



Submitted electronically

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Sherri L. Lewis
New Jersey Board of Public Utilities
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PO Box 350 Trenton
NJ 08625-0350

RE: Docket No QO26030099

Secretary Lewis,

Evergreen Action and the Environmental Defense Fund are pleased to submit these comments on the NJ Board of Public Utilities' "Straw Proposal—Virtual Power Plan Program."

Respectfully,

S/ Eric Miller
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A handwritten signature in blue ink, appearing to read "Michael Zimmerman".

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PART I. SUMMARY OF COMMENTS

Evergreen Action (Evergreen) is a non-profit environmental organization leading the fight to put bold climate action at the top of America’s agenda. Evergreen is building an ambitious, actionable policy roadmap for an all-out mobilization to defeat climate change—and to create millions of jobs in a thriving, just, and inclusive clean energy future. Evergreen is jointly submitting comments with the Environmental Defense Fund (EDF). EDF is a non-profit environmental organization working to stabilize the climate and strengthen the ability of people and nature to thrive and support people's health. Technical analysis and subject-matter expertise regarding virtual power plants supporting the preparation of this filing were provided by Rockcress Consulting, Portland, Oregon.

Jointly, Evergreen and EDF support the New Jersey Board of Public Utilities’ (referred to throughout as “Board”) decision to develop a Virtual Power Plant (VPP) Program and support the urgency reflected in Governor Mikie Sherrill’s [Executive Order \(EO\) No. 2](#) and in the July 2027 launch date. Reducing demand at system peak is among the most effective interventions available to the Board. Evergreen and EDF support moving quickly to establish New Jersey’s VPP Program, but the Program should be designed from the outset as an accountable, equitable, and durable grid resource, rather than simply another customer incentive program.

VPPs should be evaluated and compensated based on the measurable grid services they provide and placed on equal footing with other resources capable of reducing peak demand, avoiding or deferring infrastructure, improving reliability, and lowering system costs. Program success should be defined through clear metrics and measurable outcomes, including peak-demand reduction, realized ratepayer savings, avoided or deferred distribution and transmission investments, emissions reductions, customer (may also be referred to as “consumer” or “ratepayer”) participation and retention, and equitable participation by low- and moderate-income customers (LMI) and overburdened communities (OBCs). These outcomes should be subject to transparent and consistent public reporting, so the Board and stakeholders can determine whether the Program is delivering the benefits used to justify ratepayer investment.

Emissions impacts should be expressly incorporated into the Straw Proposal’s program objectives, metrics, and reporting requirements. As Staff has rightfully cited in the Straw Proposal, VPPs can reduce emissions by shifting or reducing demand during periods when the grid is most constrained and marginal generation may be more carbon intensive, while also supporting the integration of renewable generation and reducing reliance on fossil-fueled peaking resources. At the same time, not every VPP dispatch will necessarily produce an emissions benefit, particularly where charging or load shifting occurs during higher-emitting periods or where distributed generation is used to meet dispatch obligations. The Board should therefore establish a transparent methodology for measuring and reporting the net emissions impacts of the VPP Program, including both avoided and incremental emissions attributable to charging, discharging, load shifting, and dispatch. Emissions performance should be included among the Program’s core metrics and evaluated alongside peak reduction, reliability, avoided system costs, customer bill impacts, and equity outcomes. Doing so will allow the Board to ensure that VPP deployment advances New Jersey’s broader clean-energy and climate objectives while providing stakeholders with sufficient data to assess whether claimed emissions benefits are being realized.

Equity, consumer protection, and stakeholder participation should be embedded throughout the Program rather than treated as secondary considerations. The Board should establish measurable equity goals, provide meaningful opportunities for LMI, OBCs, and other vulnerable populations such as medically dependent households, consumer, community-based, and competitive-market stakeholders to participate in implementation, and coordinate the VPP Program with related proceedings—including Proactive System Upgrade Plan (PSUP), Time-Varying Rates, net energy metering (NEM) reform, Triennium programs, GridFlex, and Utility Business Model Reform (UBMR)—so that overlapping policies reinforce rather than undermine one another. Customer protections should include clear and comparable offers, transparent compensation and performance requirements, meaningful opt-out and transition protections, strong privacy and cybersecurity standards governing personally identifiable, financial, meter, and device-level information, and safeguards against customers being financially harmed when complying with a VPP dispatch.

Protection of non-participating customers must be an equally important design principle. In the near term, VPP incentives, implementation costs, and compensation structures could shift costs from participating customers to non-participants before the Program’s broader system savings are fully realized. That concern is particularly significant during the current affordability crisis, when customers

are already struggling with rising bills and service terminations. Long-term peak shaving and avoided distribution, transmission, capacity, and other system costs may ultimately moderate rates, but those benefits frequently appear as costs that are avoided or deferred—that is, bills increasing more slowly—rather than immediate reductions in customer bills. It would therefore be politically and practically unsustainable to impose material near-term costs on non-participants based solely on the promise of future system savings.

The Board should require the Interim Program to measure and publicly report participant and non-participant bill impacts and cost shifts, establish reasonable limits or corrective mechanisms where material adverse impacts emerge, and use actual Interim Program data to refine compensation and cost-recovery structures. This issue should also be coordinated directly with UBMR. If VPPs and other distributed resources can provide grid services more cost-effectively than traditional utility-owned capital investments, the utility business model should not financially favor rate-base growth over procurement of those services. UBMR should therefore consider how performance-based regulation, earnings opportunities, and appropriate return-on-equity (ROE) adjustments or reductions associated with avoided utility capital investment can align EDC financial incentives with the use of cost-effective VPP and non-wires solutions. Ratepayers should receive a meaningful share of the savings when VPPs allow the system to avoid or defer traditional infrastructure, rather than paying both for VPP services and utility earnings structures designed around capital expansion.

Priority Positions

Taken together, the following elements should be expressly embedded within Staff's guiding principles and carried through the design, implementation, and evaluation of the VPP Program:

1. **Treat VPPs as grid resources**, incorporating them into distribution planning, investment decisions, and system operations on equal footing with other resource alternatives;
2. **Incorporate emissions impacts** into program objectives, performance metrics, and reporting requirements;
3. **Require measurable performance and transparent reporting** to demonstrate whether program objectives and ratepayer benefits are being achieved;
4. **Protect participating and non-participating customers**, including against unreasonable cost shifting and unintended bill impacts;
5. **Make equity a measurable program outcome**, supported by defined metrics, targets, and reporting;
6. **Provide meaningful stakeholder engagement and oversight** throughout program design, implementation, and evaluation;
7. **Protect customer data** through clear privacy, cybersecurity, data-governance, and accountability requirements;
8. **Coordinate decisions across related dockets and programs** to avoid conflicting requirements, duplicative investments, and regulatory silos; and

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9. **Align utility financial incentives with least-cost resource solutions**, so EDCs are not financially advantaged by utility-owned capital investment when VPPs or other alternatives can meet grid needs more cost-effectively.

PART II. GENERAL COMMENTS ON FRAMEWORK AND GUIDING PRINCIPLES

TWO-PHASE STRUCTURE

Executive Summary; Sections 2 and 3

Straw Proposal § 2.3

Interim Program 2027–2029, EDC-administered; long-term open-access tariff framework 2029 onward.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support the two-phase structure, with three modifications: 1) attach an outside date to the Interim-to-long-term transition rather than conditioning it solely on milestone achievement; 2) design the Interim Program for migration from the outset so it does not entrench Electric Distribution Company (EDC) administration; and 3) preserve continuity for enrolled customers across the transition.

We support beginning with an EDC-administered Interim Program. The Distributed Energy Resource Management System (DERMS) architecture described in **Section 3.4** does not yet exist, the PJM interface and Advanced Metering Infrastructure (AMI) provisioning sit naturally with the EDCs in the near term, and an EDC-run bridge is the fastest route to a launch that the urgency of Executive Order No. 2 and the July 2027 date warrants.

Our concern is with the transition, not the starting point. A transition conditioned solely on milestone achievement can stall indefinitely: if a milestone slips, the Interim Program persists by default, the competitive open-access market is delayed, and the EDC-administered phase becomes the de facto permanent structure. Therefore, we recommend the Board attach an outside date by which the long-term open-access framework commences regardless of milestone status (consistent with the 2029 timeframe the Straw contemplates) and retain discretion to extend only through a noticed proceeding supported by findings. A specific date converts the transition from a pilot into a full program commitment.

The Interim Program should also be built for migration from the outset. Enrollment and outreach should be open to licensed third-parties and community-based aggregators from the start (see **Comment 10**), enrolled resources should be transferable into the long-term framework, and Interim terms should avoid any lock-in that would disadvantage the competitive market the second phase is meant to create.

Section 2.8(c) already provides an important foundation for migration, which we support. The Board should build on that approach by assigning objective readiness criteria and outside dates to each transferred function, requiring advance customer notice of material changes, and maintaining then-current Interim compensation during any defined parallel-transition period. Customers should retain the right to opt out without penalty if long-term tariff terms materially change.

Finally, the transition should preserve continuity for the households participating within the Interim Program and the long-term Program. A participant (or customer) who enrolled a device and participated in the Interim Program should be able to transition seamlessly without an abrupt loss of compensation (see **Comment 12**). The program’s focus on capturing both grid and participant benefits—including capacity value, avoided transmission and distribution costs, and peak-period emissions reductions—should remain consistent across all phases, ensuring that the phases operate as a cohesive program rather than as two distinct offerings.

Specifically, the transition from the Interim Program to the Long-term Program should address how participants will be notified of any potential changes in compensation, program design, program implementer, etc. These notifications should provide sufficient information needed for participants to make informed decisions on whether they would like to stay within the program or not. This need for participant clarity also favors the change from a milestone to date-based program requirement. A defined calendar timeline will make it easier to ensure accountability and transparency with actionable information to participants in a timely fashion, rather than waiting until milestone completion is imminent to give them a clear date.

THE EIGHT GUIDING PRINCIPLES

Section 1.3

Straw Proposal § 1.3

- Ratepayer savings and cost-effectiveness
- Leveraging existing assets
- Open and competitive market architecture
- Value stacking and cross-program coordination
- Equitable design
- Integrating DER grid services into Electric Distribution Company (EDC) planning
- Technology neutrality and interoperability
- Transparency and stakeholder engagement

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support all eight principles, with two proposed changes: (1) add a ninth principle on emissions reduction and qualify technology neutrality to apply among zero-emission and non-emitting resources; and (2) strengthen the existing principles so they operate as measurable program commitments.

First, contrary to New Jersey's decades long commitment to tackling economy-wide greenhouse gas (GHG) emissions, only the Ratepayer Savings and Cost-Effectiveness Framework principle mentions emissions; however, we highly recommend the Board considers making emissions a core principle.

Section 2.6 states expressly that emissions reductions are not part of the goals of the Interim Program, and uses that as a stated reason for setting aside the Societal Cost Test and the New Jersey Cost Test.

This runs counter to New Jersey's long history of addressing the climate crisis, which spans decades of legislative targets, executive actions, and regional partnerships. Landmark milestones include the 2007 Global Warming Response Act (GWRA) targeting deep emission cuts, reentry into the Regional Greenhouse Gas Initiative (RGGI), and aggressive shifts toward offshore wind and clean energy¹³¹⁵, which targets 100 percent clean electricity by 2035.²

The whole of New Jersey government, and especially the Board, has a long history of using its regulatory and policymaking powers to advance the legislative targets of the GWRA, as reflected in previous Board Orders related to solar, energy efficiency, grid modernization, and most recently, battery storage. For example, in its March 2026 Order awarding the first tranche for energy storage projects, the Board repeatedly stated its commitment to achieving the State's clean energy and climate goals.

This treatment is also consistent with [N.J.S.A. 48:3-87.9\(d\)\(2\)](#), which requires energy-efficiency and peak-demand-reduction portfolios to consider both economic and environmental factors, and with the 2024 Energy Master Plan's treatment of VPPs as part of New Jersey's clean-energy strategy.

The proposal to set aside emissions reductions as a program objective is also difficult to reconcile with the rest of the Straw Proposal. The Straw Proposal's cost-effectiveness discussion contemplates consideration of reduced emissions in communities near emitting resources and progress toward stated emission reduction goals. **Section 3** lists Emissions Reductions among the long-term value categories, and Staff's own summary of pre-Straw stakeholder input records strong consensus for a benefit valuation framework that accounts for emissions reductions. **Section 6.5** further grounds the Straw Proposal's equity commitments in the Environmental Justice Law.

This is a program whose central function is to reduce demand at system peak, which is when the regional marginal generating unit³ is most likely to be an older, less efficient, higher-emitting fossil plant. Peak reduction is among the most emissions-productive interventions available to the Board, in a state operating under a statutory mandate to cut emissions 80 percent below 2006 levels by 2050 and a

² New Jersey Department of Environmental Protection Clean Energy Page: [Energy Policy In New Jersey](#)

³ [PJM 2021 2016–2020 CO₂, SO₂ and NO_x Emission Rates](#)

target of 100 percent clean electricity by 2035. A stated principle is not merely a declaration; it governs how competing considerations are weighed when the MFR Order is drafted and when the 2028 continuation determination is made.

Proposed language for the addition of a ninth principle: **“Emissions reduction: the Program shall prioritize reductions in greenhouse gas and criteria pollutant emissions, with particular attention to overburdened communities.”**

We recommend modest changes to four of the existing principles, which align with our priority positions within **Part 1. Summary of Comments**:

- **Ratepayer savings and cost-effectiveness (i).** As explained within **Comment 8**, the Ratepayer Impact Measure (RIM) should not be the gating test. We read this principle as the program’s full value as a grid resource (e.g., avoided energy, capacity, and transmission and distribution costs, community/customer benefits) not as rate impact alone. This principle should ensure that cost-benefit analysis is aligned with resource planning that allows distributed energy resources (DERs) to be placed on equal footing as other grid resources.
- **Equitable design (v).** Equity stated as a value is not widely integrated into the design of the Interim Program and long-term Program. We recommend a measurable and quantifiable approach similar to that of what was used within New Jersey’s community solar program⁴ (e.g., a participation target, dedicated outreach for overburdened communities as designated under [N.J.S.A. 13:1D-158](#), a low-/no-cost participation pathway, and eligibility for community-based aggregators) as discussed within **Comments 4 and 38**.
- We do not recommend a rigid quota that delays otherwise cost-effective enrollment. Instead, the Board should use measurable participation and deployment targets, enhanced incentives, and public reporting—building on New Jersey’s experience incorporating equity into distributed-energy programs—to identify and correct under-participation by LMI households and overburdened communities designated under [N.J.S.A. 13:1D-157](#).
- **Integrating DER grid services into EDC planning (vi).** Expressly include non-wires-alternative use: targeting VPP dispatch to defer specific, identified distribution and transmission investments, prioritizing constrained areas and overburdened communities.
- **Transparency and stakeholder engagement (viii).** Strengthen this principle by expressly requiring meaningful public performance reporting and stakeholder participation throughout VPP implementation and evaluation. At minimum, this should include the public reporting requirements discussed in **Comments 13 and 31** and formal community, environmental-justice, and consumer representation in the VPP Working Group as discussed in **Comment 29**.

A stated emissions principle should also carry through to methodology. We recommend that avoided greenhouse gas and criteria pollutant emissions be monetized in the cost-effectiveness analysis

⁴ [Community Solar Energy Program \(CSEP\)](#) provides subscribers with a guaranteed bill credit discount of no less than 20 percent, with LMI subscribers receiving a guaranteed bill credit discount of no less than 25 percent.

(**Comments 8 and 9**) so the ninth principle influences the continuation determination rather than being a state goal.

THE FEDERAL ENERGY REGULATORY COMMISSION (“FERC”) ORDER NO. 2222 AND PJM INTERCONNECTION (“PJM”) COMPLIANCE TIMING

Section 1.4

Straw Proposal § 1.4

PJM must enable DERA participation in energy and ancillary services markets by February 1, 2028; capacity market participation begins with the 2028/2029 delivery year. Notice-of-intent deadlines precede program launch.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

The Board should require each EDC to identify, in its December 2026 filing, which PJM delivery years its proposed program is designed to reach, and should confirm in the MFR Order that participation in the State program does not foreclose PJM registration.

We agree with Staff that the PJM deadlines are near-term and argue for urgency. It adds one point the Straw Proposal does not address. The June 12, 2026 Notice of Intent date has passed, leaving December 1, 2026 as the operative deadline for the 2030/2031 auction. That date falls one month before the EDCs file their proposals and seven months before the Interim Program begins, so an aggregator must decide whether to incur PJM registration costs without knowing the compensation levels, performance obligations, or contract terms it will be asked to accept.

Requiring EDCs to state their target delivery years would make the mismatch visible before the Board issues its MFR Order confirming that State participation does not foreclose wholesale registration, subject to the anti-double-counting principle addressed at **Comment 17(a)**, costs the Board nothing and removes a question that will otherwise be resolved conservatively.

DEFINITIONS

Section 1.2

Straw Proposal § 1.2

Terms including AMI, DER, DERMS, Grid Flexibility Services, and VPP.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We recommend the Board define “grid stress condition”, which the Straw uses operationally but never defines, and confirm that the definition of DER excludes fossil-fueled generating equipment. Both of these need attention, because the terms adopted here will be carried into the MFR Order and then into the tariff.

First, “grid stress condition” appears in the Interim Program objectives as the trigger for dispatch but is left to EDC determination without stated criteria. A term determining when participants must perform should be defined, and published criteria would also allow the Board and the public to see whether dispatch is being used for peak reduction as described or for other purposes. We recommend EDCs publish the criteria as part of their Interim VPP filings. Further, we propose the following definition for “grid stress condition:” “Grid stress condition means a forecast or actual system, transmission, or distribution condition, defined by published criteria, under which dispatch is warranted.”

Second, the definition of DER should state expressly whether fossil-fueled generating equipment is included. We recommend Staff explicitly provide its definition for DERs within the Straw Proposal, such as that offered in New Jersey’s, proposed 2026 [Senate No. 1211](#), which explicitly “exclud[es] diesel fuel technologies.”

Proposed language: “Distributed Energy Resource does not include fossil-fueled generating equipment.”

The exclusion should apply to routine compensated VPP participation and should not prevent facilities from retaining emergency backup generation for resilience. If Staff allows emitting backup resources to operate during declared emergencies, that exception should be narrowly defined and should not qualify for ordinary VPP compensation.

There may also be limited circumstances in which an emitting backup resource operates during a declared emergency as part of an integrated resilience system. For example, NextEra Energy/Florida Power & Light (FPL) and Florida International University (FIU) developed a campus project integrating renewable generation, battery storage, backup synchronous generation, a microgrid, and VPP capabilities.⁵ The project demonstrates how different resources can operate as an integrated system to support grid and facility needs during emergency conditions.

Staff should therefore distinguish between routine VPP participation and emergency resilience operations. If emitting backup resources are permitted to operate during declared emergencies, the exception should be narrowly defined and limited to emergency or resilience conditions. Such operation should not make the emitting generator eligible for ordinary VPP enrollment or compensation. This approach preserves the role of backup generation in facility resilience without creating an economic incentive for fossil-fueled generation to participate in routine VPP dispatch.

⁵ FIU Energy Power Sustainability & Intelligence: [Hybrid Energy, PV & Storage Systems for Integrated Power Plants](#)

PART III. SEQUENTIAL STAKEHOLDER COMMENT REQUESTS (NOS. 1–41)

STAKEHOLDER COMMENT NO. 1 — INTERIM PROGRAM OBJECTIVES

Straw Proposal Section 2.1

Stakeholder Comment No. 1

- a. Staff seeks stakeholder input on each of the objectives outlined for the Interim VPP Programs, such as methodology to determine what qualifies a grid stress condition and validation of performance measurement.
- b. Staff also seeks stakeholder input on whether such objectives are appropriate for the Long-Term VPP Programs.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support the Interim and long-term VPP objectives with additions that make distribution-system integration, non-monetary benefits, customer experience, and cross-proceeding coordination explicit program objectives.

On (a), the Board should strengthen the Interim Program objectives in three ways. First, Objective (viii) should establish an enforceable path for using VPPs as distribution-system planning tools, not only as operational resources for near-term grid needs. The Interim Program should collect the data needed to quantify retail peak reduction and distribution-level grid-service value, while also requiring EDCs to identify the VPP capabilities needed for specific distribution planning functions and a schedule of milestones for incorporating those capabilities into planning and deployment. A VPP maturity model could be used to map capabilities such as metrology, dispatch latency, and autonomy to distribution-planning functions and potential capital deferrals.

Second, the objectives should expressly capture non-monetary benefits, including avoided emissions and other benefits that support New Jersey energy, environmental, public-health, and customer objectives. The Board should evaluate these benefits for both program participants and all ratepayers rather than treating them as outside the scope of the Interim Program.

Third, the Board should add a customer-experience objective. Long-term program success will depend not only on customer savings but also on whether customers understand the program, remain enrolled, respond to dispatch, view participation as valuable, and experience adequate consumer protections. The Interim Program should collect data on enrollment persistence, response behavior, customer retention and satisfaction, and consumer protection outcomes to inform long-term program design.

The Board should also treat coordination as a guiding principle across the objectives. The VPP Program will develop alongside the Proactive System Upgrade Plan (PSUP), Time-Varying Rates, Utility Business Model Reform, and other related proceedings. Coordinated implementation can improve customer

understanding and trust, reduce administrative conflicts, and ensure that these programs complement rather than undermine one another.

On (b), these expanded objectives should carry into the long-term VPP framework. The Interim Program should be used to build the evidence, planning capability, customer-experience record, and inter-proceeding coordination needed for the long-term program to capture distribution-system value and non-monetary benefits.

Proposed language for the following primary objectives for the VPP Interim Programs are bolded below:

- i. Reduce peak demand by no less than 3% across each EDC service territory beginning no later than July 1, 2027, through the coordinated dispatch of behind-the-meter (BTM) DERs aggregated by both EDCs and third-party aggregators. Dispatch events shall be informed by a reliable forecasting mechanism of PJM's 5 Coincident Peaks (5CP), but are not limited to 5CP hours, and should also be called during distribution-level thermal constraints, local congestion, and other qualifying grid stress conditions as determined by the EDCs. **Each EDC shall define and publish objective, criteria-based standards for qualifying grid stress conditions in its December 2026 filing and report the basis for events called under those criteria.**
- ii. Demonstrate the reliable and accurate delivery of grid services using existing utility and DER Aggregator systems, and demonstrate evaluation, measurement, and verification (EM&V) capability using existing AMI systems. **Performance measurement shall be independently verifiable, with reconciliation against AMI data and appropriate audit rights where performance data are supplied by a party whose compensation depends on the measured result.**
 - **Gather operational data** – including, but not limited to, event response rates, baseline accuracy, resource mix performance, and dispatch latency, comparative performance across non-exporting and exporting (residential storage) configurations, and participant DER selection behavior – that will inform the technical requirements and compensation design of the long-term tariff structure.
- iii. Enable customer familiarization with VPP participation and trust-building with the program and third-party aggregators, creating an enrolled customer base from which the long-term, aggregator-led market can grow. **Collect data on customer participation outcomes, including enrollment persistence, response behavior, customer retention and satisfaction, and consumer protection outcomes, to inform long-term program design.**
- iv. Test and validate the communication protocols, performance measurement methodologies, and data reporting standards between EDCs and third-party aggregators that will be carried forward into the long-term VPP framework and evaluate their consistency across EDCs.
- v. Establish a structured, competitive EDC-aggregator contracting framework in New Jersey that progressively builds third-party aggregator operational capacity, market experience, and enrolled customer bases during the VPP Interim Program period, creating the market foundation necessary for the long-term open-access VPP tariff to function effectively upon its launch.

- vi. Evaluate compensation structures, including, but not limited to fixed enrollment payments and pay-for-performance models, and test appropriate incentive levels to identify designs that reliably obtain DER aggregator response, to inform compensation and tariff design for the long-term framework.
- vii. Collect data to quantify retail peak load reduction and distribution-level grid service values, in order to establish the evidence-based foundation for future procurement of locational distribution network benefits under the long-term framework. **Develop a schedule of milestones by which EDCs will incorporate VPP capabilities into distribution system planning and investment decisions, including the use of VPPs, where cost-effective, to defer or avoid traditional capital investments.**
- viii. Evaluate the potential for VPPs to lower costs **and deliver non-monetary benefits, including avoided greenhouse gas and criteria pollutant emissions**, for both participants of the program, as well as for all ratepayers.

Across all objectives, implementation should be coordinated with related Board proceedings, including PSUP, Time-Varying Rates, and Utility Business Model Reform, to promote consistent requirements, efficient administration, and a coherent customer experience.

STAKEHOLDER COMMENT NO. 2 — MINIMUM AGGREGATION SIZE

Straw Proposal Section 2.2(iii)

Stakeholder Comment No. 2

- a. Staff seeks stakeholder comments, under section iii, “Minimum Aggregation Size”, on whether the proposed minimum thresholds of 10 kW and 100 kW are appropriate for the VPP Interim Program and the long-term tariff, respectively.
- b. Staff also seeks comments on whether separate thresholds should apply to residential and commercial & industrial (“C&I”) sectors for the interim and long-term programs.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We recommend that Board set aggregation thresholds by the service being provided, not by customer class, and preserve a low threshold for distribution-level participation so smaller residential and community aggregations are not excluded.

While we generally agree with an aggregation threshold, we recommend a threshold for each level of the grid (e.g., transmission, distribution) DERs will be dispatched to. Administrative cost is a real consideration, though it may exclude resources capable of delivering essential distribution services. The practical effect of a high aggregate floor is to favor aggregations of larger, newer, more expensive equipment — which correlates with income. We distinguish aggregations that participate only at the distribution level, where a low floor is appropriate, from those bidding into PJM wholesale markets,

where PJM's own distributed energy resource aggregator (DERA) minimum (100 kW) governs; the long-term floor should reflect that distinction rather than apply uniformly.

However, we encourage Staff to evaluate other alternatives for setting a threshold such as site level thresholds. For example, California's Demand Side Grid Support program applies a per-site minimum and requires a battery able to discharge at least 1 kW for two hours, rather than an aggregation floor.⁶ The Electric Reliability Council of Texas (ERCOT)'s Aggregated Distributed Energy Resources (ADER) pilot caps individual device size and manages scale through program-level limits.⁷ Both admit small aggregations while controlling administrative burden by other means.

These examples are offered not as a recommendation to copy either program wholesale, but to illustrate that the Board can preserve customer-level access while managing aggregator administrative burden through per-site eligibility rules or program-level limits rather than a single high aggregation floor.

Regardless of the approach, the 20 kW distribution-service threshold proposed in **Section 3.5(ii)(b)** should be reduced to 10 kW so that it aligns with the Interim Program threshold, ensuring that an aggregation eligible to participate during the Interim Program remains eligible to provide distribution-level services under the long-term tariff.

On (b), separate thresholds for commercial and residential should not be adopted for the interim program. They could potentially lead to access challenges for certain customer classes (e.g., low- and moderate-income participation). For the long-term VPP, separate thresholds should be considered based on the learnings from the interim program.

On (c), enrolled capacity and capacity delivered should be measured. Measuring only eligibility at capacity deliverable during an event conflates participation with performance, and means a community aggregation admitted in one season could be excluded in the next without any change in enrollment. Capacity delivered supports performance measurement and compensation mechanisms, which the Straw already addresses.

Separately, we recommend the program migration for both the Triennium 2 DR portfolio and the sub-programs begin in time for the summer series. We recommend the establishment of the program migration by May of 2027 that migration is complete by the July 1, 2027 launch of the VPP Interim Program. Separately, the Board should ensure that a resource migrated from the Triennium DR portfolio or bidding into PJM capacity is not compensated or counted twice across the VPP, existing demand response, and PJM markets.

⁶ [California Demand Side Grid Support FAQ](#)

⁷ [ERCOT's ADER Program: What C&I Users and Utilities Need to Know](#)

STAKEHOLDER COMMENT NO. 3 — COMMUNICATION STANDARDS AND PROTOCOLS

Straw Proposal Section 2.2(iv)

Stakeholder Comment No. 3

Staff seeks stakeholder comments, under section iv, “Communication Standards and Protocols”, on whether the proposed standards (OpenADR 2.0b/3.0, IEEE 2030.5, and CTA 2045) are required for the VPP Interim Programs and the long-term tariff while balance the feasibility, cost, and time.

Position: ☒ **Support** ☐ Support with modifications ☐ Oppose ☐ No position / not applicable

RESPONSE

The Board should require open, non-proprietary communication standards for both phases. Interoperability is what prevents a customer’s device from being confined to the platform that enrolled it, leading to customers who cannot move to a better offer or leave a bad one. Over time, it is also what allows the installed base built during the Interim Program to remain usable as the framework evolves. Enabling customer choice is consistent with the long-term vision described in the Straw’s guiding principle (iii) concerned with developing a competitive market architecture.

STAKEHOLDER COMMENT NO. 4 — INTERIM PROGRAM BUDGET SUFFICIENCY

Straw Proposal Section 2.4

Stakeholder Comment No. 4

Staff requests comment on whether the proposed budget is sufficient for EDC-administered VPP Interim Program and justification of budget that will meet the goals of the Interim Program.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We believe the proposed budgets appear sufficient as an initial starting point to pursue the 3 percent peak-reduction target, but the Board should not treat them as fixed. Instead, the Board should use program budgets to provide planning discipline and customer protection, while revisiting budgets and targets as Interim Program data become available and considering a statewide VPP potential study to better define achievable deployment, participation, and cost levels.

The Board should also require each EDC to identify and dedicate a specific portion of its budget to participation in Overburdened Communities designated under N.J.S.A. 13:1D-158, including outreach and language access for limited-English-proficiency households. Without an explicit allocation, spending

is likely to follow the lowest-cost customer acquisition opportunities rather than the Program’s equity objectives.

A statewide VPP potential study would help inform future budgets by assessing resource availability, customer participation potential, locational value, and the costs required to achieve program goals. Until that analysis is available, the Board should treat the Interim Program as an iterative learning period and adjust budgets and targets based on actual enrollment, performance, and cost data.

STAKEHOLDER COMMENT NO. 5 — BUDGET LEVELS AND HARDWARE INCENTIVES

Straw Proposal Section 2.4

Stakeholder Comment No. 5

Staff requests comments on whether the proposed budget levels are appropriate, and on whether hardware incentives costs should be incorporated into the VPP Interim Program budget or maintained as separate program costs.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We recommend that hardware incentives be kept outside the VPP budget, but require a coordination mechanism so that device affordability does not depend on the timing of a separate proceeding.

Hardware incentives and grid-service compensation do different work and belong in separate budgets. Folding device subsidies into the VPP budget would consume funds intended for performance compensation and would worsen the program’s measured cost-effectiveness under every test in **Section 2.6** by drawing hardware cost inside the program boundary.

The risk of separation has an undue burden for certain households. For a customer who already owns a battery, VPP compensation is additional income. For a customer who does not, the device incentive is the precondition for participating at all. If those incentives are set in Triennium 3 or Garden State Energy Storage Program (GSESP) Phase 2 on a timetable misaligned with the VPP launch, the participants excluded will be disproportionately low- and moderate-income.

The Board should require any hardware incentive program supporting VPP-eligible devices to state its VPP interaction expressly, and should direct the Working Group under **Section 4.9** to report on alignment ahead of each program year.

STAKEHOLDER COMMENT NO. 6 — BIFURCATED PROGRAM START DATES

Straw Proposal Section 2.4

Stakeholder Comment No. 6

Staff requests comments on the feasibility of bifurcating the start of the programs and on the feasibility of having any customers enrolling after the approval of the VPP programs to start under the VPP framework rather than the Triennium construct.

Position: ☒ **Support** ☐ Support with modifications ☐ Oppose ☐ No position / not applicable

RESPONSE

We support both the bifurcated dates and routing post-approval enrollees directly into the VPP framework.

STAKEHOLDER COMMENT NO. 7 — EVENT DISPATCH PARAMETERS

Straw Proposal Section 2.5

Stakeholder Comment No. 7

Staff requests feedback on:

- Whether the proposed preliminary event parameters are appropriate or more refined and aggressive parameters are needed
- What requirements and evaluation criteria the Board should apply in reviewing EDC-proposed dispatch parameters
- Whether an annual cap on total dispatch events is appropriate, and if so, what numeric limit (e.g., 35 events per year, inclusive of any shoulder-season events) would be reasonable
- The creation of structures that will best maximize cost savings to customers and ratepayers

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We believe the proposed event counts are too conservative, and more aggressive parameters are needed. The seasonal event counts are conservative compared to other programs aimed at serving grid needs (bulk, transmission, distribution) in addition to undervaluing the diversity of services provided by differing DERs. These events may be appropriate for a smart thermostat program which would call a longer event, but could constrain potential grid services a battery could provide, such as frequency response and distribution voltage control.

On (a), the four-hour maximum and the two-hour notice are standard. Additionally, customer opt-out provisions are appropriate and we support them. EDCs should separately report PJM-related dispatches

and distribution- or local-reliability dispatches so the Board can assess whether event frequency, performance, and customer opt-outs differ by service type and technology.

We recommend the cap on dispatch events be removed or increased at a minimum. The ConnectedSolutions programs in Massachusetts and Rhode Island dispatch roughly thirty to sixty events per season at durations of about three hours, which is substantially more frequently than the twenty summer events proposed here.⁸ Another example is Xcel's Colorado VPP program allows for up to 80 events per year (year-round) or 60 events per year (summer-only).⁹

Where a program has enrolled capacity available and elects not to use it, the emissions and capacity benefit is simply lost. Underutilization will also make it harder to recoup the value of program implementation costs, provide ratepayer cost savings, and facilitate emissions reductions. We recommend the Board consider alternative strategies such as technology or sector-wide event parameters or set the seasonal counts as a floor on EDC dispatch obligation rather than a ceiling on participant exposure, but ensure participants are allowed to opt-out. The Board should require EDCs to report annually on available capacity not dispatched. Because we ask the Board to treat dispatch as an obligation, that obligation should be paired with aggregator availability and performance requirements, with defined consequences for sustained non-performance.

The customer opt-out is the appropriate protection for participants and should be preserved without qualification. **Proposed language: "The seasonal event counts establish a minimum EDC dispatch obligation, not a maximum; participant exposure is limited only by the customer opt-out."** It also makes higher event counts sustainable, because a customer who can decline an individual event is far more tolerant of frequent dispatch than one who cannot.

On (b), dispatch parameters should be published rather than held in operating procedure, modifications noticed in advance with opportunity for comment, and EDCs required to report events called by category so the Board can verify that the grid stress discretion is used as described.

On (c), we do not recommend a fixed annual cap as the primary customer-protection mechanism. Participant opt-out rights, device-specific dispatch limits, and transparent event reporting provide more flexible protections while allowing the program to use enrolled resources when they deliver value.

On (d), the structures that maximize savings are those that maximize enrolled volume and dispatch frequency. Volume follows from accessible thresholds, adequate compensation and durable terms; frequency follows from the Board treating dispatch as the objective rather than as an imposition to be minimized.

⁸ [ConnectedSolutions: Optimize Peak Demand in Massachusetts and Rhode Island](#)

⁹ Xcel's [Aggregator Virtual Power Plant Program](#)

STAKEHOLDER COMMENT NO. 8 — COST-EFFECTIVENESS TESTS

Straw Proposal Section 2.6

Stakeholder Comment No. 8

- a. Staff requests comments on whether the proposed approach to the cost-effectiveness tests (the RIM, TRC, SCT, PACT, and PCT) are appropriate for evaluating the VPP Interim Program, or whether some should be modified, omitted, or supplemented. Staff is particularly interested in whether the RIM is well-suited to capture the full value of VPP dispatch, and whether any test should serve as the primary standard for the Board's program continuation determination.
- b. Staff also seeks comment on standard methodology to quantify the savings from avoided costs related to distribution and transmission.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We strongly recommend the Board evaluate VPPs as grid resources using a resource-value and avoided-cost framework, supplemented by established benefit-cost tests. The RIM should not serve as the sole or primary test for program continuation. At a minimum, the Board should require reporting of the New Jersey Cost Test (NJCT) to capture economic and non-monetary benefits that RIM does not.

On (a), the traditional cost-effectiveness tests should inform, but not individually determine, whether the VPP Program continues. VPPs provide dispatchable capacity, load flexibility, and other grid services that can reduce system costs and defer or avoid infrastructure needs. Program evaluation should therefore consider whether VPPs provide these services cost-effectively relative to available alternatives.

The RIM is useful for understanding impacts on non-participants but does not capture the full value of VPPs and should not be used as a stand-alone pass/fail test. The Board should evaluate multiple perspectives and, at a minimum, require EDCs to report NJCT results so that emissions, environmental, and other non-monetary effects such as energy equity are considered. The Interim Program should be used to develop the data necessary to determine the appropriate primary cost-effectiveness standard for the long-term framework.

Requiring NJCT reporting is also consistent with [N.J.S.A. 48:3-87.9\(d\)\(2\)](#), which evaluates energy-efficiency and peak-demand-reduction portfolios at the portfolio level considering both economic and environmental factors. The Board should also consider whether a defined clean-peak service should be recognized as a VPP benefit or grid-service category where dispatch demonstrably shifts load or exports to periods that reduce peak-system costs and emissions.

The recognition of a Clean Peak Service as a benefit and grid service in VPP and performance-based ratemaking frameworks aligns directly with emerging legislation in Colorado ([Senate Bill 24-218](#)), New York ([GREAT Act - A10354A/S9500A](#)), and Pennsylvania ([House Bill 2264](#)).

On (b), the Board should establish a transparent and consistent methodology for valuing avoided distribution and transmission costs across EDCs. Distribution benefits should reflect the VPP's ability to reduce demand at constrained locations and times and thereby avoid or defer otherwise necessary investments. Transmission benefits should similarly reflect demonstrated reductions in applicable transmission-related costs. Values should account for the location, timing, availability, and demonstrated performance of VPP resources rather than relying solely on statewide averages.

The methodology should be published, repeatable, and consistently applied across EDCs and program years. We recommend the [Value of Distributed Energy Resources Largely Depends on Three Things: Location, Location, Location](#) by Lawrence Berkeley National Lab as a reference source. As the VPP Program matures and resources participate in additional markets, the Board should also incorporate additional measurable value streams, including wholesale market revenues, avoided transmission charges, wholesale market impacts, and avoided emissions, where those benefits can be reasonably quantified and attributed to VPP performance.

STAKEHOLDER COMMENT NO. 9 — PEAK DEMAND REDUCTION TARGET AND COST SAVINGS

Straw Proposal Section 2.7

**Stakeholder
Comment
No. 9**

- a. Staff seeks comment on the proposed 3% peak demand reduction target, including whether it should function as a binding floor, a non-binding reference, or an EDC-specific target set within the range in Table 1; and on whether targets should be uniform across EDCs or differentiated to reflect differences in existing demand-response infrastructure and DER penetration among the service territories.
- b. Staff seeks comment on the methodology and assumptions underlying the preliminary peak load figures in Table 1, including the appropriate peak-load basis (e.g., 5CP/PLC versus NSPL) for setting VPP Interim Program targets.
- c. Staff seeks comment on the proposed categories of cost savings, on the appropriate methodology for quantifying realized ratepayer savings – including the extent to which existing cost-effectiveness tests such as the TRC are sufficient – and on whether additional savings categories beyond those enumerated should be reflected in EDC cost-reduction goals.
- d. Staff seeks comment on the approximate \$60 million preliminary estimate of annual avoided capacity costs at a 3% reduction target, as detailed in Appendix A, including the capacity-pricing assumptions on which it relies and whether transmission and distribution avoided costs should be incorporated into future estimates.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

Establish the three percent peak-reduction target as a minimum, while allowing EDCs to propose higher targets based on demonstrated VPP potential and system capabilities. The Board should: 1) commission or incorporate into the PSUP/Integrated Distribution System Planning process a current statewide VPP potential assessment; 2) establish targets using the same peak-load basis used to calculate avoided costs and savings; 3) evaluate ratepayer savings based on realized, verified performance and include avoided emissions, T&D and deferred infrastructure, reliability/resilience, locational value, and community benefits in addition to traditional cost-effectiveness measures; and 4) periodically update the preliminary \$60 million savings estimate using relevant locational capacity values and current market results.

On (a), the three percent target is modest for EDCs that already have mature demand response (DR) programs. Massachusetts has set a target of 3.5 GW from new load-management strategies by 2035 against a six-state regional peak of 26.1 GW in 2025.¹⁰ New Jersey faces the same PJM supply-demand pressure that prompted Executive Order No. 2. The Board should treat 3 percent as the minimum acceptable filing and expressly invite EDCs to propose more, with targets differentiated above that floor

¹⁰ Massachusetts's [Peak Energy Demand Reduction Focus Area Work Group](#)

based on existing Advanced Metering Infrastructure (AMI) penetration, DER infrastructure, and demonstrated VPP potential.

Because New Jersey does not yet have a current VPP-specific potential study, the Board should commission or incorporate into the PSUP/Integrated Distribution System Planning process, a statewide assessment of technically and economically achievable flexible-load and DER potential. The 2018 market potential study can serve as a historical reference, but any new assessment should reflect current DER penetration, DER programs, AMI deployment, electrification, storage, and aggregator capabilities. In addition, because GSESP Phase 2's 350 MW BTM storage target equals roughly 60 percent of the 589 MW statewide 3 percent VPP target, coordinated GSESP participation may support increasing the VPP target as implementation data become available.

On (b), we generally agree with the methodology and assumptions underlying the preliminary peak load figures in **Table 1** of the Straw Proposal, and agree that they are appropriate for setting VPP Interim Program targets. Regarding the determination of the appropriate peak-load basis (e.g., 5CP/PLC versus NSPL), these are different quantities measured over different intervals, and a percentage reduction against one does not translate into avoided cost under the other. Targets should be set on the basis used to value the result.

On (c), the enumerated savings categories are a reasonable foundation but should be measured on a realized (ex-post) basis. The total resource cost (TRC) test should remain one component of the Board's evaluation, but it should not serve as the sole or dispositive measure of VPP benefits or ratepayer value, because it measures net resource cost and omits community and distributional equity analysis,¹¹ locational value, and realized-versus-projected performance. We recommend treating it as one measurement among several rather than the sole test.

The cost-benefit framework should include community benefits such as those required in Oregon's Clean Energy Plan (known as Community-Benefit Indicators), to capture community value that most economic cost tests understate. For the Interim Program, the Board should not wait for a fully developed community-benefit framework. It can begin with ready-to-report metrics such as participation, incentives, bill impacts, enrolled capacity, and realized benefits by customer segment and OBC status, and utilize the Office of Clean Energy Equity and stakeholders to develop a more robust framework for the long-term program.

The savings categories should reflect where and what a VPP actually avoids or defers—for example, energy, generation capacity, transmission and distribution (T&D) capacity and deferred infrastructure, ancillary services, line losses, price suppression, avoided environmental compliance and carbon costs, and reliability/resilience value. Savings can be quantified using locationally and temporally granular avoided costs and verified through M&V, not ex-ante projections alone.

EDC cost-reduction goals should credit avoided T&D and deferred infrastructure, reliability/resilience value, and community benefits, and should count realized, verified savings, not forecasts alone. On (d),

¹¹ Distributional equity analysis focuses on identifying and estimating the distribution of costs and benefits across different customer types. We recommend the reference source: [Distributional Equity Analysis for Energy Efficiency and Other Distributed Energy Resources](#) by the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy.

the \$60 million estimate appears reasonable, and we appreciate the Board’s publication of its analysis. It should be tested against locational capacity pricing in the Eastern Mid-Atlantic Area Council (EMAAC) and PSEG zones rather than a figure for the Regional Transmission Organization (RTO) as a whole and updated after each Base Residual Auction rather than held static.

STAKEHOLDER COMMENT NO. 10 — ALLOCATION OF OPERATIONAL FUNCTIONS

Straw Proposal Section 2.8

Stakeholder Comment No. 10

Staff seeks comment on whether dispatch authority, AMI data provisioning, PJM communication, and marketing/enrollment should remain EDC (or implementation contractor) functions during the VPP Interim Program and transition to third-party aggregators under the long-term framework, or whether they should transition sooner, and on how the transition clause described in Section 2.8(c) should address the migration of these functions.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We recommend that the Board not treat dispatch, AMI data provisioning, PJM communication, enrollment, and marketing as a single bundle. Each function should transition to qualified third-party aggregators when defined readiness requirements are satisfied, subject to an outside date to ensure the transition occurs. Enrollment and outreach should be open to qualified third parties from launch.

Dispatch authority, AMI data provisioning, and PJM communication may reasonably remain EDC or implementation-contractor functions during the Interim Program while the necessary systems and market infrastructure are established. However, qualified third-party aggregators should be permitted to assume these functions sooner where they demonstrate the necessary technical, operational, cybersecurity, data-access, and consumer protection capabilities.

Enrollment and outreach should be open to qualified third parties from the beginning of the Interim Program. Making customer acquisition dependent primarily on EDC outreach could limit participation, particularly among LMI/OBC households, renters, and multifamily customers. Licensed aggregators, community-based organizations, and mission-based organizations should be able to support enrollment and outreach from launch.

On the transition clause at **Section 2.8(c)**, each function should have a stated condition for transfer and an outside date by which transfer occurs regardless. A transition clause without dates is a statement of intent.

STAKEHOLDER COMMENT NO. 11 — AGGREGATOR SOLICITATION PLAN

Straw Proposal Section 2.8(a)

Stakeholder Comment No. 11

Staff requests comments on whether the proposed Aggregator Solicitation Plan appropriately provides the customer choice and enables the inclusion of third-party aggregator during the EDCs' procurement processes.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We recommend the Aggregator Solicitation Plan be strengthened to include: 1) affirmatively protect customer choice and enable genuine third-party aggregator participation in the EDCs' procurement, 2) embed customer-choice and equity targets directly in the solicitation, and 3) require aggregators to report participation data granular enough for the Board to measure results across DER types, community types, and constrained areas of the grid. This is particularly important given the operational data collected during the Interim Program (i.e., event response rates, baseline accuracy, resource mix performance, dispatch latency, and customer retention) will directly inform the calibration of compensation levels under the long-term VPP as stated in **Section 3**.

The solicitation should ensure customers can enroll through a competitive third-party aggregator on comparable terms to EDC-run offerings, so the EDC's dual role as both procurer and potential competitor does not disadvantage independent aggregators. We recommend transparent, non-discriminatory solicitation terms; standardized enrollment, metering, and data-access processes; and clear, comparable compensation so customer choice is real and third-party aggregators can compete on a level footing.

Customer choice and equity should be explicit solicitation criteria. The solicitation should set participation and equity goals or targets, including meaningful enrollment among low-income, OBC, among other vulnerable populations such as historically underserved communities or medically dependent households, and weight them in aggregator selection and evaluation. This aligns the procurement with the program's equity objectives and guards against a solicitation that meets its megawatt targets while leaving underserved communities behind.

Aggregators should be required to provide standardized participation data that lets the Board measure results across:

- **DER type:** e.g., storage, solar-plus-storage, smart thermostats, electric vehicle (EV) charging, and other enrolled resources.
- **Community type:** including low-income, environmental-justice, renters, rural, and underserved communities.

- **Location on the grid:** mapped to feeders, substations, or zones, so participation can be assessed where the grid is most constrained and locational value is highest.

Standardized, disaggregated reporting on a consistent schedule enables the Board to verify that customer choice and equity targets are being met, to direct DER participation toward constrained areas where it delivers the greatest T&D and reliability value, and to track distribution of benefits over time—consistent with the Community-Benefit Indicator approach recommended in our comments above. Data collection should comply with applicable customer-privacy and aggregation protections. Specifically, public reporting should be aggregated above a minimum cell size to prevent re-identification, while participant- and aggregator-level data are treated as confidential item by item under N.J.A.C. 14:1-12.3 rather than by whole category.

The solicitation should include specific kW targets such as defining the capacity each solicitation seeks to procure and, consistent with the equity and locational aims above, those targets should be broken out where appropriate by community type and by constrained area of the grid rather than expressed only as a single system-wide number. Aggregators should be required to report enrolled and dispatchable capacity against these targets to the Board on a regular schedule, so the Board can track procurement progress, verify that committed capacity materializes, and confirm that it is landing where it delivers the most value.

STAKEHOLDER COMMENT NO. 12 — CONTRACTING FRAMEWORK AND TRANSITION TO LONG-TERM TARIFF

Straw Proposal Section 2.8

Stakeholder Comment No. 12

- Staff seeks comment on whether the proposed contracting and procurement framework appropriately balances EDC operational flexibility with the Board's interest in fostering a competitive aggregator market, and on whether additional MFR requirements are warranted.
- Staff seeks feedback on mechanisms to balance the need balance revenue certainty for aggregators with the Interim program's role as a bridge to a compensation-based tariff, including whether the Board's role should establish a minimum EDC-aggregator contract term or phase out Interim Program compensation for enrolled resources transitioning to the long-term tariff, and for what duration.
- Staff also seeks feedback on whether proposed transition timeline is reasonable

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We recommend that the Board require EDC-aggregator contracts to remain effective through the Interim Program and an orderly transition period, and phase out Interim compensation gradually rather than terminating it at tariff commencement. The objective is continuity for enrolled customers while

avoiding contractual terms that extend the Interim structure beyond the transition to the long-term tariff.

On (b), we support a contract term long enough to cover the remaining Interim Program period and the orderly transition window. The Board should avoid a fixed term that would extend the bilateral Interim structure beyond the outside transition date. Contract duration should provide reasonable cost-recovery certainty while preserving the ability of customers and resources to migrate to the open-access tariff without penalty.

The more direct concern is the household at the end of the chain. A customer who enrolled a device, accepted a multi-year commitment, and organized their consumption around a program should not find compensation ending abruptly because a contract lapsed or the Interim Program closed. A phased reduction over roughly 24 months, with resources able to migrate at any point, preserves continuity through the transition.

On (c), a 12-month parallel operation period is a reasonable floor and should not be treated as a target. Any extension that would move the program beyond the outside transition date recommended in these comments should occur through a noticed Board proceeding supported by findings.

STAKEHOLDER COMMENT NO. 13 — MINIMUM FILING REQUIREMENTS AND REPORTING

Straw Proposal Section 2.9

Stakeholder Comment No. 13

Staff seeks comment on:

- a. the proposed MFR structure
- b. the proposed performance reporting, including whether event-level reporting at the above granularity is necessary for Board oversight and what other reporting metrics are important
- c. the appropriate reporting cadence
- d. which elements of each report should be public versus confidential
- e. whether the cost- effectiveness methodologies proposed here are sufficient

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support the proposed MFR and reporting structure, but recommend modifications to strengthen distribution-planning requirements, event-level transparency, equity and emissions reporting, and portfolio-level cost-effectiveness evaluation. Quarterly reporting with an annual evaluation is appropriate. On (a), the MFRs should establish a concrete framework for integrating VPPs into

distribution planning. EDCs should identify the prerequisites for using VPPs as planning resources and map VPP capabilities to distribution needs and capital-deferral opportunities. A common VPP maturity-model approach could provide a consistent framework for this work during the Interim Program.

On (b), event-level reporting is necessary for Board oversight, and meaningful non-identifying information should also be publicly available. Reporting should include enrolled capacity and participation by EDC territory; events called and realized aggregate load reductions; and participation and benefits by customer segment, including OBC designation. The Board should also require reporting of avoided emissions using a transparent methodology and enrollment and performance within overburdened communities as designated under N.J.S.A. 13:1D-158.

On (c), quarterly reporting with an annual program evaluation is appropriate. This cadence provides sufficient information to identify implementation and performance issues during the Interim Program without creating unnecessary reporting burdens.

Before approving each Interim Program, the Board should require an evaluation plan or framework specifying the metrics, baselines, data sources, reporting responsibilities, and schedule that will govern the annual evaluation. For example, Connecticut's evaluation framework for distributed energy resources (DERs), demand-side management, and clean energy programs is coordinated through the CT Department of Energy and Environmental Protection (DEEP) and the Energy Efficiency Board (EEB), utilizing standardized measurement and verification (M&V) plans to govern annual performance metrics and reporting.¹²

On (d), confidentiality should be narrowly tailored rather than applied to entire reporting categories. Participant-level and commercially sensitive information may warrant protection, but non-identifying event-level and aggregate operational data should remain public so stakeholders can evaluate program performance, ratepayer benefits, and equitable participation.

On (e), cost-effectiveness should be evaluated at the VPP portfolio level, with sub-program results reported for informational purposes. Requiring every hardware, behavioral, or other sub-program to independently achieve a benefit-cost ratio above 1.0 could discourage technology neutrality and innovation during the Interim Program. EDCs should report benefit-cost results for each sub-program, but the applicable cost-effectiveness threshold should govern the portfolio as a whole.

This portfolio-level approach is consistent with [N.J.S.A. 48:3-87.9\(d\)\(2\)](#), which applies the benefit-cost threshold to energy-efficiency and peak-demand-reduction portfolios while considering economic and environmental factors.

¹² Energize Connecticut's 2021 the [EEB Program Evaluation & Market Assessment Roadmap](#)

STAKEHOLDER COMMENT NO. 14 — PSUP COORDINATION AND TRANSITION MILESTONES

Straw Proposal Section 3.1

Stakeholder Comment No. 14

- a. Staff requests stakeholder comment on how to best coordinate VPP tariff design with the PSUP process, and on what specific information in the PSUP would be most useful for third-party aggregators designing VPP portfolios.
- b. Staff also requests comment on the milestone-based transition framework described in the introduction to Section 3, including whether the four proposed milestones are appropriate for launching the long-term Programs and whether any should be modified and added.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We recommend that the Board coordinate the VPP tariff design closely with the PSUP process and strengthen the PSUP information and review process necessary to support the long-term VPP framework. PSUP data relevant to VPP deployment should be standardized, sufficiently granular, and publicly available. The transition milestones should be objective and enforceable, with a firm outside date of July 1, 2029, reflected in **Section 8**.

On (a), the PSUP should provide the locational and planning information necessary to design VPP portfolios that deliver measurable grid value. EDCs should provide standardized, publicly available information including feeder-level hosting and integration capacity; three- and ten-year circuit-level load, electrification, and DER forecasts; and identified feeder and substation constraints where VPPs or other non-wires alternatives (NWAs) could defer or avoid infrastructure investments. This information should support the locational value mapping contemplated in **Section 3.3(b)** and allow the Board, aggregators, and stakeholders to evaluate VPP opportunities consistently across EDC territories.

This information should be publicly available rather than limited to aggregators. Communities and community-based organizations have a legitimate interest in understanding distribution constraints, planned investments, and opportunities for local DER deployment. Locational information should also be evaluated alongside overburdened community designations, including through New Jersey's [EJMAP](#), to identify where distribution-system needs and existing environmental burdens overlap.

PSUP elements that materially affect the transition to the long-term VPP framework should also receive meaningful stakeholder review. The Board should provide at least a 180-day review period and an opportunity for discovery so stakeholders can evaluate EDC analyses, including comparisons between traditional infrastructure investments and VPP or other non-traditional solutions.

Because PSUP assumptions will influence whether VPPs are selected instead of traditional infrastructure, the review process should provide enough time and information for parties to test load

forecasts, identified constraints, alternative solutions, cost comparisons, and claimed deferral value, and not merely comment on a completed utility analysis.

On (b), we support the four proposed transition milestones, but recommend the Board tie them to objective and demonstrable readiness requirements and a firm outside date. Board approval of EDC PSUPs, Grid Modernization Forum (GMF) adoption of the service architecture, demonstration of DERMS Tier 2 capability, and completion of the 12-month Interim Program evaluation are reasonable indicators of readiness, but they should measure actual operational capability, data availability, and integration of VPPs into distribution planning—not simply completion of administrative or technology-deployment activities.

Examples of demonstrable readiness could include successful end-to-end testing of customer enrollment and authorization, secure EDC-aggregator data exchange, dispatch and override communications, performance measurement, settlement, and at least one documented distribution-planning use case showing how a VPP could defer or avoid an identified investment.

The Board should establish a firm July 1, 2029 outside date for launching the long-term tariff, with the deadline incorporated into **Section 8**. Any extension should require an EDC to demonstrate in a noticed Board proceeding that additional time is necessary for system safety or reliability. This approach preserves the milestones as meaningful readiness requirements while preventing open-ended delay in the transition to the long-term, competitive VPP framework.

STAKEHOLDER COMMENT NO. 15 — THREE-PATHWAY COMPENSATION STRUCTURE

Straw Proposal Section 3.3

Stakeholder Comment No. 15

- a. Staff requests stakeholder comment on appropriate Pathway 1 payment levels for different resource types, recognizing that enrollment and connectivity costs vary substantially across device classes.
- b. Staff requests further comment on the proposed seven-year minimum enrollment period (Pathway 1) for retaining upfront hardware incentives, including whether the period should vary by device class or incentive size.
- c. Staff requests stakeholder comments on the overall three-pathway compensation mechanism that is proposed under this section of the VPP Program Straw Proposal and solicitate the appropriate target payment ranges for each pathway differentiated by grid service provided.
- d. Also, staff requests comment on practicality of implementing location-differentiated payments in the long-term program, and on alternative approaches if locational differentiation is not immediately feasible.
- e. Staff further requests comment on whether the VPP tariff should specify default payment structures for each pathway, or should instead establish baseline terms and conditions of participation, with compensation structures and payment levels defined separately by grid service and use case.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support the overall three-pathway compensation mechanism (Enrollment, Opportunity/Reservation, and Pay-for-Performance) and suggest six key modifications to balance market flexibility, ratepayer protections, customer transparency, and equity:

- **Tiered Commitments:** Reject the rigid seven-year enrollment commitment for retaining upfront hardware incentives, replacing it with a tiered 3-to-5 year commitment based on device lifespan.
- **Two-Zone Locational Pricing:** Implement a practical two-zone approach (a baseline statewide rate and a constrained-area adder) while the PSUP is being finalized.
- **Equity Screen for Locational Pricing:** Mandate that any locational adder be checked against LMI/OBC designations to ensure grid investments do not bypass under-resourced areas.

- For example, the equity screen should not automatically create an OBC locational adder or override grid-value signals. Rather, the Board could use it to identify whether locational pricing and related Utility Business Model Reform incentives systematically steer investment away from OBCs and, if so, consider targeted participation, enabling-infrastructure, or customer incentive adders through the appropriate proceeding.
- **Flexible Non-Tariff Pricing with Floors:** Establish baseline terms and conditions in the tariff and minimum compensation protections where a pathway applies, while allowing specific payment levels to be set separately by grid service and use case so the Board does not lock in premature pricing.
- **Standardized Consumer Disclosures:** Resolve customer transparency concerns by mandating a standardized, uniform "VPP facts label" or disclosure modeled on Texas's PUCT [Substantive Rule §25.475](#).
- **Seasonal Compensation Rates:** Develop compensation rates that reflect differences in device value across seasons, including distinct winter and summer rates as demonstrated in Connecticut, while also recognizing the value devices can provide during shoulder seasons.

On (b), the proposed seven-year enrollment lock-in for retaining hardware incentives is excessively long and acts as a significant barrier to participation, particularly for LMI/OBC households, renters, and multifamily residents who may move or may inherit existing devices.

The Board should establish a 3-year commitment for smart thermostats and managed EV chargers, and a 5-year commitment for behind-the-meter battery storage. Comparable programs support a materially shorter period than seven years. Hawaii's Public Utilities Commission specified a five-year minimum duration as a preferred design element for its VPP grid services program;¹³ the ConnectedSolutions programs guarantee incentive rates for the first five seasons of participation;¹⁴ and Xcel's Renewable Battery Connect in Colorado runs on a five-year term.¹⁵ New Jersey proposes a longer commitment in exchange for lighter dispatch rights than at least one of these.

Although no repayment penalties are currently proposed, any future repayment provisions should include appropriate protections for LMI/OBC households. Specifically, repayment penalties should be waived in full when a participant relocates or when an eligible device fails through no fault of the participant.

On (a) and (c), the three-pathway structure is sound; however, we recommend enrollment payments should be differentiated by device class. For example, commissioning a networked battery and enrolling a smart thermostat differ in installation complexity and in magnitude of cost. Useful benchmarks, as of

¹³ Smart Energy Power Alliance: [VPP and Supporting DER Policy Developments: Q2 2026](#)

¹⁴ National Grid: [Battery Program](#)

¹⁵ Xcel: [Renewable Battery Connect Details](#)

August 2026, performance-based compensation of \$275 per average summer kW in Massachusetts¹⁶ and \$225 per average summer kW in Rhode Island¹⁷ under ConnectedSolutions.

Xcel's Colorado Renewable Battery Connect provides participants with an upfront incentive based on battery discharge capacity: \$250/kW for general customers (up to \$5,000), \$1,000/kW for income-qualified customers, and \$500/kW for customers in disproportionately impacted communities, with the latter two capped at 75% of equipment costs. All participants are also eligible for a \$100 annual participation incentive for five years for participating in control events.¹⁸

In June 2026, DTE Electric proposed a two-year Residential Battery Virtual Power Plant Pilot providing incentives for use of customers' existing battery systems, under which participants would receive \$105/kW-year with a maximum annual incentive of \$504.¹⁹

On (d), the locational payments are a practical approach if derived directly from the PSUP's locational map data. While the PSUP data is being finalized, EDCs should implement a two-zone approach: 1) a constrained-area adder, and 2) a default statewide rate. We ask that any locational adder be checked against overburdened community designations so that locational pricing does not inadvertently direct benefit away from communities already bearing disproportionate burden.

On (e), the tariff should establish baseline terms and conditions of participation together with the three-pathway compensation architecture and minimum compensation protections, where applicable. Payment levels should be set separately by grid service and use case, and the tariff should not require payment under a pathway that is inapplicable to a particular resource or service.

Specifying default payment levels in tariff would require the Board to determine now, and correctly, what participating resources should be paid under a competitive framework that will not exist until 2029. We do not think that is achievable, and locking in a wrong number is worse than leaving it open. Defining levels separately by service and use case also preserves the flexibility **Section 3.6** already contemplates for eligibility, where the framework is deliberately built so that resources not yet contemplated can qualify without reopening the tariff. Compensation should work the same way.

A customer cannot understand an offer whose terms are set outside the tariff and vary by service. Texas addresses this challenge through its PUCT [Substantive Rule §25.475](#) which requires every retail provider to publish a standardized Electricity Facts Label in a uniform format. It is that uniform format, rather than any constraint on what providers may charge, that makes the "Power to Choose" platform Staff cites in **Section 3.7(a)** usable. Therefore, we recommend three processes:

- **In tariff:** eligibility, telemetry and performance measurement, dispatch obligations and limits, settlement timing, and the three-pathway architecture with a stated floor for each.
- **Set separately:** payment levels by grid service and use case, revisable without a tariff proceeding but never below the tariff floor.

¹⁶ [NuWatt Energy Massachusetts ConnectedSolutions](#)

¹⁷ [Rhode Island Energy Battery Program](#)

¹⁸ Xcel Energy [Renewable Battery Connect Program](#) in Colorado

¹⁹ DTE's [Approval of Residential Battery VPP](#) through Case No. U-21653

- **Required of every provider:** a standardized VPP disclosure, given before enrollment, stating expected compensation and its basis, the dispatch obligation assumed, the term, any clawback exposure, and the minimum pass-through to the customer discussed in **Section 3.7(a)**.

Proposed language for Section 3.3: "Each DER Aggregator shall provide to each prospective participant, prior to enrollment, a standardized disclosure in the form prescribed by the Board, stating the compensation structure and expected payment, the basis on which payment is calculated, the dispatch obligation assumed, the term of participation, any recovery of incentives on early termination, and the percentage of grid service revenue passed through to the customer."

STAKEHOLDER COMMENT NO. 16 — GRID DERMS BUILD-OUT TIMELINE

Straw Proposal Section 3.4

Stakeholder Comment No. 16

Staff requests comment on the appropriate timeline for Grid DERMS build-out and on whether the Board should set minimum functionality requirements that must be achieved by specific dates.

Position: ☒ **Support** ☐ Support with modifications ☐ Oppose ☐ No position / not applicable

RESPONSE

We support the establishment of mandatory minimum functionality requirements and a standardized, statewide timeline for Grid DERMS build-out. EDCs must not be permitted to use a lack of Grid DERMS capability as an excuse to delay the launch of the open-access tariff. EDCs must achieve Tier 2 control and dispatch capability by no later than July 1, 2028, and Tier 3 dispatch orchestration by July 1, 2029.

Each deadline should be tied to a minimum functional readiness test, not merely technology deployment. The Board should require EDCs to demonstrate end-to-end functionality before a DERMS milestone is deemed satisfied, including the ability to enroll and validate participating DERs, exchange necessary operational data with aggregators, communicate or facilitate dispatch instructions, measure and verify performance, and produce the data required for settlement. Software procurement, installation, or commissioning alone should not constitute compliance.

A phased, enforceable roadmap is critical to hold EDCs accountable and give the market visibility:

- **Tier 1 (BTM Visibility):** Deadline: July 1, 2027 (Interim Program Launch): EDCs must possess near-real-time visibility into the location, nameplate capacity, and resource type of DERs relevant to VPP operations, with sufficient information to apply the program eligibility rules and support safe dispatch.
- **Tier 2 (Control and Dispatch):** Deadline: July 1, 2028: EDCs must be capable of calling localized, event-based dispatch events via open protocols (OpenADR 2.0b/3.0, IEEE 2030.5) to address feeder-level constraints, rather than relying on manual or system-wide curtailments.

- **Tier 3 (Orchestration & Continuous Optimization):** Deadline: July 1, 2029 (Long-Term Tariff Launch): EDCs must integrate Grid DERMS with Advanced Distribution Management (ADMS) and Supervisory Control and Data Acquisition (SCADA) systems, moving from reactive event calls to continuous optimization of distribution flows, integrating non-wires solutions seamlessly into daily grid operations.

The Board should ensure interoperability safeguards by requiring EDCs to publish their Grid DERMS interface specifications on non-discriminatory, open-access terms. This ensures third-party edge DERMS platforms can securely communicate with utility operating systems without proprietary software bottlenecks or licensing fees.

STAKEHOLDER COMMENT NO. 17 — REVENUE STACKING AND PJM WHOLESALE PARTICIPATION

Straw Proposal Section 3.5

Stakeholder Comment No. 17

- Staff request stakeholder feedback on what aspects of the proposed long-term VPP regulatory framework should be revised to enable wholesale market participation, including the development and valuation of distribution grid services in conjunction with wholesale market participation.
- Staff also request feedback on whether the introduction of such program participation incentives is acceptable, or whether they would alter existing state program incentives and/or prohibit participation in PJM's wholesale energy markets.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support wholesale market integration and legitimate revenue stacking to maximize DER value and reduce ratepayer costs. DERs should be permitted to receive compensation for distinct retail, distribution, and wholesale services, including services delivered during the same interval, where each is independently delivered and verified. Anti-double-counting rules should prevent duplicate compensation for the same service, not legitimate compensation for separate services.

On (a), the long-term framework should enable simultaneous distribution and wholesale market participation wherever technically feasible. A PJM dispatch should not automatically cancel or displace a coincident EDC distribution dispatch where the DER can satisfy both obligations. If both services are independently delivered and verified, the resource should be compensated for both.

Staff already proposes PJM priority over discretionary distribution dispatch. We support that baseline but recommend clarifying that a priority rule is needed only when the obligations actually conflict, and simultaneous service should remain compensable when both obligations can be met, and any EDC override should be documented.

The tariff should also clearly identify the service associated with each payment stream and establish settlement rules that prevent payment twice for the same capacity, energy, or grid service during the same interval. This distinction is important to preserve the value of distribution services and the market for non-wires solutions while preventing double counting.

On (b), state program incentives should preserve access to PJM and other value streams where the services being compensated are distinct. Performance-based compensation is appropriate, but Staff’s proposed redistribution of withheld incentives from underperforming aggregations to overperforming aggregations could create unintended incentives to under-commit. The framework should also resolve the apparent inconsistency between performance measured against “committed obligation” in **Section 3.5** and the minimum sustained response of 80% “of enrolled capacity” in **Section 3.7(b)**.

Where an aggregation fails to provide a ratepayer-funded service, withheld incentives should be returned to ratepayers or the program budget rather than redistributed to another market participant. If the Board elects to reward performance above an aggregation’s obligation, it should consider a graduated compensation structure that rewards incremental performance without creating incentives to understate commitments.

STAKEHOLDER COMMENT NO. 18 — SERVICE PATHWAYS AND PERFORMANCE CRITERIA

Straw Proposal Section 3.6

Stakeholder Comment No. 18

Staff requests comment on the appropriate number and definition of service pathways (e.g., specific response-time thresholds) needed to balance administrative simplicity against adequately capturing differentiated grid value, and on any additional technical performance criteria (beyond response time and telemetry granularity) the Board should consider in defining VPP grid services.

Position: ☒ **Support** ☐ Support with modifications ☐ Oppose ☐ No position / not applicable

RESPONSE

We support a technology-neutral, performance-based definition of VPP services, but recommend the Board establish three distinct technical performance categories mapped directly to grid needs: (1) Fast Frequency and Voltage Support, (2) Local Peak Shaving, and (3) Routine Load Shaping. Additionally, the Board should incorporate emissions intensity as an active performance and dispatch criterion.

Consistent with our response at **Comment 2(c)**, we recommend that the 20 kW distribution-service threshold align with the 10 kW Interim Program threshold.

Three Technical Performance Categories: To balance administrative simplicity against capturing true grid value, the VPP tariff should define three clear pathways based on response latency and duration:

- **Fast Flexibility (Sub-Minute Response):** Suited for behind-the-meter batteries and fast-responding commercial loads capable of providing frequency regulation and localized voltage

support. This pathway must carry a premium capacity multiplier to incentivize high-performance hardware deployment.

- **Active Peak Shaving (2-Hour Notice, 4-Hour Duration):** Suited for smart thermostats, managed EV chargers, and water heaters. This pathway targets the systemic PJM 5CP hours and localized distribution peaks.
- **Routine Load Shaping (Day-Ahead Scheduling):** A slow-response, high-duration pathway focused on moving flexible daily loads (such as EV fleet charging or water heating) to off-peak periods, reducing the baseline stress on the distribution system.

Additional Performance Criteria:

- **Emissions Reductions:** In alignment with New Jersey's clean energy goals, the Board should require EDCs to incorporate marginal emissions intensity (e.g., using real-time marginal CO2 data from PJM) into their VPP evaluation and reporting. Portfolios that can demonstrate they disproportionately displace emitting peaking resources, particularly those located within or adjacent to OBCs, should receive an "environmental adder" to reward localized air quality improvements.

STAKEHOLDER COMMENT NO. 19 — CUSTOMER PASS-THROUGH AND OFFER TRANSPARENCY

Straw Proposal Section 3.7(a)

**Stakeholder
Comment
No. 19**

Staff seeks comment on whether a minimum pass-through requirement, a public offer-comparison platform, or a combination of both would best ensure enrolled customers receive fair value from VPP participation, and on if 70% is the appropriate level of any pass-through floor.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support a combination of a minimum customer pass-through requirement and a public, Board of Public Utilities (BPU)-administered offer-comparison platform. A 70% minimum customer pass-through is a reasonable starting point for the Interim Program and should help ensure that customers receive a substantial share of the value generated by their participation. The Board should evaluate actual program data before determining whether 70% remains the appropriate minimum under the long-term framework. Equity should be advanced through targeted enrollment support, enhanced incentives, and transparent offers rather than an unsupported differential pass-through percentage.

Market transparency alone (via an offer-comparison platform) is insufficient to protect LMI/overburdened customers and those within OBCs across New Jersey. Conversely, a rigid pass-through floor alone does not help customers understand or compare complex aggregator offers. A hybrid model is essential:

- **Standardized 70% Pass-Through Floor:** A 70% floor ensures that customers receive the majority of the financial value their devices generate while leaving a viable 30% margin for aggregators to cover customer acquisition, software integration, and risk management.
- **LMI/OBC Equity Protections:** Use targeted enrollment support, enhanced incentives or adders, and standardized disclosures to ensure LMI and OBC participants receive meaningful customer benefits without relying on an unsupported differential pass-through percentage.
- **"Power to Choose" Comparison Platform:** The Board should fund and host a standardized web portal where customers can input their utility, location, and device type to receive a side-by-side comparison of active, licensed aggregator offers. Offers must be presented using standardized terms (e.g., upfront payment, seasonal capacity payment, and per-event dispatch compensation) to prevent confusing or misleading marketing practices.

STAKEHOLDER COMMENT NO. 20 — OPEN-ACCESS MARKET RULES AND DISPUTE RESOLUTION

Straw Proposal Section 3.7

Stakeholder Comment No. 20

Staff seeks comment on whether these open-access market rules and EDC coordination protocols provide sufficient certainty for aggregators to make long-term investment decisions in New Jersey, and on whether a formal EDC- aggregator dispute resolution process should be established by the Board.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support the open-access market rules and EDC coordination protocols but suggest four targeted refinements: 1) define performance obligations using capacity actually available for dispatch after excused customer opt-outs; 2) evaluate correlated platform risk when applying the 40% concentration limit; 3) establish a limited waiver mechanism allowing the Board to modify or waive the 40% concentration limit in smaller service territories where necessary to preserve viable customer access; and 4) establish a formal, expedited dispute-resolution process.

On performance obligations, performance should be measured against capacity actually available for dispatch after accounting for excused customer opt-outs. Aggregators should not be penalized for customer actions that are expressly permitted under the Program and outside the aggregator's control.

On the 40% concentration limit, we support the limit and its measurement within each EDC service territory, which is appropriate given its purpose of reducing correlated dispatch-failure risk. Statewide measurement would defeat that purpose by potentially allowing a single aggregator to control all or substantially all of the enrolled capacity within a smaller EDC territory.

We are concerned, however, that the limit as defined may not fully capture the correlated risk it is intended to address. Staff defines the aggregator for this purpose as the Board-licensed entity holding

the customer enrollment, regardless of intermediate dispatch-platform or installer arrangements. Correlated dispatch failure may instead occur at the platform level. Several separately licensed aggregators using a common dispatch platform could each remain below the 40% limit while collectively presenting a single point of failure across a substantial share of a territory's enrolled capacity. The MFR Order should therefore require aggregators to disclose the dispatch platform through which enrolled capacity is orchestrated and authorize the Board to consider platform-level concentration where the disclosed information demonstrates material correlated risk.

On a waiver for smaller service territories, the Board should establish a limited mechanism to waive or modify the 40% concentration limit where strict application would impede viable participation or customer access. In a smaller territory such as Rockland Electric's, the 40% limit could make participation less cost-effective for aggregators and potentially create a service gap for customers. Where an EDC or aggregator demonstrates that customers cannot reasonably be served while maintaining the 40% limit, the Board should be authorized to grant a time-limited waiver or modification, subject to appropriate safeguards and periodic review.

On dispute resolution, the Board should establish a fast-track, independent dispute-resolution process administered by Board Staff or a neutral third party. Disputes involving AMI data validation, performance verification, dispatch overrides, or similar operational matters should be resolved within 15 business days, with results binding on the parties subject to final Board review or audit. Override notification should be contemporaneous, include the reason for the override, and be reported to the Board annually in aggregate. Because the EDC may simultaneously serve as counterparty, data provider, dispatcher, and, under **Section 3.8**, potentially a competitor, operational disputes are foreseeable. Without an expedited process, the only recourse may be a formal complaint proceeding, which is disproportionate for routine operational disagreements.

STAKEHOLDER COMMENT NO. 21 — EDC OWNERSHIP AND ADMINISTRATION FOR TARGETED GRID NEEDS

Straw Proposal Section 3.8

Stakeholder Comment No. 21

Staff requests comment on:

- a. whether EDC ownership or administration of DER assets (e.g., battery storage) should be available as a bounded exception to the open-access framework for targeted grid needs such as constrained circuits
- b. which deployment and ownership model or models (EDC-owned, customer-owned with EDC installation, or competitive RFP) would be most cost-effective for ratepayers
- c. what safeguards are needed to ensure EDC-owned or EDC-administered resources do not undermine the EDC-neutrality principles of Section 3.7(a)

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support a narrowly bounded exception on EDC ownership as an acceptable option; available only after a transparent competitive solicitation has been run and has failed. Customer-owned assets with EDC dispatch rights should be prioritized. Where the exception is used in an overburdened community, additional public process should apply.

Regarding safeguards, EDC ownership should be available only after a competitive solicitation for the identified need has been conducted and has failed to produce a satisfactory response, documented on the record. This confines the exception to circumstances where the market genuinely cannot serve the need.

The default model should be customer-owned assets with contractual EDC dispatch rights. It avoids rate-based capital for assets the market can supply, keeps resilience benefit with the household, and does not place the EDC in the position of dispatching resources it owns in competition with resources it does not.

Where a proposed EDC-owned installation is located in an LMI/OBC community as designated under N.J.S.A. 13:1D-158, the Board may require notice to and an opportunity to be heard for that community, consistent with the participation principles reflected in the Environmental Justice Law. The additional OBC process should be designed as early, accessible community engagement, not as an implementation barrier or delay. Its purpose is to improve participation, trust, and benefit delivery in communities designated under N.J.S.A. 13:1D-1578.

We note that constrained circuits and overburdened communities frequently coincide. That coincidence is a reason for careful process, not a reason to withhold investment: these are often the areas where reliability is poorest and where local generation, if it is combustion-based, is most harmful.

STAKEHOLDER COMMENT NO. 22 — GRIDFLEX SEQUENCING AND DERMS TIER TRIGGERS

Straw Proposal Section 4.1

Stakeholder Comment No. 22

- a. Staff seeks comment on whether the proposed sequencing between GridFlex and the VPP MFR Order is sufficient to prevent definitional conflicts between distribution-level service compensation rules and VPP payment structures.
- b. Staff also seeks comment on whether conditioning the long-term VPP tariff's open-access provisions on PSUP-reported DERMS Tier 2 or 3 maturities would be an appropriate trigger mechanism, and what specific DERMS capabilities should be required before that condition is satisfied.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support the proposed sequencing but recommend the Board establish a formal Joint Alignment Process between the GridFlex and VPP workstreams in late 2026 to ensure complete integration. Additionally, while conditioning the long-term tariff on PSUP-reported DERMS maturity is appropriate, the trigger must be set at DERMS Tier 2 control and dispatch capability, rather than waiting for Tier 3, to prevent EDCs from indefinitely delaying open-market operations.

On (a), the Board must ensure that the definitions of grid flexibility services developed in GridFlex (such as circuit-level congestion relief and voltage management) align closely with the performance-based dispatch categories (Pathway 3) in the VPP tariff.

We recommend that the Board host a series of joint workshops in Fall 2026 to harmonize the GridFlex service definitions with the VPP MFRs. This will ensure that any service compensated under the VPP tariff uses the exact same telemetry, measurement, and verification protocols established in the GridFlex proceeding.

On (b), using DERMS maturity as a gating mechanism for the long-term open-access tariff is a highly practical way to align utility capabilities with market needs. Open-access functions that depend on Grid DERMS should transition as soon as an EDC demonstrates Tier 2 (Control and Dispatch) capability, while the statewide long-term tariff should launch no later than July 1, 2029, consistent with **Comments 14** and **16**. Tier 2 capability is fully sufficient to support automated, event-based dispatch and AMI-based settlement. Tier 3 (Continuous Optimization) is a highly advanced, multi-year utility software goal. Requiring full Tier 3 maturity before launching the competitive tariff would delay the open aggregator market by several years, directly violating the urgency of Executive Order No. 2.

STAKEHOLDER COMMENT NO. 23 — GSESP PHASE 2 COORDINATION

Straw Proposal Section 4.2

Stakeholder Comment No. 23

Staff seeks stakeholder comment on if the proposed GSESP Phase 2 VPP-Integration provisions create sufficient forward compatibility and on whether any barriers to third-party aggregator access for Phase 2 resource should be addressed through program design modifications.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support the proposed integration between GSESP Phase 2 and the VPP framework, but with critical modifications to address a major structural gap. The 350 MW of BTM storage targeted in GSESP Phase 2 represents 59.4% (nearly 60%) of New Jersey's entire 589 MW statewide Interim VPP peak-shaving goal, which represents a three percent reduction from the statewide 2026 peak load of 19,634.9 MW (see **Comment 9**). We encourage the Board to consider a higher target for the Long-term VPP.

Given the scale of this overlap, New Jersey's VPP target cannot realistically be achieved unless GSESP Phase 2 is tightly, legally, and operationally integrated with the VPP framework from day one. The State should not spend substantial ratepayer dollars deploying hundreds of megawatts of BTM storage under one program while separately attempting to procure peak-shaving capability from those same resources under another.

To prevent incentive silos, duplicate ratepayer payments for the same grid service, and utility-controlled barriers to participation, the Board should: 1) mandate VPP enrollment as an express condition of receiving ratepayer-funded GSESP Phase 2 upfront hardware incentives, 2) consolidate overlapping performance compensation by routing GSESP performance payments through the VPP tariff's Pathway 2 or Pathway 3, as applicable, and 3) require open, standardized, and non-discriminatory access to the telemetry and communications functionality necessary for licensed third-party aggregators to enroll, manage, dispatch, and verify participating batteries.

Because GSESP Phase 2 is projected to deploy 350 MW of BTM storage capacity, these customer-sited assets will represent a substantial share of the distributed storage available to meet New Jersey's peak-shaving goals. Ratepayers should not fund batteries that remain unavailable when the grid needs them most. Every residential and commercial BTM storage system receiving an upfront GSESP Phase 2 incentive should therefore be required to remain enrolled in a licensed VPP program for a minimum of five years, subject to reasonable protections for customer resilience needs, technical limitations, and emergency conditions.

The Board should also prevent GSESP Phase 2 and the VPP tariff from developing separate and duplicative compensation, billing, measurement, and verification structures for the same underlying grid services. Where GSESP performance payments compensate batteries for services also compensated through the VPP tariff, such as discharging during PJM coincident peak hours, those payments should flow through the VPP tariff's Pathway 2 (Capacity Reservation) or Pathway 3 (Performance) compensation streams, as appropriate. This approach would reduce administrative duplication and prevent ratepayers from paying twice for the same service while preserving the ability of participating resources to stack revenues for distinct, incremental, and independently measurable services.

Finally, the Board must ensure that GSESP incentives do not result in EDC control over access to a substantial portion of New Jersey's emerging BTM storage fleet. EDCs should be required to provide standardized, secure, and non-discriminatory interfaces that allow licensed third-party aggregators, with customer authorization, to access the telemetry and operational functionality necessary to manage GSESP-incentivized storage resources. Communications should rely on open and interoperable standards, such as IEEE 2030.5, rather than proprietary EDC-specific systems. This is essential to prevent unnecessary utility-controlled barriers to participation, preserve customer choice, and ensure that ratepayer-funded storage remains accessible to a competitive VPP market.

STAKEHOLDER COMMENT NO. 24 — TRIENNIUM COORDINATION

Straw Proposal Section 4.3

Stakeholder Comment No. 24

Staff seeks stakeholder comment on the proposed Triennium VPP coordination.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support the proposed coordination between the Triennium and VPP proceedings. However, the transition must be managed to prevent any gap in DR program availability or customer compensation while preserving energy efficiency (EE) as a foundational component of New Jersey’s VPP strategy. The Board should: 1) ensure Triennium 2 DR programs migrate seamlessly to the VPP Interim Program on July 1, 2027; 2) transition Triennium 3 connected-device incentives into VPP-linked incentives that reward enrollment and availability; and 3) recognize and reward EE strategies that measurably reduce peak demand and improve VPP performance.

The transition from Triennium-funded DR programs to the VPP framework must not disrupt existing customers. We support the Board’s July 15, 2026 Order directing EDCs to maintain existing Triennium 2 DR programs “as is” until the VPP Interim Program is fully operational on July 1, 2027. EDCs should be required to seamlessly transfer customer enrollment, device, baseline, and relevant performance data to the VPP framework, consistent with applicable customer authorization and privacy requirements. Customers should not be required to re-enroll, execute duplicative agreements, or experience a lapse in compensation simply because the State is transitioning between program frameworks.

In Triennium 3, the Board should cease offering standalone DR pilot programs, as recommended by Staff, and restructure incentives for connected and controllable devices; including smart thermostats, smart water heaters, smart EV chargers, and other VPP-capable technologies, to encourage sustained VPP participation. Customers should continue to receive a base EE incentive for verified efficiency benefits, but the portion of an incentive attributable to a device’s flexible-grid value should be conditioned on VPP enrollment. For example, the Board could provide 50% of the available incentive as a base EE rebate and the remaining 50% as a “VPP Enrollment Adder” conditioned on participation in a licensed VPP for a minimum of three years. Ratepayers should not pay a premium for flexible capabilities that are never made available to the grid.

At the same time, moving DR into the VPP framework should not separate VPPs from EE. EE should remain a foundational VPP resource. EE reduces the load that must be served, while VPPs make the remaining load more flexible and responsive. The Board should recognize EE measures and strategies that produce measurable reductions in coincident peak demand, improve VPP performance, or reduce the amount of dispatchable capacity needed to meet system requirements. EDCs should receive

performance credit for these verified outcomes, with safeguards to prevent the same benefit from being counted or compensated twice across the Triennium and VPP programs.

Ultimately, customers should not have to navigate separate EE, electrification, connected-device, DR, and VPP programs when the same technologies provide multiple grid benefits. The Triennium and VPP frameworks should operate as complementary components of the same distributed grid strategy. For example, EE reduces overall and peak load; connected technologies make load flexible and controllable; and VPPs aggregate and coordinate those resources when the grid needs them. The Board should design the programs accordingly, rather than allowing them to compete for the same customers, technologies, and ratepayer dollars.

STAKEHOLDER COMMENT NO. 25 — SOLAR AND NEM REFORM COORDINATION

Straw Proposal Section 4.5

Stakeholder Comment No. 25

Staff seeks stakeholder comment on how NEM and VPP Program design should be coordinated to encourage customers to export energy at times of the most grid value, and what anti-double-counting provisions are needed, especially where NEM credit and VPP compensation apply to the same exported energy.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We recommend coordinating net energy metering (NEM) reform with the VPP framework so New Jersey’s existing and future solar resources can provide greater grid value through storage and VPP participation. The Board should align export compensation with time- and grid-dependent value while establishing clear anti-double-counting rules that distinguish NEM compensation for exported energy from VPP compensation for capacity, availability, and dispatch services.

The Board should use the existing NEM proceeding to consider reforms that encourage solar-plus-storage customers to shift exports to periods of greater grid value. The NEM structure should not create a barrier to pairing existing solar resources with storage or enrolling those resources in VPPs. Where appropriate, the Board should consider a VPP Export Adder or other performance-based mechanism that provides additional compensation when stored energy is exported in response to a VPP dispatch during designated periods of grid need.

Anti-double-counting rules should distinguish between the underlying energy export and the incremental grid service provided by the VPP. Receipt of a NEM credit for exported energy should not prevent a customer from receiving Pathway 1 or Pathway 2 compensation for enrollment, availability, or reserved battery capacity. Similarly, a resource should be eligible for Pathway 3 compensation where it provides a separately measurable dispatch service, even if the resulting energy export also receives a NEM credit.

Where NEM and VPP compensation would otherwise pay for the same component of value, the VPP payment should be adjusted to prevent duplicate compensation. The objective should be to prevent payment twice for the same service—not to prevent legitimate revenue stacking when a solar-plus-storage resource provides distinct energy, capacity, availability, or dispatch value to the grid.

A nominal capacity or ancillary-services component embedded in a retail NEM credit is not, by itself, proof that the customer has already been compensated for the distinct operational service delivered through a VPP. Any netting should be tied to demonstrable duplication of the same service and interval, not merely to labels used to decompose a retail rate.

STAKEHOLDER COMMENT NO. 26 — AMI DATA ACCESS STANDARDS

Straw Proposal Section 4.6

Stakeholder Comment No. 26

Staff seeks stakeholder comment on whether the AMI Data Access Standards can be feasibly implemented before the completion of the Interim VPP Program, and on alternative methodologies for event performance measurement that do not rely on EDC provided data.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We agree the AMI Data Access Standards can and should be fully implemented before the completion of the Interim VPP Program. EDCs should be required to establish operational Green Button Data Standard and electronic data interchange (EDI) portals by no later than July 1, 2027. Additionally, the Board should approve telemetry-based performance measurement as an alternative methodology to prevent utility data bottlenecks.

The Board’s approval of the Notice of Adoption of the AMI Data Access Standards on June 30, 2026, represents a critical milestone. Because the regulatory foundation is complete, there is no technical reason to delay implementation:

EDCs should be able to complete the deployment of their green button connect (GBC) interfaces and EDI web portals by the July 1, 2027 Interim Program launch. This ensures that third-party aggregators have timely, secure access to interval-level usage data (with customer consent) from day one.

Relying exclusively on EDC-validated AMI meter data may act as a major market bottleneck though, as EDCs often struggle to deliver validated data within the tight timelines required for market settlement.

The Board should authorize EDCs and aggregators to utilize real-time, device-level telemetry (e.g., secure, encrypted inverter data from behind-the-meter batteries or smart EV chargers) to measure event performance. Telemetry-based measurement bypasses the utility meter and provides sub-minute accuracy, enabling immediate performance verification and settlement.

To ensure integrity, telemetry-based measurements can be verified ex-post against the customer's hourly AMI meter data on a statistical sampling basis, rather than requiring individual meter-by-meter validation for every event.

STAKEHOLDER COMMENT NO. 27 — TIME-OF-USE AND RATE DESIGN COORDINATION

Straw Proposal Section 4.7

Stakeholder Comment No. 27

- a. Staff cautions that excessive rate fragmentation due to asset-specific TOU increases administrative complexity and customer confusion, and requests stakeholder input on the appropriate scope of technology-specific TOU options.
- b. Staff seeks stakeholder comment on the appropriate long-term relationship between cost-reflective rate design and VPP compensation.
- c. Staff seeks comment on how customers should be protected from bill increases when responding to VPP dispatch events that conflict with TOU price signals, such as events calling for increased consumption during peak-price periods or injection during off-peak periods.
- d. Staff seeks comments on whether alternative interim approaches to preventing double-payment should be considered for the VPP Interim Program period and whether an alternative methodology should be considered under the long-term program.
- e. Staff also seeks comment on whether the revenue-neutrality principle and the scope of technology-specific TOU options appropriately balance customer protection, grid benefit, and program operability.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support coordinated time-of-use (TOU) rate design and VPP compensation that protects customers, avoids unnecessary rate fragmentation, preserves legitimate revenue stacking, and uses Interim Program experience to inform the long-term framework. The Board should: (1) favor technology-neutral TOU rate design; (2) treat TOU rates and VPP compensation as distinct but complementary mechanisms; (3) adopt a hold-harmless protection for customers responding to VPP dispatch; (4) prevent duplicate compensation for the same service while allowing compensation for independently delivered services; and (5) use Interim Program participation, operational, and bill-impact data to determine how revenue-neutrality principles should apply over the long term.

On (a), technology-specific TOU rates should remain the exception rather than the default. Excessive rate fragmentation increases administrative complexity and customer confusion. EDCs should favor a unified, technology-neutral rate structure capable of accommodating multiple flexible technologies, with technology-specific rates adopted only where the Board determines that measurable customer or grid benefits cannot be achieved through a broader design. A unified whole-home clean energy TOU structure could, for example, include a super-off-peak overnight period to encourage automated EV

charging and water heating and a distinct evening peak period to encourage load reduction and battery discharge.

On (b), TOU rates and VPP compensation should be treated as distinct but complementary mechanisms. Cost-reflective TOU rates provide ongoing price signals that encourage persistent and predictable load shifting, while VPP compensation reflects the incremental operational value customers provide in response to coordinated dispatch. Customers should be eligible to receive both forms of value where they provide both services as discussed in **Comment 17**. Load Shaping should be treated as a scheduled, contractually committed service beyond the customer’s ordinary TOU response and compensation should apply only to verified incremental performance above the TOU-induced baseline.

On (c), customers should not be financially disadvantaged for following a VPP dispatch instruction that conflicts with TOU price signals. The Board may consider applying VPP dispatch provisions with customer disclosures, dispatch coordination, and bill-impact monitoring as a consumer protection.

On (d), the Board should distinguish duplicate compensation for the same grid service from appropriate compensation for separate services provided by the same DER. During the 2027–2029 Interim Program, compensation rules should remain simple and transparent while allowing multiple compensation streams where the underlying services are distinct, incremental, and independently delivered and verified. Where another program already compensates the same capacity or performance during the same event, the VPP methodology should prevent duplicate compensation for that underlying service.

For the long-term tariff, the baseline methodology should account for load shifting already induced by the customer’s TOU rate. Baselines should be weather-normalized and reflect appropriate non-event TOU-period consumption so that VPP compensation rewards the incremental response attributable to VPP dispatch rather than behavior already induced by the underlying rate design.

On (e), revenue neutrality may be an appropriate rate-design constraint, but the Board should use Interim Program data before fixing the long-term methodology. The Interim Program should generate sufficient participation, operational, and bill-impact data to determine whether and how revenue-neutral rate design advances the Board’s objectives. To the extent revenue neutrality is ultimately adopted, it should be assessed at the program or rate-class level rather than customer by customer so that individual customers can still benefit financially when they shift load, provide flexibility, and respond to VPP dispatches.

STAKEHOLDER COMMENT NO. 28 — GOVERNMENT FLEETS AND FACILITIES

Straw Proposal Section 4.8

Stakeholder Comment No. 28

- a. Staff seeks stakeholder comment on the appropriate mechanism for integrating large public-sector fleet assets such as NJ Transit and Electric School Buses into the VPP framework that balance the cost-effectiveness, technology, and public interest.
- b. Staff also seeks feedback on other Government facility and assets that can be incorporated into the VPP Program, separated by Interim and long-term implementation.

Position: ☒ **Support** ☐ Support with modifications ☐ Oppose ☐ No position / not applicable

RESPONSE

We support the integration of public-sector fleets, government facilities, and other public assets into the VPP framework. Public-sector resources should participate through the same competitive pathways as comparable VPP resources, with the Board: 1) enabling participation through qualified aggregators, 2) prioritizing vehicle-to-grid (V2G) infrastructure and VPP participation at facilities located within or serving OBCs, and 3) phasing participation based on technology readiness.

On (a), NJ Transit and electric school buses should participate through the same competitive pathways as other large controllable resources. Their predictable schedules, concentrated charging loads, and substantial battery capacity make them particularly valuable for managed charging and, as technology matures, bidirectional V2G services. A separate public-sector pathway would unnecessarily duplicate administration, measurement, and compensation structures.

NJ Transit depots should use smart charging to shift or curtail load during system constraints, with V2G capabilities incorporated where technically and operationally appropriate. Electric school buses are similarly well suited to scheduled dispatch because of their predictable duty cycles and extended periods of availability. The Board should continue advancing V2G school bus pilots while allowing buses to participate through managed charging where bidirectional capabilities are not yet available or cost-effective.

On (b), other government facilities and assets should be incorporated based on technology readiness and their ability to provide measurable grid services. During the Interim Program, the Board should prioritize public facilities with existing building management systems, automated controls, distributed generation, battery storage, and other controllable loads that can participate with minimal additional infrastructure.

For the long-term framework, building electrification, grid-interactive efficient buildings, and microgrids should become core components of the State's VPP strategy. Public-building electrification should prioritize VPP-capable heat pumps, water heating, thermal and battery storage, building controls, and distributed generation so new electric loads are flexible and grid-interactive rather than unmanaged. Grid-interactive buildings and microgrids should be designed for VPP interoperability, allowing them to coordinate onsite generation, storage, and flexible loads and provide broader grid services while preserving their resilience and public-service functions.

STAKEHOLDER COMMENT NO. 29 — VPP IMPLEMENTATION WORKING GROUP

Straw Proposal Section 4.9

Stakeholder Comment No. 29

- a. Staff seeks stakeholder comment on the structure, membership, scope and meeting cadence of the VPP Working Group.
- b. Staff also solicits comment on whether any additional coordination mechanisms should supplement the VPP WG process to ensure effective ongoing program governance.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support the Working Group (“WG”) with governance, transparency, and accountability requirements that ensure balanced participation and protect ratepayer interests. The Board should: 1) establish formal representation for consumer, environmental justice, community-based, and competitive market interests, 2) require monthly meetings through the 2027 launch, transitioning to quarterly meetings thereafter, and 3) establish clear transparency, coordination, and escalation requirements.

On (a), the WG should have balanced representation and transparent governance and education that ensures both technical and non-technical perspectives. Its charter should provide formal representation for the Division of Rate Counsel; environmental justice and community-based organizations representing OBC and low-income interests; independent third-party aggregators, including original equipment manufacturer (OEM) and multi-technology providers; NJDEP; and New Jersey Economic Development Authority (NJEDA). To maintain neutrality, the WG should be co-chaired by Board Staff and an independent technical consultant rather than an EDC representative.

The WG should meet monthly from late 2026 through the 2027 launch period and quarterly thereafter, with an established meeting schedule. Materials should be circulated in advance, meetings recorded, and agendas, presentations, minutes, and recommendations posted publicly to the BPU docket.

The WG should also serve as a forum for coordinating the VPP framework with related proceedings and initiatives, including those identified by Staff, NEM reform under [Docket No. QO24090723](#), future EDC business-model reform under Executive Order No. 1, and the CEVAR Workgroup. Board Staff should maintain a regulatory roadmap identifying these related efforts, their dependencies, and how decisions in each may affect VPP implementation. This will help stakeholders understand how the proceedings fit together and reduce the risk of conflicting or duplicative requirements.

On (b), the WG should report annually to the Board on material issues it cannot resolve. The report should identify the issue, competing stakeholder positions, and any recommended options for Board consideration. A standing forum needs a clear escalation path so unresolved policy and implementation issues are surfaced for Board action rather than remaining indefinitely within the WG.

STAKEHOLDER COMMENT NO. 30 — COST RECOVERY MECHANISMS

Straw Proposal Section 5

Stakeholder Comment No. 30

Staff requests comment on what mechanisms the Board should consider for cost recovery, including the appropriate classification of program administration and incentive costs as expense versus capital investment, and whether any cost categories warrant amortization

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

The Board should treat VPP program administration, customer incentives, and aggregator payments as operating expenses. Reserve capital treatment for EDC-owned infrastructure with a multi-year useful life, including DERMS, ADMS integration, and necessary distribution-system upgrades. Ratepayer-funded participant and aggregator incentives should not be capitalized or earn an EDC rate of return. Limited amortization may be appropriate for significant start-up or systems-integration costs where necessary to avoid near-term rate impacts.

The classification of VPP costs is not merely an accounting question. It can influence an EDC's incentive to own infrastructure rather than procure services from customers and competitive providers. If third-party incentives and services are expensed while EDC-owned assets serving the same grid need are placed in rate base and earn a return, the framework creates a structural preference for utility ownership regardless of which solution is more cost-effective. That outcome would undermine the VPP framework's open-access and competitive-market principles and the safeguards against unnecessary EDC ownership.

Program administration and incentives should therefore be treated as operating expenses. Customer enrollment and performance incentives, aggregator payments, Board/EDC program-level marketing and education, and ongoing program administration should be recovered as annual, reconcilable program costs. Capital treatment should be limited to infrastructure with a demonstrable multi-year useful life, such as DERMS and ADMS integration and necessary utility-side distribution upgrades.

Amortization should be limited and transparent. Significant one-time start-up, software, or systems-integration costs may warrant amortization over their demonstrated useful life to mitigate near-term rate impacts. Any amortization period should be disclosed and supported by the expected life of the underlying investment. Amortization should not be used to convert customer incentives, aggregator payments, or routine program administration into rate-base investments.

STAKEHOLDER COMMENT NO. 31 — INFORMATION SHARING AND COST SAVINGS SCORECARD

Straw Proposal Section 6.1

Stakeholder Comment No. 31

- a. Staff seeks comment on appropriate response timeframes for each category of EDC-to-aggregator data provision – enrollment verification, unenrollment confirmation, and event-performance meter data – and on whether timeframes should differ by data category or customer class.
- b. Staff further seeks comment on appropriate feedback protocols where an EDC cannot meet an applicable timeframe, and on what consequences or aggregator remedies the Board should establish for a documented pattern of non-compliance.
- c. Staff also seeks comment on the appropriate scorecard reporting requirement and methodology to justify ratepayer cost reductions attributable to the VPP Programs.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

The Board should establish reciprocal data-access and accountability requirements for EDCs and aggregators, supported by a standardized VPP data-governance framework. The Board should also require an annual VPP Cost Savings Scorecard that captures the full range of ratepayer, grid, emissions, and equity benefits.

On (a), data-provision requirements should align with the timelines established under **Section 4.6** (AMI Data Access Standards), reflect the operational purpose of each data category, and apply reciprocally to EDCs and aggregators. Aggregators should be subject to comparable requirements for information within their control, including enrollment and unenrollment requests, customer authorizations, resource and device information, and dispatch and performance data. Each party should be accountable for the accuracy and timely exchange of the data it controls.

On (b), accountability and remedies should apply to both EDCs and aggregators. A party unable to meet an applicable timeframe should notify the affected party within that timeframe, explain the delay, and provide an expected delivery date. A documented pattern of non-compliance should trigger a corrective action plan and appropriate performance-based consequences.

Neither party should bear performance or financial consequences caused by the other party's failure to provide required data. Where an EDC data failure prevents an aggregator from meeting an enrollment, dispatch, measurement, or settlement obligation, the aggregator should not be held responsible for the resulting failure, and vice versa.

On (c), support an annual VPP Cost Savings Scorecard that measures the full value delivered to ratepayers. At minimum, the scorecard should report avoided capacity costs, avoided or deferred distribution investments, program costs and net ratepayer savings, enrollment and performance by EDC

territory, and actual versus targeted peak-demand reductions. The methodologies for calculating avoided costs and savings should be transparent and consistent with those adopted by the Board elsewhere in this proceeding.

The scorecard should also report avoided emissions and distributional equity outcomes. Emissions reporting should quantify avoided GHG and relevant criteria-pollutant emissions attributable to VPP performance using a transparent methodology. Equity reporting should include participation, customer incentives, program expenditures, and delivered VPP capacity within OBCs. These metrics should supplement, not replace, the scorecard's core ratepayer cost and system-performance measures.

The Board should also establish a standardized VPP data-governance framework identifying, for each data category, ownership or control, the authoritative system of record, storage and retention requirements, validation responsibility, access rights, and reporting obligations. At minimum, the framework should address enrollment, customer authorization, device and telemetry data, meter data, baselines, dispatch instructions, event performance, and settlement. Clear data responsibilities will improve transparency and reduce disputes, duplicative systems, and gaps in accountability.

STAKEHOLDER COMMENT NO. 32 — DER REGISTRY DATA FIELDS

Straw Proposal Section 6.2

Stakeholder Comment No. 32

Staff requests comment on whether any VPP-specific data fields should be added to the PSUP Appendix B field list through the PSUP proceeding rather than separately through this proceeding.

Position: ☒ **Support** ☐ Support with modifications ☐ Oppose ☐ No position / not applicable

RESPONSE

We support using the unified DER Registry established through the PSUP proceeding rather than creating a separate VPP registry. The Board should ensure that PSUP Appendix B includes the VPP-specific fields necessary to support program administration, prevent double counting, and track equitable participation, including: 1) OBC status, and 2) active VPP enrollment and Aggregator ID.

The PSUP DER Registry should serve as the single source of record for DER registration and VPP participation, avoiding duplicative systems and inconsistent data across proceedings.

The registry should include an OBC designation for each DER to allow the Board to track the geographic distribution of VPP participation, incentives, and benefits. Where LMI/OBC information is collected, it should be maintained and reported in a manner consistent with applicable customer privacy and data-protection requirements.

The registry should also identify whether a DER is actively enrolled in a VPP, the licensed aggregator responsible for the resource, and the applicable program or market participation pathway. These fields

will help identify conflicting enrollments and enforce the Board’s anti-double-counting requirements while supporting transparent oversight of VPP participation.

STAKEHOLDER COMMENT NO. 33 — DER AGGREGATOR LICENSING AND CODE OF CONDUCT

Straw Proposal Section 6.3

Stakeholder Comment No. 33	Staff requests comment on the following aspects of the proposed DER aggregator licensing framework:
	a. whether the proposed application requirements – covering financial viability, technical capability, customer service, data privacy, and cybersecurity – are appropriately scoped, and whether any additional or modified requirements should be considered
	b. whether the proposed fee is appropriate and sufficient to reflect the administrative costs of the licensing program
	c. whether the proposed Code of Conduct adequately addresses consumer protection concerns relevant to New Jersey ratepayers, and whether any additional provisions should be included
	d. whether the Board’s proposed enforcement authorities and the EDC-maintained quarterly aggregator list are sufficient mechanisms to deter aggregator misconduct and support informed consumer choice

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support a BPU-administered DER aggregator licensing framework with stronger consumer protections. The Board should: 1) require financial security and insurance appropriate to an aggregator’s size and activities; 2) strengthen language-access and disclosure requirements; 3) increase the proposed application fee to support meaningful regulatory review; and 4) maintain the authoritative public list of licensed aggregators.

On (a), the proposed requirements are appropriately scoped but should include risk-based insurance requirements. Aggregators should maintain coverage appropriate to their activities, including liability for aggregator-owned equipment installed at customer premises, property damage, bodily injury, and cybersecurity or data breaches. Financial and insurance requirements should scale with portfolio size and risk to protect customers without creating unnecessary barriers to entry.

On (b), the proposed \$200 application fee is too low. The Board should establish an application and renewal fee sufficient to support meaningful review and ongoing oversight while avoiding unnecessary barriers to market entry.

On (c), the Code of Conduct should strengthen language-access and disclosure requirements. Customer-facing materials should be accessible to customers with limited English proficiency. Aggregators should also provide a standardized VPP Disclosure Label identifying compensation, opt-out and termination rights, equipment ownership and responsibility, and data-sharing practices.

On (d), support strong Board enforcement authority, but the Board (not individual EDCs) should maintain the authoritative list of licensed aggregators. A centralized, publicly accessible BPU registry will provide consistent information on license status and improve accountability and consumer confidence.

STAKEHOLDER COMMENT NO. 34 — CYBERSECURITY SHARED-RESPONSIBILITY MODEL

Straw Proposal Section 6.4

Stakeholder Comment No. 34

Staff requests comment on the proposed shared-responsibility model and the allocation of roles among the Board, EDCs, aggregators, and customers; on whether the required and reference standards listed in this section are appropriate and sufficient for the VPP Interim Program and the long-term tariff

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support the proposed shared-responsibility cybersecurity model and standards, with stronger protections for sensitive customer information. The Board should require clear accountability for data security, limit collection and access to information necessary for VPP participation, and require disclosure of what customer data are collected, used, stored, and shared.

We support the shared-responsibility model, provided each party is accountable for the data and systems it controls. EDCs and aggregators should be required to protect sensitive customer information, including personally identifiable information (PII), financial and banking information, account credentials, device-level data, and other information that could compromise customer privacy or security. Customers should not be responsible for cybersecurity failures involving systems or data outside their control.

The framework should also incorporate data minimization and transparency requirements. Aggregators and EDCs should collect only the customer information necessary to provide VPP services and clearly disclose what data are collected, why they are needed, how they will be used and stored, who may access or receive them, and how long they will be retained. Sensitive information should not be shared beyond what is necessary for authorized VPP participation.

We support the proposed cybersecurity standards, provided they establish a minimum floor rather than limiting the Board's ability to strengthen requirements as technologies and threats evolve. The same core cybersecurity and privacy protections should apply consistently to EDCs and aggregators, with requirements proportionate to the systems, data, and operational risks each party controls.

STAKEHOLDER COMMENT NO. 35 — THREE-TIER DATA ACCESS STRUCTURE

Straw Proposal Section 6.4(a)-(c)

Stakeholder Comment No. 35

Staff requests comment on:

- a. the proposed shared-responsibility model and the allocation of roles among the Board, EDCs, aggregators, and customers
- b. whether the required and reference standards listed in this section are appropriate and sufficient for the VPP Interim Program and the long-term tariff

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support the proposed shared-responsibility model and three-tier data-access structure as appropriately calibrated to data sensitivity. The Board should supplement the framework with clear data-governance requirements addressing what customer data are collected and how those data are accessed, stored, retained, shared, and ultimately disposed of across all parties and platforms.

On (a), support the shared-responsibility model, but responsibilities should extend across the entire customer-data lifecycle. Each EDC, aggregator, and third-party provider should be accountable for protecting the customer data within its custody or control. Customers should receive clear disclosure of what data are collected, why they are needed, where and by whom they are stored, who may access or receive them, and how long they are retained. Sensitive information, including PII, financial and banking information, account information, and device-level data, should receive heightened protection and be collected only when necessary for VPP participation.

The Board should also establish clear requirements governing the transfer, retention, and deletion of customer data when information moves between EDCs, aggregators, vendors, and other platforms or when a customer unenrolls. Data protections should follow the information regardless of which authorized party or platform holds it.

On (b), support the proposed three-tier data-access structure and associated cybersecurity standards. The tiered approach appropriately establishes access boundaries based on data sensitivity and pairs customer consent with corresponding security controls. These standards should serve as a minimum requirement for both the Interim Program and long-term tariff and should be updated as cybersecurity risks and industry standards evolve.

STAKEHOLDER COMMENT NO. 36 — DEMONSTRATING STANDARDS COMPLIANCE

Straw Proposal Section 6.4

Stakeholder Comment No. 36

- a. Staff requests comment on appropriate methods for VPP aggregators to demonstrate compliance with IEEE 2030.5 and 2.0b/3.0 and IEEE 1547.3-2023 through certification, third-party attestation, and/or vendor documentation. Staff recognizes that the cost of a SOC 2 Type II report may represent a significant financial barrier for some aggregators.
- b. As such, Staff requests comments from stakeholders on alternative compliance pathways that provide flexibility through certification, third-party attestation, or vendor documentation.

Position: ☒ **Support** ☐ Support with modifications ☐ Oppose ☐ No position / not applicable

RESPONSE

We support robust cybersecurity verification while establishing flexible compliance pathways that avoid unnecessary barriers to market entry. The Board should allow aggregators to demonstrate compliance through state of charge (SOC) 2 Type II certification, qualified third-party attestation, or vendor/OEM documentation, with requirements proportionate to the aggregator's size, system access, control capabilities, and cybersecurity risk.

On (a), the Board should establish tiered compliance pathways rather than requiring SOC 2 Type II certification for every aggregator. Aggregators that operate through certified OEM or technology platforms should also be permitted to rely on applicable vendor documentation and certifications to demonstrate compliance with IEEE 2030.5, IEEE 1547.3-2023, and other applicable requirements, rather than duplicating certifications already completed by the underlying technology provider.

The compliance obligation should follow the cybersecurity risk and functionality controlled by the aggregator. An aggregator should not be required to independently recertify technology or systems it does not own or control, but should remain responsible for demonstrating that its own systems, integrations, and practices meet applicable cybersecurity requirements.

STAKEHOLDER COMMENT NO. 37 — ADEQUACY OF REQUIRED SECURITY STANDARDS

Straw Proposal Section 6.4

Stakeholder Comment No. 37

Staff requests comment on whether the standards identified above are appropriate and sufficient for the VPP Program. Specifically, Staff seeks input on:

- a. whether the standards required of all participants establish an adequate security baseline without imposing undue cost on smaller aggregators
- b. whether any listed standard should instead be treated as guidance, or any guidance standard elevated to a requirement
- c. whether all of the standards for EDC-operated Grid DERMS and operational-technology systems are necessary and whether their proposed interrelationship with NIST SP 800-53 is clear and appropriate
- d. whether additional standards – device-level certifications, or customer-data privacy codes – should be added whether the required standards are achievable within the VPP Interim Program timeline

Position: ☐ Support ☐ Support with modifications ☐ Oppose ☒ **No position / not applicable**

RESPONSE

We support the identified cybersecurity standards as a reasonable baseline for the VPP Program. While we do not offer specific technical recommendations regarding individual standards, the Board should maintain core cybersecurity and customer-data protections during the Interim Program while allowing reasonable, risk-based compliance pathways for requirements that cannot be fully implemented within the 2027 launch timeline.

STAKEHOLDER COMMENT NO. 38 — EQUITY AND LOW- AND MODERATE-INCOME ACCESS

Straw Proposal Section 6.5

Stakeholder Comment No. 38

Staff requests feedback on barriers that LMI customers might face in accessing VPP program benefits, and what specific program design features the Board should consider adopting to ensure equitable distribution of VPP benefits across all customer classes.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

The Board should ensure equitable participation is a measurable outcome of the VPP Program. LMI/OBC customers face structural barriers including upfront technology costs, renter and multifamily housing statuses, credit requirements, lack of dedicated program outreach, administrative complexity, historic underinvestment, and limited access to trusted program information. The Board should use the Interim Program to establish clear definitions, metrics, incentives, and participation targets for LMI/OBC households, renters, and OBCs. Accordingly, equity components (such as landlord incentives, and enabling community solar and storage and net metering) should not be confined to a single section of the Straw Proposal, but reflected throughout the program design.

The Board should require each EDC to establish measurable LMI/OBC and renter participation goals and periodically report participation, incentives, enrolled capacity, and customer benefits. These metrics should allow the Board to determine whether VPP benefits are being equitably distributed across customer classes and communities.

The VPP Program should also coordinate with the Triennium and other existing programs to provide no-cost, enhanced upfront incentives, or adders for VPP-capable technologies in income-qualified households. Direct-install pathways for technologies such as smart thermostats and controllable water heaters can reduce upfront cost barriers, while program design should specifically address the ability of renters and multifamily residents to participate.

Community-based participation models should also be supported, with municipalities, nonprofit organizations, affordable housing providers, and community-based organizations serving as trusted partners for outreach, education, enrollment, and customer support. These entities can help reach customers who may not participate through traditional commercial aggregator models and should be able to partner with qualified aggregators without unnecessary administrative barriers. Equally important, fragmented program administration, including separate applications, eligibility requirements, and enrollment processes, can discourage participation, particularly among households with limited time, language access, or familiarity with utility programs. The Board should therefore strive to simplify the customer experience through streamlined enrollment and coordinated eligibility determinations wherever possible, while enabling trusted community partners to help customers navigate and participate in available programs. Finally, equity should be measured by customer outcomes, not simply enrollment. LMI/OBC customers should clearly understand the compensation and benefits they receive, and the Board should track whether participation produces meaningful household benefits in addition to enrolled VPP capacity.

STAKEHOLDER COMMENT NO. 39 — MARKETING AND PUBLIC OUTREACH

Straw Proposal Section 7.1

Stakeholder Comment No. 39

- a. Staff seeks feedback on the roles of the Board, EDCs, third-party VPP providers, and other relevant stakeholders in VPP education, outreach, and marketing.
- b. Staff seeks comment on the quarterly distribution requirement (under Section 7.3 EDC Marketing), including its cost treatment, and on whether Board review of aggregator marketing materials should be conducted through a standardized pre-approval process or a post-distribution audit.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support a coordinated VPP education and outreach framework that clearly separates neutral program education from competitive marketing. The Board and EDCs should provide program-level education in partnership with trusted community organizations, while aggregators should be responsible for marketing their individual offers. Aggregator marketing should be subject to clear standards and post-distribution audit rather than pre-approval.

On (a), the Board and EDCs should lead program education, while aggregators market their specific offers. Board and EDC outreach should explain what VPPs are, how customers participate, customer rights, and how to compare competing offers. Outreach to LMI/OBC customers and other underserved communities should include partnerships with community benefit organizations (CBOs) and other trusted local organizations and provide appropriate language access. Aggregators should be responsible for explaining and marketing their specific products, compensation, and terms.

On (b), quarterly EDC communications should focus on neutral VPP education and information about how customers can identify and compare licensed providers. These program-level communications are appropriately treated as program administration expenses. Aggregator-specific advertising and customer acquisition are ordinary costs of doing business and should not be recovered from ratepayers.

Aggregator marketing should be subject to post-distribution audit against clear, published standards rather than Board pre-approval. Pre-approval could create unnecessary delays, increase compliance costs, and imply Board endorsement of commercial offers. Post-distribution audits, backed by the Code of Conduct and meaningful enforcement for misleading or non-compliant marketing, provide consumer protection without creating a regulatory bottleneck.

STAKEHOLDER COMMENT NO. 40 — IMPLEMENTATION TIMELINE

Straw Proposal Section 8

Stakeholder Comment No. 40

Staff seeks feedback on the proposed timeline.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

We support Staff's proposed timeline, provided each milestone includes a clear and enforceable deadline. The Board should establish specific completion dates, responsible parties, and minimum functional-readiness requirements for each milestone to ensure the Interim Program remains on schedule.

Milestones should measure operational readiness, not simply completion of an administrative or technology deployment task. Where dependencies exist between the Board, EDCs, aggregators, or other parties, the timeline should clearly identify those dependencies and establish accountability for delays. Any missed milestone should require prompt notice to the Board, an explanation of the delay, and a corrective action plan with a revised completion date, subject to the July 1, 2029 outside date recommended in **Comment 14**.

STAKEHOLDER COMMENT NO. 41 — ADDITIONAL COMMENTS AND OMITTED CONTENT

Straw Proposal General

Stakeholder Comment No. 40

Staff welcomes comment on any aspect of the VPP Program Straw Proposal not addressed by the preceding questions, including issues Staff should consider that are not raised in this document. Commenters who believe the proposal omits necessary content are encouraged to provide proposed language and identify the section to which it should be added. For all comments, commenters are encouraged to identify the specific section and, where applicable, the Stakeholder Comment number to which their input relates.

Position: ☐ Support ☒ **Support with modifications** ☐ Oppose ☐ No position / not applicable

RESPONSE

The Straw should address three additional issues necessary to provide participant and ratepayer protection and regulatory certainty: 1) aggregator market exit, 2) treatment of legacy Triennium 2 participants, and 3) the process for amending the long-term VPP tariff.

Aggregator Market Exit – Section 6.3. The Straw addresses aggregator misconduct but should also address aggregator failure or voluntary market exit. Participants should receive advance notice, a reasonable transition period, the right to select a new aggregator without penalty, and continuity of earned compensation during the transition. The Board should establish an orderly transfer process, so participants are not stranded or required to restart enrollment because their aggregator exits the market.

Legacy Triennium 2 Resources. Participants migrating from Triennium 2 programs to the VPP Interim Program should receive clear notice of any changes to compensation, participation requirements, dispatch obligations, or other material terms before migration. If the new terms materially differ from those under which the participant originally enrolled, the participant should have the right to withdraw without penalty.

Long-Term Tariff Amendments. The Board should establish a transparent process for modifying the long-term VPP tariff. Participants making multi-year investments and commitments need reasonable certainty regarding the rules under which those commitments were made. Material tariff amendments should therefore include notice and an opportunity for stakeholder comment, a defined effective date, and appropriate transition treatment for existing participants. A predictable amendment process will reduce regulatory uncertainty without limiting the Board's ability to modify the tariff as the VPP market evolves.