Demand Response Program Straw Proposal

1.0 Introduction

Demand Response ("DR") capabilities offer an important mechanism for managing the reliability and economic optimization of the electric distribution system. Traditional "knife switch" manual load shedding of large concentrated commercial loads through dedicated and proprietary control networks is rapidly evolving toward including more sophisticated and precise coordination of smaller loads, managed alongside increasing amounts of distributed energy resource ("DER") at the grid edge. In parallel with this, the urgency of achieving maximum grid integration of clean energy at reasonable cost to ratepayers means that we must provide compensative incentive for participants to utilize all their cost-effective response mechanisms, including DR and DER, in as many ways as possible.

The second Triennium (July 2024–June 2027) is a critical period for New Jersey to begin its "expansion" of energy efficiency ("EE") – otherwise known as *Permanent* Load Reduction – with the capabilities of DR, which can be similarly classified as *Temporary* Load Reduction. Unlike EE, however, which deploys dedicated, site-specific retrofits to energy consumer facilities, DR has a variable operating element for both when and how it is utilized, as well as who shares in the economic benefit of its use. This is ideally left to competitive market forces, with appropriate security and regulatory monitoring, which should be more fully available by the third Triennium (July 2027–June 2030). Nevertheless, in anticipation of these capabilities, we must proceed with current authorization for DR programs to maintain the maximum flexibility and modularity so that current investment will not be "stranded" and precluded from participation.

Recognizing these dynamics, the New Jersey Board of Public Utilities ("Board") Staff ("Staff") has attempted to frame the longer term DR Strategic Plan in Appendix A to this document, which, although aspirational, should be considered informative and relevant to the criteria that will be applied for Board authorization of the programs submitted by the electric distribution companies ("EDCs") and gas distribution companies ("GDCs") for the second Triennium.

New DR service programs may be proposed by utilities, EDCs and GDCs alike, with the constraint that rules and standards for data, and full disclosure on system modeling methodology, reliability, and economic impact are provided. As part of their response consistent with minimum filing requirements ("MFRs"), each utility should provide a detailed evaluation and conceptual plan with clear milestones for how the envisioned DR Strategic Plan should be approached, and how their proposed second Triennium service programs align with this DR Strategic Plan.

2.0 Enabling Policy

The New Jersey Clean Energy Act of 2018 states that EE and peak reduction are paired programs to achieve the State's climate goals:

> For each electric public utility and gas public utility, which shall establish reasonably achievable targets for energy usage reductions and peak demand reductions and take into account the public utility's energy efficiency measures and other non-utility energy efficiency measures including measures to support the development and implementation of building code changes, appliance efficiency

> standards, the Clean Energy program, any other State-sponsored energy efficiency or peak reduction programs, and public utility energy efficiency programs.

As with the EE programs, the peak demand reduction programs "adopted by each public utility shall comply with quantitative performance indicators." Likewise, "[t]he energy efficiency and peak demand reduction programs shall have a benefit-to-cost ratio greater than or equal to 1.0 at the portfolio level."

The current Energy Master Plan further elaborates on peak demand reduction. Goal 3.2 is entitled "Manage and Reduce Peak Demand." It has two sub-goals that provide important guidance.

3.2.1 Support and incentivize new pilots and programs to manage and reduce peak demand

> Empowering customers with pricing and consumption data, control, and incentives will enable them to manage their energy demand and shift consumption habits to off-peak times. Advanced Metering Infrastructure (AMI, or "smart meters") can provide granular data about energy use and costs to educate customers about their consumption and enable customers to manage their demand. Control over usage should include new rate designs such as Time of Use (TOU) rates to incentivize customers to reduce energy use during periods of peak energy demand. Other rate design tools, such as peak-time rebates that provide refunds to customers who adjust their energy consumption upon utility request, have also proven effective in other places.
>
> In addition to establishing peak demand reduction goals, NJBPU should explore the development of a Clean Peak Standard for meeting a percentage of New Jersey's peak demand needs through clean resources that reduce greenhouse gas emissions. A Clean Peak Standard is designed to set a minimum amount of clean generation resources that must be used to meet peak demand, in lieu of traditional peaker plants. These clean generation resources could include renewable energy, energy storage, and demand response strategies. In 2018, Massachusetts became the first state to establish a Clean Energy Standard, and other states are considering similar measures.
>
> The state must continue to advocate at PJM and federal levels for appropriate compensation of the full value stack that demand response, energy storage, and other forms of distributed energy resources (DER) contribute to the grid. Such tools are a necessary part of the energy efficiency landscape, and the state should encourage utilities, third-party providers, and customers to engage in pilot programs that incorporate demand response and other load shifting and load reduction programs.

3.2.2 Pilot alternative rate design to manage electric vehicle charging and encourage customer-controlled demand flexibility

> The state should pursue opportunities to encourage load shaping and load shifting, such as charging later at night, or during periods of lower load and higher solar output during the daytime. Peak demand reductions can be achieved by working with utilities to pilot alternative rate design to manage EV charging, thus limiting grid impact as EVs proliferate.
>
> NJBPU should also work to advance new demand response and demand management technologies, such as vehicle-to-grid ("V2G").

NJBPU can additionally develop programs for EV charging to be deployed in conjunction with storage or other DER to reduce impact on peak demand. Commercial and industrial customers with solar facilities can reduce their load and energy bill while also providing flexibility to the system by absorbing excess solar output during the day and shifting EV charging away from peak periods.

3.0 Demand Response Context and Background

DR capabilities offer an important mechanism for managing the reliability and economic optimization of the electric distribution system. Traditional programs operated by utilities are depicted in Figure 1 below and convey the "dedicated use case" approach that use DR exclusively for peak load management. This is a simplistic schematic that illustrates a centrally administered system that signals a need for reduced load at critical peak times, although DR programs could be implemented with signaling technology not being "in band" to the network (e.g., a phone call, text message, public service radio announcement, etc.). Measurement and verification, however, is always required for quantifying the achieved response.

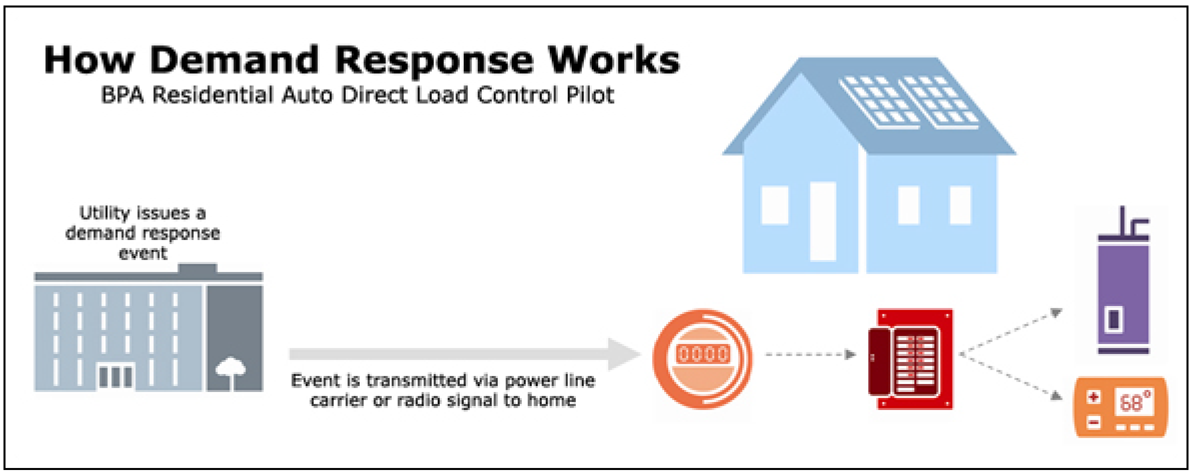

Figure 1 Traditional Demand Response Program

DR, where demand load is controlled, fits under the larger umbrella of DER (Table 1). The value of DER comes from the capacity, energy and ancillary services it provides to the grid. While BPU seeks to develop the market for DERs through solar programs, a storage program, and grid modernization and AMI proceedings, Staff recommends action during Triennium 2 of the EE programs to evolve the existing DR (load flexibility) programs.

Table 1: DER Types and Services they provide (Source: NY REV).

DER Type	Examples	Services		
		Capacity	Energy	Ancillary
Load Flexibility	- Large energy user demand curtailment - Bring your own device			
Dispatchable Net Generation	- Net metering of solar			

Dispatchable DER	- Net metering of Class 1 Renewable Generation with battery storage - Vehicle to grid			

In a recent study, Brattle classified the types of load flexibility programs and the services they provide.[1] As shown in Figure 2, they highlighted innovative programs and the added value of new services these programs provide.

1 Extend DR value streams

2 Broaden definition of DR

	Generation capacity avoidance	Reduced peak energy costs	System peak related T&D deferral	Targeted T&D capacity deferral	Load shifting/ building	Ancillary services
Direct load control	X	X	X	X		
Interruptible tariff	X	X	X			
Demand bidding	X	X	X		X	
Time-of-use (TOU) rates	X	X	X			
Dynamic pricing	X	X	X			
Behavioral DR	X	X	X			
EV managed charging	X	X	X	X	X	X
Smart water heating	X	X	X		X	X
Timed water heating	X	X	X		X	
Smart thermostat	X	X	X	X		
Ice-based thermal storage	X	X	X	X	X	
C&I Auto-DR	X	X	X	X	X	X

Figure 2. The broader range of DR programs types and the services/value streams they offer (Brattle). Appendix B provides program descriptions.

In New Jersey, the only existing DR programs are interruptible tariff programs for large energy users and a pilot Bring Your Own Thermostat program by RECO. At the request of Staff, the consultant team at DNV surveyed DR programs across the country.[2] They described several pilot programs, where customers can participate without requiring utility-provided devices on the customer-side. The pilots include bring your own device ("BYOD") programs where smart thermostats and smart water heaters are incentivized and integrated with grid-interactive utility control, as well as non-BYOD pilots. Illinois, Nevada, and California have run pilot programs to test time-of-use tariffs. Given the accelerating growth of EVs, storage, rooftop solar, smart inverters, and smart thermostats, New Jersey would be remiss not to recognize and realize the natural synergies of temporary load reduction by initiating more innovative and interoperable DR program designs, particularly those that do not require utility-provided devices.

[1] The Brattle Group, 2019, "The National Potential for Load Flexibility – Value and Market Potential Through 2030", [The National Potential for Load Flexibility: Value and Market Potential Through 2030 (brattle.com)].

[2] DNV, 2023, "DNV Advisory Support and Recommendations in Response to the NJBPU Demand Response Roadmap."

4.0 Staff Recommendations for Triennium 2

Therefore, Staff recommends the following activities for the Triennium 2 planning cycle:

a. **Demand Response Programs** – New DR service programs may be implemented by EDCs, where rules and standards for data, IT technologies, and pricing, such as time-of-use ("TOU") tariffs, should be forward-looking to reasonably align with core principles of the DR Strategic Plan depicted in Appendix A, where increasing presence of dispatchable DER offers are envisioned. These offer the potential for grid flexibility beyond the existing interruptible tariff DR programs. The programs should propose incentives and tariffs to encourage customers to purchase and install portable smart devices (i.e., devices using open, internationally recognized communication and IT standards). The programs should also leverage available AMI data for providing the measurement and verification ("M&V") at suitable granularity for future DR transaction clearing, unless there are compelling reasons to defer. Proposed program design should be cost-effective according to the NJCT and Participant Cost Test.

   Staff recognizes that the dynamics for natural gas DR events are different than for the electricity market, although natural gas fueling central electric generation does link the two. Capacity and storage constraints through the heating season drive the demand for curtailment. An extreme cold event can exacerbate the need for curtailment over an unexpected and short timeframe. Other important factors indicate a need for a different approach for the gas utilities (e.g., no currently approved AMI programs in New Jersey for gas systems). However, the CEA did not exclude the gas utilities from the requirement to offer DR programs. While there are fewer historical strategies than the broad range of programs and strategies for the electric industry, Staff encourages the GDCs to propose DR programs that can influence customer actions in peak usage either:

   1. With a TOU rate design that reflects higher natural gas prices during the peak months and potentially a critical peak signal for periodic market spikes; or
   2. Where smart thermostats and AMI are used to control natural gas demand during extreme cold events, with the resulting temperature offset acting as a measured proxy for reduced gas consumption until interval metering is available directly for GDC billing.

b. **Conduct DER Roadmap Study** – Staff recommends conducting a statewide study on a DER roadmap. The DR Strategic Plan, Appendix A, describes the mission. A roadmap would identify the priorities, experimentation, milestones, and timing to achieve the mission. Staff recommends that the study include interviews and participation with a wide range of stakeholders (i.e., PJM, aggregators, manufacturers, Rate Counsel, and the EDCs). The roadmap would be used to make a recommendation to the Board for specific actions and DER and DR programs for Triennium 3.

c. **Pilot Programs** - The utilities may identify, design, and execute pilot programs:

   - Technology application, particularly distributed energy resource management systems ("DERMS")
   - Demonstration of M&V through emerging AMI data access
   - Market pricing and clearing mechanisms (including various TOU programs)

- Market communication and aggregation frameworks

Pilot programs could include, non-generating assets, such as smart thermostats, smart water heaters, and EV chargers, and energy storage integration, including V2G, but cannot include generating assets, such as solar. Approval of pilots are predicated on their alignment with principles expressed in the DR Strategic Plan as described in Appendix A.

5.0 Minimum Filing Requirements for Demand Response Programs

The following filing requirements establish the guidelines and direction for EDC proposals on DR solutions that are suitable under Triennium 2. EDCs shall consider the mission and concepts described within Appendix A to this document, and make every attempt to propose solutions that will preserve an open market driven services paradigm envisioned for Triennium 3.

I. General Filing Requirements

a. The utility shall provide a table of contents for each filing.

b. The utility shall provide with all filings, information and data pertaining to the specific program proposed, as set forth in applicable sections of N.J.A.C. 14:1-5.11 and N.J.A.C. 14:1-5.12.

c. All filings shall contain information and financial statements for the proposed program(s) in accordance with the applicable Uniform System of Accounts that is set forth in N.J.A.C. 14:1-5.12. The utility shall provide the accounts and account numbers that will be utilized in booking the revenues, costs, expenses, and assets pertaining to each proposed program so that they can be properly separated and allocated from other regulated and/or other programs.

d. The utility shall provide supporting explanations, assumptions, calculations, and work papers as necessary for each proposed program and cost recovery mechanism petition filed under N.J.S.A. 48:3-98.1. The utility shall provide electronic copies of such supporting information, with all inputs and formulae intact, where applicable.

e. The filing shall include testimony supporting the petition, including all proposed programs.

f. For any proposed program, the utility shall be subject to the requirements in this and all subsequent Sections. If compliance with Section V and VI of these requirements would not be feasible for a particular program or sub-program, the utility may request an exemption but must demonstrate why such exemption should be granted. Examples of historical situations that have qualified for exemption include pilot programs, programs that had an educational or policy goal rather than resource acquisition focus, and programs that introduced novel ideas where documentation supporting estimated costs/benefits may not be easily produced.

g. If the utility is filing for an increase in rates, charges, etc. or for approval of a program that may increase rates/changes to ratepayers in the future, the utility shall include a draft public notice with the petition and proposed publication dates.

II. Program Description

a. The utility shall provide a detailed description of each proposed program for which the utility seeks approval, including, if applicable:

i. Program description/design, including:

- Program demand reduction (kW or therm) goals and curtailment objective(s);

- How AMI is employed to signal load demand flexibility and to track curtailment volume, including baseline volume;
- How portability, as defined in the DR Strategic Plan (Appendix A), will be determined and demonstrated.
- Detailed plan with timelines and planning priorities, addressing:
    - How their proposed second Triennium DR service programs align with DER Strategic Plan;
    - How to facilitate DERMS deployment & interoperability requirements that can aggregate grid flexibility resources;
    - How the utility plans to work with stakeholders involved in creating an open, portable grid flexibility service model.

ii. Target market segment(s) and their priorities – including
- Eligible customers;
- Measures/services;
- Eligibility requirements and processes;
- Methodology to prioritize the procurement customers for DR program participation over distribution system investments.

iii. Proposed incentives and/or tariffs
- How demand reduction performance is measured, including methodology to calculate baseline, definition of turndown events, and capacity savings;
- Program design and measurement to minimize rebound effects after a turndown event;
- Incentives structure and ranges for demand reduction performance achieved, including incentive payment processes and timeframes;
- Any mutual exclusivity terms that may be needed for avoiding double counting in newly proposed DR programs.

iv. Qualified equipment supported by incentives, such as smart thermostats and smart inverters:
- Incentives structure and ranges for the equipment, including incentive payment processes and timeframes;
- A description of data and communication standards. If the standard is not an internationally recognized standard, give justification for why.

v. Capital investments, such as IT hardware and infrastructure to support DR and DERMS. Such investments may be ratebased, but must be justified in the benefit-cost analysis.

vi. Customer financing options.

vii. Contractor requirements and role: The utility shall provide a description of the extent to which the utility intends to utilize employees, contractors, or both to deliver the program(s). The utility shall also provide a description of contractor requirements, including common application elements and training/certification/recertification requirements.

viii. Estimated program participants, by market segment each year.

ix. Projections for performance metrics for each program year relative to the program's targets or quantitative performance indicators as defined in Section VII.

x. Program budget, by year.

xi. Projected program costs, by year, broken down into the following categories, as applicable:

- capital cost;
- utility administration;
- marketing and outreach;
- outside services;
- incentives (including rebates and low- or no-interest loans);
- inspections and quality control; and
- evaluation.

To the extent that the Board directs New Jersey's Clean Energy Program ("NJCEP") to report additional categories, the utility shall provide additional categories, as applicable.

Any workforce development and job training costs, health and safety costs, and costs of outreach to community-based organizations shall be shown separately.

b. The utility shall provide the following information about the proposed Demand Response program(s):

i. Quality assurance and control standards and remediation policies: The utility shall provide a detailed description of the process(es) for ensuring the quality of the programs and resolving any customer complaints related to the program(s).

ii. Plan for workforce development and job training partnerships and pipelines for energy efficiency jobs, including for local, underrepresented, and disadvantaged workers. The utility will also provide a description of how the utility plans to engage with and support participation by minority-, women-, and veteran-owned and other underrepresented businesses to ensure equitable access to contracting opportunities under the proposed programs.

iii. Customer access to current and historic energy usage data from smart meters, including available data fields, access rules, and technology standards

iv. Total budget summary, including an annual budget summary and joint budgets with partner utilities

v. Benefit-cost analysis (as defined in Section V)

vi. The utility shall list its forecasted average cost to achieve each unit of capacity and energy savings in each program.

vii. Marketing plan: The utility shall provide a description of where and how the proposed portfolio will be marketed or promoted to the sectors served by the utility's customer base, including coordinated customer outreach on core programs with other utilities. This shall include an explanation of how the specific services, along with prices, incentives, and energy bill savings for the proposed portfolio, will be conveyed to customers, where available and applicable. The marketing plan shall also include a description of any known market barriers that may impact implementation and strategies to address known market barriers.

c. In areas where gas and electric service territories overlap, the utility shall provide a description of the program structure for coordinated, consistent delivery of programs between the utilities and estimated coordinated budgets and allocation of costs and capacity and energy savings between the utilities. The utility shall provide a description of how the utilities coordinated their program assumptions and other factors that could influence results for each coordinated program.

III. Additional Filing Information Applicable Only to Renewable Energy Projects

a. The utility shall propose the method for treatment of Renewable Energy Certificates ("RECs"), including solar incentives, or any other renewable energy incentive developed by the Board of Public Utilities ("BPU" or "Board"), including Greenhouse Gas Emissions Portfolio and Energy Efficiency Portfolio Standards including ownership and use of the certificate revenue stream(s).

b. The utility shall also propose the method for treatment of any air emission credits and offsets, including Regional Greenhouse Gas Initiative carbon dioxide allowances and offsets, including ownership and use of the certificate revenue stream(s). For programs that are anticipated to reduce electricity sales in its service territory, the utility shall quantify the expected associated annual savings in REC, solar incentive, and any other renewable energy incentive costs.

IV. Cost Recovery Mechanism

a. The utility shall provide appropriate financial data for the proposed program(s), including estimated revenues, expenses, and capitalized investments for each of the first three years of operations and at the beginning and end of each year of the three-year period. The utility shall include pro forma income statements for the proposed program(s) for each of the first three years of operations and actual or estimated balance sheets at the beginning and end of each year of the three-year period.

b. The utility shall provide detailed spreadsheets of the accounting treatment of the proposed cost recovery, including describing how costs will be amortized, which accounts will be debited or credited each month, and how the costs will flow through the proposed program cost recovery method.

c. The utility shall provide a detailed explanation, with all supporting documentation, of the recovery mechanism it proposes to utilize for cost recovery of the proposed program(s), including proposed recovery through the Societal Benefits Charge, a separate clause established for these programs, base rate revenue requirements, government funding reimbursement, retail margin, and/or other mechanisms.

d. The utility's petition for approval, including proposed tariff sheets and other required information, shall be verified as to its accuracy and shall be accompanied by a certification of service demonstrating that the petition was served on the New Jersey Division of Rate Counsel simultaneous to its submission to the Board.

e. The utility shall provide a rate impact summary by year for the proposed program(s) and a cumulative rate impact summary by year for all approved and proposed programs showing the impact of individual programs, based upon a revenue requirement analysis that identifies all estimated program costs and revenues for each proposed program on an annual basis. Such rate impacts shall be calculated for each customer class. The utility shall also provide an annual bill impact summary by year for each program, and an annual cumulative bill impact summary by year for all approved and proposed programs showing bill impacts on a typical customer for each class.

f. The utility shall provide, with supporting documentation, a detailed breakdown of the total costs for the proposed program(s), identified by cost segment, consistent with the program cost categories enumerated in Section II(a)(x). This shall also include a detailed analysis and breakdown and separation of the embedded and incremental costs that will be incurred to provide the services under the proposed program(s), with all supporting documentation. Embedded costs are costs that are provided for in the utility's base rates or through another rate mechanism. Incremental costs are costs associated with or created by the proposed program that are not provided for in base rates or another rate mechanism. Customer recovered costs is income received from customers or their agents upon exit from the program or conversion to third party operation.

g. The utility shall provide a detailed revenue requirement analysis that clearly identifies all estimated annual program costs and revenues for the proposed program(s), including effects upon rate base and pro forma income calculations.

h. The utility shall provide, with supporting documentation: (i) a calculation of its current capital structure, as well as its calculation of the capital structure approved by the Board in its most recent electric and/or gas base rate cases, and (ii) a statement as to its allowed overall rate of return approved by the Board in its most recent electric and/or gas base rate cases.

i. If the utility is seeking carrying costs for a proposed program, the filing shall include a description of the methodology, capital structure, and capital cost rates used by the utility. A utility seeking performance incentives shall provide all supporting justifications and rationales for the incentives, along with supporting documentation, assumptions, and calculations. Utilities that have approved rate mechanisms or incentive treatment from previous cases and are not seeking a modification of such treatment through the current filing are not subject to this requirement.

V. Benefit-Cost Analysis

a. The utility shall conduct a benefit-cost analysis of the programs using the most recent New Jersey Cost Test, including its most recent avoided cost methodologies, as a primary test. In addition, the utility shall conduct benefit-cost analysis using the Participant Cost Test, Program Administrator Cost Test, Ratepayer Impact Measure Test, Total Resource Cost Test, and Societal Cost Test that assesses all program costs and benefits from a societal perspective i.e., that includes the combined financial costs and benefits realized by the utility and the customer as defined in the then-current version of the California Standard Practice Manual. The utility may also provide any additional benefit-cost analysis that it believes appropriate with supporting rationales and documentation.

b. The utility must demonstrate how the results of the tests in Section V(a) support Board approval of the proposed program(s), including how the programs are designed to achieve a benefit-to-cost ratio greater than or equal to 1.0 at the portfolio level when using the New Jersey Cost Test.

c. Renewable energy programs, workforce development and job training costs, health and safety measures, and outreach to community-based organizations shall not be subject to a benefit-cost test, but the utility must estimate all direct and indirect benefits resulting from such a proposed program as well as provide the projected costs.

d. The level of capacity and energy savings shall be calculated using the most recent Technical Reference Manual approved by the Board. To the extent that a protocol does not exist or an alternative protocol is proposed for a filed program, the utility must submit a savings methodology for the program or contemplated measure for approval by the Board.

e. For calculation of capacity and energy savings, as well as for cost effectiveness calculations, the utility shall report net impact by applying applicable NTG ratios ("NTG") or some form of "direct to net" measurement. . To the extent that a NTG value does not exist or an alternative NTG value is proposed for a filed program, the utility must submit a NTG value for the program or contemplated measure for approval by the Board.

VI. Evaluation, Measurement, and Verification ("EM&V")

a. The utility shall describe the methodology, processes, and strategies for monitoring and improving program and portfolio performance related to the utility's targets established pursuant to the Reporting Plan for Performance Metrics in Section VII. Demand Response program impact methodology shall clearly define the calculation of baseline consumption and demand reduction volumes. Net-to-gross evaluation methods shall be described if the proposed measurement approach is not inherently "direct-to-net," such as measurement that uses a control group. The utility shall confirm that these methodologies, processes, and strategies conform with the current New Jersey EM&V guidance documents and standards. The utility shall also provide an EM&V budget consistent with the current New Jersey EM&V guidance documents and standards.

VII. Reporting Plan for Performance Metrics

a. The utility shall file target values based on key performance metrics applicable to each program year of the three-year program filing cycle.

b. The utility shall provide a description of how the proposed portfolio achieves the targets established for each utility pursuant to the following performance metrics as applicable for each program year:

   i. Dollars spent per customer enrolled per $ spent ($/participant) by segment for each proposed program;

   ii. Dollars spent per capacity enrolled ($/kW) by each segment for each proposed program;

   iii. Intensity impact (kWh or CO2 during peak event) for each proposed program. The utility shall, based on the program design, define the specific calculation to measure intensity impact;

   iv. Ratio of number of customer responses to control requests over number of control requests.

Appendix A – New Jersey Demand Response Strategic Plan

Introduction and Portable DR Concept

To facilitate the transition to a cleaner, more efficient, and reliable electric grid, utilities and grid operators can utilize the emerging potential of DR, DERs, and associated grid-edge technology to provide a suite of grid flexibility services. Using DERs and 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, improve operational cost-effectiveness, and facilitate participation in wholesale markets.

The Demand Response Strategic Vision ("DR Strategy") is to develop programs (utility-led and state-led) that create modular, portable demand response ("DR") services which are sufficiently flexible to become elements of an integrated "grid flexibility services" portfolio. This will enable the broadest consumer participation in aggregations of distributed energy resources ("DERs") under FERC Order 2222, which permits those without dispatchable assets (e.g., solar, batteries, and EVs) to participate.

Figure 3 illustrates the concept of "portable DR." A DR program could be a utility-run retail service or run by a third-party wholesale service aggregator. A customer would have the freedom and the data rights to choose any DR service provider. Programs rules covering data rights, communication protocols, dispatching protocols, M&V, and pricing mechanisms would have to be established to create this open DR market. At the same time, rules, regulations, and markets will be developed under the Grid Modernization program to enable service aggregators to buy and sell to the demand capacity PJM market, electric distribution companies ("EDCs"), or other aggregators.

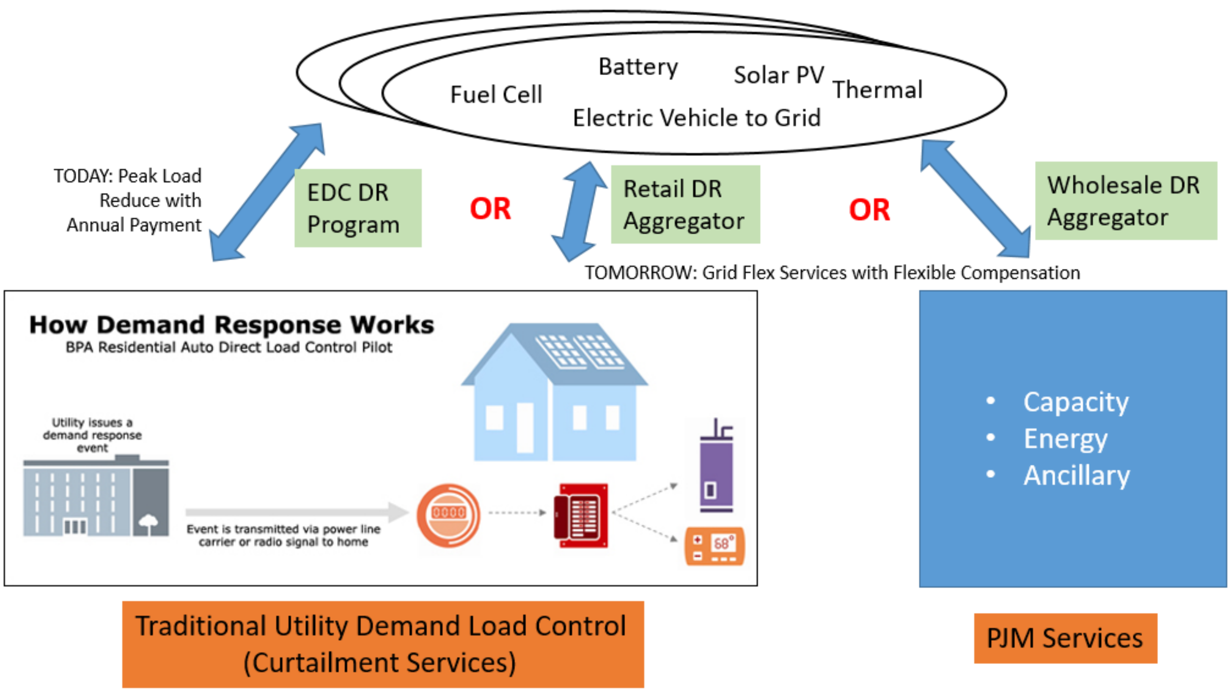

Figure 3 - Alternative Implementations of DR - Conceptual Diagram. Dedicated (e.g., all hardware, software, and program operating costs are rate-recovered, which is an inefficient and inflexible single purpose use case) or Bundled (e.g., DR can be combined in a flexible DER aggregation portfolio

providing multiple grid services). NOTE: V2G is fully responsive electric vehicle to grid "smart" charging and storage.

Distributed Energy Resources and Demand Response

While the Clean Energy Act provides the impetus to develop DR programs, DR program development is complicated by the conflation of DR with EE programs against the existence of separate programs for clean generation DER, such as solar, storage and electric vehicles operating in grid integrated modes. As described in the Introduction section, energy efficiency – referred to as *Permanent* Load Reduction – contrasts with the capabilities of DR as *Temporary* Load Reduction. EE measures are non-generating assets such as controlled load for water heaters, building envelopes, heat pumps, or even battery charging power levels. DR programs are inherently different because the equipment upgrades are simply incentivizing smart devices and since DR has a variable operating element for both **when** and **how** it is utilized, as well as **who** shares in the economic benefit of its use, this resource can be better optimized through competitive markets. The primary offering is a market for customers to choose an affordable subscription from a variety of demand response services. The utilities may offer DR programs alongside the EE programs, but to achieve an open market and maximum innovation and asset utilization, service aggregators must also offer compatible DR programs.

The types of DERs and their services are shown in Table 1.

Table 2: DER Types and Services they provide (Source: NY REV).

DER Type	Examples	Services		
		Capacity	Energy	Ancillary
Load flexibility	- Large energy user demand curtailment - Bring your own device			
Dispatchable Net Generation	- Net metering of solar			
Dispatchable DER	- Net metering of Class 1 Renewable Generation with battery storage - Vehicle to grid			

Given that EE programs focus on behind the meter energy equipment and put the utilities front and center to promote and implement such programs, the Triennium 2 proposal focuses on the first row of Table 1. The New Jersey Board of Public Utilities ("NJBPU") has solar, EV, and storage programs to develop the DER assets represented by the second and third rows of the table.

DR is essentially the modification of energy use (or load profile) to control demand loads behind the meter in direct response to a signal sent by the utility. Putting aside generation and storage, demand response of HVAC and water heating is a curtailment service (the "load flexibility" DER type in the table). Signaling to large energy users to curtail demand is a capacity service, while emergency shut-downs is an energy service when network integrity is threatened. Batteries (including EV charging), back-up generators, and more broadly thermal storage, even when non-dispatchable, offer greater curtailment control and therefore more value can be obtained. Deployment of these solutions during Triennium 2 should focus on minimizing large fixed cost "sunk" investments while ensuring that any investments authorized incent private adoption of these capabilities and prove portable.

DERs provide three key services that have defined value streams that should ideally be optimally utilized through market-based compensation. First is peak shaving or load shaping for the PJM capacity market. Second is the reduced consumption of energy, which may be EE or resilience achieved by judicial use of limited emergency power. Third is ancillary services which include voltage regulation at the distribution (EDC) level and frequency control from the transmission (PJM) level. Coordinating their dispatch and setting up markets across these services are central to future success of grid flexibility services. While not a service, the avoided cost of T&D upgrades is a benefit that Brattle found to be greater than the value of energy and ancillary services.[3]

Traditional curtailment services implemented as single-use utility-deployed DR programs to be operated *exclusively* for emergency peak load reduction represent an extremely cost-inefficient deployment of this highly flexible resource. This straw proposal seeks to move these traditional programs toward grid flexibility services, as well as introduce new programs that offer the other services. This will require the EDCs to be transparent with their curtailment decision rules and technology standards and to give access to consumer data to the consumer and third-party service providers within imposed security and privacy guidelines.

The Grid Flexibility Services construct will be developed in conjunction with the Grid-Modernization proceeding (Docket #QO21010085) through a formal working group charged with developing appropriate tariff structures that properly and fully value the DER. Part of the working group focus will be to define the needed standardization and modularity for how disparate DER elements shown in Figure 1 can effectively integrate and interoperate through communication and data standards. Technological advancements of "smart grid edge" systems using edge-compute, high speed networks, advanced AMI measurement, and low friction "apps" are sufficiently developed to enable a highly flexible and dependable aggregation of DER with maximum customer participation. Any DR solution must be "open" to portability for competitive operation and "standardized" to allow for integration as a "module" within a broader DER aggregation management.

Based on the experience in other jurisdictions, the market for modular demand response services requires time to develop standards and rules. DR service aggregators need standards to access price signals from PJM and clear transactions for event participation through utility AMI. Proceedings for time-of-use rates will need to be conducted. Rules for measurement and validation ("M&V") of claimed peak demand savings by DR service aggregators need to be established and would ideally be served by the data from AMI meters currently being universally deployed in New Jersey. A universal challenge for doing M&V with AMI for any EE or DR program is to establish algorithms to establish baseline consumption. Traditional DR establishes this "baseline" demand, which ideally is *continually* lowered, permanently and **absolutely** through energy efficiency, while any temporary "reduction" should be the **relative** drop of instantaneous load that is presented and measured at the meter interface during times of high reliability or economic value.

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[3] The Brattle Group 2018, "Real Reliability – The Value of Virtual Power", https://www.brattle.com/wp-content/uploads/2023/04/Real-Reliability-The-Value-of-Virtual-Power_5.3.2023.pdf.

Existing DR Programs in New Jersey

Curtailment Programs

Both EDCs and GDCs offer curtailment services, or intermittent tariffs. EDCs may curtail service without remuneration for emergencies where the integrity of the distribution network is threatened. PSE&G has a curtailment service, where subscribers for a fixed kWh rate may voluntarily curtail demand upon receiving a signal from the utility. The amount of curtailment is the difference in a customer-specific hourly load curve and the measured kWh during the curtailment period. The curtailment period may start any time during the day and must end by 8:00 P.M.

GDCs intermittent tariff programs differ. Because natural gas supply absolutely cannot fail, non-compliance results in severe penalties. In exchange for a lower tariff, customers must curtail usage otherwise they will lose the intermittent tariff and go on a fix tariff before they may re-apply for an intermittent tariff.

RECO Bring Your Own Thermostat Program

Rockland Electric Company ("RECO") customers may enroll in a program that allows the company to make brief, limited adjustments to central air-conditioner settings on peak days when energy consumption is high in the summer. The company mails an $85 rebate check to the customer. The company may make up to 10 adjustments to the smart thermostat per summer with no adjustment lasting more than four hours. The customer can override the adjustment.

RECO program is a step in the right direction in that the curtailment service is signaled through AMI. The next step would be for the value for all possible DR services through time-of-use or other pricing structures rather than through a flat subscription rate. The subsequent step would be to make the service implementable for third-party aggregators

Grid-Modernization Proceeding

The Grid Modernization Proceeding developed a roadmap to develop the distribution network and market for DER. The roadmap includes the following tasks:

- NJBPU will convene a technical working group to adopt and develop into N.J.A.C.14:8-5 current specific industry guidance, such as from IREC, California Rule 21, IEEE 1547, and similar sources.
- New Jersey EDCs should implement a uniform streamlined flexible queue process across EDCs that would prioritize a "first ready, first through" approach to support viable projects.
- NJBPU should define a mechanism to establish numerical cost and capacity thresholds above which grid modernization costs could be spread over a broader set of beneficiaries
- EDCs should submit integrated DER and integrated distribution plans that will allow New Jersey to meet the EMP goals.
- NJBPU should consider allowing non-renewable fuel sources, such as CHP, to play in the net metering market at a reduced rate.

While grid modernization and creating the market for grid flexibility services will take place over several years, DR with behind the meter non-generating resource (i.e., load flexibility) can happen without improvements to the interconnection process and distribution networks. These resources include, but are not limited to, smart thermostats, smart controls on water heaters, and smart EV chargers (but not V2G). Implementing non-generating resources have a clear advantage to reduce capacity because there is no need for interconnection applications nor for local distribution network upgrades.

Developing DR as a Grid Flexibility Service

There are opportunities to develop DR services that align and evolve with the broader Grid Modernization effort as it progresses. To expand the market from simple fixed-price curtailment services to a modular, portable marketplace for grid flexible DR services, the following guiding principles could be developed and iterated on throughout Triennium 2:

- Standards and Technology Integration - Communication and technology integration relies on open standards that would need to be developed. The integration of AMI, DERMS, and other technology would need to accurately measure value of services provided by smart controls for all services.
- Data Transparency and Security – The Grid Modernization Proceeding is developing rules and regulations to give customer data rights, which would enable aggregators to offer DR services. Data security protocols and standards are also being addressed.
- Efficient Price Mechanisms – Retail time-of-use price mechanisms need to accurately represent capacity, energy, and ancillary services, while accounting for locational values. The tariffs could be flexible or dynamic (e.g., "Tariffs based on real-time use, setting specific thresholds or alerts as to not go beyond power limits, and moving apparatuses towards different and more convenient price shifts.").
- Aggregators – Aggregators may offer services to retail, wholesale, or both (known as dual aggregators). Rules must be established for qualifying third party aggregators to engage with AMI and distributed energy resource management systems ("DERMS") at the retail-level. Meanwhile, grid modernization will establish rules for aggregators to offer wholesale power to PJM. Rules should preclude double-counting for aggregators who participate in both markets.
- Measurement & Verification – M&V rules would need to be developed that fairly and accurately measure and communicate savings for capacity, energy and ancillary services. One challenge is to develop methodologies to establish baseline consumption for all possible services.

DR Program Design for Triennium 2

Given the complexity of the development path for DER and grid flexibility services, and the need to avoid stranded or underutilized assets that cannot fully interoperate with rapidly growing DER technologies, Staff acknowledges that for Triennium 2, the environment to achieve commercial scale deployment of this integrative "flexibility services" concept does not currently exist. Staff, however, does recommend to the greatest extent possible that EDC investments in Triennium 2 should be made "future proof" to evolve with the DR Strategy. Therefore, any proposed Triennium 2 DR programs should demonstrate the following attributes:

  - New demand response service programs may be implemented by utilities, EDCs and GDCs alike, with the constraint that rules and standards for data, IT technologies, and pricing should be forward-looking to the future modular, portable grid flexibility services that are envisioned as mainstream for the third Triennium.

- Such programs would leverage smart devices and advanced customer information channels to enable intelligent energy management without necessarily requiring a **direct** control mechanism, but rather for customers to be motivated/compensated through utility payments or other market mechanisms.
- Programs should propose incentives to encourage customers to purchase and install non-proprietary smart devices (e.g., Open Systems) that offer "portability" for their enabled DR function to be invoked by alternative "operators and offers".
- Programs should leverage advanced metering infrastructure ("AMI") data for providing the measurement and verification ("M&V") at suitable granularity for future DR transaction clearing, unless there are compelling reasons to defer. The AMI Data Access proceeding (Docket #EO20110716**)** is establishing utility rules on data access, which should enable this M&V capability.

Demand Response Roadmap Study

NJBPU will engage a consultant to develop a DR Roadmap. The DR Roadmap would be a work stream that fits within the BPU's broader Grid-Modernization proceeding and would flow logically into the next updated Energy Master Plan ("EMP"). Milestones within the DR roadmap would need to be synchronized with milestones in the Grid-Modernization proceeding.

To inform the scope of the DR Roadmap, Staff requested DNV to provide technical guidance and identified best practices from other jurisdictions. DNV produced a memo that covers DR market potential, long-term barriers, best practices in DER integration, and key principles for DER deployment and DR grid flexibility.[4]

Based on this memo, Staff recommends that the DR Roadmap should establish priorities and timing of the following:

- Definition of first principles and goals of DR programs.
- Conduct of a market potential study to analyze:
    - Where are (and will be) DER and DR-enabling technologies are interconnected.
    - Capacity map (initial map and procedures to update) particularly for areas which are strongly tied to the Grid Modernization proceeding.
    - Cost-effectiveness of comparative load reduction alternatives
    - Customer perspectives, including outreach/education effectiveness and response quality measured by behavior change.
    - An identification of technical, policy, and financial barriers preventing modular demand response services that support multiple use cases beyond peak load control ("PLC"). What are the barriers to adoption?
    - Prioritization of key research and development questions, in coordination with evolving Grid Modernization forum workgroups, aimed at reducing barriers where possible.

[4] "DNV Advisory Support and Recommendations in Response to the NJBPU Demand Response Roadmap".

- Pilot Programs - The roadmap shall recommend the design and administration of a portfolio of pilot programs aimed at rapid evaluation of solution effectiveness or barrier reduction potential.

Staff recommends that the study team communicate and involve stakeholders, such as of utilities, PJM, aggregators, and customer representatives, during the development of the roadmap.

Appendix B - Description of load flexibility programs

Source: Brattle, 2023 [The National Potential for Load Flexibility: Value and Market Potential Through 2030 (brattle.com)].

Direct load control (DLC): Participant's equipment with a controllable motor, such as water pumps, compressors, air handlers, air conditioners, is remotely cycled using a switch on the compressor.

Smart thermostats: An alternative to conventional DLC, smart thermostats allow the temperature setpoint to be remotely controlled to reduce A/C usage during peak times. Customers could provide their own thermostat, or purchase one from the utility.

Interruptible rates: Participants agree to reduce demand to a pre-specified level and receive an incentive payment in the form of a discounted rate. Alternatively, the participant receives an offset for $/kWh energy charge for the amount of demand reduction.

Demand bidding: Participants submit hourly curtailment schedules on a daily basis and, if the bids are accepted, must curtail the bid load amount to receive the bid incentive payment or may be subject to a non-compliance penalty.

Time-of-use (TOU) rate: Static price signal with higher price during peak hours (assumed 5-hour period aligned with system peak) on non-holiday weekdays. Modeled for all customers as well as for EV charging.

Critical peak pricing (CPP) rate: Provides customers with a discounted rate during most hours of the year, and a much higher rate (typically between 50 cents/kWh and $1/kWh) during peak hours on 10 to 15 days per year.

Behavioral DR: Customers are informed of the need for load reductions during peak times without being provided an accompanying financial incentive. Customers are typically informed of the need for load reductions on a day- ahead basis and events are called somewhat sparingly throughout the year. Behavioral DR programs have been piloted by several utilities, including Consumers Energy, Green Mountain Power, the City of Glendale, Baltimore Gas & Electric, and four Minnesota cooperatives.

EV managed charging: Using communications-enabled smart chargers allows the utility to shift charging load of individual EVs plugged-in at home from on-peak to off-peak hours. Customers who do not opt-out of an event receive a financial incentive.

Timed water heating: The heating element of electric resistance water heaters can be set to heat water during off-peak hours of the day. The thermal storage capabilities of the water tank provide sufficient hot water during peak hours without needing to activate the heating element.

Smart water heating: Offers improved flexibility and functionality in the control of the heating element in the water heater. Multiple load control strategies are possible, such as peak shaving, energy price arbitrage through day/night thermal storage, or the provision of ancillary services such as frequency regulation. Modeled for electric resistance water heaters, as these represent the vast majority of electric water heaters and are currently the most attractive candidates for a range of advanced load control strategies.

Ice-based thermal storage: Commercial customers shift peak cooling demand to off-peak hours using ice- based storage systems. The thermal storage unit acts as a battery for the customer's

A/C unit, charging at night (freezing water) and discharging (allowing ice to thaw to provide cooling) during the day.

C&I Auto-DR: Auto-DR technology automates the control of various C&I end-uses. Features of the technology allow for deep curtailment during peak events, moderate load shifting on a daily basis, and load increases and decreases to provide ancillary services. Modeled end-uses include HVAC and lighting (both luminaire and zonal lighting options).