STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

CASE 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

DEVELOPING THE REV MARKET IN NEW YORK: DPS STAFF STRAW PROPOSAL ON TRACK ONE ISSUES

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I. CONTEXT AND OVERVIEW

The Commission's April 2014 Order Instituting Proceeding[1] proposes a platform to transform New York's electric industry, for both regulated and non-regulated participants, with the objective of creating market-based, sustainable products and services that drive an increasingly efficient, clean, reliable, and customer-oriented industry. Under the customer-oriented regulatory reform envisioned here, a wide range of distributed energy resources will be coordinated to manage load, optimize system operations, and enable clean distributed power generation. Markets and tariffs will empower customers to optimize their energy usage and reduce electric bills, while stimulating innovation and new products that will further enhance customer opportunities.

The Commission's ratemaking framework will also need to be revised to provide improved incentives and remove disincentives that reside in the current paradigm, while ensuring reliable service at reasonable rates and maintaining necessary consumer protections. One effect of these measures should be to monetize, in manageable transactions, a variety of system and social values that are currently accounted for separately or not at all. In the order initiating this proceeding, the Commission laid out six objectives for its Reforming the Energy Vision (REV) initiative:

- Enhanced customer knowledge and tools that will support effective management of their total energy bill;
- Market animation and leverage of ratepayer contributions;

[1] Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Instituting Proceeding (issued April 25, 2014).

- System wide efficiency;
- Fuel and resource diversity;
- System reliability and resiliency; and
- Reduction of carbon emissions.

In this proposal, the vision articulated in the April 24 Report is affirmed in its essential elements, with numerous clarifications and additions, and the initial steps of a transition toward that vision are identified. Staff recommends that the Commission adopt the measures detailed in this proposal.[2] In a subsequent order related to Track Two of this proceeding, the Commission should consider ratemaking reforms that will push utilities to enable the market transformations described in this proposal.

A. Summary of Track One Process

There are 259 parties engaged in the REV proceeding. Under the leadership of two Administrative Law Judges, the parties formed two working groups charged with gathering data that broke into five committees (Markets; Customer Engagement; Platform Technology; Microgrids; and Wholesale Markets). The working groups filed reports on July 8, 2014 and presented their results to the Commission in a July 10, 2014 technical conference. Parties were also invited to submit preliminary comments on a number of policy issues, to guide the development of this proposal, and 68 comments were submitted on July 18, 2014. Throughout this time, Staff has remained engaged in meeting with parties and other interested persons to test, refine and further develop the terms of the REV initiative. Following this Straw Proposal,

[2] This Straw Proposal is submitted by DPS Staff in its capacity as advisor to the Commission. It builds on the Staff Report and Proposal issued April 24, 2014, incorporating subsequent party working group efforts, party comments, and further deliberation by Staff. The scope of this proposal is limited to the Track One issues; it anticipates and aims to be consistent with regulatory reforms that will be developed in Track Two. Staff was helped in the preparation of this proposal by Rocky Mountain Institute, the Regulatory Assistance Project, and the New York State Energy Research and Development Authority.

parties are invited to submit further comments not later than September 22, 2014. Reply comments will be entertained until October 24, 2014.

B. Summary of Findings and Recommendations

Based on the working group reports and Staff's additional efforts, Staff finds that there is large potential for the integration of Distributed Energy Resources (DERs)[3] into the New York electricity market, via a Distributed System Platform (DSP)[4] framework. The integration of DER offers customers the opportunity to manage their usage and reduce their bills while at the same time creating important system and societal benefits such as increased system efficiency and reduction of carbon emissions.

This proposal reflects two significant types of refinement to the April 24 report. First is an emphasis on near-term measures. While the April 24 report outlined an end-state vision, this proposal also identifies measures and makes recommendations that will put New York's electricity industry immediately on a transition path toward realization of the vision. Second, the proposal includes further recommendations on key policy issues that were raised in the April report.

1. Critical Path Objectives

The reforms envisioned in this proceeding are comprehensive and transformative, and the on-going design and pragmatic implementation of them will take years. In part because of that, and driven by the imperative for change described later in this section, it is vital to begin implementing near-term actions that will lay the foundation for the full transition envisioned in REV. Staff sees the following as the near-term critical path objectives that provide the context for the recommendations made in this proposal.

- Increase the DER asset base in the state:
    - Increase the number and kind of DER projects
    - Increase the number of customers employing DER

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[3] Throughout this proposal, DER is used to describe a wide variety of distributed energy resources, including end-use energy efficiency, demand response, distributed storage, and distributed generation.

[4] The April 24 Staff Report identified the Distributed System Platform Provider (DSPP) as a central part of the REV vision. Without any change in the meaning of the term, the acronym is abbreviated to DSP in this proposal. DSP is intended to refer to both the platform function and the platform entity.

  - Develop the capacity of service companies and utilities to deliver additional DER
- Build customer and market confidence in the expanded role of DERs:
  - Increase utilities' experience relying on DER for expanded uses in distribution planning and operations
  - Increase customer awareness, interest, and confidence in DER
  - Develop service company familiarity with new DER-oriented markets
- Begin the development of DSP capabilities:
  - Reorient service company business models toward comprehensive customer service including DER
  - Provide for the transition of energy efficiency and renewable procurement programs, including reduction of system benefit charges and opportunities for competitive provision of services
  - Establish a pathway toward mature DER markets supported by an appropriate technology platform

2. Findings

Staff finds that the central vision of REV – increasing the use and coordination of DER via markets operated through a DSP – is achievable and offers substantial customer benefits. Findings from the Track One working groups support the technical feasibility of the DSP, while many party comments filed in the case speak to the numerous benefits achievable via REV in comparison to a "business-as-usual" future. Technology to support the DSP platform is achievable and to a large extent already available. The DER resources needed to support REV objectives are available in the market as evidenced by the rapid growth nationally and in New York of key technology markets, and their value can be increased by the reforms proposed here by appropriately valuing the services DERs can provide. The level of interest and engagement in this proceeding as well as Staff's assessment of the energy landscape indicate that DER providers, Energy Service Companies (ESCOs), and customers are ready in large numbers to participate in emerging DSP markets. There are significant barriers that will need to be overcome in order to optimize the use and penetration of DER, and many of these barriers form the basis of recommendations made here.

3. Policy Recommendations

With these findings in mind, Staff makes the following policy recommendations designed to address key critical path needs, each of which is further specified in this Straw Proposal:

- The Commission should adopt the basic elements of the REV vision and proceed with implementation as proposed here;
- The DSP should enable broad market participation;
- The DSP function should be served by existing utilities, whose long-term status as DSP providers should be subject to performance reviews;
- Customers and energy service providers should have access to system information, to make transparent and readily available the economic value of time- and location-variable usage;
- Individual customer usage data should be made available, on an opt-out basis, to DER providers that satisfy Commission requirements;
- Utilities should only be allowed to own DER under certain clearly defined conditions, or pursuant to an approved plan;
- Where utility affiliates participate in DSP markets within the service territory operated by their parent company, appropriate market power protections must be in place;
- An immediate process should be undertaken to develop demand response tariffs for all service territories, including tariffs for storage and energy efficiency;
- Implementation plans should include proposals to encourage participation of low and moderate-income customers;
- To protect consumers and reliability of service, the Commission should exercise oversight of DER providers;
- A benefit-cost framework should be defined appropriate to three different purposes: (1) utility DSP implementation plans; (2) periodic utility resource plans; and (3) pricing and procurement of DER; and
- As a transition toward market-based approaches to increase levels of efficiency and renewables, utilities should integrate energy efficiency into their regular operations and should take responsibility for procurement of Main Tier renewables.

These policy recommendations are accompanied by process recommendations, which are detailed in the final section of this proposal. The process recommendations distinguish between near term actions, transitional steps, and design activities toward mature markets, and suggest applying the following principles in all future design work: collaboration, transparency, standardization, non-discrimination, and action-orientation.

C. Context for a Track One Policy Decision

Prior to a detailed discussion of the Staff analysis and recommendations to the Commission, it is important to place this proposal into the larger context of the REV proceeding, which is a multi-staged initiative still in a relatively early phase.

The process defining the REV initiative began with a Commission order in December 2013 articulating objectives. An extensive Staff inquiry culminated in the April 24 Staff Report and Proposal and Commission action to initiate a proceeding. The multi-party process described above led to this Straw Proposal, which will be followed by more party participation, a Commission policy action on Track One issues, and then an extensive period of implementation. The implementation period will include both rate cases and REV-specific filings, which will come before the Commission for further decision prior to substantial investment commitments by utilities. Track Two issues will further supervene on these Track One processes.

From a substantive viewpoint, the process described above through the point of this Straw Proposal could be described as (a) recognition of converging developments and needs; (b) development of the REV vision; (c) testing, clarifying and validating the vision via further Staff inquiry and party process; (d) developing and articulating support for a Commission policy decision; and (e) recommending specific actions for Commission decision in a Track One order.

If adopted, the Track One order recommended here will contain policy decisions that set New York's electric industry on a path toward realizing the objectives articulated by the Commission. This will be further refined in a Track Two order and in a sequence of implementation actions during which investment decisions will be evaluated.

D. Support for a Track One Policy Decision by the Commission

The Track One policy order will not be an end point; rather, it will be a decision to move forward into more detailed phases of the process. The Track One order will be supported by policy considerations in conjunction with facts developed by Staff and party efforts in the working groups. The rationale underlying a decision to proceed, as detailed below, contains the following components:

- A description of a reasonably foreseeable "business as usual" scenario;
- Drivers of change that necessitate creating a more robust retail electricity market;
- Anticipated benefits from REV; and
- The achievability of the REV vision.

Overall, Staff finds that a Track One decision is supported by policy imperatives coupled with findings that the goals of REV are reasonably achievable. REV is an opportunity to improve greatly on the status quo with quantifiable system benefits, but REV is also a response to a convergence of trends presenting severe challenges that make business as usual unsustainable.

1. Business as Usual

The expected benefits and costs of pursuing the REV vision need to be considered in comparison to the cost of a "business as usual" scenario in which current programs are maintained and the electricity system develops in reasonably anticipated ways. The electric industry environment in New York in which REV is being developed is characterized by numerous conditions that indicate a need for systematic change. These include:

- Minimal load growth, projected to be 0.16% per year through 2024;
- Increasing peak loads growing at an estimated 0.83% per year, resulting in declining system efficiency as measured by load factors;[5]
- Aging infrastructure, with 14,000 MW of non-hydro generation facilities over 40 years old, and approximately $30 billion needed to support transmission and distribution systems over the next 10 years (not including NYPA and LIPA);
- Increased dependence on natural gas for electric generation, as evidenced by the 96% increase from 2004-2012;[6] and
- Increased customer adoption of distributed generation and other distributed energy resources including storage.

2. Drivers of Change

The factors described above, taken together, create strong cause for reform. The worsening system efficiency indicated by rising peaks threatens higher commodity electricity prices, especially from capacity markets and energy price spikes during peak hours. Replacement of aging infrastructure will place pressure on delivery rates, and flat sales growth means that these costs cannot be covered by an increased sales base. Further, the need to replace aging infrastructure presents the opportunity to make smart, strategic choices about how to replace those assets rather than being locked in to resource choices by default. Price volatility risks are

5 NYISO Power Trends 2013 vs. 2014 at 15.

6 NYISO Power Trends 2014, p. 34.

exacerbated by increased dependence on natural gas, as illustrated by the experience during the winter of 2014. Further, while an increase in distributed energy resources is generally desirable, a sharp increase in DER without adequate system communication and control upgrades and supporting market mechanisms and operating procedures has the potential to create new inefficiencies because this large behind-the-meter asset base would not be accounted for or efficiently utilized in system planning and operations. Increased DER and customers' generation may further erode utilities' revenue bases at the expense of remaining customers.

In addition to these concerns stemming from business as usual, there are numerous other factors indicating a need for substantial change in the overall approach to utility functions and ratemaking. These include:

- Increasing dependence on high-quality electric supply, by both residential and business customers, even as energy intensity of economic activity is reduced;
- Emerging cyber and physical threats to the centralized power system;
- The need for new reliability and resilience approaches in response to the likelihood of increasingly severe storms and heat waves;[7]
- Impending federal carbon reduction rules and, more generally, need to significantly reduce carbon emissions to mitigate climate change;[8]
- The recent D.C. Circuit Court ruling on FERC Order 745 that may jeopardize existing demand response programs;
- The need to develop new mechanisms for responsive energy demand and increased system flexibility to accommodate increased variable renewable generation;
- Rapid declines in costs and increased capabilities of DER including solar, storage, and energy management technologies, which can reasonably be expected to drive increased DER penetration even in the absence of additional enabling policies;
- The potential for an increase in the number of electric vehicles, leading to growth in electricity demand they may place on distribution circuits as well as new opportunities electric vehicles present to act as DER; and
- Continued competitive pressure on the state's economy.

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[7] Case 13-E-0030 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Storm Hardening and Resiliency Collaborative Report, Consolidated Edison Company of New York, Inc., (issued December 4, 2013).

[8] Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units; 40 C.F.R. 60, available at http://federalregister.gov/r/2060-AR33.

3. Benefits of REV

REV is a response to these drivers of change. As such, the major categories of anticipated benefits of REV are listed below. Some of these benefits are more easily quantified than others, but all should be accounted for.

- Increased customer choice and opportunity;
- Increased system efficiency and therefore cost reduction, calculated both in terms of load duration curve and in terms of overall heat rate;
- Fuel diversity, reduced fossil fuel dependence, and reduced price volatility;
- Deferral or avoidance of transmission and distribution (T&D) infrastructure investment;
- Reduced line losses;
- Increased penetration of clean distributed generation;
- Reduction in carbon and other pollutant emissions, beyond what can be achieved through ratepayer funded programs;
- Increased value of energy efficiency investments resulting from targeting programs to system needs;
- Reduced average customer bills versus a “business as usual” alternative;
- Increased grid resilience and security, including avoided restoration and outage costs;
- Increased reliance on markets with resulting innovation in DER products and benefits, and the ability to effectively integrate new innovations into the system;
- Added levels of responsive demand and system flexibility that enable long-term development and integration of variable renewables;
- Increased non-energy benefits to customers and society including, for example, reduced health impacts or increased employee productivity; and
- Securing the long-term viability of universal affordable service.

Of the more-easily quantified benefits, it is premature to develop precise figures at this time, although illustrative examples of potential savings and avoidable costs indicate the scope of the potential benefits and justify a Commission order to advance to the next stage of REV. Illustrative examples include:

- Increasing system efficiency: if the 100 hours of greatest peak demand were flattened, long-term avoided capacity and energy savings would range between $1.2 billion and $1.7 billion per year.[9] Merely increasing the system load factor from 55% to 56% would produce potential gross benefits of $150 million to $219 million per year.

- Improving fuel diversity: increasing fuel diversity will make customers less vulnerable to price spikes; the estimated total cost to New York customers from the gas-driven price spikes of the winter of 2013-2014 was over $1.0 billion.
- Carbon emissions reductions: at a value of $50 per ton, for example, the annual carbon value of New York's Renewable Portfolio Standard would exceed $127 million.
- Distribution investments: there are numerous examples of DER being proposed to defer distribution investment. The Petition of Consolidated Edison, Inc. related to its Brooklyn/Queens Demand Management (BQDM) Program[10] and the PSEG Long Island Utility 2.0 Long Range Plan filed July 1, 2014[11] illustrate both the potential benefits and the achievability of non-wires alternatives. Consolidated Edison proposes to acquire 52 MW of distributed resources to address overloaded distribution facilities. PSEG Long Island proposes to spend up to $200 million on distributed resources to, among other things, target two areas of congestion. Non-wires alternatives are being proposed to improve reliability and defer investments in other jurisdictions, as well. For example, Vermont plans to defer $400 million in traditional T&D investment through integration of energy efficiency programs into transmission planning.[12] In Washington, the Bonneville Power Administration identified a package of demand response, direct load control, distributed generation and energy efficiency to defer a 50 MW traditional investment.[13]

By systematizing the cost-effective use of distributed resources, REV will establish New York as a leader in enabling DER resources and innovating around new market structures for the benefit of its electricity customers.

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9 This estimate was derived from 2013 hourly load data, calculated for each load zone, assuming a combination of energy reduction and load shifting and calculating benefits based on avoided generation capacity, avoided T&D investment, and avoided energy payments including line losses. This estimate is more current than the one cited in the April 24 Staff Report, and varies by including avoided T&D investment as well as an assumption of energy reduction in addition to load shifting.

10 Case 14-E-0302 - Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn/Queens Demand Management Program, July 15, 2014.

11 Matter 14-01299 - In the Matter of PSEG-LI Utility 2.0 Long Range Plan, Utility 2.0 Long Range Plan Prepared for Long Island Power Authority (July 1, 2014).

12 https://www.efficiencyvermont.com/blog/blog/2014/03/24/energy-efficiency-driving-$279-million-in-electric-system-savings-for-new-england.

13 https://www.aceee.org/files/pdf/conferences/eer/2005/05eer_mweedall.pdf.

4. REV/DSP Achievability

A substantial amount of the party working groups' effort was devoted to the topics of platform technology and DER products and markets. The Platform Technology section of this proposal describes how the technology needed to enable DSP functionalities is achievable. Although system development and standardization are needed to adapt technologies to DSP functions, these developments are definable and well within the range of existing technologies and capabilities.

The inventory of DER products and services attached to the report of the Markets Committee illustrates not only the range of potential DER solutions, but also the scope of the industry that already exists to provide these products and services. Costs to achieve the benefits described above are established in part by existing programs for energy efficiency, demand response, renewables and distributed generation. More importantly, these costs will be reduced as REV is implemented, by the monetization of value streams, streamlining of delivery systems, reduction of barriers to customer participation, and economies of scale. Cost and benefit estimates will be refined in utility filings and DSP procurements.

The policy arguments for continuation of the REV initiative are compelling, and foreseeable costs to achieve REV are well within the range of potential benefits. Along with the direct tangible benefits of REV, the risks and costs of business-as-usual must be considered. The combination of policy imperatives and achievability supports an order to affirm further pursuit of the REV initiative and development of implementation plans.

E. About This Straw Proposal

The specific purposes of this Straw Proposal are to 1) articulate support for a Commission policy decision, and 2) recommend specific actions for Commission decision in a Track One order. As such, the remainder of this Straw Proposal addresses several key questions in the following chapters:

- II. Establishing REV: DSP Market Vision: What functions must be provided in the future DSP market, what is the emerging vision of the DSP market structure, and what are the roles of key actors in that system?
- III. Enabling New Roles for Key Participants: What is required to enable key actors to operate effectively in the DSP market? Who should serve as the DSP, how can customers be best empowered, and how should the DSP interact with the wholesale market?

- IV. Gauging Feasibility: Is the DSP market as envisioned technically feasible? How should cost-effectiveness be determined?
- V. Building the DSP Market: What needs to happen in the near-term to create a solid foundation and transition to the DSP market?
- VI. Mitigating Market Power: How can potential market power concerns be mitigated?
- VII. Implementing REV: Findings and Recommendations: What are the key findings and recommendations proposed by this Straw Proposal?

II. ESTABLISHING REV: DSP MARKET VISION

As context for the recommendations made in this Straw Proposal, this section describes the distribution system functions required under REV, broadly describes the envisioned DSP market structure, and clarifies the emerging vision of key market actors' roles and their interactions in the DSP market. This early and broad description will be further defined via processes laid out in the REV Implementation section of this Proposal, as well as during Track Two of this proceeding.

Staff supports the following DSP definition, developed by the Platform Technology Working Group, with minor modifications: ***The DSP is an intelligent network platform that will provide safe, reliable and efficient electric services by integrating diverse resources to meet customers' and society's evolving needs. The DSP fosters broad market activity that monetizes system and social values, by enabling active customer and third party engagement that is aligned with the wholesale market and bulk power system.***[14]

As discussed in detail below, Staff recommends that the DSP function should be fulfilled by existing utilities. Because this remains an open policy issue until the Commission decides it, the following discussion of market roles is written to leave open the possibility of a non-utility DSP.

A. Distribution System Functions Required Under REV

Regardless of what entity serves as the DSP, there is a set of functions that must be provided at the distribution level to provide reliable electricity service and to animate retail markets under the REV vision. These functions include: 1) market operations, 2) grid operations, and 3) integrated system planning, with modifications to enable the DSP market development.

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[14] This definition is slightly adapted from that used by the Platform Technology working group to conform to the use in this proposal of the term DSP rather than DSPP.

1. Regulated Monopoly Functions

i. Market Operations

The DSP will enable participation by DER service providers in a transparent market-based environment. It will create a flexible platform for new energy products and service delivery. The DSP will promote retail level markets and formulate development of new retail energy services by providing data for consumers, third parties, and energy suppliers. The DSP will manage customer and third-party participation and facilitate engagement across all customer classes.

The DSP needs to be transparent, flexible, scalable and efficient. Its operational platform will need to be interoperable among a number of diverse technologies, products, and services, and must provide for the integration of variable renewable generation. The platform access should be standardized across utility service territories to the extent practicable and meet or exceed Federal and State cyber security requirements, keeping customer data and platform operations safe and secure.

ii. Grid Operations

The DSP will need to integrate new market operation functions with both utilities' existing grid operations and advanced "smart grid" capabilities. The DSP will commit and dispatch market-based DER where appropriate and share net load impact information with the utility grid operations in real time, thereby providing greater visibility and control of the grid. It will need to achieve desired platform functionalities while minimizing system cost. The monitoring and dispatch of DERs will complement the increased use of intelligent grid-facing equipment such as sensors, reclosers, switched capacitors, and voltage monitors. The result will be an increase in the efficiency of voltage regulation as well as greatly increased diagnostic capability and reduced outage restoration times. Utility grid operations will incorporate DSP market commitment and performance data with utility planning and operations to allow for an optimized power system balancing supply and flexible demand-side resources.

The distributed grid will facilitate widespread deployment of DERs, two-way power flows, advanced communications, distribution system monitoring and management systems, and automated controls of energy sources and loads. By managing demand on a day-ahead or real-time basis, the efficiency of the power system will be optimized. This will result in lower peak demand on the bulk power system as well as greater reliability and ability to manage investment needs on the distribution system.

iii. Integrated System Planning

The utility and DSP will need to coordinate shared responsibility for distribution system planning and construction. This will require the efficient design and reliable operation of distribution systems, under conditions varying greatly from those today. This modernization of distribution systems must be accomplished in a way that meets and balances a variety of important policy objectives, such as system reliability and resiliency, customer empowerment, consumer protection, system efficiencies, cost-effectiveness, competitive markets where appropriate, energy efficiency, power quality, fuel diversity, and responsible environmental stewardship. Planning should be subject to open review and should make available the information needed by market participants.

2. Competitive Offerings

The transactional platform established by the DSP will enable the offering of value-added services, some of which are directly enabled by the utility's monopoly status and others that can be provided by multiple entities on a competitive basis. Utilities, utility affiliates, and third parties should be able to provide competitive value-added services. With appropriate incentives, utilities are expected to be innovative in developing services, and the allocation of revenues from such services should depend upon whether or not the services are enabled by the utility's monopoly. This should be further addressed in Track Two.

B. DSP Market Structure

The modernization of New York's energy system involves the development and transaction of a variety of products and services through existing and new markets. The Commission should enable these transactions and markets, ensure that appropriate rules exist to protect consumers and ensure the continued reliability of the system, and provide guidance on realizing all potential values and benefits. To do so, Staff proposes a set of principles to guide market design, and proposes to initiate procedures for achieving those, with the aim of providing appropriate signals to maximize system value, animate participation by a broad range of stakeholders, and fully realize the policy benefits envisioned in the REV proceeding.

In practice, market structure will be defined by the functional roles of the DSP, what products are transacted in the market and procurement mechanisms for those products, and the identity and activities of market participants and their interactions among each other and with the DSP. Customers will realize the greatest benefits from open, animated markets in which all participants participate on a level playing field and which provide clear signals for benefits and costs of participants' market activity. New products, rules, and entrants will develop in the market over time. Without being prescriptive, Staff recommends that a set of principles should guide future market design and, at appropriate intervals, should inform review of market performance and refinement of rules.

End-use customers and DER service providers should become active DSP market participants and sell products and services directly to the DSP. A set of regulated products will need to be defined for transactions in DSP markets. Based on this set of products, the DSP and DER service providers can provide value-added services to customers.

The Markets Committee working group developed a set of possible products that the DSP might purchase from customers and DER service providers. Products could include grid services such as base load modification, peak load modifications, non-bulk ancillary services, and products for contingency and planning such as T&D investment deferral. Importantly, the precise nature of products will need to be defined in terms of timeframes, and should interact with wholesale markets in additive and complementary ways.

Likewise, the DSP will need to provide or sell a set of products and services to customers and service providers. Those might include interconnection services, pricing and billing services, metering information services and data sharing and DER maintenance, operation, and financing. Based on these products offered by the DSP, service providers will develop new service offerings based on their assessment of customer needs. Those might include value-added electricity services, demand response and efficiency programs, contracts for DER maintenance and operations, and an untold number of other services that have not yet been imagined.

The DSP will need to administer procurement processes with competitive solicitations for the products that it buys in the marketplace. Procurement can take many forms, and may evolve over time as the market becomes established. Procurement options include regulated tariffs, automated real-time and day-ahead markets for the day-to-day optimization of distribution circuits, and responses to RFPs to address major system needs. The type of procurement process will depend on the sophistication of the DSP functionalities and markets. The DSP will also determine scheduling consistent with wholesale market scheduling requirements, and be responsible to schedule an optimized set of DERs to serve system needs.

To improve electricity system performance, the DSP market structure should monetize and exchange enhanced DER services in fair and open markets. The end-state market should be transparent, providing all market participants with the data required to understand what values different DER products could provide in different circumstances and locations and with clear information on how compensation will be provided for those values.

Through these markets, participants should have the proper incentives to develop an optimal amount of DER products based on the values the market is designed to capture. The redesigned retail markets envisioned under REV will also need to seamlessly interact with and complement wholesale electricity market operations, as well as other federal, regional and state energy programs.

Staff proposes the following principles for market design:

1. Transparency – access to necessary information by market actors, as well as public visibility into market design and performance;
2. Customer protection – balance market innovation and participation with customer protections;
3. Customer benefit – reduce volatility and promote bill management and choice;
4. Reliable service – maintain and improve service quality, including reduced frequency and duration of outages;
5. Resilient system – enhance system ability to withstand unforeseen shocks—including physical-, climate-, or market-induced—without major detriment to social needs;
6. Fair and open competition – design “level playing field” incentives and access policies to promote fair and open competition;
7. Minimum barriers to entry – reduce data, physical, financial, and regulatory barriers to participation;
8. Flexibility, diversity of choice, and innovation – promote diverse product and program options in a competitive market including financing mechanisms to increase the value of those options;
9. Fair valuation of benefits and costs – include portfolio-level assessments and societal cost analysis with credible monitoring and verification;
10. Coordination with wholesale markets – align DSP market operations and products with wholesale market operations to reflect full value of services;
11. Economic efficiency – promote investments and market activity that provide the greatest value to society, with consideration to identified externalities;

12. Others as determined by the Commission – periodically review market design principles to ensure successful market development.

C. Overview of Market Participants' Roles and Interactions

The DSP market structure described above implies new or evolved roles for key actors in the system. Those actors include customers, the DSP itself, the utility, the NYISO, and DER providers including ESCOs. This section provides an overview of these roles; the next chapter explores roles and implications for these actors in more detail.

The DSP will integrate DER into the current electricity delivery system, situated between NYISO wholesale markets, DSP market participants, and end-users. Currently, distribution utilities deliver electricity services directly to end-use residential, commercial and industrial customers. The NYISO administers and monitors wholesale electricity markets and operates the transmission network. Distribution utilities construct, maintain and operate distribution system infrastructure and assets. A small but growing number of customers are engaged in distributed generation, and demand response and energy efficiency programs are established, but those activities are not coordinated to optimize their benefit to the system.

Under the REV vision, the DSP will facilitate retail interactions with the wholesale market, in addition to operation of retail DER markets. Retail and wholesale operations should be coordinated to optimize system efficiency and full realization of the values of DER. There are at least two mechanisms by which this can be accomplished. The NYISO could accept demand reduction bids from the DSP, dispatching demand side reductions from the DSP in competition with supply side resources. The DSP would coordinate delivery of demand bids, and coordinate settlement information directly with the utility and DER provider or DSP market participant. Alternatively, the utility serving native load could optimize its bids for power purchases from the NYISO, based on the DSP's assessment of its ability to manage load on the utility's system. In the latter scenario, the utility is essentially modifying its load that is bid into the wholesale market and would be relying on the contracted DER resources to help modify its load shape. These mechanisms are not mutually exclusive; both can be pursued in tandem to create a DSP with robust capabilities. Concerted action of the NYISO, DSPs, regulators and market participants will be needed to achieve optimally efficient interoperability. As described below, a stakeholder effort will be initiated toward this goal.

The utility grid operations division will maintain responsibility for integrating and implementing distribution system planning across the electric network, including on the load-serving distribution network and connections to the bulk power system. Utility integrated plans will include supply/demand planning, transmission and distribution (T&D) upgrades, and T&D maintenance. The NYISO will continue planning for bulk system upgrades, bulk generation forecasts, and ancillary service needs.

Customers will become participants in the management and optimization of the electric system through wide-scale adoption of DER products. For larger customers this may imply an active role in managing energy usage and generation; for smaller customers this may involve the adoption of automatic technologies and controls that enhance value without any noticeable impact on comfort or convenience. DER service providers can play the role of intermediary and aggregator between customers and the DSP, providing value-added services derived from the set of regulated products that are created in the retail marketplace.

The Commission will maintain a critical oversight role in the market. This will include establishing guidance and processes for market rule making, approving investment plans and rate designs by regulated utilities, and reviewing the activities of ESCOs, third-party service providers, and utilities for compliance with market rules. The Commission's oversight role will be most pronounced during the earlier transitional phases, as markets and market rules are developed and improved.

III. ENABLING NEW ROLES FOR KEY PARTICIPANTS

A. Identity of the DSP Provider

The market operations, grid operations, and system planning functions described above could theoretically be carried out either by incumbent utilities acting as the DSP, by a newly-created independent DSP based on the NYISO's model of an independent system operator, or by some combination of both. Under any of these approaches, however, the structure envisioned under REV would not eliminate the need for integrated reliability planning, or the natural monopoly of distribution system operations.

Informed by the extensive input on this issue from parties, Staff reaffirms the recommendation originally set forth in its April 2014 Report and Proposal, and recommends that the incumbent distribution utilities serve as the DSPs. While there are substantial arguments in support of an independent DSP, they are outweighed by the numerous drawbacks of that approach and the practical advantages of the utility approach. This decision will, however, require steps to be taken to ensure standardization across the state and to prevent the unfair exercise of market power by utilities.

In reaching this recommendation, Staff is cognizant of the arguments in favor of establishing an independent DSP. First, the independent DSP would more readily establish uniform market practices across the state since it would likely be one organization as compared to six. An independent DSP could also avoid some of the market power concerns associated with having the incumbent distribution utilities serve as the DSP, as well as concerns associated with utility ownership of DER. Creating an independent DSP via a competitive solicitation for a lease-arrangement might lead to lower costs than a utility could achieve. Finally, an independent DSP may be more inclined to promote the rapid technological innovations that are expected to propel the advances achieved through REV.[15]

However, the potential benefits of an independent DSP are countered by numerous drawbacks. The operations of the utility and of the DSP will be closely connected. Because utilities already perform most of the functions of the DSP relating to the design and reliable operation of their distribution systems, assigning these responsibilities to an independent entity would create significant redundant costs. Comparing the present roles and responsibilities of incumbent distribution utilities with the envisioned roles and responsibilities of a DSP demonstrates that creating an independent DSP would be largely duplicative with respect to system planning and operations. The table below shows that, except for market functions, many existing roles and responsibilities of incumbent utilities would have to be duplicated by an independent DSP.

[15] It is also argued that an independent DSP would avoid the risk of stranded investment due to obsolescence of DSP investments. This assumes that the independent DSP would have some form of non-regulated cost recovery mechanism, which is highly unlikely since an independent DSP would still have obligations toward the reliability of the system.

Table 1

Utility and DSP Roles and Responsibilities	Utility	DSP
Market Functions		
Administer distribution-level markets including:		
- Load reduction Market		X
- Ancillary services		X
Match load and generator bids to produce daily schedules		X
Scheduling of external transactions		X
Real-time commitment, dispatch and voltage control		X
Economic Demand Response		X
Demand and Energy Forecasting	X	X
Bid Load into the NYISO	X	
Aggregate Demand Response for sale to NYISO	X	X
Purchase Commodity from NYISO	X	
Metering	X	
Billing	X	X
Customer Service	X	X
System Operations and Reliability		
Monitor real-time power flows	X	X
Emergency Demand Response Program	X	X
Ancillary Services	X	X
Supervisory Control and Data Acquisition	X	X
System Maintenance	X	
Engineering and Planning		
Engineering	X	
Planning / Forecasting	X	X
Capital Investments	X	
Interconnection	X	X
Emergency Response		
Outage Restoration / Resiliency	X	X

An alternative approach to an independent DSP is to separate the market function from the planning and operations functions that must be performed by the utility, with the DSP providing only the market function. However, it is not clear how practical such a separation might be, as grid optimization becomes a minute-to-minute function that informs, and is enabled by, real-time markets for DER. At a minimum, the independent entity would need to dedicate a large amount of resources to maintaining knowledge of and communication with the existing distribution systems and their operation.

Having the incumbent utility act as the DSP will keep the essential function of maintaining grid reliability in a single entity that already bears that responsibility. Creating a new entity would result in unnecessary delay and regulatory complication. Because an independent DSP would share responsibility for maintaining reliability, it would need to be a regulated entity, and the precise manner and extent of regulation would need to be determined. Regulatory mechanisms for supervising the DSP-related activities of the incumbent utilities, including audits, ratemaking, and operational review, are already in place. With the utility serving the role of DSP, regulatory treatment can be accomplished through existing mechanisms in the near-term, allowing the implementation of foundational components of the DSP market to begin, even while longer-term mechanisms like performance-based regulation are developed.

Finally, even if a clean separation of the market function were practical, it would resolve only some, but not all, utility market power concerns. The entity responsible for the market function would be dependent on information from the utility's planning and operation functions in setting location-based values for DER. If a utility were motivated to exercise market power in administering DSP markets, it would still have the opportunity to do that indirectly, through preferential operation of distribution systems, or by manipulating data used by an independent DSP to establish market prices, or through its planning functions that could skew investment decisions. In other words, utility market power must be addressed in any event. Mandating an independent DSP appears to be an expensive, unwieldy, and incomplete response. Market power concerns are discussed at length in Section VI of this proposal.

Vesting the utility with the DSP role creates significant challenges in addition to market power. Most importantly, having each individual utility serve as a separate DSP creates the potential for fragmentation of market rules and platform technologies. Uniformity and standardization are high priorities for attracting market participants. Accordingly the Commission should require that processes be conducted to establish standardized platforms, market rules, practices and procedures for administration of DSP markets in a manner that maximizes participation by third-party providers desiring to offer energy-related goods and services to retail customers in New York State. While there may be natural variation that necessitates some market differences across utilities, these differences should be minimized to the maximum extent possible. This recommendation is described further in Section V of this proposal.

Also, even though there are significant efficiencies to be gained by making the utility the DSP provider, the utility does not currently have all of the capabilities and competencies needed to successfully operate the DSP. Utilities will likely need to hire new staff with different skill sets. In developing the DSP, utilities should consider creating DSP market departments that sit at the same level as other key functional departments, thereby creating clear lines of responsibility and reporting.

As DSP markets and develop and mature, it may be more feasible to entertain the proposal of an independent DSP. Utility performance as the DSP will need to be monitored and evaluated for operational efficiency, standardization, and exercise of market power. If it becomes apparent that utilities are failing to meet the Commission's objectives, an independent DSP could be considered, or other utility DSPs could be allowed to compete to provide DSP functions in other service territories.

B. Customer Engagement

As the Customer Engagement Committee[16] (CEC) noted, the "vast majority of customers in New York currently lack the information, products, technologies, and incentives to fully participate in energy markets and take control of their monthly electricity bills." Further, DER technology providers lack customer energy usage data to develop technologies and services that optimize customer energy use automatically, without need for extensive direct customer actions. These findings are echoed by working group discussions and comments in previous cases.[17] Efforts to modernize the power system require a new focus on customers as actively engaged partners.

Further, a recent survey of residential electricity customers in New York conducted on behalf of Staff, NYSERDA and the New York Smart Grid Consortium[18] found that although few customers say they are knowledgeable about their electricity usage, many place a high value on easy access to information regarding energy use, the price of electricity supply, and the ability to

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16 Also known as Customer Engagement Working Group.

17 Case 12-M-0476 - Proceeding on Motion of the Commission to Assess Certain Aspects of the Residential and Small Non-residential Retail Energy Markets in New York State.

18 Case 14-M-0101; 2014 Survey of Residential Electric Customer Interest in Value-Added Products and Services, August 2014.

control energy costs. This demonstrates that many residential customers are very likely to substantially increase their engagement in energy usage and purchase decisions when presented with the information and opportunity to do so.[19] In addition, survey respondents reported a high level of interest in a wide range of specific home energy management and distributed energy products, despite the fact that these services and products are currently not widely used nor understood by residential customers in New York. This indicates the potential for substantial increases in residential customer adoption of home energy management and DER products.[20]

Within that context, this section proposes several policy options to animate DER product development and measures to remove customer barriers to increased engagement. Additionally, Staff describes DSP market principles and regulatory measures to ensure affordability protections for ratepayers. This Straw Proposal does not fully address all of the issues contained in the CEC report. However, there are a number of Track One issues that are addressed, including data access, customer awareness and acceptance of DER products and services, and affordability.

Additional issues related to rates and bill impacts are directed to Track Two. In particular, many parties identified standby rates as a barrier to distributed generation development. This is a rate design issue that will be addressed in the Track Two context.

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[19] Relatively few customers (21%) characterized themselves as being very knowledgeable about the amount of electricity consumed by appliances and equipment in their home. However, customers placed a relatively high value on the ability to access detailed information regarding energy use (44% assigned a score of 9 or 10 on a scale of 0 - 10), the ability to easily access detailed information about the costs of electricity supply (46%), as well as the ability to control their electricity costs and/or earn incentive payments by altering energy use patterns (44%).

[20] Respondents were asked about their interest in electricity-related products and services that are now rarely used by residential customers in New York. Respondents identified a high level of interest (9-10 on a scale of 0 - 10) in several energy management and DER products, including a peak load pricing plan (35%); devices to monitor home electricity usage in real time (34%); installation of solar panels (32%); smart appliances that can adjust their usage based on the price of electricity (31%); electricity priced based on time of day of electricity use (28%); and electricity pricing plan where you receive credits for providing the utility control over key appliances in peak periods (24%).

1. Data Access and Privacy[21]

System and customer data can reveal near term opportunities for DER investment and is a prerequisite to successful DER provider development of innovative products and services. DER providers require standardized, time-stamped customer energy usage information where technically available to develop business cases, attract investment, and quickly bring DER products and services to market.

Customer electricity usage data is not readily available to providers due to existing privacy regulations, data acquisition technology limitations, data acquisition costs, and data hosting costs. The objective of this proposal is to advance data access to enable markets while meeting reasonable privacy and proprietary expectations.

i. Data Exchange

Staff proposes, for further consideration by parties, a bi-directional electricity data information exchange from data acquisition assets such as meters and DER assets installed on both sides of the meter. The purpose of the data exchange is to enhance distribution system monitoring and control, reveal opportunities for near term DER products and services tied directly to customer data, and to support the development of innovative DER products and services to be traded on the DSP market.

To preserve customer privacy and security, customers should be given the option to opt-out of the information exchange. The type and format of personalized customer electricity use data that should be made available on an opt-out basis to registered DER providers through this exchange includes, but is not limited to:

- The customer's total electricity usage for the previous 12 months;
- Monthly customer electricity consumption;[22]
- Indicator of whether electricity commodity service is provided by an ESCO or the utility;
- Service classification according to the utility tariff;

[21] This section refers to DER providers, commercial entities, third parties, third party vendors and non-utility entities. Unless otherwise noted, Staff adopts the definition of DER provider contained in the attached Glossary.

[22] Customer-specific usage information that is more granular than total monthly usage may reveal information that the customer reasonably expects to be private, and therefore should be shared with the exchange only with the affirmative consent of the customer (e.g., on an opt-in basis).

- Installed Capacity (ICAP) tag, which indicates the customer's peak electricity demand;
- The number of meters associated with the customer;
- Account information that clearly identifies the customer service to a mapped distribution feeder or other distribution system identifier;
- Additional market information relevant to energy use collected by the utility or authorized third party, such as census data, weather, energy audit data, or other; and
- Other data needs as identified by the Commission.

Market participants seeking data from the exchange should be subject to data access registration requirements with the information data exchange operator. Initial data registration requirements may include, but not be limited to: affirmation that the entity is actively marketing DER, energy management products and/or other products and services that promote and support REV outcomes; certification that the information will not be disclosed to other entities; and confirmation that the market participant employs sufficient practices and protocols, in conformance with standard industry practices to secure and protect information from inappropriate release. The Commission will review and approve registration requirements periodically.

DER market participants will be required to provide DER asset and DER commitment information. The type and format of this information includes, but is not limited to:

- Standard format customer DER asset siting and technical information (technology type, location, publicly available Advanced Programming Interface);
- Standard format DER asset commitment (time-stamped commitment of DER product, e.g., kW load reduction commitment at a given time, duration);
- Standard format DER performance information (actual time-stamped load reduction history, energy and demand); and
- Any other DER commitment information deemed necessary by the Commission to complete measurement and verification of delivery of DER services.

Commercial entities will need to maintain the privacy of certain customer-specific asset information for competitive and system security reasons. Only the regulated DSP entity responsible for market operation (subject to market power protections adopted by the Commission) should have access to the above competitive market information.

The ownership and management of the exchange could be opened to a competitive procurement process. The DSP will require rapid integration of information data exchange system, but it need not own and operate the system itself, and to the extent there are multiple DSPs operating in the state, designating a single entity to operate a data exchange would ensure that data are provided in a uniform manner. Staff welcomes party comments on a proposal that a DSP market information exchange be designed and established in 2015, the key parameters of that exchange as outlined above, which entity should create and manage the exchange, and how it should be funded.

ii. Access by Customers to Their Own Data and to Comparative Product Offerings

Customers should have ready access to their own energy usage data in a secure and standard format. In addition, customers should be able to authorize that their energy usage data be provided to non-utility entities such as DER providers, to enable providers to develop and offer products and services that are tailored to the customer's specific energy patterns and needs.

New tools are increasingly being developed to make it easy for energy consumers to increase their awareness of, understanding of, and likelihood of purchasing electricity from a third party provider, as well as DER, home/business energy management products, and other energy-related value-added services. These new tools enable customers to transfer their energy usage information to third-parties they designate, and access products that enhance the value of their energy dollar. Additional tools should be developed that are tailored to New York consumers. These tools include a consumer-friendly web-based application and a mobile application that make it easy for consumers to:

- Understand what distributed energy products, renewable energy products, home/business energy management products, as well as commodity services are available;
- Filter and sort available products according to criteria, including price, selected by the customer;
- Select a product(s) that they would like to learn more about; and
- Make it as easy as possible for the consumer to comparison shop and make an informed purchase decision.

Staff has begun to explore the value of these and other customer engagement tools and will continue to coordinate with stakeholders and other entities to ensure development of the tools to facilitate customer engagement.

2. Customer Acceptance

Creating animated DSP markets as envisioned in REV implies that customers will increasingly: 1) be aware of and adopt DER technologies and services; and 2) use DER technologies in such a manner as to optimize their value to the grid and to the customer. It will also require market transparency and continued Commission oversight and involvement, where appropriate, to ensure that consumers have fair access and sufficient confidence that participation will provide them value. In order to improve and maintain customer confidence in market participants and market information, it is imperative that rules for participation are developed and enforced. The efforts to animate markets through this REV proceeding should not be seen as foregoing any of the Commission's regulatory authority – but rather a sharpening of the regulatory tools such that the Commission can swiftly deal with bad actors, improper exercise of market power, and other barriers to customer engagement without unduly burdening competition innovation.

Through the comprehensive market-based approach described here, Staff expects DER providers and utilities will have new customer data, revenue opportunities, incentives, and engagement opportunities to overcome the lack of customer awareness of DER products and service, encouraging customers to adopt and use DER resources effectively. The regulatory framework must provide sufficient ease of entry for these competitive opportunities, while providing sufficient oversight and consumer protections to allow for consumers to engage the energy markets in a robust and effective manner.

One objective of REV is to create customer choices, and facilitate multiple competing enhanced energy product and service offerings that improve people's lives. New customer engagement opportunities are arising all the time – often in forms not previously thought of as directly related to energy. Energy management is already bundled with fee-based services, such as security, entertainment, Internet, telecommunications, and others. Another non-traditional option – seen in various forms in other jurisdictions – and which received substantial attention in the CEC working group is Community Choice Aggregation (CCA). CCA programs offer the opportunity to vastly expand the number of customers receiving energy supply from ESCOs while also providing those customers with more stable fixed rates and the potential for development of community-owned distributed energy resources. Facilitation of CCA may require changes to the Commission's Uniform Business Practices. CCA interactions with DSP may merit special rules to bound the DSP and incorporate the unique characteristics of CCAs. Staff is reviewing how CCA may be facilitated and may make a proposal in the future.

The CEC working group report notes a number of barriers to market entry by third-parties and customer acceptance of third-party products and services. A full analysis of all of these barriers is beyond the scope of this proposal. Three barriers that are specifically discussed here are: 1) limited utilization of time-of-use rates, 2) billing and engagement, and 3) split incentives.

1) Time-of-use Rates – Time-of-use rates are beneficial by encouraging customers to reduce electricity usage during peak periods through cost signals that appropriately reflect the higher cost of usage during peak periods versus usage during non-peak periods. Depending on the utility and the type of meter in-use at the customers' locations, peak and non-peak intervals are usually measured in multiple-hours or smaller intervals. In New York, most high-volume commercial and industrial customers are subject to mandatory time-of-use pricing, and all customers have the option to opt-in to time-of-use pricing. Broader acceptance of optional time-of-use pricing has been very limited. Customer acceptance may depend on several factors, including knowledge of the rates and their potential consumer savings benefits, availability of interval meters or alternatives, existing usage patterns, and the ability to modify those patterns. Utilities should revisit their time-of-use rates for mass market customers seeking to develop and provide easy-to-understand interval rates and tools for customers to easily determine the benefits of those rate designs for their individual needs. In developing these customer engagement tools and rates, stakeholders should not limit their consideration to rate short intervals but should also consider the imposition of longer intervals including seasonal rates that better reflect cost of service overtime but remain manageable and valuable to a broad swath of energy customer. To the extent that the cost of advanced metering equipment presents a barrier to customer adoption of DER programs or time variant pricing, utilities and market participants should consider alternatives to AMI technologies to enable program delivery.

Time-of-use rates are not an end in themselves; they provide more accurate price signals for time-variable usage related to system costs and are intended to drive appropriate behavior and investment based on minimizing costs and maximizing value. Implementation of REV should aim at accomplishing this objective through the most cost-efficient and widely accepted means.

2) Billing and Engagement - As noted by the CEC and a significant number of the comments provided here and in related proceedings, the utility bill is recognized as an important aspect of customer engagement. Currently, only utilities and ESCOs providing energy commodity have direct access to customers through the utility bill. Moreover, regulatory requirements and legacy system limitations, among other barriers, are preventing the utility bill from reaching its full potential as a customer engagement tool. The content and format of utility bills, particularly concerning charges by non-utility entities, as well as the ability of non-utility and non-ESCO providers to bill through the utility, represent significant barriers to full DER animation, and should be explored through a collaborative effort led by Staff.[23]

More immediately, Staff suggests enhancements to consolidated utility billing (CUB), which is now in general use in New York. Specifically, Staff proposes that utilities make available approximately 1000 characters on their bills for ESCO bill messages concerning DER or other energy-related value-added products. Conceptually, ESCOs could develop customer-specific messages based on the energy usage of their customers, and use EDI to transmit that information to utilities for printing on CUB. In their comments regarding this proposal, utilities should individually quantify the cost of implementing this requirement. Utilities which cannot implement this change within six months after issuance of a Commission Order directing such action, should provide a complete explanation for their inability to do so. Staff also proposes that utilities individually quantify the cost they would expect to incur to modify their systems to accommodate customer-specific messages from ESCOs regarding DER and related products.

3) Split-incentives - A large number of potential residential DSP market customers in New York live in mixed use and multi-family buildings. Parties note the critical importance of developing solutions that address the “split-incentive” barrier confronting this customer segment. A common form of split incentive is where building owners would bear the cost of DER asset installation, while tenants would receive the benefits of the asset, with the result that beneficial

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[23] In Case 12-M-0476, the Commission invited comment on changes to Commission policies to facilitate consolidated ESCO billing (CEB) as well as potential modifications to consolidated utility billing (CUB), both of which are intended to enhance the ability of ESCOs to communicate with their customers. Staff intends to further evaluate CEB in Case 12-M-0476.

investments are frequently not made. In other cases, where residences are not individually metered, tenants are unable to realize any benefit from energy saving practices or measures.

Many of these underlying economic relationships are beyond the scope of Commission authority. However, development of new tariff and market options could enable greater participation in DER through shared savings mechanisms. In addition, transactive energy tariffs, solar leasing, community solar, and other innovative options have the potential to enable greater distributed participation of customers that cannot physically install DER assets such as distributed generation. The Commission may determine that regulated utilities need to provide new pricing plans and services, to overcome split incentive barriers. However, Staff anticipates DER providers will offer innovative pricing and service options to all customers, including this customer segment, subject to consumer protections contemplated here. The intent of the DSP market generally is to promote service innovations that reduce long-standing barriers to DER adoption, such as the physical barriers identified here. Addressing split incentives should be included within the utilities' implementation plans.

3. Affordability

i. Commitment to Affordable Service

The responsibility of the Commission and utilities to ensure reliable service at reasonable rates is fundamental. Several parties raise issues relating to affordability and low-income customer participation in the envisioned DSP market, noting the incidence of service disconnections and bill arrears in New York. Staff shares these concerns; they underscore that existing utility bill relief goals and customer protections must be maintained throughout this transition.

The creation of an effective marketplace for DER product deliveries will reduce costs for all ratepayers by optimizing distribution system operations, increasing system efficiencies, reducing the impact of distribution system management on the bulk power system, and deferring capital investments. All utility plans will be carefully considered and will not be approved unless they meet the benefit cost analysis criteria described later in this report.

The context in which REV is being considered is, however, very important. REV is not only an initiative to improve the efficiency of current operations. It is also a response to trends that could pose severe challenges to low and moderate income customers in coming years. These include rate pressure due to aging infrastructure replacements, and price volatility due to declining fuel diversity. There is also a risk in the long term that widescale customer adoption of distributed generation, in the absence of a REV framework, could result in revenue erosion for utilities that would be shouldered by the customers least able to develop DG alternatives for themselves. The cost of implementing REV must be weighed not only against the direct benefits of REV measures, but also against the cost of inaction.

ii. Low-Income Customer Engagement

There are particular concerns related to the ability of low and moderate income customers to participate in REV markets. One of these is the split incentive problem for tenants, noted above. Other major concerns are lack of access to financing, and unwillingness of some service providers to engage with customers who have histories of payment troubles.

If REV markets are properly structured and supervised, utility customers will not need to participate directly in order to benefit from them. In addition to the potential for cost savings for DER market participants, effective DSP market operation should result in more efficient system utilization. The most substantial cost savings may be generated through reduction of power that utilities will need to purchase and deliver during peak demand periods. This savings reduces the market price of electricity for all customers. While these system benefits accrue to all customers, there is additional value enabled through the DSP for those who own their own DER assets. Overcoming barriers to finance and accessibility to allow low and middle income customers to participate will be an important element of program success.

As increased DER product financing and service options emerge, low-income customers will have greater opportunities to participate. Currently, third-party solar PV finance companies offer solar systems at no upfront cost. While many of these companies have initially targeted customer segments with a higher than average credit score, DER financing companies, and other community groups are investigating ways to reach low-income markets. In the meantime, dedicated energy efficiency programs will continue to be made available to low-income customers.

One aspect of REV that will encourage participation from all classes of customers is the emphasis on targeted measures to address specific system needs. Where the need is in an area that is heavily residential, DER products tailored to residential customers will be used. Con Edison's BQDM initiative, for example, addresses system overload in an area with a high concentration of low-income customers.

The Commission should require that utility DSP implementation plans include plans to engage low and moderate-income customers in the DSP market with low or no initial investment. These plans may include basic service plans, bill relief options, and incentive programs, as available.

iii. High-Usage Customers

Although much of the discussion related to customer engagement has centered on the mass market, the participation of high-usage commercial and industrial (C/I) customers is crucial to the success of REV. There is a large untapped potential for demand response and other forms of DER in this sector. Individual customer transaction costs are lower for C/I customers, and their energy awareness tends to be higher, which allows ESCOs to have greater penetration in this sector of the market.

By monetizing the value streams of DER products, REV will encourage ESCOs to combine DER services with commodity services for C/I customers, A first step, as described below, is for expanded demand response programs to be implemented in each utility service territory. C/I customers will also benefit from the reduction in System Benefit Charges proposed in the transition to more effective energy efficiency and renewable programs, as well as the reduced rates that will result from improved system efficiencies.

Large customers identify interconnection requirements and standby rates as substantial barriers to increased development of distributed generation. Each of these issues will be addressed -- interconnection requirements as discussed below and standby rates in the tariff discussions in Track Two of this proceeding.

C. DER Providers and ESCOs

DER providers offer products and services directly to end-use residential, commercial, and industrial utility customers. DER providers may manage DER assets on behalf of those customers, bid the commitment of DER services into DSP markets, and provide market settlement to the end-use customer based on the market clearance and performance of the DER service.

DER providers may include a broad range of entities that have the potential to reach multiple end use customers, have the technical capacity to manage installation or financing of DER assets, and the ability to aggregate DER services and plans for purposes of market participation. These may include energy management companies, regulated utilities (subject to market power restrictions described below), solar providers and energy efficiency companies, local governments entities, not-for-profit corporations, housing associations, banks and registered financial institutions, energy improvement districts, telecommunications companies, real estate developers, and others.

There are also multiple ownership models associated with DER services. DER providers may own and lease DER assets to customers for systems sited on their property. DER providers may also offer DER asset management on behalf of customers-owned DER systems, enhancing the value of those systems to the grid and to the end-user. Like other firms, DER providers will have a financial incentive to maximize return on their investments in DER assets through the DSP market. In one model, DER providers will assess and determine optimal DER asset performance and commitment data, and bid the fair and optimal DER service price and service into the DSP market.

ESCOs, as defined in New York, sell energy commodity to retail customers. While ESCOs have the opportunity to act as DER providers and fully participate in DSP markets, the current focus of most ESCOs in the mass market is limited to commodity sales. The REV proceeding is an opportunity to re-focus ESCO business plans for mass-market customers toward effective delivery of DER products and services. Currently, only 24% of residential customers in New York are registered ESCO account holders. REV markets offer the potential for ESCOs not only to expand their businesses as DER providers but also to expand the level of market participation of customers.

The regulatory status of DER providers will need to be clarified. ESCOs are subject to the Public Service Law and the Commission's Uniform Business Practices (UBP). If a DER provider is not engaged in commodity sales, it is not immediately clear whether or to what extent it would be subject to UBP or other forms of Commission regulation. As with ESCOs, the Commission has a strong interest in protecting consumers and legitimate service providers from bad actors in the market. Also, because distribution utilities will rely on DER products to support reliable service, the Commission has an interest in maintaining business standards for DER providers. Accordingly, Staff recommends that DER providers participating in DSP markets should be subject to some degree of Commission oversight. Parties are encouraged to comment on this issue.

D. Wholesale Market Interactions

In its April report, Staff noted that “[w]ide adoption of DER will potentially affect both short-term and long-term load forecasting and system needs assessment. This, in turn, will affect planning, design and operation of the bulk power system and of distribution systems as well” and that “[t]here will be a need for alignment of wholesale and retail market rules relating to demand response aggregation, program eligibility, product valuation, payment protocols, communications technology and procedures, and measurement and verification methodologies.” The report also noted examples of wholesale market rules that merit review to ensure consistency with DSP market participation. Certain requirements, such as the need for a DER to meet performance standards written for generating assets, are relevant to cost-effective participation by DERs.

1. Wholesale Benefits Resulting From Expanded Use of DER

DSPs will manage DER bids (subject to market power protections in the case of affiliate bids), with the outcome of a more efficient system load profile. In addition to benefits created in terms of distribution system efficiencies, this will have direct and immediate benefits at the wholesale market level. Specifically, the aggregate effect of reduction in peak loads will drive down ICAP requirements at the wholesale level and reduce peak energy production needs. This will translate to reduced installed capacity obligations and energy costs for the DSPs as the need for the NYISO to run expensive and inefficient/polluting peaking generation decreases. The latter can result in a reduction in energy cost and airborne emissions if DERs are not fossil-fueled.[24]

The DSPs can also derive benefits as a result of acting as an interface (aggregator) between DER providers in its programs, and programs operated by the NYISO. Under current NYISO rules these opportunities exist in the energy, capacity, and ancillary services markets. DSP program development should ensure that DSP interaction in NYISO markets produces maximum benefits and reduces risk of unanticipated adverse effects. As an example of its current markets working as intended, the NYISO comments that approximately 80% of new capacity installed since the inception of NYISO markets is located east of the transmission

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[24] Between April and October 2012, 23% of the economic energy settled by load reduction was obtained from on-site generation, 87% of which was from natural gas fueled generation with an additional 6% from diesel generators. PJM 2012 Economic Demand Response Report. http://www.pjm.com/~/media/markets-ops/dsr/economic-dr-performance-report-analysis-of-activity-after-implementation-of-745.ashx.

constraints that block capacity deliverability from upstate generators to downstate markets.[25]

Staff agrees that DSP program rules should be developed to recognize the need to interact as efficiently as possible with NYISO market rules, and envisions that the development of controllable DER will be greatest where the combination of wholesale market prices and market based distribution signals are the greatest. DER, having the ability to reduce system needs, will ultimately reduce flows on the bulk power system wherever it is developed, potentially opening up the constraints that currently exist, whereas wholesale generation, if constructed in a constrained location, may exacerbate those constraints.

2. Coordination Between DSPs and the NYISO

Efficient dispatch of DER enhances market efficiency and delivery system operational control. Despite the significant potential that DER provides to deliver previously unachievable efficiencies to the bulk power system, that potential will not likely be realized without a thoughtful approach to how DER capacity is integrated into the operation of the bulk power system. As the NYISO commented:

> To avoid negative impacts, DERs that provide additional energy or load reduction must be visible to or forecasted within existing wholesale market processes in order to integrate DER activity with wholesale market activity. The precise form of integration will depend on how the DERs are expected to be used. DERs have the potential to introduce reliability challenges if they operate independently of the wholesale market and planning processes.[26]

The DSP will facilitate market dispatch of controllable DERs. As such, the DSP will require visibility and control of those assets. The DSP will assess and report available capacity of DER assets at any point in time, and is best suited to facilitate interactions between the NYISO's bulk power operations, distribution system needs and distributed resources.

In order to facilitate this role, market rules allowing DER participation at DSP and wholesale levels must be aligned to ensure DER interaction in both areas is efficient and properly valued. Market rules must be developed which ensure that DER controlled by the DSPs receive the value of benefits provided not only to the distribution system, but to the bulk power system as well. This goal can be accomplished with DSPs acting as aggregators in NYISO programs. This model could be disrupted if the NYISO loses its ability to use retail load

[25] Case 14-M-0101, Revised Comments of NYISO, August 18, 2014, footnote 2, page 3.

[26] Case 14-M-0101, Comments of NYISO, July 18, 2014, page 3.

response in its wholesale market programs as a result of the recent U.S. Court of Appeals for the D.C. Circuit Court decision vacating FERC's Order 745.

Further, measurement and verification must be aligned to the extent needed to ensure both DSP and NYISO planners have confidence in the ability of DER in their load forecasting and planning functions. NYISO market rules need to be modified to enable the efficient incorporation of DSP controlled DER into its markets, as necessary.

Another model for interaction between DSPs and the NYISO is for DSPs to independently operate load reduction programs and realize the value of those programs through their procurement of power to serve retail load. To the extent that utilities can manage load predictably, they can optimize their bids into power markets. In this model, utilities assume full responsibility for DR programs. Utilities could actively use DERs as load modifiers as is done to some extent with energy efficiency.

3. Coordination Impacts Resulting From FERC Order 745 Being Vacated

On May 23, 2014, the DC Circuit ruled that FERC did not have jurisdiction under the Federal Power Act to issue Order 745 in part because demand response is part of the retail markets, which are exclusively within the states' jurisdiction to regulate. The Order pertained specifically to demand response participation in wholesale energy markets. However, the decision could eventually be applicable to all demand response in wholesale energy markets. This topic is discussed in more depth in the Demand Response Tariffs section below.

IV. GAUGING FEASIBILITY

A. Platform Technology

The following section describes DSP functions and technologies that are available in the market to enable those functions. Further detail based on the Platform Technology Working Group is available in Appendix B. This section lays out: 1) DSP functional requirements; 2) existing utility distribution systems and capabilities; and 3) technology evaluation and relevance to DSP functions. As with other sections in this straw proposal, staff recognizes DSP functions and enabling technologies will evolve with market DSP product development.

Staff affirms the finding of the Platform Technology Working Group that multiple metering, communications, and control technologies and systems exist today and are in operation, albeit in different stages of deployment, throughout utility distribution systems.

Utilities are making ongoing improvements to distribution systems to begin developing functions consistent with the level of visibility, control and communications network that would be adequate to support the DSP. The REV process is an opportunity to focus distribution system planning such that the DSP can make the most efficient and economical decisions to enable DSP markets.

DSPs will need to procure additional data acquisition and communications technologies to support many of the envisioned DSP market functionalities. This section, therefore, focuses on the availability of technology solutions to enable the DSP functions. Technologies are available to enhance DSP operator visibility throughout the system and control functionalities that the DSP would be expected to provide. Moreover, the pace of technology innovation and associated cost reductions for enabling technologies and systems throughout the distribution system is improving rapidly.[27] The DSP market is technically and realistically achievable. Transitioning from the current system to a DSP-market will, however, require planning, investment, and coordination.

1. DSP Functional Requirements

The Technology Platform Working Group identified several functional requirements for DSP market operations. The following table is a preliminary list of DSP market functionalities sorted by three main categories; Grid, Customer/DER/Microgrids, and Market. The Grid column represents functions that the DSP would need to facilitate in order to meet the REV policy objectives in regards to grid operations. The functions listed under the Customer/ DER/ Microgrids section would facilitate the DSP's coordination and integration of the various DERs. Lastly, the functions listed in the Market column would allow the DSP to support market transactions.

[27] A preliminary inventory is available in the report of the Platform Technology Working Group.

Table 2

Grid	Customer/DER/Microgrid	Market
• Real-time load monitoring • Real-time network monitoring • Adaptive protection • Enhanced fault detection/location • Outage/restoration notification • Automated feeder and line switching (FLISR/FDIR) • Automated voltage and VAR Control • Real-time load transfer • Dynamic capability rating • Power flow control • Automated islanding and reconnection (microgrid) • Real time/predicted probabilistic based area substation, feeder, and customer level reliability metrics (MTTF/MTTR)	• Direct load control • DER power control • DER power factor control • Automated islanding and reconnection • Algorithms and analytics for Customer/DER/Microgrid control and optimization	• Dynamic event notification • Dynamic pricing • Market-based demand response • Dynamic electricity production forecasting • Dynamic electricity consumption forecasting • M&V for producers and consumers (premise/appliance/resource) • Participant registration and relationship management • Confirmation and settlement • Billing, receiving and cash management • Free-market trading • Algorithms and analytics for market information/ops

Staff lists these functionalities to solicit party comment, particularly from regulated utilities, third party DER providers and ESCOs, and innovators. Specifically, staff requests comment on 1) functionality gaps, and 2) which functionalities listed or not listed are priorities for initial utility investment in new DSP system technologies. Staff proposes the following functions available through existing technologies should be initial priorities:

- Real-time load monitoring;
- Real-time network monitoring;
- Enhanced fault detection/location;
- Automated feeder and line switching (FLISR/FDIR); and
- Automated voltage and VAR control.

With these initial foundational functionalities in place, the DSP system operators will be better able to build more advanced functionalities, including those listed in the Market category. The subsequent section further defines existing utility distribution system capabilities.

2. Existing Utility Distribution Systems and Capabilities

The existing utility distribution systems in New York have assets and functionalities that have broad similarities, but there are specific differences as well. Each existing utility distribution system includes asset management tools, operation and modeling systems, and enabling technologies. Each utility distribution system was developed in different functional environments to meet individual needs.

Utilities are making ongoing improvements to distribution systems to enable functions consistent with the level of visibility, control and communications network that would be adequate to support the 'end-state' DSP. There are various levels of visibility and communications networks, as well as diverse geography and varied demographics across utilities. Consolidated Edison's network system, for example, has thousands of miles of underground lines and numerous underground facilities, while the other New York utilities predominantly have radial systems with overhead wires.

Capabilities across a given utility's service territory are heterogeneous. Visibility to field devices is typically limited, and varies across utility. The same holds for automation and distribution system control. The platforms for the Customer Information System (CIS), Geographic Information System (GIS), asset database, Outage Management System (OMS), and Energy Management System (EMS) vary across utilities and are a mix of internally developed systems and third party vendor software.

All New York utilities have planned and are in the process of deploying technologies that will improve system visibility, enhance control, and support analytics. Enhanced visibility advances both system planning, and operational control. Enhanced communication allows for real or near real-time information updates to the control center, substations and/or other devices on the network. An integrated communication system is critical to tie together advances in the Distribution Management System, mapping and geographic data, outage management, and intelligent device installations in order to maximize optimization and system automation. Each utility has a vision and is involved with research and development efforts to develop a fully integrated and centralized control system.

3. Technology Evaluation

This section provides examples of how distribution system and customer facing DER technologies support DSP visibility, communications, and control functionalities needed to animate the DER market. This section therefore provides evidence for Staff's finding that the DSP market is technically achievable.

i. Distribution System Operations

Load and network monitoring, automated voltage, and VAR control are grid operational functions enabled by existing technologies, which will improve as grid modernization proceeds. System sensor performance and cost improvements have accelerated increasingly granular and more cost effective system and end user data acquisition. Grid operators have the ability to access near real-time data from service endpoints, primary and secondary distribution circuits, substations, transformers, switches and relays, and the bulk grid. Data telemetry has similarly advanced, enabling increasing volumes of two way data flows and near real time control of system components, including various forms of DER. Flexible and robust monitoring and control systems are critical to many DSP functions and utilities and third parties developing multi-layered, secure systems and interfaces using both wired and wireless technologies.

Integration of these types of data acquisition systems into unified meter data management systems, demand response optimization platforms, and customer-owned DER assets enhances the value of those assets to utilities and customers. For example, DSP systems will improve customer demand response forecasting and control, outage response, and improved asset management. Vendors offer increasingly complex load reduction forecast and demand response capabilities to enable distribution grid automation, control and management of DER and support of market operations.

ii. Customer Facing Technologies

Customer-facing energy management hardware and software-based solutions have dramatically outpaced utility control system innovations. Commercial building management systems, for example, monitor and control all aspects of traditional building operations such as HVAC, lighting, power systems, fire systems, and security systems.

In addition to wholesale and distribution utility demand response load relief programs, third parties, including many energy service companies, offer an increasing array of energy efficiency and energy management services to residential and small commercial customers.

Many systems are designed to provide system operation and planning value to the distribution utilities, such as direct load monitoring and control functions.

Residential customers can purchase an energy gateway that monitors DER resources, such as a home's PV inverter, learning thermostat, battery storage system, and a plug-in electric vehicle in the garage. Many of these systems integrate command and control functionality through phone-based apps. These apps have the ability to optimize residential energy use according to electricity prices and customer preferences. Battery and solar PV cost reductions have resulted in explosive growth of customer adoption of these DER resources. DER communication with utilities and envisioned DSP platforms is already available through onboard telecommunications systems.

Throughout distribution and customer-facing technology deployments, security remains a major concern and is a fundamental consideration to the electric industry in planning and operations as well as implementation of new products and systems. While embedded in the standards and protocols necessary to build the platform, cyber security must be considered and addressed when using open protocols to connect to new end use technologies and when evaluating new products and systems.

iii. Technology Platform Policy Mapping

These technology trends underscore the need for an understanding of technology development that maintains a clear "line of sight" back to the Commission's policy goals. There are clearly technical solutions available to achieve many envisioned DSP functions, but it is also evident that there are currently no available off-the-shelf, one-size-fits-all systems or solutions. Rather, there are many innovative approaches and solutions that if implemented in a haphazard way could lead to a technically fragmented situation where uncertainty, certainly from the customer or market perspective, would ensue. As discussed earlier, the New York utilities are engaged in distribution system modernization efforts. It is imperative that these efforts be harmonized to ensure consistency with policy goals and to ensure that robust, transparent and scalable systems are implemented.

To ensure line of sight to the policy goals and to provide that common approach, Staff recommends further definition and mapping of enabling technologies to the envisioned DSP functionalities as they are refined. The Platform Technology group initiated development of a tool to provide detailed definitions of required grid, customer/DER and market functionalities and definitions of the available and emerging technologies. It also provides a means to assess technology maturity and implementation needs, both immediate and in the future.

A transparent technology mapping process will help the utilities and stakeholders better understand the technologies needed to enable DSP platform functionality. These analyses will provide a valuable frame of reference, and help define implementation criteria, to guide utility implementation plans and efforts on a forward-going basis.

iv. Technology Standardization

Many technology solutions employ proprietary algorithms and advanced programming interfaces (APIs). Distribution system technology platform modernization efforts should ensure open standards-based integration of these energy management technologies. Individual incumbent utilities will perform DSP functions in each of their respective service territories. To achieve the goal of a transactional platform for DER providers and customers, DSPs will need to coordinate operational requirements.

For this reason, the Commission should require a stakeholder process with appropriate technical conferences to ensure that DSP operational procedures, tariffs, market rules, and market procedures are standardized to the maximum extent practicable. At a minimum DSPs should be required to establish standards for the architecture of the grid that will ensure interoperability within and ideally between service territories.

Staff agrees with the Platform Technology Working Group that it is important to have a clear ‘line of sight’ from policy goals to functionality to technology investments. In furtherance of technical platform standardization efforts envisioned here, the stakeholder process should pursue the following tasks, potentially supported by an independent research organization such as a United States Department of Energy sponsored national laboratory:

1. Further explore, and adopt as appropriate, a standard communications architecture (e.g. NIST 3.0, Open ADR, and others) to enable interoperability with multiple end use devices and networks; and,
2. Complete an assessment of technology availability and maturity and technology/functionality mapping and gap analysis, with a focus on identifying initial implementation shortcomings.

B. Benefit Cost Analysis Framework

A sound benefit-cost analysis (BCA) framework is required to support policy, investment, and pricing choices as the implementation of REV moves forward. This section lays out 1) proposed principles to guide BCA framework development, 2) guidance on key parameters to be included, and 3) a proposed process going forward to develop the BCA framework. Furthermore, staff recommends that the BCA framework developed through this process become the standard for BCA in all other proceedings related to REV, including rate cases.

Benefit-cost analysis is a systematic quantification and comparison of the net present value of a particular action. Such an action can be an investment, a plan, or a general policy. Businesses, such as utilities, are engaging in some form of BCA continuously for all manner of decisions and analysis,[28] although at very different levels of complexity, depending on the action. They are used to determine whether a particular action is justified from a financial perspective and/or for choosing among alternative methods to achieve an outcome.

BCA is currently used to varying degrees and in multiple applications to guide and evaluate electricity system choices in New York. In its order establishing rates for Con Edison in February 2014, the Commission stated its expectations for benefit cost analyses for future capital investment, seeking analysis that differs "from a typical utility capital expenditure analysis and assesses the relative benefits and costs of resilience of existing utility infrastructure and alternative resilience approaches such as microgrids. The risks and probabilities of future climate events, the expected useful life of assets, the impact of outages of varying duration on affected customers, and the potential risk to critical facilities, among other societal cost factors, should be considered, and should be monetized to the extent that reasonable values can be established and will be of practical relevance. This approach should harmonize the comparison of traditional utility system and alternative solutions and investments. We expect to develop a single, consistent cost/benefit approach for use in the Energy Efficiency Portfolio Standard proceeding, and in the anticipated comprehensive generic regulatory framework proceeding [REV] we announced in December 2013." As New York's electricity system evolves to one that is more integrated and market-based, it will be increasingly important that investment decisions are evaluated on a consistent, portfolio basis to ensure equivalent comparisons and accurate system-level optimization.

The BCA framework to be developed should be applied at multiple scales with accompanying adjustments to the level of detail required. At a high level, the BCA framework

[28] Sometimes called "business case analysis," or "net present value analysis."

will be used to guide overall policy decisions and to fairly compare substitutes, accounting for system-wide, aggregated benefits and costs. The primary application of the BCA framework, though, is expected to be used by utilities in planning their distribution systems, including DSP investments and DER, to meet overall system cost efficiency, reliability, resiliency, security, and societal goals. Finally, the BCA framework will be used at its most granular level to inform pricing of DER products.

1. Principles to Guide BCA Framework Development

Subject to further refinement as the case proceeds, Staff recommends that the following principles be used to guide the process going forward. To the extent possible, the BCA framework should:

- Be transparent about assumptions, perspectives considered, sources, and methodologies;
- List all benefits and costs borne by all parties, state which are not included or quantified in the overall BCA and why, and not unnecessarily combine or conflate different benefits and costs;
- Be designed to assess portfolios rather than individual measures or investments, although it may be appropriate to allow different scales of portfolios. For example, for utility investment plans, the BCA assessment should be performed at the implementation plan level not at the specific grid investment level;
- Be a full-life-of-the-investment analysis and include a sensitivity analysis on key assumptions;
- Assess the benefits and costs of “REV” investments in comparison to a reasonable business-as-usual case rather than in isolation;
- Report results of the Societal Cost Test (SCT), Utility Cost Test (UCT), and Rate Impact Measure (RIM); and
- Allow for judgment, such that if investments do not pass cost tests based on included quantified benefits, a qualitative assessment of non-quantified benefits can inform approval.

2. Guidance on Key Parameters

While it is not possible at this stage to provide comprehensive and definitive guidance on the BCA framework, Staff does provide the following initial guidance on 1) benefits and costs to be considered, 2) approaches to valuing specific benefits and costs, and 3) input assumptions.

1. Benefits and Costs to be considered. Note that benefits and costs are relational, in that the costs of one alternative are often the benefits of another. For example, most of the benefits of

energy efficiency investments derive from avoided electric production and delivery costs, as a result of serving less load. The tables below express potential net benefits relative to a reasonable business-as-usual case. The following table summarizes categories of benefits and costs identified by external studies.

Table 3

LBNL - Evaluation Framework and Tools for Distributed Energy Resources (2003)	RAP –Recognizing the Full Value of Energy Efficiency (2013)	EPRI – Methodological Approach for Estimating the Costs of Smart Grid Demonstration Projects (2010)	Electricity Innovation Lab (eLab) by Rock Mountain Institute – A Review of Solar PV Benefit and Cost Studies
Benefits •Lower electricity costs •Consumer electricity price protection •Reliability and power quality •CHP efficiency improvement •Consumer control •T&D deferral and congestion relief •Reduced transmission losses •Voltage support •Reduced security risk to grid •Enhanced electricity price elasticity •NIMBY opposition to new central power plants and transmission lines •Land use effects •Capacity deferral and increase in stranded assets •Airborne or outdoor emissions •DER fuel delivery challenges **Costs** •Indoor emissions •Noise disturbance •Capacity deferral and increase in stranded assets •Airborne or outdoor emissions •ER fuel delivery challenges	**Utility System Benefits** •Avoided production capacity costs •Avoided production energy costs •Avoided costs of future environmental regulations •Avoided transmission capacity costs •Avoided line losses •Avoided reserves •Avoided risk •Displacement of renewable resource obligation •Reduced credit and collection costs •Demand response induced price effect **Benefits to Participants** •Reduced future energy bills **Non-energy Benefits to Participants** •O&M cost savings •Participant health impacts •Employee productivity •Property values •Benefits unique to low income customers •Comfort **Societal Non-Energy Benefits** •Air quality impacts •Water quantity and quality impacts •Coal ash ponds and coal combustion residuals •Employment impacts •Economic development •Societal risk and energy security •Reduction of effects of termination of service •Avoidance of uncollectible bills for utilities •Electricity/water nexus **Energy Efficiency Program Costs** •Program administration costs (including EM&V) •Program costs •Participant contribution •Third-party contribution •Lost revenues to the utility	**Benefits** •Lower electricity costs •Avoided T&D costs •Lower O&M costs •Reduced transmission congestion •Power quality •Reduced outage •Reduced GHG, SOx, NOx, PM •PEV integration •Improved security and safety •Improved asset utilization **Costs** •Program administration •Incentives •Utility CapEx •Utility backend system design and implementation •Utility wide area monitoring •Consumer DER cost •Non-participant cost	**Benefits and/or Costs** •Energy •System losses •Generation capacity •Transmission and distribution capacity •DPV installed capacity •Reactive supply & voltage control •Regulation & frequency response •Energy & generator imbalance •Synchronized & supplemental operating reserves •Scheduling, forecasting and system control & dispatch •Fuel price hedge •Market price response •Reliability & resilience •Carbon emissions •Criteria air pollutants •Water •Land •Economic development (jobs and ta revenues)

In the context of this body of thought, Staff has identified the following list of benefits and costs that should be used as a starting point in developing the BCA framework.

Table 4

BENEFITS	RIM (rates)	Utility Cost (bill)	Societal
	PERSPECTIVE		
Bulk System			
Avoided Generation Capacity (ICAP) Costs, Including Installed Reserves and Losses	√	√	√
Avoided Energy (LBMP) Costs, including Losses	√	√	√
Avoided Ancillary Services (e.g. operating reserves, regulation, etc.)	√	√	√
Wholesale Market Price Impacts	√	√	-
Distribution System			
Avoided T&D Capacity Costs	√	√	√
Avoided O&M Costs	√	√	√
Avoided Distribution Losses	√	√	√
Reliability/Resiliency			
Avoided Restoration Costs	√	√	√
Avoided Outage Costs*	-	-	√
External (net)*			
Avoided GHG*	-	-	√
Avoided Criteria Air Pollutants*	-	-	√
Water*	-	-	√
Land*	-	-	√
Non-Energy Benefits (e.g., health impacts, employee productivity, property values)			√
*note: only the portion not already included above, net of any added external costs			
COSTS			
Program administrative costs (including M&V)	√	√	√
Added Ancilary Service Costs	√	√	√
Incremental T/D/DSP Costs (Including Incremental Metering and Communication)	√	√	√
Participant DER Cost	-	-	√
"Lost" Utility Revenues	√	-	-
Incentives	√	√	-
Non-Energy Costs (e.g., indoor emissions, noise disturbance)			√
RISKS (net)			
Compare Variability of Benefits to Variability of Costs	√	√	√

2. Approaches to valuing specific benefits and costs. Initial guidance on approaches to valuing specific benefits and costs is illustrated below, and is non-exhaustive.

Table 5

Benefit/cost	**Approach guidance**
Reduced carbon emissions	The value of reduced carbon emissions must be included in the BCA. The approach developed should consider marginal damage costs in addition to marginal compliance costs. For example, the latest RGGI auction price (as of 6/4/2014) was $5.02 per ton, reflecting the latest agreed-to quantity caps. This is a cost that will be "internalized" in the LBMP paid or avoided. However, most estimates of the marginal damage caused by a ton of CO_2 are higher than $5 per ton. It is unclear what impact proposed federal greenhouse gas regulations will have on this compliance mechanism, but a marginal damage cost approach would require estimating the total marginal damage cost, subtracting the "internalized" (e.g., RGGI) costs, and adding the increment above the projected RGGI price to the BCA. For example, the EPA estimated the Social Cost of Carbon (SCC), for various discount rates, from the existing literature through a collaborative process by an interagency group of eleven Federal government agencies including EPA, U.S. Department of Energy, and National Economic Council.[29] Using a real discount rate of 5%, the estimate for 2017 is $14 per short ton of CO2; at a 3% real discount rate the estimate is closer to $45 per short ton.
Reduced criteria air pollutant emissions	The value of reduced criteria air pollutants must be included in the BCA. For a variety of reasons, SO_2 and NOx allowance prices have been approximately $0 per ton, which clearly does not reflect the damage done by these pollutants.
Treatment of distributed resource characterization	Effectively assessing the benefits of DERs requires accurately assessing the amount of energy, capacity, and other benefits that those resources provide, and, often, when and where they will be provided. Therefore, for planning purposes, a methodology must be developed to 1) characterize DER resource profiles, and 2) determine how much energy or capacity and ancillary service needs those resources therefore avoid. A balance needs to be struck between standardized assumptions that make program-level BCA manageable and allowing a limited amount of flexibility to recognize possibly unique aspects of certain projects or resources. Such an approach should be based on best practices from around the country, albeit improved upon and adapted to New York, and may take the form of a Technical Resource Manual.

3. Input assumptions. Some inputs should be uniform across utilities, while others must reflect utility-specific circumstances. In the past, DPS Staff has developed "Long Run Avoided Cost" estimates for BCAs of Energy Efficiency programs. These reflected avoidable bulk

[29] U.S. EPA (2013b), Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 - Interagency Working Group on Social Cost of Carbon, May 2013.

energy costs, generation capacity costs, marginal losses, and distribution capacity costs. A non-exhaustive list of common inputs is as follows:

Table 6

Input Assumption	**Description/Guidance**
Energy costs (LBMPs)	These were estimated with the MAPS production costing model. A standard database would need to be created with consistent assumptions. One possibility is to use the most recent NYISO CARIS database or database assumptions.
Generation capacity costs	Forecasts should be made based on a consistent set of assumptions. The CARIS database assumptions and most recent NYISO "Gold Book" values could be used.
Losses	Assumptions about losses may be utility-specific, but the methodology used should be consistent.
Distribution costs	In the past, staff used one system-wide number for each utility for avoidable distribution capacity costs. This is clearly inadequate for the advanced planning and operation envisioned under REV. More detailed estimates of avoidable distribution costs tailored to specific locations, resources, and procurements should be developed for the BCA.
Discount rates	Because REV's goal is to integrate DER and utility investment and operations, Staff believes the proper discount rate should be based on the utility weighted average cost of capital. Utilities should comment on whether utility-specific, or a more generic WACC, should be used. For example, for evaluating the next RPS solicitation, Staff has estimated a generic New York utility "Distribution Company Discount Rate" of 4.4% (real), or 6.6% (nominal). [30]

3. Proposed Process for Developing the BCA Framework

Developing a BCA framework requires significant additional work and stakeholder engagement. Staff proposes a stakeholder process be put in place to design the BCA framework. Such a process should include an appropriate number of technical conferences to solicit

[30] This discount rate is based on the weighted cost of capital of a utility company in New York reflecting the average Commission authorized capitalization of the six major NY electric and gas combination utilities of 48% common equity and 52% long-term debt; a cost of equity of 8.60% reflecting Staff's update of its cost of equity calculation for the period ended May 2014; and a cost of debt of 4.70%, the current yield for utility debt with credit ratings matching the average NY utility of "A-" (S&P) and "A3" (Moody's), for the six months ended May 2014. To adjust between the nominal weighted average cost of capital to the real rate, the effects of 2.1% compounded long-term inflation is removed by using the Fisher model.

stakeholder input, and may require utility or third party support to create an initial straw proposal and subsequent iterations. The BCA framework developed should include further specification of what benefits and costs to include, methodologies used to value those benefits and costs, input assumptions to be used, and the application of the BCA framework. Further, it should reflect where reasonable quantifications of benefits and costs are possible, a discussion of qualitative benefits and costs where reasonable quantification is not possible, and a recommendation for ways to assess risks faced by potential deviations in the value of those benefits and costs.

Because designing and launching either of these processes may take several months, any benefit cost analysis needed to support the near-term "no regrets" actions recommended in this straw proposal should, at minimum, qualitatively report on the not-easily-monetized benefits those actions may be expected to create, aligned with the REV vision.

4. BCA for Tariff Pricing and Resource Procurement Provisions

A BCA framework consistent with the above could be used to arrive at appropriate tariff rates for certain products and services to be offered by the DSP. In addition, the same assessment could be applied to any competitive bidding, bilateral contracts, or negotiation used to procure DER. This analysis should be applied at the specific product or service level when not part of larger portfolio analysis. The utility would determine the appropriate benefits resulting from those investments to include from the suggested list. The results of this assessment can then be used to set a tariff rate or to evaluate a DER procurement offer. The application of the BCA framework to tariff pricing will be considered as part of the REV proceeding's Track Two.

V. BUILDING THE DSP MARKET

The modernization of New York's energy system involves the development and transaction of a variety of products and services through existing and new markets. Based on the Track One working group process and numerous additional conversations with New York stakeholders and electricity market experts, there is strong interest and readiness to build a DSP-based market for distributed energy resources in New York. However, the full development of those markets will take time. This section describes Staff's perspective on facilitating the transition and addresses several key elements of building the market, including: clean energy; demonstration projects; settlements; microgrids; interconnection; and planning.

A. Clean Energy

The objectives identified by the Commission for REV are consistent with the 2014 Draft New York State Energy Plan[31] which calls for transformative changes in New York's energy systems. Among the objectives included in the Draft Energy Plan is a 50% reduction of carbon emissions by 2030, putting the state onto a trajectory for an 80% reduction by 2050.[32] In addition to supporting the State's 50 x 30 goal, clean DER will play a significant role in complying with EPA's proposed new regulations governing carbon emissions from power plants. Although the final form of those rules is not yet known, as proposed they would place substantial new carbon reduction requirements on New York.

To achieve these objectives, there is a need to significantly augment the inventory of clean energy resources in New York State. One of the challenges of REV is to find the most effective means of achieving these goals. This section makes specific recommendations about energy efficiency, and poses a set of questions for party input around Main Tier renewables.

In the last 10 years, New York ratepayers have supported renewable generation, technology and market development (T&MD), and energy efficiency programs via dedicated ratepayer surcharges. The renewable portfolio standard (RPS) program has been centrally administered by NYSERDA and has supported the procurement of large scale generation, as well as smaller customer-sited renewable resources. Similarly, the T&MD program has also been administered by NYSERDA to support research and market development activities. In contrast, energy efficiency programs have been implemented by both the utilities and NYSERDA and have focused on achieving early savings within the context of prescriptive regulatory requirements. The gains of these programs have been substantial, but incremental.

Until recently, New York's clean energy portfolio has relied heavily on one-time incentives and has not been fully integrated into the distribution-level planning functions of the utilities. Recent additions to New York's clean energy portfolio, such as the Green Bank and NYSUN have begun the process of animating markets toward large scale penetration of distributed clean energy resources and a transition away from almost exclusive reliance on one-

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[31] http://energyplan.ny.gov/Plans/2014.aspx.

[32] Id. at 29.

time incentive based programs. In order to attain these results, and to meet state and federal greenhouse gas emission reduction goals, an order of magnitude greater investment is needed. This investment cannot be supplied by ratepayers alone, but will depend upon the mobilization of private capital and the transformation of the state's energy market.

1. Transition

Following institution of the REV proceeding in April 2014, the Commission initiated a Clean Energy Fund (CEF) proceeding to ensure continuity of support for clean energy programs during the transition to the more integrated and market-based approaches envisioned under the REV framework.[33] The Clean Energy Fund Order directed NYSERDA to develop and submit a comprehensive Clean Energy Fund proposal and to focus its efforts on market and technology transformative strategies and providing access to clean energy services to low-income customers and others that may otherwise not be able to readily participate in energy markets. Specifics regarding NYSERDA's future clean energy activities will be provided in the CEF proposal and will be addressed through the CEF proceeding.

In parallel, the utilities must begin planning for and facilitating greater penetration and integration of distributed and supply-side clean energy resources as part of their routine planning and operations. Utility initiatives to deploy energy efficiency and clean generation in service to their network, their customers and state policy objectives will be fundamental to the success of the REV framework.

Since a full transition to the regulatory and market reforms envisioned under REV will take place over time and the current clean energy programs are set to expire at the end of 2015, several near-term transition paths are needed to ensure continuity and growth in clean energy markets and services in each utility service territory. With regard to renewables, Staff recommends that procurement of supply-side large scale renewable resources become the responsibility of the utilities. With regard to energy efficiency, we recommend that the utilities prepare and submit energy efficiency transition implementation plans (ETIPs) no later than March 31, 2015. Recommendations regarding energy efficiency transition planning are provided in Section 3 below.

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[33] Cases 14-M-0094, et. al, Clean Energy Fund, Order Commencing Proceeding (issued May 8, 2014) (Clean Energy Order).

2. Supply-Side Renewable Resources

Various factors have influenced the RPS premium (REC) required to support wholesale grid connected renewable energy project development in the State.[34] Continued low natural gas prices result in reduced wholesale revenues for projects, exacerbating financing and hedging difficulties, and ultimately drive up ratepayer premiums to develop renewable energy. Also the continuing uncertainties and stop/start nature of federal renewable energy tax credits and grants have disrupted the renewable energy market nationwide. Staff recommends that the REC-only program approach should transition to bundled contracts for energy and RECs between the utilities and competitively selected projects. While the REC-only model served New York well in the early years of the RPS program, the factors addressed above, coupled with the availability of bundled contract opportunities in many neighboring states, have had a damping effect on large-scale renewable development in New York.

It is more important than ever to continue to support the development of large-scale renewables in New York due to the fuel diversity, low carbon emission, and economic benefits that these resources provide to the energy system and society. Assigning the procurement of renewables to utilities is only the beginning of a transition toward a market-based system in which customers take direct responsibility for supporting a sustainable energy system.

A new mechanism for procuring these resources must be in place by early 2016 to avoid a gap in the Commission's long-term support for these valuable resources. It seems likely that the mechanism of power purchase agreements is most likely to meet the near term objectives of the Commission and the Draft State Energy Plan. In the longer term, ratemaking incentives should be used to prompt development of market solutions, enabling customers to more directly engage with renewable energy providers.

Among the issues related to the transition, Staff particularly invites additional comments on the following:

1) What should be the short-term and long-term goals/targets for these procurements and what are the relevant metrics? Should the goals and metrics be set on an individual utility or collective basis?

[34] NYSERDA, as central procurement administrator for New York's RPS program, conducts competitive sealed, pay-as-bid auctions for renewable energy generation. NYSERDA pays a fixed production incentive to renewable energy generators in exchange for all rights an claims to the RPS attributes (or RECs) associated with each MWh of renewable electricity generated and delivered for end use in New York.

2) If centrally procured, should the allocation of purchases among utilities be based on load share or some other equitable basis?
3) If centrally procured, should each utility be a party to each agreement?
4) If procured by individual utilities, how could potential concerns regarding affiliated renewable generation developers or interests in potential transmission projects be addressed?
5) Whether individually or centrally procured, what existing RPS program design criteria regarding energy delivery, technology eligibility and procurement mechanisms should be revisited?

Because the issue of Main Tier renewables has not previously appeared in this case, it should be considered separately from other Track One issues and not necessarily decided by the Commission within a Track One policy order.

3. Energy Efficiency With Load Management Controls

Staff proposes the following guidelines to support the development of Energy Efficiency Transition Implementation Plans (ETIPs) as one early component of utility Distributed System Implementation Plans (DSIPs), discussed in the Implementation section of this proposal. Each utility ETIP should describe the energy efficiency programs that it intends to implement beginning January 2016. These programs would continue until supplanted by alternative or expanded approaches presented in each of the utilities'DSIPs. The ETIPs will serve as the bridge between the utilities' current energy efficiency program efforts and their expanded demand-side efforts envisioned under REV.

Funding for utility efficiency programs should also be transitioned, following the expiration of current surcharge authorization. Because efficiency programs will be integrated into normal utility operations, rather than being funded through a surcharge the funding should be recovered in the same manner as other operating expenses. This transition should be implemented in the next rate case for each utility. If a utility will not have a rate case completed prior to January 1, 2016, it should propose a cost recovery mechanism in its ETIP.

i. Scope and Scale

To prevent backsliding, each ETIP should include a portfolio of energy efficiency programs with an associated annual energy savings goal that is no less than currently assigned through the Energy Efficiency Portfolio Standard (EEPS). That is, the current assigned energy savings goal should remain the minimum obligation of each utility. As ratemaking reforms and

DSP markets develop, utility performance measures will drive efficiency to become more integrated into utility operations and current energy efficiency targets could be phased out or subsumed into an alternative performance measure. Reporting and monitoring could be used to ensure that the net level of efficiency activity is not reduced.

While efficiency targets remain in place, the means for achieving the targets should be re-evaluated. Each utility should consider incorporating whole building, fuel neutral approaches, and load and building management controls and demand response measures. To the extent that the utilities incorporate additional approaches (possibly transitioned from NYSERDA), their ETIPs could include additional performance targets, e.g., MW and carbon reductions. Utilities should consider targeting energy efficiency efforts to maximize the economic value to the utility service territory, but the utility should also work with NYSERDA and others to ensure all their customers have access to energy efficiency services to assist in managing and controlling their energy bills.

To achieve the State's carbon reduction goals, an expansion of energy efficiency efforts will be needed. Current program targets effectively constitute a ceiling; they will need to become a floor. This cannot, however, be achieved by expanding conventional ratepayer-funded programs. By valuing the system and environmental benefits of efficiency, REV markets will create incentives for third party providers and customers to pursue innovative efficiency methods.

ii. Quantification and Verification of Achievements

Because efficiency will be utilized to serve system needs, utilities will have an expanded interest in verifying the values of distributed resources. Utilities should have significant additional flexibility, as well as responsibility and control of key tools and resources to allow these resources to evolve to meet their individual system needs and priorities. Each utility ETIP should include a description of the tools that they will use to assess and monitor the effectiveness of their energy efficiency programs in achieving their ETIP goals and objectives, including but not limited to the following:

- Benefit cost analysis: Each ETIP should describe the utility's use of benefit cost analysis (as described in another section of this proposal) to optimize and monitor their energy efficiency portfolio in support of improved system efficiency and operation.

- Program cycle and evaluation planning: Each ETIP should include a program cycle and evaluation, measurement and verification plan that is practical and useful to improving the reliability of program results to both the customer and the utility.
- Technical Resource Manual: Staff recommends that the utilities assume responsibility for developing and maintaining utility-specific TRMs, for the prescriptive portion of their portfolio and that these TRMs be included as a supplemental filing with their ETIP.

iii. Reporting and Data Management

In addition to filing the initial ETIP, Staff recommends additional reporting requirements to ensure that the utilities' planning assumptions and program activities are transparent to Staff and interested stakeholders. As performance metrics are adopted and refined, the reporting requirements should be reconsidered. During this transitional period, the following should be maintained:

- ETIP Updates –as needed to reflect program changes;
- TRM Updates – as needed to reflect program changes; and
- Evaluation Studies - as completed.

To provide DPS Staff and interested stakeholders with a means to monitor and track the progress of energy efficiency deployment in New York State and to ensure each utility is transparent with regard to energy efficiency resources installed on its network, a new integrated data management system needs to be put in place. Utility access to energy efficiency data is important to its future DSP planning, operations, and markets functions, but there is also a need to compile, compare and report all utility and NYSERDA energy efficiency efforts to ensure advancement toward the State's broader energy and environmental goals and potentially to comply with EPA's carbon pollution standard. A new data management system that is flexible enough to meet individual utility and the collective data needs of DPS and the State must be acquired. Staff recommends that a joint utility-NYSERDA effort, in consultation with Staff, be formed to research "off-the-shelf" systems that may be available, identify the pros and cons of each, develop specifications for an adaptable system, and have NYSERDA issue a Request for Proposals (RFP) by the third quarter 2015 to procure this system.

B. Demonstration Projects

While many of the technologies needed to develop a DSP are available today, further technology integration and validation is needed to demonstrate and fully implement DSP functionalities. Development of mature DSP functionalities will involve technology and programmatic choices that can be better informed through data acquired from selective demonstration projects. Demonstrations can also serve to measure and predict customer responses to programs and prices associated with future DSP markets.

Generally, staff defines demonstration projects as those focused on beta-testing DER provider and utility DER services with a limited group of customers. The following criteria should guide Commission consideration of demonstration project proposals associated with initial technologies and communications platforms to achieve DSP functionality. The criteria that should guide utility investments in DSP system technologies include, but are not limited to:

- Directly related to the six REV policy objectives—Consistent with the broader discussion of the technology platform, which requires DSP market technologies to map to their policy objectives, projects should seek to demonstrate programs that directly relate to the REV policy objectives;
- Scalable—To maximize the potential for expanded DER impact across the state, projects should demonstrate technologies and products that can easily scale beyond the initial testbed to a larger percentage of customers in a particular customer class, and across other customer classes;
- Replicable—While staff recognizes differences in utility distribution system design, projects in one DSP territory should be replicable to other DSPs. As a result, projects should be able to target customers in aging or otherwise congested distribution system areas across multiple distribution system designs;
- Technology neutrality—The optimal platform design should be neutral to multiple technology communications protocols, technology types, or interconnection processes;
- Portfolio approach to integrate all types of DER—In the end-state market, the DSP will welcome a portfolio of technologies to participate. Customer should be able to bring their own devices and DER assets to the DSP operator for seamless account recognition and interconnection, regardless of the make and model of the asset. Utilities in other jurisdictions have piloted this approach;[35]
- Expedient—Projects should develop strategies to produce substantive results expediently. These strategies should include methods to rapidly recruit customers, install equipment, measure and verify data, and report;
- Well-defined and measurable output—Demonstrations should develop strategies to clearly define outputs and utility-grade metering options to measure and share data with utilities to inform DSP development;

[35] For example, Austin Energy and Southern California Edison have piloted “bring your own thermostat” programs in 2013 and 2014.

- Defined methodology for value exchange— Proposals should explain how values are defined and quantified, and whether they will accrue to the DER provider, the distribution system owner, or to customers. Proposals should explain the rationale for such allocations. Similarly, the metered energy usage associated with the project should assign prices and values to various actors in the DER market, to include the DER provider, distribution system, or customers. This information should be made transparent to the customer; and
- Favor partnerships with third parties, including small firms and innovators.

Of these, staff prioritizes the final criterion that requires utilities to leverage public and private partnership opportunities, particularly where utilities can gain experience from partnerships with third party DER providers. Utilities should be open to potential contribution of smaller firms and innovators that may not yet have achieved a recognized, scalable solution. Staff encourages regulated utilities to continue to meet with innovators to offer practical guidance on business plans, technological approaches, and potential for scalability in the DSP market.

In addition to technical functionality, demonstration projects should seek to validate customer acceptance of DER technologies and customer participation in DER provider offerings. Parties raise an ongoing concern that low-income residential customers will not be able to participate in DER programs or services that reduce energy bills and high-income residential customers will not be interested. However, there is a lack of data on customer participation generally in response to voluntary time of use pricing or other program services. DSP forecasts of the potential for demand side reductions will rely on customer participation data. Additional data-driven research on customer responses will therefore serve a commercial and operational role.

Staff recognizes utilities and DER providers have ongoing pricing and other technology demonstrations in place to target customer responses. Staff invites innovative approaches to financing demonstration projects that validate and make available data on customer engagement and customer responses to enhanced information and DER services.

C. Interconnection Procedures

The parties have identified interconnection rules as a barrier to higher penetration of DERs. For example, developers cite significant expense of both time and money in interconnecting distributed generation with the local regulated utility’s systems. In future DSP markets, technical requirements and safety aspects of interconnections will need to be carefully balanced to ensure power quality and safety, while mitigating the negative market impacts resulting from burdensome transaction costs related to poorly designed interconnection requirements. To accomplish this, the Commission should create greater transparency into the interconnection process, including improved information sharing via public queue, and utilities need to improve their workforce capacity to review interconnection requests in a timely manner.

Standardized interconnection requirements for new DG connections and related DER technologies ensure safe connection of DERs to the power grid. The Commission has established the New York Standardized Interconnection Requirements (NY SIR) for Distributed Generation projects 2MW and below to ensure safety, reliability, and prevent operations failures and electrical hazards caused by faults and improper islanding or reconnection. Interconnection projects in New York above 2MW are governed by FERC, the NYISO, the Commission and the utilities.

The Commission has established a mechanism in the NY SIR to track interconnection approval times to ensure appropriate and timely responses to applications from developers, which will increase in volume as distributed energy resources proliferate. There is a gap, however, for those systems that are above 2 MW. In the absence of standard procedures, these larger systems can be subject to burdensome technical review that can slow or prevent projects that would be beneficial to the grid.

The quantity, pace, and technological complexity of interconnection applications will increase as the REV market increases demand for distributed generation on the grid, and ongoing innovation leads to new types of DER technologies and services. As companies bring new products to market, interconnection reviews must accommodate technological advances, while maintaining standard requirements to ensure the reliability and safety of interconnected distributed energy resources. This should include consideration of the direction of market development and the future technology landscape. Utility staff will need to increase their ability to review interconnection requests and issue determinations, including for new technologies that are not currently addressed in interconnection rules. When interconnection requests are denied or delayed on the grounds of concerns for non-compliance, the reasoning for the denial should be available publicly and subject to scrutiny.

Staff recommends the Commission consider a periodic interconnection reform process to expedite interconnection processes and minimize costs, in order to facilitate increased adoption of distributed energy resources that require interconnection. As part of this process, Staff recommends future technological advances be considered to avoid interconnection process delays. Staff recognizes that non-traditional technologies are under development that do not require standard interconnection methods and reduce balance of system costs (e.g., plug-and-play systems); consideration should be made to ensure that these technologies are not unduly hindered by cumbersome interconnection rules.

Standardizing aspects of the interconnection approval process, where appropriate, across all of New York State's regulated electric distribution utilities would add predictability and repeatability to the process while ensuring safe, reliable, and efficient approval procedures. This could be accomplished, in part, by increasing the NY SIR to a higher threshold, such as 5 MW. Larger distributed energy resources, such as cogeneration facilities that typically operate above this threshold, should also be considered for a standardized approval process.

Considerations for fair practices for interconnection procedures are discussed further in the Mitigating Market Power section.

D. Microgrids

Microgrids are a special class of distributed energy resource that have been targeted for promotion in New York State for the robust services they offer above and beyond other DERs. Generally, a microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid may be able to connect and disconnect from the grid to enable it to operate in both grid-connected or island mode.[36]

Beyond this general definition, a variety of microgrid configurations or business models are possible, each with implications for market and technical integration. Some of these already exist or are under development in the State; others can be imagined for future development. As a general principle, DSP market design, including treatment and valuation of services from DER, should also be applicable to microgrids; in some cases, new rules and procedures will need to be developed to address the diverse capabilities and technical considerations of microgrids.

[36] This is the US Department of Energy's definition, modified to reflect that a microgrid need not necessarily have the ability to operate in island mode in order to provide system benefits in a REV framework.

1. Benefits of Microgrids

Microgrids generally deploy forms of distributed generation,, which typically use cleaner fuel sources, including natural gas, renewables, and storage. Microgrids also offer the potential for efficiency improvements. If there is a need for thermal energy (such as steam, hot water, or cooling), distributed combined heat and power (cogeneration) natural gas turbines or fuel cells can produce electric and thermal energy at up to 90% efficiency. Also, with generation sited at or near the load, there are negligible line losses compared to the typical line loss experienced in the centralized generation system.

If designed and maintained appropriately, a microgrid can offer increased reliability and resiliency. The ability, where installed, to intentionally island from the surrounding grid during an outage allows critical loads within the microgrid to be served with little or no interruption. The reliability benefits of microgrids can be especially valuable to local communities' critical infrastructure facilities that provide for public health and safety such as first responder stations, emergency shelters, fuel depots, water and sanitary facilities, and kitchen and dining areas. Further, community-based microgrids can enable a community to customize its energy solutions to provide for its unique needs and values.

The utility grid can also realize benefits from having microgrids installed on the system. Due to their uniquely flexible nature, microgrids can offer capacity, elastic load (demand response), and ancillary services (voltage support, frequency regulation, black start capability, etc.) to the distribution and bulk electric systems. In facilitating the proliferation of clean distributed energy resources, microgrids can help achieve carbon goals and meet renewable energy standards.

2. Barriers to Microgrid Development

To achieve REV objectives of increasing efficiency and facilitating the proliferation of distributed energy resources and avoiding traditional investments in centralized infrastructure, DSPs should incorporate microgrids into system planning when it is advantageous and cost effective. A number of barriers to microgrid deployment exist, however, preventing their full value to be realized. One such barrier is the lack of a regulatory framework specifically devoted to microgrids. Without such a framework, microgrid developers can structure their proposals to meet the statutory requirements for a qualifying facility or lightened regulation, but difficulties can be encountered in tailoring those regulatory requirements to the kind of flexibility demanded by the marketplace. Other barriers are detailed in the report produced by the Track One Subcommittee on Microgrids and Community Grids, incuding:

- Standby rates and tariff treatment;
- Inadequate valuation of benefits, especially for value of reliability and resiliency;
- Interconnection procedures;
- Wholesale market treatment; and,
- Customer education and expectations.

A combination of regulatory reforms by the Commission and successful DSP market development will address the identified barriers to microgrid development.

Various models of ownership and control of the infrastructure within a microgrid exist and continue to be created, including ownership and control of generation and distribution infrastructure (microgrid controllers, conductors, distribution poles, conduits, etc.). Those include:

- Campus-style microgrids that serve a single customer with multiple buildings on contiguous property;
- Multi-customer microgrids of contiguous properties or adjacent buildings;
- Multi-customer microgrids that serve non-adjacent buildings and might cross utility right-of-ways; and,
- Community grids that serve a larger area than those above, essentially functioning as a "virtual" microgrid that rely on the utility for balancing services.

The above list is not exhaustive and other configurations can be imagined that have components of one or more of the above. At this stage, ownership models should not be constrained. Developers wishing to create, own, and operate their own distribution infrastructure and billing systems should be allowed to do so. Those wishing to collaborate with their local electric distribution utility to provide these facilities and services should also be free to do so, subject to any restrictions on market power as discussed below. Microgrids participating in such an agreement could rely on the utility to be the balancing authority, paying the utility a network charge for use of the system.

A new regulatory framework would assist in encouraging such microgrids. Consideration should be given to a new tariff structure that allows groups of customers to sign up to receive a microgrid delivery service wherein the Commissions regulatory policies are implemented in advance through the tariff without the need for qualifying applicants to obtain direct Commission approval for the structuring of a microgrid.

Standby tariffs and demand charges represent significant costs to an interconnected microgrid. Net metering rules vary for the various types of distributed energy resources, leading to regulatory and financial uncertainty in microgrids that use them in tandem. The application of standby tariffs, demand changes, and net metering should be reconsidered in the context of microgrids, and evolved towards a comprehensive valuation mechanism that bases cost and compensation on performance, taking into account the diversity and redundancy of supply built into the microgrid. These issues will be further developed as part of Track Two.

Unlocking the value of microgrids will require reform to the compensation mechanisms and tariff structures applicable to them. Development of a new benefit-cost framework widely applicable to DERs, as recommended in this straw proposal, will go a long way to compensating microgrids for the full value they provide. Additional benefits can be tapped by the strategic placement of a microgrid to avoid the need for central transmission and distribution infrastructure investment, benefiting the utility and ratepayers.

Better incorporation into wholesale markets is also needed to properly compensate microgrids. Cogeneration is presently excluded from participating in NYISO capacity and energy markets and is only able to participate in the 10-minute non-spinning reserve ancillary services market (not the regulation, spinning reserves, or black start markets). The A-06 Operating Reserve Criteria substantially limits the ability of distributed energy resources in general and cogeneration in particular to participate in and derive financial benefits from the ancillary-services market. Microgrids could be made more competitive in New York if these rules are reevaluated to allow microgrids to obtain revenue streams from wholesale markets generated from their on-site, behind-the-meter assets.

Improved interconnection procedures for all DERs are discussed more broadly above. Interconnection standards, however, are not as well established for multi-customer or community microgrids as they are for individual customer connections. The Commission should re-assess its NY SIR to determine what improvements are needed for the specific circumstances of microgrids, given that such arrangements were not contemplated previously. In particular, standardization of procedures and requirements for projects larger than the current 2 MW threshold should receive additional attention in light of the needs of microgrids, keeping in mind that the ability to safely, reliably, and effectively operate a microgrid system in conjunction with the utility system is imperative.

The microgrid market will also benefit from readily available information about where microgrids can provide the greatest value to the grid. Knowledge of where an interconnected microgrid would fulfill system needs would allow developers to pursue projects that would add the most value to the grid, averting costly transmission and distribution upgrades that might be required to connect a microgrid elsewhere. The DSPs should develop a transparent process to inform developers where microgrids (and distributed energy resources generally) would provide the most value to the grid and are most easily able to interconnect. This would help developers better choose where to concentrate their designs.

E. Demand Response Tariffs

On May 23, 2014 the DC Circuit ruled that FERC did not have jurisdiction under the Federal Power Act to issue Order 745 in part because demand response is part of the retail markets, which are exclusively within the states' jurisdiction to regulate. The Order pertained specifically to demand response participation in wholesale energy markets. However, the decision could eventually be applicable to all demand response in wholesale power markets. Further legal proceedings could create delay and uncertainty.

Uncertainty creates risk and negatively impacts the DER industry. Aggregators tend to move their operations to jurisdictions with active DR programs structured in a manner that provides the perception of stability and the opportunity to earn profits. Once those attributes are in jeopardy, aggregators often move from that jurisdiction to another that provides better opportunities. Reversing slippage in program activity by correcting structural problems can occur, but may be difficult to achieve. It is therefore important to start to create opportunities for DER to participate in expanded DR programs whether the NYISO is ultimately able to allow retail participants into its programs or not.

Accordingly, the Commission should direct a process in which stakeholders work with distribution utilities, Staff and the NYISO to immediately develop programs that allow demand response providers, interfacing with the distribution utilities, to respond to bulk power system needs currently addressed by the NYISO’s Special Case Resource (SCR) and Emergency Demand Response Programs. Staff intends to immediately convene discussion with utilities and stakeholders to begin the development of the programs.

Toward the goal of developing mature DER markets, distribution utilities should further be directed to revise reliability-oriented DR programs, as needed, to use DR as an economic system resource and provide a platform on which DSPs can ultimately utilize DER as a component of their supply portfolio along with purchases from the bulk power system.

At present only retail customers of Consolidated Edison have the option to participate in utility demand response programs. As discussed below, Staff recommends statewide expansion of existing utility-offered demand response programs in the near term in order to give customers more opportunities to benefit from participation in programs that offer reservation and performance incentives for load reductions. These programs have the added benefit to DER providers through identification of opportunities for near-term DER investment on the distribution system.

While the immediate goal of the utility DR programs is to stand in the place of NYISO Special Case Resource programs if necessary, in the longer term utility DR programs should be expanded to take advantage of economic opportunities, and the terms of the programs should be carefully constructed to maximize economic participation by customers. As part of this expansion, staff recommends that utilities file a proposal to inform customers of these new DR programs, using state-of-the-art marketing tools and methods designed to increase DR adoption.

F. Planning REV Implementation

While there are a number of actions that can be taken in the near term and to support the transition to REV, the scope and scale of transformation envisioned by REV necessitates further planning along a number of dimensions. The planning efforts recommended here fall into two broad categories: 1) transition and implementation planning performed by individual utilities, and 2) DSP platform and market vision planning performed jointly. These two types of planning should occur in parallel.

1. Transition and Implementation Planning

The purpose of transition and implementation planning is to begin to pragmatically address the transition to REV even while long-term planning is underway. Staff proposes this planning effort take three sequential steps:

- Energy Efficiency Transition Implementation Plan (ETIP)
    - **Purpose:** As described in the clean energy section of this Straw Proposal, the purpose of the ETIP is to put in place a plan for how the utility will

procure energy efficiency starting in 2016, as a transition from procurement via the Clean Energy Fund.
    - **Scope:** The proposed scope of the ETIP is described in the clean energy section.

- Proposal for Interim Actions
    - **Purpose:** In this Straw Proposal, Staff recommends a set of near-term and transitional actions that the utility should take. As a means of ensuring transparency, cohesiveness, and coordination around these actions, Staff proposes utilities file Proposals for Interim Actions that summarize how the utility intends to achieve those near-term and transitional recommendations specified here.
    - **Scope:** Proposals for Interim Actions should identify what actions the utility intends to take, how that action responds to the Commission order, the scope and plan for implementing the action, and the proposed approach to engaging DER providers, entrepreneurs, and customers in that action.

- Distributed System Implementation Plan (DSIP)
    - **Purpose:** The Distributed System Implementation Plan should indicate how the utility proposes to implement REV actions over the next five years, and should be updated every two years. The plan should not be limited to REV actions alone, but rather the utility's entire system plan.
    - **Scope:** The DSIP should present the utility's proposed investment plan for the next five years, and should reflect an integrated view of T&D investment needs and DER resource alternatives. Beyond resource investments, the DSIP should include the utility's plan for implementing DSP platform and market components in the plan period. The actions proposed in the DSIP should be evaluated via a business plan that includes a benefit-cost assessment, a qualitative assessment of non-quantifiable benefits, and a risk assessment. The DSIP should be updated every two years and, in so doing, should continue to evolve along with the evolution of the DSP Platform and Market Vision discussed in the following section.

An important precursor to the first DSIP is to establish the methodology to be used. The methodology should include the benefit-cost analysis framework, a list of what components must be included in the DSIP, and any guidance on specific approaches or inputs to be used. As recommended in the BCA Framework section, the BCA Framework and the broader methodology for the DSIP should be developed via a stakeholder process with a set of technical conferences to enable stakeholder input. The final DSIP methodology should be approved by the Commission.

2. DSP Platform and Market Vision Planning

There is significant work needed to further define, scope, and plan for the full implementation of the DSP platform and market. Standardization in the DSP platform and market will be critically important, to facilitate DER service provider participation. Therefore, Staff recommends a three-part planning process to address these issues:

- Technical Platform Design Stakeholder Process:
  - **Purpose:** Further develop the technology platform design for the DSP market, with a particular focus on standardization.
  - **Scope:** The Technical Platform Design Stakeholder Process should make recommendations for standardized DSP operational procedures, tariffs, market rules, and market procedures. At a minimum, DSPs should be required to establish open standards for the architecture of the grid that will ensure interoperability within and ideally between service territories. The process should further explore a standard communications architecture (e.g., NIST 3.0, Open ADR, and others) to enable communication with multiple end use devices and networks. It should complete an assessment of technology availability and maturity and technology/functionality mapping and gap analysis, with a focus on identifying initial implementation shortcomings. Staff recommends this process be supported by a national lab such as Pacific Northwest National Lab or Lawrence Berkeley National Lab to provide expertise, credibility, and the ability to integrate diverse technology perspectives.

- Market Design Stakeholder Process:
  - **Purpose:** Further develop the market design for the DSP market, with a particular focus on standardization, and elimination of barriers to entry.
  - **Scope:** The Market Design Stakeholder Process should further define DSP market rules, interactions between key actors, and products and services to be exchanged. Market designs should be standardized to the maximum extent possible such that customers and DER providers have a seamless experience across different DSP markets. Staff recommends that this process be supported by an outside consultant to provide cutting-edge, independent expertise needed to effectively design the market and incorporate stakeholder input. The Market Design Stakeholder Process should be conducted in parallel to and closely coordinated with the Technical Platform Design Stakeholder Process.

- Jointly-filed Uniform DSP Plan:
  - **Purpose:** While each utility will report its individual plan and progress in a DSIP, a joint utility filing should be used to reflect the recommendations of the stakeholder processes described above to ensure efficiency and standardization.

- **Scope:** The joint process will distinguish between operational elements that can be unique to a single DSP and those that must be uniform in order to enable efficient markets. Most of the issues identified in the Platform Technology discussion will be resolved at this level, as well as market design issues.

VI. MITIGATING MARKET POWER

With the recommendation that the utilities fulfill the platform functions comes a range of concerns about the potential for various misuses of their monopoly position. Market power concerns arise from utility's direct commercial involvement with distributed energy resources, from utility control of platform functions including scheduling and dispatch, and from utility control of access to its network, including interconnection and access to both system and customer data. These concerns include (1) the potential for a utility-provided platform to maintain barriers, such as burdensome interconnection requirements and outmoded tariffs, to robust entry into the market by DER providers; (2) potential reluctance of a utility-provided platform to provide the system or customer data needed by DER providers to succeed; and (3) the potential for functional competitive advantage on the part of the utility/platform regardless of utility behavior.

A. Utility Engagement in Distributed Energy Resources and Vertical Market Power Concerns

The Commission's 1998 Vertical Market Power Policy (VMP) specifically addressed the issue of ownership of generation by vertically integrated utilities. This policy established a rebuttable presumption that ownership of generation by an affiliate of a utility would unacceptably exacerbate the potential for vertical market power.[37] The Vertical Market Power Policy only created a rebuttable presumption, however, and it speaks in terms of unacceptable degrees of market power. Given the choice of adopting a presumption against utility ownership of generation or allowing such ownership and requiring market power mitigation measures, in

[37] Cases 94-E-0891, et al., - Statement of Policy on Vertical Market Power (issued July 17, 1998), Appendix I, p. 1. The Commission adopted this policy in the context of establishing guidelines for review of transfers of generation assets, in recognition that divestiture of generation was a key means of minimizing utility abuse of vertical market power. In that decision, the Commission concluded it was preferable to eliminate the incentive for abuse unless there were demonstrable efficiency gains and adequate mitigation procedures. A utility could make such a showing in a particular case. Id., p. 4.

that context the Commission chose the presumption against ownership. Nonetheless, the flexible approach employed by the Commission was grounded in its recognition that such matters involve balancing different policy considerations.

In the context of REV, the balancing is complicated by a number of variables. Utilities' potential motivation to exercise market power will depend on how cost recovery for DER activities is determined. The ability of utilities to exercise market power will depend in part on how their role as the DSP market operator is defined. Both the potential harm, and the potential benefit, of utilities' ownership of DER will vary based on the type of DER, the relative maturity of markets for different types of DER, and the location of and need for the DER, among other factors. The Commission should consider whether a VMP policy developed for bulk systems is directly applicable to ownership issues at the distribution level.

Market power concerns arise not only with direct utility ownership of DER but with other forms of commercial engagement as well. These could take the form of operating agreements for example. A relationship that gives the platform provider a commercial stake in the success or failure of a particular DER investment creates a market power concern.

1. The Advantages and Disadvantages of Utility Engagement in DER

One of the principal, immediate imperatives of REV is the expeditious growth in DER penetration of the New York energy market. The advantage of utility DER ownership is that utilities are well-positioned to accomplish or at least contribute to this growth with their own DER products and services. They have direct access to customers, credibility as a familiar energy provider, and knowledge about their distribution systems to identify where and how DER can be integrated with the greatest effect. Direct utility participation in DER can accelerate the transformation to a more fully distributed electric grid. Utilities can achieve these ends by leveraging existing ratepayer-funded assets and in-house expertise related to system planning, design and operations, and customer communications. Utilities can identify and demonstrate new DER technologies that are reliable and effective, thereby helping customers adapt to and exploit these technologies.

Utilities can also act to promote development of DER technologies and, in turn, markets, by providing financing at relatively low cost. In this way, utilities can take advantage of their economies of scale, with concomitant lower production costs that can establish market viability.

Using these advantages, utilities can promote the adoption of innovative DER technologies not yet been widely in use.

Utility engagement in DER would also give utilities experience and confidence in how the integration of DER will affect the reliable operation of distribution systems. Whether or not utilities own DER, they must put in place transparent procedures and controls related to the reliable use and dispatch of DER; however, utility ownership would facilitate the planning process.

Direct ownership of DER by a utility can reduce the risk of revenue erosion. Where a utility owns assets behind the meter, the customer is retained, and revenues from that customer, as well as costs and benefits of the asset, accrue to all ratepayers.

As to the disadvantages of utility engagement in DER, the most obvious is the risk of vertical market power at the distribution level. In its 1998 policy statement, the Commission stated vertical market power occurs "when an entity that has market power in one stage of the production process leverages that power to gain advantage in a different stage of the production process."[38]

Where a utility has a stake in DER and also owns the distribution system and operates DSP markets, the utility may have incentives to favor its own facilities. A utility could discriminate against third-party competitors in various ways. For example, a utility could create barriers to entry through burdensome or delayed processing of interconnection requirements. A utility would have an incentive to create or maintain distribution constraints that favor the economics of its own DER. The prospect of such vertical market power is great at the distribution system level because distribution circuits are easily constrained.[39] In a mature DSP market, utilities would have an incentive to favor their own projects and affiliate-owned projects in the dispatch of DER.

A related risk stems from the informational asymmetry that favors incumbent utilities. This risk applies both to information about the capabilities and limitations of their distribution

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[38] Case 94-E-0891 - Electric Rate/Restructuring, Statement of Policy Regarding Vertical Market Power (issued July 17, 1998), Appendix I, p. 1.

[39] In the long term, market power concerns are not limited to utilities. In a mature market where DER pricing is differentiated at the level of individual distribution circuits, a third party provider controlling a significant portion of load on a given circuit could have the ability to manipulate power flows in order to create favorable pricing opportunities.

systems and to customer usage data in utilities' possession. Given their knowledge of distribution system needs and capabilities, and customer energy usage, incumbent utilities can readily identify where DER can be sited most efficiently. In a vertically integrated model, such efficiencies are part of the rationale for allowing a monopoly. In a competitive model, however, such asymmetry can effectively dissuade private capital from participating in emerging markets.

One of the principal reasons for the transition into a competitive model for electric generation was to transfer risk of failure away from ratepayers and onto market participants. If utilities are allowed to own DER, their relatively lower business risk will enable them to undercut some competitors who do not enjoy the utilities' lower costs of capital. Utility ownership risks crowding out new investment in New York DER. Commenting parties point out that investors have choices, and a New York DER market with utility ownership can discourage investors from choosing New York. Long-term success in animating a DER market in our state depends on leveraging private capital and spreading risk beyond ratepayers. These goals could be threatened by utility DER ownership.

Concomitantly, as many parties note, with competitive investment comes the strongest force for innovation. Unrestricted utility ownership of DER could, even if immediately successful, stifle the growth of an innovative, competitive DER market for the longer term.

2. Factors to Consider in Mitigating Market Power

An absolute prohibition against utility engagement in DER would eliminate these concerns but would also deny the potential benefit of DER growth that is needed to develop an asset base for DER markets. Therefore Staff does not recommend this outcome. Many parties also support a pragmatic approach. This requires consideration of various combinations of mitigation measures to overcome the potential for vertical market power.

In considering whether or not to allow utility engagement in specific cases, the Commission should take into consideration a range of variables:

- what type of DER is at issue: the balancing of market power concerns versus potential benefits will vary depending whether the DER is generation, storage, demand response, or energy efficiency;
- what type of engagement: utilities can be engaged in DER by direct ownership, through contracting for services, or by providing financing assistance;
- the need for the DER: if it is targeted to resolve a major system need, a direct coordinated effort by a utility may be warranted;

- what type of location: ownership by a utility on its own property, particularly where there is a direct operational benefit from such location, may give rise to a different analysis than utility ownership on customers' premises;
- the transitional concern: the Commission's analysis of the market power issue may vary depending on which stage of REV and the extent of market penetration of particular DER products; and
- how the ownership is structured: DER ownership by a utility affiliate with the potential to earn unregulated profits raises the possibility of a greater incentive toward the exercise of market power than would a regulated utility activity.

3. Discussion and Recommendations

There are two principal risks: discriminatory behavior by the DSP, and asymmetric advantage of utilities even in the absence of discriminatory behavior. Where the goal is to eliminate the risk of discriminatory behavior by the DSP, impartiality relies on creating indifference. This can be accomplished by some combination of three methods, all with appropriate oversight:

- restrictions on activity: creating rules that place certain types of activity off limits for utilities;
- functional separation of the DSP: as discussed above, isolating the market function of the DSP reduces risk of discriminatory behavior; and
- ratemaking incentives: the manner in which the Commission allows cost recovery for DER activities could remove any incentive for utilities to discriminate, or could go further and create an incentive to favor third party actors.

Asymmetric structural advantages cannot be mitigated by creating indifference, because they operate regardless of the motivation of the entity enjoying the market power. Even if utility incentives can be established properly, some form of restriction on market power will still be necessary.

Other jurisdictions have considered similar questions. For example, in 2013, the California Public Utilities Commission (CPUC) decided utilities may own up to 50% of storage at the distribution level and behind-the-meter, but not more than half of total storage that each utility applies toward fulfillment of its storage target.[40] The CPUC adopted a definition of storage in the proceeding that is intended to embrace a mix of ownership models and contribute to a diverse portfolio that can encourage competition, innovation, partnerships, and affordability." In 2008, The North Carolina Utilities Commission allowed utility ownership of

[40] California PUC Rulemaking 10-12-007, Decision 13-10-040, issued October 17, 2013.

residential rooftop PV installations, where the utility leases the rooftop from homeowners. The NC Commission permitted cost recovery through a combination of riders and rate-basing of costs.[41]

Considering the factors listed above, it is likely there will be circumstances in which some forms of utility engagement are of clear benefit to customers. For example, if a utility can situate DER onsite at distribution facilities to address reliability needs, those investments should be allowed and should be classified as distribution system assets. Other types of utility engagement are likely to be most helpful in the earlier phases of REV implementation. If a utility issues an RFP for competitive DER solutions and no reasonable competitive solution materializes, or if the utility can demonstrate that its solution is superior to the competitive alternatives presented, it could be allowed to invest in the DER on a regulated basis. The ratemaking for such utility investments should aim toward eliminating any utility bias in favor of its own projects.

Although the optimal result might vary with circumstances, an *ad hoc* project-by-project approach to this issue would create uncertainty and would be cumbersome and untimely to administer. Therefore, for direct involvement by regulated utilities, Staff recommends an approach in which certain categories of engagement are clearly permitted, while all others are generally prohibited unless they are included in an approved implementation plan. This will provide predictability and will tend to concentrate the utility DER activity where it is most needed.

Staff recommends the following approach to utility engagement in DER:

For direct activities of regulated utilities:

- The following limited forms of direct utility participation in DER are permitted:
    - sponsorship and management of energy efficiency programs; and,
    - generation or storage located on utility distribution property.
- other proposals for engagement in DER must be specified in utility Distributed System Implementation Plans and must meet the following conditions:

[41] North Carolina Utilities Commission, Docket No. E-7, Sub 856, Order issued December 31, 2008.

- the proposal must address a substantial system need;
- the proposal must demonstrate why the benefits of utility engagement outweigh the market power concerns, with reference to the factors discussed above; and
- where the proposal involves ownership, it must include a competitive solicitation for construction and operation, absent compelling circumstances.

Unregulated utility affiliates present a different question. In some respects the market power concern is at least equivalent, as the prospect of an affiliate earning unregulated returns increases the utility's incentive to favor the affiliate's product, or to delay system improvements on circuits where the affiliate enjoys revenues. On the other hand, the participation of utility affiliates can enhance DER markets, and structural separation methods may be applied to mitigate market power. Staff recommends as follows:

For activities of an unregulated utility affiliate within the utility's service territory:

- code of conduct rules governing interaction with the regulated utility must be observed;
- increased regulatory scrutiny will be triggered:
  - DPS will monitor interconnection complaints; and
  - an ombudsman for DER providers must be established;
- if affiliates bid into utility DER procurements, an independent entity will select winning bids;
- a cap will be placed on total market share of the affiliate within the service territory; and
- a cap will be placed on market share of the affiliate within distribution circuits (or the smallest planning level).

Parties are encouraged to propose alternative mechanisms for achieving separation and allaying market power concerns. The market power mitigation approach detailed above should be reviewed, as the transition into DSP markets becomes more fully developed. In addition to these restrictions, utility financial incentives should be structured, in Track Two of this proceeding, to reward utilities for the efficient development of DER on their systems in a manner that either makes them indifferent to ownership, or favors ownership by third parties.

In addition to the identity and ownership issues described above, utilities, in the role of DSP and in general, have the ability to exercise market power as gatekeeper to the distribution system's physical infrastructure and related communications network. As with other energy markets, meeting REV's goals of creating market liquidity and a level DSP market playing field for DER providers in order to drive system efficiency will require some degree of open access to available system data, at minimal transaction/interconnection costs, subject to a fair tariff structure, and under a nondiscriminatory and transparent dispatch criterion.

Accordingly, Staff recommends the Commission assess interconnection policies, dispatch rules, and distribution system data access rules, to enhance fair opportunity for third party participation in DSP markets.

B. Interconnection

Utilities can exercise market power through their authority to review and approve distributed energy resource interconnection applications. Standardized interconnection requirements for new distributed generator and related DER technologies ensure safe connection of distributed energy resources to the power grid. Interconnection requirements in general are addressed in a separate section of this proposal. For purposes of market power mitigation, standardization is the best approach and the size threshold for standardized procedures should be increased. To the extent that individualized analysis is required for approving larger interconnections, Staff will take an active role in addressing complaints and monitoring utility interconnection approval processes.

C. Dispatch

Parties correctly note that the DSP will have a great deal of market power through the control of the distribution and dispatch of resource bids. To the extent that the DSP is responsible for market dispatch and is also a market participant, the DSP has an incentive to favor its own resources via anti-competitive dispatch and control. In its role in supervising the market, the DPS should observe dispatch procedures to ensure fairness; and should audit market dispatch results data when appropriate or necessary.

As with the history of FERC's regulation of independent system operators, the Commission has the responsibility from the outset of the DSP market to require utilities as DSPs to demonstrate that market outcomes are consistent with those of a financially independent entity. At a minimum, the initial step for independent, neutral market operation is to develop standardized DSP telemetry requirements and visibility requirements applicable to all market participants. The second step is to develop open standards to deliver transparent price signals to DER market participants.

For the interim, Staff recommends the Commission require DSPs to deliver quarterly reports on key operational metrics in standardized templates. These templates will be publicly available to facilitate open and transparent review of system operations.

D. System Data

Utilities manage distribution system operations and determine capital upgrades based on regularly updated distribution system data. As with interconnection, utilities have the potential to exercise market power through their provision (or lack thereof) of distribution system data.

Distribution system data assets owned and managed by regulated utilities include, but are not limited to: Supervisory Control and Data Acquisition data, Distributed Energy Resource Management system and Demand Response Management System data, standard capital infrastructure data (equipment age, type, serial number), localized system outage data, existing interconnection data, and updated cost of service data.

Utilities regularly present system upgrade costs in publicly available general rate case filings. Utilities are increasingly opening some of this data (outage location and duration) to customers to provide enhanced customer service. In addition, utilities are opening some distribution upgrade prioritization data.

In addition, utilities provide proprietary customer usage and SCADA data to contractors to manage the distribution system to optimize performance, increase asset life, and maintain robust, reliable distribution system monitoring and control.

However, much of the distribution system infrastructure asset and cost data is proprietary to the utility and not available to the general public or to vendors, based on legitimate concerns about cyber security, public safety and reliability. Within the context of an animated DER market, DER market participants will require enhanced, standard format, time-stamped system distribution system data in real time to develop a detailed business case. Transparent system data access will also enable transparent bid load reductions into an interoperable DSP system.

At present, a lack of enhanced, standard-format system data creates information asymmetry, a classic barrier to new market development and entry of new market participants. Transparent distribution system data access will uncover where and when DER can provide the most economic benefit to the grid. Enhanced data acquisition and sharing will fulfill system needs and allow DER developers to pursue projects that would add the most value to the grid, averting costly transmission and distribution upgrades that might be required to interconnect a microgrid.

The Commission should require utilities to develop and expand universal and transparent access to system data through the information exchange described in the customer engagement section. This will enable DER product developers to determine where distributed energy resources would provide the most value to the grid and are most easily able to interconnect. Examples of system data that might be required for sharing include capital investment and network maintenance plans; seasonal reports with detailed information for which feeders and transformers were most heavily loaded during peak load hours, including specific location and timestamp data; and, possibly, SCADA-level real-time operational data based on which DER providers can design and optimize products. Staff seeks party comments, including from DER providers, on what types of system data will be most useful for developing DER services and making investments of highest value. Comments should include details for how data will be used, why it is needed, and preferred data format.

VII. IMPLEMENTING REV: FINDINGS AND RECOMMENDATIONS

After extensive investigation and stakeholder input, Staff concludes that the central vision of REV – increasing the use and coordination of DER via markets operated through a Distributed System Platform – offers substantial benefits and is achievable. Findings from the Track One working groups support the technical feasibility of the DSP, while many party comments speak to the numerous benefits achievable by REV. Specifically:

- The technology needed to support DSP platforms is achievable and to a large extent already available;
- DER resources to support REV objectives are available in the market and their value can be increased by the reforms proposed here;
- DER providers, service companies, and entrepreneurs are ready in large numbers to participate in emerging DSP markets; and
- An overview of likely benefits and costs of REV supports moving forward with phase planning and implementation efforts proposed in the remainder of this section.

Based on these findings, Staff recommends the following policy decisions:[42]

- The Commission should adopt the basic elements of the REV vision and proceed with implementation as proposed here;
- The DSP should enable broad market participation; the DSP function should be served by existing utilities, whose long-term status as DSP providers should be subject to performance reviews;
- Customers and energy service providers should have access to system information, to make transparent and readily available the economic value of time- and location-variable usage;
- Individual customer usage data should be made available, on an opt-out basis, to DER providers that satisfy Commission requirements;
- Utilities should only be allowed to own DER under certain clearly defined conditions, or pursuant to an approved plan;
- Where utility affiliates participate in DSP markets within the service territory operated by their parent company, appropriate market power protections must be in place;
- An immediate process should be undertaken to develop demand response tariffs for all service territories, including tariffs for storage and energy efficiency;
- Implementation plans should include proposals to encourage participation of low and moderate-income customers;
- To protect consumers and reliability of service, the Commission should exercise oversight of DER providers;
- A benefit-cost framework should be defined appropriate to three different purposes: (1) utility DSP implementation plans; (2) periodic utility resource plans; and (3) pricing and procurement of DER; and
- As a transition toward market-based approaches to increase levels of efficiency and renewables, utilities should integrate energy efficiency into their regular operations and should take responsibility for procurement of Main Tier renewables.

Further, the following principles are fundamental to animating the platform and markets suggested by REV, and should guide all of the next steps recommended here:

- Collaboration -- include stakeholders in the design and review of major functionalities, both market and technology;

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[42] The timing of various filing requirements should be determined in a Commission order in view of party comments and interim developments.

- Transparency—create transparency and enable access to customer and system data, within the bounds of privacy and security considerations, to support DER providers' ability to develop new business models and customer offerings;
- Standardization—require an appropriate level of standardization around platform technology and standards, market design and products, and valuation frameworks such that customers and market actors can seamlessly engage with different DSPs;
- Non-discrimination—design strategies to create market confidence, ensure a level playing field, and minimize the risks of vertical market power concerns that arise from the proposals that the utility be the DSP and have some, albeit limited, ability to own DER; and
- Action-orientation—develop targeted and collaborative on-going planning to further develop the end-state platform and markets, and nearer-term transitional steps recommended here.

Based on these findings, policy recommendations, and principles, this section describes Staff's high-level view on transition phases and critical path objectives, makes recommendations on 1) near-term “no regrets” actions to be immediately implemented, 2) transitional steps requiring further exploration and recommendation development, and 3) needed plans for designing and implementing the mature platform and markets. These activities should proceed in parallel. That is, transitional steps and planning for mature markets should begin immediately. At all stages of planning and implementation, Staff and the Commission will play an active oversight role, not merely monitoring compliance but actively reviewing and ensuring opportunities for engagement by stakeholders.

A. Transition Phases and Critical Path Objectives

The comprehensive, complex, and transformative nature of REV will require years of iterative planning and increasingly granular design determination, which should begin as soon as the Commission makes a policy decision to proceed. At the same time, given the imminence of system needs, it is important to take actions in the near-term even while longer-term transition and market design plans are being developed.

Staff has identified three general phases of activity defining the transition to REV. The purpose of describing these phases is not to set a specific deadline or stage gate for each, but rather to provide clarity on Staff's view of the objectives of each phase, and therefore to provide context for the implementation recommendations in the remainder of this section. Implementation recommendations are all intended to begin immediately and in parallel as soon as a Commission makes a policy decision, even though some recommendations set up actions in later phases. Broadly, the transition to REV should include:

Table 6

	Phase		
	Immediate	**Transition**	**Full Implementation**
Purpose/critical path objectives	• Demonstrating & capturing value and low-hanging fruit • Demonstrating commitment • Gaining experience	• Increasing the DER asset base • Proving the suitability of DER for the expanded uses suggested by REV • Removing barriers to DER adoption • Gaining experience and developing capabilities around DSP functions, markets, and ability to deliver DER	• Creating appropriate level of standardization • Operating a platform and markets that are liquid and successfully meet REV's goals
Type of recommendation included in straw proposal[43]	Near-term "no regrets" actions	Transitional steps that should be started now, including those that require further specification before a recommendation for action can be made	Planning that should be started now to support the development of a mature platform and markets

B. Near-Term "No Regrets" Actions

In general, near-term actions should be self-justifying, that is, actions that will be beneficial under conventional regulatory approaches as well as reformed approaches not yet fully adopted and implemented. They should also target activities that can immediately make incremental progress towards REV and help the Commission, Staff, utilities, and others gain important experience around key aspects of REV. The Commission should order the following:

- Based on capital plans filed with the Commission, each utility should determine and indicate which of the most significant capital projects are likely candidates for deferral or avoidance through the procurement of DER alternatives. This proposal should include a plan for a competitive DER procurement process and for making available customer usage data sufficient to allow potential DER providers to effectively participate and offer viable solutions;
- Each utility should file an Efficiency Transition Implementation Plan (ETIP) as described in the section on Clean Energy above. The ETIP will eventually be subsumed into the Distributed System Implementation Plan (DSIP) recommended below;

[43] Note that additional recommendations to support each of these phases are being developed as part of Track Two.

- Each utility should file a demand response tariff;
- Utilities should jointly design and develop web-based tools to enable customers to shop for, and purchase, DER and other energy-related value-added services; and
- The Commission should adopt measures enabling ESCOs to provide value-added service, as well as measures holding ESCOs to certification standards.

C. Transitional Steps

The critical path objectives of the transition phase are to 1) increase the DER asset base, 2) build market and customer confidence in the expanded role of DERs, 3) remove key barriers to DER adoption, and 4) gain experience and develop capabilities that will support the ultimate implementation of the REV platform and markets. Given those goals, Staff recommends the following transitional steps be launched immediately:

- Each utility should be required to file a Proposal for Interim Actions that states how the utility plans to implement the near-term and transitional recommendations specified in this Straw Proposal;
- Each utility should be required to file a Distributed System Implementation Plan (DSIP) that lays out its investment plans over a five year period, including alternative demand and supply resource portfolios considered, its proposed resource portfolio, how it proposes to procure needed DERs, and its BCA of those choices. DSIPs must be transparent in their assumptions and methodologies. The DSIP should encompass the ETIP and be coordinated with the separate development of a BCA framework. DSIPs should be filed periodically by each utility, at least once every two years. Plans should include proposals for engaging low and moderate income customers and proposals for mitigating market power;
- The methodology for the DSIP, including the BCA Framework, should be developed via a stakeholder process with a set of technical conferences;
- A recommendation should be developed to integrate Main Tier renewable resources into utilities' resource planning and provision;
- The Commission should adopt rules toward making distribution system data and customer usage data available to market participants, and should launch an information and data exchange to enable that; and
- Utilities should be required to develop or solicit demonstration projects to inform decisions related to DSP platform and market development. Projects that involve partnerships between utilities and innovative third party providers should be prioritized. Project plans should be filed with the Commission but should not require specific approval.

D. Plans for Mature Platform and Markets

Recommendations included here are focused on planning efforts that should be started now because they are needed to support the eventual implementation of the full REV platform and market. All plans should be subject to the BCA framework as proposed above.

- A Technical Platform Design Stakeholder Process should be designed and launched to facilitate multi-stakeholder engagement and recommendation creation for design parameters and standardization;
- A Market Design Stakeholder Process should be designed and launched to facilitate multi-stakeholder engagement and recommendation for market design parameters and standardization;
- Utilities should be required to jointly file a Uniform DSP Plan that describes the system and technologies to be deployed that will allow for the desired functionalities envisioned under REV, with the standardization needed to enable statewide a market. The Uniform DSP Plan should encompass both technology platform and market design issues; and
- A strategy for providing appropriate market oversight and auditing, and a process and timeline for a comprehensive review of progress toward REV should be established by DPS.

E. Considerations for Next Steps

Many of the recommendations in this Proposal, if accepted and adopted by the Commission, will require the establishment of some type of ongoing structure, or follow-up process whether short-term or ongoing. Examples of structures include a body to design the standards and technologies for the DSP to ensure standardization and uniformity, as far as possible, among the state’s utilities; and they also include an entity to monitor the progress of DER market penetration in the state and ensure that barriers to market entry are eliminated as best as possible. Examples of processes include the development of a methodology to approach and design a reimagined approach to the calculation of benefits and costs, and the development of consumer protections for basic electric service.

Staff also recognizes that DPS will have an important monitoring role in the REV transition and that establishment of these structures will also require some reorganization of the agency’s priorities.

In ordering the measures needed to effectuate the REV initiative, the Commission should seek the correct balance of utility initiative, input from market participants, and Commission and Staff supervision. In this instance that delineation is complicated by the overlay of utility rate cases that will, of necessity, supervene on the REV process. The Commission should require that any major electric rate case filing, subsequent to a Commission Track One order, should include each of the near term actions. Beyond the near term actions, a general rule would not be advisable at this time due to individual circumstances of the different utilities. In each case, either the utility or Staff or an intervenor may propose the inclusion of REV components.

APPENDICES

I. Existing Utility Distribution Systems and Capabilities

The existing utility systems in New York have assets and functionalities that have broad similarities, but there are specific differences as well. Each existing utility distribution system relies on three broad categories; asset management tools, operation and modeling systems, and enabling technologies. But each utility is a separate entity, and the distribution systems were developed in different environments to meet different needs. As a result, the asset management tools, operational controls, and system technologies are not always consistent amongst the utilities. These differing starting points add a layer of complexity for utilities transitioning from their existing legacy systems to a Distributed System Platform (DSP) in a uniform way. For example, there are various levels of visibility and communications networks, as well as diverse geography and varied demographics across utilities. Additionally, capabilities across a given utility's service territory are not necessarily homogenous. Utility systems are large and complex and getting to a fully functional DSP will be an evolution. The necessary investments will be key considerations in the cost/benefit analysis and build out of infrastructure required to effectuate the DSP.

No utility currently has a distribution system with the level of visibility, control and communications network that would be adequate to support the 'end-state' DSP. For example, there is SCADA on only about half of National Grid's substations, while Central Hudson has connectivity to a majority of substations. Visibility to field devices is typically limited, but also varies across utility, as do automation and distribution system control. The platforms for the Customer Information System (CIS), Geographic Information System (GIS), asset database, Outage Management System (OMS), and Energy Management System (EMS) vary across utilities and are a mix of internally developed systems and 3rd party vendor software.

Geography and customer density have been key factors that shaped utility distribution systems. As a result, the needs and priorities for each utility and their customers have often been much different and led to diverse decisions that shaped the distribution systems differently. Consolidated Edison's network system, for example, has thousands of miles of underground lines and numerous underground facilities. The other New York utilities predominantly have radial systems with overhead wires and above ground substations. In all likelihood, these factors will continue to drive divergent approaches across utilities, and unique customer and system demands will need to continue to be met by each utility.

The REV process is an opportunity to re-focus distribution systems so that the DSP can make the most efficient and economical decisions for the benefit of all customers. In addition to the supplemental functions and technologies to meet the different system demands, there will be foundational functions the DSPs will need to execute uniformly. Interoperability and standardization will be essential to the development of thriving markets.

Utility Advancement towards a Smart Grid

All New York utilities have been planning and deploying technologies that will improve system visibility, enhance control, and support analytics that can help achieve the Commission's policy objectives described in REV. Utilities are also attempting to flesh out advanced, fully integrated communication and control systems to replace their current approaches which have developed in a piecemeal fashion. In addition, New York can build on advancements being made in advanced grid technology and the support of Distributed Energy Resources (DER) around the world by utilities and industry leaders.

Enhanced visibility is critical to advancing both system planning, and operational control. Each of the utilities has on-going work and projects that would enhance system visibility. One example of an approach to increase visibility is Advanced Metering Infrastructure (AMI). AMI is a grid edge technology that enables real time visibility and control up to and beyond the meter with significantly greater granularity and frequency than traditional meters. AMI also provides customer by customer data that the utilities/DSP would be able to use for models, planning and operational decisions. AMI could allow the DSP to communicate directly with the meter, which would be a valuable asset for Outage Management Systems (OMS), among other uses. Iberdrola USA envisions an energy control system that would utilize AMI to achieve better granularity of real-time system visibility and control.

There are alternative methods of enhancing system visibility and control that do not rely on AMI. Central Hudson, Consolidated Edison and National Grid also have efforts to increase grid visibility as part of larger projects for a fully integrated system.

Enhanced and integrated communication is also critical because it allows for real or near real-time information updates to the control center, substations and/or other devices on the network. An integrated communication system is critical to properly tie together advances in the Distribution Management System (DMS), mapping and geographic data, outage management, and intelligent device installations in order to maximize optimization and system automation.

Central Hudson has a proposed architecture with a multi-tier network. Still in the development phase, testing of tiered networks such as microwave for Tier 1 (fast) and mesh networks for Tier 2 (medium) are some of the development efforts.

The utilities also have many projects and demonstrations that utilize automated/intelligent devices and sensors. Iberdrola USA has a conceptual map for substation automation and integration design. Central Hudson is considering intelligent devices that provide 2-way status and control such as electronic reclosers/midpoint ties, switched capacitors, regulators, and voltage monitors. These devices allow the utility to meet two objectives (1) Conservation Voltage Reduction (CVR)/Volt-VAR Optimization (VVO) and (2) Fault Location, Isolation, and Service Restoration (FLISR) and Automatic Load Transfer. CVR/VVO is not a new idea or technology, but is becoming a popular strategy to increase efficiency by managing voltage as system granularity improves thanks to smart grid/meter advances. Central Hudson already has a successful initial trial result that decreased demand over an 11 month testing period, with a significantly bigger demonstration slated for 2016 that will involve a mix of over 1,000 customers.

National Grid is also looking specifically at VVO as a non-wires alternative that can help in the deferral of expensive capital expenditures. National Grid is also investigating the effectiveness of different feeder configurations. The project uses a primary system monitoring to incorporate a centralized optimization and control scheme. The project will measure the improvement of delivery system efficiency and efficiency of consumption.

Each utility has a vision and/or is involved with R&D efforts to develop a fully integrated and centralized control system. Consolidated Edison developed a Demand Response Management System (DRMS) and Distributed Energy Resource Management System (DERMS), which are being used as engineering design tools, but have the capability to be operational tools. The engineering design aspect gives Consolidated Edison a platform to model and run various scenarios, which is critical for advanced planning of DER and DR programs. For example, Consolidated Edison has issued DR calls on the model and has achieved load reduction as a result. A notable difference between DRMS and DERMS is that DRMS is a blunt DR tool where the call goes out to all DR participants, while DERMS would facilitate targeted DR.

The DRMS has an extensive architecture that enables a number of functionalities such as event management, device & load management, dispatch optimization and strategies, baseline calculations and settlement preparation as well as customer notification. DRMS can send specific information and requests to customers. The communications can be through Consolidated Edison systems and/or 3rd party systems such as mesh networks, point to point, or the internet. DRMS, however, does not plan as granular as building planning/analysis, which at the moment would be required by the building management, an aggregator, or another 3rd party vendor. DRMS also interfaces with Consolidated Edison tools and systems such as CIS, load forecasting, GIS/visualization platform, meter data system, and settlement system.

An example of one DRMS process is the built in functionality of the baseline calculation which uses historical usage to determine average usage prior to an event, and then calculates the actual performance during a DR event. This information is fed into the settlements preparation engine, and interfacing with Consolidated Edison's settlement system, calculates performance based payments. The credits/payments are then automatically submitted to Consolidated Edison's billing system.

The DERMS is a more comprehensive tool as it includes DR and DER integration with the distribution system. DERMS utilizes a decision aid software that can make recommendations to mitigate overload conditions in the network. There is continuous information flow that enables new analysis about every 5 minutes, which at the moment Consolidated Edison considers to be more than adequate due to typical response times of current devices. The analysis is granular down to the feeder level, and when feeders are overloaded, the program looks across the entire system grid to optimize the DR call and target the most efficient DER. In addition, DERMS tracks the resources that have been used and the remaining availability. Analyses can then be run with known future environmental conditions (sun going up/down, load forecast going up/down, battery storage reserve/depletion, etc.) and operators have the ability to then potentially make proactive decisions. DERMS is currently deployed on a limited number of Consolidated Edison feeders. As advanced versions of DERMS become more widely deployed, they should be able to inform automatic and real-time functions of the DSP.

The goals of Central Hudson's smart grid and integrated communication strategy are to improve grid efficiency and better utilize existing assets, enhance resiliency, and allow for greater DER penetration. Three strategic components critical to achieving these goals are developing an advanced DMS (ADMS), installing intelligent devices and sensors, and developing an Integrated Communications System. Objectives of the ADMS include development of an integrated, near real-time model of the distribution system to enable optimization as well as an integrated transmission system, and further development of modeling and integration of DER, and a centralized workstation to manage data. The system model developed for a demonstration project (NYSERDA PON 1913) includes the modeling of 4 circuits at a substation. The modeling includes all conductor attributes such as capacity and impedance, all customers such as load data and transformer connectivity, and all switches to assist in fault location determination.

Iberdrola has described a system that includes Energy Control Systems, advanced substations, and Advanced Metering Infrastructure (AMI). The Energy Control System would essentially be an advanced control center that would facilitate centralized real-time control and monitoring across the entire grid, and better accommodate distributed generation and active load management. Such a platform would increase grid and energy efficiency and improve reliability and resiliency. A key step is the full integration of components such as SAP, GIS, DMS, OMS, all within compliance of FERC and NERC requirements. Real-time transmission and distribution situational awareness will follow from full integration. The re-engineering of systems and processes to modern or advanced levels will facilitate automation on the network and allow for centralized, efficient operation. Another critical aspect for Iberdrola is development and integration of an advanced OMS. The OMS would capture meter-level outage information. Real-time information on customer outages and improved identification of interrupted equipment and circuits would significantly decrease outage times. In addition, meter events or "pings" can determine power status and clear outage work orders. As part of the integrated system, geographic mapping also becomes possible, which improves cost-efficiency of restoring power to as many customers as quickly as possible.

National Grid favors upgrading their existing EMS and OMS systems to an ABB Network Manager, which is built on an open platform with a component architecture. The common platform enables current and future capabilities to be more quickly and easily leveraged. Initial benefits include real-time exchange between the EMS and OMS that includes device status for optimization of outage prediction and enhanced situational awareness due to integration of telemetered analog data. National Grid is expecting future capabilities to be leveraged on the system to include VVO, AMI, and Restoration Switching Analysis that would be a powerful tool for fault and outage management. Additionally, because each function is a separate entity that interfaces with the rest of the system through the Network Manager, it is easy to tailor the system to user requirements, define execution sequences, and add software modules from 3rd party suppliers.

A National Grid project in Massachusetts includes a combination of Grid Facing and Customer Facing elements. There is an overall effort to optimize utilization of the existing equipment. The grid capabilities being employed include increased visibility (monitoring efforts of distribution circuits and individual transformers), distribution automation, voltage control devices such as capacitors and regulators, and various experiments to determine fault location. As part of the customer initiative, smart meters were installed (15,000), as well as deployment of in-home tools (i.e. Home Displays, Smart Thermostats) at various levels in order to test customer adoption rates and the impact of increased visibility and control on customer efficiency. A local support center has also been setup to offer counseling to customers with hopes to improve customer knowledge base.

II. Platform Functionality

A starting point in the transition to a DSP-based model is properly defining the DSP and its functional requirements. Through the work of the Platform Technology Working Group, a draft definition was developed that Staff supports:

> ***The DSP operates an intelligent network platform that will provide safe, reliable and efficient electric services by integrating diverse resources to meet customers' and society's evolving needs. The DSP fosters broad market activity by enabling active customer and third party engagement that is aligned with the wholesale market and bulk power system.***

The scope and role of the DSP falls into three key areas – (1) market operations, (2) grid operations, and (3) integrated system planning.

With regard to market operations, the DSP will enable transparent market based customer participation, creating a flexible platform for new energy products and services to improve overall system efficiency, grid reliability and differentiated energy sources to better serve customer needs. The DSP will promote retail level markets and formulate entry of new retail energy service providers. The DSP will provide robust information for consumers, third parties, and energy suppliers, making possible customer participation and engagement across all customer classes. The DSP will need to be transparent, flexible, scalable and efficient. It will need to be interoperable amongst a number of diverse technologies, products, and services. The platform should be standardized across utility service territories. The platform will meet and exceed Federal and State cyber security requirements, keeping customer data privacy and platform operations safe and secured.

The task of the DSP from the grid perspective is to operate a secure, reliable, and resilient electric power system, similar to the utilities responsibilities and roles today. Nonetheless, the DSP will need to promote greater visibility and control of the grid. It will need to achieve desired platform functionalities while minimizing system cost. The DSP needs to employ scalable and flexible technologies in order to minimize risk of obsolescence while optimizing new platform functionalities and innovative enabling technologies. The DSP will promote greater and more efficient use of DER, including microgrids, sequentially, maximizing system efficiency of existing utility infrastructure.

The work of the DSP in regards to integrated system planning is to incorporate both market operations and grid operations to allow for an optimized power system utilizing both market and grid drivers. The DSP will promote the development of net-zero and grid-integrated premises and develop mechanisms to interact with them through the delivery of other services. The DSP will need to continue coordination with the NYISO bulk system, comparable to what the utilities do today, and be diverse enough to assimilate many different sources of distributed energy resources. DSP integrated planning analytics will include supply and demand planning, transmission and distribution upgrades, and maintenance. The DSP will target DER site locations and sources, while optimizing the use of existing infrastructure.

As New York moves towards a DSP-based model, it is important to recognize where the DSP fits in the context of the current environment. Clarity around this role aides all parties in understanding the benefits the DSP model will bring in support of the REV vision. In the current environment we have the NYISO, the distribution utilities and end use customers. The NYISO's current role of operating the transmission network and administering and monitoring the wholesale electricity markets is expected to continue under a DSP-based model. The traditional role of the utilities, including maintaining and operating distribution system infrastructure and assets, are envisioned to be subsumed into the DSP with additional roles of integrating, monitoring and controlling DER by means of grid automation and modernization. The end-use customers in the DSP-based model become less passive recipients of electric service and become active market participants.

A core intention of REV is the development of an animated market where the DSP would offer basic and value added regional distribution system market based products by facilitating retail transactions for which there is no current market, and create opportunities to aggregate retail to wholesale transactions. The NYISO market would continue its current functions, possibly modified to accommodate the potential of the DSP...

The DSP will be responsible for integrating and implementing distribution system planning across the three electric network levels; the transmission network, the distribution system, and the customer. DSP integrated planning analytics will include supply/demand planning, transmission and distribution (T&D) upgrades, and T&D maintenance. The NYISO will continue planning bulk system upgrades, bulk generation forecasts, and ancillary service needs based on the input and output of the DSP. The DSP will work with the customer or energy service provider to plan new system connections, analyze DER production data, and customer load data.

The following table is a preliminary list of DSP functionalities sorted by three main categories; Grid, Customer/DER/Microgrids, and Market. The Grid column represents functions that the DSP would need to facilitate in order to meet the REV policy objectives in regards to grid operations. The DSP would need to coordinate and integrate the functions listed under the Customer/ DER/ Microgrids section. Lastly, the DSP would need to make possible the necessary Market transactions listed below.

Grid	Customer/DER/Microgrid	Market
• Real-time load monitoring • Real-time network monitoring • Adaptive protection • Enhanced fault detection/location • Outage/restoration notification	• Direct load control • DER power control • DER power factor control • Automated islanding and reconnection • Algorithms and analytics for Customer/DER/ Microgrid control and optimization	• Dynamic event notification • Dynamic pricing • Market-based demand response • Dynamic electricity production forecasting
• Automated feeder and line switching (FLISR/FDIR) • Automated voltage and VAR Control • Real-time load transfer		• Dynamic electricity consumption forecasting • M&V for producers and consumers (premise/appliance/ resource)
• Dynamic capability rating • Power flow control • Automated islanding and reconnection (microgrid) • Real time/predicted probabilistic based area substation, feeder, and customer level reliability metrics (MTTF/MTTR)		• Participant registration and relationship management • Confirmation and settlement • Free-market trading • Algorithms and analytics for market information/ops

The DSP functions and capabilities will develop over time; as an initial step, however, basic functionalities need to be determined. While each DSP will be starting from its unique position and may propose to obtain these functionalities in different ways, in order to support consistency and provide appropriate signals to the market place with regard to New York's DSP-based model, these foundational functionalities need to be determined. These foundational functionalities may include real-time load and network monitoring, enhanced fault detection/location, automated voltage and VAR control, and automated feeder and line switching (FLISR/FDIR). Due to the importance of this step, party comments on whether these foundational functionalities are appropriate, and/or which other functionalities should be considered as foundational, will help inform the Commission and aide in the initial implementation phase of the DSPs.

III. **Standards, Protocols, and Architecture**

Successful implementation of REV requires interoperability and consistency among each of the DSPs. Standards, protocols and a structured system architecture are some of the elements that can help to support this goal. There are a number of Standards and Protocols, at various stages of maturity and market adoption, in existence that could support the DSP. While standards and protocols are complex and sometimes conflicting, they also can be integral in helping to support wide-scale integration of DER, customer participation, market transactions and operational control by providing a level of clarity and minimizing confusion, which staff believes is needed to animate the markets. As the DSP evolves so too will the standards and protocols that support it.

Conceptually visualizing the design of the DSP is important in defining early steps. The use of a structured architectural standard is a way to illustrate the integration of various components and interfaces in a complex network. By facilitating a standardized systematic approach, the DSP will be able to achieve seamless distributed grid operations and market functions.

The benefits of architecture development include:

1. Identifying gaps in technologies and Standards & Protocols;
2. Creating interoperability through the definition of domains, boundaries and terms;
3. Providing a common understanding and frame of reference that all parties can understand and communicate with when developing something as complex as the DSP;
4. Describing the evolution of DSP functionality over time; and
5. Providing a common framework to show DSP interactions, which will be of particular use as the DSP will be creating new interactions over time.

Some of the relevant standards, protocols and architectures and the organizations that have developed them include:

Institute of Electrical and Electronics Engineers (IEEE) P2030 - This standard provides guidelines in understanding and defining smart grid interoperability of the electric power system with end-use applications and loads. Integration of energy technology and information and communications technology is necessary to achieve seamless operation for electric generation, delivery, and end-use applications at the distribution edge of the grid.

EPRI IntelliGrid 2.0 - Created by the Electric Power Research Institute (EPRI), IntelliGrid architecture provides methodology, tools, and recommendations for standards and technologies for utility use in planning, specifying, and procuring IT-based systems, such as advanced metering, distribution automation, and demand response. The architecture also provides a living laboratory for assessing devices, systems, and technology. Several utilities have applied IntelliGrid architecture including Long Island Power Authority.

National Institute of Standards and Technology (NIST) Framework and Roadmap for Smart Grid Interoperability Standards 2.0 – the most current document in approved form.[1] The Energy Independence and Security Act (ESIA) 2007 assigned NIST the "primary responsibility to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of Smart Grid devices and systems…." In response NIST developed a three-phase plan:

1. To accelerate the identification and consensus on Smart Grid standards.
2. To establish a robust Smart Grid Interoperability Panel (SGIP) that sustains the development of the many additional standards that will be needed.
3. To create a conformity testing and certification infrastructure.

The Smart Grid Interoperability Panel (SGIP) is a public/private funded, global, non-profit organization that supports the work behind power grid modernization through the harmonization of technical interoperability standards to advance grid modernization. SGIP's stakeholders include utilities, manufacturers, consumers and regulators. SGIP's mission is to accelerate the implementation of interoperable smart grid devices and systems. SGIP furthers Smart Grid interoperability by:

1. Developing reference architectures and implementation guidelines;
2. Facilitating and harmonizing standards development;
3. Identifying testing, certification, and security requirements;
4. Informing and educating stakeholders;
5. Conducting outreach to establish global interoperability alignment.

GridWise Architecture Council (GWAC) Stack - consists of eight layers that comprise a vertical cross-section of the degrees of interoperation necessary to enable various interactions and transactions on the Smart Grid.

[1] NIST 3.0 – is currently in draft form.

Open Automated Demand Response - (OpenADR) is an open and interoperable information exchange model and emerging Smart Grid standard. OpenADR standardizes the message format used for Auto-DR so that dynamic price and reliability signals can be delivered in a uniform and interoperable fashion among utilities, ISOs, and energy management and control systems.

Standards and protocols have played a role in most technologically advanced industries. Often there is a race between vendor-developed standards and protocols and those developed through Standards Development Organizations (SDOs). Usually out of the many standards and protocols a subset achieve full industry adoption.

Staff believes the shift to a DSP-based model for New York's Electric Distribution System will be no different. However due to the complexities of the DSP, the Commission should articulate its support for the role that standards and protocols will play in achieving the REV outcomes.

There are a number of ways the adoption of standards and protocols could take place. First, the Commission could mandate the use of a particular standard(s) or protocol(s). Second, the Commission could indicate that this is purely a market-based decision and therefore should be undertaken by the industry.   While there are pros and cons to each of these approaches, Staff believes a third more appropriate option is for the Commission to endorse a collaborative effort to conduct further research in this area and reach consensus regarding a path forward for New York. Staff believes, much like the evolution of the DSPs themselves, this activity will be a long-term initiative and should be structured as such to provide the DSPs as well as market actors an opportunity to be engaged in the process or monitor its activities overtime. Staff recommends a group be formed including the Staff, the DSPs and other interested parties to identify the appropriate next steps and timetable to advance New York's position in this area. Some of the topics this group would be expected to address would be the role for 'open' versus proprietary solutions, cyber-security, testing and certification requirements, how to accelerate adoption of standards and protocols and future-proofing.

IV. Platform Technology

There are many enabling platform technologies in the market today, and the pace of innovation is increasing. Technologies and systems exist today for many of the functionalities that a DSP in New York would be expected to provide. Real time load and network monitoring, automated voltage and VAR control, and power flow control are three grid functional areas, for example, where vibrant technology solutions are being demonstrated and made operational. There are also many technology solutions and approaches being applied to meet evolving customer needs and to implement needed market infrastructure.

Underlying this fertile technological space are key trends that will impact DSP platform evolution. Throughout the electric system there have been advances in recent years to data acquisition and telemetry. Sensors, and measurement equipment in general, is getting smaller, faster, more intelligent, and increasingly packaged and integrated with other functions. These devices can provide a wealth of near real-time data from all parts of the electric distribution system from service endpoints (e.g. advanced meters), secondary and primary distribution circuits, substations, transformers, switches and relays, and up to the bulk grid. Data telemetry has similarly advanced, enabling increasing volumes of two way data flows and sophisticated, near real time control of system components, including various forms of DER. Flexible and robust communications systems are critical to many DSP functions and utilities and others are developing multi-layered, secure systems and interfaces using both wired and wireless technologies.

There has also been much technological progress in dealing with the vast amounts of data available from advanced data acquisition and telemetry. Integration of disparate systems and sophisticated “Big Data” analytics are providing utilities value, for example, through improved outage response and improved asset management increasingly granular capabilities are being developed and demonstrated that enable distribution grid automation, control and management of DER and support of market operations.

For REV to succeed, the growth in distribution system capabilities needs to be aligned with advances that are occurring in customer side technology. Building management systems, for example, can comprehensively monitor and control all aspects of traditional building operations such as HVAC, lighting, power systems, fire systems, and security systems. These systems are increasingly integrating DER resources and providing functionalities overlapping and complementary to envisioned DSP functions. Third party providers are leveraging advanced technologies to provide a burgeoning number of value added services to customers. In addition to well established demand response programs, third parties, including many Energy Service Companies, are providing an increasing array of energy efficiency and energy management services to residential and small commercial customers. Many of these systems are being designed to also provide system operation and planning value to the distribution utilities, such as direct load monitoring and control functions.

Security remains a major concern and is a fundamental consideration to the electric industry in planning and operations as well as implementation of new products and systems. Cyber security will be embedded in the standards and protocols necessary to build a platform, and must be considered and addressed when developing open protocols to connect new end-use technologies and when evaluating new products and systems.

These trends present both opportunities and challenges, and underscore the need for an understanding of technology development that maintains a clear "line of sight" back to the Commission's policy goals. There are technical solutions available to achieve many envisioned DSP functions, but it is also evident that there are currently no available off-the-shelf, one-size-fits-all systems or solutions. Rather, there are many innovative approaches and solutions that if implemented in an unplanned, haphazard way could lead to a technically fragmented situation where uncertainty, certainly from the customer or market perspective, would ensue. As discussed earlier, the New York utilities are engaged in distribution system modernization efforts and it is imperative that these efforts be harmonized and a systematic approach be taken forward, to ensure consistency with policy goals and to ensure that robust, transparent and scalable systems are implemented.

To ensure line of sight to the policy goals and to provide that common approach or understanding, further defining and mapping enabling technologies to the envisioned DSP functionalities is a critical step in the path forward of DSP implementation. This step was begun within the Track 1 – Working Group II-Platform Technology group through the use of a tool, that when populated, will provide detailed definitions of required grid, customer/DER and market functionalities and definitions of the available and emerging technologies. It also provides a means to assess technology maturity[2] and implementation needs, both immediate and in the future.

By defining, mapping and understanding these technologies across functions, and understanding technical maturity, technologies available today can be identified, and

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[2] The technology subgroup used a common assessment method to identify technology maturity - the industry-recognized five stage Gartner Technology "Hype Cycle". The Hype Cycle is a 1 to 5 scale that characterizes the maturity, adoption and social application of technologies where 1 is considered the early concept stage characterized by innovation and early R&D while 5 is the stage where technology is considered very mature and widely adopted.

shortcomings or gaps identified. Also, technologies that may be able to provide a number of DSP functions could be identified and prioritized for implementation.

Working towards these goals in an open, transparent process will help the utilities and all stakeholders better understand what technologies, and accompanying efforts, over time, will be needed to enable DSP platform functionality. These analyses will provide a valuable frame of reference, and help define implementation criteria, to guide utility implementation plans and efforts on a forward-going basis.

V. <u>Conclusion</u>

From a technology stand-point the DSP is achievable. Transitioning New York from our current system to a DSP-based model will require structured thought, planning, and coordination. The DSP functionalities will evolve as technology and markets evolve and wide-scale integration of DER occurs. The need for certain DSP functionalities will drive technology development. Just as a certain DSP function will drive the creation of a technology to perform understood function, how the DSP will perform will be driven by how the grid needs to be operated, customers' and society's needs, and market evolution. The platform needs to be future-proofed, meaning technologies need to be interoperable, standards based, and capable of continuing to function as the DSPs evolve over time. Therefore, a consistent and uniform DSP framework becomes prominent and critical during the formation of the DSP implementation process. While the precise details of the end state technology cannot be known at this time, it is important to have a clear 'line of sight' from policy goals to functionality to technology investments.

Staff recommends that a focused, joint stakeholder effort be initiated to further the efforts begun by the Platform Technology Working Group with respect to Standards & Protocols and Technology Mapping. This effort comprised of Staff, utilities, and interested parties, can further Staff's, and all market actors, understanding and ultimately Commission direction in the implementation of REV. Staff believes this effort can and should run parallel and complementary to other REV efforts underway. This effort should explore the appropriate path forward for New York in the area of Standard and Protocols, which is essential to interoperable and scalable DSP development. Additionally, methodically assessing the availability and maturity of technology solutions available to enable the DSP functionalities will aide implementation and assist in furthering thinking on various staged approaches based on technical capabilities.

Specific technical tasks that are recommended to be addressed through a focused joint effort:

1. Further explore, and define as appropriate, a standard "architecture" (e.g. NIST 3.0) and develop, if possible, an accompanying standardized implementation "approach" for New York to take.
2. Complete an assessment of technology availability and maturity and technology/functionality mapping and gap analysis, with a focus on identifying initial implementation shortcomings.

Completing these tasks through a joint process will establish a basis upon which technical implementation efforts – by all parties, but in particular the utilities – can be better planned and affected. The results of these efforts would achieve the following:

1 Will ensure "line of sight" vigilance to policy objectives.
2. Ensure standardized implementation strategies or approaches are used.
3. DSP platform functionalities will be commonly defined & understood.
4. Technologies that provide a number of DSP functions, in particular during initial implementation, can be identified and more highly considered.
5. Provide technical guidance and/or criterion for utility implementation plans used by Staff, the Commission and other stakeholders to both gauge implementation progress.

Appendix B: Glossary and Acronyms

Glossary

This glossary is provided to define frequently used terms in the straw proposal in order to maintain consistency and provide clarity to all parties. In instances where the straw proposal does not directly define a term, a commonly used definition is provided. Staff recognizes the potential for the market to incorporate new actors, roles, products, and services. As a result, this list should not be construed to define the universe of all actors, roles, products and services, nor to serve as a legal definition.

Distributed system platform (DSP)

- The DSP operates an intelligent network platform that will provide safe, reliable and efficient electric services by integrating diverse resources to meet customers' and society's evolving needs. The DSP fosters broad market activity by enabling active customer and third party engagement that is aligned with the wholesale market and bulk power system
- The DSPs can also derive benefits as a result of acting as an interface (aggregator) between DER providers in its programs, and programs operated by the NYISO
- The acronym "DSP" is abbreviated, for convenience's sake, from the acronym "DSPP" which referred to Distributed System Platform Provider. DSP is meant to refer to both the function and the entity providing the function.

Market Actors

Market actors include all entities that participate in New York electricity markets (both wholesale and retail) including those anticipated to participate in future DSP retail markets. Further description follows for the most significant market actors expected under the REV vision.

- **Customers**
    - Residential, commercial, or industrial customers that procure electricity products or services in the DSP marketplace from their utility, an ESCO, DER provider, or other entity
    - Customers can include:
        - Residential, small commercial or large commercial and industrial retail customer of utility
        - Retail customer of energy service company
        - Customers of any classification of DER providers

- **DER customer**
    - Any end use/retail electric customer who employs distributed energy resources that are integrated with the DSP market

- **DER service providers/developers**
  - Providers of distributed energy products and services to retail customers
  - An interface between end-use customers with DERs and the DSP
- **DSP market participant**
  - Any customer or DER service provider that directly interacts with the DSP. In many cases, DER service providers will aggregate DERs from multiple residential and small commercial customer to serve as an intermediary between customers and the DSP. In some cases, large commercial customers may interface directly with the DSP.
- **DSP**
  - The institutional entity that creates and operates the distributed system platform. Responsible for planning, designing, constructing, operating, and maintaining needed upgrades to existing distributions facilities
- **Distribution utilities**
  - Distribution utilities construct, maintain and operate distribution system infrastructure and assets.
  - Distribution utilities deliver electricity service to ESCOS and directly to end use residential, commercial and industrial customers.
  - Per the Staff proposal, distribution utilities and DSPs are the same entities.
- **Energy Service Company (ESCO)**
  - Energy service companies provide commodity electric service to customers, delivered by distribution utilities.
  - ESCOs may also be DER service providers. Per the Staff proposal, ESCOs will be encouraged to provide DER services.

Other relevant terms

- **Market animation**
  - Creating animated DSP markets as envisioned in REV implies that customers will increasingly: 1) be aware of and adopt DER technologies and services; and 2) use DER technologies in such a manner as to optimize their value to the grid and to the customer.
- **Demand response**
  - A reduction in or shift in time of use of end-use customer consumption. Demand response programs employ a combination of price signals and automated technology (e.g. programmable, controllable thermostats) to reduce load during specific periods (daily or only in critical periods).
- **Distributed energy resource (DER)**
  - Distributed Energy Resources (DER) is used in this context to include Energy Efficiency (EE), Demand Response (DR), and Distributed Generation (DG)
  - DERs are engaged at the low voltage, distribution level of the electric grid, either on the customer-side or utility side of the meter.

- **Distributed generation (DG)**
  - Any distributed energy resource that generates electricity. Examples include combined heat and power, photovoltaic, and small wind.
- **Energy efficiency**
  - Products and services that reduce electricity consumption relative to baseline usage
  - End-use customers can procure energy efficient products individually (e.g. via purchase of LED lights to replace incandescent) or through service offerings provided by DER providers
- **Microgrids (adapted from U.S. DOE definition)**
  - A group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid may be able to connect and disconnect from the grid to enable it to operate in both grid-connected or island mode
  - Microgrid types
    - Campus-style microgrids that serve a single customer with multiple buildings on contiguous property;
    - Multi-customer microgrids of contiguous properties or adjacent buildings;
    - Multi-customer microgrids that serve non-adjacent buildings and might cross utility right-of-ways; and,
    - Community grids that serve a larger area than those above, essentially functioning as a "virtual" microgrid that rely on the utility for balancing services.

Acronyms

- AMI – Advanced Metering Infrastructure
- API – Application Programming Interface
- BCA – Benefit-Cost Analysis
- BQDM – Brooklyn Queens Demand Management Proposal
- CCA – Community Choice Aggregation
- CEB – Consolidated ESCO Billing
- CEC – Customer Engagement Working Group
- CHP – Combined Heat and Power
- CIS – Customer Information System
- CO2 – Carbon Dioxide
- CPUC – California Public Utilities Commission
- CUB – Consolidated Utility Billing
- DER – Distributed Energy Resource
- DG – Distributed Generation
- DLRP – Distribution Load Relief Program
- DPS – Department of Public Service
- DR – Demand Response
- DSIP – Distributed System Implementation Plan
- DSP – Distributed System Platform
- EE – Energy Efficiency

- EMS – Energy Management System
- EPA – Environmental Protection Agency
- ESCO – Energy Service Company
- ETIP – Efficiency Transition Implementation Plan
- EVSE – Electric Vehicle Supply Equipment
- FERC – Federal Energy Regulatory Commission
- FERC – Federal Energy Regulatory Commission
- FLISR/FDIR – Fault Location, Isolation and Service Restoration, Fault Detection, Isolation and Recovery
- GIS – Geographic Information System
- ICAP – Installed Capacity Market
- LBMP – Location-based Marginal Price
- LCE – Low Carbon Emission Resources
- MW - Megawatt
- NIST – National Institutes of Standards and Technology
- NOx – Nitrous Oxide
- NY SIR – New York Standardized Interconnection Requirements
- NYISO – New York Independent System Operator
- NYPA – New York Power Authority
- NYSERDA – New York Start Energy Research and Development Authority
- OMS – Outage Management System
- Open ADR – Open Automated Demand ResponsePSEG – Public Service Enterprise Group
- PV – Photovoltaic
- REV – Reforming the Energy Vision
- RGGI – Regional Greenhouse Gas Initiative
- RIM – Rate Impact Measure
- RPS – Renewable Portfolio Standard
- SCADA – Supervisory Control and Data Acquisition
- SCC – Social Cost of Carbon
- SCR – Special Case Resource
- SCT – Societal Cost Test
- SO2 – Sulfur Dioxide
- T&D – Transmission and Distribution
- T&MD – Technology and Market Development
- UBP – Universal Business Practice
- UCT – Utility Cost Test
- VMP – Vertical Market Power Policy