

REFORMING THE ENERGY VISION

NYS DEPARTMENT OF PUBLIC SERVICE
STAFF REPORT AND PROPOSAL

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Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision

DPS Staff Report and Proposal

April 24, 2014

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I. INTRODUCTION AND SUMMARY

The Commission's Order of December 26, 2013 in Case 07-M-0548¹ (the "EEPS Order") announced a fundamental reconsideration of our regulatory paradigms and markets, examining how policy objectives are served both by clean energy programs and by the regulation of distribution utilities. With respect to our regulation of distribution utilities, the Order identified the following key questions:

- What should be the role of the distribution utilities in enabling system wide efficiency and market based deployment of distributed energy resources and load management?
- What changes can and should be made in the current regulatory, tariff, and market design and incentive structures in New York to better align utility interests with achieving our energy policy objectives?

For purposes of that inquiry, five policy objectives were identified²:

- Customer knowledge and tools that support effective management of their total energy bill
- Market animation and leverage of ratepayer contributions
- System wide efficiency
- Fuel and resource diversity
- System reliability and resiliency

On January 7, 2014, the draft State Energy Plan was released. Among other initiatives, the draft Plan calls on the Commission to:

"Enable and facilitate new energy business models for utilities, energy service companies, and customers to be compensated for activities that contribute to grid efficiency. Maximize the cost effective utilization of all behind the meter resources that can reduce the need for new infrastructure through expanded demand management, energy efficiency, clean distributed generation, and storage."

¹ Case 07-M-0548, Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard, Order Approving EEPS Program Changes, issued December 26, 2013.

² The Commission stated that, although carbon reduction is implied as an objective, we should consider whether it needs to be included as a specific objective among these five. Given the importance of the issue, and the need to clearly indicate the Commission's policy priorities to parties, Staff recommends that "reduction of carbon emissions" be added to this list.

This Staff proposal provides a framework to respond to the challenges articulated in the Commission's Order and the draft State Energy Plan. Each of those documents, in turn, reflects a convergence of circumstances that are driving fundamental change in the electric industry. These include:

- Cost pressure caused by the need to replace aging supply and delivery infrastructure.
- Increased customer reliance on reliable and high-quality electricity.
- The need to reduce carbon emissions and the associated costs and threats to infrastructure posed by increasingly severe climate events.
- Security threats to electric systems, both cyber and physical.
- Technology developments in distributed generation and information systems, which challenge incumbent systems and present opportunities for transformation of those systems.
- Electric price volatility caused by increasingly greater dependence on natural gas as a primary generation fuel source.

While the bulk power system has seen major regulatory changes in recent decades, the basic cost-of-service paradigm for regulating distribution utilities remains in place. Current ratemaking provides few incentives for utilities to innovate or to support third-party innovation, to address the current challenges in ways that promote a more efficient system and benefit consumers. Programs to encourage efficiency and clean energy are funded through surcharges and programs that are not directly integrated with utility business models. Although the existing paradigm served adequately for many years, it now falls short of the pace of technology development that defines many parts of our economy.

This report 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 consumer-oriented industry. One key outcome of the transformation is to address the Commission's stated objective to make energy efficiency and other distributed resources a primary tool in the planning and operation of an interconnected modernized power grid. Under the customer-oriented regulatory reform envisioned here, utilities will actively manage and coordinate a wide range of distributed

resources to accomplish the policy objectives described by the Commission. Markets and tariffs will empower customers to reduce and optimize their energy usage and electric bills, and will stimulate 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. 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. For this reason the initiative is called Reforming the Energy Vision (REV).

The vision of the interactive utility presents many issues, detailed in the body of this report, which should be analyzed in a public proceeding. Issues include:

- Technology and system requirements.
- Definition of utility roles vis-à-vis other market participants.
- Benefit/cost standards for utility investment.
- Realigning ratemaking incentives.
- Creating a new transaction model for customer decisions, including markets and tariffs.
- Addressing barriers and opportunities related to customer engagement.
- Alignment of wholesale markets with distribution-level markets.
- Phased implementation – short, medium and long-term measures.

Preparation of this report involved an extensive outreach effort by Staff, including numerous meetings with entities directly involved with energy markets. Most of these meetings examined technical areas, including: energy storage, demand response, smart grid technology, building management systems, integrated solutions, ancillary services, and microgrids. The outreach effort also examined regulatory models utilized in other jurisdictions, and the role of Energy Service Companies (ESCOs).³

³ Staff recognizes the support and assistance provided by the New York State Energy Research and Development Authority, the Regulatory Assistance Project, and the Rocky Mountain Institute in the preparation of this report.

Staff recommends that the Commission institute a proceeding to consider the matters put forward here, with a target for a policy decision regarding the role of utilities before the end of 2014, followed by ratemaking reforms and utility-specific implementation plans.

II. SETTING AND VISION

A. The Current System for Meeting Reliability Expectations

For most of its history, the basic design of the electric grid has remained essentially the same. Electricity is generated at central stations, transmitted long distances via high-voltage lines, then stepped down in voltage and delivered to customers through local distribution systems. When the system was developed, this design was needed in part because of the limitations of pre-computer-age communications, and in part because customer demand was relatively inelastic. The system was built to serve the instantaneous demand of customers, with a large reserve margin to accommodate plant outages and other contingencies. Limitations in communications and control technology also caused the generation of power to be considered a natural monopoly. The generation of power was owned, operated and coordinated by utilities, which were regulated based on their cost of providing service.

From the 1970s through the 1990s, a number of factors led to a restructuring of the vertically integrated electric industry. These factors included the energy price shocks of the 1970s, cost overruns and safety issues with nuclear generating plants, the development of efficient combined heat and power technologies which were promoted by the federal Public Utilities Regulatory Policy Act, and the development of communication technology that enabled the control and management of a more diverse pool of generation sources.

The combination of these factors led to the potential for competition in the generation sphere. However, with utilities retaining control of the transmission system, access to customers was limited. This led to a federal restructuring of bulk power markets, requiring open access to transmission under the recognition that vertical integration was hindering competition and innovation. Under the new federal rules, independent regional transmission operators were formed, dispatching power based on reliability and economic criteria that provide transparent market signals. As the bulk power markets have evolved, more sophisticated products such as ancillary service, demand response, and financial products have developed. These market

innovations have increased the efficiency of generation and operations of the bulk power grid. However, notwithstanding the efforts of the Federal Energy Regulatory Commission (FERC) and the system operators, markets have not shown the same beneficial value to the development and use of downstream distributed resources and products.

In New York and other states, the restructuring of utilities was not limited to competition at the level of wholesale generation. Retail markets were opened to competitive service providers, with the expectation that markets would develop price competition and associated innovative energy services to help customers manage their bills. The Commission recently found that while large customers benefit from the competitive energy service market, small-usage customers have not experienced the same value. Indeed, this past winter's Polar Vortex events provided evidence of this failure. It appears that throughout the State, most residential and small business customers continue to be exposed to the volatilities and potential price shock of variable short-term gas supply and electric markets. Many residential customers with average usage levels saw their winter electric bills increased by over 80 percent.

This lack of system efficiency cannot be blamed on a limited weather related event. The operation of the bulk power market eliminated some older generation sources but has led to increased dependency on natural gas. Since natural gas usually sets the marginal price for electricity, and is itself volatile, it can drive a more volatile market to the detriment of consumers. Also wholesale markets in general have proven unable to attract investment in resources that supply attributes including environmental externalities and local economic stability, beyond short term energy price. Moreover, the markets are not designed or operated to value system based investments and operation protocols that drive distribution utility innovation and efficiency.

In the absence of optimal demand side design and operations, the bulk generation and transmission system retains its inherent inefficiencies. The bulk power system is designed to meet retail peak demand, which in New York tends to be approximately 75 percent higher than the average load. For that reason, much of the system is underutilized most of the time. Moreover, approximately nine percent of generated power is lost because it has to travel long distances over transmission and distribution lines. In New York, the total rate of system

utilization is under 60 percent.⁴ By conventional standards in the utility industry, this is a normal rate and has been considered tolerable due to the need to be prepared to meet the highest anticipated peak demand.

The efficiency of the commodity market for electricity is also hampered by several factors. To a large extent, demand has been insensitive to price, due in part to a lack of incentives that reward responsiveness. Also, electricity is difficult to store on a large scale. Storage difficulties are combined with supply constraints due to transmission limitations and other local factors. Price sensitivity, storage, and ready supply are important to efficient markets. Their absence has been tolerated in electricity markets, but at a cost.

Though efforts to mitigate these drawbacks have been undertaken through government policy and market initiatives, success has been limited. A limited amount of elasticity of demand has been enabled via demand-response programs and also by the use of time-sensitive prices. Overall demand levels have been reduced through energy efficiency programs funded through surcharges paid by all customers. Diversity in the power generation mix, and emission reductions, are pursued through a Renewable Portfolio Standard (RPS) also funded through customer surcharges.

B. Recent Trends: Stresses and Opportunities

At present there are a number of factors placing significant stress on the traditional utility model. These include:

- The modern economy is increasingly dependent on electricity; the power needs of the digital economy increase the need for reliability and resilience in the power supply.
- Global markets increase competitive pressure on all sectors of the economy, and as the economy grows more dependent on electricity, there is increased pressure to eliminate inefficiencies in the power system.
- The state's electricity infrastructure is aging; capital investment needed in New York over the next 10 years is estimated at \$30 billion.⁵

⁴ As used here, "system utilization" means average demand divided by peak demand.

⁵ Much of this sum reflects needed infrastructure replacement. To the extent it cannot be avoided, it adds cost pressure to the system and increases the need for greater system efficiency.

- The sales base for utilities is relatively flat while peak demand continues to grow.
- An outlook of increasingly severe weather events may force a wider range of planning scenarios, and exacerbate the inefficiencies of building to meet unmanaged peak demand.
- Extreme weather, coupled with the resiliency and reliability needs of the digital economy, may impel customers toward self-generation solutions, while some self-generation solutions approach grid parity in cost.
- Heavy dependence on natural gas for electricity generation, caused by market forces and emission standards, has increased system vulnerability and price volatility at peak times, including winter peaks. This also increases the need for coordination of gas and electric infrastructure development and consideration of the downstream impacts on fuel availability and security.
- The need to reduce carbon emissions causes a trend toward more reliance on gas, with the attendant concerns described above, and also creates a need for the electricity system to accommodate larger contributions from intermittent resources such as wind and solar power.
- The potential for wide scale adoption of rechargeable electric vehicles could challenge the capacity of some distribution circuits.

These stresses are countered by, and give rise to, opportunities for a rethinking of the traditional model. They include:

- The digital economy and global competition have created new industries and technologies that enable changes in the roles of distribution utilities and customers.
- Developments in information technology improve utilities' ability to manage their distribution systems, including diagnosis of faults and rerouting of power flows, with real-time awareness and control.
- Developments in information technology make it possible for customers to manage their electricity demand without inconvenience, and enable utilities to coordinate customer-side resources to an extent not previously possible; this in turn enables more predictable and manageable system load with resulting system efficiencies.
- Increased reliance on electricity has created greater awareness among customers of opportunities to assume control over their energy decisions.
- Efficiencies of many Distributed Generation (DG) technologies including solar, Combined Heat and Power (CHP), and storage, are improving while costs are declining.

- A burgeoning industry has developed in building system management and industrial system controls, and the technology to enable integrated energy management in residential buildings is mature.
- Electric vehicles can potentially be used to provide ancillary services on distribution circuits.
- New York has a single-state Independent System Operator, which facilitates timely conforming of state initiatives with wholesale market rules.
- New York has mature energy efficiency, clean generation, and technology R&D programs run by NYSERDA and utilities.
- New York has established a Green Bank to facilitate financing of innovative market participants.

C. Vision

Utilities are responsible for providing reliable service at reasonable cost. The stresses and opportunities identified here indicate that a business-as-usual approach should no longer be considered the only cost-effective way to meet this responsibility. Addressing these challenges and opportunities involves questioning two assumptions of the traditional paradigm: that there is little or no role for customers to play in addressing system needs, except in times of emergency; and that the centralized generation and bulk transmission model is invariably cost effective, due to economies of scale.

The approach to distributed resources should be reevaluated to determine how demand management can be used not as a last resort but rather as a cost effective, primary tool to manage distribution system flows, shape system load, and enable customers to choose cleaner, more resilient power options.

It is technically feasible to integrate energy-consuming equipment, as well as distributed generation and storage, fully into the management architecture of the electric grid. The purpose of this inquiry is to examine how the distributed grid architecture that is now technically feasible can be achieved on a wide scale. Such an architecture offers the potential of increased efficiency and reduced volatility in system management at both bulk and distribution levels, as well as reduced total consumption and greater penetration of clean and efficient technologies, with ensuing benefits in overall system costs, reliability, and emissions. It also offers the potential for

customers to optimize their individual priorities with respect to resilience, power quality, cost, and sustainability. It is not intended to replace central generation, but rather to complement it in the most efficient manner, and to provide new business opportunities to owners of generation and other energy service providers.

Distribution utilities will play a pivotal role, representing both the interface among individual customers and the interface between customers and the bulk power system. The utility as Distributed System Platform Provider (DSPP) will actively coordinate customer activities so that the utility's service area as a whole places more efficient demands on the bulk system, while reducing the need for expensive investments in the distribution system as well. The function of the DSPP will be complemented by competitive energy service providers; both generators of electricity and retailers of commodity will expand their business models to participate in Distributed Energy Resources (DER) markets coordinated by the DSPP. The vision of the DSPP, and issues related to realizing the vision, are elaborated in subsequent sections of this proposal.

Developing the enhanced role for utilities entails a reexamination of numerous assumptions and practices, including not only system design but also the Commission's regulatory and ratemaking practices. As the Commission undertakes the dramatic transformation envisioned here, the regulatory paradigm will need to be revised. The Commission's expectations of utility performance will change, as will the methods and assumptions that underlie the setting of utility rates. Perhaps most importantly, customers' roles and opportunities will change as they become partners in problem solving and active participants in markets. This modernization also must take into account the equitable needs of customers who, for a variety of reasons, may be less able or less willing than others to participate in new market activities.

In recent years, the Commission has begun to take steps toward a distributed grid architecture and an evolution of the regulatory paradigm. These include:

- Demand response programs at the distribution level, as well as cooperation with the New York Independent System Operator's (NYISO) bulk level demand response programs.

- Performance-based rate incentives; these have consisted primarily of negative adjustments for failure to meet minimum service thresholds.
- Revenue decoupling mechanisms that make utilities indifferent to changes in sales volume that may result from customers adopting energy efficiency and distributed generation.
- Interconnection standards for customer-sited generation connected to the distribution system.
- Standby rates (*i.e.*, rates paid to utilities, by customers that own generation equipment, for the value of having the utility system available as a backup).
- Time of Use rates (voluntary for smaller customers) to encourage off-peak usage.
- Gas delivery rates for customers with distributed generation.
- Energy efficiency programs.
- Customer-sited clean energy programs under the Renewable Portfolio Standard.
- Advanced energy technology research and development programs.
- A Green Bank to facilitate financing of advanced energy projects.
- Implementation of statutory net metering requirements.

These measures originated in a variety of proceedings and contexts, addressing a variety of regulatory purposes. The combined reach and effectiveness of these measures can be greatly enhanced by a comprehensive plan in the service of a unified vision. They place New York in position to undertake a sweeping reform that allows us to secure material economic and environmental benefits for our consumers and, at the same time, drive economic development by establishing the scale that supports private investment in the existing and new companies that will provide these benefits.

While the transformation described above can and should occur, we recommend a pragmatic approach to enabling the transformation, reflecting the facts that the system is complex, that affordable and reliable electric service is essential, and that technology and customer demands are likely to move faster and in different ways than we can envision today. Transition to a DSPP model should occur through incremental steps that are guided by a clear set of long-term goals and objectives. Emphasis should be placed on developing the regulatory and

system platforms that support innovation while providing the appropriate level of protections to consumers. Moore's law will tend to outpace regulatory change. Because technology as well as service and product innovation are at the heart of the distributed grid, it will be important for the Commission to remain focused on framing the vision and the regulatory incentives. The Commission should enable the risk and reward mechanisms that enable innovation without trying to select the winning technology or products. At the same time, it will be critical to take the first tangible steps that will drive change and long-term value. Thus, in addition to establishing regulatory and incentive platforms that will support long term market based transformations, this proceeding should allow participants to identify the technologies and programs that serve as a base for supporting the transformation. These technologies and programs should have immediate consumer benefit and be scalable to support systemic change. To leave no doubt, Staff emphasizes that this initiative will be driven by the overriding statutory mission of ensuring safe, reliable, environmentally sustainable electric service at just and reasonable rates. What we propose is a dramatically improved set of means toward achieving those ends.

III. THE DISTRIBUTED SYSTEM PLATFORM PROVIDER

A. Overview

One of the central components of the REV vision is the concept of the utility as a Distributed System Platform Provider (DSPP). This section describes Staff's view of the central issues related to the DSPP model. Staff's views should serve as a starting point for a full discussion with parties.⁶

The DSPP will modernize its distribution system to create a flexible platform for new energy products and services, to improve overall system efficiency and to better serve customer

⁶ Numerous publications have described a transformation in the role of electric utilities, similar to that being proposed here. See, for example, papers by the Electric Power Research Institute (EPRI), the Rocky Mountain Institute (RMI), and America's Power Plan, all cited in the attached Bibliography. New York's major electric utilities along with several other entities have released a paper titled "Creating a 21st Century Electricity System for New York State." The paper has not been formally filed with the Commission. It contains both convergences and divergences from the positions stated in this Staff Proposal. The appropriate forum for addressing the specifics of that paper, and others, will be the public proceeding recommended in this Proposal.

needs. The DSPP will incorporate DER⁷ into planning and operations to achieve the optimal means for meeting customer reliability needs. The factors to be considered in such planning will be grounded in the State's policy initiatives, such as policies promoting clean generating technologies, reducing costs, and making the electric grid more resilient and secure.

The DSPP will create markets, tariffs, and operational systems to enable behind the meter resource providers to monetize products and services that will provide value to the utility system and thus to all customers. Resources provided could include energy efficiency, predictive demand management, demand response, distributed generation, building management systems, microgrids, and more. This framework will provide customers and resource providers with an improved electricity pricing structure and vibrant market to create new value opportunities. The DSPP will enable the adoption of information technology and real-time information flow among market participants, and establish a platform to support demand-side markets and technology innovation. DSPP products and pricing structures will allow for large scale deployment of clean DER, including energy storage that complements renewables, into the electric system.

The DSPP should serve simultaneously as the interface among retail customers in distribution-level markets, and the interface between retail customers as a whole and the NYISO. At present, a utility generally bids its load into the market as a price taker. Taking advantage of more responsive distributed energy resources, it could bid load in a more predictive fashion that saves money for customers and creates greater system wide efficiencies. The DSPP could function as the aggregator of aggregators and interface with the NYISO in this manner. In addition, just as we have seen in the bulk power markets, as technology evolves the DSPP can introduce new markets and products at the distribution level that will yield further benefits to consumers.

B. Functions of the DSPP

1. DSPP Planning Functions

The DSPP will be responsible for planning and designing its respective distribution system in a manner that integrates DER as a primary means of meeting system needs. This

⁷ Distributed Energy Resources (DER) is used in this context to include Energy Efficiency (EE), Demand Response (DR), and Distributed Generation (DG).

planning function will continue to ensure that distribution systems are capable of safely and reliably meeting projected loads to ensure the long-term reliability of the grid. Traditional utility investments relating to needed transmission and distribution assets will remain necessary as aging infrastructure needs replacement, and system upgrades become necessary to meet load growth in particular regions.

In addition to traditional functions, DSPPs will plan for and accommodate customer sited generation and demand response resources. The intelligent integration of DER can solve distribution system planning challenges and improve the resilience of distribution systems. For example, installation of DG could potentially increase the useful life of existing feeders by reducing their loading. This can prolong the life of existing distribution facilities, and accommodate localized load growth without the need to upgrade feeders. Such an approach can also minimize infrastructure investment costs through targeted application of DG.

The spectrum of DER, including solar, wind, CHP, microgrids, storage, efficiency, demand management, and demand response could also be targeted to address load growth. Such resources could be well suited, for example, to address local reliability support in electrically constrained areas of the grid, or voltage support at the local level. DER could be used to address thermal and voltage security violations such as those that have been experienced in southwestern New York. Such DER could provide critical distribution system resiliency during widespread outages caused by extreme weather events. Developing more responsive demand will also enable more efficient reliance on intermittent generation.

This will require the DSPP to use localized, automated systems to balance production and load in real time while integrating a variety of DER, such as intermittent generation resources, and energy storage technologies. The DSPP would manage DER products and services in real time, using technologies that allow the flexible and instantaneous use of generation or demand response to meet customer and system needs. Such applications could potentially maximize the operational and economic efficiency of DER and distribution systems. Implementation of DSPP functionalities will need to be carefully staged, taking into account cost-effectiveness, customer participation, local system needs, and the scalability of near-term measures toward long-term implementation of a fully integrated grid.

The DSPP will be responsible for monetizing the value of DER products, targeted to meet specific identified needs, measuring and verifying that such resources have actually been used to meet such needs, effecting payments to reflect the value of such DER in meeting those needs, and reconciling such transactions as necessary.

A host of technical issues are presented in this context. For example, DER will include intermittent resources such as wind and solar, the nameplate capacity of which may have to be discounted, depending on the extent to which they are complemented by storage. Valuation of different types of DER will depend on a number of factors, including the type of resource (e.g., intermittent, base load, dispatchable), the degree of control over the resource, and the response time of a given resource. Resources could be valued more highly, the closer to real time that they can be controlled directly by the DSPP. Conversely, if resources are customer controlled, then the DSPP must have performance history data to measure and value such a resource, and must have reconciliation mechanisms in place if and when a resource is unavailable when called upon.

Storage is expected to play an essential role in DSPP planning. California recently required its utilities to plan for the acquisition of over 1,100 MW of storage by 2020.⁸ Under REV, rather than setting a specific numeric target, the DSPP in conjunction with market participants will identify economic applications of storage, including, facilitation of clean intermittent generation.

Thus far, there has been limited incorporation of demand response and energy efficiency into distribution system planning efforts, and very little incorporation of distributed generation. There are many reasons for this. System planners are appropriately conservative, and inclined to consider only resources that are well known and can be relied upon to meet projected system needs. Some DER technologies have yet to fully mature, and the use of certain types of DER for system reliability purposes is still relatively new. These challenges, however, should not

⁸Public Utilities Commission of the State of California, Order Instituting Rulemaking Pursuant to Assembly Bill 2514 to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems.

preclude consideration of available, feasible, and cost-effective DER solutions as part of any distribution system planning efforts. DER resources with reliable track records should have an opportunity to compete equally with more traditional solutions. Planners must become more fully conversant with the capabilities, applications, and costs of DER. Only in this way will progress be made toward using new solutions for problems presented in distribution system planning.

More generally, DSPPs should take steps to ensure that distribution systems continue to be modernized through the use of “smart grid” technologies, such as remote sensors and remote monitoring and control devices which can increase the efficiency of existing systems, promote integration of DER, and improve system resiliency and restoration.

The DSPP should also coordinate its planning functions with the implementation by customers of customer-sited DER. To the extent the DSPP can influence such developments, it should promote a broad range of DER, to enhance resource diversity and, thereby, system resiliency. In general, DER should be located where most beneficial to the greatest number of customers, and distribution networks. The DSPP will have to accommodate customer-driven and public policy-driven DER investments. In that regard, the DSPP planning functions should be transparent and coordinated with customer or policy-driven investments, and the DSPP will be responsible for setting rates or prices that properly compensate the benefits of such development.

Questions include:

- What changes in planning processes are needed?
- How can the planning process translate identified system needs into realizable values?
- What planning metrics would be used for comparing alternative approaches to meeting system needs?
- How can system-wide factors (e.g. fuel diversity and system peak) be incorporated into distribution planning?

- How will customer control of siting and operation of DER affect planning?
- How can planning account for market-based procurement approaches?

2. DSPP Markets

a) Benefits and Costs

Understanding the benefits and costs of DER will enable effective investment decisions and identification of the products and services that could be exchanged between the DSPP and other actors. The DSPP would have an important role to play in the following:

- Defining benefit/cost classes in ways that are meaningful for the system,
- Providing transparency with respect to benefits/costs since they are not absolute, but contingent on the changing state of the system, and
- Defining products and services that can be transacted with the grid.

Each type of distributed resource has its own siting, operational, and ownership characteristics, so that each produces a different level of net value to the electricity system and to specific stakeholders. Depending on numerous factors, net value can be either positive or negative. An initial list of possible benefits and costs is as follows:

Categories of Benefits and Costs

Energy Load Reduction	<ul style="list-style-type: none"> • Energy generation • System losses
Capacity Load Reduction	<ul style="list-style-type: none"> • Generation capacity • Transmission and distribution capacity
Grid Support Services/Ancillary Services	<ul style="list-style-type: none"> • Reactive supply and voltage control • Regulation and frequency response • Energy and generator imbalance • Synchronized and supplemental operating reserves • Scheduling, forecasting, and system control and dispatch
Financial Risk	<ul style="list-style-type: none"> • Fuel price risk/hedge • Market price response
Security Risk	<ul style="list-style-type: none"> • Reliability and resilience
Transactional Platform	<ul style="list-style-type: none"> • Advanced Distribution System Management capital and operating expenses
Environmental	<ul style="list-style-type: none"> • Carbon emissions • Criteria air pollutants • Water • Land
Social	<ul style="list-style-type: none"> • Resilience of critical facilities • Improved housing stock • Economic development (jobs and tax revenues)
Other	<ul style="list-style-type: none"> • Administrative costs • Resource diversity and flexibility

Importantly, these potential benefits and costs need to be understood along two dimensions:

- 1) Those that are monetized directly within the existing market structure vs. those that are not, and
- 2) How each benefit or cost accrues to different stakeholders within the system.

Monetizable vs. Non-Monetized Benefits and Costs

Monetizable Within Existing Market Structure	Non-Monetized
<ul style="list-style-type: none"> • Energy and capacity values • Some ancillary service benefits • Operational and capital system impacts • Financial credits or penalties associated with emissions or resource use • Commodity hedging values • Reliability (where a performance-based contract exists) • Tax revenues 	<ul style="list-style-type: none"> • Some ancillary service impacts • Reliability (where performance contracts do not exist) • Resource diversity • Environmental impacts without market pricing mechanisms • Economic development (e.g., job creation, business diversification) • Community development and housing impacts

The second dimension for analysis is how these potential benefits and costs accrue to different stakeholders within the system. Relevant stakeholder categories include DER customers, non-DER customers, the DSPP, NYISO, and society. Depending on current rate and market structures, benefits and costs may accrue to different actors within the system, potentially creating misalignments. For example, non-monetizable environmental benefits may accrue to society at large, but the customer who pays for the DER is not compensated for providing that service. Similarly, net metered customers may not fully pay for the grid infrastructure needed to support their service, thereby impacting non-DER customers.

Questions include:

- What other categories of benefit and cost are relevant, and how should each be defined in ways that are meaningful to the system?
- How should relevant benefits and costs be measured and calculated at the appropriate level of analytical granularity, and how should the system be designed to promote a rigorous and transparent accounting of benefits and costs?
- For monetizable costs and benefits, how will the timing, location, and ownership structure of DER development and use impact value over time? Are current valuation approaches able to support the changing environment, or do they need to be adjusted?
- For non-monetizable costs and benefits, are current risk-based approaches adequately factoring their potential value? Or, are additional market-based approaches required to “internalize” the value in the market?

b) Products and Services

Products and services will be crafted to help capture the monetizable values in the market. In this way, the DSPP model will create new business opportunities for market participants, including owners of central generation, to expand their business models to include participation in distribution-level markets. With new business opportunities, ESCOs will be expected to play a substantial role in DSPP-level markets as more than just brokers of commodity service.

Products and services can be exchanged between the DSPP and the owner of the DER (either the customer directly or aggregated by an ESCO), and between the DSPP and the ISO. To enable ESCOs to operate efficiently, and to align with wholesale markets, it will be important to drive some degree of uniformity in products and services across DSPPs. A framework that breaks out relevant products and appropriate time frames must be created, as well as guidance on methodologies for valuing products and services. Additionally, it will be important to distinguish those products and services bought and sold in the market from those procured on a longer time horizon (e.g., transmission and distribution capacity). Access to customer data will be a critical factor in shaping many products. Privacy and ownership issues related to data must be resolved.

Products and services under a DSPP model will not be limited to DER but may also include value-added services that may be offered by the utility and/or by competitive providers. The potential for unbundled services, and associated pricing and revenue allocation issues, are discussed below in the Rate Design section of this report.

Questions include:

- What relevant products and services could DER owners or the DSPP offer?
- What should be the basis for valuation of products and services?
- How can or should there be a reasonable degree of uniformity in identifying and calculating the value of products and services across DSPPs?
- How can the need for uniformity be balanced with the goal of creating flexibility to support innovation in developing new products and services?

- What regulatory decisions, if any, are needed to address issues related to specific products?

c) Pricing

The DSPP will be responsible for providing pricing structures for DER products and services. The pricing structure could be market-based, tariff-based, or contractual. The DSPP will identify which pricing mechanisms will best represent the value of the products and services. As well as costs, prices should reflect the various benefits provided which would include benefits to system reliability and resilience, economic benefits, public policy and other benefits. In all cases, the pricing of DER products or services should provide clear signals to incent movement toward achieving articulated policy objectives. To achieve greater levels of demand response, for example, the DSPP must develop incentives to motivate customers to employ demand reduction technologies.

Resolution of pricing issues in a DSPP model could affect the long-term role of net metering for solar and other clean energy projects. Net metering acts as an incentive to promote desirable technologies, and also serves as compensation for the system contribution made by customer-sited generation that feeds into the grid. If DSPP markets are developed correctly and aligned with the Commission's policy objectives, in time they should serve as a replacement for net metering that serves both functions -- incentive and compensation -- via market mechanisms that more properly value both environmental benefits and system contributions.

Questions include:

- Can markets and pricing be made sufficiently uniform among service territories and/or across states?
- How can system-wide benefits and externalities be integrated into market prices?
- Should the DSPP be allowed to charge a transaction fee to aggregators and DER participants to cover the costs of performing the DSPP market functions (similar to the NYISO)?
- How should the Commission treat the distinction between a product that is competitive and one that is monopolistic (i.e., market based vs. regulated)? Should the revenues from

these types of product be treated differently, and how do they relate to regulatory incentives?

- How will pricing of DER values affect existing standby rates and net metering?

3. Energy Efficiency

In recent years, utilities have implemented energy efficiency programs under the Energy Efficiency Portfolio Standard (EEPS). These programs have had efficiency savings targets and have been funded by a dedicated surcharge. Principal goals of the programs have been to reduce the bills of participating customers and to reduce emissions. The programs have not generally been integrated into distribution-level planning functions of the utilities. To a limited extent, some efficiency programs have been targeted to system needs.

Under REV, utilities will more fully integrate the goal of bill reduction with the targeted use of efficiency to meet system needs. Rather than a specific program funded through a surcharge, efficiency will be one of the DER tools at the utility's disposal. The DSPP will integrate energy efficiency into its system planning, targeting efficiency where it will produce maximum system value, and thus optimizing the economic value of energy efficiency expenditures for all customers. Efficiency programs may also be implemented on a territory-wide basis where this will enhance customers' ability to manage bills and other objectives of the Commission. Rather than being funded through a dedicated surcharge, efficiency expenditures will be treated like any other part of the utility's revenue requirement.

In parallel with the evolution of the utility role, New York State Energy Research and Development Authority's (NYSERDA) programs are expected to refocus on market and technology transformative strategies designed to provide temporary intervention and support to overcome specific barriers and produce self-sustaining markets. Beyond supporting market intervention strategies that facilitate greater penetration of clean generation and efficiency technologies, NYSERDA's portfolio should continue to provide access to clean energy for low-income customers who may not otherwise benefit from the new markets. Efficiency programs, whether operated by utilities, NYSERDA, or ESCOs, will enhance customers' ability to manage their bills and should encourage customer engagement in broader packages of DER products.

4. Advanced Distribution Management Systems

The DSPP will serve as the local balancing authority, forecasting load and dispatching resources in real time to meet customer needs and balance supply with load in real time to maintain reliability. At present, utilities use a distribution management system (DMS) to operate distribution systems securely, reliably, and efficiently. A DMS typically consists of a detailed network model that is upgraded continually to inform operational decisions. The distribution system model is developed with information and data drawn from numerous other systems, such as geographic information systems (GIS), customer information systems (CIS), billing systems, supervisory control and data acquisition systems (SCADA), and other data sources.

The existing DMS infrastructure must be upgraded as a part of the anticipated transformation of the electric grid. The DSPP must procure and employ advanced distribution management systems that will be needed to enable distribution systems to serve as the platform for integrating DER technologies. Such advanced systems will be essential to allow wider deployment of DER, including renewable generation resources such as solar and wind. These advanced system upgrades will allow distribution system operators to model and control customer-sited DER, such as generation, storage and demand response, that are connected to local distribution networks.

The widespread integration of DER will present new complexities and challenges to the continued reliable supply of electricity. Relatively predictable, one-way power flows within distribution systems required less sophisticated system monitoring and power flow management tools. In an enhanced grid, however, power flow will be bi-directional. Energy supplies will come from multiple new technologies, and various sources, of varying sizes and capabilities. Such changes will cause more complex challenges at the local level relating to network power flows, electrical constraints, voltage fluctuations, and reactive power characteristics.

DSPPs will still be required to operate systems and networks securely, and to reliably provide quality power. In such an environment, advanced distribution management systems will be needed to monitor, analyze, and balance distribution networks in real-time. Such systems must be integrated with existing systems used to operate distribution networks, maintain

customer relationships, and respond to emergencies.⁹ These will include SCADA, CIS, GIS, outage management systems (OMS), and, where applicable, automated metering infrastructure (AMI).

There is, as yet, no standard solution for this need, although the technology is available.¹⁰ The advanced management of distribution systems must be developed for each utility, based on current conditions, anticipated or planned system upgrades, customer needs, and the regulatory and policy environment within which these changes will take place. The development could be done in phases, starting with the most cost effective applications.

5. Communications Infrastructure

Developing a smart grid will require highly accurate monitoring of energy supply and demand, sophisticated analysis and modeling of supply and demand patterns under numerous conditions, real-time fault detection, and reliable nearly instantaneous control of varied and dispersed energy resources. To meet these goals, the DSPP must adopt communications networks capable of supporting a smart grid. Issues presented will relate to the reliability, reach, cost, latency and security of such systems.

The systems must be capable of supporting key smart grid applications including SCADA, telemetry, distribution automation, and data backhaul. Both terrestrial and satellite based systems should be evaluated. The options potentially include broadband internet-based, wired, wireless, and fiber optic applications.

Security of the power supply is one of the factors motivating customers to adopt self-generation, while the integration of two-way power flows on the grid creates potential security threats to the grid operator. DER is thus a solution to one type of security issue and the source

⁹ For example, to ensure system resilience in the face of severe weather events, DMS resources must be integrated with weather-related data collection systems (including weather information collected through SCADA and web-based and other weather forecasting systems). The information developed through such means must then be analyzed along with weather sensitive load profile data for areas potentially affected by storms. These analyses will then be integrated with OMS to best manage storm responses, and ensure efficient utilization of field crews.

¹⁰ See, for example, "Toward a 21st Century Grid," Abi-Samra *et al*, Public Utilities Fortnightly, March 2014

of another. Ensuring the cybersecurity of energy delivery systems is absolutely vital. The energy sector is faced with unprecedented threats to security, which can potentially disrupt control systems that monitor and operate electric distribution infrastructure. Securing SCADA has been identified as one of the most important technical initiatives for making the nation safer across all critical infrastructures.¹¹

In addition to being secure, energy delivery communications systems must be scalable, interoperable, and upgradable. They will need to interface with multiple existing distribution utility systems, as well as external customer-based systems such as building management systems. Standards must be developed to ensure such interoperability. Such systems must provide broad functionality, including the ability to handle vast amounts of data collected from distribution systems, and customer-sited DER.

Questions related to distribution management and communication systems include:

- What investments will be needed for the DSPP to balance supply with load in real time, and forecast load and dispatch resources in real time?
- What system upgrades will be needed to allow the DSPP to model and dispatch customer-sited DER?
- Can and should the development of advanced DMS be accomplished in scalable phases?
- What communications networks are needed to support the integrated grid?
- How will the DSPP protect cyber security of the integrated distribution system?

C. Regulatory Issues

1. Incumbent Distribution Utilities as DSPPs

The question of who should serve as the DSPP is theoretically open to a choice between the incumbent utility and an independent entity. To the extent the DSPP manages a market, an

¹¹ See generally, Idaho Nat'l Lab., Prepared for the USDOE Office of Elec. Delivery & Energy Reliability, Contract DE-AC07-05ID14517, Vulnerability Analysis of Energy Delivery Control Systems (September 2011). The U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability implemented the Cybersecurity for Energy Delivery Systems (CEDDS) program to develop cybersecurity solutions for energy delivery systems. It emphasizes collaboration among governments, industry and others to address the unique environment of energy delivery systems. See <http://www.energy.gov/oe/technology-development/energy-delivery-systems-cybersecurity>

independent operator is arguably preferable. However, when the actual functioning of a DSPP is considered in a practical context, it is clear that incumbent distribution utilities should serve as DSPPs.

The DSPP will identify, plan, design, construct, operate, and maintain the needed modifications to existing distribution facilities to allow wide deployment of distributed energy resources. The DSPP will therefore be responsible for transforming existing distribution systems into a platform not only for DER, but also for a range of products and services that will enable greater efficiencies in the generation, management, and consumption of electric energy. To achieve this, the DSPP will also have to control, manage and balance distribution-system-level DER in real time, and promote new products and services to meet customers' evolving needs.

The incumbent distribution utilities are best situated to perform these functions and tasks. As the entities that planned, designed, built, and have operated existing distribution systems, they are uniquely positioned. Just as importantly, they know how existing distribution systems are operated under real world conditions, and engage in frequent contact with the ISO related to system reliability issues. They also know the specific needs of many customers served by such systems.

The incumbent utilities already possess the particular and unique resources needed to transform the grid and realize the REV vision. They can begin investigating and planning immediately, and can most efficiently design and construct upgrades to existing distribution systems. In many instances, the upgrades needed to facilitate two-way power flows, automated controls, instantaneous communications and dynamic management of energy sources and loads can and will be designed and engineered to work with existing facilities. The incumbent utilities are best positioned to carry out this work. Their existing resources and capabilities, including an experienced and specialized workforce, will be critical to an informed and efficient rebuilding of the electric grid.

Ratepayers funded the existing capabilities of the incumbent utilities. That value must be preserved for the benefit of ratepayers during this transformation. Breaking up these functions, or assigning them to a new entity serving as the DSPP would create inherent inefficiencies that

would squander the value already established in the incumbent utilities. To create an independent DSPP that must perform planning and develop and maintain a detailed knowledge of individual distribution systems would involve a large amount of redundant cost. Doing so to advance the theoretical value of an independent distribution system operator is unwarranted. At this juncture, there is no indication that the cost of such an approach would be outweighed by values or efficiencies that might be promoted by employing an independent DSPP.

In taking on the role of DSPP, the distribution utility expands its function from being a physical conduit for delivery of electricity, to also being a transactional platform for a distribution-level market. The relationship between utilities and regulators has long been shaped by the fact that physical delivery of electricity across a service territory has been a natural monopoly. The introduction of widespread distributed resources can be perceived as challenging the natural monopoly model of utilities. But even if the sources of power are distributed, the need for a single entity to be responsible for reliability of the overall system remains. The REV vision does not eliminate the natural monopoly of the distribution system operator; rather the locus of the natural monopoly is shifted from sheer physical delivery to management of a complex system of inputs and outputs while maintaining reliability.

Questions include:

- What would be the cost of an independent DSPP?
- Are the functions of the DSPP necessarily tied to the real-time operation of the distribution system?
- Could the market management function alone be separated for performance by an independent entity?

2. Utility Ownership or Control of DER

An important issue in the definition and implementation of the DSPP vision will be the extent to which utilities are directly engaged in DER-related activities, beyond the planning and operational functionalities described above. Direct utility engagement with DER could come, for example, in the forms of ownership, financing, operation, contracting, or any combination of these.

The Commission's Vertical Market Power Policy established a rebuttable presumption that ownership of generation by an affiliate of a utility would unacceptably exacerbate the potential for vertical market power.¹² It could be argued that the rationale for this policy would also apply to utility ownership of generation at the distribution level, where utilities are also operating distribution systems and retail-level markets for DER products.

There are, however, significant differences that must be taken into account. Utilities are actively engaged on a daily basis with the planning and operation of distribution systems. Coordinating and actively managing a wide array of DER on a real-time basis, with implications not only for system economy but also for reliability, will require a degree of utility engagement greater than what would be needed at the bulk system level. Although competitive processes are more likely to stimulate innovation in DER products for consumers, there may be products that are so closely tied to critical reliability interests that direct utility engagement is needed. Further, as noted below in the discussion of ESCOs, competitive markets for value-added services at the level of small customers have been slow to develop. At a minimum, the public interest will require that utilities be available to provide essential services that are not provided through competitive markets. Where a utility has imminent operational and planning needs and/or can provide resources that are not available in the commercial market, a pragmatic approach may be preferable to a theoretical approach to the optimal operation of markets in an as-yet-unrealized system.

More generally, the Vertical Market Power Policy created only a rebuttable presumption, and it speaks in terms of unacceptable degrees of market power. The flexible approach employed by the Commission was grounded in its recognition that such matters involve balancing different policy considerations.¹³ The same holds true in this context. The policy goal that protects against unacceptable levels of market distortions will be balanced against other valid policy goals undergirding the REV initiative, such as promoting DER, encouraging

¹² Case 96-E-0900, Statement of Policy on Vertical Market Power, App. I, at p. 1 (issued and effective July 17, 1998).

¹³ The Commission is currently dealing with an unintended effect of strict application of the Vertical Market Power policy at the bulk distribution level, as the retirements of various plants not owned by utilities pose system reliability issues.

renewable energy resources, increasing system efficiency, and enhancing the reliability and resiliency of the grid. Potential impacts of utility involvement can be addressed not only through direct market rules but also through ratemaking incentives that create a financial interest for utilities in optimizing the efficient use of DER without regard to ownership. For these reasons, the proceeding should consider utility engagement in DER activities with a realistic appraisal of the Commission's Vertical Market Power policy.

Questions include:

- Can near-term and incremental approaches to this issue be distinguished from long-term systematic formulas?
- How can the ability to obtain DER products competitively from generation owners and other market participants be ascertained?
- Should rules distinguish among different types of utility engagement (e.g., ownership, contracting, financing, and operation)?
- What is the range of potential rules for utility engagement (e.g., utility engagement as a backstop only; allowing utility engagement up to certain quantified limits; distinguishing between reliability and economic projects; or establishing correct ratemaking incentives)?

3. Microgrids and Community Grids

A microgrid is a connected group of electric loads, served by a dedicated generation source or sources, and may also employ an energy management system to balance generation and load, optimizing efficiency and ensuring critical loads within the microgrid remain energized. A microgrid can operate in parallel with the larger grid but can also operate independently. A community grid is a style of microgrid that supports many customers in an area, including critical customers as well as businesses and residents. Microgrids can generate electricity with clean power sources that may be always operational such as natural gas turbines or fuel cells employing combined heat and power, solar panels, etc.

Microgrids can also support the overall utility grid, lightening the burden on congested infrastructure and avoiding investment in traditional system upgrades. Microgrids could also

participate in distribution level ancillary services markets, supporting the utility grid with frequency regulation, voltage support, and black start capability.

Although microgrids are only one form of DER, they warrant separate discussion here because there are several regulatory issues unique to microgrids that must be addressed. Tariffs for utility backup service need to be analyzed for their application in a multi-customer or campus setting; standards for interconnection need a similar analysis. Also, regulatory uncertainties are created where one person within a microgrid sells power to another, where existing utility lines within the microgrid are used, and where the lines of a microgrid cross public rights-of-way.

In order to facilitate the development of microgrids, the Commission must adopt a consistent policy toward them so developers can better understand the regulatory environment. This is especially important in light of the recent announcement of the NY Prize initiative, a \$40 million competition aimed at jump-starting at least ten independent, community-based electric distribution systems across New York State, along with the industry trend toward developing microgrids for increased reliability, resiliency, and energy efficiency.

If interconnecting at the distribution level, an interconnection agreement must be made between the microgrid facility and the local distribution utility. Distributed resources including microgrids must meet the technical requirements that allow for parallel operation with the utility system. During a utility grid outage, the microgrid can intentionally island itself to maintain critical loads. In such a configuration, equipment must be employed to ensure the safe and appropriate disconnection of the microgrid from the rest of the grid. It is critical that the islanding is intentional as it ensures that the surrounding grid will not be unintentionally energized (backfed) by the energy resources contained within the microgrid. Isolating from the grid to provide service in the event of widespread outages can be a considerable benefit for customers. In addition to ensuring safe operations, reliability and resiliency concerns must also be addressed. Infrastructure must be employed within the microgrid to ensure good power quality, such as generation and load management (balancing) systems, and black start capability, which ensures that the microgrid can come online in the event of a utility grid outage.

Questions include:

- What changes in current rules (e.g., interconnection and standby rates) are needed to enable microgrids and community grids?
- What are the issues regarding the relationship between utilities and microgrids (e.g., ownership of distribution lines within the microgrid, and regulatory status of microgrid owners as sellers of power)?
- What role do microgrids play in the DSPP planning function, related to system needs as well as critical facility resilience?
- Where microgrids serve critical facilities should this be reflected in pricing of utility services?

IV. CUSTOMER PARTICIPATION

A. Overview

The focus of traditional regulatory efforts has been on utilities' provision of safe and reliable service and the Commission's setting of just and reasonable rates. Trends driving the REV initiative impel a new focus on *customers* as active partners in addressing the challenges and opportunities of the modern electric grid. In order for distributed energy resources to be fully integrated into the management of the system, customer interests in managing energy concerns must be aligned with the roles of utilities and other market participants in the operation of sustainable markets.

A strategy for engaging customers should have three main components: products, information, and enabling technology. DSPPs and other market participants must offer products to customers, the values of which will include both price and non-price factors. Customer awareness will be needed, as well as technology that allows most of the day-to-day utilization of DSPP products to be automatic.

Although participation of customers and competitive energy service providers is essential to the success of the integrated grid, it is important to note that this may develop over a period of time, and need not develop at the same pace among all customer classes. As noted in the discussion of the DSPP model, the roll-out of new utility capabilities will need to occur in increments. The engagement of customers in the distributed grid will also need to occur in

increments, and the phasing in of new utility functions should coincide with the development of new customer products, information, and enabling technology.

B. Customer Engagement

1. Barriers to Participation

A number of barriers to better integration of distributed energy resources exist, including regulatory, economic, and transactional barriers. The current regulatory framework provides neither the proper economic incentives nor the transactional platform needed to empower customers to participate as “prosumers” (producer-consumers) of energy and ancillary services. All of these will need to be addressed to achieve optimal levels of customer participation.

The market is composed of different segments and there are varying barriers even within the segments. In order to animate markets, the factors that motivate customers in different segments must be identified. Most demand response under existing programs is provided by larger customers; but the programs are designed to appeal to the price points that are important to those customers. Price alone, in the wholesale market, fails to identify other public interest goods. In the same manner, price signals alone may understate what might motivate other consumers to act. One challenge for DSPP market participants will be to develop products that appeal to the different motivations and capabilities of residential and small commercial customers.

a) Barriers to Demand Response

The NYISO began its demand response programs in 2001. A 2002 study of the first year of the program¹⁴ indicated a wide range of reasons for not participating in the day ahead programs: the noncompliance penalty; the level of curtailment payments; short notice; unclear value proposition for the customer; lack of information and understanding. Many non-participants identified staffing and resource limitations as reasons for not participating.

Automated building management systems address many of the concerns identified in 2002. Building management systems provide the enabling technology that, along with products

¹⁴ Neenan, Bernard F. “NYISO Price-Responsive Load: Program Evaluation Final Report.” Neenan Associates, LLC. 8 Jan. 2002.

and awareness, can make DER successful. Developers of these systems, however, continue to identify barriers at the customer level. These include: incorrect incentives on the customer side, both for building manager performance and in budgets; bidding requirements that penalize capital outlays; and risk-aversion toward new technologies, both in procurement and in operation.

Several other key areas need particular attention in order to achieve New York's full demand response potential. Measurement and verification challenges associated with energy market baseline calculations will need to be addressed. Barriers to participation in ancillary services markets need to be remedied. Changes in time-varying retail rate designs should be considered in order to provide effective and appropriate stronger price signals. Rates and tariffs need to recognize and provide for the value that innovative technology and business models can provide to the grid and its customers.

b) Barriers to Distributed Generation

Customers considering installation of distributed generation face some clearly identified obstacles. The economics of many distributed generation projects, measured on a straight price basis, are not competitive with traditional utility service that does not price in system and social values. Interconnection standards, though they are essential to provide for the safe functioning of the grid, can be expensive and time-consuming to comply with. Standby tariffs may, for some customers, make a project uneconomic. For many customers the standby tariff will not have a major effect in practice, yet the existence of standby tariffs may discourage many customers from even exploring a distributed generation project.

The failure of current markets and tariffs to account for the full value of distributed generation presents other barriers. Demand response programs do not credit the load reduction from a base-load generation project. Financing of non-traditional technologies may be difficult to obtain, or may be obtained only at a premium that undermines the economics of the project. Many customers are reluctant to take on the responsibility of owning and maintaining generating equipment. In urban settings, combined-heat-and-power projects may face emission or thermal restrictions, despite the fact that they result in a net reduction of carbon and other emissions. Net

emission benefits from clean distributed generation are not credited. Some new technologies may also face local code restrictions related to battery types or fuel storage.

c) Customer Awareness

Limited access to information, high customer acquisition costs and other transactional hurdles appear to be barriers common to many customer classes. Confusion and a lack of information regarding the factors that impact a customer's overall energy options are commonly reported as barriers for increased demand side management. Many customers do not understand the various elements of their bill, which leads to confusion and frustration regarding how and to what extent they can control their costs by managing consumption. Customers, even many large users, often do not fully appreciate the various elements including delivery, commodity and demand charges. The current regulatory framework does not provide proper and sufficient price signals to motivate and empower customers.

Energy services providers and other resources that may educate, simplify and otherwise increase the value of demand side management measures are currently in the market for large commercial customers and, more recently, within the multi-family sector and mixed use buildings. However, as the Commission recently found, the market for energy management and demand side management services related to smaller commercial and residential customers has been very slow to develop.¹⁵

d) Access to Data

Access to energy consumption data is important to all sectors. Customers should have ready access to the information that is collected about their own usage. Understanding how and when a customer uses energy is critical to being able to manage that usage. For large commercial, industrial and multi-family consumers, detailed usage information permits optimization of building management systems and benchmarking. Smaller customers can also benefit from ready access to detailed usage data – whether the energy management system consists of a fully automated control system, a simple programmable thermostat, or a decision to

¹⁵ 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, Order Taking Actions to Improve the Residential and Small Non-Residential Retail Access Markets, issued February 25, 2014.

vary the hours of operation for a home appliance. However, in order to benefit, customers must have access to the information in a usable format, an understanding of the value of the information and access to goods or services that empower them to extract value from the data. Many larger buildings, particularly newer ones, have existing energy management devices or systems that can benefit significantly from increased granularity of and access to usage data.

Third parties, including energy service companies, NYSERDA and perhaps others, will play a crucial role in optimizing customer participation, and improved access to data may be needed for these market participants. The regulatory framework must balance that usefulness with appropriate protections related to individual privacy, critical infrastructure, trade secret and other confidentiality concerns. These issues are also being examined in the recently initiated phase of Case 12-M-0476.

e) Non-Price Economic Factors

Many DER products involve a significant initial outlay of capital. Whether a particular demand side measure represents a capital or operating expense can have an impact on the cost/benefit equation for customers. Payback period for measures is also an important factor in many customer decisions related to demand side management. Many customers forego cost effective measures because payback periods don't fit into their business plans.

Barriers related to financing are particularly acute for low income customers. Often, the housing stock available to those with fewer financial resources is very energy inefficient, representing opportunities for cost-effective investment. Many low income customers, however, are renters. Rental situations present a split incentive, as a tenant may have an interest in reducing energy bills but does not own the property that needs to be improved. The split incentive decreases the likelihood that demand side management or energy efficiency measures are readily accessible to these customers.

f) Behavior Patterns

While the integrated electricity grid is driven by technological advances, its success depends on customer engagement. Understanding the factors that lead to customers taking

control of their energy consumption will be an important part of utilities' and ESCOs development of energy markets, as important as any particular technology or regulatory factor.

Marketers will need to identify incentives and technologies to increase customers' knowledge and ability to manage their energy bills. For example, energy product interfaces (e.g., web portals, mobile applications, etc.) should be easy to use, simple to understand, and educate customers through the use of these technologies. Also, many customers will stay with a default option over an option that requires an affirmative decision. Default options for usage data access should be carefully weighed both for their effectiveness in shaping consumer decisions and their fairness to all customers. In many other cases, customer behavior is simply a matter of resource allocation.

Market participants must design, and the Commission should carefully monitor, promotional frameworks that address the cultural and behavioral challenges presented by this fundamental and transformative change in how we generate, deliver, use, manage, and regulate electric energy.

2. Opportunities to Facilitate Customer Engagement

Customer participation will be driven by products, information, and enabling technology. If these elements are developed properly, many customers will choose to take an active role in managing their own energy use. Other customers may not have the resources or interest to do so. The regulatory framework should be broad and flexible enough to stimulate the market and provide value to all customers while remaining aligned with the Commission's major policy objectives.

A vital part of a healthy market is information. Toward this end, customer outreach and education best practices will need to be identified. The interplay between traditional methods (i.e., bill inserts, direct mailings, print and digital media, etc.) and more contemporary methods (i.e., social media and community-based marketing approaches) will need to be examined. Customer diversity should be considered to accommodate different customer segments in demand-side programs. A one-size-fits-all marketing approach is not likely to be effective.

Commission rules and DSPP tariffs must be crafted so as not to undermine innovative business models. Competitive markets will identify ways of meeting customer demands that address non-energy needs while also enhancing a customer's energy profile. For example, where a customer requires a ventilation solution or a periodic turnover of electronic equipment, these needs can be met with higher efficiency equipment if both the provider and the customer are able to share in the value of the electric system benefits that result.

Aggregation of customers can increase participation levels by decreasing transaction costs, and increasing opportunities for financing. Aggregation of small customers will also be important in establishing the value of DER products including ancillary services; reliability is enhanced with large numbers of small providers, where the risk of coincident failure is low. ESCOs are expected to play an active role in aggregating customers. In addition, opportunities for community-based DER projects should be considered.

An important step to encourage aggregation is for the Commission to establish protocols and standards for accessing and sharing customer information. Statewide standards should provide consistency and clarity to enable utilities, customers and third parties access to the data in an understandable format while developing the technologies and business models to maximize the value of that information for research, commercial purposes, and customer education.

Various aspects of customer data need to be explored, including identification of the type of data considered necessary, effective presentation of the data, and the protocols to efficiently transmit the data, along with other factors, that will determine its value to customers, the market and the public.

A tremendous amount of data will be generated through the modernized grid in addition to the types of customer data that already exist. Resolving the privacy and proprietary issues surrounding data will be crucial to optimizing customer participation.

Enabling technology must make customer participation both convenient and financially transparent. Successful, market driven technologies will also require interoperability, connectivity and open standards. As DER integration increases, upstream markets will respond

and manufacturers will have market-driven motivation to produce standardized products operating on common protocols that are capable of interacting directly with DSPPs or aggregators of demand reduction services.

The design of the markets and the administrative details of participating in them will need to continue to evolve to move from hundreds of coordinated supply resources to an operational and financial system that can support thousands of smaller distributed energy resources. The market, if functioning effectively, will increasingly shift from a market of large, discrete, slow supply resources that have limited dispatch capability to one that values a large number of fast responding, smaller resources.

Financing barriers can be addressed, in the first instance, by improving markets to make product offerings and payback periods more predictable. Utilities and/or third party aggregators can also be better positioned to take risk than individual customers are. Even with best efforts by regulators and utilities, the novelty of the products and markets will result in disparities between what deserves to be financed and what is available in the financial markets. The Green Bank is expected to play a crucial role in bridging these gaps and enabling customers to realize the values inherent in new markets.

Other sorts of financing opportunities will be developed by the market as customers become more engaged in making their own energy decisions. An example of this kind of innovation is the crowdsourcing of financing for solar systems.

Questions include:

- What factors most affect customer participation? What are the most significant barriers?
- Of the factors and barriers, which can be addressed through Commission action versus market participant action?
- How can the participation of low/middle income customers and rental customers be increased?
- What type of compensation is more likely to attract customer participation, bill savings or direct payments?
- How large of a factor is customer education and is this a Commission responsibility?

C. ESCO Facilitation

1. Overview

This initiative will establish new markets for demand management services and tools, as well as cleaner and more resilient power options. Some products of this nature are now offered by energy services companies (ESCOs), utilities and other vendors, primarily oriented toward larger electricity users. One objective of this proceeding is to explore whether, and how, a broadly expanded portfolio of these products and services can be developed and made available to all electricity consumers. ESCOs, utilities and other vendors will have a key role in developing and selling these innovative services. This section identifies impediments and barriers to achieving this goal that are faced by ESCOs, identifies which are currently being investigated, and highlights additional issues requiring review.

At the outset, we note that New York is anomalous in its terminology related to energy service providers.¹⁶ In most of the rest of the nation, an “ESCO” is a provider of energy services beyond mere commodity. “ESCOs” in New York, at the level of smaller customers, have generally been providers of commodity only. One aim of this initiative is to make New York’s use of the term “ESCO” consistent with the industry-wide use of the term – not by definitional fiat but by cultivating ESCO participation in a range of markets and services. We also expect that the distinction between “ESCOs” and “generators” will become less relevant as companies owning central generation expand their business models to participate in new markets as full service providers.

2. Status

In a recent Order regarding certain retail energy market issues, the Commission reiterated the critical role of retail energy markets in the State’s regulatory framework, particularly in fostering innovation and economic investment required to continue to modernize New York’s

¹⁶ The General Business Law (Section 349-d.1(b), Public Service Law (Section 44.5) and Commission regulations (16 NYCRR Section 11.2) define an ESCO as “an entity eligible to sell electricity and/or natural gas to end-use customers using the transmission or distribution system of a utility.” ESCOs may provide other retail products or services such as the energy-related value-added services being addressed in this proceeding. Some other jurisdictions define ESCOs as firms that provide energy efficiency-related and other value-added services.

power system design and operation. The Commission articulated its goal of establishing “competitive retail energy markets in which ESCOs and other vendors offer a wide range of innovative products and services to enable [all] customers to more effectively manage and control their energy bills.”¹⁷

Currently, approximately 274 ESCOs are eligible to provide energy service to New Yorkers, and 219 actively provide such service. ESCOs provide the vast majority of electricity used by large commercial and industrial customers, and lesser amounts for small commercial and residential customers, as detailed below.

Customer Type	% Customers Served by ESCOs	% Eligible Load Served by ESCOs
Large Commercial/Industrial	72.4%	82.4%
Small Commercial	34.7%	66.7%
Residential	24.1%	27.0%

In general, retail energy markets serving large non-residential customers are achieving the Commission’s goal. A large majority of those customers obtain their energy supply from an ESCO and report savings and/or benefits from value added services, such as demand response and load management. Competitive pressures in those markets are resulting in energy-related value-added services from ESCOs and other vendors for these large users of electricity, an outcome that is expected to continue in the future.¹⁸ In contrast, the Commission found little evidence of ESCOs offering energy-related value-added services such as demand management programs or tools, or voluntary dynamic pricing programs, to small commercial or residential customers. This proceeding, as well as Case 12-M-0476, should create further opportunities for

¹⁷ Case 12-M-0476, et al., Proceeding on Motion of the Commission to Assess Certain Aspects of the Residential and Small Non-Residential Retail Energy Markets in New York State, Order Taking Actions to Improve the Residential and Small Non-Residential Retail Access Markets, February 25, 2014. Parties have filed petitions for rehearing, reconsideration and clarification of this order, which are currently pending before the Commission.

¹⁸ In some cases, the value-added service provided by the ESCO is mitigation of the impact of mandatory hourly pricing. This indicates that ESCO service, per se, does not advance the Commission’s policies. The type of value-added service provided by an ESCO is important.

ESCOs to go beyond reselling energy commodity and instead offer a wide range of energy-related value-added services to all customers.

3. Opportunities and Potential Business Models

With the markets and products that will be opened for consumers through the REV initiative, ESCOs should become providers of bill management services. The vision in which retail suppliers, demand management companies and others develop and provide innovative products and services may be achieved through a wide range of business models. Staff has begun to compile an inventory of where such products and services are now available, and from what provider, to help identify new developments as well as the practices under which the development of such products and services may flourish in New York.

Large commercial and industrial customers are benefitting from a wide range of energy management products and services, including building management systems, demand response and energy efficiency programs, and behind the meter DER such as solar PV, micro-wind turbines, and battery storage. Some of these services are provided by vendors such as demand management companies, which do not provide energy commodity, and some are provided by ESCOs either alone, or in partnerships with other vendors.

Small commercial and residential customers in New York and other states are beginning to benefit, to a limited extent, from metering retrofit services, wireless HVAC control and diagnostic sensors, single open protocol software platforms, controllable Wi-Fi thermostats, energy advisory support, mobile applications, desktop dashboard alerts, and financial business incentives. ESCOs and other vendors are generally just beginning to offer these products and services to mass market customers. In addition, the cable television industry is beginning to offer energy commodity service as well as home energy management tools to residential customers. Products designed to change customers' behavior regarding their energy use have been developed by companies that are partnering with utilities and ESCOs to promote behavior change primarily for residential customers.

Other business models include community aggregation programs (e.g., municipal, community, commercial, non-profit), community and multi-family building based renewal

energy projects, regional “Main Street” venues which might include the sponsorship of micro grid projects or community based DER/generation projects, and “buy local” green power initiatives. New technologies are being developed by a wide array of companies, some very large and well-established, others start-up, that will invariably lead to additional innovative products and services if markets are established that enable customers to have access to these products.

There are opportunities for ESCOs and other entities to expand the availability of energy-related value added products and services to additional customers in New York. The market design and regulations associated with REV should anticipate and accommodate a wide variety of business models to deliver these products and services to customers.

4. Issues related to ESCOs’ Participation in DSPP Markets

Staff’s work with ESCOs and non-commodity vendors has identified several barriers to achievement of the Commission’s vision of a flourishing market for energy-related value-added services. These include the cost of acquiring new customers, particularly customers with relatively small loads; the difficulty for ESCO consumers receiving consolidated utility bills to remain engaged with their ESCO; certain aspects of utility billing systems which make it impractical for ESCOs to offer time-of-use products; and the unavailability of certain data concerning customer energy use and information regarding local electricity system constraints to facilitate development of targeted demand management products.

As described above, expanded access to customer-specific energy usage data is of particular importance in designing innovative energy management services. Commission policies now permit an ESCO, when marketing to a prospective customer, to obtain certain information regarding the customer’s energy usage from the utility, with consent of the prospective customer. The Commission recently expanded the customer-specific information that the ESCO may obtain in these circumstances to include a wide range of additional information about the prospective customers’ historic energy usage patterns, to assist ESCOs in creating a product to meet the particular customer’s energy management needs, particularly for dynamic pricing options and demand response tools. Further work is required to define the conditions under which customer-specific energy usage data can be shared with non-utility

parties. The recently initiated phase of Case 12-M-0476 should explore best practices related to data ownership, data interchange and rules for third-party data access, incorporating appropriate consumer privacy protections, as well as whether and how statewide policies should be developed.

This proceeding should also examine whether market penetration of energy-related value added services should be enhanced by modifying the role of utilities in energy commodity markets. Requiring utilities to cease offering energy commodity, and requiring customers to obtain energy commodity service from an ESCO, may increase customer engagement in energy management decisions and may lead to the economies of scale that would make it possible for ESCOs to offer innovative energy-related value added services to customers with relatively small usage. Such a requirement, though, would serve little purpose if it only resulted in customers obtaining commodity from ESCOs rather than from utilities. Commodity service is readily available from utilities at a just and reasonable price. In addition, when utilities assume the DSPP role, opportunities will arise for ESCOs and other vendors to form partnerships with utilities in designing and delivering innovative new demand management services or facilitate newly created ancillary service market opportunities on the DSPP level. Clear delineation of the roles and responsibilities of utilities will determine how these partnerships evolve to address customer needs.

To the extent that ESCOs are providing services related to system needs, reliability concerns will arise. Utilities, and the Commission, will have an increased interest in the qualifications and performance of ESCOs where their products, such as demand response and ancillary services, must be relied on by operators of distribution and bulk systems. For this reason, the Commission's current review of eligibility requirements for ESCOs should include these issues.

Questions include:

- What rules should govern access to customer data?
- Where utilities will rely on services provided by ESCOs, is it necessary for qualifications of ESCOs to be certified?

- Should utilities be prohibited from providing commodity service, to create economies of scale for ESCOs? If so what additional consumer protections are needed?
- How can DSPP markets, clean energy programs, and Green Bank financing be coordinated so that ESCOs can offer optimal products?

V. WHOLESALE MARKETS

The electric sector is regulated at both the federal and state levels. The Federal Power Act (FPA) grants the Federal Energy Regulatory Commission (FERC) jurisdiction over the sale of electric energy at wholesale in interstate commerce, practices affecting FERC-jurisdictional wholesale electric rates, the transmission of electric energy in interstate commerce, and the reliable operation of the bulk power system. States retain jurisdiction over facilities used for the generation of electric energy, facilities used in local distribution of electricity, and standards for the adequacy or safety of electric facilities or services. States also retain primary jurisdiction over the siting of electric transmission facilities, while FERC, under certain circumstances, may assert jurisdiction over the siting of transmission facilities.

Achieving the vision of the DSPP will require examining how enhanced integration of DER by the DSPP will impact, and be impacted by, already existing wholesale-level competitive markets, programs, and processes. These will include wholesale energy, capacity, and ancillary services markets administered by the New York Independent System Operator (NYISO). Wide 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. More active and dynamic participation by demand in the wholesale energy markets through the DSPP could improve the overall efficiency of the wholesale market, and may require changes to existing wholesale market rules to accommodate increased demand participation.

There 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. Such coordination will be necessary to fully realize the values of distribution-level markets as well as to protect against risks of double payments, inconsistent incentives for peak load

reduction, and programmatic inefficiencies caused by conflicting policy objectives and market rules.

Federal practices will both inform the State's work and be informed by the State's work. This will require a high degree of State and federal cooperation. A brief overview of existing federal markets and programs will illustrate the scope and breadth of the challenges ahead.

It is envisioned that DSPPs will balance demand and supply at the distribution system level, and also interface with the NYISO. Coordinating demand response programs at the distribution system level will require managing a complex array of distributed energy resources, managing multiple peaks at the distribution level, and then coordinating those capabilities with demand response programs at the bulk power system level. The services and products offered must be appropriately valued and clearly designated for specific purposes. There will be times when resources could be called for local DSPP reasons, times when they are needed by the NYISO, and times when calls by the DSPP and NYISO occur simultaneously. Issues that need to be addressed include the basis for multiple payments for DER resources during an event called simultaneously by the DSPP and the NYISO, including the recognition of discrete sets of benefits on the distribution and bulk power systems.

A possible result is that certain NYISO programs will see a reduction in the number of individual participants as the DSPP assumes more responsibility for its own load forecasts. The DSPP, acting as a coordinator of load reduction resources, could bid its load into the NYISO in multiple layers and bear the risk of non-compliance by customers, or errors in forecasting by the DSPP. Under this scenario, the DSPP rather than the NYISO would be responsible for eligibility requirements and the activities and qualifications of individual customers. Structuring such coordination in a way that satisfies NYISO reliability requirements is an important related question.

Whether specific rules are established by the NYISO or the DSPP, there must be measurement and verification (M&V) processes in place to ensure that committed resources have actually provided services when called to do so, and rules that address payments received for services that were not provided. Such processes will be necessary to foster an environment

where resources will be available when called upon. Decisions will have to be made as to the role of the DSPP in addressing M&V requirements imposed by the NYISO for its programs.

Control of DER will also be central to coordinating the use of DER. As discussed above, DER could be subject to automatic control, manual local control, or direct remote control. Whether DSPPs or service ESCOs exercise control or not will also be relevant. The degree of control over DER will likely vary, depending on the specific resources, their application, the degree of their penetration, and the scope and nature of the particular system security needs and circumstances.

To achieve this, reliability rules, including rules governing both reliable operation of the system in real time, and the long-term adequacy of energy resources to meet projected demand levels, must be closely aligned. This will impact both operational requirements, and minimum resource requirements. Accordingly, operational requirements for reliable operation of the bulk power system and long-term planning efforts to support the bulk power system and local distribution systems will have to be closely coordinated.

A preliminary review of existing NYISO requirements indicates a number of areas in which utilities, the Commission, and market participants will need to work with the NYISO to ensure optimal efficiency and the fullest feasible participation in these programs. Some examples are:

- The Economic Demand Response program currently has a 1 MW minimum size requirement.
- Participation in demand response programs is currently limited to one reliability program (SCR or EDRP) and one economic program (DADRP or DSASP).
- Aggregations are limited to the same Load Serving Entity.
- Distributed generation capacity in excess of the host load is not allowed to participate in Demand Response programs.
- A capacity resource is required to participate for a minimum of 4 hours.
- Rules for distributed generation participation in the DADRP program have not been developed.

- The terms of a real-time Demand Response program have not been developed.

As stated above, the task of reconciling distribution-level activities with NYISO requirements may be simplified greatly if the DSPP acts not only as an aggregator but actively sets rules for DER participation in its own distribution-level market.

Questions include:

- Do NYISO market rules prevent DSPPs from acting as aggregators or limit their ability to do so?
- What are the thresholds for participation in each NYISO market?
- Does DSPP aggregation make minimum aggregation levels easier to accomplish? Should any of the minimum levels be lowered to ensure greater participation?
- Where DER are under the control of customers or third parties, will they need to be discounted for reliability purposes and if so, what will be the respective roles of NYISO and DSPPs in making that determination?
- What issues, if any, could arise because the NYISO generally operates on a nodal basis with respect to generation resources, and a zonal basis with respect to demand? Will the DSPPs be pricing on a zonal basis? How might this impact netting practices?

VI. REGULATORY REFORM

A. Incentive Ratemaking

1. Overview and Objectives

The December 2013 EEPs Order stated that, “the time has arrived for a fundamental refocus of, not only the system benefit programs, but also comprehensive consideration of how our regulatory paradigm and the retail and wholesale market designs either effectuate or impede progress of our policy objectives underlying these programs”.¹⁹ The Order identified the core policy objectives to be: customer tools, market animation, system efficiency, resource diversity, and resiliency. The Order specifically requested that the scope of the new proceeding address changes regarding the current regulatory, tariff, and market design and incentive structures in New York to better align utility interests with achieving our energy policy objectives.²⁰

¹⁹ EEPs Order, *supra*, pg. 21

²⁰ EEPs Order, *supra*, pg. 24

Many of these key policy outcomes lend themselves to outcome based metrics and could be considered for incorporation as critical elements of the regulatory redesign. As noted in the EEPS Order, “all regulation is incentive regulation”²¹ and ratemaking approaches “reward some patterns of behavior and deter others.” The Commission should consider adopting a more outcome-based approach to ratemaking designed to encourage utility long term planning that optimizes investments and leads to lower customer bills.

2. New York Experience

a) Evolution of cost of service ratemaking

Traditional rate-of-return ("ROR") regulation, using an annual rate case cycle, provides very little incentive to the utilities to improve performance. Benefits of any efficiency gains are reflected in the next year's rate case. ROR regulation may also encourage the utility to over-invest in capital spending, because earnings are directly tied to rate base.²² For the same reason, utilities are rewarded for the inefficiencies in the bulk and distribution systems that require capital spending to build for unmanaged peak loads.

Since the 1980s, the Commission has shifted from annual litigated rate cases to negotiated multi-year rate plans where feasible. Extending the term of rate plans can encourage utilities to seek innovation and efficiencies since the longer period between rate cases allows utilities the opportunity to keep or share savings. Long term plans typically contain earnings sharing mechanisms (ESMs). ESMs allow utilities to keep a portion of earnings in excess of the allowed return while requiring a portion of the over-earnings to be passed back to customers. These mechanisms allow customers to share in efficiency gains achieved during the terms of the rate plans.

²¹ The EEPS Order attributed this quote to one of our former Chairmen, the late Alfred Kahn. Upon further study it was determined that this phrase was actually coined by Peter Bradford, another of our former Chairmen, in the book Regulatory Incentives for Demand-Side Management, edited by Nadel, Reid and Wolcott, American Council for an Energy Efficient Economy, 1992, pg. ix.

²² The incentive for regulated companies under ROR regulation to over invest as a means of increasing profits is widely known as the Averch–Johnson effect. See Averch, Harvey; Johnson, Leland L. (1962). "Behavior of the Firm Under Regulatory Constraint". *American Economic Review* 52 (5): 1052–1069.

Under long term plans, utilities have a strong incentive to reduce O&M expenses and capital projects to boost earnings. While reducing expenses and capital projects could lead to more efficient operations, excessive cutting could have adverse impacts on customer service, reliability, and safety. In order to mitigate these risks, a number of revenue adjustment and other ratemaking mechanisms have been incorporated into the regulatory framework as part of long term rate plans. These additional mechanisms were necessary to protect consumers from the effects of unintended consequences as utilities sought to implement efficiencies.

Generally, most New York electric utilities are subject to several performance metrics with negative-only revenue adjustments for failing to meet certain criteria. These metrics are related to outage duration, number of outages, customer service, safety, and various metrics targeted to particular needs identified for individual utilities. Earnings exposure for electric company operations, by rate plan, range from total negative incentives of 263 basis points to total positive incentives of 45 basis points including positive incentives for energy efficiency.²³

In addition, most regulated electric utilities are subject to a downward-only (one-way) net plant reconciliation mechanism. This mechanism is intended to remove the financial benefit to utilities from slippage (under-spending) in their capital expenditure budgets in long term rate plans. Otherwise, given the long term nature of capital projects, the adverse impacts of slippage might not be reflected in annual performance metrics until many years into the future.

Unfortunately, this mechanism does not distinguish between achieved cost savings and slippage, meaning that the utility is not rewarded for efficiently managing capital budgets. Also, the mechanism potentially discourages beneficial projects with higher up-front capital budgets, since overspending is absorbed by the utility until rates are reset.

Another important ratemaking mechanism is the revenue decoupling mechanism (RDM). Where costs are recovered through volumetric delivery rates, utility profits are highly dependent upon sales volume. That is in direct conflict with the goals of encouraging energy efficiency and distributed generation, each of which would ultimately reduce utility sales. The RDM provides

²³ In addition, there are unquantified benefits associated with earnings sharing mechanisms and property tax expense sharing for electric.

that the utility is kept whole for lost sales, since sales volumes built into rate forecasts are reconciled after the fact. However, the RDM provides no positive incentive for utility bill management and exposes the utility and customers to the risk that as some customers reduce demand, the cost of service is borne by the remaining customers.

The Commission has long experience with performance based incentive plans for the telecommunications industry. The results of these plans include both positive models and lessons learned; in both respects they are instructive for designing incentive plans for the electric distribution utilities. A number of telecom company plans were entered into during a similar period of technological change. These plans were longer lived to ensure that both the companies and ratepayers could benefit from expensive up front market transformative investments and operational changes. They involved incentives to develop the means necessary for innovative technologies to gain a market footing.²⁴ A longer term utility performance-based incentive plan might also have a gateway review provision. The gateway review would examine the extent to which the utility met the performance targets established for the first few years of the incentive plan. If and only if those performance expectations were met would the utility company be allowed to continue on into the latter years of the performance-based rate plan.²⁵

b) Considerations from New York State Experience

New York's experience with ratemaking reforms over the last three decades gives rise to numerous lessons learned, that should be considered as we move forward. These include:

- Rate plans should have pre-established means to determine whether a utility is spending adequate levels on necessary investments and maintenance of its system, so that later catch-up spending is not needed. There should also be upside protections on Capex spending to prevent unnecessary inflation of the rate base.
- Performance metrics need pre-established trigger points for re-evaluation, especially when the incentive includes both upward and downward reconciliations. Plans should have provisions to review and assess the long-term effect of the incentives and to modify them, as necessary.

²⁴ See, e.g., Case 00-C-1945-Verizon Incentive Plan, Case 92-C-0665 Verizon New York Performance Regulatory Plan, and Case 93-C-0033-Rochester Telephone Open Market Plan.

²⁵ See for example, the New York Tel Performance Regulation Plan in Case 92-C-0665.

- Despite the level of competition and incentives in the marketplace, continued monitoring of performance is essential.
- Revenue adjustments should be sized so that companies will perform to standards rather than finding it economic simply to pay penalties. In addition, Staff must have access to all underlying performance data for auditing purposes.
- Innovative performance plans should be developed through participation by all market providers.
- Utilities should have the ability to make incremental investments that represent modest calculated risks without fear of penalty, allowing the trial and error process that enables larger investments to be made with more confidence.

c) **Implications of Existing Ratemaking for the DSPP model**

The reforms described above have mitigated but not eliminated the way in which ROR ratemaking can present barriers to the achievement of policy objectives. In the long term, utilities still have an incentive to maximize their capital expenditures, and little incentive to optimize system efficiency to reduce capital needs. With respect to operating expenses, utilities can earn money for shareholders by "beating" the operating expense allowances provided for in a rate case; this contributes to contentious ratemaking processes and, more importantly, gives utilities no financial incentive to manage operating resources positively toward the achievement of policy objectives. Revenue decoupling mechanisms also provide no positive incentive; at best they make utilities indifferent to efficiency and distributed generation. Because RDMs spread the lost revenues across all remaining sales, they leave utilities and remaining customers vulnerable to the long-term implications of widespread revenue loss.

3. **Potential Changes in the Ratemaking Paradigm**

a) **Long Term Rate Plans**

Extending the length of the rate plan (to as long as eight years, see later discussion of RIIO) may provide benefits such as better planning, more certainty, and fewer rate cases. This may give utilities the time and opportunity to implement an innovative 'sea change.' An extended rate plan will create very powerful efficiency incentives (for both capital and operating expenditures) since utilities may reap more of the benefits of efficiencies until rates are reset. The term may enable utility management to focus less on rate matters and more on performance and customer goals.

In an extended term rate plan, there should be annual compliance reporting and detailed performance measurements. However, these may require review and verification; depending on the extent and dollars associated with these measurements, they could become controversial.

Multi-year incentive plans approved by the Commission have typically begun with an initial, one year rate case review. This initial year is then used as the base year for the determination of rates for subsequent years of a multiyear rate plan, which includes forecasts of inflation and other factors. In addition, for certain uncontrollable costs, utilities are allowed to defer and true-up a portion or all of the differences between rate case allowances and actual spending. In some instances this can lead to large unexpected balances and rate impacts on customers.

Deterioration of plant has always been a risk under multi-year plans and can be mitigated by clear metrics and oversight. The impacts of some extraordinary unforecasted changed circumstances (e.g., taxes, interest and inflation rates) can be resolved via reopeners; the need for flexibility and the benefit of certainty are balanced both through uniform policies and in individually negotiated cases.

Perhaps the most effective tool to mitigate unintended results from extended rate plans is the presence of an earnings sharing mechanism with associated monitoring of the results.

b) Input Versus Outcome-Based Ratemaking

Much of the current New York regulatory regime is focused on input based ratemaking. In input based systems, utilities are measured against their own past performance, i.e., profits rise if they can beat internal budgets and rate allowances. Also, performance penalties are avoided if utilities can beat targeted performance metrics based largely upon their historic performance. Success is not measured against optimal performance.

Utilities in the future will be expected to perform new functions surrounding customer information, resilience, integration of renewable generation, carbon reduction, and security, and thus deliver greater value to customers. The utilities will have to invest to achieve better system

efficiency and ultimately manage utility bills. The current regulatory system may not holistically consider these added values.

In contrast, a results-based model shifts the focus of regulation from the reasonableness of historically incurred costs to the pursuit of long-term customer value. Regulatory incentive plans make it possible to place more focus on outputs, not inputs. This is consistent with economic theory regarding the workings of competitive markets. Firms in competitive markets have the leeway to choose those combinations of inputs that will allow the output characteristics (i.e., price and quantity) demanded in the marketplace.

Outputs against which performance can be measured should be broad based, quantifiable, and specific enough to produce intended outcomes. Outcome-based regulation can lead to profit and financial variability, which increases risk. It is critical to avoid overly general objectives that can only be measured by subjective judgments. Post-hoc subjective judgment of whether general objectives have been met is problematic from a process standpoint, and creates uncertainty that may impair financing. A performance-based incentive plan should contain financial provisions to ensure that the utility company retains its long term financial stability.

The most effective outcome paradigm may be one that creates a network of incentives with an enterprise-wide effect. That is, any given employee or mission within the enterprise should be linked in some way to an outcome that, if achieved, will result in improved earnings.

Because a utility has an obligation to serve, a purely outcome-based approach is not feasible; at some level, the inputs needed to meet the obligation to serve must be provided for. Developing specific metrics will undoubtedly be a challenge. Setting specific metrics for new performance areas where there is no track record (e.g., DER-related outcomes) will require careful deliberation. It will also be important to avoid the creation of incentive gaps. Utilities may focus intensely on areas where specific metrics and incentives are detailed and may neglect other areas where there is not an incentive.

c) Symmetrical Versus One-Way Incentives

Historically, most of our incentives have been one-way negative-only revenue adjustments. This approach was based upon the premise that the utility has an obligation to serve and is given the opportunity to fully recover its costs and earn a fair return on investment. Under this approach a positive incentive is arguably an unnecessary windfall, and negative revenue adjustments are necessary to enforce the obligation to serve. A result of this approach, however, is that the only way for a utility to enhance its earnings is to cut spending, and no explicit rewards are provided for providing superior service or otherwise meeting policy objectives. Ratemaking should optimize the level of inputs needed to achieve policy outcomes; near-term reduction of expenses will not always achieve this goal.

While negative-only incentive approaches have generally produced acceptable results, in order to achieve more enhanced performance it may be necessary to consider symmetrical incentive approaches that would reward the utility with additional earnings if it achieves superior results in areas such as innovation and customer service.

Utilities may have concerns regarding potential negative adjustments for metrics that depend on customer decisions, e.g., DER participation. One possible approach to address this would be through positive-only incentives, at least related to elements where direct customer participation is needed for the utility to achieve its goal. To address the "windfall" concern, in this scenario, initial rates could be set at a level in the low range of rate of return, with positive-only incentives for achieving higher levels of performance.

d) Threat of Disruptive Technologies as an Incentive

Technological and economic changes are challenging the electric utility industry and have the potential to force dramatic transformations. Alternatives to utility service become more attractive as utility prices rise. Moreover, the depreciation schedule for traditional utility investments tends to be measured in decades, and revenue erosion may potentially occur over a much shorter period. It can be argued that when faced with disruptive challenges, the utility will have a natural incentive to take whatever actions are necessary to retain its customer base, including the maintenance of excellent service and reasonable prices.

The threat of disruptive transformation may be a strong motivator for utilities, but it is not by itself a constructive way to regulate. The risk inherent in this approach can inhibit financing and could ultimately lead to higher rates for remaining captive customers. Reliance on this threat, to motivate utilities, places risk on the most vulnerable customers that lack the means to participate in the disruptive trends.

Of equal importance, the Commission will want utilities to promote DER technologies, not to view them as a threat. The point of this initiative is to align utilities' incentives with our objectives, by placing utilities in a position to encourage the development of desirable technologies and markets.

e) Incentives Related to Capital and Operating Expenditures

Regulators attempt to simulate competitive interests by allowing utilities to earn a reasonable return on capital investment, and to earn on operating expenses by reducing spending below the levels budgeted in the rate-setting process. One of the values of DER, however, is to reduce utilities' need for capital expenditures. Another objective – reducing peak demand on the bulk system – may have the incidental effect of reducing utility investment. Under conventional ratemaking, a utility will have no incentive to pursue these measures that would reduce its rate base. If utility rates approach levels where they can no longer be increased without exacerbating customer migration, then utilities would lose the incentive to invest in rate base; but that scenario carries even greater concerns and should be avoided. The Commission should consider ratemaking approaches that encourage the most efficient allocation between capital and operating expenses to advance Commission objectives.

4. The United Kingdom Model

In the United Kingdom, the regulator (the Office of Gas and Electricity Markets or Ofgem) found that an increase of 75 percent in value of the current network investment was needed over the next ten years. Ofgem stated that “investment is only half the story, and it is not just a case of replacing like with like. Electricity networks were originally designed to transport power from large centrally located power stations to homes and businesses around the country. In the future they will need to be reconfigured to manage electricity flows from a much larger number of smaller renewable plants which will connect to the networks...It is the scale of the

investment challenge and the need to deliver smarter, more innovative networks which has led Ofgem to conclude after extensive consultation with a wide range of interested parties that a radical change is needed to the price control regime.”²⁶ New York faces much the same situation.

In response to this challenge, Ofgem created a new regulatory regime called RIIO. RIIO is an acronym for “Revenue set to deliver strong Incentives, Innovation and Outputs.” Under the RIIO model, the main ratemaking features include: creating a detailed set of outputs expected of the utility based on an extensive business plan, extending the term of the rate plan to eight years, providing explicit incentives that are partially symmetrical, use of extensive stakeholder involvement, use of external benchmarking of costs, use of a total expenditure concept (totex), and use of uncertainty mechanisms.

While there are many similarities between RIIO regulation and New York regulation (explicit service quality incentives, multi-year rates, etc.), RIIO also introduces some promising innovations that could potentially be implemented here to achieve our policy objectives. These include the use of an extended (eight) year term. This is designed to encourage the UK utilities to engage in long-term planning focused on capital innovation where the benefits produced by capital projects take a long time to manifest. Coupled with a strong reliance on outcomes, it places the burden on utilities to plan for, and achieve, articulated policy objectives. Annual reopeners, pass-through, trigger, and true up mechanisms provide protection from uncontrollable costs, uncertainty, and investment shortfalls.

Another innovative aspect of RIIO is the use of a ‘totex’ approach to setting rates. This aims to remove utility bias in favor of capital costs by attempting to make utilities indifferent to capital vs. expense treatment of costs. Also, the RIIO approach uses some semi-symmetrical incentives with a larger potential upside than downside, which may sharpen focus on desired outcomes.

The RIIO approach to ratemaking relies heavily on benchmarking among the jurisdictional utilities. While benchmarking in general holds promise, there are some key

²⁶ Ofgem “RIIO - a new way to regulate energy networks” April 10, 2010 pgs. 1-2.

differences that could affect the efficacy of this part of the RIIO approach in New York. The legacy systems in New York are very diverse, and the legacy costs in New York are from a system that is more than a century old. External benchmarking would be a very different challenge here.

5. Other Considerations

Under US accounting standards²⁷ regulated utilities are permitted to defer costs on their books, which would otherwise be charged to expense, if it is probable that the regulator will allow recovery of such cost in future rates. Generally, to make this finding, there must be a linkage between a utility's costs and its rates. This accounting policy provides financial and rate stability. If the rate setting process changes and it becomes no longer clear if and how a regulator will allow recovery of deferred assets in future rates, the utility may have to write off the deferred costs to remain in compliance with Generally Accepted Accounting Principles (GAAP). Any future ratemaking approaches should consider how such changes could affect the utility's ability to maintain consistency with accounting standards.

In addition, the likely response of the financial community (credit rating agencies, bankers, investors, equity analysts) should be considered before adopting significant ratemaking changes, because of the capital intensity of the business and future need for utilities to be able to continue raising capital at reasonable costs. At the same time, the financial outlook of utilities under a business-as-usual approach needs to be taken into consideration. Given the stresses identified above, the utility industry may be moving into an era of increased risk under traditional regulatory approaches.

Public Service Law (PSL) rate case requirements must be fulfilled. One such requirement includes a maximum 11 month suspension period; this could provide an insufficient amount of time necessary to develop and negotiate the complex and comprehensive long term plans envisioned here.

²⁷ Accounting Standards Codification (ASC) 980-Regulated Operations.

Questions related to outcomes-based ratemaking include:

- How should the incentives and disincentives embedded in current ratemaking be modified in order to achieve the Commission's objectives?
- How can ratemaking be revised to encourage an optimal mix of capital and operating expenses?
- What specific outcomes of REV should be incentivized?
- What percentage of utilities' potential earnings or how many basis points of earnings should be tied to these incentives at standard and superior performance levels?
- What ratemaking should apply to bridge investments that do not produce complete results during the term of the incentive period?
- Should cost and performance benchmarking be part of an incentive paradigm?
- Can ratemaking incentives be used to remove any utility bias in favor of owning DER versus developing DER through competitive markets?

Questions related to long-term rate plans include:

- Are longer term rate plans a preferable way to enable utilities to achieve identified strategic outcomes?
- Is there an optimal length for all utilities' rate plans or should it be determined for each utility?
- How can long-term rate plans provide assurance that utilities will focus on long-term priorities?
- Should earnings sharing mechanisms be retained, modified, or eliminated?
- How should initial rates including the return on equity be determined in the context of outcome-based long-term plans?
- How should long term plans accommodate reopening conditions, exogenous factors, and reconciled pass-through items? What periodic reporting requirements should be imposed?
- How can long term rate plans best be structured to address the financial stability of utilities and application of accounting standards?

- Is it possible to create a long-term plan with new outcome-based metrics within the constraints of the 11-month suspension period of a rate case?

B. Rate Design

1. Overview

Rate design changes will be necessary to allow for new pricing models and new methods of cost allocation for the products and services to be bought and sold by electric utilities. Rates should provide dynamic price signals that reflect system needs and costs over short and long term horizons. This will allow customers to align investments in DER in the most economic and efficient manner. Traditional electric rate design has been based on the embedded cost to serve each customer class with the assumption that the peak demands of the class drive the costs. Rate designs for the occasional use of the grid have been employed through standby rates and through buy back tariffs. New rate design approaches will be necessary to recognize the two-way transactive grid and the future roles of the utility that are envisioned under REV. Certain products and services can be provided competitively and their prices should be market based with revenues accruing, at least in part, to utility earnings. Other products and services will be natural monopolies and therefore should be tariff based.

The DSPP will be the provider of reliability, standby service and power quality as well as the integrator of widespread DER. Because the transactions between customers and the DSPP will be two-way, the rate designs under REV will need to reflect: the value of grid service to consumers with DER; the value of grid service to consumers without DER; and the value that DER can provide to the grid. Reflecting these energy values in future rates and tariffs will require a greater unbundling of these products and services. Payment structures for DER should reflect the value based on timing, location, flexibility, predictability and controllability of the resource. As discussed above in the description of the DSPP and its role, this proceeding should examine the distinction between bundled and unbundled products and services and how to structure the associated payments that will ultimately communicate the needs of the grid system so that DER resource investments can be aligned with system needs and benefits.

2. Maintain Commitment to Affordable Universal Service

Reliable utility service will continue to be available to all customers at the lowest cost achievable. The distributed grid should be developed in a manner that does not introduce cost

shifts from self-generating customers to non-self-generating customers. Rate design changes must ensure that the burden of providing the utility's revenue requirement do not fall disproportionately on those customers who lack the opportunity to install DER or otherwise participate in DSPP markets. Rental and low income customers, for example, are less likely to invest in or own DER. For those customers that do not have or desire to have DER behind the meter, default service must continue to be available on reasonable terms. The definition of default service will need careful examination and development in this proceeding with the understanding that participation in DER must be by consent, not imposed on customers.

3. Rate Design Under a DSPP Model

The DSPP will be a purchaser, an aggregator, and a seller of products and services. For each product or service, it is necessary to determine the best basis used to determine the price – market, tariff, or contract. That determination will affect the rate design to be employed.

When considering the appropriate rate design for the products and service to be bought, sold and aggregated by the DSPP, it is helpful to understand the expected outcome of the various rate designs that have historically been deployed. For example, an approach that uses a fixed charge plus volumetric rates could most accurately reflect traditional cost allocation principles, with fixed costs recovered through fixed charges, and variable charges recovered through volumetric charges, but increasing the amount of revenue recovered through fixed charges can dilute price signals delivered through volumetric charges.

There are several approaches to the design of the variable rate components. For example, flat rates can be used which are simple and easiest for customers to understand since they send a consistent price signal for all usage levels, but they may not accurately reflect the variable nature of costs being priced and therefore would not promote customer engagement. Inclining block rates would send a strong price signal to incent efficient use of the product, but may not accurately reflect the economies of scale of the product being priced. Declining block rates could be used to more accurately reflect the economies of scale in the product being priced, but at the same time may send a perverse price signal to promote higher usage as the unit price decreases.

Variable rate components can be set not only with respect to the volume used, but also with respect to the time of use. Pricing tied to peak and off-peak times can be indexed in a precise manner to minutes or hours, or more simply to months or seasons. Such rate designs should consider the impact on customers that are least able to change behavior and respond to price signals, and recognize that customers differ in their tolerance for price variability.

Revenue decoupling mechanisms, described above, are a prominent component of rate design in New York. While RDMs eliminate disincentives for utilities to support energy efficiency programs, they also result in the reconciliation of much more than the utility's energy efficiency related revenue erosion, such as the impact of weather, the economy, and forecasting errors.

a) Rate Design Structures to Optimize the DSPP Model

i. Rate Design for a DER-intensive System

In addition to the standard rate design structures that have predominantly been used, there are other less common rate designs that may be better suited for a two-way transactive grid. For example, to promote the objective of system efficiency, rates could include a discounted demand rate for improving load factors. In addition to time-sensitive pricing, rates to optimize system efficiency could also include a locational factor. Algorithms would be necessary that include solving for reliability, economics and overall system efficiency, depending upon the product being transacted. Time-sensitive rates will require investment in advanced metering, which is more likely to be cost-effective for larger customers.

If the distribution utility is allowed to invest in DER behind customers' meters, the implications on rate design will need consideration. For example, a customer could be provided with a direct payment for allowing the utility to locate the DER on its property or the customer could be allocated a portion of the ongoing DER benefit.

The evolution of the DSPP and additional DER not only impact the electric market, but certain distributed energy resources such as CHP rely on gas supply and are dependent upon a steam host to be most efficient. In order to maximize the efficiency of the energy delivery systems as a whole, the need for changes to gas and steam rates should be examined.

ii. Rate Design Applicable to Enhanced and Competitive Services

One of the likely outcomes under a DSPP model is that enhanced service products will become available to customers and aggregators on a fee basis. The transactional platform established by the DSPP will enable the offering of non-essential value-added services, which are enabled by the utility's monopoly status. For example, a DSPP might charge an aggregation fee to third party providers, or might offer a mobile outage notification service for customers who use electric garage-door openers as the means of entry into their houses. Revenues derived from such services should accrue primarily to the benefit of ratepayers, with some portion allocated to utility earnings to provide an incentive. As competitive services enabled by the DSPP platform increase in sophistication and variety, they will provide increasing benefits to utility customers.

The cost of providing basic utility service should continue to be allocated among all customers. Likewise, utility payments for DER products that are used to manage load and optimize system operation belong to the class of costs that are recoverable as part of the utility's revenue requirement.

4. Standby Tariffs

a) Grid Service Tariffs to Individual DER Customers

The value of grid service to customers will vary depending upon the type of customer and nature of the load or services desired. This could have a negative impact on utilities and non-participating customers. Therefore, the pricing of grid service needs to accurately reflect the value that it provides.

The Commission has examined the value of grid service to customers that employ self-generation but also need the availability of backup service from the grid. In Case 99-E-1470²⁸, the Commission approved guidelines for the design of standby service rates. Each utility's standby cost allocation matrix was approved in the early 2000s and they have not been materially changed since.

²⁸ Case 99-E-1470, Proceeding on Motion of the Commission to Initiate an Inquiry into the Reasonableness of the Rates, Terms and Conditions for the Provision of Electric Standby Service.

Current standby rates are designed to reflect the full cost of delivery of service under the assumption that customers' onsite generation would not be available during the time period during which those customers' demands are at peak levels. Standby rates are reflective of the same degree of cost recovery as are standard rates and are set to preserve the existing allocations of costs to the various service classifications. The actual rate design includes a combination of demand and usage charges. The contract demand charge is based on a customer's potential annual demand and reflects the customer's responsibility for paying for the local facilities that were put in place mainly to serve that customer. The daily as-used demand charge is based on a customer's coincident peak demand and reflects that customer's intermittent use of shared facilities, or those facilities that are farther away from the customer.

b) Potential Modifications to the Existing Standby Rate Design

With the implementation of REV, new hardware and capabilities may modify the cost allocation between local facilities (recovered in as-used demand charges) and shared facilities (recovered through the contract demand charge). In light of new technologies becoming available and widely adopted, the Commission should re-examine the overall standby rate design.

The central issue that should be considered is what rate design will reflect the most economic proposition for DER customers without harming non-participant ratepayers. For example, a rate structure that is based solely on volumetric energy charges could be most favorable to DER, because it allows the customer to avoid any distribution charges when operating their own generation; but the rates for non-participant ratepayers would necessarily have to cover the other costs not paid by standby customers. Non-participant ratepayers would in effect be subsidizing the DER customers' rates. On the other hand, demand charges can potentially discourage DER that remains interconnected with the grid. In designing the new rate structures, distribution utilities should consider the long run impacts of the potential for the cost and reliability of DER to reach a point where customers can isolate from the grid and avoid all distribution charges.

One potential modification to the existing standby rate design would be to add the option of a physical assurance requirement. Customers could be required to install load-limiting hardware which regulates the maximum amount of kW-demand they are able to impose on the utility grid. The Contract Demand charge can then be designed to recover the costs of only the demand limited by the physical assurance device. The result is similar to an interruptible rate approach.

A related modification would be to require automated demand response that is controlled by the utility. Standby rate customers would be required to submit a Demand Response Action Plan to the utility demonstrating their ability to shed or shave demand load during an on-site generator outage. The utility could then build local facilities to serve the customer based on the customer's maximum demand less the demand response capability of the customer. This would lower the customer's fixed Contract Demand charge they might otherwise be charged by demonstrating their ability to decrease their maximum demand through demand response.

Lastly, the current standby rate design could be modified to reflect the diversity of DER. DER resources have differing daily, weekly, seasonal and annual operating histories and some have installed redundant equipment to provide reliability. The current rates assume that the utility must provide enough delivery capability to meet the customer's entire peak demand. It is unlikely that all DER resources would fail at once and all during the system peak hour. If the diversity is recognized, the need for electric service is reduced both as a class and as a single customer.

The current rate design is based on the assumption that full backup capacity for all standby customers must be maintained in the event that all distributed generation units go offline at the same time during the system peak. Where there are a number of DER customers on a circuit, the probability of coincident DER outages should be weighed in determining the amount of backup capacity needed. Revisions to current standby rates may be a short run solution to providing grid services since ultimately the DSPP may provide those unbundled services like reliability, ancillary services, storage, depending upon the type of customer.

c) Standby Tariffs for Microgrids

Standby rates were designed to apply to a single customer that has a generator installed behind the meter. This proceeding should examine the application of standby tariffs to multiple buildings that are not owned by the same owner, and where there may be a single owner but multiple interconnected generation facilities. A principal issue will be the extent to which a microgrid provides its own redundant service and demand management, and the level of standby service that it should be expected to pay for.

d) Exceptions to Standby Rates

Currently, there are exemptions from standby rates for certain on-site generation using eligible designated technologies including fuel cells, wind, solar thermal, photovoltaic, biomass, tidal, geothermal, methane waste and CHP systems of less than 1 MW that meet certain efficiency and environmental criteria. The size of a photovoltaic facility that may qualify for the exemption is 2 MW. The current project in-service deadline for qualifying for the exemption from standby rates is May 31, 2015.

Net metering arrangements also provide an exemption from standby rates. Electric utility customers installing certain generation technologies rated at or below specified capacity limits may obtain net metering under PSL §§66-j and 66-l. The PSL sets the minimums at 1% of the electric corporation's peak electric demand for the year 2005. The Commission has recently raised the net metering minimum limitations for all the major electric corporations to 3% of each utility's 2005 peak demand.

Net metering can help to defray a customer's cost of installing DER and serves as a rough proxy to compensate the customer for the value that the DER is contributing to the system. A DSPP market for DER could, in time, replace the function provided by net metering, as market prices reflect the additional system and environmental values represented by technologies that are currently eligible for net metering. In this manner, the function now served by net metering can be performed with greater efficiency and the need for standby exemptions and volume caps could be eliminated.

Questions related to rate design include:

- How do the customer incentives and disincentives under current rate design affect DER participation?
- How should tariffs for DSPP products be designed to monetize system benefits and externalities?
- What new rate designs would help to achieve the Commission's objectives (e.g., load factor-based rates; change in structure between fixed and volumetric rates; increased utility discretion related to rates for non-essential services; modifications to revenue decoupling mechanisms)?
- How can rates best be structured to equitably share system benefits among participating and non-participating customers?
- Should rate design reflect different levels of service (e.g., essential monopoly service versus non-essential value-added competitive service)? Can fees from non-monopoly services constitute a portion of the incentives otherwise provided through ratemaking?
- Should current standby rates be revised to reflect increased diversity of DER?
- Should current standby rates be revised to reflect environmental or system values of certain types of DER?
- Do current standby rates need to be revised to accommodate multi-customer microgrids?
- Do gas and steam rate designs need to be evaluated for their impact on gas-fired DER?

VII. CONCLUSION

A. Rolling Out the Vision

The REV vision will need time to be fully actualized. A reasonable and realistic sequence will be essential, both for the making of key policy decisions and for the actual roll-out of infrastructure, tariffs and markets. Among other things, the full availability of DSPP markets to all customers will likely depend on standardization in the manufacturing of end-use and communications equipment associated with DER for small customers.

Scalability will be a very important factor in the design and evaluation of infrastructure projects. Near term projects should be consistent with a longer-term roll-out of the transactional, situationally aware system envisioned for REV. As the proceeding develops into implementation

phases, each utility will need to establish priorities based on its own system and customer needs. One possible formulation would be for utilities to identify initial improvements that have the greatest value to the system and customers with a relatively low initial investment. A “small bets” approach allows a utility to take risks that even if wrong are valuable for lessons learned; this is an investment approach that is traditional for entrepreneurs but has not been encouraged among utilities and regulators.

Utility-specific system needs may also support geographically focused early roll-out of DER initiatives. Consolidated Edison, for example, has committed in its recently approved rate plan to consider DER initiatives to address system needs in certain areas where growth is projected to require system upgrades in the near future. That is an example where location-specific values may support DER activities at the small customer level in the near term, though not yet in the mode of full-fledged DSPP functionality as described here.

The importance, and the challenge, of the transitional issues must be underscored. Developing incremental steps toward achievement of the DSPP vision will be a major issue requiring input from parties and market participants as the Commission’s proceeding moves through its policy-making and implementation phases.

B. Conclusion

Staff has examined the potential for sweeping changes in regulatory paradigms to achieve the objectives announced by the Commission. Staff’s preliminary conclusion, subject to further development in a multi-party process, is that need and opportunity both argue for the changes proposed in this Report. Staff recommends that the Commission institute a proceeding to develop these proposals.

APPENDICES

A. - WHOLESALE MARKET PRODUCTS

B. - BIBLIOGRAPHY

APPENDIX A

WHOLESALE MARKET PRODUCTS

Energy Markets

At present, the NYISO operates a number of wholesale competitive markets. There are two distinct markets for the electric energy, the Day-Ahead market, and the Real-Time market. Approximately 98% of the electric energy used in the State is scheduled in the Day-Ahead market with the remaining 2% accounted for in the Real-Time market.

In the Day-Ahead market, the NYISO co-optimizes the Energy, Operating Reserves and regulation markets by utilizing bid-based Security Constrained Economic Dispatch (SCED) and Security Constrained Unit Commitment (SCUC). Day-ahead bids are due by 5:00 a.m. on the day before the unit will run, and the NYISO posts the day-ahead schedules and the market clearing prices by 11:00 a.m. Clearing prices are based on LBMP (Locational Based Marginal Pricing), which is the cost to supply the next MW of load at a specific location in the grid. By so doing the NYISO ensures that resources are available to satisfy loads that are forecast for the day.

The NYISO also runs Real-Time markets to efficiently and economically balance actual system loads and a large number of changes continuously taking place on the system, such as unanticipated transmission and generation outages. Real-time bids are due 75 minutes prior to the hour of operation. Differences between day-ahead schedules and actual load and generation are priced at real-time LBMPs, which are calculated every 5 minutes.

Day Ahead Demand Response Program (DADRP)

The DADRP allows end-users to participate in the day-ahead energy market by offering load reduction bids. DADRP participants are paid at the LBMP market price for the amount of their winning bid and have a performance obligation much like winning generators. Participation in the NYISO's DADRP is currently limited to curtailable load. A recent FERC Order, however, ruled that behind-the-meter generation must also be allowed to participate. Eligibility is limited to providers that can demonstrate an ability to curtail at least 1 MW of load, and at present, there is a \$75/MWh minimum offer floor. However, in the NYISO's compliance

filing in response to FERC's Order 745, the new monthly floor will be determined through the application of a "net benefits test."

Capacity Markets

The NYISO establishes Installed Capacity (ICAP) requirements to ensure sufficient resources are available to adequately serve the forecasted summer peak New York Control Area (NYCA) system load. ICAP suppliers must satisfy semiannual tests of maximum output, and must meet deliverability requirements (sufficient transmission to reach load in their respective capacity regions). The NYISO operates capacity markets to facilitate the purchase, by Load Serving Entities (LSEs), of the capacity they are required to procure. In this context, "capacity" is not the electricity itself, but instead the ability to produce electricity when necessary.

ICAP requirements are set based upon projected peak NYCA load, plus an additional reserve amount to ensure the system can reliably serve peak demand even in cases of unplanned outages (known as "contingencies"). This reserve amount is known in New York as the "Installed Reserve Margin" (IRM). In addition to the Statewide IRM, the NYISO imposes minimum Locational Capacity Requirements (LCRs) in areas of the State that have limits on their ability to import power from outside areas. Thus, there are LCRs established for New York City (Zone "J"), Long Island (Zone "K"), and the newly established Lower Hudson Valley capacity zone (Zones "G" through "J"). LSEs are subject to ICAP requirements based on their respective share of coincident system peak load for the State (i.e., the IRM). Where applicable, they must satisfy part of that requirement with resources which are electrically located within their Zone.

All ICAP supplies must "clear" in the mandatory, NYISO-administered, "spot" markets, which are held monthly. LSE bids in the spot auctions are determined by administratively-set "demand curves". Supply offers in New York City (Zone "J") and the Lower Hudson Valley (Zones "G" through "J") are subject to bid caps (for incumbent suppliers) and bid floors (for new entrants), under market power mitigation rules established by FERC. ICAP suppliers within a zone subject to LCRs (i.e., Zones "J," "K," and "G" through "J") receive the higher of the statewide capacity price or the applicable locational price for their respective zones. The NYISO also operates voluntary forward auctions, for the summer (May-October) and winter (November-

April) capability periods. Supplies obtained in the forward auctions must also be offered into and clear the spot auctions in order to satisfy LSE ICAP requirements.

Ancillary Services Markets

In addition to the energy and capacity markets, the NYISO operates markets for “ancillary services.” There are five separate categories of ancillary services at the wholesale/bulk power system level: regulation services, voltage support services, synchronous and non-synchronous reserves, black start services, and demand side ancillary services. These will each be briefly discussed in turn.

Regulation Services

System “regulation” is the practice of continuously balancing power supply resources with load. Regulation service is accomplished through transparent day-ahead and real-time markets which receive bids from participating, qualified energy suppliers (having automatic generation control capability), demand-side resources (also see DSASP) and energy storage resources. A bid evaluation program selects specific resources and the amount of power to be delivered on the basis of each participant’s bid price, unit response rates, location and existing transmission constraints. Updates to the desired generation levels expected from each unit, occur every six seconds.

Voltage Support Service

Voltage Support, more formally known as Reactive Supply and Voltage Control Service (“Voltage Support Service” or VSS), is necessary to maintain transmission voltages within acceptable limits. Facilities under the NYISO control are operated to produce or absorb reactive power, as necessary, to maintain transmission voltages within acceptable limits.

VSS facilities must meet a number of criteria to be eligible to participate. For example, they must have demonstrated the ability to produce and absorb reactive power within specific limits, be able to maintain a specific voltage level under both steady-state and post-contingency operating conditions, and be capable of automatically responding to voltage control signals. In general, eligible VSS providers are generators with automatic voltage regulators, synchronous condensers, and qualified non-generator Voltage Support Resources.

Payments to eligible providers are based on an annual VSS rate established by the NYISO. Generators that are given energy delivery schedules may be eligible to receive lost opportunity costs under certain circumstances when dispatched for voltage support reasons. VSS providers can also be assessed penalties if they fail to provide VSS as directed or if they fail to maintain their automatic voltage regulators.

Synchronized and Non-Synchronized Reserves

To ensure reliable operation of the bulk power system, the NYISO's "Operating Reserve Service" provides needed reserves in the form of generation or demand response if a real time power system contingency requires emergency corrective action. The NYISO provides markets for 10-minute spinning, 10-minute non-synchronized, and 30-minute non-spinning reserves with a NYCA-wide requirement as well as an Eastern and Long Island requirement and a Long Island requirement.

The minimum reserve requirements are based on the largest single "contingency" (in MW), as defined by the NYISO. Providers of Operating Reserves must be properly located electrically and geographically to ensure the ability to deliver energy reserves as necessary. The NYISO must procure sufficient Operating Reserves to comply with applicable Reliability Rules and standards. All suppliers of Operating Reserves must be located within the New York Control Area, and under NYISO Operational Control.

The NYISO administers two ancillary services markets (Day Ahead and Real-Time) through which LSEs can procure needed resources for required Operating Reserves. Each supplier that bids into these markets must be able to provide electric energy or reduce demand when called upon.

Black Start Services

In the event of a partial or system-wide blackout, Black Start Capability Service is provided by generators having the ability to re-start their facilities without the need for an external supplier of electricity. Such black start generators are either under the control of the NYISO or, in some cases, under the control of the local Transmission Owner. The NYISO selects the generating resources with black start capability by considering a number of design and operating characteristics, including electrical location, startup time in response to a NYISO order to start, response rate, and maximum power output.

Generation resources providing black start service must successfully conduct and pass annual black start capability testing. Payments for service, called Restoration Services payments, are provided under the NYISO's Open Access Transmission Tariff. Any Generator awarded Restoration Services payments that fails a Black Start Capability Test must forfeit all payments for such services since its last successful test.

Demand Side Services

The NYISO also administers a Demand Side Ancillary Services Program (DSASP) intended to facilitate economic use of demand side resources to meet electricity needs. Participation is allowed for interruptible loads for Spinning Reserves or Regulation. Loads with qualified behind-the-meter generation may provide Non-Synchronous Reserves. The minimum resource size is 1 MW and there is a \$75/ MWh minimum bid. The payment is the Regulation or Reserve clearing price.

NYISO Demand Response Programs

The NYISO also administers several different demand response programs. These include the Special Case Resources Program (SCR), the Emergency Demand Response Program (EDRP), and the Day Ahead Demand Response Program (DADRP)²⁹.

²⁹ See the description of energy markets for a discussion of the DADRP.

Special Case Resources

Participation in the NYISO's SCR Program is open to interruptible loads or loads with a qualified behind-the-meter Local Generator. There is a minimum of 100kW reduction, and participation is mandatory during reliability events. There is a mandatory test each capability period and capacity can be sold either in a bilateral contract or through the NYISO capacity auctions. Payments are in capacity and energy payments.

Emergency Demand Response

Participation in EDRP is open to interruptible loads or loads with a qualified behind-the-meter generator. Load reduction is voluntary and there is a minimum of 100 kW reduction for participation. Participants are compensated through an energy payment equal to the greater of \$500/ MWh or the applicable real-time LBMP.

APPENDIX B

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