Memo to:
Philip Chao, Paul Heitmann (NJ BPU)

Copied to:
Jonathan Maxwell, Ken Agnew, Kytson McNeil, Kristina Kelly, and Miriam Goldberg

From: DNV
Date: May 11, 2023
Prep. By: Nick Posawatz

DNV Advisory Support and Recommendations in Response to the NJBPU Demand Response Roadmap

The NJ BPU Demand Response (DR) Roadmap highlights an approach to evolve past current DR curtailment programs to facilitate a marketplace for DR grid flexibility services provided by various types of distributed energy resources (DER). This advisory document provides an overview of DNV's insight into key aspects of DR and DER planning for future aggregation and grid flexibility services.

In the near-term DNV recommends BPUs continued approach of building on programs like Rockland Electric Company's (RECO) Bring Your Own Thermostat (BYOT) program that delivers curtailment service through AMI. While much of the information here serves to confirm the approach outlined in the BPU's Demand Response Roadmap Straw Proposal already, the document also summarizes DER/DR best practice research and offers recommendations for future research (conducted throughout triennium 2) that may provide additional insight into program planning and development, and key design principles further carried out in triennium 3.

1 KEY TAKEAWAYS & RECOMMENDATIONS

The following takeaways and recommendations can help inform long-term planning timelines, development of priorities, and important design elements. These are high-level priorities and are explored further in the last section. Detail on specific program deployment and development of frameworks in other states are also highlighted in the following sections.

Figure 1. High-Level Priorities and Recommendations for Future Road Mapping Implementation

2 INTRODUCTION AND OVERVIEW OF GOALS

The New Jersey Board of Public Utilities (BPU) is engaged in facilitating the transition to a cleaner, more efficient, and reliable electric grid through the development of DER offerings that can provide a suite of grid flexibility services. Using

DERs as DR assets coupled with advanced communication platforms allows utilities to provide greater temporal and locational control, achieve greater value from customer resources to enhance grid reliability, and improve operational cost-effectiveness.

Traditional DR curtailment deployed for peak demand reduction is limited in its ability to provide flexible grid solutions. In a world with an increasing number of distributed assets spread throughout the grid, utilities must find ways to harness this flexible potential through effective tariff structures, technology standards and interoperability requirements, and frameworks that facilitate aggregated deployment. This effort requires careful planning and coordination with grid modernization efforts to ensure that appropriate steps are taken now to promote future market growth.

This advisory document aims to provide insight into road mapping beyond just near-term enhancements to existing curtailment programs. It identifies utility best practices for identifying market barriers and determining DER/DR-enabling technology potential, and establishing frameworks for advanced DER offerings that align with grid modernization efforts. This will also help further elucidate the guiding principles underpinning road mapping and triennium planning efforts.

3 ANALYSIS OF MARKET POTENTIAL AND LONG-TERM BARRIERS

In order to develop effective pilot programs and frameworks that encourage the development of a modular DR market, a detailed analysis of market potential and barriers to future deployment of DERs and other DR-enabling technologies is recommended. A potential assessment provides a current overview and future snapshot given potential market conditions. Supporting research can also provide decision-makers with insights into customers' current willingness to adopt technologies and engage in DR programs and how to effectively motivate increased customer engagement. A market potential study could consist of a variety of activities, but overall should identify:

- Where customer DERs and other DR-enabling technologies are currently located on the electric system?
- What types and how much load reduction potential exists throughout the system (identification of current and future use-cases)? And how much of that is cost-effective and achievable under current market conditions?
- What is the magnitude and type of grid benefits that these resources could provide? Both in terms of energy and capacity (peak demand reduction) and other grid flexibility benefits.
- What are different customer perspectives related to DER and other DR-enabling technology adoption? And what are the price elasticities of different resource types?
- What future scenarios or market enhancements could accelerate the adoption of traditional and more grid flexible resources? And what are the barriers to adoption (system cost, compensation, interoperability, etc.)
- What is the likely future emissions impact of DERs?

A DR market potential study can identify high potential near-term resources that can be the foundation of pilot programs (i.e., BYOT, BYOD, TOU rates, etc.). These programs can then evolve with appropriate compensation mechanisms to capture resources with enhanced grid flexibility offerings over time (i.e., auto-DR, EV managed charging, etc.). Pathways that open up the market to high-value DERs can be identified, including the priority market barriers that would need to be addressed. California pursued a three-phase approach in identifying the range of DR services and frameworks for DR to provide flexible grid support for a high variable renewable energy (VRE) grid. Phases 1 and 2 highlighted the priority use cases and DR supply curve forecasts. Phase 3 concluded in identifying DR potential through 2030 and focused on the load shifting potential for multiple DR types.

Additionally, if aligned with integrated distribution planning efforts and hosting capacity analyses, granular geospatial forecasts (feeder- or circuit-level) can also highlight where DERs could provide most value to the grid, providing more accurate locational valuation. The development of robust and dynamic maps indicating load and generation potential can aid significantly in ongoing potential assessments, identifying system capacity needs potentially mitigated through DER deployment or non-wires alternatives that utilize DER and DR resources to mitigate location-specific system infrastructure upgrades. Hosting capacity maps (NJ EDCs are currently developing these through grid modernization proceedings) created through integrated planning and grid modernization efforts are being used and improved by utilities to accomplish some of these goals, but comprehensive maps and planning tools accessible for all stakeholders should be the end goal.

Overall, the assessment of system potential and analysis of multiple scenarios can identify high-value resources now and into the future, as well as barriers and how they could be addressed (alternative rate structures, evolving compensation mechanisms, customer targeting, etc.). Several states and utilities offer specific examples of how potential assessments have informed pilot programs, and the development of accompanying standards and platforms that facilitate the marketplace for grid flexibility resources, expanded upon in the next section.

4 BEST PRACTICES IN DER INTEGRATION AND SUPPORTING INITIATIVES

The movement towards DR for grid flexibility services requires a baseline knowledge of system conditions and resource potential that can be expanded upon to create programs and integrate smart grid components. Potential market conditions can inform the deployment of advanced software and resource management platforms (ADMS, DERMS, etc.) required to evolve pilot programs into a more transactive energy marketplace. Accurate, real-time resource valuation informed by these systems and advanced system infrastructure can also stimulate the movement towards more economically driven programs.

The following sections highlight specific examples of state and utility-specific efforts to improve valuation, enhance smart grid device communication and aggregation, and create advanced DR programs that enable modular DR to provide grid flexible services.

4.1 Accurate DER Valuation and Pricing Mechanisms

Emerging DER valuation approaches are important in stimulating market activity and growing individual programs for flexible resources. In addition to traditional avoided capacity and transmission and distribution (T&D) values, market-based frameworks and tariff options are being developed to align DER and DR performance with evolving and more granular distribution system needs. The following table highlights some emerging programmatic and rate-based approaches states and utilities are using to evaluate and test existing and new frameworks.

Table 1. Existing & Emerging DER Valuation Approaches

State / Utility	Valuation Metrics	Applications
New York	• **Value of DER (VDER)** – Energy (LBMP), capacity, environmental, demand reduction, and location system relief	Rates & Tariffs
California	• **Locational Net Benefit Analysis (LNBA)** – Capacity, voltage support, reliability, and resiliency (present worth method to quantify distribution deferral value) • **DER Deferral Tariff** – Testing new approach to BTM DER procurement through Partnership Pilot	Distribution Planning / NWAs
Hawaii	• **Customer Renewable Programs** – Post-NEM export credits depending on individual customer program – 5-year credits accepted by PUC • Shifting to Standard DER Tariff & Bundled Grid Services Tariff	Rates & Tariffs

Maine	• **Utility Cost Test (UCT)** incorporating AESC avoided costs comparing revenue requirements of wires solution – Energy, wholesale price impacts (DRIPE), line losses, capacity (DRIPE), T&D, outages, emissions, and customer/NEIs (flexible based on individual NWA solutions)	Distribution Planning NWAs **–** NWA Coordinator (NWAC) investigates small T&D projects and identifies cost-effective NWA solutions
Minnesota	• **Value of Solar Tariff (VOST)** – Energy, T&D capacity, generation capacity, fuel, line losses, O&M, reserve capacity, and environmental value	Rates & Tariffs (Community solar only)
Oregon	• **Resource Value of Solar (RVOS)** – Energy, capacity, line losses, T&D capacity, integration, administration costs, hedging, price response, and environmental (customer) • Testing DER valuation (demand flexibility) through Smart Grid Test Bed (SGT)	Rates & Tariffs (commission adopted, not yet implemented by utilities)
Arizona	• **Distributed Demand-Side Resource (DDSR) Aggregation Tariff** – Capacity, demand reduction, load shifting, locational value, voltage support, and ancillary services (ACC approved)	Distribution Planning / NWAs; Rates & Tariffs
Nevada	• **Grid Services Set (GSS)** – Feeder peak load management, voltage support, feeder phase balancing, TOU bill management (distribution); energy arbitrage, frequency regulation (transmission) • DOE grant project investigating value of aggregated DER facilitated by DERMS & DCA	Distribution Planning / NWAs
Illinois	• **Locational Marginal Value (LMV)** – Temporal & locational value to identify distribution-level value (capacity, voltage, reliability) complemented by market value for energy/ancillary services • **Shadow Exchange for DERs (SEEDER)** – Testing to enable a transactive energy marketplace (TEM) for DER customers to quantify distribution location marginal prices (DLMP)	Distribution Planning / NWAs (using DERVT tool and implemented at (10) feeders)

In addition to the valuation metrics highlighted above, the deployment of smart grid devices and advanced metering infrastructure (AMI) also provides an avenue to provide a more granular and real-time value of DER and DR. This can in turn drive benefits for customers through the creation of advanced rate design or automated device management (auto-DR). The deployment of AMI can efficiently be utilized with coordinated pilot program offerings and be expanded after program evaluation, as long as data privacy concerns are adequately planned for and addressed throughout. While AMI does makes quantification of DR-specific load reduction easier, it is not without risk. For example, CAISO experienced inconsistencies when estimating performance reported by demand response providers (DRP), CAISO settlement coordinators, and third-party evaluators. Accurate baseline development is an ongoing challenge in evolving DR programs that should be addressed in long-term planning efforts.

Overall, the following key themes continue to be identified as drivers in developing future valuation approaches:

- Increasing exploration and emphasis on locational value for designing pricing & procurement mechanisms
- Aggregated DER/DR tariffs are being developed and actively incorporated into procurement mechanisms and rate design structures
- Increasing saturation of AMI can inform advanced rate design to capture DER value and automate management based on real-time price information
- Increasing alignment between advanced rate design (ARD) strategies and load flexibility use-cases
- Defined procurement mechanisms for DERs are continuing to emerge in integrated and distribution planning

4.2 Effective Market Communication and Aggregation Frameworks

In order to develop a DR marketplace capable of providing grid flexibility services, utilities need to be able to communicate effectively with resources under common standards and platforms, and aggregated service offerings should exist within a unified rule framework with qualified set of providers. Additionally, security standards with regards to data and platform privacy should be an early foundation in developing a robust future program. The following sections provide additional examples of how aligning program and market rules, and communication frameworks is an important method of alleviating future concerns as DER penetrations increase.

- ***Market Coordination & Communication.*** The coordination of market participation for resources (especially those with multiuse applications) should be clearly defined and communicated to all market participants. As multiuse (retail & wholesale) resources increasingly have the ability to participate in different markets and at different timescales, mechanisms for coordinating dispatch within a utility program compared to at the market operator-level should be clearly documented. This will increasingly become important as resources have a wider range of opportunities through FERC 2222. Conversely, multiuse applications should not be limited in their ability to participate in multiple markets. For example, NYISO is currently working on dual participation rules to align combinations of allowable retail and wholesale services.
- ***Platform Standardization & Communication Protocols.*** Communication procedures and smart devices that interact with central operations should adhere to standardized rules or guidelines developed early in the process and aligned with other grid modernization efforts. Interoperability should be a key target metric in the creation of standards that require the coordination of different devices and types of software. Many states are identifying smart inverter standards (IEEE 1547) that offer enhanced operational visibility and utility control for interconnected DERs (CA Rule 21, HI Rule 14H, ISO-NE SRD, MN (TIIR), MD (PC44). Additionally, in order to facilitate future resource aggregation and program modularity, common communication protocols and data networks are required at the program level for continued growth. For example, Southern California Edison (SCE) identified improvements to their integration of 3rd-party aggregator technology platforms for the PowerFlex virtual power plant (VPP) program.
- ***Aggregator Marketplace Development & Rules.*** Similar to standardization of communication protocols and software platforms, a standardized approach to developing an aggregator marketplace (similar to DRPs) is advantageous in deploying and evolving DER aggregation programs that include DR-enabling technologies. The continued growth of market-enabling aggregators to develop program solutions and facilitate DER customer engagement should be bound by clear rules for technical qualification, market participation, customer communication, and program evaluation. States can offer guidance and qualification parameters on these metrics that consider overall system potential and interactions with wholesale market rules (FERC 2222). Adherence to program interoperability requirements should also be a key area of focus as it relates to aggregator or vendor qualification. The Hawaiian Electric Company (HECO) is pursuing the development of a marketplace for aggregators to fully manage the "aggregator + customer + utility" relationship and deliver grid services and is continuing to develop an "aggregator handbook" that provides guidance and technical standards for aggregators.
- ***DERMS Framework & Deployment Timeline.*** A key technology component in the advanced deployment of DERs are distributed energy resource management systems (DERMS). This is a highly functional piece in the efficient operation of highly saturated DER grids that can optimize for cost-effectiveness and grid services. States and utilities continue to explore DERMS standardization and efficient deployment, but many are bound by the complexity of their integration within current distribution systems. Creating a marketplace for individual DERMS solutions that adhere to a common framework is beneficial in encouraging competition among providers and facilitating product growth in re-bid cycles. In order to maximize future potential, many utilities have developed deployment plans with distinct phases tied to specific

deployment goals. These typically include testing phases for discrete use cases at certain locations on the distribution system. Some examples include:

- SCEs EPIC project tested a DERMS portfolio of aggregated resources (DPV, battery storage, DR) to serve local needs, leading to key lessons learned for continued phases of development
- Eversource continues to pursue incremental DERMS deployment starting with their existing EE portfolio and plans to expand to diverse customer DERs and incrementally add aggregators
- Arizona Public Service (APS) offered Residential Battery Pilot incentives combined with enrollment in TOU or TOU-plus rates to test performance and control metrics ($2,500 – performance data sharing, additional $1,250 for DERMS utility control)

4.3 Advanced DR Program Incentives & Development

Several states and utilities are exploring advanced pilot or beyond-basic program offerings incorporating the considerations described above into their planning and goal frameworks. Many have identified the need to evolve beyond traditional peak reduction programs to integrate a wider array of resources, allow for a larger range of use cases, and achieve more targeted grid flexibility benefits. Multiple programs also offer incentives for integrating and testing advanced technologies that will facilitate enhanced load flexibility in the future. A sampling of these programs not already described in the sections above are highlighted below.

- **Portland Gas & Electric (Oregon):** Customers in PGEs Smart Grid Test Bed (SGT) can participate in the Smart Water Heater Rewards BYOD program that allows for grid-interactive utility control.
- **APS (Arizona):** Implemented a rewards program (Battery, Cool, and Reserve Rewards) expansion from thermostat DLC to include storage and grid interactive hot water heaters (BYOD & direct install) facilitated by increasing DERMS testing and coordination.
- **ComEd (Illinois):** ComEd offers distributed generation (DG) rebates approved by the Illinois Commerce Commission (ICC) for C&I customers that requires smart inverter systems that meet specific settings defined in the tariff in order to provide grid support capabilities.
- **Nevada Energy (NVE):** Proposed a Distributed Solar+Storage Residential Demand Management Trial in its most recent Integrated Resource Plan (IRP) that supports the targeted deployment of DERs to test proposed TOU CPP + DDP rates and utility aggregation for demand flexibility at a local level.
- **California:** California's DR Partnership Pilot recently incorporated an aggregated DER 'ratable procurement' structure to foster additional growth in of aggregated BTM DERs over longer time horizon.

5 REFINING KEY PRINCIPLES FOR DER DEPLOYMENT & DR GRID FLEXIBILITY

Lessons learned from other state and utility programs moving towards DR as a grid flexibility service can be consolidated into a set of guiding principles used throughout the road mapping, planning, and program development process. These can help to set boundaries for early program development and offer insight into expanding use cases over time. BPUs role in this process may evolve over time but should be focused on coordinating detailed market insights for use in program development, maintaining coordination among stakeholder groups, and guiding the development of standard frameworks and protocols. Below is a consolidated list of the key guiding principles informed by existing New Jersey programs and best practices from other states.

1. **Standards & Technology Integration:** Ensuring technical standards are clearly defined and adhered to throughout the planning and implementation process, including grid requirements such as capacity, voltage, power quality, and reliability/resiliency; additionally, identify timelines for advanced technology integration (DERMS, smart inverters, control devices, etc.) and common communication protocols that facilitate enhanced grid interactivity.
2. **Equitable & Evolving Goals:** Identify goals for achieving technology-agnostic programs that provide a fair valuation and distribution of all costs and benefits, allow for a competitive and equitable process for all market participants, and consider evolving multi-market and multi-use resource guidelines.
3. **Program Design Parameters:** Pursue streamlined program development and implementation procedures informed by pilot program results, that also offer transparency and appropriate confidentiality for all participants; this structure should reflect experimental design early on that integrates the development of price-responsive frameworks with varying frequency and duration.
4. **Program Evaluation & Adjustment:** Develop baselines based on identified resource potential and customer attitudes towards DR & DERs, and evaluation timelines for the adjustment of programs based on customer feedback, program results, and changing market and technology conditions. This can ensure efficient future program development and key refinement areas to meet targets.
5. **Stakeholder Coordination:** Develop frameworks to maintain key stakeholder communication and coordination for new activities throughout development and implementation processes, including transparency into data and communication frameworks that require close coordination among all stakeholders to achieve desired results (state, utilities, developers, aggregators, and wholesale market operators). This helps to ensure efficient market operation and adequate balancing of stakeholder needs.

This list can serve as a guiding set of principles to inform goals and timelines for triennium planning efforts in order to ultimately create a marketplace for portable DR service offerings. For example, triennium 2 should clearly inform the overall long-term vision for achieving clean energy goals through DER deployment and DRs providing grid flexibility. It may not define all technical and communication standards rather but identify pathways to evaluating and finalizing full implementation and interoperability in triennium 3. Additionally, design elements for the expansion of existing curtailment programs may evolve from triennium 2 to 3, but pilot programs can adhere to forward thinking goals throughout. Overall, the sequence of modular DR service offerings developed for Triennium 3 and beyond can be informed by lessons learned and guiding principles from other states, but concept testing and refinement specific to New Jersey will be a key factor in long-term program success.