot project period, requiring utilities to bring a small percentage, perhaps 10%, of projects forward to be considered for third party provided solutions. If deemed successful, each year a greater percentage of projects could be made eligible for third party solutions until all qualified projects are considered within a specified timeframe (e.g., 10 years). Projects eligible for third party solutions could be limited based on certain criteria. Such criteria could include a

minimum cost threshold which would encourage utilities to keep their "wired" solution costs down. Other criteria could include limiting projects to only situations where "wired" solutions are feasible (service area expansion, etc.).

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?

Rate Counsel stresses the importance of not passing-on unjustified costs onto ratepayers. Pay-for-performance models protect ratepayers from paying for services that were not actually delivered and are the optimum compensation mechanism to ensure ratepayer dollars deliver benefits to the system. Pay-for-performance models have the added benefit that they account for dynamic or time-varying system changes in that incentives are only earned if the service is provided at the time it is needed.

Compensation tariffs should only be considered with a minimum duration of availability, thus providing aggregators assurance of the compensation mechanism over time. To attract customer participation, up-front incentives can be effective along with on-going incentives for customer retention. These programmatic structures can be left to the aggregator and their program design. Compensation to the aggregator under the tariff should closely reflect the value derived by the utility.

To the extent the Board considers any compensation structure, it should be required to demonstrate cost-effectiveness relative to conventional alternatives, including capacity procurement through PJM and traditional infrastructure investment. If the goal of the VPP program is to reduce peak demand and avoid grid spending, the compensation mechanism must be cheaper than the spending it is intended to avoid. A tariff design that costs ratepayers more than the alternative it displaces has failed its own purpose.

Rate Counsel also recommends that VPP compensation be settled using measurement and verification (M&V) protocols consistent with PJM standards, and be subject to penalties for non-performance.

Value-stacking could be used in specific situations, but only in instances where the deployed DER is proven to be able to deliver on each of the multiple value streams. Value-stacking arrangements introduce complexity and raise the risk of duplicative compensation for overlapping services, the costs of which are borne by ratepayers. Rate Counsel has raised double compensation concerns in prior comments in this docket and in BPU Docket No. EO24020116.[1] Dynamic and time-varying rate designs impose behavioral expectations that may be unrealistic for residential and low-income households and can produce bill volatility that undermines the affordability objectives that EO2 identifies as central to this proceeding.[5].[2]

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?

DER aggregators may have difficulty recruiting residential and small commercial customers who do not own their home/place-of-business, such as renters, because without site ownership renters may not be able to gain permission to install DERs at their home/place-of-business. This is a classic split-incentive model, observed in energy efficiency programs, and is a problem because this model disproportionately impacts LMI communities by excluding large numbers of renters.

To compensate for this problem where neither landlord nor renter is incentivized to act, utilities could offer increased incentives to DER aggregators who develop projects in LMI

[1] Rate Counsel Comments, BPU Docket No. EO24020116 (Response to Questions 4, 6, and 13) (filed in response to March 7, 2024 RFI and January 31, 2025 Technical Conference)
[2] Exec. Order No. 2 (Jan. 20, 2026), 58 N.J.R. 1041(a) (Feb. 17, 2026)

communities. The aggregator can structure their programs to offer upfront incentives to landlords who install DERs while on-going incentives can flow to the renters impacted when control events take place (the renter gets rewarded when their devices help the grid).

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

While this question is directed to EDCs, Rate Counsel comments on the principles that should govern any incentive structure. Rate Counsel supports performance-based compensation over upfront payments. Upfront incentives compensate deployment regardless of whether the resource delivers measurable grid services, placing all performance risk on ratepayers. Incentive levels should be based on demonstrated avoided costs, not modeled projections, and should be benchmarked against the cost of alternative resources available through PJM or conventional infrastructure to ensure ratepayers are not paying more for DER services than equivalent supply-

side value.

To coordinate incentivized assets, all EDC infrastructure investments including DERMS, telemetry, and hardware, should be itemized, justified, and recovered through program-specific fees rather than socialized to all ratepayers. Projects already receiving incentives under existing programs should not receive additional compensation under future GSESP or VPP programs without a demonstration that the additional payment produces incremental value not already compensated and does not result in double recovery. The Board should require enforceable non-performance remedies including incentive clawback, payment suspension, and program removal for persistent failure to meet dispatch obligations. Upfront incentives without performance accountability should be avoided.

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:

a. **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?

b. **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?

c. **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?

The Board should approach VPP models from other jurisdictions with caution. While certain programs offer useful structural elements, no jurisdiction has demonstrated that VPP programs deliver net benefits to ratepayers at the scale New Jersey is contemplating. New Jersey should avoid any VPP framework that merely increases DER enrollment or creates new revenue

opportunities for aggregators without demonstrating measurable, verified net benefits for ratepayers.

To the extent other states' programs are instructive, the most relevant elements are cost-benefit review, pay-for-performance compensation, program caps, anti-double-counting rules, wholesale revenue crediting, and protections for non-participating customers.

The Board should study Connecticut's Energy Storage Solutions program for what it reveals about the need for ongoing regulatory oversight. Connecticut's program provides storage incentives to residential and commercial customers, is paid for by electric ratepayers, and is administered by the Connecticut Green Bank, Eversource, and United Illuminating under PURA oversight.[3] PURA identified as a key program objective that the program must provide positive net present value to all ratepayers.[4]

However, after four years of operation, the program has approved only approximately 15 MW of residential battery storage and 140 MW of commercial and industrial projects.[5] PURA itself found the original incentive design insufficient and in early 2026 overhauled the program, shifting toward a higher pay-for-performance model that replaces upfront incentives with ongoing performance payments tied to Active Dispatch participation.[6] This trajectory should give the Board pause, because it demonstrates that even a well-supervised program will require significant mid-course correction at ratepayer expense, and the capacity delivered remains modest relative to system needs.

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[3] Connecticut PURA, Energy Storage Solutions Program, Program Manual. https://portal.ct.gov/pura/electric/office-of-technical-and-regulatory-analysis/clean-energy-programs/energy-storage-solutions-program.
[4] Energy Storage Solutions Program Manual, Version January 19, 2024, PURA Docket No. 21-08-05
[5] Connecticut Green Bank, "Connecticut's Energy Storage Solutions Program Adopts New Performance-Based Framework to Deliver Greater Value for Ratepayers and Customers," February 2, 2026, https://www.ctgreenbank.com/connecticuts-energy-storage-solutions-program-updates-2026ratepayers-and-customers/.
[6] *Id.*

For compensation design, the Board should study Massachusetts and Rhode Island's ConnectedSolutions programs. ConnectedSolutions compensates customers on a pay-for-performance basis for the average kW curtailed or discharged during called demand response events during peak grid demand periods.[7] This is a sound compensation principle because it pays for measured grid value, not enrollment or nameplate capacity.

However, ConnectedSolutions also illustrates the scalability problem. The aggregate capacity these programs deliver is marginal relative to system-level capacity needs. If New Jersey faces the supply-demand gap EO2 describes, programs delivering tens of megawatts of intermittent, distributed capacity are not a substitute for firm supply-side resources.

This is a sound compensation principle because it pays for measured grid value, not enrollment or nameplate capacity.

For wholesale market integration, the Board should study Maryland's experience because Maryland is also a PJM state working to coordinate retail VPP development with FERC Order No. 2222 implementation. Maryland's PSC issued Order No. 91917 implementing the DRIVE Act, directing utilities to propose pilot programs compensating customers and aggregators for using DERs to reduce demand or supply energy to the grid.[8]

Notably, the Maryland PSC rejected the utilities' initial pilot proposals as too limited in scale and found that they failed to achieve the intended impact of reducing peak electricity demand, requiring utilities to refile with expanded program designs.[9] This outcome reinforces

[7] National Grid, Program Materials for ConnectedSolutions for Small Scale Batteries, https://www.nationalgridus.com/media/pdfs/resi-ways-to-save/ma_resi_battery_program_materials.pdf
[8] Maryland PSC, Order No. 91917, DRIVE Act Implementation, PC 44 (October 21, 2025), https://www.psc.state.md.us/wp-content/uploads/Order-91917_ML-323522-9761-1.pdf.
[9] Maryland PSC, Press Release, "Maryland PSC Orders Utilities to Scale Up DRIVE Act Proposals," October 21, 2025, https://www.psc.state.md.us/wp-content/uploads/MD-PSC-Orders-Utilities-to-Scale-Up-DRIVE-Act-Proposals_10212025.pdf (finding utility pilot proposals "too limited in scale" and that they "failed to achieve the intended impact of the law, particularly in reducing peak electricity demand").

Rate Counsel's concern that even regulators actively designing VPP frameworks are finding that the programs do not deliver the anticipated results. Any VPP resource that participates in PJM capacity, energy, or ancillary service markets could generate wholesale revenues. Those revenues should be tracked and credited back to ratepayers where ratepayer funds supported customer incentives, DERMS platforms, metering, administration, or other enabling infrastructure.

Because the VPP Program is being developed alongside Phase 2 of the GSESP, the Third Triennium EE, and Peak Demand Reduction framework, GridFlex, and PJM Order No. 2222 implementation,[10] the Board should treat VPPs as reviewable demand-flexibility programs, not as open-ended subsidy mechanisms. Any VPP proposal should include a defined budget, benefit-cost analysis, cost-causation review, performance metrics, annual reporting, and true-up mechanisms.

Rate Counsel recommends that the Board adopt the following safeguards for any New Jersey VPP program:

- require a transparent cost-benefit analysis before approval;
- assign costs consistent with cost-causation principles;
- use pay-for-performance compensation;
- impose budget or capacity caps during early program phases;
- prohibit double compensation for the same DER capability;
- credit PJM market revenues back to customers where ratepayer funds supported the VPP;
- ensure benefits are system-wide and quantifiable; and

[10] *See* RFI Notice at 3-4, Docket No. QO26030099

- allocate costs proportional to beneficiaries of the VPP program to protect non-participating customers from subsidizing benefits that primarily flow to DER owners or aggregators.

The Board should not treat other states' programs as evidence that VPPs are proven or cost-effective. They are early-stage, small-scale, and subject to ongoing correction. New Jersey's VPP program should begin with clear limits, transparent review, and measurable performance requirements, and should be benchmarked at every stage against the cost of conventional alternatives available through PJM. The objective should not be to maximize DER enrollment or aggregator revenue; it should be to ensure that any ratepayer-funded VPP costs produce verified net benefits for customers.

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?

Rate Counsel recommends that EDCs and DER aggregators should be required to ensure their systems are in compliance with current standards involving data and cybersecurity, such as IEEE 2030.5, DNP3, IEEE1547.3-2023, NERC CIP. Rate Counsel recommends the Board ensure that utility tariffs and contracts with DER aggregators require compliance with these established cybersecurity standards for the energy industry. Rate Counsel also recommends that the Board require utilities and DER aggregators to adhere to the data privacy and consumer protection laws already in place through state laws or other associated rulemaking proceedings. All stakeholders should be encouraged to participate in the on-going development of additional rules and standards in this rapidly developing field to ensure customer protections remain effective and a top priority.

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)?

Rate Counsel's role is to act as a consumer advocate to ensure ratepayers are appropriately represented as the impact of DER aggregators and VPPs grows. Rate Counsel's participation and comments will help ensure costs incurred for utility services are commensurate to the value being provided ratepayers, appropriately allocated and that utility service is provided in a safe, adequate, and proper manner at affordable rates.

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

B. Distribution System Impacts and Operational Constraints

33. **For all stakeholders**: Should EDCs be allowed to develop and operate storage systems to relieve congestion in those areas?

Rate Counsel opposes allowing EDCs to develop and operate storage systems as a general matter. Utility-owned storage becomes a rate base asset on which EDCs earn a guaranteed return that is recoverable from all ratepayers regardless of whether those ratepayers benefit from those resources. This approach shifts investment risk entirely to captive customers, removes competitive discipline from procurement, and creates an inherent conflict of interest when the EDC is simultaneously the owner of the storage asset and the entity responsible for evaluating whether that asset is the least-cost solution to a distribution constraint.

If localized congestion relief is genuinely needed, the EDC should be required to demonstrate through a transparent, competitive procurement process that utility-owned storage is the least-cost option relative to alternatives, including non-wires alternatives, third-party storage providers, demand response, and traditional infrastructure upgrades. Absent that demonstration,

EDC storage ownership is simply another mechanism for expanding utility rate base at ratepayer expense.

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.

Hosting capacity limits are generally reached when the amount of DER generation (typically solar) on a particular circuit, results in reverse power flow, voltage increases, or other problematic conditions. Energy storage and VPPs can mitigate these hosting capacity problems by providing additional load for the excess DER generation to serve (i.e. the load of charging the storage device or the shifting of device loads to the time of DER generation).

Rate Counsel cautions that the extent to which storage and VPPs can increase hosting capacity is circuit dependent. For example, energy storage can be deployed to absorb excess DER generation on a feeder, but the storage must discharge back to the grid when the DER is not generating. This may occur at night, which usually corresponds to a time when the circuit has less load. Therefore, the amount of energy storage that can be utilized becomes constrained by the amount of nighttime load available to be served.

35. **For all stakeholders:** How does BTM energy storage charging behavior affect the following:

a. Distribution system peak load,
b. Minimum load conditions,
c. Voltage

BTM energy storage could have different impacts on each of the conditions listed depending on how the storage is utilized and where on the system it is deployed, because different circuits peak at different times within the distribution system. For purposes of this response, Rate Counsel is assuming a traditional distribution circuit load profile peaking in the late afternoon/early evening and that customers are deploying storage in their own self-interest

and either 1) deploy storage in conjunction with solar, or 2) deploy stand-alone storage to benefit from rate arbitrage or demand charge reduction.

a. Energy storage systems may help reduce the distribution system peak load by serving the customer's own load once solar generation subsides or by being dispatched to reduce the customer's peak demand.

b. Customers with solar using storage to meet their nighttime load will cause a decrease in minimum load conditions on a circuit. Stand-alone storage is likely to increase a circuit's minimum load as the storage will be charged during minimum load hours, typically during the night.

c. BTM storage should have minimal detrimental impacts on feeder voltage. Available smart inverter technology may even be utilized to support and smooth voltage variances.

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?

EDC's should retain the right to override or curtail BTM storage in circumstances where the storage is designed solely to export power back to the grid and the risk of an inadvertent islanding condition is possible. This situation is rare in that most BTM storage is designed to serve the customer's own load and such systems are interconnected under IEEE 1547 standards which contain anti-islanding provisions.

If customers have invested in behind the meter storage ("BTM") with their own capital, EDC authority to override or curtail those resources should be narrowly limited to documented, verifiable emergency conditions posing an immediate threat to system safety or equipment protection. Any broader curtailment authority risks undermining the economic value proposition that justified the customer's investment and effectively transfers operational control of a customer-owned asset to the utility without compensation.

The Board should require EDC's to publicly report every curtailment event, including the specific safety or reliability condition that triggered it, duration, affected customers, and the operational data supporting the decision. A transparent mechanism is required to prevent EDC's from using broadly defined reliability authority as a routine operational tool rather than an emergency measure.

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?

Rate Counsel suggests that there are not any specific interconnection risks or costs that exist which inherently limit the benefits of distributed energy storage. Rather, deploying distributed energy storage comes with certain interconnection requirements to ensure the safe and reliable operation of energy storage.

Distribution system upgrades required to accommodate VPP can be substantial, and the question of who bears those costs has direct rate impact implications. To the extent interconnection costs are socialized across all ratepayers rather than assigned to the interconnecting resource or its beneficiaries, non-participating customers are subsidizing the deployment of privately owned storage assets from which ratepayers derive no direct benefit. This creates a fundamental cost causation problem of which the Board should be cautious.

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?

Rate Counsel supports utilities and DER aggregators adopting policies and technologies which accelerate DER deployments but not at the expense of existing fundamental cybersecurity, NERC CIP protections, and customer data privacy protections. These security protections must remain in place.

E. Pathway to Future Aggregation / VPP Participation

42. **For all stakeholders:** Should Grid Scale Energy Storage Program ("GSESP") Phase 2-eligible systems be able to participate in any NJBPU VPP program in the future? Why or why not?

No. GSESP Phase 2-eligible systems already receive substantial ratepayer-funded incentives intended to support their development. Allowing the same resources to earn additional compensation through VPP program participation will create an impermissible double-recovery. Ratepayers would be paying twice for the same resource once through the storage incentive and again through the VPP dispatch compensation. If the GSESP incentive was not sufficient without stacked VPP revenues, then the original program's cost-effectiveness assumptions were flawed and should be revisited and revised before expanding eligibility into new compensation streams.

As Rate Counsel understands GSESP Phase 2 proposed incentives, there is likely to be an administrative set upfront battery rebate as well as an operational performance incentive. Given this structure, GSESP Phase 2-eligible customers should only be allowed limited participation in future DER aggregation or VPP programs. GSESP Phase 2 upfront incentive recipients should be required to fulfill the durational term associated with the incentive before being able to consider any future program. Once the term is completed the customer could enroll in a performance incentive program so long as the term of any Phase 2 incentive has expired. These conditions would help ensure ratepayers are not incentivizing upfront costs more than once and that performance benefits are not being double counted and double incentivized.

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 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?

If the Board permits cross-program participation despite the risk of double recovery, any energy storage system receiving GSESP Phase 2 incentives should be required to forfeit those incentives in full before joining the VPP program.

This approach is warranted for several reasons:

- It prevents ratepayers from funding both deployment incentives and dispatch compensation for the same resource and the same or overlapping services.
- A partial offset would still create a subsidy borne by non-participating customers without a corresponding benefit.
- Tracking, auditing, and enforcing partial offsets or service-by-service distinctions across overlapping programs would add administrative complexity and cost that ratepayers would ultimately bear.

In short, requiring participants to choose one compensation pathway or the other is the clearest and most cost-effective approach. It reduces administrative burden and helps ensure that ratepayer funds are used only for the purpose each program was designed to serve.

An alternative to prevent GSESP Phase 2 program participants from being compensated for the same service more than once, Rate Counsel recommends that the Board ensure GSESP Phase 2 incentives have a defined term of service associated with both any up-front and any pay-for-performance incentives. GSESP Phase 2 participants should be excluded from participating in any VPP programs until the term is completed.

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?

Application to the PJM queue is a standard application process that will facilitate any large-scale battery storage. For tracking of smaller storage facilities, potential options include Generation Attributes Tracking System ("GATS") or internal tracking. Once a system is registered with PJM, there are monthly financial settlements that need to be processed – payments and accounting for what each resource actually delivered to the market.

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?

EDC-directed dispatch could conflict with resource obligations to the PJM market if the required dispatch periods are not coincident. Strict program guidelines around value-stacking need to be enforced to ensure the energy storage resources are only being incentivized for benefits that can actually be delivered to the grid. As EDCs are likely to prioritize dispatch for local distribution reliability over capacity market calls, it is uncertain the energy storage resource could be relied upon as a supply side resource. Therefore, it is more appropriate that such resources be considered "load reducers" toward the EDC's load forecast.

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?

As described above, committed capacity market obligations may interfere with participation in a VPP that concentrates on distribution level management of the system. Additionally, other federal wholesale regulation may affect battery storage unfettered participation in other state subsidy programs. An option to address these regulatory barriers would be a formal application process, contract, separate rate, fees and incentives built into the agreement between the distribution grid operator and the battery system owner. The agreement could explicitly provide that the system can be registered for any additional incentive programs.

49. **For all stakeholders:** How can Phase 2 be structured to facilitate a smooth transition of resources into future aggregation frameworks?

Phase 2 should include defined durational terms of service tied to receiving any incentive. In addition, Phase 2 should create pay-per-performance models which can be emulated by VPP program providers in the future. With clear terms and strict pay-for-performance standards, the participants will be able to focus their investments on participation in subsequent phases that are the most likely to deliver benefits to ratepayers.

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?

The most significant barrier to BTM energy storage participation is affordability. The Governor's own Executive Order No. 2 declares a statewide energy emergency and identifies mounting affordability challenges as a central concern, recognizing that the widening gap between electricity supply and demand in PJM territories is a significant driver of New Jersey's electricity affordability crisis. The customers the Board hopes to reach through expanded BTM storage programs are the same customers bearing the impact of that crisis. Creating new

ratepayer-funded incentive programs to drive storage adoption does not address affordability; it risks worsening it by adding program costs to the bills of non-participating customers who did not choose to participate and may never benefit. Every dollar spent on storage incentives recovered through rates or surcharges is a dollar added to the bills of customers already struggling under current rate levels.

Rather than designing incentive structures to accelerate BTM storage adoption, the Board should allow market forces to determine participation. If BTM storage is useful and cost-effective, the market will adopt it as the technology matures and costs decline. Attempting to accelerate adoption through ratepayer-funded incentives risks distorting the market, over-incentivizing installations that are not yet cost-effective, and creating a subsidy structure that primarily benefits asset owners and aggregators at the expense of non-participating ratepayers. The Board's role should be to remove regulatory barriers to interconnection and participation, not to fund deployment through captive ratepayer bills.

BTM energy storage program participation is limited by the split incentive structure where renters do not own the site and there is no incentive for the landlord to make the capital investments in DERs/VPPs. Net metering adds complexity to unlocking the value of residential BTM storage.

Current net-metering regulations only allow BTM storage to serve the customer’s load, limiting additional valuable revenue streams that may be available if the storage could be exported to the grid, which is important for both LMI customers and commercial customers. A potential solution to this could be metering energy exported from BTM storage and excluding that energy from what is applied to net metering. As the market matures net metering reforms

will eventually need to be made where residential customers are only provided the "wholesale" value of the energy they export and not the full retail rate.

51. **For all stakeholders:** How do controllability, telemetry, or charging management requirements affect participation feasibility for different customer classes?

Controls, telemetry, and charge management requirements can add cost to DER installations, potentially making projects financially non-viable. This is especially true for small DER installations found at the residential or small-commercial level. To reduce DER costs for residential and small commercial customers, utilities should not require the same level of control and telemetry equipment as required on large systems, the requirements should be proportional to the size and utility of the system. In additional, utilities should be able to leverage the data collection and control functionality native to these smaller DERs by integrating with third party aggregator systems already in place, such as Distributed Energy Resource Management Systems deployed at the edge of the grid ("Grid-Edge DERMS").

54. **For all stakeholders:** What are the benefits/drawbacks of allowing EDC owned and operated distributed energy storage systems?

The disadvantages of EDC ownership materially outweigh any asserted benefits. Utility-owned storage is placed in rate base and earns a guaranteed return from all ratepayers, whether or not the asset produces net benefits. This model removes competitive discipline from procurement, shifts investment risk to captive customers, and creates a conflict of interest by allowing the utility to both own the asset and judge whether it is the least-costly solution to a distribution need. It also raises competitive neutrality concerns because the utility would compete with third-party storage providers while controlling the interconnection process and key distribution system information. Any claimed operational benefits can be achieved through competitive procurement with appropriate performance requirements, without utility rate-base

ownership. Utilities should only act as neutral market facilitators, providers of interconnection, data access, and system visibility; not DER asset owners or preferential aggregators.

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?

For the reasons stated in its response to Question 54, Rate Counsel opposes setting MW procurement targets for EDC-owned distributed energy storage. A mandatory target presumes that EDC ownership is appropriate, even though there is no evidence that is so. It would also obligate ratepayers to fund a fixed amount of rate-based investment without first establishing that those investments are cost-effective, competitively procured, or better than available alternatives. If the Board nonetheless allows EDC ownership over Rate Counsel's objection, procurement should be based on identified, location-specific distribution needs supported by engineering analysis and a competitive solicitation process. Rate Counsel also urges the Board to require any EDC seeking to own distributed storage to show, through a transparent and competitive process, that utility ownership is the least-costly option compared with third-party alternatives, demand response, traditional infrastructure upgrades, and supply-side resources available through PJM.

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 front-of-meter ("FOM"))? Should cost savings to ratepayers be the sole criterion, or should the Board also consider improved reliability and/or emissions reductions?

Cost savings to ratepayers should be the primary criterion. Reliability and emissions reductions are legitimate policy considerations but should not be used to justify programs that fail a ratepayer cost-effectiveness test. When speculative or difficult-to-quantify benefits are given equal weight alongside direct cost impacts, program costs escalate and ratepayer savings

fail to materialize. To the extent the Board considers reliability and emissions benefits, those benefits must be measurable, independently verifiable, and valued using conservative methodologies. Generalized assertions of reliability improvement or emissions reduction are not a substitute for rigorous quantification.

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?

No benefits or value stream should be included in the calculation of Phase 2 performance incentives until it has been empirically demonstrated and independently verified through annual operation data. Avoided capacity costs, avoided energy costs, reliability improvements, and emissions reductions are all theoretically attributable to distributed storage, but none should be assumed or credited to incentive calculations before they are proven. Ratepayers should not fund performance incentives tied to value steams that exist only in modeling projections.

58. **For all stakeholders:** What portion of estimated or actual savings should appropriately be included in the derivation of the performance incentive payment?

Only actual, verified savings should be used in the derivation of performance incentive payments. Estimated savings are inherently speculative and should not serve as the basis for ratepayer-funded compensation. The portion of actual savings included in the incentive payment should be set at a level that ensures the majority of realized savings flow back to ratepayers who fund the program, and not to asset owners or aggregators. Ratepayers bear the costs and risks of these programs and should receive the predominant share of any benefits they produce.

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?

Rate Counsel does not support different incentive levels for FOM and BTM projects at this stage. Before setting any incentive levels, the Board should first determine whether distributed storage performance incentives are cost-effective and provide verified net benefits to ratepayers. Creating separate incentive levels now would add administrative complexity and assume a level of program design detail that is premature without that threshold analysis. If the Board moves forward, any distinction should be based only on demonstrated differences in measurable system value, not on assumed or modeled benefits

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?

Rate Counsel does not support creating a separate or alternative tariff for FOM projects at this time. FOM storage projects are grid-connected resources that can participate directly in PJM's wholesale energy, capacity, and ancillary services markets. If those projects are economically viable, they should compete through existing market mechanisms without a ratepayer-funded retail tariff. If they cannot do so without a dedicated tariff or additional ratepayer-supported revenue, that suggests they are not cost-effective relative to available alternatives. The Board should evaluate the full costs of FOM projects—including interconnection, distribution system upgrades, program administration, and any incentive payments—against the wholesale market revenues those projects can earn on their own. Ratepayers should not be required to close revenue gaps for projects that cannot sustain themselves through market participation. If the Board nevertheless considers a tariff for FOM

projects, cost-causation principles require that participating project owners and their customers bear the full cost of service and that non-participating ratepayers be held harmless.

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?

Performance incentive rates should be reevaluated annually - at a minimum. Ratepayer-funded incentives that are locked in for extended periods without review create a risk of persistent overcompensation as market conditions, technology costs, and system needs change. Reevaluation criteria should include verified savings actually realized by the EDC, changes in avoided cost benchmarks, comparison against the cost of alternative resources available through PJM, and cumulative ratepayer cost impacts. The Board should retain authority to reduce or suspend incentive payments if reevaluation demonstrates that the program is not delivering net benefits to ratepayers.

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?

Rate Counsel opposes allowing GSESP Phase 2 participants to stack incentives from multiple ratepayer-funded programs. As stated in response to Questions 42 and 43, allowing a single resource to collect compensation from both GSESP Phase 2 and a VPP program creates a double-recovery problem where ratepayers fund the same asset through multiple channels. Participants should be required to elect one compensation pathway. If the Board permits any form of stacking despite Rate Counsel's objections, it must require a full 1:1 offset so that combined ratepayer-funded compensation never exceeds the verified value the resource delivers to the system.

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?

Rate Counsel opposes launching fixed incentives before a complete performance incentive framework is in place. Fixed incentives pay for asset deployment without requiring proof that the resource delivers measurable system benefits or that the fixed amount is appropriate for all projects. Starting with fixed incentives and postponing performance accountability would expose ratepayers to costs without any assurance of corresponding value. That is the sequencing concern Rate Counsel raises throughout these comments. If the Board is not ready to measure and verify performance, it should not commit ratepayer funds.

Launching fixed incentives prior to developing and deploying a complete performance incentive design risks increasing the already apparent duplicative compensation streams (e.g., retail incentives plus wholesale market revenues) for the same services. This principle is consistent with prior Board treatment of renewable incentives under N.J.S.A. 48:3-87, and basic accountability required in ensuring just and reasonable utility rates.

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?

GSESP Phase 2 performance incentives should be based on 2 specific criteria:

a. Energy storage system availability during critical hours with data demonstrating the storage system was charged and ready during the critical window

b. Actual performance during scheduled events with data showing the storage systems performance during each event called.

Programs should provide participants clear, advance notice of what to expect. These expectations; such as an indication of the expected event season, number of events expected, and critical hours when the event may occur, provide customers and aggregators predictability to properly manage their batteries. For example, events may be called between June and September between the hours of 3:00 pm and 7:00 pm no more than 20 times per calendar year. For system wide capacity purposes, critical hours should be uniform across all EDCs. Storage being deployed to meet local distribution needs, however, may require different, individual critical hours windows.

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?

There is no need to standardize performance call hours. Performance call hours should correspond to the demands of the problem being mitigated, be that three hours, four hours, or longer. The aggregation of GSESPs and VPPs can be constructed in a manner that satisfies system needs.

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?

Yes, Phase 2 up front incentives should be contingent upon the customer being able to avoid charging during system critical periods. Pay-for-performance incentives are self-managing as they would not be paid if charging were to occur during 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)?

Rate Counsel has raised concerns with aspects of the Board's Energy Efficiency framework in other proceedings, but at a minimum, any storage incentive program should be subject to the same type of periodic review process, including regular reassessment of incentive levels, benefit-

cost evaluation, and performance measurement. Storage incentives should not receive less oversight than EE programs. The Board should also establish minimum technology and interoperability requirements as a condition of receiving ratepayer-funded incentives. Inc entivizing storage installations that cannot communicate with aggregation platforms or respond to dispatch signals creates stranded ratepayer investment that delivers no system value. Beyond these baseline safeguards, Rate Counsel urges the Board to exercise restraint in setting incentive levels and allow the market to drive storage deployment where it is cost-effective. Overly generous incentives distort price signals, attract installations that would not otherwise be econom ically justified, and expose ratepayers to costs that exceed any realized benefits.

68. **For all stakeholders:** What tradeoffs should the Board consider between maximizing participation and ensuring operationally capable resources?

Increased participation without ensured operational performance places additional costs and risks on ratepayers. Rate Counsel recommends the Board prioritize programs that ensure incentives are provided to operationally capable resources, highlighting the value of pay-for-performance incentives.

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?

(1) Board control of the incentive framework:

Rate Counsel supports allowing EDCs to propose program goals and operational details through MFR filings, but the performance incentive mechanism itself should be designed and controlled by the Board. EDCs have a financial interest in maximizing cost recovery and minimizing accountability. Allowing EDCs to define both the program and the metrics used to judge their performance invites self-serving

design. Utilities may propose aspirational goals, but the Board should decide when incentives are earned and when penalties apply.

(2) Performance and penalty standards:

The Board should retain full authority to reward strong performance and penalize underperformance. A framework that rewards overperformance but imposes no meaningful consequences for underperformance creates a one-way cost to ratepayers. The Board should also require strict protections against cost overruns. Cost performance should be evaluated alongside reliability and VPP dispatch results. A program that meets dispatch targets but exceeds its budget is not a success for ratepayers. Rate Counsel also urges the Board to adopt performance and penalty standards that are uniform with clearly stated and measurable performance metrics.

(3) Cost-effectiveness benchmark:

This point reflects a broader principle. If the purpose of VPP programs is to avoid spending on transmission upgrades, distribution infrastructure, and new generation capacity, then the programs must be judged against those alternatives. A VPP program is worthwhile only if it is demonstrably more cost-effective than the resource or investment it is intended to displace.

The Board should compare the full cost of a VPP program—including ratepayer-funded incentives, DERMS infrastructure, AMI upgrades, aggregator compensation, program administration, and regulatory oversight—against the cost of conventional

alternatives such as a combined-cycle plant, transmission upgrades, or additional PJM capacity procurement. If the VPP program costs more than the alternative, it fails its stated rationale, and ratepayers are better served by the conventional option.

(4) MFR safeguards:

These programs will require substantial time, money, and regulatory resources. To justify that investment, they must perform as promised and remain within budget. The MFR framework should therefore include explicit cost-effectiveness benchmarks measured against supply-side alternatives, along with clear triggers for program suspension or termination if costs exceed those benchmarks. If the VPP program cannot outperform the alternative, the Board should pursue the alternative instead.

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)?

Rate Counsel recommends quarterly performance reporting at a minimum, with monthly data collection underlying each quarterly report. Longer reporting intervals delay the identification of underperforming projects and allow costs to accumulate before corrective action can be taken. True-up payments should be based exclusively on verified, measured performance data, not modeled or projected values. The Board should also require that cost performance be reported alongside operational performance at each reporting interval, consistent with Rate Counsel's position that cost overruns are as significant a program failure as dispatch underperformance. If a project consistently underperforms or exceeds cost benchmarks across

consecutive reporting periods, the Board should have the authority to suspend or reduce incentive payments without waiting for an annual review cycle.

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?

Certain standard information should be included in agreements between EDCs and developers including:

1. All engineering specifications necessary for the system;
2. Location of facilities;
3. All applicable fees and costs associated with interconnection;
4. Rate that it's associated with; and
5. PJM approval, if needed.

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.

While this question is directed to EDCs, Rate Counsel has a direct interest in how GSESP Phase 2 administrative costs are classified, functionalized, and recovered. Rate Counsel strongly supports recovering Phase 2 administrative costs through program-specific fees assessed to participating projects, rather than socializing those costs to all ratepayers. The administrative costs of Phase 2, including program management, application processing, performance measurement and verification, incentive disbursement, DERMS integration, reporting, and compliance monitoring, are incurred to support a program that benefits participating storage developers and asset owners. Consistent with cost-causation principles, the entities that cause

and benefit from these costs should bear them. Non-participating ratepayers receive no direct benefit from Phase 2 program administration and should not be required to fund it.

To the extent EDCs classify these costs as O&M or A&G and seek to recover them through base rates or riders applicable to all customers, the Board should reject that approach. Embedding Phase 2 administrative costs in general rate recovery obscures the true cost of the program, eliminates transparency, and guarantees that ratepayers who neither participate in nor benefit from distributed storage deployment subsidize its administration. Program fees also create a useful market discipline: if the administrative costs of the program are high enough to deter participation, that is a signal that the program design is too costly, not a justification for shifting those costs to captive ratepayers.

Rate Counsel urges the Board to require EDCs to provide a detailed, itemized accounting of all anticipated Phase 2 administrative costs, classified by function, before the program launches. The Board should not approve Phase 2 cost recovery until it has reviewed and verified these costs and determined that program-specific fee recovery is feasible and sufficient.

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?

Potential advantages of Phase 2 eligibility for distribution-connection FOM storage include:

a. Dedicated resource, not only trying to provide customer value which could detract from grid value; and

b. Optimized siting when being used to address distribution constraints.

The primary disadvantage of Phase 2 eligibility for distribution-connection FOM storage is the challenge of accounting for and paying for the energy used to charge FOM storage assets.

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

To optimize participation of FOM resources in Phase 2, Rate Counsel recommends the Board develop an export tariff that accounts for energy costs for charging along with costs associated with using existing infrastructure (poles, wires, transformers) for delivering product to market.

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.

(1) The Board has not answered the threshold question. This RFI asks stakeholders how to design VPP and GSESP Phase 2 programs. It does not ask whether these programs are the right answer to the reliability and affordability challenges identified in EO2. The Board has not produced or required a comparative cost-effectiveness analysis evaluating VPP and distributed storage programs against conventional supply-side alternatives, including combined cycle generation, transmission upgrades, distribution infrastructure investment, and capacity procurement through PJM.[11] Rate Counsel raised this concern in its May 15, 2026 comments in Docket No. QO26030099 and reiterates it here.[12] Absent this foundational analysis, the Board is designing programs before determining whether they are the least-costly solution to a vaguely identified need. Rate Counsel urges the Board to require this analysis before committing ratepayers to new program costs.

[11] *See* Rate Counsel Comments, Docket No. QO26030099 (May 15, 2026)
[12] Id.

(2) Cumulative ratepayer cost exposure must be assessed holistically. New Jersey ratepayers are simultaneously funding GSESP Phase 1, the forthcoming GSESP Phase 2, VPP program development, the Third Program Cycle EE and Peak Demand Reduction programs, Grid Modernization Forum initiatives including GridFlex and IDDER, AMI deployment, and ongoing NEM costs,[13] as well as possibly subsidizing additional nuclear or gas generation. No proceeding to date has produced a comprehensive accounting of the cumulative ratepayer cost burden across these overlapping programs, nor measured the cumulative impact towards a vague goal of reliability. Individual program-level benefit-cost analyses, even where they exist, do not capture the aggregate impact on ratepayer bills. The Board should require a holistic assessment of total ratepayer cost exposure across all active and planned DER, storage, VPP, EE, and grid modernization programs before approving additional cost commitments. The Board should also determine what is actually needed. Even if the individual procurements are cost effective, over procurement will result in unnecessarily high bills. While Rate Counsel generally supports modernizing the electric grid, energy storage initiatives, and integrated distributed energy resource solutions, neither EDECA nor subsequent statutes abrogate the Board's obligation to ensure just and reasonable rates. Accelerated deployment cannot come at the expense of ratepayer protections.

(3) Aggressively short timelines increase the risk of poor program design. EO2 directs the Board to launch Phase 2 within 90 days and commence VPP program development within 180 days.[14] Rate Counsel acknowledges the urgency the Governor has identified but cautions that compressing program design timelines increases the risk of locking ratepayers into long-

[13] Exec. Order No. 2, §§ 3-4 (Jan. 20, 2026), 58 N.J.R. 1041(a) (Feb. 17, 2026).
[14] Connecticut Green Bank, "Connecticut's Energy Storage Solutions Program Adopts New Performance-Based Framework to Deliver Greater Value for Ratepayers and Customers," February 2, 2026, https://www.ctgreenbank.com/connecticuts-energy-storage-solutions-program-updates-2026ratepayers-and-customers/.

term cost commitments under programs that have not been adequately vetted. Connecticut's experience with its Energy Storage Solutions program demonstrates that even programs developed through deliberate stakeholder processes require significant mid-course correction.[15] Rushing design to meet political timelines compounds this risk. The Board should not sacrifice program quality for speed, particularly when ratepayers will bear the costs of design errors for years.

(4) The Board should establish sunset provisions and termination triggers. This RFI does not address what happens if the VPP or Phase 2 programs fail to deliver anticipated benefits. Rate Counsel recommends that the Board build explicit exit ramps into both programs, including defined cost-effectiveness benchmarks measured against conventional alternatives, performance thresholds below which programs are suspended or terminated, and hard budget caps that cannot be exceeded without a new Board order supported by updated benefit-cost analysis. Otherwise, the Board risks exasperating the affordability crisis rather than fixing it. Ratepayers should not be committed to open-ended program obligations with no mechanism for termination if costs exceed benefits.

(5) Regulatory resource burden. This RFI spans five simultaneous dockets and asks stakeholders to address questions touching VPP program design, GSESP Phase 2, Order 2222 implementation, GridFlex, and IDDER planning. The volume and pace of parallel proceedings strains the resources of all parties, including Rate Counsel and Board Staff. Rate Counsel urges the Board to consolidate overlapping workstreams where possible and sequence proceedings in a manner that allows for meaningful stakeholder engagement rather than fragmenting attention across multiple simultaneous dockets operating on aggressively compressed timelines.

[15] RFI Notice at 1, Docket Nos. QO26030099, QO26040116, QO24020116, QO26030059, QO24030199.

(6) If the capacity need is real, conventional alternatives remain the most proven and cost-effective response. EO2 identifies a widening gap between electricity supply and demand in PJM and recognizes this imbalance as a significant driver of New Jersey's affordability crisis.[16] If that gap is as urgent as EO2 describes, the most reliable and cost-effective response is to procure firm, dispatchable capacity through existing PJM market mechanisms or conventional generation investment. Moreover, the Board must recognize that the gap is caused by data center driven demand, not New Jersey's other ratepayers, and must ensure that any solution does not unfairly shift costs from those data centers to ratepayers.

A combined cycle plant delivers hundreds of megawatts of firm capacity at known construction and operating costs with decades of performance data. VPP and distributed storage programs, by contrast, require years of design, infrastructure buildout, customer enrollment, and regulatory oversight to deliver marginal, intermittent capacity. The administrative and infrastructure costs per megawatt of deliverable capacity from distributed programs are dramatically higher than conventional supply-side resources.

Ratte Counsel does not oppose the exploration of distributed resource programs in principle, but the Board must confront the cost-effectiveness comparison it has so far avoided. Ratepayers should not fund speculative programs when proven alternatives can meet identified needs at lower cost and lower risk.

(7) Technology lock-in creates stranded investment risk. Phase 2 contemplates 10-year performance incentive commitments.[17] Battery storage technology is evolving rapidly. Committing ratepayers to decade-long incentive structures based on current technology creates the risk that ratepayers fund systems that become obsolete or underperforming relative to future

[16] Exec. Order No. 2, §§ 1-2 (Jan. 20, 2026), 58 N.J.R. 1041(a) (Feb. 17, 2026).
[17] RFI Notice at 2, Docket No. QO26030099

alternatives. The Board should structure incentive commitments with shorter initial terms and periodic reassessment to preserve flexibility as technology and market conditions change.

CONCLUSION

Rate Counsel reiterates that energy storage and grid modernization and flexibility must proceed in a manner that is disciplined, transparent, and firmly grounded in statutory ratemaking principles. The Board should reject proposals that rely on speculative benefits, insufficient safeguards, or unjustified cost shifting. It is imperative that any costs be properly assigned such that the party causing (and finically benefitting) from the need be the party that pays for it, be that data centers for the increase in demand or private entities seeking to interconnect their project to the system. There is substantial profit to be made in all these endeavors, and ratepayers should not see higher bills to simply increase those profits.

Respectfully submitted,

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cc: Service List

I/M/O Advancing the Virtual Power Plant Program in the State of NJ; Garden State Energy Storage Program- Phase 2; NJ's DER Participation in Regional Wholesale Electricity Markets; Developing Grid Flexibility Services for Aggregated DER; Developing Integrated DER Plans to Modernize NJ's Electric Grid

BPU Docket Nos. QO26030099, QO26040116, QO24020116, QO26030059, QO24030199

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