Straw Proposal:
Virtual Power Plant Program

In the Matter of Establishing of a Virtual Power Plant ("VPP") Program in the State of New Jersey

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NOTICE TO STAKEHOLDERS

Staff of the New Jersey Board of Public Utilities ("NJBPU" or "Board") hereby invites all interested parties and members of the public – especially third-party distributed energy resource ("DER") aggregators; energy storage developers, owners, and operators; and the four Electric Distribution Companies ("EDC"): Atlantic City Electric, Jersey Central Power & Light, Public Service Electric & Gas, and Rockland Electric Company – to provide written responses to this Virtual Power Plant ("VPP") Straw Proposal ("Straw") on the evaluation and development of VPP program.

The Board is accepting written and/or electronic responses regarding this Straw. All public responses should be filed under Docket No. QO26030099.

The deadline for responses on this matter is 5 p.m. on August 17, 2026.

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

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

Written comments may also be submitted to:

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Secretary of the Board
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Trenton, NJ 08625-0350
Phone: 609-292-1599
Email: board.secretary@bpu.nj.gov
Staff look forward to receiving and reviewing stakeholder responses.

Sherri L. Lewis
Secretary of the Board
Dated: July 15, 2026

ABBREVIATIONS LIST

5CP: 5 Coincident Peaks
ACE: Atlantic City Electric Company
ADMS: Advanced Distribution Management System
AMI: Advanced Metering Infrastructure
API: Application Programming Interface
AVPP: Aggregator Virtual Power Plant
BCR: Benefit-to-Cost Ratio
BD: Building Decarbonization
BESS: Battery Energy Storage System
BPU: Board of Public Utilities
BRA: Base Residual Auction
BTM: Behind the Meter
BYOD: Bring Your Own Device
C&I: Commercial and Industrial
CEA: Clean Energy Act of 2018
CEVAR: Cost Estimation, Validation, Allocation, and Recovery
CIP: Critical Infrastructure Protection
CSF: Cybersecurity Framework
CTA: Consumer Technology Association
DEP: Department of Environmental Protection
DER: Distributed Energy Resource
DERA: DER Aggregator
DERMS: DER Management System
DF: Demand Flexibility
DLC: Direct Load Control
DOE: Department of Energy
DR: Demand Response
DY: Delivery Year
EDC: Electric Distribution Company
EDECA: Electric Discount and Energy Competition Act
EDI: Electronic Data Interchange
EE: Energy Efficiency
ELCC: Effective Load Carrying Capability
EM&V: Evaluation, Measurement, and Verification
EMS: Energy Management System
EO2: Executive Order No. 2
EV: Electric Vehicle
FERC: Federal Energy Regulatory Commission
FLM: Flexible Load Management
FOM: Front of Meter
FPR: Forecast Pool Requirement

GBC: Green Button Connect
GMF: Grid Modernization Forum
GSESP: Garden State Energy Storage Program
GW: Gigawatt
HVAC: Heating, Ventilation, and Air Conditioning
IC: Implementation Contractor
IDDER: Integrated Distribution of Distributed Energy Resource
IEC: International Electrotechnical Commission
IEEE: Institute of Electrical and Electronics Engineers
IIP: Infrastructure Investment Program
IRM: Installed Reserve Margin
ISO: Independent System Operator
JCP&L: Jersey Central Power & Light Company
kW: Kilowatt
kW: Kilowatt-hour
LD: Light-Duty
LMI: Low-to-Moderate Income
MDPSC: Maryland Public Service Commission
MFR: Minimum Filing Requirements
MHD: Medium- and Heavy-Duty
MOU: Memorandum of Understanding
MUD: Multi-Unit Dwelling
MVP: Minimum Viable Product
MW: Megawatt
NEM: Net Energy Metering
NERC: North American Electric Reliability Corporation
NJBPU: New Jersey Board of Public Utilities
NJEDA: New Jersey Economic Development Authority
NIST: National Institute of Standards and Technology
NSPL: Network Service Peak Load
NWA: Non-Wire Alternatives
OBC: Overburdened Community
OEM: Original Equipment Manufacturer
OpenADR: Open Automated Demand Response
OT: Operational Technology
PACT: Program Administrator Cost Test
PCT: Participant Cost Test
PDR: Peak Demand Reduction
PJM: PJM Interconnection, LLC (a regional transmission organization)
PLC: Peak Load Contribution
PSC: Public Service Commission
PSE&G: Public Service Electric & Gas Company
PSUP: Proactive System Upgrade Plan
PV: Photovoltaic

QPI: Quantitative Performance Indicator
RBP: Reliability Backstop Procurement
RECO: Rockland Electric Company
REV: Reforming the Energy Vision
RFI: Request for Information
RFP: Request for Proposal
RIM: Ratepayer Impact Measure
RTO: Regional Transmission Organization
SCADA: Supervisory Control and Data Acquisition
SCT: Societal Cost Test
SOC: State of Charge
T&D: Transmission and Distribution
T2: Triennium 2
TLS: Transport Layer Security
TOU: Time-of-Use
TRC: Total Resource Cost
UCAP: Unforced Capacity
UL: Underwriters Laboratories
V2B: Vehicle-to-Building
V2G: Vehicle-to-Grid
V2H: Vehicle-to-Home
V2X: Vehicle-to-Everything
VPP: Virtual Power Plant
VPP WG: Virtual Power Plant Working Group

EXECUTIVE SUMMARY

New Jersey faces a widening supply-demand gap in the PJM regional electricity market, marked by sustained capacity auction price increases that flow directly to ratepayer bills. In response, Governor Mikie Sherrill issued Executive Order No. 2 ("EO2")[1], declaring a statewide energy emergency and directing the Board to commence the development of a Virtual Power Plant ("VPP") program within 180 days. This Straw Proposal fulfills the EO2 direction, establishing a framework to aggregate behind-the-meter ("BTM") distributed energy resources ("DER") into a coordinated, utility-grade supply of grid services. It aims to reduce peak demand, improve grid reliability, support community resilience and participation, and advance New Jersey's clean energy goals – to ensure that electricity does not become an even greater financial burden for New Jersey's residents, families, and economy in the near term, while steps are taken to lower rates in the long term.

This Straw presents a two-phase implementation framework and addresses the cross-program coordination on which VPP effectiveness depends. This Straw therefore engages with Board-administered programs and proceedings in energy storage, clean transportation, energy efficiency, grid modernization, advanced metering infrastructure ("AMI"), solar, and net energy metering ("NEM"), identifying how those programs must be coordinated and sequenced to build the DER foundation that a successful VPP program will require. Staff views this Straw as a foundational document, to be refined through stakeholder sessions and parallel proceedings.

The goals for the VPP Program are programmatic, operational, and strategic. Programmatically, a successful VPP Program should create a durable, open-access market structure that attracts competitive third-party aggregators; and positions New Jersey DER aggregations to participate in PJM wholesale markets, unlocking private capital to drive further enrollment of existing customer-owned assets. Operationally, the program should provide equitable access to opportunities for ratepayers to achieve savings through peak load reductions by building a coherent, mutually reinforcing program architecture between BPU programs to encourage VPP participation. Strategically, successful VPP programs will support the evolution of the utility business model toward one in which grid services provided by DERs are integrated into distribution system operations and planning, deferring or avoiding costly traditional infrastructure investment. Achieving this more flexible, modernized grid will require sustained coordination across multiple Board proceedings and EDC programs over both near- and long-term horizons.

Staff proposes a two-phase implementation:

Phase 1 – VPP Interim Program (2027-2029): A two-year, EDC-administered bridge program launching no later than July 1, 2027. The VPP Interim Program will deliver a measured and verified peak demand reduction target in each EDC's service territory by leveraging existing AMI, direct load control ("DLC") platforms, and the demand response ("DR") customer base enrolled

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

under the Triennium program, with nominal incremental investment in coordination and automation. The program is technology-neutral, expressly transitional in design, and primarily focused on gathering operational data to inform and refine the long-term framework, while simultaneously providing grid services that can produce near and long-term savings by shifting utility models to less costly non-wires solutions.

Phase 2 – Long-Term Open-Access VPP Framework (2029 onward): A market-based structure built on an open-access VPP tariff with a defined compensation structure. This framework requires substantial stakeholder inputs, EDC investment, and third-party systems integration around a fully specified service architecture, and enables enrolled DERs to stack distribution-level grid service payments with PJM wholesale market revenues where permitted. It is designed to position New Jersey DER aggregations competitively for optimal market participation.

Overall, the VPP program is governed by eight (8) principles:

i. Ratepayer savings with cost-effectiveness framework;

ii. Leveraging existing DER assets and programs for progressive development of the VPP Interim Program;

iii. A long-term open and competitive market architecture with non-discriminatory aggregator access and friction-free enrollment and exit for qualified, participating resources;

iv. Maximizing enrolled DER value stack across wholesale and distribution markets, with cross-program coordination to prevent duplicative compensation;

v. Integrating DER grid services, including VPPs, into EDC planning and operation to create ratepayer savings;

vi. Equitable program design and inclusive participation opportunity;

vii. Technology neutrality and open-standard interoperability; and

viii. Transparency and stakeholder engagement through public reporting and ongoing stakeholder input.

SECTION 1. INTRODUCTION AND PROCEDURAL BACKGROUND

1.1 Purpose and Scope

This Straw Proposal is issued by Staff of the New Jersey Board of Public Utilities (the "Board" or "NJBPU") to solicit stakeholder input on the design of a statewide Virtual Power Plant ("VPP") Program. Through this Straw Proposal, Staff seeks to advance a near-term, technology-neutral VPP framework administered in coordination with the State's four Electric Distribution Companies ("EDC") – Atlantic City Electric Company ("ACE"), Jersey Central Power & Light Company ("JCP&L"), Public Service Electric and Gas Company ("PSE&G"), and Rockland Electric Company ("RECO") – while simultaneously laying the structural foundation for a long-term, open access tariff that enables third-party DER Aggregators to participate in distribution-level grid services and PJM Interconnection, L.L.C. ("PJM") wholesale markets.

This proposal is issued pursuant to Governor Mikie Sherrill's Executive Order No. 2, dated January 20, 2026, which declared a statewide energy emergency, identified a widening supply-demand gap in the PJM region, and directed the Board to commence the development a VPP program within 180 days.[2] EO2 states that the VPP Program will be administered by EDCs and third-party suppliers to reduce peak demand by aggregating BTM DERs. For this Straw proposal, Staff adopts the working definition of a VPP as an aggregation of DERs and other load management technologies that can balance electrical loads to defer or avoid a transmission or distribution upgrades and provide utility-scale, utility-grade grid services analogous to those provided by traditional generation resources.[3] For purpose of this Straw Proposal, "DER" also includes behind-the-meter load-modifying resources – such as smart thermostats, managed electric vehicle charging, electric water heaters, and commercial and industrial demand response – consistent with the scope of "DER Aggregation" under N.J.A.C. 14:8-5.1, as well as extends to "behind the meter load-modifying resources", in addition to interconnected DER facilities.

Virtual power plants offer a cost-effective alternative to traditional peaking resources. The U.S. Department of Energy's *Pathways to Commercial Liftoff: Virtual Power Plants* report and Brattle Group analysis found that procuring peaking capacity through a VPP composed of residential smart thermostats, water heaters, EV chargers, and behind-the-meter batteries can cost a utility system approximately 60% less on net than procuring equivalent capacity from a new gas peaker plant.[4] The DOE VPP Liftoff report further found that expanding U.S. VPP capacity to 80-160 GW by 2030 could address 10-20% of peak load, which would avoided generation buildout, defer

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

[3] U.S. Department of Energy, Pathways to Commercial Liftoff: Virtual Power Plants (September 2023), 2. Pathways to Commercial Liftoff: Virtual Power Plants

[4] Hledik, R.; Peters, K. The Brattle Group, Real Reliability: The Value of Virtual Power (May 2, 2023) https://www.brattle.com/wp-content/uploads/2023/04/Real-Reliability-The-Value-of-Virtual-Power_5.3.2023.pdf (Accessed June 18, 2026); Jennifer Downing, Loan Program Office et al., U.S. Dep't of Energy, Pathways to Commercial Liftoff: Virtual Power Plants (September 2023), https://climateprogramportal.org/wp-content/uploads/2025/06/LIFTOFF_DOE_VPP_2023.pdf. (Accessed June 18, 2026) ("DOE VPP Liftoff Report").

infrastructure investments, and reduce reliance on peaking resources.[5] The Brattle Group further estimated that a 60 GW VPP deployment could save utilities $15-$35 billion in capacity investment over 10 years, with an additional $20 billion in societal benefits from emissions reductions and improved resilience over that same period (undiscounted 2022 dollars).[6] The North American market reflects this trajectory: Wood Mackenzie's *2025 North America Virtual Power Plant Market Report* documents 37.5 GW of VPP capacity across the continent, reflecting 13.7% year-over-year growth and active company deployments, unique offtakers, and monetized programs are up more than 33%.[7]

PJM is identified in Wood Mackenzie's report as a near-term growth market – a finding directly relevant to New Jersey's opportunity to position its DER assets ahead of the future Base Residual Auction ("BRA"). Due to the sustained delays in building new firm generation for 5 or more years[8] and the steep increases in projected load within the same time-horizon from interconnecting data centers, PJM's regional market is looking to procure capacity and energy from available resources that are already connected to the grid; VPPs are integral in meeting that moment by helping utilize existing capacity contained in previously unrecognized residential DERs. Staff recognizes this cost-reduction potential for New Jersey ratepayers as directly relevant to the affordability and reliability challenges identified in EO2. In order to realize the full savings potential, utilities must fully integrate grid services into planning and operations. This represents a fundamental shift in the utility model prioritizing the avoidance of costly distribution and transmission infrastructure investment for more nimble, technological solutions to meet the grid's needs. This Straw is designed to lay out the steps necessary to ensure that ratepayers see those savings as quickly possible and lays out the multiple workstreams by which that must be achieved.

This Straw Proposal builds upon, and is intended to be coordinated with, several active Board proceedings, including, but not limited to:

i. The Virtual Power Plant ("VPP") Request for Information ("RFI") issued by the Board on April 20, 2026 (BPU Docket No. QO26030099);

ii. The Garden State Energy Storage Program ("GSESP") proceedings, including the Distributed Phase 2 segment (BPU Docket No. QO26040116);

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[5] DOE VPP Liftoff Report at 32.

[6] Hledik, R.; Peters, K. The Brattle Group, Real Reliability: The Value of Virtual Power, 5 (May 2, 2023) https://www.brattle.com/wp-content/uploads/2023/04/Real-Reliability-The-Value-of-Virtual-Power_5.3.2023.pdf (Accessed June 18, 2026).

[7] Hertz-Shargel, B., Akhavan, E., and Issokson, M. Wood Mackenzie, 2025 North America Virtual Power Plant Market Report. https://www.woodmac.com/news/opinion/virtual-power-plant-growth-is-getting-very-real/ (Accessed June 18, 2026).

[8] Noble B. 5-year waits and rising costs: How demand is redefining the gas turbine market. (March 23, 2026) https://www.utilitydive.com/news/5-year-waits-and-rising-costs-how-demand-is-redefining-the-gas-turbine-mar/813385/ (Access July 7, 2026).

iii. The Second Triennium of the Energy Efficiency ("EE") and Peak Demand Reduction ("PDR") Programs ("Triennium 2") (BPU Docket No. QO19010040, QO23030150 and QO17091004) and The Third Triennium of the Energy Efficiency and Peak Demand Reduction Program Straw proposal ("Triennium 3") issued November 25, 2025 (BPU Docket No. QO25050300);

iv. The Grid Modernization Forum ("GMF") Proceedings, including: the Integrated Distribution and DER System Planning ("IDDER") workgroup and Proactive System Upgrade Plan ("PSUP") (BPU Docket No. QO24030199) and the Grid Flexibility Services (GridFlex) workgroup (BPU Docket No. QO26030059);

v. EO2 Request for Information ("RFI") Proceeding (BPU Docket No. QO24030199);

vi. The Advanced Metering Infrastructure ("AMI") Data Access Standards rulemaking at N.J.A.C 14.5-10 (BPU Docket No. EX24090717);

vii. The EDC's existing and pending proceedings for Electric Vehicle ("EV") and managed EV Charging (BPU Docket Nos. QO21060946 and QO20050357); and

viii. The Matter of Net Metering for Class I Renewable Energy Systems (BPU Docket No. QO24090723).

Staff anticipates that this VPP Straw Proposal will serve as the framework for an EDC Minimum Filing Requirement ("MFR") Order to launch the Interim Program. Staff anticipates that the MFR Orders will be in **October 2026,** and that EDCs will file program proposals **by December 31, 2026**. Following stakeholder comment, Staff will prepare recommendations for the Board's consideration.

For the long-term VPP Program, Staff intends for this Straw to highlight the workstreams that must be coordinated to ensure a robust, resilient, reliable, flexible, and cost-effective grid. Following stakeholder comment, Staff will continue to explore a number of the long-term solutions, gather feedback, and develop recommendations for future programs. This Straw Proposal does not represent a final policy determination by the Board. Staff anticipate revisions to reflect the record developed through the VPP RFI,[9] PSUP Straw,[10] GridFlex Workgroup,[11] GSESP Phase 2,[12] written stakeholder comments on this proposal, and any technical conferences and future stakeholder sessions.

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[9] In re Advancing Virtual Power Plant (VPP) Program in the State of New Jersey, Notice Request for Information, BPU Docket No. QO26030099. Notice dated April 20, 2026.

[10] In re Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid, Notice, BPU Docket No. QO24030199. Notice dated May 8, 2026.

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

[12] In re The Garden State Energy Storage Program – Phase 2 Distributed Storage, BPU Docket No. QO26040116, Notice dated April 20, 2026.

1.2 Definitions

These definitions are aligned with similar definitions in the PSUP Straw, published on May 8, 2026, but are meant to be utilized for the purposes of this straw.

"Advanced Metering Infrastructure" or **"AMI"** means the same as defined within N.J.A.C. 14:5-1.2 ("an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers' meters").

"AMI Data" means the same as defined within N.J.A.C. 14:5-10.2 ("any information collected regarding a customer's electrical usage, energy demand, or information measured to calculate such quantities – recorded over regular intervals of time, as measured – that is stored or transmitted by an EDC-owned smart meter. AMI data does not refer to any other data collected independent of the customer's usage, unless specifically stated as such").

"Baseline Distribution System Assessment" means an evaluation of the existing state and performance of the distribution grid that including but not limited to load profiles, infrastructure condition, grid performance, and system vulnerabilities and fault recovery.

"Distributed Energy Resource" or **"DER"** means any equipment used to generate and/or store electricity, as defined in N.J.A.C. 14:8-5.1,[13] as well as load management technologies including, but not limited to, smart thermostats, EV chargers, electric water heaters, and demand response technologies utilized by commercial and industrial customers.

"DER Aggregator" or **"DERA"** means the entity that aggregates one or more distributed energy resources for the purposes of participation in the capacity, energy and/or ancillary service markets of the regional transmission organizations and/or independent system operators or for the participation in a retail EDC program or market.

"DER Registry" means a web platform or other system that allows collection, compilation, and analysis of data or DERs like rooftop solar, battery storage, electric vehicles, etc. The registries facilitate better management and orchestrated operation of growing number of DERs.

"DER Management System" or **"DERMS"** means a software platform that monitors, manages and/or operationally controls DERs such as solar panels, electric vehicles, energy storage systems, and smart thermostats to support grid operators in a number of uses including, but not limited to, balancing power flow, advanced control and optimization, aggregation and asset orchestration, demand response, and load flexibility. The platform can be divided into two

[13] As defined in N.J.A.C. 14:8-5.1, "Distributed Energy Resource" or "DER" means the equipment used by an interconnection customer to generate and/or store electricity that operates in parallel with the electric distribution system. A DER may include, but is not limited to, an electric generator and/or energy storage system, a prime mover, or combination of technologies with the capability of injecting power and energy into the electric distribution system, which also includes the interconnection equipment required to safely interconnect the facility with the distribution system.

subtypes, which should be standardized and interoperable to the greatest extent:

> **"Grid DERMS"** means a distribution network model-aware system that is able to monitor and manage utility-scale/grid-wide DERs for reliability and support coordinated, system-wide stability, operations, power flow optimization.
>
> **"Edge DERMS"** means a distributed system that manages and orchestrates customer-owned, behind-the-meter assets like home batteries, rooftop solar, EVs, smart appliances, etc.; aggregates flexible loads; enables demand response; and expands DER participation. It may include inverter controlling devices.

"Distribution Services" means benefits to the distribution system and utility operations that DERs or other non-traditional distribution solutions can provide, such as distribution capacity or energy, voltage support, peak shaving, and infrastructure deferral and avoidance. These services are typically defined by specific requirements based on: season, time of day, severity/magnitude, duration of resource operation, the frequency of energy and/or capacity provided by the resources, as well as a corresponding compensation mechanism.

"Demand Response Resource" or **"DRR"** means a resource with a demonstrated capability to provide a reduction in demand or otherwise control load that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction.

"EDC grid flexibility services" means the same as defined in N.J.A.C. 14:8-5.1, ("are control capabilities procured from a customer-generator, which may be compensated by the EDC, that help to maintain distribution system reliability and safety, whether separately or as part of a DER aggregation.")

"Grid Needs" means measures at the substation or feeder level identified by an assessment of the distribution grid, against any gaps identified for the planned future state. Grid needs may be associated with multiple distribution services.

"Integration Capacity" means a combination of hosting capacity, as defined in N.J.A.C. 14:8-5.1, and load-serving capacity. It is equivalent to the maximum amount of capacity available to new distributed generation or new load to connect to the distribution requiring minimal to no distribution upgrades or operational restrictions without violating any of the following technical restrictions: thermal, voltage, or distribution protection.

"Non-Traditional Distribution Solutions" means the utilization of distribution services offered by DERs to defer or replace traditional infrastructure upgrades or other identified grid needs when deemed cost effective. It means the same as non-wires alternatives or non-wires solutions.

"Proactive System Upgrade Plan" or **"PSUP"** means a comprehensive plan that provides an electric distribution company's: baseline distribution system assessment; three- and ten-year projection of distributed generation and load growth, anticipated grid needs; and the identification of cost-effective solutions to the anticipated grid needs in order to increase transparency, optimize investments, and reduce costs.

“Smart Inverters” means power electronics that can convert direct current (“DC”) output to alternating current (“AC”) while also providing grid-supporting capabilities such as islanding disconnection, ride-through capabilities and voltage/frequency support through four-quadrant power control. Smart inverters are compliant with the IEEE 1547-2018 standard, or other iterations of the standard adopted after 2018, and UL 1741 SB.

“Supervisory Control and Data Acquisition” or **“SCADA”** means a system of software and hardware elements that allows distribution system operators to remotely gather, monitor, and process data from sensors deployed along the distribution system.

“Transmission Services” means services provided by transmission service providers to transmission customers to move energy from a Point of Receipt to a Point of Delivery, encompassing both point-to-point and network integration transmission service as provided under the FERC-jurisdictional Open Access Transmission Tariff.

“Vehicle to Grid” or **“V2G”** means a system in which there is capability of controllable, bi-directional energy flow between a vehicle and the electrical grid. V2G is a specific application of what is known as V2X, which means “vehicle to everything”. Another specific application is “vehicle to building” or “V2B” which includes behind the meter exports such as home power backup.

“Virtual Power Plant” or **“VPP”** means an aggregation of distributed energy resources and other load modifying technologies that are enrolled either directly with an electric public utility or indirectly through a distributed energy resource aggregator and are operated in a coordinated manner to provide one or more grid flexibility services. These services can defer or avoid transmission or distribution upgrades, providing savings to the ratepayer. A VPP may include both behind-the-meter and front-of-the-meter resources interconnected to the distribution system.

1.3 VPP Straw Guiding Principles

PJM’s most recent capacity auctions have produced sustained price increases that flow directly to ratepayer bills, and PJM’s own load and resource adequacy forecasts contemplate the possibility of constrained reserve margins through the latter half of this decade absent timely additions of capacity, reduction of peak energy demand, or significant revisions to load forecasts, procurement mechanisms, such as PJM’s Reliability Backstop procurement (“RBP”) process. .[14] At the same time, the deployment of customer-sited solar photovoltaic (“PV”) systems, residential and commercial battery energy storage, smart thermostats, building energy management systems, electric vehicle (“EV”) chargers, and other connected devices is

[14] 2026 PJM Long-Term Load Forecast, January 23, 2026, Molly Mooney. PJM Load Analysis Subcommittee: 20260123-item-03---pjm-2026-long-term-load-forecast---presentation.pdf

accelerating. Properly configured aggregation and orchestrated dispatch of these resources can provide capacity, energy, ancillary services and locational distribution services to utilities and the wholesale market on faster timelines than costly traditional central-station generation or transmission and distribution ("T&D") system upgrades, and may introduce opportunity cost savings borne by ratepayers.

Staff, in order to build a long-term open market while realizing peak load shifting in the short term, acknowledges that there will be several steps before reaching our long-term goals. The first phase is a near-term, VPP Interim Program designed to leverage existing infrastructure and the current capabilities of EDCs to coordinate with third-party aggregators to reduce New Jersey's overall capacity commitment within PJM. The VPP Interim Program seeks to build on the existing DR framework under the Triennium Energy Efficiency Programs to reduce peak demand starting mid-2027 using existing BTM assets, AMI, and program experience drawn from a variety of BPU and EDC-led programs over the last decade. These savings will reduce participants energy costs, and will also help reduce future capacity needs resulting in lower costs in the PJM auction. The second phase will be designed as an evolution into a durable long-term framework – anchored by an open-access VPP tariff, an EDC-filed Proactive System Upgrade Plan ("PSUP") under New Jersey grid modernization efforts, a statewide approach to DER registration and aggregator qualification, and intentional coordination with the Energy Storage, Energy Efficiency, Clean Transportation, AMI, Solar, and NEM workstreams at the Board. The effort will position New Jersey DERs to substantively participate in PJM wholesale markets as soon as practicable, leveraging the most efficient and cost-effective approaches to retail and wholesale market participation.

The VPP Interim Program is expressly designed as a precursor to the long-term framework. Allowing enrolled DR and Pilot Program customers, AMI infrastructure, and other technologies proven in other jurisdictions to carry forward directly, with the transition paced to reflect the operational maturity that experience already provides, while the bilateral EDC-aggregator contracting structure is transitioned to an open-access tariff as the long-term VPP Programs. Together, the two phases build a grid that integrates customer-sited DERs as a reliable, dispatchable source of grid services like peak demand reduction, and thereby mitigates rising capacity costs for ratepayers as well as fairly compensates participating customers and aggregators for the measurable grid value they deliver across retail distribution and PJM wholesale markets.

Staff proposes the following guiding principles to govern the Board's development of the VPP Program in New Jersey. These principles are intended to balance speed of deployment with long-term market integrity, to preserve regulatory flexibility, and to protect ratepayers as the program matures while giving the EDCs a viable transition path into grid modernization needed to support the high penetration of DERs.

i. **Ratepayer Savings and Cost-Effectiveness Framework.** VPP programs must deliver measurable ratepayer savings over time. All program designs must include a robust cost-effectiveness analysis, performance, and reporting framework that protects ratepayers and considers fundamental benefits such as avoided PJM capacity market costs, avoided and deferred transmission costs, and avoided and deferred distribution costs. Additionally, broader benefits may be considered in the long term, such as reduced emissions in communities with/near emitting resources, further achieving stated emission reduction goals, increasing both local and state revenue and the creation of quality jobs. The Board will evaluate cost-effectiveness strategies for VPP programs.

ii. **Leveraging Existing Assets and Programs for Progressive Development of the VPP Interim Program.** The VPP Interim Program will be implemented through technology-neutral VPP programs administered by the EDCs that build on existing assets and infrastructure including, but not limited to, AMI, residential and commercial direct-load-control programs ("DLC"), flexible load management programs ("FLM"), and managed EV charging programs. These primarily "non-injecting" programs will serve as a bridge while the long-term tariff structure is developed and as the EDCs identify and develop the operational and procurement capabilities necessary to support open-market heterogeneous DER aggregations that can be configured and orchestrated for bidirectional capabilities. The VPP Interim Program is designed to deliver measurable peak demand reductions that reduce wholesale costs and avoids or defers grid investments, build market capacity, and operational track records across EDC service territories. The MFRs will require EDCs to achieve these outcomes whether through performance-based contracts with third-party aggregators or through direct EDC-administered dispatch using existing platforms.

iii. **Long-Term Open and Competitive Market Architecture.** In the long term, the Board will adopt structures that support a competitive market for third-party aggregators to build and operate VPPs. These VPPs should be capable of (a) serving as a peak-shaving and locational distribution resource for the EDCs, (b) participating in PJM's wholesale markets (capacity, energy, and ancillary services) as aggregated resources pursuant to FERC Order No. 2222, and (c) deferring or avoiding traditional infrastructure upgrades where possible.[15] The long-term framework should also support simple, non-discriminatory enrollment and exit of qualified participating resources, lowering barriers to aggregator entry and enabling a flexible and competitive market. Where competitive aggregation by third parties is likely to deliver value at lower long-term cost, that approach should be preferred; however, EDC-owned and/or EDC-operated solutions may be warranted as a use case to address localized capacity needs.

iv. **Value Stacking and Coordination Across Programs at NJBPU.** Aggregated DERs should be able to leverage their technology and device agnosticism to access multiple value streams simultaneously, especially when each of these value streams independently benefits the grid. The Interim program prioritizes reducing the overall capacity commitment for New Jersey using PJM's determined Network Service Peak Load

[15] Participation of Distributed Energy Res. Aggregations in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators, Order No. 2222, 172 FERC 61,247 (2020), order on reh'g, Order No. 2222-A, 174 FERC 61,197, order on reh'g, Order No. 2222-B, 175 FERC 61,227 (2021).

for each EDC service territory to conduct peak demand reductions to achieve cost savings, while collecting the operational data needed for the long-term success of the VPP program. All relevant BPU clean energy workstreams will be coordinated to reinforce the VPP program. The specific delineations between the VPP tariff and other programs such as PSUP, GridFlex Workgroup, and GSESP will be established through subsequent proceedings.

v. **Equitable Program Design and Inclusive Participation.** Program designs should reduce, and not reproduce, existing barriers to DER adoption and aggregation participation, particularly for low- and moderate-income ("LMI") households, renters, multifamily housing, small commercial customers, and customers in overburdened communities ("OBC"). This priority must be balanced by the fact that localized utility needs may create additional program opportunities in specific areas.

vi. **Integrating DER grid services into the EDC plans.** Programs designs should prioritize non-traditional distribution systems that provide cost savings. By encouraging EDCs to prioritize these cost-saving measures and integrate them into their PSUPs, ratepayers should be able to see the impact of deferred or avoided transmission and distribution costs.

vii. **Technology Neutrality and Interoperability.** Programs should be technology-neutral, device- and vendor-agnostic to the maximum extent practicable and should rely on open-standard communication protocols (including, where applicable, OpenADR 2.0b/3.0, IEEE 2030.5, CTA-2045, and Green Button Data Standard) to prevent vendor lock-in and to support heterogeneous DER aggregation portfolios.

viii. **Transparency and stakeholder engagement through public reporting and ongoing stakeholder input.** VPP Program performance – including, but not limited to, customer enrollment, events called, response rates, peak reduction achieved, savings achieved, and program costs will be reported in a standardized and publicly available format on the Board docket, with appropriate confidentiality protections for proprietary information. The Board will provide ongoing opportunities for stakeholder input on Program design and implementation through educational forums, technical conferences, roundtables, or written comments on the Board docket.

1.4 FERC Order No. 2222

In September 2020 the Federal Energy Regulatory Commission ("FERC") issued Order No. 2222, which required all Regional Transmission Organizations ("RTO") and Independent System Operators ("ISO") to revise their tariffs to allow DERs and DER aggregators ("DERA") to participate directly in wholesale markets.[16] Order 2222 defines a DERA as the direct participant

[16] Participation of Distributed Energy Res. Aggregations in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators, Order No. 2222, 172 FERC 61,247 (2020), order on reh'g, Order No. 2222-A, 174 FERC 61,197, order on reh'g, Order No. 2222-B, 175 FERC 61,227 (2021).

in the wholesale market on behalf of the individual DER owners. Order 2222 addresses several structural barriers that previously prevented DERs from wholesale market participation, including minimum size thresholds, telemetry and communication requirements, metering standards, and performance obligations designed for central-station generators. RTOs and ISOs were required to remove these barriers by establishing participation models tailored to the characteristics of DERs and aggregations thereof.

On May 1, 2025, FERC approved PJM's final compliance filing for implementing tariff revisions related to Order 2222.[17] PJM must implement tariff changes enabling DER aggregation participation in the energy and ancillary services markets by February 1, 2028, and has enabled DERA participation in the capacity market beginning with the 2028/2029 delivery year BRA. A DER Aggregator seeking to participate in the 2029/2030 BRA, which is set to occur in December 2026, must submit a notice of intent to PJM by June 12, 2026. To participate in the 2030/2031 BRA, set to occur in May 2027, Aggregators must submit a Notice of Intent by December 1, 2026. These near-term deadlines underscore the urgency of establishing New Jersey's VPP regulatory framework to ensure that the state's DER owners and aggregators are positioned to access wholesale market revenue streams as soon as permitted by PJM.

The Board's engagement on FERC Order 2222 has included: an initial RFI in March 2024 directed specifically to New Jersey stakeholders on Order 2222 implementation,[18] a Technical Conference held in January 2025,[19] at which PJM presented its DERA participation model and timeline, and EDCs, aggregators, and academics discussed registration, technical, and cost-allocation issues; and post-conference stakeholder comments addressing DERA registration, EDC roles, dispute resolution, code of conduct, cybersecurity, data access, double counting, dispatch override, cost allocation, and affordability.[20] This Straw Proposal is designed to address the principal issues identified through that engagement.

PJM’s May 2025 Order 2222 compliance filing, approved by FERC, establishes the DER Aggregator Participation Model (e.g., specific registration, telemetry, metering, and performance standards) that DERAs must satisfy to participate in PJM’s capacity, energy, and ancillary services markets. Key requirements directly relevant to the design of New Jersey’s VPP Program include the following: aggregation minimum size; component DER maximum size; telemetry and communication; AMI metering; performance assessment; and distribution utility coordination.

Staff notes that PJM's compliance filing also addresses the interface between state-level compensation and wholesale market payments and specifically provides that state-level distribution service payments do not create a barrier to wholesale market participation, provided

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[17] PJM Interconnection, L.L.C., 191 FERC 61,097 (2025).

[18] NJBPU Request for Information on FERC Order No. 2222, 2024

[19] Notice of Technical Conference, In re New Jersey’s Distributed Energy Resource Participation in Regional Wholesale Electricity Markets, BPU Docket No. EO24020116. Jan. 7, 2025.

[20] In re New Jersey’s Distributed Energy Resource Participation in Regional Wholesale Electricity Markets, BPU Docket No. QO24020116, dated Feb. 20, 2024

that appropriate protections against double-counting of the same underlying capacity service are in place.[21] This Straw Proposal's three-pathway compensation structure (**Section 3.3**) aims to be consistent with PJM's double-counting provisions to ensure that aggregations of DERs have access to the entirety of PJM's wholesale markets in addition to providing distribution-level grid services [under discussion as part of the Grid Modernization Forum's Grid Flex Services Workgroup.]

1.5 Procedural History

Below are the procedural histories of the relevant BPU workstreams that will inform, participate or otherwise impact the establishment of a VPP Program.

1.5(a) Triennium

The Clean Energy Act of 2018 ("CEA") plays a key role in achieving the State's goal of 100% clean energy by 2050 by establishing aggressive energy usage reduction requirements, among other clean energy strategies.[22] The CEA set in motion a comprehensive redesign of the State's EE and PDR program delivery framework. The CEA requires the Board to adopt quantitative performance indicators ("QPI"s) that represent reasonably achievable energy usage and PDR targets, taking into account the utilities' EE and other measures, including support of the development and implementation of building codes, appliance standards, New Jersey's Clean Energy Program, and other State-sponsored EE or PDR programs. The CEA also requires the Board to ensure that the utilities' incentives or penalties are based on performance and take into account the growth of EVs, microgrids, and DERs.[23]

Additionally, the CEA sets specific requirements for evaluation, measurement, and verification ("EM&V"), which include the following:

i. The EE and PDR programs shall have a benefit-to-cost ratio ("BCR") greater than or equal to 1.0 at the portfolio level, considering both economic and environmental factors.[24] The methodology, assumptions, and data used to perform the benefit-to-cost analysis (or cost-benefit analysis) shall be based upon publicly available sources and subject to stakeholder review and comment.[25] An individual program may have a BCR of less than 1.0 but may be appropriate to include within the portfolio if implementation of the program is in the public interest, including, but not

[21] PJM Interconnection, L.L.C., 191 FERC ¶ 61,097 (2025).

[22] L. 2018, c. 17 (N.J.S.A. 48:3-87.8 et seq.).

[23] Ibid. DERs refer to a variety of technologies that generate or store electricity at or near the point of use. These can include renewable energy sources, energy storage systems, electric vehicles ("EVs"), and demand response ("DR") technologies. DERs "can reduce utility bills . . ., help communities meet climate and equity goals[,] and make the electric grid more resilient." World Resources Institute, "How Distributed Energy Resources Can Lower Power Bills, Raise

[24] N.J.S.A. 48:3-87.9(d)(2).

[25] Ibid.

limited to, based on benefits to low-income customers or promotion of emerging EE technologies.[26]

ii. Each utility shall file with the Board implementation and reporting plans, as well as EM&V strategies to determine the energy usage and peak demand reductions achieved by the EE and PDR programs approved by the Board.[27] The filings are required to include details of expenditures made by the utility and the resultant reductions in energy usage and peak demand.[28]

iii. Each utility shall file an annual petition with the Board to demonstrate compliance with the EE and PDR programs, to demonstrate compliance with its performance targets, and for cost recovery of the programs.[29] If a utility achieves its performance targets, it shall receive an incentive as determined by the Board pursuant to N.J.S.A. 48:3-98.1 for its EE and PDR measures for the following year.[30] If a utility fails to achieve its performance targets, it shall be assessed a penalty as determined by the Board pursuant to the same statutory section.

Under the framework of the Triennium, the board has taken actions on multiple proceedings to implement the goals set forth by the Clean Energy Act of 2018. This includes:

1.5(a)(1) First Triennium of Energy Efficiency Programs (Triennium 1)

By Order dated June 10, 2020, the Board approved the first regulatory framework for EE programs implemented pursuant to CEA. From September 2020 through June 2021, the Board issued Orders approving stipulations of settlement for the EDCs to implement their EE programs. The first program cycle (July 1, 2021 through December 31, 2024) achieved aggregated statewide results of 4.1 million megawatt-hours of annual electricity savings, 11.7 million MMBtu of annual natural gas savings, and 3.1 million metric tons of annual greenhouse gas emissions reductions. While these results also demonstrate the scale of passive demand response potential in New Jersey, Triennium 1 did not direct the utilities to create demand response programs.

1.5(a)(2) Second Triennium of Energy Efficiency Programs (Triennium 2)

By Order dated May 24, 2023, the Board approved the following initial aspects of the Triennium 2 EE framework: program administration and design, filing and

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[26] Ibid.

[27] N.J.S.A. 48:3-87.9(d)(3).

[28] Ibid.

[29] N.J.S.A. 48:3-87.9(e)(1).

[30] N.J.S.A. 48:3-87.9(e)(2).

reporting requirements, cost recovery, EE as a resource, and EM&V.[31] By Order dated July 26, 2023, the Board approved additional aspects of the Triennium 2 ("T2") framework necessary for the utilities to submit their Triennium 2 filings.[32] Besides the core EE programs, the Order directed the utilities to propose building decarbonization and demand response programs. By Order dated October 25, 2023, the Board extended Triennium 1 by six months, ending on December 31, 2024, with budgets and energy savings targets adjusted accordingly. By Orders dated October 30, 2024, the Board approved petitions filed by each of the utilities proposing their T2 programs, including core EE programs and new Building Decarbonization ("BD") start-up and DR programs. T2 runs for two and half years from January 1, 2025 through July 1, 2027. Program Year 4 is January 1, 2025 to June 30, 2025. Program Years 5 and 6 align with the Board's fiscal years of 2026 and 2027. The DR MFRs directed the utilities to propose pilot DR programs. "Annual Demand Savings," defined as verified net peak demand savings (measured in Peak MW or peak-day therms), was a Quantitative Performance Indicator ("QPI") with a 10% weight in determining utility performance under a performance incentive mechanism. All net peak demand savings from both EE and DR programs were counted.

1.5(a)(3) Triennium 2.5 Straw Proposal

The Triennium 2.5 Straw Proposal, released on November 20, 2025, proposed a transition year between Triennia 2 and 3 (July 1, 2027 to June 30, 2028). The straw stated that the programs, including the DR programs, and their associated QPIs, shall remain unchanged for the transition year. On July 15, 2026, the Board approved the Triennium Program Year 7 Order establishing MFRs that aligned with the concepts in the Straw. The Order directs to the Utilities to continue the Triennium 2 DR programs as is until such time as the Interim VPP Programs are operational. The Order directs the utilities to reduce annual budgets by at least 25% and to set Triennium Program Year 7 budgets across programs proportionally to their Triennium 2 budgets. The approved statewide DR program budgets for Triennium Program Years 4, 5, and 6 are $12M, $22M, and $25M, respectively.

[31] In re the Implementation of P.L. 2018, c. 17, The New Jersey Clean Energy Act of 2018, Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs; In re the Implementation of P.L. 2018, c. 17, the New Jersey Clean Energy Act of 2018, Regarding the Second Triennium of Energy Efficiency and Peak Demand Reduction Programs; In re Electric Public Utilities and Gas Public Utilities Offering Energy Efficiency and Conservation Programs, Investing in Class I Renewable Energy Resources and Offering Class I Renewable Energy Programs in Their Respective Service Territories on a Regulated Basis, Pursuant to N.J.S.A. 48:3-98.1 and N.J.S.A. 48:3-87.9 - Minimum Filing Requirements, BPU Docket Nos. QO19010040, QO23030150, and QO17091004, Order dated May 24, 2023.

[32] In re the Implementation of P.L. 2018, c. 17, The New Jersey Clean Energy Act of 2018, Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs; In re the Implementation of P.L. 2018, c. 17, the New Jersey Clean Energy Act of 2018, Regarding the Second Triennium of Energy Efficiency and Peak Demand Reduction Programs; In re Electric Public Utilities and Gas Public Utilities Offering Energy Efficiency and Conservation Programs, Investing in Class I Renewable Energy Resources and Offering Class I Renewable Energy Programs in Their Respective Service Territories on a Regulated Basis, Pursuant to N.J.S.A. 48:3-98.1 and N.J.S.A. 48:3-87.9 - Minimum Filing Requirements, BPU Docket Nos. QO19010040, QO23030150, and QO17091004, Order dated July 26, 2023 ("July 2023 Order").

Based on the Order's budget guidance, the Triennium Program Year 7 budget for DR will be approximately $18M.

1.5(a)(4) Third Triennium of Energy Efficiency Programs (Triennium 3)

On November 25, 2025, the Board issued a Straw Proposal for the Third Triennium of the Energy Efficiency and Peak Demand Reduction Programs (Docket No. QO25050300) (Triennium 3). The Triennium 3 Straw Proposal identifies four focus areas: (1) energy affordability; (2) energy use intensity; (3) DR program and infrastructure advancements; and (4) energy assurance. The third focus area is particularly relevant to this VPP Straw Proposal. The Triennium 3 Straw Proposal included a Demand Flexibility ("DF") Roadmap that proposed the evolution from the Triennium 2 closed DLC programs toward open grid flexibility services markets, and explicitly anticipated that DF services could evolve to form an open-market solution involving the aggregation of behavioral DR, thermostats, small-appliance loads, battery storage, managed EV charging, and other DERs.

Last, the Triennium 3 Straw retained a peak demand savings QPI. However, Staff proposed to limit the peak demand savings from DR programs and exclude any DR savings from EE programs.

Staff notes that the Triennium 3 and VPP proceedings must be carefully coordinated to avoid duplicative or conflicting program designs and cost recovery. Specifically, where a Triennium 3 EE or DR program proposes to compensate customers for the same DER service that would also be compensated through the VPP tariff proposed herein, the programs should be consolidated or the compensation streams clearly delineated to prevent ratepayer double-payment. Staff anticipates that, following stakeholder comment on this Straw Proposal, it will work with program administrators and EDC staff to identify and resolve specific overlaps. **Section 4.3** of this Straw Proposal addresses the EE-VPP interface in greater detail.

1.5(b) Clean Transportation

The Board has advanced managed EV charging programs that support EV load management as a foundational component of the VPP Program. EO2 identifies electric vehicles, alongside other behind-the-meter DER assets, as resources that can be aggregated into VPPs to reduce peak demand.

1.5 (b) (1) Light-Duty Ecosystem

By Order dated October 20, 2020, the Board established Light-Duty ("LD") EV charging MFRs ("LD MFRs") which built a framework for charger deployment, managed charging, make ready planning, and EV charging infrastructure incentive programs.[33] Additionally, the Board established its own programming including the Charge Up New Jersey Home Charger, as well as a suite of commercial charging incentives, including Clean Fleet, Multi-Unit Dwelling ("MUD"), and EV Tourism incentives.

Both the EDC and BPU programs required incentive recipients to install networked, Wi-Fi enabled chargers which are capable of managed charging and data collection. The Board's commercial charger incentives also required grantees to install dual-port chargers to reduce the number of make-ready installations required.

Additionally, BPU's programs required that applicants share data with the Board. This data provides Staff with insight into charging behaviors across the residential, MUD, quasi-public, and public settings and informs Staff's development of managed charging recommendations under the upcoming Light Duty Rules.

In the LD MFRs, the Board required the EDC programs to implement residential managed charging solutions. In response, the EDCs offered incentives for off-peak overnight charging. The Light Duty Rules will build on this foundation by beginning the transition to active managed charging and more dynamic pricing. There are also significant opportunities to shift lengthy charging sessions to overnight hours in MUD and public level 2 sectors.

. Public Level 2 chargers can reduce daytime loads and improve charger availability through time-of-use incentives that shift charging sessions to overnight hours. Public fast chargers co-located with storage present additional VPP integration opportunities, using stored energy to offset demand charges and reduce peak grid draw.

The Board called for the EDCs to propose programs that "incent EV owners to use charging services in a manner that has the least impact on the reliability and costs of [an EDC's] distribution system."[34] The routine load management components (i.e. TOU rates) of the EV ecosystem will be addressed in upcoming Light Duty rulemaking while the event-based EV load management components are addressed in this VPP proceeding. Both proceedings are intended to complement and work in tandem.

The data collected from these programs can serve as a ready resource when creating VPPs to effectuate EO2.

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[33] In the Matter of Minimum Filing Requirements for Light-Duty, Publicly-Accessible Electric Vehicle Charging, BPU Docket No. QO20050357.

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

1.5 (b) (2) Medium-and- Heavy-Duty "(MHD") Utility Incentive Programs

By Order dated October 28, 2024 (October 2024 Order), the Board furthered load management policy by establishing[35] MFRs that required the EDCs to propose managed charging programs for fleets. As fleets may have many vehicles charging concurrently at a single location, they can have large peaks. Requiring private fleets that utilize EDC incentives to enroll in a managed charging program not only reduces peak demand; it also allows for data collection to better understand fleet charging behaviors. The MFRs required EDCs to offer such managed charging programs to public fleets. These insights, combined with the data from the LD programs, will help develop future managed charging programs. Additionally, these MFRs laid the groundwork for colocation, V2G, and interconnection.

1.5(c) Energy Storage

The Board has advanced the Garden State Energy Storage Program ("GSESP"), New Jersey's primary vehicle for accelerating energy storage deployment across the state. On June 18, 2025, the GSESP was launched, following a 2-year period of extensive stakeholder engagement. The GSESP's 2025 launch opened its first tranche of Phase 1, which solicited 350-750 MW of transmission-scale storage projects ("Tranche 1"). On May 20, 2026, the Board awarded incentives to three utility-scale energy storage projects totaling 355 MW under Phase 1, Tranche 1, and subsequently launched Tranche 2, which has attracted strong market interest. Staff is currently preparing for final bid submissions and Board consideration of Tranche 2 awards. While a stakeholder process has been previously conducted on Phase 2, this Straw Proposal seeks additional input on Phase 2 design to ensure coordination with the VPP program. Phase 2 is intended to provide incentives in proportion to the value a project provides, through mechanisms such as reduction of peak load and/or injection of power into the distribution system during performance periods.

1.5(d) Grid Modernization

The Grid Modernization initiative is guided by a thorough compilation of stakeholder comments and learned best practices from other states on DER interconnection reform, summarized in the Grid Modernization Report, which the Board accepted on November 9, 2022,[36] while tasking staff with implementing the nine recommendations. The recommendations were as follows:

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

[36] In re Modernizing New Jersey's Interconnection Rules, Processes, and Metrics, BPU Docket No. QO21010085, Order dated Nov. 9, 2022.

i. Implement the Institute of Electrical and Electronics Engineers standard 1547-2018 across all EDC service territories;

ii. Streamline and automate the interconnection application process;

iii. Improve the accuracy and usability of public-facing EDC hosting capacity maps;

iv. Establish a mandatory pre-application process for DERs above a certain threshold;

v. Update EDC tariffs to incorporate new rules;

vi. Improve the efficiency of sequencing interconnection studies;

vii. Update methodologies for determining distribution infrastructure upgrade cost allocation and estimation;

viii. Develop proactive integrated DER plans; and

ix. Interconnect hybrid resources that include both emitting and non-emitting energy resources behind a single meter.

The first four recommendations were implemented via amendments and new rules at N.J.A.C. 14:8-5, which govern the interconnection process for DERs. The formal rulemaking proceeding spanned from initial proposal in June 2024 to final adoption in January 2026.

The Board developed the GMF, a collection of expert stakeholder workgroups, to develop specifics around the latter recommendations in the Grid Modernization Report, which focus on increasing DER hosting capacity and grid flexibility in New Jersey. To date, the GMF has launched two workgroups. The first workgroup is IDDER,[37] whose goal is to develop an MFR for EDCs to file PSUPs that provide baseline distribution assessments, more granular and sophisticated load and DER generation forecasting, and the identification of cost-effective potential solutions for future grid needs. As a whole, each EDC's PSUP will describe the evolution of its distribution grid into a more adaptive, flexible system with higher DER hosting capacity and with lowered barriers to DER participation for valuable grid support services. The second workgroup is the Grid Flexibility ("GridFlex"),[38] Services Workgroup with the goal to develop a service architecture for future tariffs that enable interoperable DERs to provide distribution-level services – such as energy injection and voltage management – to the EDCs and be compensated for those services. This service architecture-driven tariff will form the foundation for the long-term

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

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

VPP program.

On May 8, 2026, the Board released the PSUP Straw under the Docket No. QO24030199 to solicit stakeholder comments. Because the PSUP MFR has not yet been finalized, Staff expects the VPP Programs design to be revisited as needed to remain consistent with the distribution plans that the EDCs ultimately file. As set forth in the PSUP straw, Staff envisions that the PSUP MFR will require EDCs to propose a plan to develop and evolve to develop platforms (which includes both a "Grid DERMS" and the interoperable "Edge DERMS") as a foundational operational platform for orchestration of the long-term VPP Programs.

1.5(e) Advanced Metering Infrastructure ("AMI")

The Board is advancing AMI Data Access Standards that are foundational to VPP operations. In September 2025, the Board proposed new rules under N.J.A.C. 14:5-10 establishing customer ownership of Advanced Metering Infrastructure meter data, standardized data sharing through the Green Button Data Standard, and enabling third parties access to interval data through an electronic data interchange using the EDCs' supplier web portals.[39] By enabling aggregators and VPP platforms with timely access to granular, interval-level usage data (with proper customer authorization), these rules can directly support the enrollment, dispatch, measurement and verification and compensation functions that an effective VPP Program will require, without requiring duplicative and costly additional metrology. At its June 30, 2026 meeting, the Board approved the Notice of Adoption of the AMI Data Access Standards for publication in a subsequent edition of the New Jersey Register. These rules will become final upon publication.

1.5(f) Solar and Net Energy Metering ("NEM") Reform

Under current net energy metering policy, customer-generators are credited at the full retail rate for each kilowatt-hour produced by a class I renewable energy system installed on the customer-generator's side of the electric revenue meter, up to the total amount of electricity used by that customer during an annualized period.[40] The authorizing statute permits the Board to allow an electric power supplier or basic generation service provider to cease offering net metering to customers that are not already net metered. Board Staff has initiated a proceeding with a robust stakeholder process to develop recommendations to the Board for potential implementation of an updated mechanism of net metering for new customers that facilitates the State's least-cost path to achieve its clean energy goals, supports the State's solar industry, and promotes equity in access to the benefits of clean energy. Staff hosted the first public stakeholder meeting in November 2024 and a technical conference in February 2025. Staff anticipates a report to be released in 2026. Staff intends for any proposal for future compensation mechanisms for distributed renewable

[39] 57 N.J.R. 1949(a) (Sept. 2, 2025).

[40] N.J.S.A. 48:3-112

energy resources to consider how it would integrate with systems with energy storage and participation in VPP Programs.

1.5(g) VPP Request for Information ("RFI")

On April 20, 2026, the Board issued a RFI under Docket No. QO26030099 to solicit stakeholder feedback on the design of the VPP Program.[41] By the May 20, 2026 deadline, Staff received responses from a diverse group of parties spanning multiple stakeholder categories, including all NJ EDCs, third-party DER aggregators, DERMS and technology platform providers, energy storage developers and operators, trade groups, advocates, and members of the public. Staff has carefully reviewed the full RFI response record and incorporated relevant lessons and stakeholder recommendations throughout this Straw proposal. Key themes included:

i. **Phased program design with ratepayer safeguards:** Stakeholders broadly support a minimum viable product ("MVP") approach for near-term implementation, building on existing AMI platforms, direct load control programs, and established demand response customer bases. The initial program should deliver measurable peak load reductions while generating the operational data needed to refine the long-term open-access tariff framework. Stakeholders further recommend that defined budget caps and performance benchmarks be established before ratepayer funds are committed.

ii. **EDC and aggregator coordination:** EDCs and third-party aggregators hold different views on program administration. EDCs generally support utility-centric program administration, EDC-managed DER registries, and distribution-first dispatch authority to protect grid reliability. Third-party aggregators and other stakeholders emphasize the need for a statewide DER registry, standardized cross-EDC data access, and a competitive procurement framework to enable market participation.

iii. **Interoperability, technology neutrality, and EM&V:** Stakeholders broadly support open interoperability standards, technology-neutral resource eligibility, and EM&V. There is strong consensus on the need for explicit anti-double-counting guardrails and a benefit valuation framework that accounts for avoided capacity costs, deferred T&D investment, and emissions reductions alongside direct bill savings.

iv. **Value stacking and PJM wholesale integration:** Stakeholders emphasize the importance of enabling value stacking across retail and wholesale market revenues. Many identify PJM's Order 2222 compliance timeline as an immediate

[41] In re Advancing Virtual Power Plant (VPP) Program in the State of New Jersey, BPU Docket No. QO26030099, Notice dated Apr. 20, 2026.

design constraint, requiring near-term retail program infrastructure that aligns with wholesale market registration and telemetry requirements.

v. **Equitable access as a program performance standard:** Stakeholders urge the Board to treat equity as a measurable program outcome, including dedicated pathways and enrollment support for low- and moderate-income ("LMI") households, renters, multifamily buildings, and overburdened communities ("OBC").

1.5(h) VPP Roundtable with NJ EDA

On April 24, 2026, the New Jersey Economic Development authority ("NJEDA"), in partnership with Board Staff, convened a VPP Roundtable bringing together clean energy developers, DER aggregators, technology providers, and industry experts to identify opportunities and barriers to VPP implementation in New Jersey, discuss potential program design, and strengthen partnerships in support of the State's clean energy goals. Discussion focused on three topic areas: the existing policy and regulatory environment, partnership opportunities between public and private sector actors, and implementation strategy and future priorities, including cost allocation, infrastructure ownership, and equity considerations. Participants also examined how existing BPU workstreams could be better coordinated to accelerate VPP deployment and support a self-sustaining open VPP market over the long term. Staff has incorporated the perspectives and recommendations from this roundtable throughout this Straw Proposal.

1.5(i) VPP Roundtable with EDCs and the Division of Rate Counsel

On June 16, 2026, Board Staff convened a roundtable with representatives from all four New Jersey EDCs and the Division of Rate Counsel to solicit early input on the design of the VPP Programs prior to issuance of this Straw Proposal. The session was structured as a facilitated dialogue rather than a formal proceeding, with EDCs and the Rate Counsel presenting their respective perspectives and Staff posing questions on short- and long-term program considerations. Several areas of consensus emerged from the discussion, including a shared preference for building upon existing demand response programs through a phased, pilot-first approach before scaling; technology-neutral and device-agnostic program design; and the importance of affordability as the central evaluative standard for any VPP program. Participants also discussed the operational and investment requirements associated with standing up longer-term compensation mechanisms and the potential role of PJM capacity market participation in offsetting ratepayer costs. Staff has incorporated the perspectives and lessons from this roundtable throughout this Straw Proposal.

SECTION 2. VPP INTERIM PROGRAM

2.1 Program Purpose, Design Philosophy, and Objectives

Staff proposes a two-year VPP Interim Program framework that operates from **2027 to 2029** as the first phase of New Jersey's two-phase VPP implementation and would require each EDC to submit interim VPP programs filing, consistent with a Board-issued MFR Order, for its specific VPP Interim Programs to satisfy the vision that is laid out in this VPP Straw. The VPP Interim Programs should form an extension of the current DR and VPP Pilot Programs within the Triennium, building upon those learnings to better address long-term goals, collect necessary data points, and create the appropriate guardrails to ensure program efficacy and efficiency. The VPP Interim Programs will produce measurable near-term peak demand reductions while the long-term open-market compensation-based tariff structure, aggregator qualification framework, and enhanced grid infrastructure are established. The VPP Interim Programs are expressly intended as a transitional mechanism – not a permanent program – and the design should facilitate, rather than impede, the migration of enrolled DER assets into the long-term tariff framework as that framework becomes operational in the future.

The VPP Interim Programs will be technology-neutral, meaning they should not specify or grant preference to particular DER types or manufacturers, and instead be defined by the grid services to be delivered and the technical requirements necessary to demonstrate reliable delivery. The programs will build directly on existing AMI infrastructure, EDCs' Triennium 2 DR programs, and enrolled customer bases from Triennium 2 DR to reduce program launch costs and accelerate time to scale. The Triennium Program Year 7 Board Order calls for the existing DR programs to continue and notes that they will migrate to the VPP Interim Program in the future. This migration is an acknowledgement that the Board wants to continue the programs without interruption until the VPP Interim Programs are established.

Staff proposes the following primary objectives for the VPP Interim Programs:

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 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.

ii. Demonstrate the reliable and accurate delivery of grid services using existing utility and DER Aggregator systems, and demonstrate EM&V capability using existing AMI systems;

iii. 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;

iv. 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;

v. 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.

vi. 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.

vii. 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.

viii. 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.

ix. Evaluate the potential for VPPs to lower costs for both participants of the program, as well as for all ratepayers.

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.

2.2 Technology-Neutral Eligibility and Participating Resources

The VPP Interim Programs shall be open to all DER types capable of delivering dispatchable demand reduction on a reliable, event-driven basis. Consistent with the guiding principle of technology neutrality, eligibility is not limited to any specific device class, vendor, or communication platform. Staff further proposes the following program design parameters governing resource eligibility, aggregation thresholds, and technical standards for the Interim Program:

i. **Existing Infrastructure and Program Migration:** All VPP Interim Programs shall be designed to build on existing grid infrastructure and customer-owned DER assets rather than requiring new customer-side hardware at program launch. EDCs are expected to utilize their existing and future deployed infrastructure – including, but not limited to, smart thermostats, smart water heaters, EV chargers, solar, and storage – as the initial resource base. Additional devices may be added over the program period through hardware incentives offered under other Board-approved programs, including, but not limited to, the EV residential charging program and the Triennium programs, provided those incentives do not duplicate VPP compensation streams. Staff further expects EDCs to apply the operational and enrollment learnings from their Triennium 2 DR portfolios. Existing DR and VPP pilot programs currently approved under a Triennium proceeding shall migrate to the VPP Interim Programs for appropriate Board approvals and cost recovery. Programs that migrate from the Triennium 2 DR portfolio to the Interim Programs should start on July 1, 2027; VPP Interim sub-programs that were not part of the Triennium 2 DR portfolio should start on June 1, 2027, so the new resources are operational to most fully account for the 2026 Summer 5CPs recorded by PJM.

ii. **Residential Storage:** While the focus of the VPP Interim Programs shall be on compensating existing grid resources, Staff recognizes that the existing DR programs within the Triennium 2 framework also provided incentives for the installation of residential storage in certain territories. Residential storage is a key component of many VPP programs in other territories outside of New Jersey and Staff proposes to allow the EDCs to propose such incentives in their VPP Interim program to ensure that we do not lose momentum on programs already established. Any proposal for such sub-programs shall include eligibility criteria, incentive levels and the calculations that were utilized to establish such incentive levels to determine the gap needed to bring the technology to market.

iii. **Minimum Aggregation Size:** Staff proposes a minimum aggregation size threshold of 10 kW per program event. This threshold is intentionally set lower than the 100 kW proposed for the long-term tariff to reflect the different cost structure of the Interim Program, where EDCs and contracted third-party aggregators may operate with lower per-device administrative overhead than independent aggregators seeking to recover costs through competitive market revenue alone.

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.

	c. Staff further seeks comment on whether the 10 kW interim threshold should be measured as enrolled capacity or as capacity deliverable during a dispatch event, and on how it should relate to the 20 kW distribution-service threshold proposed in Section 3.5.

iv. **Communication Standards and Protocols:** The VPP Interim Programs shall accept devices using any open-standard communication protocol supported by the relevant EDC's AMI or DLC platform, including but not limited to OpenADR 2.0b/3.0, IEEE 2030.5, and CTA-2045. Each EDC's MFR filing must disclose the specific protocols currently supported by its infrastructure and provide a roadmap for expanding protocol support to cover additional device classes by a date to be specified in the MFR Order. This filing shall maintain consistency with the longer-term EDC-filed PSUP.

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.

2.3 Enabling Technologies

The VPP Interim Programs should utilize the experiences and program architecture of the demand response programs that were stood up in response to Triennium 2, as well as the existing AMI infrastructure that New Jersey EDCs have deployed or are actively deploying.

Each of NJ's four EDCs has achieved substantial AMI penetration.[42] AMI meters provide the interval-level (typically 15-minute) energy usage data that are foundational to VPP programs' functions, including, but not limited to:

i. **Customer enrollment verification**: confirming that enrolled accounts have interval metering and that baseline consumption can be established;

ii. **Event performance measurement**: measuring the demand reduction achieved by an enrolled resource during a dispatch event against a baseline calculated from pre-event AMI data; and

[42] In re The Petition of Atlantic City Electric Company for Approval of The Smart Energy Network Program and Cost Recovery Mechanism and Other Related Relief, BPU Docket No. EO20080541, Order dated July 14, 2021; In re The Petition of Public Service Electric and Gas Company for Approval of Its Clean Energy Future-Energy Cloud ("CEF-EC") Program on a Regulated Basis, BPU Docket No. EO18101115, Order dated Jan. 7, 2021; In re The Petition of Rockland Electric Company for Approval of an Advanced Metering Program; and For Other Relief, BPU Docket No. ER16060524, Orders dated August 23, 2017 and Feb. 19, 2020; In re The Verified Petition of Jersey Central Power & Light Company for Approval of an Advanced Metering Infrastructure (AMI) Program (JCP&L AMI), BPU Docket No. EO20080545, Order dated Feb. 23, 2022.

iii. **Long-term VPP program evaluation**: tracking enrolled customer usage patterns over time to assess program impacts and inform program design improvements.

Staff notes that AMI alone is not sufficient for VPP program operations. AMI provides the measurement layer; dispatch control requires a separate communication channel to enrolled devices. The current EDC DR partner platforms (e.g., aggregators, OEMs) that support the Triennium 2 DR Programs (e.g., two-way radio, cellular, and other communications used for thermostat and load control switch programs) provide this dispatch layer for the Interim program. Staff expects that the VPP Interim Programs MFR Order will require each EDC to document its partners' existing dispatch communication capabilities, the estimated number of enrolled devices and customer accounts eligible for VPP Interim Programs participation, and any gaps or constraints that may limit program scale in the near term.

Staff also notes the AMI Data Access Standards rulemaking under N.J.A.C. 14:5-10,[43] which establishes customer ownership of AMI data, standardized data sharing through the Green Button Standard, and non-discriminatory third-party access to that data in support of the long-term aggregator-led market.

Through other proceedings, some EDCs have established Grid DERMS that may also assist in coordinating demand response programs through the coordination of FOM devices. Staff expects that the Board will not require or support recovery of large EDC owned infrastructure as part of the VPP Interim Programs but will primarily aim to utilize existing resources to see peak reductions quickly. The PSUP mechanism may enable EDC planning for DERMS investment, and the long-term VPP Program may require EDC investment for Grid DERMS, and opportunities to competitively bid for third-party edge DERMS providers that can allow additional capabilities.

2.4 EDC Program Budgets

Staff proposes the following preliminary budget allocations for the 2-year VPP Interim Program. These allocations are designed to reflect the scale of each EDC's service territory and existing program infrastructure, recognizing that PSE&G has already planned a VPP pilot and relevant operational demand response programs thus has lower start-up costs than other three EDCs. Staff emphasizes that these are preliminary proposals and that the Board may establish final budgets in the MFR Order following stakeholder comment.

EDC	Proposed Budget (2027– September 30, 2029)
PSE&G	~ $30 million
JCP&L	~ $16 million
ACE	~ $20 million

[43] In re Advanced Metering Infrastructure (AMI) Data Access Standards, BPU docket No. EX24090717, proposed new rule dated Sep. 2, 2025.

EDC	Proposed Budget (2027– September 30, 2029)
RECO	~ $2.0 million

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

The proposed budget is intended to cover:

i. **Administration, Program Implementation**: costs to administer the program, including EDC staff time, and costs associated with contracted implementation contractors ("IC") and incremental technology and integration necessary to connect enrolled devices to the EDC's VPP dispatch platform.

ii. **Customer Incentives**: enrollment and performance-based payments to enrolled participants (to be established in the MFR filings).

iii. **Evaluation, Measurement, Verification (EM&V)**: cost associated with baseline development and performance verification, including the program evaluation described in **section 2.6**; and

iv. **Marketing**: customer outreach, education, and enrollment marketing, including marketing conducted jointly with OEMs and third-party aggregators; and

v. **Others**: costs that do not map to the categories above.

Each EDC shall propose, in its MFR filing, the allocation of its proposed program budget across the categories above and create budget worksheet described in **Section 2.9**. Hardware incentives that facilitate enrollment in VPP-eligible programs, including, but not limited to smart thermostats, EV chargers, and storage systems, are proposed to be addressed separately through the Triennium Program Year 7 and Triennium 3 Energy Efficiency Program and GSESP Phase 2 programs, with VPP enrollment as a condition of receiving the incentive.

Stakeholder Comments 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.

The Board anticipates that EDCs will be required to file VPP Interim Program proposals by December 31, 2026, and that programs that had previously been in Triennium 2 will continue to be operational in the VPP Interim Programs by July 1, 2027 and all other VPP sub-programs will be operational by June 1, 2027. Each EDC proposal should address, at a minimum, the following elements, each as further specified in the MFR in Section 2.9:

i. Target Customer Class(es)

ii. Eligible DER types and enrollment process

iii. Event dispatch protocol and notification timeline

iv. Customer incentive structure, which may include a residential storage incentive

v. Performance measurement and baseline methodology

vi. Strategies to comply with all standards and guidelines outlined in the MFRs, which are proposed within Section 2, 5, 6, and 7 of this document as applicable.

vii. Data reporting and EM&V plan; and

viii. Strategy for transitioning enrolled resources to the long-term VPP Program framework.

Stakeholder Comments 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.

2.5 Event Dispatch Protocol

Staff proposes that VPP Interim Programs dispatch events be structured as defined curtailment events during periods of high grid stress, as determined by the EDC in coordination with PJM. Events may be triggered by, for instance, system peak conditions, distribution-level thermal constraints, or PJM energy market conditions. Staff proposes the following preliminary event parameters, which will be refined through the MFR process. Staff also suggests that EDCs should be able to propose additional dispatch opportunities and rules to maximize cost savings to the customer:

i. **Maximum event duration**: 4 hours per event;

ii. **Maximum number of events per season**: 20 events per summer season (June 1-September 30) and 10 events per winter season (December 1-February 28), with a total of no more than 35 dispatch events per calendar year, inclusive of any events called outside the defined summer and winter windows (e.g., in response to an unplanned reliability need in the spring or fall months, test calls to ensure system readiness not included in this total count);

iii. **Minimum advance notification**: 2 hours for standard events; 10 minutes for emergency events;

iv. **Opt-out provisions**: Customers should be provided the ability to opt out of any individual event, subject to the understanding that frequent opt-outs may affect customer incentive payments.

Staff proposes that the EDC's dispatch platform be capable of segmenting enrolled resources by locational node, technology type, and response capability, enabling the EDC to dispatch only those resources that provide locational coincident value during a specific event. This geographic targeting capability is essential for demonstrating the distribution-level locational value of DERs, which will be a key input to the long-term compensation methodology described in **Section 3.**

Stakeholder Comment No. 7	Staff requests feedback on: a. Whether the proposed preliminary event parameters are appropriate or more refined and aggressive parameters are needed; b. What requirements and evaluation criteria the Board should apply in reviewing EDC-proposed dispatch parameters; c. 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; and d. The creation of structures that will best maximize cost savings to customers and ratepayers.

2.6 Performance Measurement, Reporting, and Program Review

Staff proposes that performance measurements for the VPP Interim Program be based on a customer-specific baseline methodology using verified AMI interval data. The baseline for each enrolled account should be calculated as a weighted average of the account's usage during a specified number of non-event days immediately preceding the event. The EDC MFR Order will specify requirements for the baseline methodology; each EDC shall propose its exact methodology in its MFR filing, including the number of reference days, adjustment factors for weather normalization, and treatment of accounts with seasonal load profiles.

The cadence, content, and confidentiality treatment of EDC reporting to the Board for the VPP Interim Program – including quarterly, annual, post-season, and event-level reporting – are set forth in **Section 2.9**.

The interim program is designed to move quickly to generate short term savings for ratepayers but to create a framework for long term savings through a prioritization of grid services and non-wires alternatives to solve for distribution and capacity needs. In reviewing how to most appropriately quantify these savings Staff looked at the savings tests currently utilized by the Energy Efficiency programs:

i. Ratepayer Impact Measure ("RIM")

ii. Total Resource Cost ("TRC")

iii. Societal Cost Test ("SCT")

iv. Program Administrator Cost Test ("PACT")

v. Participant Cost Test ("PCT")

vi. New Jersey Cost Test ("NJCT")

Staff determined that the RIM is the most appropriate way to evaluate the program and to be able to compare its efficacy to other EDC and BPU programs. The TRC test helps to quantify the avoided distribution costs as well as the avoided cost of building new capacity but does not yet provide a way to quantify savings from reduced capacity market obligations. Staff suggests that a new metric be created to quantify this additional savings along with what the current TRC quantifies. The SCT and the NJ Cost Test include non-monetary elements, including emissions reductions that are not part of the goals of this Interim Program. The PCT evaluates the cost to the participant vs the savings generated, in this proposal there is not a cost to the participant, there is only the opportunity to gain revenue from curtailing certain use, thus the PCT is not relevant to this program. Lastly the PACT reviews the program from the administrator's perspective to determine that it is cost effective for the utility. This particular test may not be relevant to the current metrics as the Board is currently pursuing a new Business Model, such a test should be revisited once the new model is determined and new metrics are identified.

Staff further proposes that a comprehensive program evaluation report be completed no later than twelve months after program launch (by approximately Q2 2028). This evaluation is proposed to assess program cost-effectiveness using some or all of the following tests: the New Jersey RIM, and TRC, and analysis identified by the Board to appropriately measure the deferred and avoided transmission and distribution costs. The evaluation will also assess performance against the peak reduction targets established in the MFR Order. Based on the evaluation findings, the Board will determine whether the VPP Interim Program should be continued, modified, expanded, or phased out in favor of the long-term VPP Program framework. This evaluation will draw on the quarterly, annual, and post-season reports described in **Section 2.9**.

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.

2.7 Program Targets

A successful VPP program will not only achieve peak demand savings as outlined in EO2 but will ensure those savings translate into cost savings for all ratepayers, not just program participants.

2.7(a) Peak Demand Reduction

The following table presents Staff's preliminary estimates of near-term PJM 5CP peak shaving potential for each EDC service territory, based on 2026 PJM peak load data[44], expressed as a range of peak reduction target (see Table 1 and Appendix A). Staff proposes these figures as a planning reference, not as binding targets for the VPP Interim Program, pending refinement through EDC PSUP filings and stakeholder engagement. Staff notes that additional peak and ancillary services opportunities depend on many factors, including, but not limited to locational coincidence between DER availability and distribution-level grid constraints, which will be more accurately characterized through the EDC PSUP filings (upon future adoption by the Board). Staff also notes that additional potential exists in non-peak-coincident resources, including, but not limited to, capacity, energy, and ancillary services, that the long-term VPP Program framework is designed to capture.

Each EDC shall propose a peak demand reduction target, expressed in MW, for the first full operating year of the VPP Interim Program. Table 1 presents Staff's preliminary reference range for each EDC, derived from PJM's 2026 Network Service Peak Load ("NSPL") data. Each EDC's MFR filing shall identify a target at or above 3%, or justify a deviation below it, and shall in either case provide the assumptions underlying the proposed target. The figures in Table 1 are illustrative and become final only through the MFR Order for the VPP Interim Program. Staff recommends a target of no less than 3%. This target is more aggressive than the traditional Triennium goal of 2% overall reduction and also reflects the importance of using peak shaving to drive cost savings for participants and ratepayers. Establishing aggressive goals at the outset helps build a market that can sustain itself without subsidy.

[44] PJM Network Service Peak Loads (NSPL) for 2026, PJM Interconnection L.L.C.

Electricity Distribution Company	Peak Load (MW)	2% (MW)	3% (MW)	4% (MW)	5% (MW)	6% (MW)	7% (MW)
PSE&G	10,229.5	204.6	306.9	409.2	511.5	613.7	716.1
JCP&L	6,273.4	125.5	188.2	250.9	313.7	376.4	439.1
ACE	2,709.1	54.2	81.3	108.4	135.5	162.5	189.6
RECO	422.9	8.5	12.7	16.9	21.1	25.4	29.6

Table 1. Potential Peak Shaving Goals for NJ EDCs (2026 Peak Load Basis)

In reviewing the projected peak demand savings, Staff also considered the savings that would result from prioritizing grid services and non-wires alternative solutions over traditional infrastructure on the distribution and transmission system. Staff estimates that by achieving the 3% peak demand reduction target, New Jersey ratepayers could avoid roughly $60 million in capacity payments.[45] This estimate is based on capacity pricing, rather than the avoided costs traditionally used in the TRC test, which combined points to even greater savings potential than shown here.

2.7(b) Cost Savings

The VPP Interim program is designed to move the market to deliver cost savings to customers while developing the correct administrative and market parameters. Cost savings from VPPs come from several different buckets:

i. **Participant Savings:** Customers that participate in VPP programs can see near immediate savings on their energy costs, from reduced energy use during peak events and additional revenue earned by responding to curtailment calls that offsets their utility bills;

ii. **Avoided transmission and distribution costs:** Using VPPs, especially for localized constraints can create significant savings for the utility – and thus the ratepayer – by delaying or avoiding altogether the need to upgrade the distribution system. These avoided costs can be quantified through the Total Resource Cost Test ("TRC Test"); however, as discussed in section 2.6, Staff proposes to develop a methodology that more fully captures realized ratepayer savings.

[45] See Appendix A for a more detailed breakdown of the methodology and assumptions used in this estimate.

iii. **Avoided capacity costs:** Using VPPs to reduce projected peak load reduces the amount of capacity that zone needs to procure and thus reduces overall capacity costs for that zone.

iv. **Avoided Energy costs**: VPPs that respond during peak demand events can reduce reliance on high-cost peaking generation, lowering wholesale energy market costs. Staff notes that the pass-through of these savings to customers is shaped by the Basic Generation Service ("BGS") procurement process.

In addition to the peak demand reduction target in Section 2.7(a), each EDC shall propose cost-reduction goals derived from VPP participation and non-wires alternatives. Such goals shall include all four (4) savings categories outlined above, and may include other savings opportunities where described in detail, including but not limited to:

i. PJM capacity market savings from reduced capacity obligations identified by the 5CP;

ii. Transmission cost savings from projects avoided or deferred due to a reduction in capacity identified by the 5CP, as applicable;

iii. Reduced allocated capacity and transmission charges from reduced peak demand as identified by the 5CP;

iv. Distribution cost savings from projects deferred or avoided, as applicable; and

v. Total cost reduction relative to the counterfactual (expressed both in nominal terms) as an impact on residential rates.

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.

2.8 EDC and Third-Party Aggregator Coordination Framework for the VPP Interim Program

The Interim Programs are proposed to be EDC-administered, delivered in practice through a combination of EDC staff and contracted Implementation Contractors ("IC") – consistent with the operating model of New Jersey's Triennium 2 DR pilots. Staff recognizes that third-party aggregators are essential for a competitive, open-access VPP market and bring specialized enrollment capabilities, technologies, customer relationships, and competitive cost that EDCs alone cannot replicate at scale. This section describes the selection process on a competitive basis that will evolve into the open-market architecture this Straw Proposal is designed to build.

Under the existing Triennium 2 DR pilot model, operational responsibilities are typically divided between the EDC and its contracted Implementation Contractor as follows: the EDC calls dispatch events, provides AMI data to the Implementation Contractor, and coordinates marketing and customer sign-up (in coordination with OEMs where applicable); the Implementation Contractor operates the edge DERMS, controls enrolled devices, and verifies event performance. Communication with PJM regarding aggregated DER performance has historically been an EDC function, though it is not currently active under existing pilots. As the VPP Program evolves toward the long-term, Order 2222-aligned framework described in **Section 2.8(c)** and **Section 3**, some of these functions may be better positioned with third-party aggregators rather than the EDC or its Implementation Contractor.

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.

2.8(a) Customer Choice and Competitive Aggregator procurement

Each EDC's VPP Interim Program shall offer enrolled customers at least two service delivery pathways: (1) an EDC-administered pathway, utilizing existing already available technology; and (2) a third-party aggregator pathway in which an aggregator manages the customer's devices through an edge DERMS interfacing with the EDC's DERMS. For an EDC that has not yet established a DERMS, the third-party aggregator pathways may instead interface with the EDC's existing demand response dispatch communications described in **Section 2.3**, provided the EDC's MFR filing describes how this interim interface will be replaced by a DERMS interface as that capability is developed.

Staff notes that VPP Interim Program solicitations should be open to both Original Equipment Manufacturer ("OEM") aggregators – device manufacturers such as EV charger or smart thermostat vendors who directly manage and aggregate their own installed devices – and independent third-party aggregators who aggregate one or multiple kinds of DER device across one or more OEM platforms. EDCs shall not restrict participation to a single aggregator type, and the solicitation evaluation criteria should be technology- and vendor-neutral to the maximum extent practicable. Aggregator and OEM relationship established under an EDC's existing Triennium 2 DR Programs may continue and transition into the VPP Interim Program consistent with **section 2.2**, without requiring a new competitive solicitation; however, the solicitation for procurement of those services may be opened to other aggregators during the terms of the Interim Programs. For any new or incremental third-party aggregator capacity sought under the VPP Interim Program, the selection process must be competitive; sole-source or relationship-based selection is not permissible. The Utility must include, as part of its MFR filing (**Section 2.9**), an Aggregator Solicitation Plan covering:

i. The solicitation form, evaluation criteria, and fee associated to the solicitation plan;

ii. The anticipated number of aggregators by resource type and/or customer segment;

iii. EDC-established interim qualification criteria for aggregator participation, which staff will draw on in developing Board licensing under **Section 6.3**; and

iv. A timeline ensuring selected aggregators can begin enrollment.

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.

2.8(b) Performance-Based Contracts and Disclosure

All EDC-Aggregator Contract term length needs to align with the timeline of the VPP Interim Programs to give aggregators the revenue certainty necessary to justify customer acquisition investment. In addition, all EDC-aggregator contracts in the VPP Interim Programs must be performance-based. Contracts must include:

i. **Performance-based compensation**: a methodology by which performance payments are progressively reduced or eliminated as response rates decline (e.g., a $/kW incentive rate applied to the average kW delivered during called events in a season);

ii. **A cost-effectiveness metric**: a ceiling on the cost per kW of dispatched demand reduction consistent with avoided-cost benchmarks; and

iii. **A contracted MW commitment**, including incremental enrollment goals over the contract term. Data on contracted and achieved MW commitments collected during the VPP Interim Program will inform the design of the long-term three-pathway compensation structure described in **Section 3.3**, including the Pathway 2 capacity reservation mechanism.

The Utility must also, as part of its ongoing reporting obligations under the VPP Interim Programs (Section 2.9), disclose to the Board no later than **30 days** following the close of each program year:

i. The total contracted value, broken down by payment type consistent with the budget categories described in **Section 2.4** (e.g., enrollment/participation payments and performance-based dispatch payments); this disclosure will inform the design of the long-term three-pathway compensation structure described in **Section 3.3**;

ii. The minimum customer pass-through requirement and methodologies the EDC imposed on each aggregator by contract; and

iii. The contractual safeguards preventing double-payment with co-enrolled Triennium 2 DR Programs.

2.8(c) Transition to the Long-Term Framework

VPP Interim Program contracts must include a transition clause enabling enrolled customers managed by a third-party aggregator to migrate to the long-term open-access tariff without re-enrollment, preserving the aggregator's customer relationships. A parallel operation period of no less than **12 months** – during which both the VPP Interim Program contract and the long-term tariff are simultaneously available – will enable a managed handoff rather than an abrupt termination of the Interim Program. This transition includes not only the customer relationship and enrollment data described above, but also any of the operational functions described in **Section 2.8** – dispatch authority, AMI data access, PJM communication, and marketing/enrollment – that the Board determines should shift from the EDC (or its Implementation Contractor) to third-party aggregators under the long-term framework.

Stakeholder Comment No. 12	a. 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. b. 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. *c.* Staff also seeks feedback on whether proposed transition timeline is reasonable.

2.9 VPP Interim Program Minimum Filing Requirements (MFRs) for EDCs

Each EDC's VPP Interim Program MFR filing, which Staff anticipates will be due December 31, 2026, must include the following:

i. **Program Description**: the target customer class(es); eligible DER types and enrollment process (**Section 2.2**); the EDC's aggregator engagement model, including the respective roles of the EDC, any Implementation Contractor, and any third-party aggregators (**Section 2.8**); the event dispatch protocol and notification timeline (**Section 2.5**); the customer incentive structure, including any proposed residential storage incentive (**Section 2.2**), uses cases that will be included; and a narrative explaining how the proposed program meets the objectives of **Section 2.1**, including the cost saving goals and how they will be achieved, and how the program is positioned to transition to the long-term VPP Program framework described in **Section 3**. The Program Description shall also include an implementation schedule with key milestones from Board approval through program launch.; a description of how the program will reduce barriers to participation for low- and moderate-income customers and customers in overburdened communities, consistent with Section 6.5; and a description of how the program will comply with the applicable standards and guidelines in Section 2, 5, 6, and 7.

ii. **Forecast Table**: a table, by program and by year, presenting forecasted values for the number of participants; total load under management (kW or MW); load dropped (kW or MW, averaged across PJM's 5 Coincident Peaks); program budget; cost to achieve ($/kW); and percent peak shaving (load dropped divided by total peak).

iii. **Budget Worksheet and Cost-Effectiveness**: a budget and cost-effectiveness worksheet that (a) allocates the proposed program budget across the categories described in **Section 2.4** (Administration/Program Implementation, Customer Incentives, Marketing, EM&V, and Other); and (b) demonstrates and details, with all underlying math, assumptions, and justification, that each proposed program achieves a Benefit-Cost Ratio greater than 1.0 for every VPP programs.

iv. **Enabling Infrastructure** (**Sections 2.2 and 2.3**): the communication protocols currently supported by the EDC's infrastructure and a roadmap for expanding protocol support; and documentation of existing dispatch communication capabilities, including those of DR program partners and any Implementation Contractor, the estimated number of enrolled devices and eligible customer accounts, and any gaps or constraints limiting near-term program scale.

v. **Planning and Operations Integration**: a description how the EDC will incorporate VPP -provided grid services into its distribution planning and operations during the Interim Program period, including coordination with its anticipated PSUP filing.

vi. **Performance Measurement and EM&V Plan (Section 2.6)**: the EDC's proposed customer baseline methodology, including the number of reference days, weather-normalization adjustments, and treatment of accounts with seasonal load profiles; its approach to verifying event performance using AMI data; and its data reporting and EM&V plan.

vii. **Peak Demand Reduction Target** (**Section 2.7**): a proposed peak demand reduction target (Table 1 and Appendix A), expressed in MW, for the first full operating year, identified within Staff's preliminary reference range or justified if outside that range, together with the assumptions underlying the proposed target.

viii. **Cost Savings Target (Section 2.7)**: a proposed cost savings target, for each type of savings, including a detailed narrative of how the EDC proposes to achieve said savings.

ix. **Aggregator Solicitation Plan** (**Section 2.8(a)**): the solicitation form, evaluation criteria, and associated fees; the anticipated number of aggregators by resource type and/or customer segment; EDC-established interim qualification criteria for aggregator participation; a description of how the EDC defines and categorizes aggregators, OEMs, and other organizations within the DER portfolio, and how current Triennium 2 DR aggregator and OEM relationships will transition into the program; and a timeline ensuring selected aggregators can begin enrollment.

x. **EDC-Aggregator Contract Disclosures** (**Section 2.8(b)**): confirmation that the EDC will disclose, within 30 days following the close of each program year, the total contracted value with third-party aggregators, broken down by payment type consistent with the budget categories in **Section 2.4**; the minimum customer pass-through requirements and methodologies the EDC proposes to impose by contract; and the contractual safeguards preventing double-payment with co-enrolled Triennium 2 DR Programs.

xi. **Transition Strategy** (**Section 2.8(c)**): confirmation that EDC-aggregator contracts include a transition clause and the proposed parallel-operation period enabling enrolled customers to migrate to the long-term open-access tariff without re-enrollment; and a description of how any operational functions identified in Section 2.8 – such as dispatch authority, AMI data provisioning, PJM communication, and marketing/enrollment – will transition from the EDC (or its Implementation Contractor) to third-party aggregators over time.

xii. **Reporting**: As part of this filing, EDCs shall confirm their commitment to provide the following reports to the Board on the cadence specified below:

a. *Quarterly (public)*: enrollment progress; budget tracking; progress toward the forecasted KPIs in the Forecast Table above; and infrastructure and contracting milestones.

b. *Annual (public)*: full-portfolio Benefit-Cost Ratio; cost to achieve ($/kW); enrollment trends; and a comparison of forecasted versus achieved KPIs.

c. *Post-season (public)*: performance during PJM 5CP events; average MW reduction; opt-out rates; and baseline comparison, consistent with the EM&V approach described in **Section 2.6**.

d. *Event-level (confidential, BPU/EDC only)*: dispatch confirmation; MW delivered versus committed; and settlement data.

Stakeholder Comment No. 13	Staff seeks comment on the proposed MFR structure; on 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; on the appropriate reporting cadence; on which elements of each report should be public versus confidential; and on whether the cost-effectiveness methodologies proposed here are sufficient.

SECTION 3. LONG-TERM VPP PROGRAM FRAMEWORK

The long-term VPP framework will build directly on the foundation the VPP Interim Program establishes and expands its capabilities to maximize the value of VPPs at scale, particularly as non-wires alternatives that defer or avoid distribution and capacity investment and relieve localized grid constraints. The operational data collected during the Interim Program – 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

Program. Enrolled customer relationships are preserved through the contractual migration mechanism in **Section 2.8(c)**, which provides a parallel-operation period enabling a managed handoff rather than an abrupt termination of the Interim Program.

While the VPP Interim Program is designed as a bespoke EDC program to gain jurisdiction-specific information and is limited by the current capabilities of the EDCs, the long-term framework will be market-based and tariff-governed: any Board-licensed aggregator may participate on non-discriminatory terms, distribution services are compensated through tariff that will be established with the collaboration with the Grid Flex Workgroup under GMF, and DER aggregations are positioned to participate competitively in PJM wholesale markets. To enable the open-access tariff, Staff proposes a milestone-based approach to govern each EDC's transition from the Interim Program to the long-term VPP Program. Each milestone reflects a foundational capability or regulatory determination – developed through the GMF's parallel PSUP and Grid Flexibility Services workstreams – that Staff considers necessary for an open, competitive VPP market to function effectively. The milestones need not be satisfied in sequence, and, upon stakeholders' inputs, Staff recommends that all milestones be met and reviewed by the Board before the long-term VPP Program launches:

i. The PSUP MFR Order has been issued, and the EDC has filed its PSUP that has been approved by the Board (see **Section 3.1**);

ii. The Grid Flex Workgroup has finalized distribution-level service architecture and compensation, and the Board has adopted them (see **Section 3.2**);

iii. The EDC has demonstrated DERMS Tier 2 capability confirmed by Board order (see **Section 3.4**); and

iv. The 12-month VPP Interim Program evaluation under **Section 2.6** has been completed and reviewed. This milestone-based approach protects against premature launch while giving EDCs, aggregators, and customers a clear, transparent roadmap toward a durable, open, and competitive VPP market.

3.1 Proactive System Upgrade Plan as Long-Term Foundation

The Board has been developing a requirement for EDCs to file a PSUP, detailing three- and ten-year projections into future identified grid needs. The PSUP proceeding is the result of the IDDER Workgroup and can be reviewed at BPU Docket No. QO24030199 (*"In the Matter Of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid"*). These filings will be foundational to the long-term VPP framework. The long-term VPP framework requires each EDC developing and filing a forward-looking plan for distribution system infrastructure upgrades informed by a current distribution system assessment; load and DER generation forecasting; the identification of future grid needs; and insight into the EDCs' control capabilities to identify, enroll, and dispatch heterogeneous DER portfolios. The PSUP, much like the envisioned DR Roadmap in the Triennium proceedings, challenges historically reactive EDC planning models. The PSUP also serves as a policy tool,

i. Affordably increase integration capacity to prepare for increased DER penetration, load growth from electrification, and large loads such as data centers;

ii. Evaluate the most cost-effective solutions (e.g. non-traditional or non-wires, provision of grid flexibility services, or traditional upgrades) to decrease infrastructure upgrade costs, where possible, that typically get passed down to ratepayers.

iii. Enable the participation of DERs to configure and orchestrate VPPs to improve distribution system operational flexibility and serve load to the greatest extent with local generation.

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.

3.2 VPP Tariff Design: Open-Access Framework

Staff proposes that ultimately, each EDC develop and file an open-access VPP tariff that governs the terms and conditions under which DER aggregators may participate in the EDCs' VPP program as third-party service providers. The tariff is under development via the Grid Flex Workgroup under the Grid Modernization Forum, will supplement, not replace, the EDC's existing interconnection and retail tariffs, and will establish the rights and obligations of DER aggregators, individual DER owners, and the EDC with respect to VPP enrollment, dispatch, and compensation.

The VPP tariff should be designed to satisfy the following core functional requirements:

i. **Non-discriminatory access**: The tariff must be available on non-discriminatory terms to all qualified DER aggregators, without preference for any particular technology, ownership structure, or commercial affiliation, provided that DER aggregators affiliated with EDCs shall be subject to additional safeguards, consistent with applicable affiliate relations standards, to prevent preferential access, cross-subsidization, or the use of confidential customer or grid data obtained through the EDC's regulated operations.

ii. **Interoperability**: The tariff must specify, as minimum requirements, the open-standard communication protocols that enrolled DERs must support and must not specify proprietary protocols that would create vendor lock-in.

iii. **Stackable value streams**: The tariff must explicitly permit enrolled DERs to simultaneously receive compensation for distribution services from the EDC and to participate in PJM wholesale markets through the DER Aggregation Participation Model [46], subject to appropriate anti-double-counting provisions[47], that include EDC, BPU and PJM compensation.

iv. **Performance-based**: The tariff shall ensure that a material portion of an aggregator's total compensation is tied to demonstrated performance; The market structure may evolve over time and may differ from the structure described in Section 3.3, but the majority of compensation should continue to be performance-based

v. **Scalability**: Ultimately, the tariff must accommodate the full range of eligible DER performance characteristics, from residential smart thermostats to commercial and industrial battery storage systems. Staff notes that, in order to achieve this, tariff design may need to adapt over time, or multiple tariffs may be needed to address different use cases.

Staff proposes that the Grid Flex Workgroup (Docket No. **QO26030059**) develop the detailed terms of the open-access VPP tariff, including technical interconnection and enrollment standards, in parallel with the development of this Straw Proposal. The Grid Flex Workgroup is charged specifically with developing tariffs that enable interoperable DERs to provide distribution-level services to EDCs and be compensated for them. Staff anticipates that the VPP tariff filings will be issued in **2027**.

3.3 Compensation Mechanism: Building a Market Structure

A tariff that compensates businesses or residents for participation in a VPP will allow the open market to encourage adoption and add resources to the grid. Establishing this tariff is work that the Grid Modernization team at the Board has already begun through the Grid Flex Working group. This tariff would be designed to compensate aggregators for the services that the VPPs are intended to provide.

Aggregators would in turn provide incentives to customers to encourage participation in the VPPs. Based on the current market and the variability of grid services each DER asset class can provide,

[46] PJM FERC Order 2222 Team, DER Aggregator Participation Model: Full Model Design (March 9, 2026). 20260309-item-05---updated-der-aggregator-participation-model---full-model-design---informational-only.pdf

[47] PJM Operating Agreement, Schedule 1 Section 1.4Bh DER Aggregator Participation Model 232 (March 10, 2026). oa.pdf

Staff envisions that customer enrollment and participation in the program may be supported by a compensation framework comprising the following three pathways. While Pathway 3 will be foundational to any VPP incentive structure, Pathways 1 and 2 may not be applicable to all devices:

i. Pathway 1: Enrollment

ii. Pathway 2: Opportunity Cost and Capacity Reservation

iii. Pathway 3: Pay-for-Performance Dispatch

For the retail market services, the payment may flow from the EDC to the aggregator, and from the aggregator to individual DER owners, under contractual arrangements established between the aggregator and each customer. For wholesale market services, the compensation may flow directly to EDCs and/or aggregators through the PJM market clearing mechanism and then pass to the individual DER owners. In both retail and wholesale markets, Staff proposes that EDCs and aggregators be required to disclose the pass-through methodology to enrolled customers as a condition of registration. In these models, the EDC funding flows through the aggregator to individual customers under contractual terms; the aggregator, not the EDC, generally determines how that compensation is structured and passed through, particularly in the residential sector. As a result, the revenue a customer sees may include more than pay-for-performance (Pathway 3); it may also include incentives to encourage enrollment. The structure below reflects one such model that is currently being utilized in many areas. Staff proposes that all programs receiving tariff compensation disclose their cost basis and methodology for each pass-through step.

Staff does not intend the structure to operate as a single, uniform compensation structure for every grid service. Different grid services may warrant different compensation structures. Staff therefore envisions that the VPP tariff would establish the baseline terms and conditions of participation for aggregators and customers, including enrollment eligibility, telemetry and data requirements, dispatch and measurement protocols, and disclosure obligations, and anti-double-counting provisions, while compensation structures and payment levels within each pathway would be defined by grid service and use case. Rather than a single fixed payment rate published in the tariff, aggregators would present enrolled customers with the specific compensation offers available to them based on location, the services their resource(s) can provide, and commitment level.

3.3(a) Pathway 1: Enrollment

Pathway 1 payments are paid by the aggregator and, through the aggregator, to the DER asset owner for the act of enrolling an eligible DER asset and maintain it in a state of availability – that is, configured and connected such that it can receive and respond to dispatch signals. Pathway 1 is intended to offset the upfront enrollment costs and any ongoing software or connectivity costs associated with VPP participation. Pathway 1 compensation is not intended to guarantee revenue independent of enrollment or connectivity costs. Where Pathway 2 and/or Pathway 3 compensation for a given resource or service is sufficient to offset those costs, Staff recognizes that Pathway 1 payments may reasonably be reduced or set to zero.

Staff envisions that Pathway 1 be structured as an annual per-enrolled-kilowatt payment, paid quarterly based on the enrolled nameplate capacity of DERs maintained in active status. For resources or services where recurring baseline payments are not appropriate – for example, where Pathway 2 and/or Pathway 3 compensation is expected to cover ongoing enrollment and connectivity costs – Pathway 1 may instead be structured as a single upfront payment tied to enrollment and may come in the form of a hardware incentive. The appropriate $/kW-year level shall be set by the aggregator based on the administrative and connectivity costs associated with the applicable use case, expressed on a $/kW basis, and shall not result in an excessive or unearned benefit.

Staff further proposes that for any BPU or EDC run program that incentivizes hardware that can participate in VPPs, requirements be established for participation that would also act as a Pathway 1 incentive. Incentives that require enrollment in a VPP tariff should require the recipient to remain enrolled in the VPP tariff for a minimum period – proposed as seven years – as a condition of retaining any upfront hardware incentive provided through NJBPU-administered programs. This condition would prevent the scenario in which a customer receives a hardware incentive and immediately exits the VPP program, thereby capturing a subsidy without providing the grid service that justified the subsidy. Staff notes that aggregators could use this same structure of providing a device as enrollment incentive with a commitment to remain in the VPP.

3.3(b) Pathway 2: Opportunity Cost and Capacity Reservation

Pathway 2 payments compensate the aggregator for maintaining headroom – that is, reserving a portion of the enrolled DER's operational capability for dispatch by the EDC or by PJM during designated availability windows. This is distinct from Pathway 1, which compensates for enrollment. Pathway 2 compensates for the opportunity cost of forgoing alternative uses of the DER’s capacity during the agreed availability window.

Staff recognizes that headroom varies between the different DER asset types. For example:

i. For battery storage resources, headroom means maintaining a minimum state of charge (“SOC”) sufficient to provide the committed dispatch capability during an event or dynamic operation window.

ii. For Heating, Ventilation, and Air Conditioning (“HVAC”) resources, headroom means accepting temperature setpoint constraints during pre-cooling or pre-heating periods that maintain dispatchable thermal mass.

iii. For managed EV chargers, headroom means reserving charging capacity that could otherwise be provided to the EV owner during the availability window.

Where a capacity reservation payment is appropriate to the grid service being procured, Staff envisions that Pathway 2 may be structured as a seasonal capacity reservation payment expressed in $/kW-summer or $/kW-winter, set by the aggregator based on the applicable use case. This seasonal capacity reservation payment will be analogous to the capacity payment received by traditional generation resources in PJM's capacity market. For resources that elect to participate in PJM's capacity market through a DER Aggregation registration, Pathway 2 would represent the distribution-level component of capacity value not already captured by the PJM capacity payment. For resources that do not participate in the PJM capacity market, Pathway 2 would represent the full opportunity cost of capacity reservation for distribution-level use.

Staff notes that the appropriate Pathway 2 payment level depends critically on the locational value of the DER within the distribution system (e.g., a resource on a capacity-constrained feeder may provide substantially higher value than one on a feeder with abundant spare capacity). Staff also notes that there may be cases where the EDC identifies a value in offering an incentive for Pathway 2 to address localized constraints. Staff proposes that Pathway 2 be differentiated by distribution location, using the locational value map developed through the PSUP process, with higher payments available for resources enrolled on high-value feeder circuits.

Staff recognizes that a standing capacity reservation payment will not be appropriate for every resource type or grid service. In Connecticut and Massachusetts, for example, ongoing compensation for behind-the-meter energy storage resources is tied to dispatch performance rather than to capacity availability. Where the value of a resource's availability is captured through Pathway 3 performance compensation, Pathway 2 may be reduced or omitted for that resource or service.

3.3(c) Pathway 3: Pay-for-Performance Dispatch

Pathway 3 payments compensate the aggregator for actual performance during dispatch events and will be applicable to all devices enrolled in a VPP. This pathway is the core performance-based element of the compensation structure and is intended to ensure that the VPP program delivers its intended grid value.

Staff proposes that Pathway 3 events be classified into two categories based on the nature of the dispatch:

i. **Local Events/dynamic operational needs**: Events dispatched by the EDC in response to distribution-level needs, including, but not limited to, voltage support events and local reliability or thermal-constraint events, which may warrant distinct compensation treatment. Compensation for Local Events will be set by the EDC through the VPP tariff, calibrated to reflect the value of the service to the distribution system (e.g., the avoided cost of a distribution capital project or the locational value of relief at the relevant point on the distribution system). Payments will be made by the EDC and recovered through the cost recovery mechanisms described in **Section 5**.

ii. **PJM-Dispatched Events/dynamic operational supports**: Events dispatched by PJM through the DER Aggregation wholesale market registration, in response to system-level energy, ancillary services, or demand response needs. For RTO-dispatched events, the primary compensation flows from the wholesale market to the DER Aggregator through PJM's settlement processes. The EDC's VPP tariff could provide a complementary distribution value payment where a distribution-level benefit is realized during PJM-dispatched events, subject to anti-double-counting provisions.

Staff proposes that Pathway 3 payments be calculated based on the verified demand reduction achieved during the event, measured against the AMI-based baseline described in **Section 2.6**. The base payment rate ($/kWh-dispatched or $/kW-event) should be differentiated by season, time of day, and distribution location, consistent with the value of the service at the time and place of dispatch.

Staff notes that the three-pathway structure proposed herein is broadly consistent with frameworks adopted in other jurisdictions. Colorado's Aggregator Virtual Power Plant ("AVPP") program similarly distinguishes among enrollment, capacity reservation, and performance payments. Connecticut's Eversource and UI Energy Storage Solutions programs compensate storage resources on an upfront enrollment plus performance-dispatch basis, consistent with a Pathway 1 and Pathway 3 structure without an intervening capacity-reservation payment.

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.

3.4 DERMS Architecture and Distribution Infrastructure

Effective VPP program operations require a DERMS architecture capable of:

i. Maintaining a real-time or near-real-time inventory of enrolled DERs and their current operational state;

ii. Issuing to, and confirming receipt of, dispatch signals to individual devices or device aggregations;

iii. Connecting performance telemetry sufficient to verify event response; and

iv. Interfacing with both the EDC's Supervisory Control and Data Acquisition ("SCADA") system and, for PJM-dispatched resources, PJM's dispatch and telemetry infrastructure.

Staff distinguishes between two functional layers within DERMS architecture:

i. **The Grid DERMS** is the utility-operated platform that manages DERs from the grid operator's perspective – providing system-wide visibility, integrating with distribution operations infrastructure (e.g., ADMS, AMI, SCADA), and issuing or executing dispatch signals at the distribution grid level.

ii. **The Edge (customer-side) DERMS** is the platform – typically operated by EDC, often through a third-party DERMS software vendor or by a third-party aggregator – that communicates directly with individual BTM devices, manages customer devices, and aggregates smaller resources into dispatchable portfolios.

Consistent with the upcoming PSUP filing, staff proposes that each EDC's filing includes a detailed assessment of existing Grid DERMS capabilities and, where supported by the EDC's identified grid needs, a capital investment roadmap for expanding those capabilities to support:

i. **Tier 1: BTM Visibility** – EDC achieves real-time or near-real-time visibility into DER assets across its distribution system. EDCs will establish the foundational data infrastructure and network model accuracy.

ii. **Tier 2: Control and Dispatch** – an EDC moves from passive monitoring to active control of enrolled DERs and develops the full operational stack of a demand flexibility capability.

iii. **Tier 3: Dispatch Orchestration and Optimization** – Grid DERMS matures from a demand response platform into an integrated grid planning and operational tool, extending beyond the event-based control achieved in Tier 2 to continuous optimization and integration with distribution planning. This will also include third-party aggregator integration via edge-DERMS to orchestrate and optimize the grid needs. The DERMS shall be capable of evolving to support dynamic price signals as a future dispatch control method option.

iv. **Tier 4: Market Integration** – Grid DERMS enables DER aggregations to participate as dispatchable resources in the PJM wholesale markets and the EDC has achieved full transmission-distribution operational coordination.

Staff further proposes that the EDC's Grid DERMS interface specification be made available to all registered aggregators on non-discriminatory terms, to enable Edge DERMS platforms to communicate with the EDC system without proprietary barriers.

Staff notes the practical reality that building out comprehensive Grid DERMS capability requires investment and multi-year implementation timelines. The VPP Interim Program is designed to operate within existing EDC dispatch capability, while the PSUP filing provides an avenue for EDCs' planning roadmaps to achieve full Grid DERMS functionality by the time the long-term tariff is operational.

Stakeholder Comment	Staff requests comment on the appropriate timeline for Grid DERMS build-out and on whether the Board should set minimum functionality requirements that

No. 16	must be achieved by specific dates.

3.5 Revenue Stacking and PJM Wholesale Market Participation

A central design goal of New Jersey's long-term VPP framework is enabling enrolled DERs to access the full value stack available from their operational flexibility. Staff proposes including, but not limiting to:

i. Distribution-level services compensated through the VPP tariff: VPPs can be configured quickly and orchestrated to respond to several types of local grid events within the distribution system, reducing the need to build centralized and emitting generation requiring a multi-year interconnection process. The implementation and orchestration of VPPs can serve as an alternative to traditional distribution system infrastructure upgrades, and, where distribution and transmission peaks coincide, may also reduce transmission-related costs. Staff notes, however, that the times at which distribution-level and transmission-level services are needed may not be coincident, and the associated value streams should be measured separately. VPPs can leverage the heterogeneity (e.g., technology agnostic, bidirectional capabilities) within aggregations to provide grid services that reduce the need to import energy during peak demand hours, reducing the energy that must be dispatched at the RTO-level to meet the state's energy needs. Recognizing the value of retail grid services VPPs provide will help Staff quantify the avoided/deferred costs, as well as incentivize the development of a retail marketplace for DER aggregations that also protects ratepayer interests. Below are some potential Distribution-level grid services Board Staff is contemplating compensating through its long-term VPP regulatory framework:

    a. Local Peak Demand Reduction ("PDR");

    b. Circuit-level Congestion Relief;

    c. Reverse Power Flow Mitigation;

    d. Managed Charging/Load Shaping;

    e. Deferred/Avoided Distribution Upgrades; and

    f. Emissions Reductions

ii. Wholesale revenues from PJM capacity, energy, and ancillary services market: Staff seeks to ensure that the long-term VPP regulatory framework will not impede access to the regional wholesale market revenue streams. Staff is engaging in the PJM stakeholder process to ensure that state regulatory frameworks surrounding VPPs are considerate of the timelines, constraints, and prerequisites necessary to enable participation in PJM's capacity, energy, and ancillary services markets. To best facilitate access to wholesale revenue streams, Staff proposes the following considerations:

a. **Program timelines** – Staff proposes that program enrollment be completed annually (Summer and Winter) by no later than May 31st to ensure that resources are properly accounted in EDC-respective Peak Shaving Adjustment Plans, due to PJM no later than 10 business days prior to September 30 to be effective for the next PJM load forecast update. Program enrollment should be re-verified by no later than November 1st to determine expected participation in dispatch events during the winter season.

b. **Aggregation limits** – Staff proposes a minimum aggregation threshold of 20kW to enable smaller DER aggregation participation in the provision of distribution-level grid services. Staff believe that setting this lower threshold helps to establish a competitive retail VPP market in New Jersey and give ratepayers a wider array of electric related service providers to aggregate their DER assets at the wholesale level.

c. **Telemetry and metering requirements** – Staff propose requiring third-party aggregators orchestrating VPPs in conjunction with the EDCs to meet PJM telemetry and metering requirements for each respective resource type, or to otherwise prove that the orchestration of the aggregation will have no safety or reliability impacts as verified by the respective EDC at the time of registration.

    1. EDCs must make validated AMI data accessible to customers or their authorized agents no later than 24 hours after the meter readings are captured, as required by PJM.

d. **Communications and Dispatch Protocol** – Staff recognize that EDC-directed distribution reliability dispatch could conflict with a resource's PJM capacity market obligation if both call on the resource simultaneously, creating a potential for double-counting of services[48]. Staff therefore propose that PJM capacity market obligation dispatch signals sent through the available web-based, software, or ancillary tools (e.g., EMS, DRHub, Markets Database, eDART, Data Viewer, ALL-CALL, Direct Phone Lines) take priority over discretionary distribution dispatch, unless the EDC determines it will cause a safety or reliability concern. In the event an aggregation that is authorized to participate in PJM's wholesale markets receives a dispatch signal from PJM, and the EDC determines that the aggregation's response to the wholesale market dispatch signal does not cause any safety or reliability impacts to the distribution system, the aggregation can

[48] NOPR, 157 FERC ¶ 61,121 at P 134.

respond to the dispatch signal and receive compensation from wholesale market revenue streams.

iii. Resources that are dispatched for distribution-level reliability or safety reasons will receive compensation through the BPU's Long-Term VPP Program following EDC verification, with the potential for that compensation to be revoked in the absence of a verifiable load reduction or injection at the end-use site within 48 hours of dispatch. Staff justify this requirement because it aligns EDCs with the recently implemented data access rules and takes steps to better conform to PJM's requirement to provide submit location specific settlements data within 24 hours.

iv. To prevent double counting, resources that are part of aggregations providing retail services will not be able to receive compensation from the wholesale market for providing that same service (e.g., Net Energy Meter Resources operating in PJM's Economic Load Response Regulation Only Participation Model, TOU rates). However, these resources are able to be dispatched to provide other services at that time and receive compensation from the wholesale market. The BPU will only credit the Aggregator for the services provided in response to the distribution-level dispatch received if one or more of those same services are not also provided as part of a wholesale market transaction or another retail sale; and

v. Any applicable state program incentives – Staff propose incentivizing the coordinated orchestration of VPPs by providing incentives for aggregations who meet performance thresholds. Aggregations that maintain >80% dispatch response across their aggregations will receive an incentive for sustained participation throughout the program season/year. Aggregations that fail to achieve 50% or greater participation in events throughout the season (e.g. Summer or Winter) will receive a penalty of a 25% reduction in performance incentive funds. To prevent habitual non-participation, Staff additionally propose to compensate aggregations that exceed greater than 100% of their committed obligation when providing grid services to disincentivize non-performance. Overperforming aggregations would receive the additional compensation from the 25% reduction of the performance incentives allocated to aggregations that failed to achieve 50% or greater dispatch response. Aggregations that fail to respond to 30% or less of dispatch signals received will only receive hardware incentives for the following season until participation increases to 50%.

Stakeholder Comment No. 17	a. 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. b. 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.

3.6 Aggregation Rules and Qualification Criteria

Staff propose that the long-term VPP tariff include the following rules governing aggregation composition and qualification:

i. **Minimum aggregation size**: Staff proposes a minimum aggregation size of 100 kW of enrolled capacity for aggregations participating in PJM wholesale markets under the long-term tariff, with the lower 20 kW threshold in Section 3.5(ii)(b) available to aggregations providing only distribution-level services. This threshold is consistent with minimum DER aggregation size requirements imposed by FERC Order 2222[49] that PJM is implementing[50], and is intended to ensure that the administrative overhead of managing an aggregation is proportionate to its grid impact;

ii. **Geographic boundaries**: Staff proposes that all DERs within a single aggregation must be located within a single EDC service territory, consistent with PJM's requirement that DER aggregations be within a single EDC's control area for purposes of distribution system coordination;

iii. **Balancing resource neutrality and appropriate compensation**: Staff proposes that VPP grid services be defined by measurable technical performance requirements – such as required response time (e.g., sub-minute or sub-five-second dispatch response), sustained response duration, or telemetry granularity – rather than by DER technology type. Compensation for a given service is resource-neutral: any enrolled DER capable of meeting that service's technical requirements receive the same $/kW payment for providing it, regardless of the underlying technology. A resource unable to meet the requirements of a faster or more demanding service (e.g., sub-minute dispatch) remains eligible to provide, and be compensated under, a different service suited to its actual capabilities (e.g., smart thermostats, water heaters, or managed EV chargers providing a slower-response service). This structure is intentionally technology-neutral rather than technology-specific: because eligibility is defined by performance rather than by naming particular DER types, resources not yet contemplated in this proposal can qualify for any service they are technically capable of meeting, without requiring the tariff to be reopened or amended. Staff further notes that the resulting differentiation in compensation across service types is an intended feature of this design. It preserves incentives for higher-performing resources while remaining fully inclusive of slower-responding resources within the services appropriate to their capabilities.

[49] Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 2222, 172 FERC ¶ 61,247 (2020) ("Order No. 2222")

[50] PJM Interconnection, L.L.C., 191 FERC ¶ 61,097 (2025).

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.

iv. **Customer Consent**: DER enrollment in the VPP tariff requires affirmative customer consent, including consent to third-party control of the enrolled device during dispatch events, sharing of AMI interval data with the aggregator, and the terms and conditions of the customer-aggregator agreement.

v. **Dispatch override rights**: The EDC retains the right to override aggregator dispatch instructions in defined grid-safety circumstances, including situations where aggregated dispatch would create voltage violations, overloads, or reliability hazards on the distribution system. These circumstances must be defined using objective, measurable technical thresholds (e.g., specific voltage or thermal limits) rather than generalized discretionary criteria. The VPP tariff should specify the notification process for dispatch override events and the compensation treatment for events that are overridden.

3.7 Open-Access Aggregator Market Framework and EDC Coordination Framework

The long-term VPP framework shifts the EDC-aggregator relationship from bilateral, performance-based contracts (**Section 2.8**) to a tariff-governed open market in which any Board-licensed aggregator participates on non-discriminatory terms without negotiating directly with the EDC. This shift is the central to the advancement of long-term VPP programs in New Jersey and must be implemented with sufficient clarity and structural protection to give aggregators, EDCs, and all relevant stakeholders the certainty needed to commit to long-term market participation.

3.7(a) Non-Discriminatory Access, Compensation Flow, and EDC Neutrality

The VPP tariff must be available on identical terms to all Board-licensed aggregators, with no preference for size, technology, ownership structure, or prior EDC relationship. The EDC shall make available to each Board-licensed aggregator its Grid DERMS interface specifications – communication protocols, registration APIs, dispatch signal formats, and telemetry requirements – and shall maintain that documentation on a current basis updating any changes in advance of their effective date with timely notice to affected aggregators, so any Board-licensed aggregator can design and maintain a compatible Edge DERMS without proprietary barriers. The EDC is prohibited from providing any aggregator preferential access to enrollment data, dispatch priority, or settlement information.

Compensation flows from the EDC to the aggregator under the three-pathway compensation structure in **Section 3.3**, and from the aggregator to the customer under the customer-aggregator agreement. Staff acknowledges that steps must be taken to ensure that the tariff is compensating for the value provided to the grid and is not an over subsidization to the market. Staff proposes that aggregators shall pass through to enrolled customers not less than 70% of pay-for-performance payments and shall disclose the compensation structure and pass-through methodology to customers in accessible and plain language before enrollment.[51] As a complement or alternative to a fixed pass-through requirement, the Board may establish a public offer-comparison platform – modeled on the Public Utility Commission of Texas' "Power to Choose" site for retail electric competition – that allows customers to compare aggregator offers on standardized terms and uses market transparency to encourage competitive compensation. Where an aggregator also receives PJM wholesale revenues from the same enrolled DER, revenue stacking must be disclosed to customers and may not be misrepresented as the totality of VPP compensation.

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.

3.7(b) Performance Standards, Dispatch Coordination, and Market Standards

Aggregators shall maintain a minimum sustained response rate of 80% of enrolled capacity across all required dispatch events in a program season. Aggregators falling below this threshold in two consecutive seasons may be suspended from new enrollment pending Board approval of a remediation plan. Aggregators shall post a performance assurance amount – structured as a letter of credit or cash deposit – calibrated to one season's expected Pathway 2 payments for the enrolled portfolio or, where Pathway 2 is reduced or omitted for the resources involved, to an equivalent share of expected Pathway 3 performance payments, to be drawn upon in cases of material performance failure. Aggregator-level performance data shall be published quarterly on the Board's docket, with appropriate confidentiality protections for customer-level data.

In the event of distribution-level safety dispatches, the EDC's dispatch shall take priority over all aggregator dispatches in its service territory. Where the EDC overrides an aggregator instruction to prevent a voltage violation or reliability issue, it must notify the aggregator **within one hour** and document the override in the **quarterly** performance report; overridden events do not count against the aggregator's performance record. To

[51] The 70% minimum pass-through is a proposed threshold informed by publicly reported aggregator business models, under which aggregators typically retain a commission of roughly 10-30% of customer program payments. https://codibly.com/blog/articles/how-demand-response-aggregators-make-money-business-models-for-the-8-44b-flexibility-market; Staff is not aware of a directly comparable state-mandated pass-through percentage and seeks comment on the appropriate level.

reduce correlated dispatch failure risk, no single aggregator may account for more than 40% of enrolled capacity in any single EDC service territory. For the purposes of this concentration limit, the “aggregator” is the Board-licensed entity that holds the customer enrollment and, where applicable, the executed PJM DER aggregator participation agreement for the enrolled capacity, regardless of intermediate dispatch-platform or installer arrangements.

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.

3.8 EDC Ownership and Administration for Targeted Grid Needs

The open-access framework in **Section 3.7** establishes third-party Aggregator participation on non-discriminatory terms as the default structure for the long-term VPP market. Staff recognizes, however, that a purely voluntary, market-driven model may not reliably deliver resources to the specific locations where they provide the greatest grid value. Because participation depends on where customers and Aggregators choose to enroll, DER deployment may not materialize on the constrained circuits where it is most needed. To ensure the long-term VPP Program advances in the most cost-effective manner for ratepayers, Staff seeks comment on whether EDC ownership or EDC of third-party DER assets (e.g., battery storage) should be available as a bounded exception to the open-access default, limited to defined circumstances where the open market is unlikely to meet an identified distribution system need. Staff notes that EDC ownership of generation-adjacent assets such as battery storage may implicate EDECA's separation of generation and distribution functions (N.J.S.A. 48:3-49 et seq.) and would require confirmation from the Legal and legislative clarification, if found to exceed existing Board authority before any such exception could be adopted.

The clearest such circumstance is a constrained circuit. Through the PSUP process (**Section 3.1**), each EDC will identify constrained circuits, those expected to experience substantial load growth, and determination methodologies. Where the PSUP identifies a circuit on which targeted storage or other DERs could defer or avoid a more costly traditional distribution upgrade, that circuit is a strong candidate for a more directed deployment approach than voluntary enrollment alone. Staff proposes that the Board establish a process under which an EDC may file a petition to launch a constrained-circuit program authorizing the EDC to deploy storage and other DERs expeditiously to address an identified capacity need on a specific circuit or set of circuits.

Should the Board approve such a process, Staff recommends that it remain open to a range of deployment and ownership models rather than committing to a single structure at the outset. Models adopted in other jurisdictions include:

i. Customer-owned storage or other load modifying technology, in which the customer receives an incentive to offset installation cost, and the EDC retains defined dispatch rights;

ii. a competitive procurement model, in which the EDC issues a request for proposals to develop and operate storage on specified constrained circuits. This model preserves a role for the open market while allowing the EDC to direct deployment to priority locations the grid needs most; and

iii. EDC-owned storage, in which the EDC owns and operates the asset as non-traditional distribution solutions as refer in the PSUP, commonly known as a non-wires alternative solutions;

Staff proposes that the Board evaluate these models, and the corresponding cost-recovery mechanisms, to determine which is most cost-effective for ratepayers before authorizing any particular structure.

Because EO2 directs the Board to develop a dedicated tranche of capacity for EDCs to support DER interconnection and grid stability, Staff anticipates there will need to be coordination with the GSESP Phase 2 utility-developed tranche (**Section 4.2**). Coordinating the constrained-circuit process with GSESP Phase 2 avoids establishing duplicative procurement and recovery mechanisms across proceedings.

To preserve the integrity of the open-access market, any EDC ownership or administration authorized under this Section must be subject to safeguards consistent with the EDC-neutrality principles in **Section 3.7(a)**. In particular, EDC-owned or EDC-administered assets must not receive preferential dispatch, enrollment, or settlement treatment relative to third-party Aggregator resources participating under the open-access tariff; the EDC must maintain functional separation between its asset-ownership role and its program-administration role; and EDC ownership must remain limited to targeted circumstances approved by the Board and informed by the PSUP filing rather than displacing open-market participation more broadly. Where the Board authorizes an EDC to own, build, or administer storage as part of a VPP solution, any associated construction or installation work should be procured under terms that ensure contracts are awarded to firms in good standing and that support a skilled New Jersey workforce. Entity-fitness standards for program participants are addressed in **Section 6.3**; workforce and contractor-responsibility standards specific to EDC-procured construction would be established in the procurement terms of the approved program.

Staff notes that EDC ownership of generation-adjacent assets such as battery storage may implicate EDECA's separation of generation and distribution functions (N.J.S.A. 48:3-49 et seq.)

Stakeholder Comments	Staff requests comment on whether EDC ownership or administration of DER assets (e.g., battery storage) should be available as a bounded

No. 21	exception to the open-access framework for targeted grid needs such as constrained circuits; on which deployment and ownership model or models (EDC-owned, customer-owned with EDC installation, or competitive RFP) would be most cost-effective for ratepayers; and on what safeguards are needed to ensure EDC-owned or EDC-administered resources do not undermine the EDC-neutrality principles of Section 3.7(a).

SECTION 4. VPP COORDINATION AMONG BOARD PROGRAMS

4.1 Grid Modernization

The Board's Grid Modernization initiative began in 2021 with the intention of evolving the legacy electric distribution system into a more adaptive, flexible, and fully utilized grid that benefits from the configuration and orchestration of local DERs that can actively support local load and other operational needs and be compensated for providing those services. The Grid Modernization initiative and VPP Program are inherently connected. A flexible modern grid with integrated distributed generation is the foundation of a successful VPP Program, while a specifically targeted VPP Program reduces utility costs by providing flexibility alternatives to traditional generation procurement and infrastructure investment. By using orchestrated DERs in place of, or to defer, traditional transmission and distribution upgrades, and by reducing peak demand, a VPP lowers the capital investment (transmission and distribution) recovered through the rate base and reduces the capacity New Jersey must procure at PJM auction, helping to lessen prices for ratepayers.

The Board is currently undertaking several grid modernization workstreams through the Board's GMF, a collection of expert stakeholder workgroups focused on increasing DER integration capacity and grid flexibility. Two GMF workstreams are particularly integral to VPP Program development: PSUP process (Docket No. QO24030199), which intends to establish a mechanism through which each EDC will file a three- and ten-year distribution system planning strategy; and the Grid Flex Workgroup (Docket No. QO26030059), which has the goal of developing the service architecture for distribution-level grid flexibility services, including: service definitions and use cases, service valuation mechanisms, compensation structures, and interoperability standards that will govern how DERs are compensated for providing distribution services. The outputs of these workstreams are expected to inform and shape key elements of both the VPP Interim and long-term Programs.

Additionally, the collective work of the GMF includes a third workgroup, Cost Estimation, Validation, Allocation, and Recovery ("CEVAR"), which will evaluate and recommend viable alternatives for future distribution system upgrade methods so that a more efficient, effective, and equitable method of scarce capital allocation can be achieved to accelerate expanded hosting capacity while lowering costs for ratepayers. This work requires significant coordination with the

Governor's Executive Order No. 1 on future EDC business model reform.

4.1(a) VPP Interim Program Period (2027-2029)

The VPP Interim Program is intentionally designed to operate within existing EDC grid infrastructure operational control paradigms and to utilize existing AMI, current DER asset control tools including all nascent DERMS Tier 1 capabilities, and existing demand response program infrastructure utilizing contracted Curtailment Service Providers. The two GMF workstreams contribute to the VPP Interim Program as follows:

i. **PSUP***:* PSUP filings will provide the most granular picture of circuit-level integration capacity constraints and each EDC's DERMS maturity. While PSUP filings will not be complete before the VPP Interim Program launches, each EDC's VPP Interim Program filing shall include a summary of current distribution system capabilities relevant to VPP operations, drawing on work already underway for PSUP preparation, which Staff envisions having EDCs file in 2027;

ii. **DER Registry**: The DER Registry being standardized across EDCs under the PSUP proceeding serves as the enrollment infrastructure backbone for DER Aggregations serving the VPP Program. VPP enrollment data shall be maintained in a format compatible with that registry structure, avoiding duplicative systems and ensuring VPP records remain available for PSUP planning purposes as the registry matures. DER Aggregations are configured in the Registry as the physical inventory of enrolled assets; the VPP orchestrates those configured Aggregations when called into service in response to a dispatch event. Staff notes that this is a VPP filing requirement, not an additional PSUP obligation; and

iii. **Grid Flexibility Services Workgroup**: GridFlex's near-term service definition and compensation work is directly relevant to the VPP Program's compensation structure. Staff proposes that the VPP MFR Order, targeted for Fall 2026, be developed in parallel with GridFlex's evolving draft service architecture and compensation language to ensure consistency and prevent definitional conflicts. Any conflicts identified prior to the MFR Order's adoption will be flagged to the Board.

4.1(b) Long-Term VPP Tariff (2029 and Beyond)

In the long term, grid modernization efforts create the foundational service architecture that supports the VPP Program to ensure its sustained success, continuous improvement, and delivery of meaningful grid and ratepayer benefits. The GMF workstreams remain the primary vehicle for this ongoing coordination, with the following outputs directly shaping the long-term VPP tariff framework:

i. **Proactive System Upgrade Plan (PSUP):**

a. **DERMS Maturity**: The long-term tariff's enrollment targets – the maximum MW each EDC must accept under the open-access tariff – shall be informed by PSUP-identified integration capacity projections for each service territory. The relationship is bidirectional: just as PSUP integration capacity projections inform the tariff's enrollment targets, the DER grid services that VPPs provide are incorporated into PSUP development as non-traditional distribution solutions evaluated alongside traditional infrastructure to meet identified grid needs. Additionally, the tariff's full open-access market features, including non-discriminatory third-party aggregator access and AMI-based automated settlement, shall become operative for each EDC upon Board confirmation that the EDC has achieved **DERMS Tier 2 capability as described in Section 3.4**, creating a concrete, measurable link between the grid modernization efforts and VPP program milestones.

b. **Flexible Interconnection**: The Board is exploring appropriate mechanisms to flexibly interconnect both sources of DER generation and large loads (such as data centers) through the Grid Flexibility Services workgroup (BPU Docket No. QO26030059), data acquisition through the PSUP, and a future workgroup under the Grid Modernization Forum.

ii. **Grid Flexibility Services**: GridFlex's primary deliverable is proposed tariff language defining distribution-level flexibility services, including discovery and access methods, and participant compensation; Staff intends this to be directly incorporated as the foundation of the long-term VPP tariff framework. Distribution services that DER aggregators are compensated for through the VPP tariff, such as peak demand reduction and voltage support, should align with the service architecture defined in GridFlex. The tariff also should reflect the impact of the future NEM reform that is under the Docket No. QO24090723 to address potential double counting issues. Staff targets completing this alignment through coordination between the VPP straw comment period closing August 20, 2026, and GridFlex's service and compensation discussions running through fall 2026.

Stakeholder Comments 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.

4.2 Energy Storage and Coordination with GSESP Phase 2

The GSESP **Phase 1** has initiated two tranches and is targeted to incentivize Grid Scale storage installations that are interconnected at the PJM transmission level. These storage assets will be bidding into the existing wholesale markets and will not be participating in VPP aggregations.

The GSESP **Phase 2** aims to support rapid adoption of smaller, decentralized energy storage resources that will often be implemented in conjunction with distributed generation and other energy conservation technologies

Battery energy storage system ("BESS") represents the high value DER asset class for VPP programs, due to their bi-directional capability, sub-second dispatch response, and ability to provide multiple grid services from a single asset. Staff proposes that GSESP Phase 2 be designed with forward looking integration into the VPP program in mind. Staff anticipates Phase 2 to be structured around a performance-based incentive framework that provides long-term revenue certainty to incentive awardees while directly linking compensation to system performance during the PJM capacity and transmission peak hours, or Coincident Peaks (CP). Additional performance factors, such as response to EDC dispatch signals, may also be required of incentivized systems to ensure the value of BESS system deployment is maximized. In its initial implementation, Capacity Block 1 (Block 1) would be designed as a low-complexity, financeable, near-term deployment mechanism that neither relies on nor conflicts with emerging systems such as DERMS. Its performance-based framework aligns with PJM market signals, targeting up to 350 MW of behind-the-meter (BTM) energy storage capacity in Block 1.
Grid Flexibility Services (Docket No. QO26030059) as described in the previous section are discussing the inclusion and tight integration of distributed energy storage, including the potential for bi-directional EV power flow (a.k.a., V2G), within the service architecture are under development. The Grid Flex team will continue to work to develop programs to inform the resulting Long Term VPP Tariff, which is the tariff that is currently being worked on by the Grid Mod Grid Flex workgroup.

Specifically, Staff proposes that both the GSESP Phase 2 and VPP Programs include the following integration provisions:

i. Telemetry and Communication Standards;

ii. Compensation, Incentives, and Anti-Double-Counting between GSESP and VPP; and

iii. Third-party Aggregator Access for Phase 2 Resources

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.

4.3 Energy Efficiency and Coordination with Triennia 2 and 3

EE measures provide persistent, passive demand reduction. For example, insulation reduces demand at all hours. The EDCs administer EE programs that incentivize cost-effective, high-efficiency measures, including connected devices and appliances (e.g., smart thermostats, smart panels, high-efficiency HVAC systems, and smart water heaters). These incentivized connected devices and appliances may be enrolled in a VPP program to the extent the specific EE measure is able to provide the requisite grid services.

Staff anticipates that a Triennium Program Year 7 Order will provide guidance that the current DR and VPP Pilot Programs and their recovery should be migrated into the VPP Interim Program pursuant to the parameters of the VPP Interim Program. This will provide assurances to the market that the DR programs will not abruptly stop while the VPP Interim Programs are designed, filed and reviewed by the Board.

Staff recommends that Triennium 3 not offer any DR and VPP pilot programs. Staff further recommends that the programs continue to offer appropriate hardware incentives (i.e., smart thermostat, smart water heater, etc.) and review where it is appropriate to require enrollment in a VPP as part of the incentive and where it is appropriate to offer an "adder" incentive for enrollment.

Stakeholder Comment No. 24	Staff seeks stakeholder comment on the proposed Triennium VPP coordination.

4.4 Clean Transportation and EV Load Management

EV load management represents high value opportunity for both near-term and long-term VPP resource opportunities in New Jersey because of the rapid growth in EV adoption within the state and the significant load represented by EV charging, particularly during peak times that coincide with grid stress. EV load management is a broad term describing any strategy used to mitigate, control, optimize, or coordinate EV charging loads, including but not limited to managed charging, hardware capacity configurations, vehicle charging sequencing, Time-of-Use ("TOU") rates, transformer protection schemes, and vehicle-to-grid (V2G" technologies:

i. **Passive Managed Charging:** Load management strategies that influence charging behavior through static or dynamic price signals without direct utility or third-party control over individual charging sessions. Passive managed charging strategies may include rate designs, default charging schedules, delayed charging, preferred charging windows, or other mechanisms designed to encourage charging during lower-cost or lower-demand periods while minimizing customer burden and preserving customer autonomy.

ii. **Active Managed Charging:** Load management strategies that involve direct or automated modification of EV charging behavior in response to utility, third-party aggregator, or grid conditions. Active managed charging may include managed charging events, dynamic charging schedules, charging pause or throttling capability, automated optimization based on customer preferences, or other mechanisms designed to actively shape charging load while maintaining customer override capability.

iii. **Vehicle to Anything ("V2X"):** Load management strategies involving bidirectional power flow between an EV battery and a building or the electric grid. V2X strategies may include Vehicle-to-Home ("V2H"), Vehicle-to-Building ("V2B"), or grid export ("V2G") functionality designed to support grid reliability, peak load reduction, resilience, or other grid services. EVs at scale, have significant energy storage and power flow management capacity which can become a valuable grid resource.

iv. **Charger Load Balancing Foundations:** Load management strategies designed to dynamically allocate available electrical capacity across multiple EV chargers or charging ports connected to a constrained electrical service, circuit, or panel. Charger load balancing strategies may include power sharing, dynamic amperage allocation, shared-circuit charging, site-level charging management, or other methods intended to maximize charging access while minimizing infrastructure upgrade needs and system impacts.

v. **VPP:** Load management strategies that involve direct or automated modification of EV charging and discharging in coordination with other DER assets in response to operational grid service needs or market opportunities.

The Board's existing EV charging programs, established through a series of Orders from 2020 through 2026, have created an enrolled customer base and a body of program experience that the Interim VPP Program can leverage. Staff proposes the following principles for integrating load management into the VPP framework:

i. During events, aggregators may slow or stop EV charging for residents that opt-into event-based incentives.

ii. During events, residents may receive incentives for discharging into the grid.

iii. These actions will increase grid reliability and lower costs for all Ratepayers.

The VPP proceedings are designed to work concurrently with LD Rule proceedings and the pending MHD EDC proceedings as they are both designed to reduce EV peak loads. VPPs are currently primarily event based, while load management programs handle daily loads and address daily peaks. Staff envisions incorporating the following principles into future EV programs, including the LD Rules.

i. Programs should focus on deploying infrastructure capable of participating in load management programs and enrolling residents in these programs. This can include enhanced incentives for those who enroll in VPP or managed charging programs or limiting incentives to only those who agree to such participation. Incentive levels should be tied to market adoption.

ii. Programs should prioritize the co-location of EV chargers with storage, V2G capabilities and on-site generation where feasible and cost effective.

iii. Programs should encourage the development of Time of Use rates that reflect the cost of service and encourage load shifting through behavior.

Additionally, compatible EVs, at scale, have significant storage and power flow management capacity and by accelerating EV adoption, the Board continues to deploy significant grid storage resources. This capacity can be harnessed through V2G capabilities that are tightly integrated into a service architecture which enables this valuable bidirectional capacity to flexibly combine with other distributed generation and load management into “callable” grid flexibility services for a variety of grid needs.

Concentrated load created by coincident fleet charging of larger Class 6-8 EVs represents a different solution opportunity and constraint set. The incremental large load presented by these applications in some ways resemble that introduced by data centers. Several factors must be considered.

i. Commercial vehicles represent a wide variety of use profiles, ranging from local delivery box trucks, through school buses with predictable daily short cycle routes to long haul semi-tractors.

ii. Most commercial duty cycles are mission critical for business operational needs, and (along with larger battery capacities requiring extended recharge windows) have less discretion or flexibility to be severely curtailed during recharging.

iii. Large concentrations can represent significant near-term load serving needs that require local generation as a “bridge to wires” which can involve years long infrastructure builds in addition to local charge “sharing” management solutions

iv. Commercial installations are on tariffs that feature significant demand charge elements, which prompt site specific BTM investments or load management for managing local peaks

VPPs may help address these constraints by freeing up capacity within a distribution system segment that needs to serve this load.

4.5 Solar and Net Energy Metering (NEM) Reform

Residential and commercial solar PV systems are among the most widely deployed DER assets in New Jersey, with approximately 4,350 MW of installed behind-the-meter solar capacity as of March 2026. However, the grid-service value of fixed solar PV is limited by sunlight availability and cannot be directly controlled by an EDC or aggregator. Updates to net energy metering compensation mechanisms may enhance the value of solar energy that is delivered to the grid at the most optimal times. The principal opportunity for solar resources in the VPP context:

i. Relate compensation of solar power to its value to the grid, not only retail rates;

ii. Enhance economic viability of installing energy storage paired with residential and non-residential solar systems; and

iii. Encourage participation in a VPP Program to export solar energy at times when it is most valuable

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.

4.6 AMI Data Access Standards

AMI represents an initial pathway to obtain an essential data layer of New Jersey's VPP program. Reliable access to interval-level customer usage data can enable the foundational VPP program functions of event performance measurement and long-term program evaluation. Therefore, Staff proposes that the EDCs leverage the existing capabilities of AMI deployments to minimize incremental investments necessary to meet the Interim VPP Program goals.

For the long-term VPP Program, Staff proposes that AMI Data Access Standards act complementary to other available methods to achieve both retail and wholesale market participation that is cost-effective to ratepayers. The AMI data access standards provide that each EDC must make AMI data accessible and shareable using the Green Button Data Standard as well as enable authorized third parties access to Electronic Data Interchange ("EDI") through the EDCs' supplier web portal. This should support the basic event performance measurement needs of an established wholesale VPP market. One potential remaining hurdle is the ability for EDCs to provide validated data within the timeframe required by PJM for market settlement, as identified below. The AMI Data Access Standards provide that validated data must be made available within 48 hours. Staff believes that this is not an insurmountable issue and will explore expedited validation for customers participating in VPP Programs. However, further examination of the use of the local data stream or other available methods of measurement is warranted. Continuing to rely on utility meter level data for event performance measurement may act as a bottleneck, potentially limiting the ability to stack revenue where allowed. This is because utility meter level data granularity may not account for the capabilities of multiple devices aggregated at the same premises to provide a variety of grid services.

Staff proposes that EDCs must verify beyond a reasonable doubt that:

i. The EDC coordinating with the third-party Aggregator has provided an accessible, standardized, and secure format to transmit end-site settlement-level meter data within 24 hours for end-use customers enrolled with the third-party Aggregator;

ii. The third -party Aggregator seeking to enroll end-use customers within the EDC service territory has received explicit consent from the customer to utilize the end-site meter data for participation;

iii. The third-party Aggregator is a registered Member of PJM and is able to participate within retail and wholesale market mechanisms (e.g., PJM's Economic Load Response Program); and

iv. EDCs have reviewed and approved or denied such authorizations within 10 business days, with results being subject to audit from an independent third party determined by disputing parties.

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.

4.7 Time-of-Use (TOU) and Rate Design Coordination

The relationship between rate design and VPP participation is a significant policy consideration that Staff treats as an active area of policy development requiring further stakeholder engagement. Staff recognizes that VPPs and rate design are complementary mechanisms that drive customer behavior and together shape load and DER delivery profiles. TOU rates that accurately reflect the time-varying cost of electricity can align customer incentives with grid needs; however, improperly designed TOU rates can complicate the customer value proposition for VPP participation, create measurement challenges for VPP performance evaluation and/or create or aggravate equity issues. Staff proposes to coordinate rate design and VPP compensation structures so that both mechanisms work together to maximize ratepayer benefits. Staff further recognizes the view that, over the long term, rate reform that fully reflects the temporal and locational cost of service could provide a market signal that reduces reliance on explicit compensation for grid flexibility services, and that persistent reliance on such compensation in the absence of cost-reflective rates raises concerns about equity among customers with differing access to DERs.

Staff proposes the following principles to govern the interaction between rate design and VPP programs:

i. **Revenue neutrality**: Any TOU rate structure implemented in coordination with the VPP program shall be revenue-neutral relative to the EDC's existing rate structure for customers. This means the EDC shall design TOU rates so that, applied to the customer class's existing (pre-TOU) load profile, the rate structure does not increase the EDC's total revenue collection relative to current rates. Revenue neutrality ensures that TOU is not a barrier to VPP participation. Staff notes that revenue neutrality is a design constraint on rate implementation, not a prohibition on bill impacts for individual customers; TOU is intended to reward load flexibility, and customers who shift consumption to off-peak periods must see bill reductions.

ii. **Asset-specific TOU**: Staff proposes that the EDC should evaluate determined whether separate TOU tariffs or supplemental TOU riders should be available for customers enrolling DERs, including, but not limited to, EVs, battery storage, smart thermostats or other grid service programs, in the VPP program. Technology-specific TOU rates can better align the dispatch economics of particular DER types with grid needs. For example, a late-night off-peak EV rate may encourage charging patterns that reduce feeder-level peak demand without requiring explicit VPP dispatch. Proposed TOU rates should reflect the true cost of service.

iii. **Interaction with VPP compensation**: Where a customer is subject to both a TOU rate and a VPP dispatch event, the event baseline used to calculate pay-for-performance payments shall be determined using the EDC's approved baseline methodology, which shall reflect the customer's actual recent consumption behavior, including any load shifting already induced by an applicable TOU rate. To prevent double-payment, a customer shall not receive VPP dispatch compensation for a load reduction that is separately compensated through TOU pricing.

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.

4.8 VPPs and Government Facilities

4.8 (a) NJ Transit

New Jersey Transit ("NJ Transit") operates one of the largest public transportation systems in the nation, with a fleet of electrified rail vehicles and rapidly growing inventory of electric bus assets across service areas spanning all four EDC service territories. NJ Transit's electrified infrastructure, particularly its bus depot charging systems and rail yard with high-voltage power connections, represents a significant potential VPP resource if appropriately configured for demand-response dispatch. Staff proposes that the Board initiate formal coordination with NJ Transit to explore the various VPP participation pathways.

4.8 (b) Electric School Buses

Electric school buses represent a promising VPP resource: they are typically parked and plugged in during peak afternoon and early evening hours – aligning with periods of highest grid stress – and carry large battery packs capable of providing meaningful grid services when outfitted with bidirectional charging capability and enrolled in an aggregation program. On December 17, 2025, the Board authorized a Memorandum of Understanding ("MOU") with the New Jersey Department of Environmental Protection ("DEP") to fund up to four V2G school bus pilot hubs, with DEP to report on the pilots' results.[52] Staff proposes that electric school buses may participate through several

[52] In re The Matter of a Memorandum of Understanding Between the Board and the Department of Environmental Protection to fund DEP's FY26 Electric School Bus Program V2G Pilot, BPU Docket No. QO25110591, MOU dated

pathways, including but not limited to a V2G program and an Electric School Buses Aggregation Program, with program design to be informed by pilot findings.

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.

4.9 VPP Working Group

Staff proposes the establishment of a VPP Implementation Working Group ("VPP WG") to support the ongoing design, implementation, and iterative refinement of the VPP Program across both the Interim and long-term program. The VPP WG is intended to serve as the primary technical and operational forum through which Board Staff, the four New Jersey EDCs, Rate Counsel, third-party aggregators, advocates, and other relevant interested stakeholders collaborate on program design and implementations questions that cannot be fully resolved through the straw proposal process alone and that require ongoing coordination as interim operational data becomes available.

The VPP WG's role is advisory and technical: to discuss implementation challenges, review program performance data, and develop consensus recommendations for Staff consideration ahead of key VPP program milestones. Staff will facilitate VPP WG meetings and may retain technical consultants to support specific agenda topics. The VPP Program docket will be used to ensure transparency and broad access to VPP WG materials.

The VPP WG is also expected to coordinate closely with many of the Board's proceedings that are being undertaken, including, but not limited to the Grid Flex Workgroup and PSUP process.

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.

SECTION 5. COST RECOVERY MECHANISMS

VPPs are designed to lower costs through avoided infrastructure build outs and reducing new capacity needs. To ensure that these new costs drive savings for all ratepayers, Staff recognizes that careful attention must be paid to how the costs of VPPs are recovered.

The Board is reviewing the traditional utility business model pursuant to Executive Order No. 1 and looking to modernize rate proceedings and recovery mechanisms. As Staff contemplates the VPP Interim Program design and the long-term VPP tariff, cost recovery for both should be developed in coordination with those proceedings. For the VPP Interim Program, consistent with the Triennium Program Year 7 Order's direction that the migrating DR programs and their recovery move into the Interim Program (see Section 4.3), Staff anticipates that Interim Program costs will be recovered through the existing mechanisms applicable to those programs, with specific cost recovery treatment to be addressed in the MFR Order.

In contemplating programs, Staff proposes a focus on moving toward performance-based ratemaking to encourage participation in VPPs and peak shaving. Staff also recommends closely scrutinizing what is classified as capital investment, as much of the program administration and incentive costs should be recovered as an expense rather than capitalized into rate base. Staff further plans to investigate any costs that should be amortized over time.

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.

SECTION 6. SUPPORT MARKET STRUCTURES THROUGH INFORMATION SHARING, TRANSPARENCY, ACCESS, AND CODE OF CONDUCT

6.1 Information Sharing and Transparency

As the Board seeks to establish a new market for VPP services, appropriate information sharing requirements are essential both to protect ratepayers and to enable the Board to oversee program performance. Staff recognizes that significant amounts of commercially sensitive information will be created in the course of VPP program operations, including, but not limited to, aggregator cost structures, customer usage data, and device-level performance data. Any information sharing framework must balance the ratepayer and public interest in transparency with legitimate confidentiality interests.

Staff proposes the following information sharing requirements:

i. **EDC data provision to aggregators**: As a condition of administering the VPP tariff, each EDC shall provide registered aggregators with the data necessary to enroll customers, process unenrollments, and verify event performance, including applicable AMI meter data, on a non-discriminatory basis and on the same terms available to any EDC-affiliated aggregator. At a minimum, the EDC shall provide:

   a. Enrollment verification data (customer eligibility, account and meter identifiers, and applicable rate schedule) upon an aggregator's enrollment request;

   b. Unenrollment confirmation and any associated meter or account data upon a customer's departure from an aggregation; and

   c. Interval meter data sufficient to verify event performance and support settlement following a dispatch event.

ii. **Program cost reporting**: Aggregators must provide the Board with annual reports on program costs, disaggregated by cost category (enrollment, technology, customer acquisition, device integration, and administrative overhead). This information is necessary to allow the Board to assess whether tariff compensation levels are appropriately calibrated to the actual costs of building and operating an aggregation platform, and to protect ratepayers from excessive margins. Information provided under this requirement may be treated as confidential trade information, with public disclosure of anonymized, aggregated statistics on program costs across all registered aggregators.

iii. **Performance reporting**: Aggregators must provide the EDC with event-level performance data sufficient to verify Pathway 3 payment calculations, including device-level telemetry, event timestamps, and dispatch confirmations. This data will be used by the EDC for settlement purposes and EM&V program evaluation.

iv. **Customer data protection**: Aggregators must comply with all applicable state and federal data privacy requirements with respect to customer usage data accessed through either the Green Button Data Standard or EDC-hosted EDI portals[53] or authorized data-sharing pathways. The Board's N.J.A.C. 14:5-10 rules establish a baseline data protection framework. At a minimum, aggregators must comply with these rules when accessing AMI Data and as a condition of VPP tariff registration.

Staff further proposes that the Board publish an annual VPP Market Report that aggregates and summarizes program performance across all EDCs and all registered aggregators, including:

i. Total enrolled DER capacity, by resource type and by EDC;

[53] Green Button Standards initiative, U.S. Department of Energy.

ii. Number of events called aggregate demand reduction achieved;

iii. Total VPP program expenditures, separated by cost category;

iv. Number of DER Aggregator registrations made with PJM and estimated wholesale market revenue generated; and

v. A VPP Cost Savings Scorecard reporting the ratepayer cost reductions attributable to the VPP Program. Staff intends the scorecard to serve as the Program's performance indicator. The scorecard shall report, at minimum:

   a. avoided capacity costs (unforced capacity, or "UCAP", value avoided through VPP-driven reductions in each EDC's coincident-peak contribution, estimated from applicable capacity auction results);

   b. avoided or deferred T&D infrastructure costs that are directly attributable to VPP services, having been explicitly incorporated into VPP program design and dispatch; and

   c. progress toward peak demand reduction targets.

Reported savings shall identify the basis of estimate and the methodology used.

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.

6.2 DER Registry

Staff recognizes that a statewide DER Registry is a foundational component of both the long-term VPP framework and the PSUP filing requirements under Docket No. QO24030199. Rather than establish a separate VPP-specific registry, Staff proposes that the DER Registry required under the PSUP Order serve as the unified registry for VPP program purposes. The PSUP framework intends to require each EDC to develop a DER Registry with a consistent structure and common data by the four EDCs – that architecture satisfies the VPP program's enrollment verification, anti-double-counting enforcement, locational tracking, and PJM wholesale market coordination functions.

The minimum data fields for VPP enrollment and dispatch tracking shall be those specified in Appendix B of the PSUP Straw Proposal (Docket No. QO24030199), as finalized in the PSUP MFR Order. Staff does not propose additional VPP-specific registry fields at this time but reserves the right to supplement the PSUP registry requirements through the VPP MFR Order if operational experience during the VPP Interim Program identifies gaps.

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.

6.3 DER Aggregator Licensing and Code of Conduct

Staff proposes the establishment of a DER aggregator licensing framework administered by the Board to ensure that third-party aggregators operating in New Jersey's VPP market meet minimum standards of financial capability, operational competence, and consumer protection. Licensing provides the Board and the public with a list of authorized aggregators eligible to enroll New Jersey ratepayers in VPP programs and creates accountability mechanisms for aggregator conduct.

Staff proposes that DER aggregator licenses be issued by the Board on an annual basis, with renewal required each year. The proposed application fee for a DER Aggregator License is $200 with a $100 annual renewal fee. Annual renewal will align with wholesale market timelines for confirming DERA participation in PJM market products. The licensing process should include:

i. **Application requirements – Applicants must demonstrate**:
   a. financial viability (minimum capitalization or bonding requirement, to be established by the Board in future proceedings based on stakeholders' feedback);

   b. technical capability to meet the monitoring, control, and reporting requirements established in the VPP tariff;

   c. a customer service plan, including a complaint resolution process;

   d. compliance with applicable data privacy and cybersecurity requirements;

e. possession of all valid licenses, registrations, and certifications required by applicable federal, State, county, or local law to operate as a DER Aggregator in New Jersey;

f. an attestation that the applicant and its principals have not, within the preceding five years, been debarred or suspended by any federal, State, or local government agency, nor had any business, contracting, or trade license, registration, or certification revoked or suspended;

g. an attestation that the applicant and its principals have not, within the preceding five (5) years, been convicted of any crime relating to the operation of a business; and

h. an attestation that the applicant has not, within the preceding five years, been found in violation of any energy, consumer protection, data privacy, or related regulatory law applicable to its business where the result was the payment of a fine, restitution, or other penalty.

ii. **Code of Conduct**: Licensed aggregators must comply with a Board-established code of conduct governing their interactions with enrolled customers. The code of conduct should address, at minimum:

a. required disclosures in customer agreements;

b. prohibited sales and enrollment practices;

c. limitations on financial penalties imposed on customers for opt-outs;

d. customer data usage restrictions; and

e. obligations to notify enrolled customers of changes to program terms.

iii. **Reporting:** Licensed aggregators must comply with Board-established reporting requirements to ensure consistency.

iv. **Enforcement**: The Board should have authority to suspend or revoke an aggregator's license for material violations of the code of conduct, failure to maintain required capitalization, or persistent performance failures. The Board may also impose administrative penalties in accordance with applicable law.

Staff notes that Maryland's Public Service Commission ("PSC") established an analogous DER Aggregator licensing framework pursuant to MDPSC Order 91674, which requires aggregators to obtain a license before enrolling Maryland customers in wholesale market programs. New York's Reforming the Energy Vision ("REV") proceeding similarly established qualification standards for distributed system platform providers. Staff's proposal draws on these precedents while adapting them to New Jersey's regulatory structure.

Staff proposes that each EDC, as part of establishing the tariff, maintain and publish a list of currently licensed aggregators on its website, updated on a quarterly basis, and to provide this list to customers who inquire about VPP participation. Providing customers with a list of Board-approved aggregators reduces the risk of customer harm from unqualified or fraudulent operators and supports informed consumer choice.

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; and 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.

6.4 Cybersecurity

VPP operations can pose cybersecurity risks. Aggregators send dispatch signals to many behind-the-meter devices, and customer data moves among customers, aggregators, EDCs, and PJM. Staff proposes a **shared-responsibility model**, with roles set out below. Standards should be scaled to the sensitivity of the data and the impact of the service, so that a single residential battery or smart thermostat does not face the same cybersecurity requirements as a large commercial or utility-scale resource. Staff recognizes that many existing commercial platforms already provide the core security functions needed for dispatch and customer data protection, such as encrypted communications, access control, and incident response. The VPP Interim Program is not intended to wait on, or be conditioned upon, a full set of cybersecurity standards. At the same time, the Interim Program should begin building the baseline practices and requirements that the long-term program will rely on, so the transition is smooth. The detailed standards should be developed through the stakeholder process described below.

Staff proposes the following allocation of cybersecurity and data-protection responsibilities:

i. **The Board**: establishes minimum cybersecurity, data-privacy, and interoperability standards for all participants, and reviews them periodically. The Board verifies compliance primarily through certifications and third-party attestations submitted by participants rather than Board-conducted audits, enforces those standards under the authority in **Section 6.3**, and serves as the final authority for unresolved data-access and security disputes.

ii. **EDCs**: secure the systems that receive, validate, and store aggregator data. EDCs operate the Grid DERMS in a securely segmented environment, whether on-premises or cloud-hosted, connect to it only through controlled interfaces, and keep audit logs and intrusion detection. EDCs must share data securely; once data is shared under approved protocols, the receiving aggregator is responsible for protecting it, subject to the Code of Conduct (**Section 6.3**) and Board enforcement.

iii. **Third-party Aggregators, OEMs, and DERMS providers**: secure devices, communications, and customer data using the recognized standards described below, including encryption, strong access control, and patch management. They must obtain and keep customer authorization, ensure equipment integrations meet program standards, maintain an incident-response plan, and report incidents and data breaches on the timelines and thresholds to be established.

iv. **Customers**: authorize the collection and sharing of their energy-usage data and can see what is collected and with whom it is shared, consistent with Information Sharing and Transparency in **Section 6.1**.

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.

Data access and security rules should match the sensitivity of the data; hence, staff proposes a three-tier data-access structure:

6.4 (a) Tier 1: Enrollment Data

Customer ID, enrollment status, DER type and capacity, and feeder location: shared between the EDC and aggregator under a data-sharing agreement. No customer consent is needed beyond program enrollment, though this data – including feeder location – remains subject to the security and confidentiality under Information Sharing and Transparency **in Section 6.1**. The Board will require an enrollment process that is as frictionless as possible for the customer while still yielding the information necessary to complete enrollment. Where feasible, EDCs should obtain identifying information such as the customer account or meter ID through utility-side account matching rather than requiring the customer to supply it at enrollment.

6.4 (b) Tier 2: Interval Meter Data

AMI data at fifteen-minute or finer intervals: needs customer authorization. It should be shared through the Green Button Data Standard or EDC-hosted EDI portals, consistent with Information Sharing and Transparency **in Section 6.1**.

6.4 (c) Tier 3: Real-time dispatch data

Sub-minute device-level control signals: governed by a direct aggregator-customer agreement and the strongest controls, including end-to-end encryption, mutual authentication, continuous monitoring, and role-based access.

Stakeholder Comment No. 35	Staff requests comment on whether this three-tier data-access structure (enrollment, interval meter, and real-time dispatch data) is the appropriate framework, and whether the consent and security requirements assigned to each tier are correctly calibrated.

All participants (e.g., EDCs, aggregators, OEMs, and DERMS providers) should follow recognized security frameworks. This lowers cost and lets participants use certifications they already hold. A baseline set of standards will be required of all participants, while the broader operational-technology catalogs serve as guidance for EDC-operated DERMS rather than as requirements for every aggregator.

VPP aggregators are encouraged to utilize the NIST Cybersecurity Framework (CSF) and will be required to follow the baseline set of standards listed in the table below. Staff continues to evaluate appropriate methods for VPP aggregators to demonstrate compliance with these standards, but anticipates at least accepting SOC 2 Type II reports.

Required of all VPP aggregators or vendors:

Standard	What it covers
Foundational Guidance	
NIST Cybersecurity Framework (CSF)	Overall security governance
Required Standards	
IEEE 1547.3-2023	DER-specific cybersecurity guidance
IEEE 2030.5 and 2.0b/3.0 (with	Secure device communication and dispatch signaling (as

built-in security profiles: mutual TLS and certificate-based authentication)	mentioned in Sections 2.3 and 3.4)
Green Button Data Standard	Secure, API-based exchange and authorization of customer energy-usage data; supports the interval-meter data tier and customer authorization

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. b. Staff recognizes that the cost of a SOC 2 Type II report may represent a significant financial barrier for some aggregators. As such, Staff requests comments from stakeholders on alternative compliance pathways that provide flexibly through certification, third-party attestation, or vendor documentation.

Grid DERMs and operational-technology systems will be required to follow a set of foundational or "Backbone Standards", as well as elements of "Complementary Standards" that are not captured in the "Backbone Standards". Grid DERMs and operational-technology systems are also encouraged to follow relevant elements of the NERC Critical Infrastructure Protection (CIP) Standards and, of course, comply with such requirements where necessary.

Standards for EDC-operated Grid DERMS and operational-technology systems:

Standard	What it covers
Backbone Standards	
NIST SP 800-53	Security and privacy controls catalog
NIST SP 800-82 (Rev. 3)	Operational-technology (OT) system security
DOE DataGuard Energy Data Privacy Program	Voluntary code of conduct for customer energy-usage and billing data privacy
Complementary Standards	
IEC 62443	Industrial automation and control systems security
NIST SP 800-61	Incident-response planning and handling; informs the incident-response plan required of aggregators
IEC 62351	Power-system communication security; companion to IEEE

	2030.5 for EDC-facing dispatch interfaces
Required as Compliance Dictates; Otherwise Encouraged	
NERC Critical Infrastructure Protection (CIP)	Bulk-system security, applied as informed practice at the distribution level

Customer privacy should be protected by collecting only what is needed, handling personal information carefully, and getting clear consent. Only data needed for operations, settlement, and compliance should be shared. Where possible, measurement and verification should use grouped data rather than individual customer records. **Section 6.1** and the Code of Conduct in **Section 6.3** also apply.

Aggregators and EDCs should report serious cybersecurity incidents that affect VPP operations (e.g., a 1,000-customer notice trigger) to the Board **within five business days**, using existing utility reporting channels where possible. Confidential treatment is available under N.J.A.C. 14:1-12. Consistent with the AMI Data Access rule proposal, unauthorized releases of customer information shall be noticed within 48 hours. The Board may suspend or remove an aggregator from the qualified list for repeated failure to meet data, dispatch, or cybersecurity obligations, under the enforcement authority in **Section 6.3**.

The detailed technical rules, which will build on the foundation laid out in this straw proposal, will be developed by the VPP Implementation Working Group (**Section 4.9**) in partnership with the GridFlex Services Workgroup, so that such rules are consistent with the PSUPs. These rules will cover encryption, device authentication, supply-chain and firmware controls, network separation between VPP control systems and corporate IT, and the incident-reporting threshold, recipients, and timeline. Staff intends the standards to apply statewide, with compliance accepted across EDCs to avoid duplicate reviews.

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; and e. whether the required standards are achievable within the VPP Interim Program timeline.

6.5 Equity and Low-and-Moderate-Income Access

Ensuring equitable access to VPP program benefits is a central priority of this Straw Proposal, consistent with the Board's obligations under the New Jersey Environmental Justice Law (P.L. 2020, c. 92) and the Board's longstanding commitments to universal service and ratepayer protection.

Staff will assess projected LMI bill impacts as VPP program costs and budgets are developed, with the goal of ensuring that programs benefits are distributed equitably across customer classes.

Staff notes that the DOE VPP Liftoff Report identifies equity as one of three cross-cutting challenges for VPP deployment at scale, and that several states – including California, Illinois, Massachusetts, Connecticut, and New York – have established dedicated LMI VPP tracks with modified program requirements to reduce participation barriers. Vermont's Green Mountain Power BYOD (bring-your-own-device) program has demonstrated that device-agnostic, customer-centric program designs can achieve significant LMI enrollment when combined with targeted outreach and no-cost device installation options. Staff recommends that the Board study these programs as models for New Jersey's LMI VPP strategy.

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.

SECTION 7. VPP MARKETING AND PUBLIC OUTREACH

Staff recognizes that consumer awareness and trust are essential preconditions for successful VPP program enrollment and operation. A VPP program must be both technically well-designed and effectively communicated to potential participants to achieve VPP Program's objectives. This section describes Staff's proposed marketing and outreach framework, which allocates responsibilities among the Board, the EDCs, and third-party aggregators.

7.1 VPP Education and Public Outreach

Staff proposes that the Board convene a public stakeholder meeting following the release of the VPP Straw Proposal. The meeting should be designed to explain, in plain language:

i. What the goals of this Straw Proposal are in the short- and long-term;

ii. What the current DR and VPP Programs are in New Jersey; and

iii. How these programs have worked in other states

Staff envisions a long-term education and stakeholder process, with regular meetings to discuss the various workstreams that will impact and inform VPPs. The proposed schedule is:

Target Date / Period	Milestone / Activity
Q3 2026	VPP Straw Proposal Released; Conference on existing EDC programs, VPP best practices, and stakeholder feedback on the straw
Q4 2026	Net metering Report Discussions on VPP, Storage and how PSUP will impact programs Light Duty EV Straw
Q1 2027	Discussion on PJM and VPP data collection and communication Net Metering Reform Straw VPP/Grid Flex Tariff Straw
Q2 2027	Discussion on Clean Transportation interaction with VPPs
Q3 2027	Discussion on Solar interaction with VPPs
Q4 2027	
Q1 2028	VPP Interim Programs Review, VPP Long Term Programs Filing
Q2 2028	
Q3 2028	Future of EDC DR Program Straw Released
Q4 2028	Future of EDC DR Program MFR Filing

7.2 BPU Marketing

Staff also proposes a series of marketing campaigns that should be coordinated with the existing consumer outreach infrastructure within the NJBPU and should leverage multiple media channels, including NJBPU Clean Energy Website, digital advertising, social media, and community partnerships with trusted organizations, to ensure that materials are appropriate and accessible to customers.

These campaigns should be coordinated with the timing of the MFR Order to provide New Jersey residents with information about what VPPs are, what they can expect from them and when programs will be developed.

7.2 EDC Marketing

Staff proposes that each EDC's VPP Interim Program filing includes, as part of the MFRs in Section 2.9, a customer marketing plan addressing:

i. How the EDC will promote participation in the VPP Interim Program through bill inserts, digital communications, and customer service channels (e.g., website, social media);

ii. How the EDC will provide information to customers about the list of Board-approved third-party aggregators available in its service territory; and

iii. How the EDC will ensure that customers receive timely notification of dispatch events and opt-out instructions.

Once the long-term VPP tariff is operational, Staff proposes that each EDC be required to distribute marketing materials to customers on behalf of registered aggregators on a quarterly basis, at no cost to the aggregator, as a condition of the non-discriminatory access requirements of the tariff. This provision ensures that even smaller aggregators without extensive marketing budgets have access to the EDC's customer communication channels. Staff proposes that the materials be subject to Board review to ensure accuracy and consistency with program terms.

7.3 Third-Party VPP Provider Marketing

VPP providers are expected to be the primary driver of customer enrollment in the long-term VPP market and are expected to fund their own customer acquisition and marketing activities as part of their business model. Staff notes VPP provider marketing costs, as a component of the overall cost of building and operating a VPP portfolio, will be visible to the Board through the annual cost reporting requirement.

Staff proposes that the aggregator licensing code of conduct (**Section 6.3**) establish clear requirements for marketing materials accuracy and prohibited practices, including prohibitions on misrepresenting program benefits, financial implications, or the Board's endorsement of any specific provider. VPP providers must clearly distinguish in their marketing materials between NJBPU-regulated program benefits and any additional commercial benefits or services the aggregator may offer.

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.

SECTION 8. IMPLEMENTATION TIMELINE

Staff proposes the following preliminary implementation timeline for the VPP Program. Dates are subject to revision following stakeholder comment and Board Decision.

Target Date / Period	Milestone / Activity
Q3 2026	VPP Straw Proposal Released; Triennium Program Year 7 Order PJM Peak Shaving Adjustment Plan Due
Q4 2026	VPP MFR Order/Filings Due Net metering Report Triennium PY 7 Filings Triennium 3 Order PSUP Order Light Duty EV Straw
Q1 2027	Net Metering Reform Straw VPP/Grid Flex Tariff Straw Triennium 3 Filings Due MHD Filings
Q2 2027	VPP Interim Program MFR Filing Settled PSUP Filings Due Triennium Program Year 7 Approved VPP/Grid Flex Tariff Order Net Metering Reform Order
Q3 2027	VPP Interim Program Begins Triennium Program Year 7 Begins PJM Peak Shaving Adjustment Plans Due
Q4 2027	
Q1 2028	VPP Interim Programs Review VPP Long Term Tariff Filing
Q2 2028	VPP Interim Program Report Submitted

Q3 2028	Future of EDC DR Program Straw Released
Q4 2028	Future of EDC DR Program MFR Filing

Stakeholder Comment No. 40	Staff seeks feedback on the proposed timeline.

Stakeholder Comment No. 41	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.

SECTION 9. APPENDICES

Appendix A: Proposed Peak Shave Goals

Table 1 – MW Shaved at Each Target

EDC	Peak Load (MW)	2% (MW)	3% (MW)	4% (MW)	5% (MW)	6% (MW)	7% (MW)
PSE&G	10,229.5	204.6	306.9	409.2	511.5	613.7	716.1
JCP&L	6,273.4	125.5	188.2	250.9	313.7	376.4	439.1
ACE	2,709.1	54.2	81.3	108.4	135.5	162.5	189.6
RECO	422.9	8.5	12.7	16.9	21.1	25.4	29.6
Statewide	**19,634.9**	**392.7**	**589.0**	**785.4**	**981.7**	**1178**	**1374.4**

Table 2 – Gross Annual Capacity Cost Savings ($ mm/yr)

Savings = MW shaved x FPR x BRA price x 365 x performance factor (91% based on PJM ELCC Class Rating for 28/29 DY)

EDC	Peak Load (MW)	2% ($mm/yr)	3% ($mm/yr)	4% ($mm/yr)	5% ($mm/yr)	6% ($mm/yr)	7% ($mm/yr)
PSE&G	10,229.5	$21.3	$31.9	$42.6	$53.2	$ 63.8	$ 74.5

JCP&L	6,273.4	$13.1	$19.6	$26.1	$32.6	$ 39.2	$ 45.7
ACE	2,709.1	$5.6	$8.5	$11.3	$14.1	$ 16.9	$ 19.7
RECO	422.9	$0.9	$1.3	$1.8	$2.2	$ 2.6	$ 3.1
Statewide Saving	**19,634.9**	**$40.8**	**$61.3**	**$81.7**	**$102.1**	**$ 122.5**	**$ 143.0**

Table 3 – Gross Annual Capacity Cost Savings ($ mm/yr)

Savings = MW shaved x FPR x BRA price x 365 x performance factor (64% based on average DR participation in 2025 events)

EDC	Peak Load (MW)	2% ($mm/yr)	3% ($mm/yr)	4% ($mm/yr)	5% ($mm/yr)	6% ($mm/yr)	7% ($mm/yr)
PSE&G	10,229.5	$14.8	$22.2	$29.6	$37.0	$ 44.4	$ 51.8
JCP&L	6,273.4	$9.1	$13.6	$18.2	$22.7	$ 27.2	$ 31.8
ACE	2,709.1	$3.9	$5.9	$7.8	$9.8	$ 11.8	$ 13.7
RECO	422.9	$0.6	$0.9	$1.2	$1.5	$ 1.8	$ 2.1
Statewide Saving	**19,634.9**	**$28.4**	**$42.6**	**$56.8**	**$71.0**	**$ 85.2**	**$ 99.4**

Methodology, Math, and Source Justification

1. Peak loads (MW)	PSE&G 10,229.5 / JCP&L 6,273.4 / ACE 2,709.1 / RECO 422.9 MW. Source: PJM, Network Service Peak Loads 2026, https://www.pjm.com/-/media/DotCom/markets-ops/settlements/network-service-peak-loads-2026.pdf. These are the zonal peaks PJM uses for transmission/capacity settlement allocation, making them the right base for sizing the value of shaving each zone's peak.
2. Why peak shaving saves money	PJM allocates capacity costs to Load Serving Entities (LSEs) based on their zone's contribution to system peak. Load serving entities in a zone must buy capacity equal to peak load contribution times a reserve-margin gross-up. If VPP dispatch reduces the zone's measured peak (and that reduction flows into PJM's load forecast, e.g., via a Peak Shaving Adjustment, or into lower customer PLCs), the zone buys fewer MW of capacity, and that avoided cost flows to ratepayers.
3. Core formula	Annual savings ($) = Peak Load (MW) x Shaving % x FPR x BRA clearing price ($/MW-day) x 365 days x Performance factor. Example (PSE&G, 1%, FPR 0.926, 100% performance): 10,229.5 x 1% = 102.3 MW; 102.3 x 0.926 x $333.44 x 365 x 1 = ~$11.5 million/year.
4. Capacity price: $333.44/MW-day	PJM 2027/2028 Base Residual Auction cleared at the FERC-approved cap of $333.44/MW-day (UCAP) across the entire PJM footprint (up 1.3% from $329.17 in 2026/2027). Source: PJM 2027/2028 BRA Report, Dec. 17, 2025, https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-report.pdf. Because all zones cleared at the cap, one price applies to all four NJ EDC zones. Note this is a capped price: PJM's simulation indicates an uncapped clearing of roughly $530/MW-day, so the savings here are conservative relative to an untapped market.
5. FPR gross-up (0.926)	Load's daily capacity obligation equals its peak load contribution times the Forecast Pool Requirement, which embeds the installed reserve margin (target IRM ~17.8% per PJM's Q3 2025 State of the Market figures cited in the RFI record) net of pool-average forced-outage derating. A value of 0.926 is consistent with recent PJM planning parameters. Each MW of avoided peak therefore avoids slightly more than 1 MW of purchased capacity. Set the cell to 1.00 on the Assumptions sheet for a no-gross-up conservative case. Verify against the current PJM Planning Period Parameters before external use.
6. Performance factor	Savings only materialize if the shaved MW perform during the five coincident peak (5CP) hours that set capacity obligations, or are reflected in PJM's load forecast. Devices fail, customers override, and events can be mis-forecast. Table 2 shows statewide savings at 91% realization to reflect the ELCC Class Rating for DR for the 2028/2029 Delivery Year. Table 3 shows statewide savings at 64% realization to reflect average DR participation across the five events in 2025. The VPP RFI record (e.g., Massachusetts ConnectedSolutions: ~$19M program cost vs ~$51M savings, per ACT's filing) supports the premise that well-run programs achieve net-positive ratios. ~$51M savings, per ACT's filing) supports the premise that well-run programs achieve net-positive ratios.
7. What is NOT included	(a) Program costs: incentives, aggregator payments, M&V, administration – gross savings shown, not net benefits. (b) Transmission savings: peak shaving also reduces NSPL-based network transmission charges, an additional upside. (c) Energy and ancillary value during dispatch. (d) Avoided distribution investment / NWA deferral value. (e) Capacity price suppression effects: large load-forecast reductions can lower the clearing price itself for ALL load, a potentially much larger benefit not modeled here.

8. Key risks to the estimate	(a) Future BRA prices may fall if supply responds or the cap framework changes. (b) PJM must recognize the reduction (Peak Shaving Adjustment timing matters; forecast reductions affect Incremental and future Base Residual Auctions). (c) Double-counting: MW already enrolled in PJM demand response or wholesale supply cannot also be counted as load-forecast reductions. (d) Peak loads shift year to year; 2026 NSPL values are a snapshot.