STRAW PROPOSAL - PROACTIVE SYSTEM UPGRADE PLANNING REQUIREMENTS

Proposed Guidelines and Requirements for Electric Distribution Companies' Filing of Proactive System Upgrade Plans to indicate three- and ten-year distribution grid planning strategies.

New Jersey Board of Public Utilities, Division of Clean Energy

Executive Summary

The objective of this document is to propose guidelines for New Jersey's electric distribution companies ("EDCs") to create and publicly file Proactive System Upgrade Plans ("PSUPs" or "Plans"). PSUPs align with the goals expressed in Governor Mikie Sherrill's Executive Order No. 1 ("EO1")[1] and Executive Order No. 2 ("EO2")[2] which call for acceleration of Distributed Energy Resource ("DER") deployment, especially solar and battery energy storage; development of policy to encourage and enable Virtual Power Plants ("VPP"); and examination of more transparent and modern utility rate and cost recovery mechanisms including multi-year rate plans, re-examination of infrastructure improvement investment ("IIP") rate recovery mechanisms, and other innovative rate-setting frameworks. PSUPs are a policy tool which, when aligned with other potential policy initiatives, will qualitatively describe cost-effective three- and ten-year distribution system strategies to:

i. Affordably increase generation hosting and load-serving ("integration") capacity to prepare for increased penetration of DERs and load growth from electric vehicle ("EV") charging infrastructure and data centers;
ii. Utilize DER Management Systems ("DERMS") and relevant non-traditional distribution solutions, such as Volt/VAR control and energy storage systems, to better oversee the distribution system and increase distribution system utilization; and
iii. Enable the participation of DERs to form configured and orchestrated VPPs to improve distribution system operational flexibility, locally serve load, and provide opportunities for grid service compensation.

PSUPs intend to establish a qualitative and visionary planning mechanism for distribution grid expansion to interconnect and utilize clean energy resources; identify prudent grid modernization investment types including traditional but highly selective substation and feeder upgrades that are envisioned in conjunction with non-traditional distribution solutions for cost-effective system segment improvement; and enable a future energy system that is more flexible, participatory, and equitable. While cost and rate recovery mechanisms will be examined in separate proceedings, ultimately PSUPs can inform more transparent and stable recovery of needed infrastructure costs.

Staff of the Board of Public Utilities ("Board" or "NJBPU") extends gratitude to the members of the Integrated Distribution of Distributed Energy resources ("IDDER") Workgroup (In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid, BPU Docket #QO24030199) for input on technical capabilities, newer technologies, and current system capabilities and planning processes. The IDDER Workgroup was organized by the Board under its Grid Modernization Forum ("GMF"). The members of the IDDER workgroup include the following entities and organizations:

- Atlantic City Electric ("ACE");
- Clean Energy States Alliance ("CESA");
- Electric Power Research Institute ("EPRI");
- Institute of Electrical Engineers and Electronics ("IEEE");
- Interstate Renewable Energy Council ("IREC");

[1] Exec. Order No. 1 (Jan. 20, 2026), 58 N.J.R. 1039(b) (Feb. 17, 2026).
[2] Exec. Order No. 2 (Jan. 20, 2026), 58 N.J.R. 1041(a) (Feb. 17, 2026).

- Jersey Central Power & Light ("JCP&L");
- Lawrence Berkeley National Laboratory ("LBNL");
- Mid-Atlantic Solar and Storage Industries Association ("MSSIA");
- New Jersey Department of Environmental Protection ("NJDEP");
- Public Service Gas and Electric ("PSE&G");
- Rockland Electric Company ("RECO"); and
- Solar Energy Industries Association ("SEIA").

NJBPU Staff ("Staff") appreciates all the entities listed above for their time, insightful collaboration, and thoughtful discussion, as well as for the valuable input provided by various subject matter experts brought in for select topical presentations to the group. Staff looks forward to receiving additional feedback from all members of the stakeholder community on the current draft.

Proactive System Upgrade Plan Outline and Requirements

I. Introduction

a. Background

This straw proposal lays out a proposed framework for future PSUPs to be filed by New Jersey EDCs which would subsequently be updated every three years thereafter, at minimum.

The purpose of a PSUP is to provide transparency into the EDC's assessment of: the state of their distribution system in terms of system oversight, asset control, optimization, and DER dispatch; forecasted future DER penetration and load growth; potential expansion or upgrade project types to increase integration capacity or address other grid needs; what cost-effective or non-traditional distribution solutions are/were considered in lieu of or to complement traditional infrastructure investments; and the EDC's plan to integrate load growth with generation by enabling DERs to participate in orchestrated VPPs, while reducing costs to NJ ratepayers.

PSUPs do not govern or mandate specific capital investments or preclude capital investments not included in a PSUP. PSUPs do not constitute requests for cost recovery but rather an EDC would be required to formally file a PSUP with the Board targeting upgrade paths for which the EDC could later request cost recovery.

b. Procedural History

Executive Order 28, signed by Governor Murphy on May 23, 2018, directed the Energy Master Plan Committee, chaired by the Board, to complete an Energy Master Plan ("2019 EMP") that would provide a comprehensive blueprint to achieve 100% clean energy in New Jersey by 2050.[3] The 2019 EMP identifies several strategies to achieve New Jersey's clean energy and greenhouse gas emissions reduction goals. Key among the 2019 EMP strategies is the accelerated procurement of renewable energy and distributed energy resources and the electrification of the transportation and building sectors. These strategies were further supported in the 2020 Global Warming Response Act 80x50 Report published by the New Jersey Department of Environmental Protection.[4]

Staff undertook a comprehensive stakeholder process to implement the interconnection reform process called for in the 2019 EMP and reiterated in the 2024 Energy Master Plan ("2024 EMP") and held five separate stakeholder meetings between October 26, 2021, and June 27, 2022, involving hundreds of oral and written comments. Guidehouse, Inc., the Board's contracted consultant, compiled these comments, as well as learned best practices from other states, into a final report with nine specific recommendations for modernizing New Jersey's electric distribution grid ("Grid Mod Report"). The recommendations were to:

1. Implement the Institute of Electrical and Electronics Engineers standard 1547-2018 across all EDC service territories;
2. Streamline and automate the interconnection application process;
3. Improve the accuracy and usability of EDC hosting capacity maps;
4. Establish a mandatory pre-application process for new interconnection requests above a certain size;
5. Update EDC tariffs to incorporate new interconnection rules;

[3] Exec. Order No. 28 (Murphy, May 23, 2018), 50 N.J.R. 1394(b) (June 18, 2018).
[4] DEP 80x50 Report. NJDEP| Climate Change | GWRA 80x50 Report (Accessed Jan. 14, 2026)

6. Improve the efficiency of sequencing interconnection studies, including through clustering and other similar methods;
7. Update methodologies for determining upgrade cost allocation and estimation;
8. Develop an integrated distribution distributed energy resource ("IDDER") plan; and
9. Interconnect hybrid resources that include both emitting and non-emitting energy resources behind a single meter.

The Board accepted the Grid Mod Report on November 9, 2022, and tasked Staff with implementing all of the recommendations. Recommendations 1 through 4 were considered "near-term" concepts that could be immediately implemented through proposed amendments and new rules at N.J.A.C. 14:8. Recommendations 5 through 9 were "longer-term" concepts that required workgroup deliberations before implementation, due to the more complex market and EDC business-model implications.

Board Staff formed the Grid Modernization Forum ("Forum") in response to recommendations 5 through 9 in the Grid Mod Report with the intention to establish expert working groups that are focused on the individual recommendations. The IDDER workgroup, which corresponds to Recommendation #8 of the Grid Mod Report, was formed on July 15, 2024 to develop recommendations for reasonable minimum filing requirements for EDCs to proactively identify grid needs and develop solutions at a reasonable cost without burdening ratepayers. The IDDER workgroup met biweekly through December 16, 2025. A summary of workgroup discussions can be found at BPU Docket #QO24030199, In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid.

c. Authority

The authority for this straw proposal is derived from N.J.S.A. 48:2-13 and 48:2-16.

d. Instructions for Straw Comments

The deadline for comments on this Straw Proposal is 5:00 P.M. on May 29, 2026. Please submit comments for BPU docket No. QO24030199 (*In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid*) directly by using the Board of Public Utilities' (Board) Public Document Search tool, search for the specific docket listed above and post by utilizing the "Post Comments" button. Written comments may also be submitted. Please include subject matter and docket number and submit to:

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Secretary of the Board
New Jersey Board of Public Utilities
44 South Clinton Ave., 1st Floor
PO Box 350
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II. Definitions

"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 secure two-way communication between utilities and customers' meters").

"AMI Data" means 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. For the purposes of this subchapter, AMI data does not refer to any other data collected independent of the customer's usage, unless specifically stated as such.[5]

"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" has the same meaning as defined in N.J.A.C. 14:8-5.1 ("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").

"DER Aggregation" has the same meaning as defined in N.J.A.C. 14:8-5.1 ("a grouping of discrete interconnected customer-generator facilities or behind the meter load-modifying resources working as a combined or coordinated group for purposes of providing energy, grid services, or other value streams, on an aggregated basis, for the purposes of participating in either retail or wholesale markets"). See also "**Virtual Power Plant"** or **"VPP."**

"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 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 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,

[5] Identical to the definition proposed as N.J.A.C. 14:5-10.2 at 57 N.J.R. 1949(a) (2025).

demand response, and load flexibility. The platform can be divided into two subtypes, which should be standardized and interoperable to the greatest extent:

> **"Grid DERMS"** means a centralized monitoring or management of utility-scale/grid-wide DERs for reliability and support coordinated, system-wide stability, operations, power flow optimization.
>
> **"Edge DERMS"** means a decentralized or 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 System" – EDC PSUPs should provide the definition of Distribution System that they use for purposes of system planning. For the purposes of planning, distribution systems might include components of the cyber-physical distribution grid as represented by the information, telecommunication, and operational technologies needed to support infrastructure comprised of transformers, wires switches, and other apparatuses.

"Distribution Services" means benefits to the electric power system that DERs or other non-traditional distribution solutions can provide, such as distribution capacity, voltage support, reliability, and resiliency, including wildfire and flood prevention, mitigation, and recovery.

"Flexible Interconnection or Energization Tariff" means a way to energize a new load or interconnect a distributed energy resource to an EDC's system that is governed by a set of rules and requirements and includes an agreement for curtailing the import or export of electricity from and to the electric distribution system at certain times or operation conditions by use of certified power control systems or other load management technologies.

"Grid Enhancing Technology" or **"GET"** means hardware or software that reduces congestion or enhances the resiliency and flexibility of electric transmission and distribution systems by increasing the capacity of a line or rerouting electricity from overloaded to uncongested lines and includes but is not limited to dynamic line ratings, advanced power flow conductors, and topology optimization.

"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 be connected to the distribution system 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 or GETs to defer or replace traditional infrastructure upgrades or other identified grid needs when deemed cost effective. It means the same as non-wires alternatives.

"Proactive System Upgrade Plan" or **"PSUP"** means a comprehensive strategy that keeps the public informed and guides utilities in requesting approval for infrastructure investments (through traditional Rate Case and IIP mechanisms) over a specified timeframe to meet the evolving needs of the distribution grid and seamlessly incorporate, manage, and optimize participating DERs.

"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.

"Trend Assessment Report" or **"TAR"** means an interim update (submitted halfway to the next PSUP filing) that provides a narrative form identification of observed trends in technology, markets, demand, policies, and other areas that could develop into significant changes to the revised PSUP. A TAR filing is intended for transparent communication to and consumption by the general public.

"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. A variation is known as V2X which includes other behind the meter exports such as home power backup.

"Virtual Power Plant" or **"VPP"** means a configured and orchestrated network of DERs, including demand responsive load management and power export, which is called through a centralized software-based platform to provide distribution services. See also "**DER Aggregation."**

III. Objectives

The PSUP relies on a data-based review of the current and recent historical system characteristics, asset health, load serving and generation hosting interconnection trends, and relevant operations to provide basis and context. The EDCs may re-submit information from the Annual System Performance Report ("ASPR"), required under N.J.A.C. 14:5-8.8, with the PSUP to help establish the reliability and performance aspects of the Baseline Distribution System Assessment.

The goal of an electric distribution system PSUP is to provide the Board and other interested parties with a comprehensive understanding of the EDC's identified system upgrade needs and prioritization of possible infrastructure investments that support the State's resource planning, policy, and grid modernization objectives including acceleration of DER integration and streamlined interconnection, enhanced resilience and reliability, increased grid utilization, and lower costs to customers. In addition, an overarching objective is to modernize the electric grid in New Jersey in a manner that supports the achievement of the State's clean energy goals, as outlined in the 2024 EMP and Governor Sherrill's EO1 and EO2, through increased integration capacity, asset oversight, and orchestration of DERs. The EDCs shall be guided by the following objectives for their PSUPs:

1. Perform a Baseline Distribution System Assessment and identify current levels of distribution system utilization, DER asset visibility, and DER control and dispatch;
2. Forecast anticipated load and distributed generation growth and identify areas of the grid which are anticipated to have limited integration capacity;
3. Propose reliable and cost-effective non-traditional distribution system solutions to increase integration capacity, operational flexibility, and security to support customer generation and electrification needs; and
4. Create avenues for DER participation and orchestration in a retail market and optimize DER value through advanced grid management capabilities.

The PSUP and updates should be in accessible formats that are easy to understand for non-technical stakeholders.

IV. Schedule and Stakeholder Outreach

Each EDC will submit its draft PSUP to the Board Secretary and post publicly-available versions to Docket No. QO24030199 (*In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid*). Public comments posted to the docket may be considered by the EDCs as advisory. Public versions of the PSUP will also be posted to the EDC's internet website. Board Staff will review each EDC's PSUP and, within 90 days of filing, either the Board will approve the filing or Staff will request revisions. The EDCs may submit their PSUPs in accordance with their company's existing study cadence and include relevant data from their most recently filed ASPR, as required under N.J.A.C. 14:5-8.8, to reduce administrative burden.

In addition to the initially filed plan and its subsequent three-year updates, there is a required Trend Assessment Report ("TAR") to be filed halfway between each update that is intended to keep the public current on early observed trends that could signal significant pivots in the next PSUP update.

V. Confidentiality

An EDC may include in its filing requests for confidential treatment of any portion or portions of a PSUP pursuant to the Board's regulations at N.J.A.C. 14:1-12.1.

VI. Filing Requirements

a. Baseline Distribution System Assessment

The Baseline Distribution System Assessment shall focus on information that directly informs integration capacity, DER interconnection efficiency, distribution-level flexibility, or DER management and dispatch needs. Operational program descriptions shall be included only where they materially affect integration capacity or DER operations. EDCs shall provide aggregated, non-sensitive summaries in the public PSUP filing. Detailed feeder-level topology, asset health data, or vulnerability-related information may be submitted confidentially pursuant to N.J.A.C. 14:1-12.

1. **Customer Base.**

The EDC shall provide a breakdown of its customer base by sector (e.g., residential, commercial, industrial) and by rate classification type (e.g., standard electric, electric heating, geothermal HVAC). The EDC shall also identify any large load customers, including data centers, within its service territory.

2. **System Data.**

(a) Asset Health and Condition: The EDC shall provide a summary of its distribution system assets to provide the basis of its planning efforts. Relevant information includes, but is not limited to the asset age, condition (such as failure rates, outage/interruption causes, and quantifiable impacts from extreme weather events), location, planned upgrades, or decommissioning;

(b) Threat-based risk assessment: The EDC shall provide a narrative summary of its top threat-based assessments (e.g., flood mitigation, wildfires, cybersecurity) that materially affect hosting capacity, DER operations, or integration capacity planning. The narrative should identify how the EDC would rate progress in risk abatement, how confident the EDC is in its assessment of the risk, and where risks seem to be increasing;

(c) Software & modeling: the EDC shall describe its current Energy Power System ("EPS") modeling capabilities and level of visibility into behind the meter ("BTM") DERs. This should include a discussion of what is currently modeled, as well as the software and methodologies used for that modeling. Known limitations of such modeling systems or upcoming improvements should also be described;

(d) Grid utilization metrics: The EDC shall provide a substation-level overview of its Distribution System and propose appropriate grid utilization metrics for their distribution systems, such as the following:

1. The ratio of distribution system peak load to total distribution electric grid capacity;
2. The ratio of current electric load delivered to total potential deliverable electric load over the distribution system;
3. The percentage of kilowatt-hours of electricity lost during the distribution process or by the distribution system;
4. An analysis of constrained circuits on the distribution system; and
5. An evaluation of the performance of the distribution system at system peaks.

(e) Worst-performing circuit analysis: The EDC shall provide a narrative summary of its worst-performing circuits as assessed in the ASPR and Feb. 2026 RFI[6] and discuss if/how they may be constraining integration capacity, and whether/what remedy may exist.

[6] In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid, Request for Information, BPU Docket No. QO24030199 (Feb. 4, 2026).

(f) Asset management strategy: The EDC shall provide an overview of the condition and performance of its physical grid assets to better manage physical infrastructure for delivering electric service and identify where assets may require upgrades or replacement in the future.

(g) Operations and Programs. The EDC shall provide a brief discussion or summary of the EDC's current operation strategy including descriptions and overlay maps of any planning and historic distribution system investments.

(h) Resource Challenges. The EDC shall provide a description of any recent historical or ongoing resource challenges, such as workforce or material supply. Where applicable, the EDC shall identify whether alternative materials or equipment could address supply constraints.

3. Financial Data.

(a) Historical Operations and Maintenance ("O&M") and Capital Spending. EDCs shall provide a summary of recent O&M and capital spending. Summaries must specifically call out:

i. System expansion or upgrades for integration capacity; and
ii. System expansion or upgrades for reliability and power quality.

Examples of other relevant topics that may be discussed in the summary include, but are not limited to: Age-related replacements and asset renewal; Emergency damage restoration; New customer projects and new revenue; Grid modernization and pilot projects; Compliance with local (or other) government requirements; Metering.

(a) All non-EDC investments in distribution system upgrades (e.g., those required as a condition of interconnection) by subset (e.g., Community Solar Garden ("CSG"), customer-sited, Power Purchase Agreement ("PPA"), and other) and location (i.e., feeder or substation)

(b) Provide any available cost benefit analysis, including current methodologies, in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement.

4. DER Deployment.

Provide estimates for the following:

(a) Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes, such as by planning areas, service/work center areas, cities, etc.)

i. Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the EDC considers "high" DER penetration.
ii. Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.
iii. Amount of power export within nameplate capacity limited by interconnection agreement, by substation/feeder circuit.

b. Load and Distributed Generation Forecasting

The Load and Distributed Generation Forecasting should be projected for three- and ten-year time horizons, to align with the three- and ten-year strategies. The EDC must provide a baseline forecast, as well as additional scenarios that consider different rates of load growth and DER adoption.

1. **Baseline Forecasting**

As part of the baseline forecast, the EDC must share the following information related to predicted load and distributed generation in their service territories over three- and ten-year time horizons:

(a) Load Forecast Methodology: The EDC shall provide an overview of load forecasting methodology and capabilities and any deviations from previous methodology and capabilities. Describe any utilization of advanced analytics and modeling tools to enhance load forecasting and reliability projections, thereby improving the accuracy of planning.

(b) Projection of Customer Base: The EDC shall provide a summary of its projection of its customer base by sector and by rate classification type over the three- and ten- year time horizons.

(c) Projection of Gross Load: The EDC shall provide a summary of its projection of gross load at three- and ten-year time horizons, which projects historical local trends into the future, along with an explanation of the factors included in that projection.

(d) Assessment of Load Modifiers: The EDC shall provide a high-level assessment of load modifiers and their impacts. Load modifiers may include anticipated distributed generation (e.g., solar photovoltaics) and other DERs, energy efficiency, smart thermostats, V2X, geothermal, and air source heat pumps. A qualitative discussion of the anticipated impacts of FERC Order 2222 and potential impacts from the related FERC Docket ER22-962-000 (PJM Interconnection Compliance Filing with Order 2222) should also be included.

(e) Granular Locational Forecasts: The EDC shall provide projections, based on its own reasonable assumptions, of loads and DER generation at the distribution substation, or other level of granularity, as may be determined by future Board Order, that provide locational and temporal information to inform the type and timing of distribution system investments needed.

(f) Forecasted O&M and Capital Spend Projections: For the three-and ten-year projections, EDCs shall include a description of forecasted spending for major expected O&M and capital projects with an explanation of how they specifically close the identified gaps preventing reaching future target system operational state.

(g) Forecasted Workforce and Material Resources: Any resource challenges noted in Section VI(a)(2)(h) above should be projected and quantified to its impact on system planning. When describing challenges, distribution plans must provide tangible examples of resource or material supply shortages and quantify the impact to system planning. Citing general market dynamics or the potential for global supply chain risks/bottlenecks are insufficient basis when estimating future planning requirements. EDCs should also identify and consider whether alternative materials or equipment may reduce costs and procurement lead times before attributing constraints to planning requirements.

(h) Anticipated Changes to Operations Programs: If the EDC anticipates any changes to Operations Programs from what was provided in Section VI(a)(2)(g), it should be described under this section.

(i) Resilience Approach and Planning: The EDC shall provide a high-level vulnerability assessment at the three- and ten-year intervals, a description of any proposed resilience programs, and projected cost and rate impacts.

2. Requirements of the Scenario Analysis.

To understand the potential impacts of different rates of DER adoption and load growth, EDCs must define and develop conceptual base-case, medium, and high scenarios regarding increased load and increased deployment of distributed generation and other DERs. Scenario selection should be based on the information provided under the above sections VI(a) Baseline Distribution Assessment and VI(b) Load Forecasting, considering what level of penetration by DERs is realistic, where on the system those DERs are most likely to interconnect, and anticipated growth of large loads (e.g. data centers, large electric vehicle charging depots, mass electric vehicle adoption). The EDC shall use the Scenario Analysis to assess the potential impact of various plausible future events to inform the flexibility needed in grid plans, and to test their robustness under different potential conditions. Each of the two required scenario analyses should include the following:

(a) Methodology: The EDC shall describe the methodologies used to develop the two scenarios, including the DER adoption rates, geographic deployment assumptions, expected DER load profiles, relevant regulations and legislation, and any other relevant assumptions factored into the scenario discussion.

(b) Identified Grid Needs: The EDC shall provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER generation and load integration for each scenario, including whether existing processes and tools would be sufficient.

c. Solution Identification

As stated in Section I above, the purpose of the PSUP is to communicate strategies on a three- and ten-year basis which can affordably increase integration capacity to prepare for grid developments anticipated for the future[7] and enables participation of these DERs as grid edge resources to configure and orchestrate VPPs that improve operational flexibility of the EPS and serve local load. In addition, the plans should utilize DERMs and relevant non-traditional alternatives to support optimal EPS management and energy resource utilization.

[7] Such as, but not limited to, increased penetration of DERs, integration of energy storage systems, load growth from EV charging infrastructure, and large-scale load growth from data centers.

The requirement of Section VI(a) to provide Baseline Distribution System and Financial Data helps to establish the existing operations of an EDC and a baseline from which to plan. The requirement of Section VI(b) to provide Load and Distributed Generation Forecasting helps to establish the load needs and generation capacity in the future. The requirement under Section VI(b) to provide two additional scenario analyses (based on what the EDC reasonably finds most likely) requires the EDC to anticipate (1) the load growth and DER integration required under specific scenarios and (2) the actions the EDC would seek to undertake to accommodate those future scenarios.

This section VI(c) requires that the EDC utilize the information and analysis from the Baseline Distribution System and Financial Data, the Baseline Forecasting, and the Scenario Analysis to inform and develop its three- and ten-year plan that cost effectively utilize distribution services and non-traditional distribution solutions to plan for and address the identified grid needs and other objectives described in Section III. In addition, the requirements under VI(c)(5) require the EDC to consider the costs and benefits of the system upgrades that may be necessary to accommodate the load growth and increased integration of DER, with a focus on exploring optimal mix of non-traditional solutions with traditional infrastructure investments for meeting the envisioned needs of specific segments of the distribution grid. The EDC shall provide a methodology for all quantitative impacts and benefits calculated. Benefits that may be considered, includes, but is not limited to, the following: Distribution system upgrades avoided due to increased integration capacity; Reduced O&M expenses; Improved voltage regulation; Faster DER interconnection; Reduced outage impacts; Avoided energy from incremental integration capacity; and Reduced customer electricity costs.

In consideration of all the above, the three- and ten-year strategies must include plans for the following elements:

1. **Increasing Grid Management and VPP Enablement.**
   The PSUP shall describe the EDC's current level of DERMS capability (See Appendix A1) and strategy for allowing grid-edge DERs to participate in third-party and retail VPPs.

   (a) Grid-DERMS.[8] The PSUP must:

   1. Identify projected requirements of functions, scale, performance, and cybersecurity;
   2. Consider systems integration requirements and data availability;
   3. Ensure organizational and operational alignment with:
      i. Existing DMS/SCADA; and
      ii. Edge-DERMS interfaces by ensuring compliance with CIM(IEC61968-70) standard, integration with external devices based on either such as the DNP3.0 standard, Open automated demand response ("ADR"), or IEEE 2030.5 standard, which may be updated via Board order.

[8] A list of DERMs use cases are provided in Appendix A for reference.

(b) DER Registry. A PSUP must include a plan for developing a DER registry. The DER registry will have a consistent structure across EDCs and contain common data fields and definitions (see Appendix B for more details), and will be instrumental in enabling the development of and enrollment for VPPs, and helping to ensure reliability of the grid. EDCs should anticipate working jointly with the other EDCs to align this structure.

2. Increasing Integration Capacity.

The PSUP must include a description of how the EDC will increase integration capacity on its distribution system to accommodate the most likely scenario forecast with respect to DER penetration and load growth. The PSUP shall specify goals for additional hosting and load-serving capacity for each year in the three- and ten-year periods.

(a) **Smart Inverters**. The PSUP must show effective utilization of advanced smart inverter functionality through use of Volt/VAR and Volt/watt functions with newly interconnected DERs that are compliant with the IEEE inverter standard 1547-2018 and UL 1741 SB, or subsequent revisions to these standards to reduce losses, maintain power quality, and boost efficiency to the greatest extent possible.

3. **Developing flexible interconnection and energization tariffs.**

The PSUP must describe plans and future steps towards the development of flexible interconnection and flexible service/energization tariffs and identify barriers to creating such tariffs.

4. **Resource Planning.**

The PSUP must include a general organizational design and resource plan that corresponds to the respective three- and ten-year distribution system evolution points. This information shall include:

(a) Key staffing positions and resource utilization intensity envisioned for achieving and maintaining the predicted level of integration capacity and operational flexibility, which may include, but is not limited to, any new functions or governance roles related to AI, data, and advanced analytics as it pertains to the PSUP; and

(b) Anticipated needs for future EDC, affiliate, and contractor personnel.

5. Cost-Effectiveness Evaluation.

The EDC shall provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER and balance locally served load at the listed penetration levels. In addition, the EDC shall provide a Cost-Effectiveness Evaluation that provides high-level estimates of the costs and benefits associated, including the methodology, with non-traditional solutions considered in the plan as compared to traditional infrastructure investments to demonstrate their value. The Cost-Effectiveness Evaluation only applies to the three-year time horizon in each scenario analysis. The EDC shall provide a narrative description of any changes anticipated in their methodology on a ten-year time horizon. The Cost-Effectiveness Evaluation shall be qualitative and limited to identifying cost drivers, customer-benefit pathways, and potential affordability considerations. Detailed rate or bill impacts shall be addressed in subsequent rate cases or IIPs. The PSUP must outline:

(a) Spend prioritization;
(b) External funding opportunities exploration and grants;
(c) Customer rate impacts by customer class (residential, commercial, and industrial); and
(d) The EDC must identify and adequately consider the use of cost-effective non-traditional distribution solutions, including, but not limited to, the following:
    1. Smart Inverter Functions: Utilize advanced grid-support capabilities such as Volt/VAR, Volt/Watt, and other cost-effective functional settings to manage voltage, maintain power quality, boost efficiency, and increase DER hosting capacity.
    2. Reverse Power Flow at the Substation: Regulate voltage and reactive power, maintaining power quality as flow direction changes; enable a flexible operation; increase DER hosting capacity.
    3. Virtual Power Plant (VPP): Aggregates DERs, dispatches supply and demand response and enhance grid reliability and flexibility.
    4. Energy Storage Systems: Behind-the-meter and grid-scale batteries that absorb excess generation during low demand and discharge during peak time, balancing supply and demand of the grid.
    5. Rate Design and Load Management: Using pricing structures or incentives to encourage energy use patterns that support grid reliability.
    6. Energy Efficiency Programs: Implementing technologies and practices that permanently reduce overall electricity consumption at home and business.
    7. Demand Response: Incentivize customers to temporarily shift or reduce their electricity use to lower grid stress during system peak demand, or to offer flexibility for normal distribution system operation.
    8. Bi-Directional Charging (V2G/V2X): EVs act as distributed energy storage that provides power to the grid, buildings, or other critical loads in response to grid needs and market signals. It supports peak shaving, voltage & frequency regulation, congestion relief, and grid resilience services.

II. Appendices

a. DERMS

i. Capability Tiers

The capability tiers are categorized according to[9]:

(a) BTM Asset 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.

1. Maintain an accurate, GIS-integrated DER asset registry covering all interconnected DERs, including asset type, capacity, locational data, and metering type.
2. Achieve real-time or near-real-time visibility into DER generation and load at the feeder level using AMI data.
3. Maintain, document, publish, and update feeder-level hosting capacity maps, reflecting current DER penetration.

(b) Control and Dispatch:

EDC moves from passive monitoring to active control of enrolled DERs and develops the full operational stack of a demand flexibility capability. This includes, but is not limited to:

1. Dispatch Strategy
2. Event Communications
3. Resource Aggregation (demonstrate the ability to aggregate dispatch signals across a portfolio of enrolled DERs)
4. Evaluation, Measurement, and Verification (EM&V) of dispatches
5. Maintaining Automated or Semi-automated Settlement Process (to ensure timely, transparent, and auditable approach)

(c) Dispatch Orchestration and Optimization:

Grid DERMS matures from a demand response platform into an integrated grid planning and operational tool. This will also include third-party aggregator integration via edge-DERMS to orchestrate and optimize the grid needs.

1. Technology roadmap and prioritization
2. Third-party integration
3. Non-traditional distribution solutions quantification
4. System Operator Interface with PJM on the information and plan include, but not limited to, DER telemetry sharing, dispatch signal

[9] Schellenberg, Josh A. and Frick, Natalie Mims. "Moving Beyond Direct Load Control: A Maturity Model for Realizing the Promise of Demand Flexibility." Jan. 2025. https://doi.org/10.2172/2502076

priority conflicts between distribution and wholesale needs, and real-time visibility sharing for DER aggregations.

(d) 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.

1. Aggregator coordination and wholesale market participation via the FERC Order No. 2222
2. Interface with PJM wholesale markets via VPP platform coordination of the Grid DERMS and Edge DERMS
3. Fully integrated transmission and distribution

ii. Use Cases and Functions

Potential use cases and functions may include, but are not limited to the following:

i. Constraint of DERs participating in wholesale markets for distribution grid reliability;
ii. DER flexible interconnection;
iii. Distribution grid upgrade deferral;
iv. Distribution grid voltage support;
v. Economic optimization;
vi. Fault restoration support;
vii. Load reduction to extend maintenance window;
viii. Load shifting and duck curve management;
ix. Peak load reduction;
x. Scheduled dispatch;
xi. Wholesale energy price response;
xii. Backup power;
xiii. Microgrid control;
xiv. Self-consumption of renewable DER;
xv. Contingency frequency response (Primary Control)
xvi. Contingency voltage response (Primary control);
xvii. ISO Market products- day ahead or real time energy;
xviii. Regulation reserve;
xix. Spinning contingency reserve;
xx. Transmission system voltage support

b. DER Registry

Each EDC shall each develop a DER registry. The DER registries of all the EDCs shall have a consistent structure with common data fields and definitions. The EDCs shall jointly develop and propose this structure. Development of the DER registry may consider what categories of data DERs actually have available and are willing to publicly share (e.g. are not proprietary or otherwise confidential). Key registry fields may include, but are not limited to:

a. Enrollment data:
   i. Aggregator (EDC or third-party name);
   ii. Type of DER;
   iii. Device manufacturer;
   iv. Device model number;
   v. Device serial number;
   vi. Account ID;
   vii. Address;
   viii. Meter ID;
   ix. AMI meter indicator;
   x. Bulk power system node;
   xi. Feeder ID (for distribution services);
   xii. Rate schedule;
   xiii. Customer segment (e.g., residential, small business);
   xiv. Customer Summer peak load;
   xv. Customer Winter peak load;
   xvi. Enrollment start and end dates;
   xvii. Enrollment state and end dates for other programs/aggregators;
   xviii. Energy capacity (kWh), (e.g. How much energy it carries);
   xix. Demand capability (kW), (e.g. How fast it can charge and discharge);
   xx. Import/export limits;
   xxi. Availability hours, days of week, and seasons;
   xxii. Limits on number of consecutive hours or days; dispatched; and
   xxiii. DER ownership status (e.g. owned vs leased); and
b. Operational data:
   i. Notification lead time;
   ii. Override capability;
   iii. Device runtime or state of charge;
   iv. For EVs - where the vehicle is located and charging;
   v. Dispatch date;
   vi. Dispatch start and end time;
   vii. Expected performance;
   viii. Aggregator market bid prices and amounts (if applicable);
   ix. Cycling strategy or thermostat temperature setback (for AC load control); and
   x. Dispatch group (may be defined by one or more customer or operational characteristics).

c. Cost Effectiveness Evaluation Examples

Reverse Power Flow at Substation

Costs: Transmission protections, upfront costs, maintenance, sensors for flow visibility, DERMS and Advanced Distribution Management System ("ADMS"), substation upgrades (developer cost).

Benefits: Enables more solar, Prevention of failures, less maintenance to system, non-traditional solutions such as energy storage can absorb excess generation to prevent backfeed.

VPP of existing DERs

Costs: Upgrade AMI to intervals needed for FERC 2222 (i.e. transfer of 24 hours of validated data), infrastructure investments in communications equipment, DERMS and ADMS, infrastructure.

Benefits: Regulate voltage, decrease capacity prices, enable the interconnection of additional solar, customer-specific reliability, overall reliability and flexibility.

Demand Response

Costs: Circuit-level visibility to determine program eligibility, Incentives, program implementation.

Benefits: Shifted or reduced electricity usage during peak, lowered grid stress and peak demand.

Energy Efficiency Programs

Costs: Project implementation, incentives.

Benefits: Least-cost load reduction, permanent energy and demand reduction.

Energy storage systems

Costs: Infrastructure, installation, maintenance, battery itself, land, permits, communications systems, maintenance, cooling.

Benefits: Enable more solar, defer future infrastructure investments, supports system reliability.

Reconductoring

Costs: Installation.

Benefits: Increased hosting capacity, increased system reliability, grid flexibility.

V2G/V2X

Costs: Infrastructure, Customer incentive, Technology for commercial charging.

Benefits: Flexibility, integrated load and generation, peak management.

DERMS

Costs: Software, maintenance, integration with current system.

Benefits: Reduced restoration costs (to restore power and replace damaged equipment), shorter outage duration, avoided resilience events, lower unserved energy, avoided customer interruption costs, increased safety during extreme weather conditions (or under cyber or physical security threats, if applicable), comparison of costs and benefits for the proposed resilience program.