STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

# ORDER ADOPTING A RATEMAKING AND UTILITY REVENUE MODEL POLICY FRAMEWORK

Issued and Effective: May 19, 2016

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on May 19, 2016

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Patricia L. Acampora
Gregg C. Sayre
Diane X. Burman, concurring

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

# ORDER ADOPTING A RATEMAKING AND UTILITY REVENUE MODEL POLICY FRAMEWORK

(Issued and Effective May 19, 2016)

BY THE COMMISSION:

## INTRODUCTION AND SUMMARY

### A. Introduction

Drawing from an exhaustive analysis of trends in technology, markets, and environmental policy, the Commission has concluded that its core statutory duties can no longer be met with the utility regulatory model of the previous century.[1] The February 2015 order adopting a regulatory policy framework for REV (the "Framework Order") described the need to reform the utility business model and to align ratemaking practices with an evolving set of regulatory and policy objectives.

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[1] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (Framework Order).

The ratemaking changes adopted in this order add to other actions taken by the State and by this Commission under REV to enable the growth of a retail market and a modernized power system that is increasingly clean, efficient, transactive and adaptable to integrating and optimizing resources in front of and behind the meter. The focus of this decision is to create a modern regulatory model that challenges utilities to take actions to achieve these objectives by better aligning utility shareholder financial interest with consumer interest. We build from the conventional cost-of-service ratemaking approach to add a combination of market-based platform earnings and outcome-based earning opportunities. Utilities will have four ways of achieving earnings: traditional cost-of-service earnings; earnings tied to achievement of alternatives that reduce utility capital spending and provide definitive consumer benefit; earnings from market-facing platform activities; and transitional outcome-based performance measures. These additional measures are collectively intended to create a regulatory environment where utilities can create shareholder value, comparable to or superior to conventional investments, by integrating third-party solutions and capital that improve the efficiency, resiliency and flexibility of the physical networks, reduce consumer total costs and achieve the State's policy objectives.

Three principles of the Framework Order are particularly relevant to the reform of ratemaking. First, the unidirectional grid must evolve into a more diversified and resilient distributed model engaging customers and third parties. Second, ensuring universal, reliable, resilient, and secure delivery service at just and reasonable prices remains a function of regulated utilities. Third, and critically important to this order, the overall efficiency of the system and consumer value and choice must be improved by achieving a more productive mix of utility and third-party investment.[2]

Achieving these objectives requires a review of traditional ratemaking practices. All ratemaking encourages some actions and discourages others. The traditional revenue model encourages investment in a utility system that is based on central station generation, unidirectional flows (both of power and transactions) and minimal elasticity of demand.

While cost-of-service ratemaking has served reasonably well for the last century, it was developed under several assumptions that may no longer hold. First was that the customer demand driving capital investment was largely beyond the influence of utilities and regulators. Second was that economies of scale almost invariably favored large utility-scale investments. Third was that the need to instantaneously balance supply and demand, coupled with the obligation of reliable universal service, inevitably required large expenditures for redundancies throughout the system. Fourth was that end-use customers were the only substantial source from which system costs can be recovered.

Another assumption, which has defined the limits of ratemaking, is that information regarding cost of service is asymmetrical, i.e. utilities will have a far better understanding than regulators do of actual business costs and potential alternatives. The problem of asymmetry, combined with the assumptions described above, drives regulators to accept a sub-optimal approach to ratemaking that is risk-averse and provides utilities with little incentive to seek out innovative solutions that can increase customer value or reduce system costs. With recent advances in information technology and

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[2] Ibid. p. 16.

automation, the structure of competitive markets outside of the utility industry has changed dramatically. This allows the assumptions that have framed traditional ratemaking to be questioned. Across all aspects of the economy, customers' ability to compare options and maximize value has increased greatly, placing competitive pressure on companies that fail to adequately focus on generating consumer value. Technology allows competitive industries to improve capital productivity by reducing excess inventory and increasing asset utilization. Technology also enables innovative marketing strategies – such as reservation sharing in the airline industry - that allow competitors in capital-intensive industries to further improve productivity.[3] Consequently, in many sectors, the traditional provider's role has evolved to a platform service that enables a multi-sided market in which buyers and sellers interact. The platform collects a fee for this critical market-making service, while the bulk of the capital risk is undertaken by third parties.

Until recently, regulated distribution utilities have been insulated from the opportunities and the competitive pressures of the modern information economy. As a result, gains in capital productivity remain low and the efficiencies made possible by information technologies and new business models have been slow to materialize in the utility sector.

The Framework Order described how the widening gulf between the competitive realities of the modern economy and the regulated utility model of the previous century makes the *status quo* unsustainable. The combination of large impending infrastructure needs, decreasing system efficiency, environmental demands, weather and customer driven resilience

[3] This new mode of business is sometimes referred to as "coopetition."

requirements, and an increasing ability for customers to choose other options, present challenges to utilities and regulators that are both constructive and disruptive. Left unaltered, the current utility and regulatory model could lead to uneconomic grid defection and eventually result in stranded investments and increasing financial challenges.

Innovations in ratemaking can create new financial opportunities for utilities in response to the challenges of the modern marketplace. Utility regulation should perform the functions that competition would otherwise play in a market, e.g. management of entry, setting efficient prices, and prescribing quality and conditions of service.[4] Regulatory models need to evolve in response to competitive advances and challenges presented by the digital economy.

While many parties have argued that change in traditional methods must occur with caution and deliberation, no party made a convincing case that the utility model envisioned in REV will be adequately served for the indefinite future by *status quo* ratemaking approaches.

Utilities as delivery companies will retain many of the attributes of natural monopolies, and will still need to deploy large amounts of capital with an opportunity to earn a fair return. Increasingly, however, and complementing the opportunity to earn a fair return, earnings must be connected to increased consumer value. Consumer priorities vary; however, the ability to choose the source of supply, manage energy costs and ensure reliability and resiliency are consistent themes. To serve consumer requirements, utilities must be prepared to design and operate systems that are adaptable and supportive of third-party investments that increase both the system and

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[4] See, e.g., Kahn, Alfred, The Economics of Regulation: Principles and Institutions (1988), p. 17.

economic efficiency of the fully integrated grid. System efficiency will require more cooperative and productive arrangements among regulated utilities, non-utility developers, and consumers. New earning opportunities will be a combination of outcome-based performance incentives and revenues earned directly from the facilitation of consumer driven markets. In this manner, regulation will ensure that the utilities have the opportunity to align with the interests of their customers and embrace, instead of resisting, the rapid innovation that is occurring in the sector.

An example of an early step toward cooperative arrangements is represented by non-wires alternative projects such as Consolidated Edison's Brooklyn Queens Demand Management program (BQDM). While BQDM is groundbreaking from the standpoint of system planning and operations, it also demonstrates the new direction in ratemaking established here. Recognizing that the utility is displacing capital investment with operating expenses, and thus foregoing the growth of its rate base, the Commission authorized a return on total program expenditures, as well as performance incentives tied to the achievement of goals that will produce customer savings. While the details in approaches will evolve, BQDM represents a new direction of aligning utility financial incentives with the best interests of customers.[5]

The public interest is best served when utilities' economic objectives are decisively and substantially aligned with public policy and consumer interests. In our role as regulators we are most effective when we clearly establish the

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[5] Case 14-E-0302, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program, Order Establishing Brooklyn/Queens Demand Management Program (issued and effective December 12, 2014).

desired policy objectives and create the appropriate financial inducement for utilities and markets to pursue them. The critical challenge that REV creates is to develop the regulatory environment in which a utility will naturally and aggressively pursue system solutions that simultaneously create consumer benefit and increase the utility's earning opportunity. For this to occur effectively, the approach of tying innovative third-party solutions that provide customer value to earnings that are comparable to or superior to traditional earnings, must mature to be ubiquitous within the utility financial, operating, and planning model.

New York and many other states have used performance incentives for years to encourage reliability, customer service, and other priorities. Performance incentives are a useful tool in a cost-of-service ratemaking context, but present numerous theoretical and practical issues, as illustrated by the wide range of party comments in this case. Taking the difficulties of large-scale incentive mechanisms into consideration, we adopt an approach that uses outcome-based earning opportunities, targeted toward results that will create consumer savings and enable and build market activity, with an assumption that the need for regulated incentive mechanisms will be continually reviewed in light of progress in the development of transactive markets.

While regulated performance incentives will play an important role in establishing markets, over time revenues will be earned increasingly from the facilitation and operation of more transactive retail markets. The platform function of utilities in a mature distribution-level market will generate revenues from third-party market participants. These revenues can be used both to offset traditional revenue requirements, and to provide utilities with financial incentives to promote the most efficient mix of third party and utility investment.

This approach is designed to maintain reliable service and sound utility finances, while encouraging utilities to meet evolving customer expectations and enable market dynamics to increase capital productivity in the system taken as a whole. This whole-system approach to capital efficiency follows from the vision explained in the Framework Order, in which the integrated electric system will be treated as "a single machine … [meaning] that each customer premise and every power consuming device is, in actuality, part of the grid."[6]

The immediate subject of this order relates to financial incentives for REV activities such as DER integration and grid modernization. There is no fixed line, however, between "REV" activities and "conventional" activities, and that distinction will grow less relevant as improved information and market tools enable a wider reach of the whole-system approach to efficiency. Various efforts to improve cost-of-service ratemaking, including price cap regulation, have all encountered the obstacle of information asymmetry. With improved access to system and customer information, through the DSIP and data access processes established in REV,[7] visibility of market and profit opportunities will be greater for all parties. As a result, historical concerns on our ability to monitor utility costs are mitigated by the information transparency and ease of consumer access that characterize more competitive markets and multi-sided platform businesses.

The regulatory counter to information asymmetry is power asymmetry, i.e., regulators have the last say in ordering

[6] Framework Order, p. 8.

[7] "DSIP" is an acronym for Distributed System Implementation Plan, see infra.

specific activities, setting prices and levying revenue adjustments. As DSIPs, data access, and transparency in market transactions reduce information asymmetry, the Commission will need to adopt a new approach to its own exercise of authority. Rather than specifying or pre-approving all of the actions it believes need to be taken, the Commission will allow markets to bring forward the best options to achieve the broad policy objectives identified by the State.

The whole-system approach will also require reforms in the area of rate design. As the customer side of the grid becomes a system resource, and customers increasingly make investments in energy generation, storage, and management technologies, the efficiency of those investments will be a direct function of the price signals experienced by customers. Rate design must provide more efficient value signals, both in the rates paid by customers for utility service, and in compensation earned by customers for value that energy management and distributed generation can provide to the system.

Just as reform to utility revenue models must be done in a way that maintains reliable service, reasonable costs, and sound utility finances, reforms to rate design must accommodate factors such as equity and gradualism that have long been fixtures of rate design policy.

Ratemaking, by its nature, is an exercise in pragmatism, balancing a range of conflicting priorities in an atmosphere of incomplete and asymmetric information. There is no single ideal formula. Instead, there is the constant work of adjusting existing practices to meet new circumstances. Where circumstances change dramatically, as they are doing with the emergence of the distributed grid, then dramatic changes in ratemaking must be considered. Some parties have questioned whether the market reforms proposed in the Staff White Paper[8] are necessary or realistic. The direction of this order is to remove barriers so that markets may show that they can produce superior results. Markets cannot prove out their potential unless the opportunities are opened.

With this direction we begin a new turn toward a modernized utility business model, developing earnings opportunities for utilities that are aligned with consumer value and with a more efficient and resilient distributed low-carbon electric system. More effective value signals to provide incentive and reward for customers to manage their bills and usage will be essential. We provide directional guidance for long-term reform and a carefully measured set of near-term actions designed to facilitate needed change and meet policy objectives, while maintaining traditional principles of gradualism, equity, and opportunity to earn fair returns on investment.

B. The Staff White Paper

On July 28, 2015, Staff issued a White Paper for comment and discussion. The White Paper discussed an extensive set of issues related to ratemaking in the context of REV, and included 20 recommendations ranging from incremental near-term measures to far-reaching changes in regulatory direction.

The White Paper began by articulating a set of foundational principles to guide the development of a new ratemaking model:

- Align earning opportunities with customer value
- Maintain flexibility

[8] Case 14-M-0101, supra, Staff White Paper on Ratemaking and Utility Business Models (White Paper), filed July 28, 2015.

- Provide accurate and appropriate value signals
- Maintain a sound electric industry
- Shift balance of regulatory incentives to market incentives
- Achieve public policy objectives

The White Paper described at length the inadequacies of traditional ratemaking methods in the context of a decentralized, market-oriented utility system, concluding that, "A new ratemaking approach must support the emergence of the modern utility whose economic interests and financial growth are distinctly and firmly aligned with its customers' interests in total bill management and the encouragement of DER provider investments and operations that help provide these benefits."[9]

Following these principles, Staff discussed three categories of reform:

- Market-oriented utility business models
- Incremental reforms to traditional utility revenue models
- Rate design changes to provide accurate value signals while meeting public policy objectives

1. Market-Oriented Revenue Models

The White Paper analyzed the ways in which the traditional cost-of-service ratemaking paradigm incentivizes utilities. The paper concluded that while cost-of-service regulation has served adequately in the context of a centralized system with steadily growing load, it fails to provide incentives to innovate and to adjust to rapidly changing market, technology, and environmental factors. The overall intention of Staff's package of recommendations is to "offer utilities the

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[9] White Paper, p. 27.

opportunity to thrive in a changing environment if they succeed in meeting customer-oriented objectives."[10]

The White Paper recommended a transition toward Market-Based Earnings (MBEs) for utilities, to complement conventional cost-based earnings and, eventually, to provide the bulk of utilities' financial incentives. (The concept of "MBE" as proposed by Staff is combined, in the discussion below, with Platform Service Revenues (PSRs). In order to avoid confusion, this order will use the term "PSRs" throughout.) PSRs would be earned by utilities through their provision of Distributed System Platform (DSP) services. Increased PSRs would encourage utilities to support access to their systems by DER providers, and offset required base revenues derived from ratepayers. While the White Paper acknowledged that this transition would take a considerable length of time, it recommended that demonstration projects and other initiatives should be oriented toward developing PSR opportunities. The ultimate purpose of the transition is to create "a business and regulatory model where utility profits are directly aligned with market activities that increase value to customers."[11]

To complement the development of PSRs, Staff recommended a set of new incentive measures or Earnings Impact Mechanisms (EIMs). (As explained below, this order will adopt the term "Earnings Adjustment Mechanism" (EAM) and to avoid confusion will use the term EAM throughout.) EAMs are oriented toward near-term measures to create customer savings and to develop market-enabling tools. Over time, as PSRs become a larger component of utility revenues, the need for EAMs should

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[10] Id.

[11] White Paper, p. 10.

diminish as utilities enable the success of markets in order to enhance their own earnings.

The EAMs recommended by Staff for immediate adoption relate to:

- Peak reduction
- Energy efficiency
- Customer engagement
- Affordability
- Interconnection

Staff further recommended adjustments to two current ratemaking mechanisms – net plant reconciliation or "clawback", and earnings sharing mechanisms (ESMs). Staff proposed extending rate plans to five years under some circumstances, in order for utilities to have time to achieve results. Staff also discussed the possibility of eliminating the distinction between operating and capital expenses (the "totex" approach) to remove any bias toward return-earning capital expenditures.

2. Rate Design

Staff analyzed rate design in the context of REV and found that, much like the utility revenue model, current rate design practice fails to provide adequate incentives and value signals. Traditional rate design formulas evolved in an era before modern information technology was available, and in which the customer side of the utility system was not widely engaged as a participatory resource. Staff stated, "The combination of cost, reliability, environmental, and competitive challenges facing the industry require that resources be optimized at the customer end of the system as well as the centralized production end."[12] The crux of the issue, according to Staff, is that "residential and small commercial customers are not provided with information about the true components of cost or the means to effectively respond to the price signals such information can provide."[13] Rather than simply allocating costs, rate design should be used to send value signals that enable the reduction of total system costs in the long run.

To guide a transition to a modern rate design, Staff distinguished among types of customers:

- Traditional consumers — those customers who do not choose to actively manage their energy usage, or for whom it is difficult to do so[14]
- Active consumers — those customers who undertake DER measures that allow them to actively modulate their usage in response to rate signals with the purpose of reducing their bills
- Prosumers — those customers who install or participate in DER including generation or other technologies that allow them to provide services to the grid

Staff further identified the dimensions along which granularity should be developed:

- Temporal — time-differentiating prices that vary in response to marginal price
- Locational — reflecting congestion or capacity constraints in pricing; for example, locational marginal pricing or distribution locational marginal pricing
- Attribute — unbundling rates to reflect the individual attributes embedded in electricity service; for

[12] White Paper, p. 11.

[13] White Paper, p. 74.

[14] Consumers who rent their homes, reside in multi-family or mixed-use facilities, and/or do not have individual metering may lack either an economic incentive or practical access to manage their energy usage by investing in DER.

example, energy, capacity, ancillary services, environmental impacts, or others

Finally, Staff proposed a set of rate design principles to guide reforms under REV:

- Cost causation
- Encourage outcomes
- Policy transparency
- Decision-making
- Fair value
- Customer-orientation
- Stability
- Access
- Gradualism

Staff's specific rate design proposals were divided into near-term specific recommendations and long-term directional proposals that will need further process. The near-term recommendations made by Staff were:

- Utilities should file voluntary smart-home tariffs
- Opt-in time of use rates should be improved
- Rates for large customers should be examined to improve their reflection of time variability
- Low-income discounts should be located within a basic usage block
- Standby rates should include a reliability credit and a campus tariff

Long-term recommendations were:

- Analyze potential bill impacts of demand-based and default time-varying charges
- Review cost allocations for potential revisions to standby rates

In addition to changes in customer rates, Staff proposed that a method should be developed for valuing the contributions of DER. This method is applicable generally to markets for DER and specifically to suggested reforms of net energy metering (NEM). Staff proposed that NEM for small rooftop installations should be retained, and that monetary credits involved in larger NEM projects should reflect more granular valuations of the value of DER.

3. Party Comments

Comments and replies were submitted by 52 parties. A full summary of party comments is attached as Appendix C, and relevant party comments are referenced in the discussion of individual issues. For purposes of defining our approach to the Track Two issues, several general themes in the party comments are particularly important.

First, while parties expressed a wide range of views on the issues discussed in the White Paper, most parties stated their support for the overall purposes of the REV initiative, and made it clear that their ratemaking comments should be read in that context.

Second, parties who are typically on opposite sides of rate cases – utilities and customer advocates – all recommend caution in departing from the cost-of-service approach to utility revenues.

Third, most parties agree that some form of market-based earnings can play an important role in utility revenues; however, DER providers are concerned that market-based earnings should not become a vehicle for utility domination of competitive markets.

Fourth, there are significant disagreements around the theoretical basis for utility incentives, e.g. whether they should be linked to market outcomes versus direct utility control, and the relative value of positive, symmetrical, and negative adjustments.

Fifth, although there is general agreement on the basic principles of rate design, parties disagree strenuously on the application of those principles to particular issues. Comments on rate design reveal outcome-driven divisions that are tied to the rational interests of various adversarial constituencies.

## C. Context of the Order and the Pace of Reform

### 1. Context

In the two years since this case was initiated, the Commission focused its efforts on examining the assumptions, defining the task, and establishing policy direction for the modern retail electric utility industry and markets. Our work product throughout has benefited from written comments, Staff papers, technical conferences, an extensive series of party working groups, and directed studies of critical topics.

As we observed in the Clean Energy Fund Order, the primary focus of REV has switched from conceptual policy to practical implementation.[15] Specific changes established over the last several years to begin the transformation have already shown results. These include NY Sun which has supported installed solar levels of 457 MW as of the end of 2015, the NY Green Bank, which allows ratepayer funds to be leveraged multiple times to support achievement of clean energy objectives, and utility demonstration projects that provide utilities and third parties multiple opportunities to form

[15] Case 14-M-0094, Proceeding on Motion of the Commission to Consider a Clean Energy Fund, Order Authorizing the Clean Energy Fund Framework (Issued and Effective January 21, 2016).

partnerships and new business models to create substantial consumer value. In several ongoing processes, we are establishing the implementation blueprint that will build on these early successes and create the regulatory and market systems of a transformed electric industry:

- The Clean Energy Fund, which sets guidelines that support the New York State Energy Research & Development Authority's (NYSERDA's) plans to focus on the fundamental market barriers to clean energy adoption and, in cooperation with the utilities and third parties, drive the systematic changes that support sustainable and independent market growth;[16]
- The Benefit Cost Analysis (BCA) framework that provides for a consistent and comprehensive approach to ensuring that investments properly consider economic and environmental consequences;[17]
- Guidance for Distributed System Implementation Plans in which utilities will integrate REV objectives into their customary planning process by identifying system needs, potential non-wires alternatives, standards for access to system information, and detailed strategies for building the capability to function as Distributed System Platforms;[18]

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[16] Ibid.

[17] Case 14-M-0101, supra, Order Establishing the Benefit Cost Framework (issued January 21, 2016).

[18] Case 14-M-0101, supra, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016).

- A process for determining the full value of DER, for both planning and transactional purposes;[19]
- Demonstration projects oriented not only toward new technologies but also toward developing customer engagement and new utility revenue opportunities;[20]
- Standards to enhance access to customer data for customers and market participants including privacy and security safeguards;[21]
- Improved processes for interconnection of distributed generation projects including PV and combined-heat-and power;[22]
- Improved approaches to affordability of electricity for low-income customers;[23]
- Community Distributed Generation and Community Choice Aggregation rules to allow municipalities and smaller groups of customers to act in combination to control costs and participate in distributed energy options;[24]

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[19] Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources.

[20] Framework Order, p. 97.

[21] See infra.

[22] Case 15-E-0557, In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Distributed Generators 2 MW or Less.

[23] Case 14-M-0565, Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers.

[24] Case 14-M-0224, Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs; Case 15-E-0082, Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program.

- Approval of advanced metering infrastructure to enhance system operations and to enable market participation by consumers;[25] and
- Requirements for each utility to propose and implement a Dynamic Load Management program to reduce peak costs, increase system reliability, and build the market capabilities of the DER industry.[26]

The Commission's recent order adopting the terms of a Clean Energy Fund articulated four integrated principles for this implementation process:

- First, our targets will be clear and ambitious. The 2015 New York State Energy Plan includes a target to meet 50% of the State's electric consumption with renewable resources in 2030, as well as targets of a 40% reduction in greenhouse gas emissions from 1990 levels and a 600 trillion Btu increase in statewide energy efficiency.
- Second, we must revise the policies and practices governing how we regulate utilities and their business practices, impose obligations, and oversee retail market design, including rates and prices for electric service, to make certain that our regulatory practices are consistent with the changes that need to occur.
- Third, we will reexamine how we use the tools of incentives and financial support for clean energy technology and markets to reduce costs, drive scale and reduce barriers to entry.

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[25] Case 15-E-0050, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions (issued March 17, 2016).

[26] Case 14-E-0423, Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs, Order Adopting Dynamic Load Management Filings with Modifications (issued June 18, 2015).

- Fourth, the state will lead by example in its participation as an energy consumer and provider.[27]

This order complements these implementation principles, as well as the Framework Order, by addressing the second of the pillars described above. While policy issues around ratemaking and business models are by no means closed following this order, a basic direction is established, as well as a number of near-term actions and further process toward longer-term actions.[28]

2. Transition

The pace of reform, and the methods of achieving it, must be considered and undertaken with great care. Parties on different sides expressed mutual concern that ratemaking reforms should proceed at a deliberate pace with quantitative analysis, demonstration, and public participation. We agree. Ratemaking reforms will proceed deliberately and with regard for traditional ratemaking principles. We will not, however, artificially restrict the pace of change where it is driven by the success of markets and new technologies. The structures put into place in this order will be adaptable to the pace established by market participants.

Over the course of the twentieth century, the electric industry became a foundational component of economic stability and growth. Reliability, affordability and universal availability of electricity have long been recognized as critical priorities. The rapid digitalization of the economy in

[27] Case 14-M-0094, supra, Order Authorizing the Clean Energy Fund Framework (Issued and Effective January 21, 2016), pp. 2-3.

[28] As well as the generic proceedings detailed above, REV implementation will also continue to occur in rate proceedings and other individual utility proceedings.

our current century, as well as the challenge of climate change and the increasing electrification of transportation and building end uses, create an even greater imperative to ensure that industry regulation and electric markets are maximally effective.

As we proceed towards a business model for a power system that is more nimble, distributed and consumer focused, we will continue to observe enduring regulatory and market principles that ensure consumer, investor and policymaker confidence. This requires a careful balance of immediate regulatory changes to support necessary systemic changes with ensuring that the needs of consumers of all types are met, that the industry remains financially attractive to capital markets, and that new entrants can invest and build businesses with confidence in our markets. To this end, the actions ordered here will include near-term measures oriented toward foundational elements of REV, and longer-term initiatives that will include extensive additional public involvement and party scrutiny.

While we will remain pragmatic in our approach, we also emphasize that neither regulators nor industry participants should rest on an assumption that regulation and business models always need to adapt slowly and modestly to consumer demands and technology innovation. As the Framework Order explained, the need to develop a demand-responsive, climate-friendly, information-centered electric system does not afford us with the luxury of time. With billions of dollars of infrastructure investment impending, as well as carbon reduction requirements and rapid improvements in customer-side technology, the historic pace of regulatory change is inadequate. Recent developments in this and other industries demonstrate that slow and deliberate progress is not always an option and may no longer be acceptable.[29] Accordingly, if New York is to succeed in achieving the compelling reforms that are necessary in this century without sacrifice to the enduring public interest principles enumerated above, we must establish regulatory platforms that allow and support faster adoption of business model change.

D. Summary of the Order

Policy direction is established in the Introduction and elaborated in the discussion of specific issues below. Cost-of-service ratemaking, while it will remain applicable to conventional utility investments for the near future, inhibits innovation in general, and discourages numerous activities that utilities need to undertake to implement REV. Consumers benefit when utilities aggressively pursue more economic alternatives to traditional rate based capital investment. Consumers also benefit when cost-effective energy efficiency and distributed energy resources are integrated into utilities' basic business operations.

Utility revenue opportunities must be expanded to more closely align utilities' financial interests with the consumer benefits from these elements of a modernized electric system. As utilities develop capabilities to implement platform functions, and markets develop around these functions, utilities must have the opportunity to earn platform revenues that offset the need for traditional revenue requirements and support innovation throughout the energy value chain to produce the most economically efficient mix of resources on the system.

[29] The Commission will continue to monitor utilities' progress throughout the implementation process. The Commission stated in the Framework Order, "if DSPs are failing to meet the objectives of REV, we will consider options to allow other entities to serve that function." Framework Order at 45.

Efficient markets will require more precise value signals and access to system and customer data. In the interim, and while the market is developing, outcome-based incentives are required to encourage growth of markets, the efficient use of capital toward lower total system costs, and achievement of State policy goals.

Specific measures

Measures decided or initiated in this order include the following:

1. Earning opportunities.[30]

(a) Platform service revenues: Platform service revenues are new forms of utility revenues associated with the operation and facilitation of distribution-level markets. In early stages, utilities will earn from displacing traditional infrastructure projects with non-wires alternatives. As markets mature, opportunities to earn with PSRs will increase. A process is established to facilitate the approval of products and services that could generate PSRs, and for the pricing of those services and the allocation of revenues between ratepayers and shareholders. This process will distinguish between (a) services that the Commission will require the utility to provide as part of market development; (b) voluntary value-added services that are provided through the DSP function that have an operational nexus with core utility offerings; and (c) competitive new services that can be readily performed by third parties, including non-regulated utility affiliates, and should not be offered by regulated utilities. A set of criteria is established to ensure that utilities have the opportunity to

[30] All specific earning opportunities will be subject to reevaluation as markets develop.

develop new revenues without intruding into arenas best served by competitive markets.

(b) Earning Adjustment Mechanisms: Guidelines are provided for the scope and structure of potential incentives, and outcome-based incentives are discussed for several categories:

- System efficiency: Each utility will propose a peak reduction target and a load factor improvement target. Each proposal will meet a list of requirements including targets, an analysis based on the BCA framework, and a proposed incentive for economic savings. These may include complementary strategies to build electric load, improve load factor, and reduce carbon emissions such as encouraging conversion to electric vehicles, geothermal heat pumps, and other efficient and beneficial uses.
- Energy efficiency: The Clean Energy Advisory Council will develop targets for energy efficiency beyond the existing Energy Efficiency Transition Implementation Plan and Clean Energy Fund targets. Positive earning opportunities will be developed for utilities to achieve and exceed the developed targets.
- Customer engagement: Because customer engagement underlies many other earning opportunities, and because the principal tools are mandated, no general EAM is required. Utilities will be able to propose positive opportunities based on customer uptake in innovative engagement programs.
- Interconnection: A positive earning opportunity will be developed based on satisfaction surveys of DER providers regarding utilities' progress in timely and cost-effective interconnection approvals. Satisfactory achievement of a baseline level of SIR timing requirements will be a threshold condition for earning positive adjustments. The Commission will also consider on a case-by-case basis negative earning adjustments for failure to meet established standards.
- Affordability: In accord with the recommendations of low-income advocates, affordability metrics will be established as scorecards rather than EAMs, and financial incentives will be established in rate cases as appropriate. Low-income issues in general will be considered in Case 14-M-0565.

(c) Greenhouse Gas reductions: In a separate proceeding, the Commission is considering a Clean Energy Standard (CES) to achieve the State's target of 50% renewable generation by 2030.[31] Utilities should have earning opportunities tied to reducing the overall cost of achieving the CES goal. The specific nature of opportunities will depend on policy and implementation decisions that will be made in the CES proceeding. Utilities will also be encouraged to propose programs to accelerate the conversion of transportation and building end uses to efficient electric alternatives.[32]

2. Competitive market-based earnings: Unregulated utility subsidiaries are authorized to engage in competitive value-added services. To engage in these activities the utilities must have in place standards of conduct to avoid affiliate abuse, to be monitored by the Commission.

3. Data access. The conditions under which utilities may charge for individual customer usage data are established. Standard reporting of aggregate customer data is provided for. Certain basic levels of information will be free of charge, while utilities may charge a fee for provision of more refined data or analysis.

4. Clawback reform: During a rate plan, utilities will be encouraged to displace capital expenditures with third party DER investment where cost-effective.

5. Standby service: Utilities will establish campus tariffs and reliability credits, and will begin a process to modernize the calculation of standby tariffs to ensure that they do not create an unnecessary barrier to entry.

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[31] Case 15-E-0302, supra.

[32] Such conversion programs could serve the purposes of system efficiency and carbon reduction,and care will be needed to ensure consistent treatment.

6. Opt-in rate design: Voluntary participation in advanced rate design will be encouraged in two ways:

- Opt-in time of use rates: Each utility will examine its existing Time of Use (TOU) rates with reference to rates in other jurisdictions that have higher participation; each utility will also develop improved promotion and education tools.
- Smart Home rates: Utilities will collaborate with NYSERDA and third parties to develop Smart Home Rate pilots.

7. Large customer demand charges: Rate cases will examine the existing demand charges applicable to commercial and industrial customers to determine if they can be made more time-sensitive.

8. Scorecard metrics: A non-exclusive list of ten scorecard measures is adopted, and a collaborative process will be conducted to establish metrics for each measure.

9. Mass-market rate design: Staff will work with stakeholders, and will report to the Commission, regarding the scope of an analytic approach to examine bill impacts, for various classes of customers, of a range of opt-out variable rate scenarios including time-of-use rates, demand charges, and peak-coincident demand charges.

## E. Process

This order is a continuation of a process that started in December 2013, when the Commission ordered Staff to begin a re-examination of our regulatory paradigms and markets.[33] Staff issued a Report and Proposal on April 24, 2014, and the Commission initiated the present proceeding. On May 1, 2014, a

[33] 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).

list of 26 questions related to ratemaking was issued to parties, and 18 responses were filed. In addition, many comments related to ratemaking issues were offered at eight public statement hearings conducted by the Commission between January 28 and February 12, 2015. On July 28, 2015, Staff issued its White Paper on Ratemaking and Utility Business Models. A Notice of Proposed Rulemaking was published in the State Register on August 19, 2015 (SAPA 14-M-0101SP13). Fifty-two parties filed comments. Initial comments were filed on October 26, 2015 and replies were filed on November 23, 2015. Detailed summaries of party comments are attached as Appendix C. Nine additional public statement hearings were conducted between November 5, 2015 and February 1, 2016. In addition to the comments given at the public hearings, over three thousand comments have been received in this proceeding since the White Paper was issued. The overwhelming majority of those comments express concerns over climate change, urge a shift toward using renewable resources and express general support for the REV objectives. Throughout this process, Staff has conducted focus group meetings with representatives of customer advocacy, environmental, service provider, utility, and government interests.[34] Staff also conducted several technical conferences. Technical conferences on access to data were held on December 16, 2015, and January 20, 2016; 37 parties filed comments related to data. On January 28 and 29, 2016, Staff conducted a technical conference on several issues, mostly related to earnings incentives, at which all parties had an opportunity to engage in discussion.

[34] Staff's review was assisted throughout by the New York State Energy Research and Development Authority, the Rocky Mountain Institute, and the Regulatory Assistance Project.

## UTILITY REVENUES

### A. The Limits of Traditional Utility Revenue Models and the Need for Reform

#### 1. Staff's Review

Staff provided an extensive review of current ratemaking practices and the ways in which they may be inconsistent with the needs of a modern electric system.

Current methods of cost-of-service ratemaking provide two primary means of increasing total earnings over time: increasing rate base in the long run and decreasing operating expenses in the short run. The former is accomplished through capital investments recognized in rate plans. The latter is accomplished by spending less than the allowance that is built into rates.

Rate cases and regulatory review seek to limit capital costs to the lowest that is reasonably needed to serve system needs, while utilities have a natural incentive to grow the rate base to the maximum extent consistent with good utility operations and keeping rates at reasonable levels. Although increased capital spending does not raise the rate of return on investment, it does increase the total on which the return is earned. The information asymmetry inherent in the regulatory process makes it difficult for regulators to limit capital spending, because utilities have the best information as to their needs and the alternatives that might control spending.

At the same time, utilities are encouraged to achieve operating efficiencies because they are allowed to retain any difference between the amount allowed in rates and the amount actually spent. This incentive, however, is short lived because the actual spending level will be reflected in the next rate plan, at which time the allowed amount is adjusted downward. The result, in theory, is a long-term reduction in operating expenses paid by ratepayers. In practice, this cycle of tightening operating allowances may naturally drive utilities to favor capital expenditures over operating expenses.

The result of these concerns is that utilities under traditional ratemaking have little financial incentive to initiate long-term efficiencies, optimal balancing between capital and operating expenditures, or system improvements that are not expressly rewarded by regulators. These concerns have long been noted by regulatory economists.[35]

Staff's White Paper identified four basic priorities of utility regulation: operational efficiency, dynamic efficiency, consumption efficiency, and policy objectives.[36] Among these priorities, dynamic efficiency (i.e. forward-looking investment efficiency) is least well-served by the current framework for ratemaking. This attribute, however, is critically important in addressing the challenges that now face the electric system. Traditional concerns about dynamic efficiency are even more pronounced in the context of REV. REV contemplates expansion of system resources owned by customers and third parties, often as alternatives to traditional utility investments. REV also contemplates utilities relying on DER

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[35] See White Paper, pp. 18-21 and Appendix B of the White Paper. Staff also noted, and we concur, that utilities have other motivations, including professionalism and public service responsibility, and have made many incremental improvements over the years "despite the inherent disincentives of the ratemaking system." White Paper, p. 19. Nothing in this analysis of ratemaking incentives implies improper motives on the part of utilities. We simply assume that utilities are rational actors who should be expected to respond to the financial incentives that the revenue model creates for them. It is unknown, however, how many innovations and improvements may have been discouraged over the years by inherent rate disincentives.

[36] White Paper, p. 16, citing "The Future of the Electric Grid: An Interdisciplinary MIT Study" (2011).

through procurements that would traditionally be accounted for as operating expenses. Reliance on DER also reduces the direct control that utilities maintain over their systems, which can create the perception of increased risk.

Under traditional ratemaking, DERs encounter twin barriers: they displace the growth of utility rate base, and they add to operating expenses. After rates are set under a traditional rate plan, if a utility has a choice between an operating expense and a capital solution, it will tend to favor the capital solution. This is because the operating expense will decrease earnings dollar for dollar, net of tax, whereas the capital expense will only decrease the earned return by the fraction associated with the annual return and depreciation net of tax and will be allowed future recovery over time. Further, under the existing capex clawback mechanism, that capital expense solution will go toward ensuring that there is no clawback required.[37]

Some parties questioned the need for general reform to address any counterproductive incentives that might exist. Multiple Intervenors (MI) stated that the current system strikes a reasonable balance with respect to the large majority of utility expenditures. Nucor Steel Auburn, Inc. (Nucor) and New York City were skeptical whether utilities are motivated by capital bias. The Joint Utilities[38] argued that any perceived bias is countered by regulatory oversight.

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[37] The clawback mechanism is described in detail below.

[38] The Joint Utilities filed comments representing the views of Central Hudson Gas and Electric Corporation; Consolidated Edison Company of New York, Inc.; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation d/b/a National Grid; Orange and Rockland Utilities, Inc.; and Rochester Gas and Electric Corporation.

The Advanced Energy parties, whose DER services would be most affected by a capital bias, agreed with Staff that reforms are needed to place operating expenses on a level field with capital expenditures.

2. Discussion

Prior debates and reforms regarding cost-of-service ratemaking have occurred within the framework of a traditional unidirectional utility system. Those discussions tended to revolve around three concerns – lack of an incentive to innovate, bias toward capital expenditures, and asymmetry of information in the rate-setting process. In this order, we consider how those discussions extend to the framework of a modern distributed and bi-directional transactive electric system. The incentives implicit in traditional ratemaking must be evaluated for the manner in which they will affect a modernized electric system.

Staff accurately described how cost-of-service ratemaking contains implicit disincentives to innovate in developing improvements that meet consumer needs at a reduced level of expenditures. This is one of the principal shortcomings of the traditional method, and its implications for a utility transition to a platform role are clear.

The question of whether there is a bias toward capital spending is less important than the concern that utilities have a more general incentive to favor their own spending over third-party investment. Even if the difference between capital and operating expenditures were eliminated, utilities will still have incentives, both financial and institutional, to favor their own spending and their own facility investments. The current framework encourages a natural tendency in utilities toward investments that utilities make and control, versus an inclination to favor the use of third-party resources where they offer economic, reliability and environmental benefits to consumers and to the grid.

Information asymmetry is among the greatest challenges in cost-of-service ratemaking, but it also affects any alternative regulatory approach. The work of Nobel Prize-winning economist Jean Tirole is particularly instructive on this point. Tirole emphasizes that asymmetry of information regarding true costs, benefits, and alternatives impairs the efficiency of ratemaking. As Tirole states, regulated firms "have superior knowledge about their environment: their technology, the cost of their inputs, the demand for their products and services … [and] they take actions that affect cost and demand …"[39] Tirole concludes that, "authorities that neglect asymmetry of information fail to deliver effective, cost-efficient regulation."[40]

One alternative to cost-based regulation is price-cap regulation, which allows the utility to earn as much as it can by operating efficiently under a pre-determined fixed revenue cap. Tirole demonstrates that this alternative is also highly vulnerable to information asymmetry, and can result in unfairly high profits even compared with the suboptimal cost-of-service approach.[41] More novel approaches to revenues are needed to

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[39] Tirole, Jean, "Market Failures and Public Policy," Nobel Prize Lecture, December 8, 2014.

[40] Ibid., citing Caillaud, B. and B. Jullien, "Chicken & Egg: Competition among Intermediation Service Providers," RAND Journal of Economics, 34(2): 309-328 (2003).

[41] "While the poor incentive properties of rate-of-return and cost-plus regulation had already been recognized, the Laffont-Tirole model highlighted a subtle problem with price caps: high-powered incentives imply large rents to efficient firms, which is very costly if public funds are raised by distortionary taxation, or if the regulator has

counter the problem of information asymmetry as the industry enters an increasingly complex platform market environment.

The Joint Utilities, as well as several consumer advocates, are skeptical of the need for a marked departure from the cost-of-service revenue model. First, the utilities stated that REV should aim for the optimal mix among traditional utility investments and DER. Second, they observed that a transition to greater reliance on DER, and developing markets for DER, will take a considerable period of time. Third, they argued that utilities will need to make substantial investments in DSP capabilities to implement REV, and a cost-of service approach to recovering those investments will result in the lowest financial costs. New York City argued that there is no imminent need for a dramatic change from current methods.

We agree with each of these assertions to the extent that the Commission should proceed with deliberative caution in the changes that it makes. As we have affirmed, maintaining the financial integrity of the electric industry is crucial to the State's overall welfare and to the reliable and affordable delivery of electricity. None of these observations, however, refutes Staff's underlying analysis of the inadequacy of traditional ratemaking for a modernized system that maximizes capital productivity and consumer value by including advantageous third-party capital investment.

Utilities now have the ability to capture the value of customer-sited resources and a smarter grid to improve the reliability, resiliency, and value of the system. When enabled by adequate information and pricing, DER can drive greater

distributional objectives. To reduce these rents, optimal regulation will generally not induce first-best levels of cost-reduction." Tirole, J., "Market Power and Regulation," October 2014.

system efficiencies, increase system resiliency, facilitate the use of weather-variable renewable resources both in front of and behind the meter, and reduce the overall energy bill for the benefit of all New York customers.[42] The wide-ranging support among parties for the basic direction of REV, including from utilities, demonstrates a general recognition that the challenges and opportunities facing the electric system warrant a significant change in direction.

In order for utilities to enable these developments, they must take actions that run counter to the practices that are encouraged by traditional ratemaking. At the planning and operational level, this means enabling markets for distributed resources that will complement, and eventually transform, the centralized unidirectional system. At the revenue and earnings level, this means actively pursuing results that could be adverse to the interests of a utility under classical ratemaking. These results include lower sales volume, reduced capital expenditures, and greater reliance on market-driven outcomes as opposed to cost-of-service inputs.

Achieving the most productive mix of utility and third-party capital will require utilities to forego - and, crucially, to *plan* to forego - some level of capital investment on which they would ordinarily earn a return. Even if capital and operating expenses are treated identically, utilities will still be required to plan for a substantial level of third-party involvement in the system and, correspondingly, a reduced utility share of total expenditures. The disincentive is exacerbated as DSP markets mature and the utility acts increasingly as a platform to facilitate multi-sided transactions. Absent some change, the mix of resources that is

[42] Framework Order, pp. 14-29.

most effective and efficient from the whole system's perspective will not be consistent with the utility's inherent financial interest.

Due to both the critical importance of the power industry and its inherent complexity, there is an inertial tendency for regulation to preserve the status quo and to follow change, as opposed to developing mechanisms to facilitate or lead it. However, as we noted in the Framework Order, the fundamental changes occurring in technology, markets, and consumer demands create a greater risk to the State from ignoring these factors and straining to maintain existing systems. When regulators and companies ignore changing circumstances and set policies based solely on the rear view mirror, they do so at the peril of the constituencies they are seeking to protect and the financial integrity they are looking to preserve.

Just as many stakeholders argue that we retain the status quo, there are other representatives of consumers and new market entrants that are impatient for the future and are concerned that utilities are not up to the task of facilitating it. In the process leading to the Framework Order, some parties argued that the DSP function should be performed by an independent entity, because utilities would have inherent self-interest in promoting their own investments.

The Commission found that utilities should perform the DSP function due to operational and planning practicalities, but that several protections should be put into place: utilities are generally prohibited from investing in DER (with exceptions);[43] codes of conduct governing affiliate transactions will be

[43] Framework Order, pp. 66-72.

upgraded and enforced;[44] and utility system planning will be performed through a transparent process subject to Commission supervision.[45] These findings are echoed in a comprehensive analysis of this issue recently sponsored by Lawrence Berkeley National Laboratory.[46]

A fourth level of protection that is initiated here is to reform utilities' financial incentives, to remove or minimize any self-interest that might be opposed to the goal of a vibrant DER market, and to create new opportunities.There is no functional equivalent within the traditional ratemaking model to emulate the pressures and opportunities that modern competitive markets present, to enhance earnings through increased value to customers and partnerships with third parties.

The modernized role of DSP provider brings the utility business model closer to the platform model that is increasingly common among other industries, including telecommunications, financial markets, and internet services.[47] Platform economics promotes new business orientations and pricing structures in which many of today's most successful businesses thrive as intermediaries, through which market participants interact across their systems. Multi-sided platforms create a structure for bidirectional (or multidirectional) transactions and exchange of information, where the lines between producer and consumer may be blurred but positive network externalities are

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[44] Ibid., p 72.

[45] Ibid., p. 129.

[46] "Distribution Systems in a High Distributed Energy Resources Future," Berkeley Lab Report No. 2, October 2015.

[47] Claire M. Weiller and Michael G. Pollitt, "Platform Markets and Energy Services," Working Paper, University of Cambridge, Energy Policy Research Group, 2013.

created and innovation results in greater capital productivity.[48] Financial markets and automatic teller machines (ATMs), for example, match buyers to sellers and allow competing financial institutions to seamlessly communicate in the service of customers. Computers, tablets, and smart phones, and the operating systems on which they run, let third-party developers create new programs and applications, as well as facilitate access to customers who buy those services.

As the Framework Order described, the electric system has begun a transition toward a platform model. One result of this transition will be the opportunity for the electric system to take advantage of the efficiencies of platform markets.[49] The platform industries described above each offer case studies for the transition of the utility to a platform business that is customer oriented and drives value creation. They indicate new market designs in which updated pricing structures are required and earnings opportunities will be developed relying on payments other than those from utility ratepayers.

In light of both the disincentives inherent in cost-of-service regulation, and the opportunity inherent in transitioning to a platform market, we agree fully with Staff that a fundamental realignment of utility revenue incentives is needed. We also acknowledge that even if enabled by our regulatory processes, the change in institutional direction we anticipate for the utilities and the changes we are imposing through our policies and practices will not occur without continuous monitoring and measurement. Consequently, it will be critical as we move forward to constantly assess our progress

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48 T.R. Eisenmann, G. Parker and M. Van Alstyne, "Strategies for Two-Sided Markets," Harvard Business Review, October 2006.

49 Weiller and Pollitt, 2013, supra.

and be prepared to make changes in direction, including the role of individual utilities as the DSP, if warranted by the facts.

Finally, we also agree with parties who argue that even with regulatory reform, there will be substantial utility investment in conventional rate-based infrastructure, and that reform must be carefully modulated to avoid costly and counter-productive changes in financial risk. The broader economy has innumerable examples of traditional industries and business models disrupted by new models that are enabled by technology. The electric industry, however, is unique. Socially and economically it falls within a small group of services that are indispensable to modern living; and it is physically unique because of the need to maintain an instantaneous balance of supply and demand at a precise voltage.

For this reason the approaches we are taking in this order strike the balance of taking immediate steps to unlock market forces and technology innovation while preserving the ability of utilities as regulated monopolies to maintain stable and reliable electric service for all customers as well as retain their opportunity to earn a fair return.

Aligning financial incentives with policy goals is the best way to assure the furtherance of these goals. Where possible, markets and positive financial incentives – rather than direct regulatory mandates with negative consequences - should be the primary drivers of the countless implementation actions, decisions, and initiatives needed to transform the industry. We therefore determine that the direction of rate regulation is towards aligning financial incentives with REV objectives by combining discrete reforms to conventional ratemaking with new earning opportunities that better align the utility and consumer economic welfare interests.

New York utilities historically have been leaders in the development and application of solutions to complex engineering and system problems. However, as we have repeatedly observed, these solutions were developed within a very different technology and consumer framework than the one that is emerging today. The symptoms of climate change that are already impacting New York, rapid technology changes, and consumer preferences are converging to require utilities to expand their innovative capabilities to new business and earnings models reflecting their role as enabler of a multi-sided market for distributed energy resources. The reformulation of earnings models will motivate New York utilities to become as proficient at accommodating innovative third party partnerships, technology solutions, and new planning and operating models that bring value to consumers, as they are today in the delivery of reliable and safe electric service.

In sum, along with the other complementary changes we are requiring in utility planning and information sharing, the pricing of distributed resources, and retail market reform, the ratemaking reforms are designed to ensure that rather than resisting third party investments and operational and market changes that increase consumer value and the achievement of critical State economic and environmental goals, New York utilities will embrace these changes as consistent with and vital to their own financial interests.

## B. Platform Service Revenues

### 1. Staff's Proposal

The Staff White Paper stated that the overall goal of ratemaking reform is to provide utilities the opportunity to thrive in a changing environment, if they succeed in meeting the Commission's customer-and-market-oriented objectives. As markets develop liquidity and volume, according to Staff, utilities should be expected to derive a growing share of net income from market-based earnings in exchange for value-added services that they provide to the market.

Staff stated that market-based earnings will develop as DER markets attain full scale and platform pricing grows from initial development into a fully operational market. In Staff's words, this will "complete the transition to a business and regulatory model where utility profits are directly aligned with market activities that increase value to customers."[50]

Staff provided examples of potential market-based services that could generate revenues for utilities. These include: customer origination via the online portal; data analysis; co-branding; transaction and/or platform access fees; optimization or scheduling services that add value to DER; advertising; energy services financing; engineering services for microgrids; and enhanced power quality services.

Staff identified numerous potential benefits of PSRs, including:

- Facilitating market entry and unlocking potential system value: The DSP will enable market entry for DERs by reducing transaction costs. Utilities' opportunity to earn from an increasingly wide use of the platform will provide an incentive to make access to the platform and to customers as simple as possible. This in turn will enable new system value to be created by DERs.

- Offsetting and allocating costs of DSP capital and operating expenses: Charging those who utilize the platform will allow sharing the platform costs among participating customers and the general customer base, while total system costs are reduced.

- Providing incentives for utilities to innovate and serve REV objectives: Effective operation of the platform will advance cost-effective market activity while enhancing

[50] White Paper, p. 10.

utility earnings and serving the public objectives of REV. Utilities will have an incentive to expand market offerings and platform utilization both through their own initiatives and through accommodation of innovations in the market.

- Supplementing utility revenues as third-party market share increases: Utility business models must evolve to embrace market and technology changes that would otherwise be viewed as competitive threats. This will be enhanced by the opportunity to earn PSRs.

- Reducing uneconomic grid defection: PSRs will encourage utilities to work with DER providers to produce grid-connected values for customers greater than values achievable from grid defection.

The distinction between monopoly and competitive services is critical in the ratemaking treatment of new revenue sources. Earnings opportunities from competitive functions, according to Staff, should depend on the extent to which utilities place shareholder funds at risk. Revenues from monopoly functions should be considered on a par with other revenues associated with conventional utility functions, subject to the hybrid of incentive and cost-of-service rate treatment described in the discussion of outcomes-based ratemaking. For example, natural gas delivery companies earn revenues from selling pipeline capacity that is not needed to serve their native load. Because these revenues derive from ratepayer funding of a monopoly service, they are allocated principally to the benefit of ratepayers, with a percentage allocated to the utility as an incentive to maximize the revenues. In New York, revenues from these capacity sales are shared, with 85% of proceeds to ratepayers and 15% to shareholders, although there is no single allocation formula for all types of shared revenues.

Staff stated that PSRs are particularly appropriate for demonstration projects, to provide experience to inform their design, and to help refine standards. Several of the demonstration projects now underway will directly inform the development of PSRs, such as Con Edison’s Clean Virtual Power Plant and Iberdrola’s Community Energy Coordination or Flexible Interconnect project.

Staff stated that the determination of appropriate charges for various types of PSRs would involve a balance between developing new revenue streams for utilities and encouraging the growth of markets. This will remain a matter for research and demonstration.

Parties had a variety of responses to the PSR proposal. The Joint Utilities, National Fuel Gas Distribution Corporation (NFG), and the Exelon Companies (Exelon) recognized the potential value of PSRs as an important revenue stream, but cautioned that they will take time to develop and will be inherently difficult to predict. The utilities argued that the uncertain potential for market-based revenues will not support financing, and anticipated revenues should not be imputed to utilities in fulfillment of revenue requirements. They emphasized that cost-of-service recovery should remain the basis of ratemaking, while PSRs could be used to supplement revenue requirements with appropriate sharing between customers and shareholders.

Multiple Intervenors also recognized the potential for PSRs, with the caution that they are a long-term prospect. MI took a different position from the utilities regarding imputation, contending that the value of PSRs will consist in corresponding rate decreases, with an equitable sharing for utility shareholders. MI warned that PSRs should not result from utilities using their monopoly position to gain a competitive advantage.

The City of New York argued that the idea of PSRs is not well developed and not supported by an analysis of costs, benefits, and burdens. NYC is concerned that customers might continue to bear the utilities' full revenue requirements while the costs of participating on the platform will also be passed through to customers by DER providers.

DER providers drew a sharp distinction between monopoly-based PSRs and competitive services. With respect to PSRs, there was general acceptance assuming they are properly regulated by the Commission.

With respect to competitive services, DER providers as a group were strongly opposed to utilities participating in markets that can be served by non-utility providers. The Advanced Energy Economy Institute (AEEI)[51] and the National Energy Marketers Association (NEM) stressed that PSRs should be based on facilitation of markets, not competing within markets. NRG Energy, Inc. (NRG) contended that any product or service that can be sold by competitive means, should only be sold by competitive providers. Other parties that similarly opposed non-monopoly-based PSRs include: BlueRock Energy, Inc. (BlueRock); Charge Point, Comverge, Inc. with EnergyHub (Comverge/EnergyHub); Energy Technology Savings; IGS;[52] Microgrid Resources Coalition (MRC); and Mission:data.

Other parties including The Alliance for Solar Choice (TASC), the New York Energy Consumers Council (NYECC), the Retail Energy Supply Association (RESA), and the Northeast Clean

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[51] AEEI filed comments jointly with the Alliance for Clean Energy New York and the New England Clean Energy Council. Those joint comments will be referred to in this order as submitted by AEEI.

[52] References to IGS are to the joint filing made by IGS Generation, IGS Solar and IGS Energy.

Heat and Power Initiative (NECHPI) were non-committal until the idea of PSRs is more fully developed.

2. Discussion

The ratemaking aspect of utility regulation is informed both by legal constraints and by economic principles. Rates must be just and reasonable, for customers and utilities, and in consideration of their obligation to serve, utilities are entitled to an opportunity to earn a fair return of and on their investments.[53] In the absence of competitive markets, the ratemaking process is designed to determine a fair profit given the risk profile of the utility, and to promote achievement of policy objectives. As a general matter, the goal is for the establishment of revenue requirements, prices, and earnings, to mirror unregulated industries to the extent consistent with achieving policy goals.

In the competitive economy, advances in information availability, the emergence of technology-based services, and increased competition, have placed a premium on capital efficiency and increasing consumer value. In the context of DSP-enabled markets, updating the manner in which regulation emulates markets is not only consistent with, but furthers progress toward, critical policy goals of system and capital efficiency and energy affordability.

The expanded role of utilities is marked by new obligations and opportunities to facilitate the multi-

[53] See, e.g., Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944). The Public Service Law grants the Commission wide discretion in the methods that it uses to satisfy its mandate. Abrams v. Public Service Commission of the State of New York, 67 N.Y.2d 205, 214-15 (1986); New York State Council of Retail Merchants v. Public Service Commission of the State of New York, 45 N.Y.2d 661, 668 (1978).

directional transactive retail electricity market. This role includes eliminating barriers that can impede the adoption of cost-effective DER by end-use consumers, as well as supplying the information and price signals that provide fair value for these resources as part of grid operations. The utility in its DSP function will provide these services as an expansion of its existing obligation to provide reliable, cost-effective and lean power resources.

A number of proposed modifications to ratemaking conventions were identified and discussed in the Staff White Paper and party comments. The proposals generally fall into three categories. First, and at the heart of REV, is the development of new transactive-based revenues between and among DSPs, end-use consumers, and third-party market participants. These revenue opportunities reflect the nascent market and will evolve over time. Second, in order to spur this evolution, Staff proposed earnings adjustment mechanisms (EAMs).[54] EAMs are an expedient device that can work within the current structure, and are framed by regulatory determinations that must also evolve and will eventually be superseded by market opportunity. The third category of proposals includes changes in current rate setting mechanisms to eliminate unintended consequences and to achieve policy objectives. These include changes to the so-called “clawback” mechanism, earning sharing mechanisms, and the duration of rate plans.

A fourth type of new earning opportunity, which was not discussed extensively in the White Paper or in comments, has already been adopted. This is the rate treatment of non-wires-alternative (n/w/a) programs such as Con Edison’s BQDM initiative. Until platform markets are fully developed,

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[54] As proposed by Staff the mechanisms were termed Earnings Impact Mechanisms.

distinct n/w/a projects are a means by which third-party investment can be integrated with utility systems to improve efficiency and reduce bills. As we did in the BQDM proceeding, we expect to approve n/w/a projects that will result in customer savings, with earnings opportunities for utilities that are commensurate with or superior to earnings that can be achieved through traditional investments.

All of these potential changes can coexist in an evolving regulatory environment, and the Commission must continuously balance certainty and continuity with the recognition that markets may support the modification or ultimate elimination of individual components. This is particularly true in the case of EAMs.

Staff initially defined "MBEs" as "utility earnings derived from facilitating the creation and transaction of value-added services by active users of the DSP."[55] Staff further distinguished between MBEs as PSRs and as "value-added" services. Parties observed that PSRs could constitute value-added services, and that the distinction between what is competitive and what is monopoly-based was not clear.

To simplify, we adopt a single category of revenues, to be known as platform service revenues, which represent all new forms of utility revenues associated with the operation or facilitation of distribution-level markets. The precise nature and characterization of PSRs will evolve as markets evolve. Therefore, rather than establishing rigid definitions, we will adopt a process-based approach for approving new charges and revenues, which will evaluate proposed utility activities on an individual basis.

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[55] White Paper, Appendix B.

This discussion applies only to regulated utility activities. Affiliates may offer competitive services on an unrestricted basis so long as they comply with prescribed codes of conduct.

a. Approval Process for Platform Service Revenues

All utility charges and revenues must be authorized by tariffs. A utility filing for a new PSR must include the following items, which are explained below:

i) a description of the product or service;
ii) a description of how the product or service meets the criteria for approval;
iii) a description of the method to be employed to price the product or service;
iv) a proposed allocation of the revenues between ratepayers and shareholders; and
v) proposed deferral accounting and reporting requirements to monitor activity until rates are reset.

i. Criteria for Approval

A proposed PSR must identify one of two options for meeting approval criteria.

The first option is to demonstrate that the underlying product or service is inherently a monopoly function that cannot effectively be performed by non-utility parties.

The second option applies to activities that could be performed by competitive entities. Staff's proposal to allow utilities to participate as competitive providers drew numerous comments. DER industry members argued that regulated utilities should be kept out of the competitive arena, where they will inevitably have unfair advantages and will inhibit the development of markets. Stated in that way, we agree, for the reasons set out in the Framework Order where the Commission determined that regulated utilities should generally not own DERs in competitive markets.[56]

Like the DER ownership issue, however, there are exceptions to the general prohibition on utility participation in competitive value-added services. In limited areas of competitive services, the activity of regulated utilities may be beneficial both to utility customers and to the operation of markets. Some parties argued that if a service could potentially be provided by third parties, then utilities should be absolutely banned from it. Others stated that the interests of markets might be served by having some types of competitive services provided by utilities even though they are theoretically open to third party competitors.

We agree with the latter position. Regulated utilities should be allowed to earn revenues from activities whose principal effect is to facilitate the growth and operation of markets. These opportunities should include, in most cases, utilities assuming a portion of financial risk for the cost of offering the service, with proportionate opportunity for greater returns. This will encourage due diligence in the assessment of the opportunity and will also encourage the further pursuit of earning opportunities that do not rely fully on ratepayers.

The criteria that will be considered in approving potentially competitive services will be (a) whether the service facilitates the growth and operation of markets; (b) whether there is already a third-party market for the service that adequately serves all sectors of the market; (c) whether utility economies of scale and/or existing utility expertise are likely to result in cost-effective stimulation of the market; (d) whether utility provision of the service is likely to

[56] Framework Order, pp. 53-61.

prevent other providers from entering the market; and (e) the extent to which a utility has proposed placing shareholder funds at risk.[57]

ii. Pricing Method

Although PSRs derive from a ratepayer-funded platform, their pricing need not be strictly cost-based. The principle governing the pricing of PSRs is to optimize value for the utility's ratepayers, with the recognition that optimal value includes enabling a vibrant market for DER services. In other words, the correct pricing will combine the need to stimulate

[57] The criteria are intended to support a balanced judgment, as opposed to a set of binary determinations that must all be made in the affirmative. An example of a competitive value-added service that can meet these criteria is the provision of data analysis. In this example, there could be three types of services associated with data, with three different types of regulatory treatment. First, in the context of this order and the DSIP, utilities will be required to make some level of data available to customers and to third parties, at no cost. In cases where customers request information that is more detailed and/or more frequent than basic required data, utilities could supply this value-added data for a nominal fee. This second type of service – additional data – would derive directly from the monopoly function and be treated as a PSR. In the third case, utilities may perform analysis of customer-specific data, and provide recommendations based on that analysis, conditioned on utilities implementing tools to allow customers to easily share their usage data with third-party vendors including firms providing data analysis. This third type of service – analysis and recommendation – would be competitive but would meet the criteria described above.

Another example of a competitive service that could meet the criteria is customer origination. Customer origination is a significant cost element for DER providers. While this can be performed by third parties, utilities may be best situated to provide origination in a cost-effective manner that facilitates market penetration, based on analysis of customer data and/or connecting interested customers with DER providers via a marketplace portal.

markets with the goal of maximizing benefits for ratepayers. This could include below-cost pricing in the early days to build scale, and value-based pricing in a mature market, to derive the greatest benefit for ratepayers. Optimal platform pricing requires more experience; for this reason, we will allow utilities to propose varying approaches to fee structures.[58]

iii. Allocation Formula

Like the definition of permissible PSRs and pricing methods, allocation of revenues between ratepayers and shareholders will not follow a single rigid formula and will be responsive to developments in DSP markets. Because they derive from monopoly functions, in most cases a large portion of these revenues should inure to ratepayers. A portion of PSRs should be allocated for utility earnings, in order to provide an incentive to optimize the use of the platform. Off-system sales of gas pipeline capacity provide a useful model.[59] Because traditional ratemaking treatment might not encourage efficient development of a PSR, the extent to which a shareholder incentive is needed must be considered in the context of specific PSRs.

Because most value-added services will involve incremental costs, utility proposals will be more likely to gain

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[58] See, Tabors, Parker, Centollela and Caramanis, "White Paper on Developing Competitive Electricity Markets and Pricing Structures," April 2016

[59] It has been argued that off-system pipeline capacity sales are different because they involve already sunk customer-funded investments, while PSRs involve new DSP investments. DSP investments, however, will not be made for the purpose of generating PSRs. They will be made for the purpose of developing a platform to provide customers with modern electric service, regardless of whether platform service charges are ever imposed.

approval if they place shareholder funds at risk, with a commensurate opportunity to increase earnings. In these cases, where the utility has an opportunity for increased earnings, the allocation of program costs to ratepayers will be reduced. For example, 80% of the incremental cost of providing a service might be allocated to ratepayers, and all revenues allocated to ratepayers up to that amount, with the utility entitled to retain a larger portion of revenues above the allocation level.[60] As electricity markets become increasingly multi-sided and utilities respond as platform providers, opportunities to enhance both shareholder earnings and ratepayer benefits, without placing ratepayer funds at risk, are expected to increase.

Because the total levels of PSRs will not be easily predictable, they should not be imputed to revenue requirements in early years but instead should be used to create customer credits. In a mature market environment when PSRs are both large and more predictable, it will become appropriate to impute the revenues when developing rate plans.

#### iv. Approval Process

In keeping with the likely diversity and fluidity of market opportunities, the implementation of PSR proposals should not be slowed by a presumption of impermissibility or a lengthy approval process. Instead, tariff filings will be deemed compliance filings with respect to the approval criteria and the pricing method. Each filing will be published and if neither Staff nor any party files an objection within 30 days of publication, the proposed tariff amendment will be in effect 60

[60] Utilities may choose to undertake demonstration projects to test the viability of offerings prior to committing resources on a large scale.

days after publication. An objection must include a substantial description of why the proposal should be rejected in light of the criteria. To facilitate review by interested market participants, the Secretary will maintain a service list of persons who wish to be automatically notified of PSR filings.

With respect to the allocation formula, the appropriate proportion of shareholder incentive will vary both by individual service and over time, and will need to be approved by the Commission. In order not to delay the development of services, and to avoid burdening parties, we establish an expectation that an 80% allocation to ratepayers and a 20% allocation to shareholders will be considered reasonable for services that stem directly from monopoly functions. This expectation will be revisited as experience with PSRs is gained.

#### b. Process for Reviewing Existing Services

Upon petition of a party or Staff based on a showing of changed circumstances, the Commission will review whether aPSR that has already been approved and which is already in the market continues to meet the criteria, especially with respect to criterion (d) where a petition demonstrates that the service could be provided effectively by market participants. In considering such a petition, the Commission should take into account the extent of utility investment and reasonable expectations of continued ability to provide the service.

## C. Earnings Adjustment Mechanisms

### 1. Staff Proposal

Staff identified several approaches to aligning utility financial interests with the Commission's REV objectives. The most straightforward of these is the use of direct incentives linked to specific outcomes. In June of 2014, Staff presented a list of 26 outcomes to parties, for consideration as potential incentives.[61] Parties generally supported the list but commented that prioritization was needed.

In the White Paper, Staff prioritized outcomes in part by their overall relevance to REV objectives but also, and equally important, by their instrumental near-term value. Staff proposed five near-term incentives as EAMs. The five measures proposed by Staff would apply to:

- Peak reduction: oriented toward near-term system savings and development of DER resources;
- Energy efficiency: oriented toward integrating efficiency with demand reduction and increasing the total amount of efficiency activity;
- Customer Engagement: oriented toward near-term activities to educate and engage customers and provide access to data;
- Affordability: oriented toward promotion of low-income customer participation in DER, and toward reduction in terminations and arrearages; and
- Interconnection: oriented toward increasing the speed and affordability of interconnection of distributed generation.

Staff identified numerous implementation issues around new EAMs, and made recommendations with respect to the following:

- Existing rate incentive measures should be retained but should be reviewed for their continued usefulness;

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[61] Case 14-M-0101, supra, Ruling Posing Questions on Selected Policy Issues, June 4, 2014.

- New EAMs should be positive-only in direction, with the exception of customer engagement and interconnection, which should be symmetrical;
- Positive-only EAMs in the longer term should be tied to a bill impact metric;
- EAMs may be oriented toward outcomes that utilities can influence and need not be confined to activities over which utilities have direct control;
- Most EAMs should be on a multi-year basis rather than annual, to allow time to develop desired outcomes;
- EAMs should be compensated or charged via accounts that are reconciled in rate cases;
- All utilities should have EAMs for the same categories, while details may vary among utilities; and
- Total size of revenues at stake need to be determined on a case by case basis.

Parties submitted a wide and voluminous range of comments on the EAM issues. In addition, parties participated in a two-day technical conference that was focused primarily on EAMs. Party comments are summarized in Appendix C; many of the most salient are described here.

Parties generally agreed that existing incentive metrics should be retained, and reevaluated in rate cases as needed.

The Joint Utilities disagreed with several aspects of Staff's proposal. In particular, the utilities argued that EAMs must be focused on results that are within the utilities' control. The utilities agreed that new incentives should be positive in direction, but they stated that a bill impact metric is impractical, because two-thirds of the customer's total bill consists of elements beyond utility influence, such as taxes and commodity supply. The utilities proposed a framework for developing incentives that emphasizes (a) importance to developing REV and value for customers, (b) utility degree of control, c) whether the EAM is sufficiently developed, and (d) whether the EAM is broad-based or targeted to a specific outcome.

Multiple Intervenors disagreed with the premise that REV warrants increased reliance on incentive ratemaking. MI argued that the Commission can mandate the changes that need to occur, and incentives will unduly enrich utilities. AARP also expressed reservations over the basic approach of performance ratemaking.

The City of New York agreed with Staff that EAMs are appropriate, but disagreed with Staff’s position that EAMs may apply to outcomes over which utilities do not exercise direct control. Numerous other parties agreed with NYC and the utilities that EAMs should only apply to items under utility control.

The Energy Democracy Alliance[62] did not support incentives for activities that are part of utilities’ normal responsibilities; rather, they proposed incentives for environmental and social equity goals.

The Public Utility Law Project (PULP) questioned whether an adequate record exists to support new EAMs, and questioned whether a bill impact metric is practical.

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[62] The Energy Democracy Alliance filed comments jointly on behalf of Alliance for a Green Economy, Binghamton Regional Sustainability Coalition, Center for Social Inclusion, Citizens' Environmental Coalition, Citizens for Local Power, Long Island Progressive Coalition, Nobody Leaves Mid-Hudson, and Push Buffalo.

NRG, Solar Energy Industries Associaiton (SEIA) and several other DER parties supported outcome-based incentives, as opposed to utility-controlled measures, with an emphasis on encouraging outcomes that result from competitive providers and market activities.

Several parties including the Environmental Defense Fund (EDF), the NYU Institute for Public Integrity, and the Clean Energy Organizations Collaborative (CEOC)[63] urged that EAMs should be more oriented to environmental goals and specifically to carbon reduction, renewable energy, and energy efficiency.

CEOC commented extensively on EAMs and recommended a large expansion of Staff's proposal. CEOC stated that EAMs and scorecard metrics are the most immediate and direct way to encourage REV results. CEOC recommended that targets should be derived from the Distributed System Implementation Plan (DSIP) process and that metrics should be tied as much as possible to data already reported to various authorities. CEOC suggested that costs and rewards to ratepayers should be balanced; CEOC also argued that rewards should not take the form of basis point adjustments to the entire rate base, because this could have the counterproductive effect of encouraging the growth of rate base.

CEOC proposed a list of scorecard and EAM items that is much more extensive than Staff's. CEOC proposed 50 separate scorecard formulas and 21 EAMs around 13 category areas.[64] In addition to the EAM categories proposed by Staff, CEOC

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[63] CEOC includes Acadia Center, Association for Energy Affordability, Citizens for Local Power, Clean Coalition, Environmental Advocates of New York, Environmental Entrepreneurs, Natural Resources Defense Council, Nature Conservancy, New York League of Conservation Voters, New York Public Interest Research Group, Pace Energy and Climate Center, and Sierra Club.

[64] See, CEOC Initial Comments (filed October 26, 2015), pp. 28-29.

recommended EAMs specific to demand response, distributed generation, electric vehicles, storage, time of use rates, standby rates, and carbon reduction.

With respect to the specific EAMs proposed by Staff, party comments are summarized in the discussions of those EAMs.

2. Discussion

Performance standards have been a fixture of the Commission's regulatory strategy for many years. They are typically negative adjustments for failure to meet standards related to basic service – reliability and customer service – or specific identified program needs, e.g. stray voltage inspection. The size of total potential adjustments is large in terms of basis points,[65] although adjustments that are actually experienced tend to be a small fraction of the total potential.[66] In practice, these standards have a deterrent effect against poor service.

There is little controversy over the success of these standards and the merit of retaining them. We agree with Staff that existing measures should generally be retained, although specific measures (such as the stray voltage metric identified in the White Paper) should be examined in rate cases and, if they have little remaining value, should be adjusted or eliminated.

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65 These measures vary among utilities. Total potential negative adjustments range from a low of 139.6 basis points to a high of 262.5. Total positive adjustments including earning sharing mechanisms range from a low of 65.8 basis points to a high of 120.3. See, White Paper, Appendix C.

66 On average over the past ten years only 3 basis points have been incurred annually by each utility on the negative side, with a maximum 38 basis points by any one utility in one year.

Staff's proposal to create new incentive measures is directed not to traditional basic service but to new types of performance expectations. Some of these new expectations run counter to conventional methods of operation and, importantly, also run counter to the *implicit* financial incentives that are embedded in the cost-of-service ratemaking model. If cost-of-service calculations are to remain the basis of utility rates for the foreseeable future, then creating new earning adjustment opportunities are both a fair and a necessary means of promoting change.

The new mechanisms proposed by Staff are distinguished from the earning incentives built into Con Edison's Brooklyn-Queens Demand Management (BQDM) program.[67] The BQDM incentive model is tied to a single project. Other non-wires-alternative projects may include incentives following the BQDM model, to be considered on a case-by-case basis. The incentives proposed by Staff involve system-wide outcomes that promote the development of wider markets, and that approach is the focus of this discussion.

At the outset, we note that Staff proposed the phrase "earnings impact mechanism" rather than "incentive" in order to avoid confusion with program incentives paid to customers and developers under efficiency, demand response, and other programs. To further clarify, we will adopt the phrase "earnings adjustment mechanism" or "EAM" for future use.

Staff suggested that EAMs should play a transitional role until other forms of market-based revenues are available in scale and at a level of predictability that they can become a meaningful contributor to fulfilling utilities' revenue

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[67] Case 14-E-0302, supra, Order Establishing Brooklyn/Queens Demand Management Program (issued and effective December 12, 2014).

requirements. We agree that EAMs are best thought of as a bridge. As we discuss further in our discussion of earning sharing mechanisms, our expectation is that through the opportunity to earn from platform service revenues that produce sustained value to end-use customers and utility shareholders, the need to establish specific EAMs to accomplimish the same consumer benefit will diminish. The outcome is critical, not the precise form of the financial incentive.

Yet while we view EAMs as a transitional component of regulatory redesign, we will not place a time limit on any particular EAM and we anticipate that some EAMs will complement and supplement the contributions of platform service revenues for the foreseeable future. The specific set or portfolio of EAMs may also change over time, as some objectives are achieved or become standard practice, allowing an EAM to be retired, while other EAMs are created or modified as new needs are identified in the future.

a. <u>EAM Structure</u>

Comments revealed a wide range of positions over the optimal structure of EAMs. Much of this discussion reflected expectations created by existing performance standards. As explained above, however, EAMs serve a different set of purposes. They must both encourage achievement of new policy objectives and counter the implicit negative incentives that the current ratemaking model provides against REV objectives. Structural issues around new EAMs must be seen in that light.

To the extent possible, the financial details of EAMs should be developed in rate proceedings, because the relative weight of each EAM will vary by utility based on its potential value within the service territory, the capabilities of the utility, and the unique financial situation of each utility.

These matters are best left to the processes that produce multi-year rate plans. As a transitional matter and to ensure timely progress toward REV goals, because each utility is at a different stage of its rate plan, some implementation will be ordered outside of rate cases, as provided below.

While the size and method of recovery should be addressed in rate cases, structural issues require guidance from the Commission in order to provide clear direction and avoid unnecessary and time-consuming argument in rate cases. The discussion of structural issues below should be treated by parties as strong policy preferences when they negotiate or litigate specific EAMs in future proceedings. Parties are also encouraged to relate those arguments to practices from regulatory literature and relevant experiences in New York and elsewhere.[68]

*Outcome-based incentives.* Staff proposed an approach based on outcomes that align with policy objectives, rather than an approach based on specific utility inputs or attainment of specific program targets. This approach was questioned by numerous parties who assert that incentives should be confined to results over which utilities have direct control or strong influence.

The formula for any individual EAM will depend on specific circumstances, the nature of the goal, and the underlying activities that are likely to achieve the goal. As a general matter, we reject the arguments of parties that would confine EAMs to items under direct control or strong influence

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[68] See, e.g., Whited, Woolf, and Napoleon, "Utility Performance Incentive Mechanisms, A Handbook for Regulators," March 9, 2015; Aggarwal and Burgess, "New Regulatory Models," March 2014; Orvis, "Lessons for Designing Counterfactuals in Earnings Incentive Mechanisms: California as a Case Study," April 2016.

of the utility, to the extent that "influence" is interpreted as the implementation of specific approved programs.

To the contrary, we agree with Staff that an outcome orientation will tend to be the most effective approach to address the mismatch between traditional revenue methods and modern electric system needs. There are a number of reasons we arrive at this conclusion.

First, a central function of REV is to integrate the activities of markets, including customers and third-party DER developers, into an optimized distribution system. By definition, utilities will not have control over the market activities of customers and third parties, even though these activities in the aggregate will be critical to the optimal performance of the system. Utilities will enable markets to drive outcomes. Limiting shareholder incentives to items under utility control would omit a wide range of desired outcomes.

Second, outcome-based incentives encourage innovation by the utility, as opposed to merely conforming to plans approved or ordered by the Commission. Several parties commented that utilities should simply be ordered to implement specific tasks, with no need for incentives. Other parties argued that utilities should not be rewarded merely for performing what is expected of them. These arguments assume that regulators are in the best position to know precisely what actions are needed to achieve policy outcomes. In fact, the optimal role of regulators is not to dictate program terms but rather to set policy and ensure that results are just and reasonable. A construct in which regulators presume foreknowledge of how innovation must occur is antithetical to the premise of REV. Outcome-based incentives will allow utilities to determine the most effective strategy to achieve policy objectives, including cooperation with third parties and development of new business concepts that would not be considered under narrow, program-based incentives.

Third, outcome-based incentives encourage an enterprise-wide approach to achieving results. Targeted program-based incentives are appropriate for discrete and clearly defined tasks, such as testing for stray voltage or replacing a set number of miles of leak-prone pipe. Program-specific incentives with their own metrics, however, inherently limit the scope of the company's efforts and encourage a siloed management approach. Outcome-based incentives are appropriate where the programmatic inputs are not simple to isolate, and where the beneficial outcome is influenced by a holistic approach and a range of company activities that are planned to jointly influence the outcome along with customers and third parties.

Peak reduction, for example, can be influenced by a wide range of utility activities. A non-exhaustive list includes: establishing effective demand response tariffs and encouraging customers to participate; encouraging customer-initiated DG and storage projects and facilitating interconnection; developing effective time-variable tariffs and encouraging customers to participate in them; promoting energy efficiency projects and market activity around measures that have a demand-reduction impact; promoting effective building codes and assisting customers in developing energy management systems; encouraging development and location of business customers with high load factors and/or substantial off-peak operations. This is only an illustrative list and demonstrates the point that utilities and their industry partners should be encouraged to innovate and build policy priorities into their enterprise-wide business plans, as opposed to simply carrying out defined tasks that are dictated by the Commission.

Fourth, regulation should seek outcomes that simulate competitive market behavior where possible and beneficial. Financial results for companies engaging in unregulated markets are determined by a wide range of variables, many of which are beyond the company's control. Attribution of results to company efforts is important for internal planning, but the marketplace is ultimately indifferent to the merit of the company's efforts or degree of control. This is in contrast with cost-of-service ratemaking, which is directly tied to the company's efforts. Whether a complete shift away from cost-of-service would improperly expose utilities to financial risk is a question that is not raised here, because there is no such proposal at this time. Outcome-based incentives base a portion of the utility's return on market outcomes, while maintaining a reasonable overall return as an end result.

Finally, as Staff observed in the White Paper, having utility earnings affected by market outcomes over which they have limited influence is not a new principle. Under traditional ratemaking, prior to decoupling of sales from revenues, sales levels were among the largest variables in utility earnings. Total sales are the result of countless market and behavioral factors at the customer level, but utilities had a general incentive to promote growth in sales as an enterprise-wide priority. One of the arguments against decoupling was that it could eliminate an implicit economic development incentive.[69] The treatment of sales levels prior to

[69] Case 03-E-0640, Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation, Order Requiring Proposals for Revenue Decoupling Mechanisms (Issued and Effective April 20, 2007).

decoupling is an example of the principle that all ratemaking is incentive ratemaking.

*Avoidance of counterfactuals.* Incentive mechanisms are less effective and lead to significant controversy when metrics rely on complicated verification processes and debatable baseline assumptions. Incentives that depend on a determination of what *would* have taken place in the absence of the incentive — that is, the proving of a counterfactual — are challenging to administer, can lead to contentious *ex post* review processes, and may result in tremendous administrative expense for uncertain net benefit. The California Public Utility Commission, for example, found that this was the case with the Energy Efficiency Risk-Reward Incentive Mechanism.[70]

To avoid counterfactuals, metrics should, where appropriate, establish fixed performance targets on a predetermined basis. Fixed targets are preferable to metrics that require *ex ante* and/or *ex post* analytic exercises that rely on contestable calculations and input assumptions.[71] In addition to making incentives more effective and easier to administer, fixed metrics also tend to be more outcome oriented rather than based on narrow programs.

Particularly in the early stages of REV, we recognize that in limited circumstances counterfactuals calculated against status quo figures that are relatively easy to identify are necessary and appropriate. These include the development of non-wires-alternative projects and the system efficiency EAM discussed below.

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[70] See, Orvis, Robbie, "Lessons for Designing Counterfactuals in Earnings Incentive Mechanisms: California as a Case Study," America's Power Plan, April 2016.

[71] Orvis, 2016, supra.

*Symmetry*. Staff proposed a mix of positive, negative, and bi-directional measures. Some advocates argued that positive incentives are rarely if ever appropriate, because utilities have enough incentive simply to earn their allowed return by meeting mandated expectations.

EAMs deal not with conventional basic service but with new expectations. Meeting these expectations will require innovative management and new forms of cooperation with thirdparties and customers. Meeting the expectations will also require overcoming implicit disincentives that exist in the cost-of-service model. For these reasons, as well as the reasons articulated by Staff, positive incentives may be warranted.

Staff proposed a pragmatic approach to this question and we agree. The proper direction for any given EAM will be determined by factors that are unique to that measure. Although this order specifies direction for the first iteration of various incentives, the direction of the incentive should be open for reconsideration in future cases based on demonstrated efficacy of the EAM in driving desired outcomes. For example, if EAMs with positive-only incentives prove to be ineffective, symmetrical or negative incentives should be considered.

Negative adjustments for EAMs should not be routine. Existing negative adjustments for reliability and customer service are intended to deter problems, and the less they are actually imposed, the better for customers. Most EAMs, in contrast, are established for activities with positive value; therefore the more they are awarded, the better for customers. Most EAMs should be constructed so that achieving the maximum award is a desirable result for customers as well as the utility. Negative adjustments should typically be reserved for exceptional instances of inadequate effort or performance.

*Size of incentives.* Staff proposed that the size of EAMs should be negotiated in rate cases, responsive to the various factors that define an individual utility rate plan. Proposals for the size of incentives will be evaluated within the larger picture of how the incentives impact the overall financial picture of the utility, including with respect to platform service revenues and other earnings opportunities newly available, and the impact to ratepayers. Rate cases should review the full picture of earning opportunities to establish an appropriate EAM amount for utilities.

Review of other jurisdictions illustrates a wide range of size of performance incentives.[72] In Illinois' legislatively defined program, 0.38% of utility revenue is at stake in a negative-only direction.[73] In the United Kingdom's RIIO program, 6% of revenues are at stake in a quasi-symmetrical system.[74] Current incentives in New York, described above, range between 2.77% and 5.69% of delivery revenues on the negative side and between 1.33% and 2.49% on the positive side.[75] Because each regulatory agency uses different approaches to these calculations, it is difficult to compare with great precision.

There is no established formula for determining the correct level of earning adjustments. Each metric must be continually reevaluated for its effectiveness, with reference to

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[72] See, Whited 2015, Aggarwal 2014, supra.

[73] See, Illinois Energy Infrastructure Modernization Act of 2011.

[74] RIIO is an acroynm for "Revenue set to deliver strong Incentives, Innovation and Outputs." In the RIIO system, each individual metric is symmetrical but the total downside potential is capped.

[75] These figures reflect percentages of delivery revenues. Stated as percentage of total bills, the ranges are 1.13% - 2.59% on the negative side and 0.49% - 1.03% on the positive side.

progress toward the outcomes that are the subject of the EAM. Where incentives are directly tied to customer savings and system value creation, the scope of estimated savings should be the most important reference point in establishing an upper limit on the earning opportunity.

Incentive opportunities should be financially meaningful and structured such that they encourage enterprise-wide attention at the utility and encourage strategic, portfolio-level approaches beyond narrow programs. When establishing levels, it is important to recognize that the upper bounds on available earning opportunities, and associated performance targets, will not be achieved in all cases. The incentive provides a target and structure to evaluate program investments against, and allows the utility to make strategic judgments about how much investment and effort is justified for the available rewards (mimicking management decisions in any competitive market).

To support utility rate case proposals and our evaluation of those, we provide guidance for how large EAMs can be. As initial bounds on the first round of REV initiated EAMs, the maximum amount of earnings should not be more than 100 basis points total from all new incentives. The value of individual EAMs may vary based on the underlying activity, its anticipated cost, value to customers, and relative degree of opportunity in the particular utility territory.[76]

Although basis points provide an important accounting tool for determining appropriate relative size of incentives for

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[76] Using statewide averages, 100 basis points are equivalent to 2.4% of delivery rates or 1.1% of total bills. The total relative number of basis points can be higher if higher ratepayer value is demonstrated through the benefit cost analysis associated with the incentive (for example, this may be the case with system efficiency).

different utilities, and the initial potential rewards should generally be referenced to basis points of earnings, the ultimate form of incentives should not be directly tied to basis points. Increasing the size of the allowed return on equity can have the unintended consequence of increasing bias toward growth of utility rate base. A preferred alternative is to calculate the maximum award with reference to basis points, and then translate that maximum award into an absolute dollar figure.

*Shape of the line.* Most incentives can be constructed as some variation on a line or other geometric function that links increasing performance to increasing reward. The "shape of the line" is a significant determinant of the incentive's effectiveness.[77] By adhering to a few basic design guidelines, the intended outcome of incentives can be better assured, and unintended consequences minimized.

Although some incentives might properly be formed on a simple pass/fail basis with abrupt cutoffs, the outcome-based opportunities identified here should utilize a graduated line that avoids abrupt steps. Abrupt steps are problematic because they distort the marginal value of incremental achievements. As a pass/fail target is approached, the incremental value of each measure of achievement rises dramatically, until the target is reached at which point the incremental value drops to zero. In cases where the pass/fail target is unlikely to be reached, the incremental value of each measure is also near zero. This results in a zero-sum game that is not conducive to market-oriented outcomes that appropriately balance the costs and benefits of activities.

[77] Whited, Woolf and Napoleon, "Utility Performance Incentive Mechanisms: A Handbook for Regulators," Synapse Energy Economics, prepared for the Western Interstate Energy Board, March 2015.

A linear slope for performance awards, with ceilings and floors reflecting a reasonable range of desired outcomes, resolves these concerns and is the preferred approach. Other structures including the use of deadbands or use of inflection points to change the marginal reward at different levels of achievement may be appropriate under some circumstances, for example for bi-directional incentives.[78]

*Time frame for achievement.* As Staff recommended, outcome-based incentives should generally be structured on a multi-year basis. In contrast with program-specific incentives that can be tied directly to actions and results on an annual basis, outcomes are achieved across a wider range of activities and will often take more time to materialize.

*Process for considering new EAMs.* The Joint Utilities proposed a framework for the sequential consideration of proposed incentives. For each proposed incentive, the utilities' framework would consider (a) importance to developing REV and value for customers, (b) utility degree of control, (c) whether the EAM is sufficiently developed, and (d) whether the EAM is broad-based or targeted to a specific outcome.

As discussed above, the emphasis on utility control is misplaced in the context of REV-oriented earning opportunities and we adopt an outcome-based approach. With that exception, the framework proposed by the utilities is reasonable when used as guidance. Because an outcome-based approach will necessarily involve a wider range of factors than a specific program-based approach, the utilities' proposed framework will not be applied in a rigid manner. Instead, EAMs will be evaluated for their

[78] See, for example, Lowry and Woolf, "Performance-Based Regulation in a High Distributed Energy Resources Future," Lawrence Berkeley National Laboratory, January 2016; Whited, Woolf and Napoleon, March 2015, supra.

effectiveness with opportunities to revise EAMs and to retire or introduce new EAMs based on future system needs.

b. Specific Earning Opportunities

*Peak reduction/system efficiency*. Staff proposed an EAM to reduce peak demand on the bulk system by approximately 14% over a five-year period, which would require reducing the load associated with the average load of the top 10 peak days of the calendar year to ultimately reduce the top 100 peak hours. This goal would be met with existing programs as well as new, incremental efforts. Recognizing that this is an ambitious goal, Staff proposed that the EAM should be positive-only in direction.

The Joint Utilities and other parties including AARP expressed concern that the costs of achieving this reduction goal might exceed its benefits. PULP noted that the manner in which peak reductions would be monetized to benefit customers must be specified. NFG and MI noted that a peak reduction metric must not have the effect of discouraging expanded operation or new economic development. MI and Nucor proposed that system load factor would be a preferable metric. AEEI, Comverge/EnergyHub, and CEOC stated their concern that if the goal was to be achieved using only existing demand response programs, a 100-hour target would require calling on customer reductions too frequently. IREC also questioned the 3% annual goal. The New York Battery and Energy Storage Technology Consortium (NY-BEST) believed the 3% annual goal is achievable but states that ratepayer impacts and degree of utility control should be considered. BlueRock suggested that the peak reduction EAM should be geared toward the avoided costs of infrastructure investment as well as total energy savings.

The utilities also discussed the complications created by the fact that bulk system peak is not always coincident with distribution system peak and/or individual circuit peaks. Con Edison, in particular, described the differences among its network peaks in relation to system peak, and the concern that transmission and distribution savings that are potentially achievable through demand reduction could be lost if load is shifted from system peak to network peak. NYC, EDF, TASC, and MRC supported these concerns.

*Discussion*

One of the most important objectives of REV is improving overall system efficiency including the efficiency of capital investment to create value for customers. Toward that objective, peak reduction is among the most immediate priorities for REV implementation. It will reduce need for bulk power investment as well as transmission and distribution investment, and it will also build the capabilities of customers and providers to participate in markets.[79] The tools used to achieve peak reduction will enable achievement of renewable goals under the proposed Clean Energy Standard, because dynamic load management will enhance the cost-effectiveness of a larger proportion of weather-variable generation. Significant peak reduction may be cost-effectively achievable in New York State—according to one study, as much as 13 to 17% of system peak depending on the degree of technology enablement, program design, and market transformation.[80] Peak reduction, even if

[79] See, "The Economics of Demand Flexibility: How 'Flexiwatts' Create Quantifiable Value for Customers and the Grid," Rocky Mountain Institute, August 2015.

[80] "A National Assessment of Demand Response Potential, Federal Energy Regulatory Commission (FERC) Staff Report," June 2009.

entirely in the form of load shifting, will also reduce the marginal rates of carbon emissions from the bulk power system, as demonstrated by the study filed by CEOC in its Reply Comments.

Rather than a metric limited to peak reduction, we will adopt a system efficiency EAM oriented toward both peak reduction and load factor improvement. MI and Nucor are correct that load factor is an important indicator of system efficiency. Increasing system load factor means that total system costs are spread across a larger number of sales units, thus reducing the cost burden for individual customers.

Load factor should be a strong consideration in building a system efficiency program, but it should not be the only metric as proposed by MI and Nucor. Many desirable efficiency measures, such as LED street lighting and efficient combined-heat-and-power, may have the effect of reducing load factor, so a sole focus on load factor may produce unintended and undesirable consequences.

The comments on the importance of load factor illustrate a broader tension that can exist among the three highly important goals of peak reduction, load factor improvement, and carbon reduction through energy efficiency. All energy efficiency measures reduce total megawatt-hours, but individual efficiency measures will have varying relative effects on peak and load factor.[81] Conversely, load factor could be improved simply by increasing total usage, but that may have a harmful effect on carbon goals.

Furthermore, the relative values of load shifting, energy efficiency, and end-use fuel conversion will change over

[81] For example, street lighting measures will tend to reduce load factor while air conditioning measures will tend to increase it.

time as the makeup of the generating fleet changes. In 1977, at a time when fossil fuels including coal and oil dominated electric generation and thermal efficiency of electric generation was very low, the Commission adopted a policy that banned the promotion of any increased use of electricity.[82] As the Clean Energy Standard is implemented, a scenario in which the off-peak power supply consists entirely of non-emitting generation, at very low marginal costs, is foreseeable.

The interrelation of these factors might otherwise be ignored if the three policy goals are each treated in isolation. The trade-offs among different measures as they affect different goals should be considered in the deliberative stakeholder process of the Clean Energy Advisory Council. The Clean Energy Advisory Council should generically analyze the potential impacts of energy efficiency measures on peak reduction and load factor, and individual utilities should take this analysis into account in making system efficiency proposals.

We will require each utility to propose system efficiency targets that include both peak reduction and load factor. These targets will accompany energy efficiency targets, as described below, and should be implemented in a manner that achieves an optimal balance among the policy goals.

Many parties argued that peak reduction is best served by a program-specific approach. Staff’s proposal was based on an outcome approach, without prescribing the specific means by which the peak reduction goals would be achieved. As discussed above, we generally agree that outcome-based approaches will be more compatible with promotion of distribution-level markets. For immediate purposes, however, we agree with parties that utility-specific strategies are the most efficient way to ensure

[82] “Statement of Policy on Advertising and Promotional Practices of Public Utilities,” (issued February 25, 1977).

cost-effective near-term system efficiency results that will open the door to a wider range of market activities in the future.

We will not adopt Staff's proposed statewide target at this time. Instead, we order each utility to propose targets for peak reduction and load factor improvement that are appropriate for its territory, under a defined cost-effective strategy, over a period of five years. Individual utility targets may be either annual or cumulative with milestones, taking into account relevant benchmarks including peak reduction potential studies and targets established in other jurisdictions.

Peak reduction targets should establish either a specific MW objective for system peak or a percentage reduction from a defined MW amount (e.g., percent reduction below a historical reference year). Both peak reduction and load factor improvement targets should be ambitious in size to encourage a portfolio approach beyond conventional programs.[83] Ambitious targets are appropriate in this case, as they will encourage market building investments and business strategy.

Proposals by each utility should include:

- A description of stakeholder consultation undertaken in assembling the proposal, including consultation with the Clean Energy Advisory Council
- Peak reduction targets

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[83] The EmPOWER Maryland program provides an example of a multi-year peak reduction program based on outcome-based targets. The state has a target for 15% demand reduction below 2007 levels (as well as 15% reduction in total electric consumption), and has achieved 82% of the demand target (80% of total consumption target) by end of 2015, with some utilities far exceeding the target in their territories. (Public Service Commission of Maryland, "The EmPOWER Maryland Energy Efficiency Act Standard Report of 2014," April 2015).

- Load factor targets
- Weather normalization factors
- Description of methods and budgets proposed to achieve targets
- Description of ways in which the strategy supports overall goals of REV, including market transformation, customer engagement, cost control, and system efficiency
- Delineation of bulk system peak targets from distribution system or circuit targets, with an explanation of how the program will optimize peak reduction across these systems, and how this delineation affects system peak coincident versus non-coincident reductions
- A business case for the defined strategy, grounded in the BCA framework where appropriate
- A demonstration of how peak reduction and load factor values, obtained through efforts of the distribution utility, will be monetized to benefit customers of that utility[84]
- A proposed shareholder incentive based on: a portion of estimated customer savings; and a market diversity component ensuring that a reasonable number of market participants are involved in implementation

The Commission will not approve detailed programs that utilities will be bound to follow. Rather, we will approve

[84] Methods of monetization may include a general reduction in costs to all LSE customers, or could include aggregating demand response services into ISO markets with revenues credited directly to utility delivery customers.

targets and incentives that are based on reasonable and persuasive strategies. In this way an outcome-based approach to incentives can be maintained, while informed by a suite of detailed inputs. This approach to a system efficiency EAM will maintain a line of sight to a more straightforward outcome approach that can be used as markets develop at the distribution level. There are numerous ways in which a distribution utility can influence peak at both the bulk and distribution levels. These individual actions do not necessarily aggregate into a defined peak reduction program, but rather should represent an enterprise-wide priority that filters through into many areas of utility activity.

Targets and awards should be established on a graduated basis that encompasses both moderate levels of achievement and superior results. Because targets will be tied to customer savings, positive adjustments will be used, with the size of the adjustment graduated to the extent of achievement. Demonstration of achievement for purposes of the EAM will require analysis of the contribution of each component of the program, in order to avoid any incentive to achieve by reducing economic activity.

Initial EAMs for system efficiency should be established as positive-only in direction. In individual cases of inadequate effort or performance, as demonstrated during interim reviews, the Commission will reserve the right of establishing negative adjustments on a going-forward basis for individual utilities.

*Energy Efficiency*. Staff proposed linking an energy efficiency metric directly to achievement of peak reduction targets, by requiring that a positive EAM for peak reduction can only be earned if all of the energy efficiency targets are also achieved. In addition, Staff proposed that at least 10% of the incremental peak reduction needed (i.e. in addition to current programs) should be achieved through energy efficiency. This would provide an incentive for utilities to exceed their efficiency targets.

The Joint Utilities questioned whether tying efficiency metrics to peak reduction might undermine some of the efficiency programs that currently produce large MWh reductions. The utilities also questioned whether the peak reduction targets are achievable. They urged that after utility efficiency programs have been approved, there will be better information to determine whether a new approach to EAMs is preferable to program-specific shareholder incentives.

AEEI supported Staff's approach to an efficiency EAM. CEOC and Energy Efficiency for All[85] supported the use of an EAM as a backstop to ensure achievement of efficiency targets, but also advocated for additional metrics including peak reduction on distribution circuits, cost-effectiveness, and energy saved as a percentage of each utility's total load (i.e. energy intensity). They also recommended linking efficiency metrics more directly to achievement of State Energy Plan goals. EDF and the Energy Democracy Alliance stated that the EAMs proposed by Staff are not oriented toward environmental achievements and that the energy efficiency EAM as proposed does not address this failure. MI opposed the creation of a new efficiency incentive and emphasized the difficulty of establishing targets and measuring compliance.

[85] Energy Efficiency for All includes Natural Resources Defense Council, Pace Energy and Climate Center, the Association of Energy Affordability, the Center for Working Families, and the Green and Healthy Homes Initiative.

*Discussion*

Developing an incentive approach for energy efficiency is essential, in part because efficiency is critically important to State energy policy and the Clean Energy Standard, but also because efficiency is a field where REV begins a transition toward elevating market opportunities for greater achievement at lower cost to electricity customers.

Our approach to an EAM for energy efficiency is informed by the recent orders approving Efficiency Transition Implementation Plans (ETIPs)[86] and a Clean Energy Fund (CEF)[87]; by recent trends in evaluation, measurement and verification of efficiency achievements (EM&V); and by the assumed contributions of energy efficiency in the development of a Clean Energy Standard.

Efficiency incentives should serve our strategic goals of phasing down surcharge-funded resource acquisition programs and increasing market transformation achievements, including both targeted efficiency that is enabled by newly monetized value streams and transactional platforms, and also efficiency implemented by customers and third-party market participants with a reduced need for direct utility support.

We are also informed by past experience with shareholder incentives for energy efficiency. In 2008, the Commission adopted symmetrical incentives in the EEPS proceeding, geared toward approved targets, ranging from a full negative adjustment at 50% achievement to a full positive award

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[86] Case 15-M-0252, In the Matter of Utility Energy Efficiency Programs, Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2016 – 2018 (ETIP Order)(Issued and Effective January 22, 2016).

[87] Case 14-M-0094, supra, Order Authorizing the Clean Energy Fund Framework (Issued and Effective January 21, 2016).

at 100% achievement.[88] In 2011, as part of its comprehensive recommendations for continuation of EEPS, Staff recommended that shareholder incentives should be eliminated. Staff's rationale was that incentives tied to direct utility achievements caused a continual state of argument over targets and budgets and distracted from the critical task of improving programs.[89] This finding is consistent with the avoidance of counterfactuals guidance described above, and parallels an almost identical finding of the Energy Division of the California Public Utility Commission in the analysis of its own incentive program.[90]

In adopting a second stage of EEPS funding, the Commission partially agreed with Staff, but determined that some form of performance incentive should remain in place. The Commission ordered a positive-only incentive program with substantially reduced award levels, effective through 2015. The Commission also incorporated an outcome component that tied utility incentives to achievement of statewide goals including those of NYSERDA.[91]

Shareholder incentives under REV will continue this direction away from utility-specific resource acquisition and toward more outcome-oriented metrics that encourage market

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[88] Case 07-M-0548, supra, Order Concerning Utility Financial Incentives (Issued and Effective August 22, 2008).

[89] Case 07-M-0548, supra, Energy Efficiency Portfolio Standard Program White Paper (filed July 6, 2011).

[90] The CPUC Energy Division described savings calculations as causing "protracted disputes" and a "diversion that has consumed too much … time within the IOUs, other stakeholders, and the CPUC." "White Paper on Proposed Energy Efficiency Risk-Reward Incentive Mechanism and EM&V Activities," April 1, 2009, at 7.

[91] Case 07-M-0548, supra, Order Authorizing Efficiency Programs, Revising Incentive Mechanism, and Establishing a Surcharge Schedule (issued October 25, 2011).

participation and collaboration across efforts, and which support the State's efficiency and carbon reduction goals.[92]

In the ETIP order, the Commission stated that ETIP targets should be the minimum and that additional savings should be achieved through more market-based approaches.[93] Without excluding other innovative opportunities, three possible value-based ways of increasing efficiency achievements are: efficiency measures responding to locational needs as identified in DSIPs; efficiency measures bundled by DER providers with demand response, time-variant pricing, and/or other measures to reduce customers' total bills; and market transformation efforts in cooperation with NYSERDA and local governments.

Utility shareholder earning opportunities will be oriented toward these opportunities for enhanced achievement. The ETIP targets themselves will serve as a baseline, but for purposes of a utility earning opportunity, a longer term and more expansive efficiency target will be developed.

In the CEF order, a Clean Energy Advisory Council (CEAC) was established.[94] The CEAC will recommend a target or set of targets that are tied to State Energy Plan and Clean Energy Standard goals, and toward reducing the cost of achieving

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[92] See, e.g., "Metrics for Energy Efficiency: Options and Adjustment Mechanisms, America's Power Plan," April 2016; "Energy Efficiency Policy Manual," Illinois Energy Efficiency Stakeholders Advisory Group, August 2014; "We All Did It-Attribution of Savings in an Environment with Many Helpers," Energy Trust of Oregon, 2006 ACEEE Summer Study on Energy Efficiency in Buildings; "The Next Quantum Leap in Efficiency," Regulatory Assistance Project, January 2016 pp. 18-21.

[93] ETIP Order, pp. 28-29.

[94] Case 14-M-0094, supra, Order Authorizing the Clean Energy Fund Framework (Issued and Effective January 21, 2016).

these goals through cost-effective and market-initiated efficiency.

The Commission will adopt a target or targets following recommendations from the CEAC, incremental to ETIP targets, which will support an earning opportunity metric for utilities.[95] One of the metrics for earning opportunity should be electric usage intensity across the utility's territory. A metric tied to system-wide usage intensity will encourage utilities to facilitate CCAs, ESCOs, and DER providers in bundling energy efficiency with other value-added services to reduce customers' total bills. It will also encourage utilities to collaborate with NYSERDA, local governments, and CCAs toward achieving mutual local and statewide objectives.[96] A number of energy intensity metrics can be considered, including kWh per capita, kWh per customer, and kWh per GDP.[97]

Additional earning opportunities may be based on program-specific savings tied either to efficiency achievements that exceed minimum program targets, or cost savings achieved by cooperative activities or innovative market approaches requiring

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[95] The discussion in this order is directly applicable to electric rates and electric efficiency targets. The CEAC should also consider applying this approach to gas efficiency targets, with comparable EAMs to be considered in gas rate cases.

[96] System-wide reductions can be brought about by a combination of ETIP programs, third-party-initiated and targeted measures, and market transformation including improvements in codes and standards and enforcement. Normalization for weather, economic development, increases in electric vehicles and heat pumps, and possibly other factors will also be required. A precise method will be recommended by the CEAC process.

[97] See, e.g., "Metrics for Energy Efficiency: Options for Adjustment Mechanisms," America's Power Plan, April 2016, pp. 4-5.

fewer incremental ratepayer funds. Any earning adjustments related to net savings should be tied to advances in Evaluation, Measurement and Verification (EM&V) that utilize direct customer information.[98]

Utilities may also propose EAMs tied to innovative efficiency measures that help to achieve goals established in the low-income affordability proceeding.[99] Because NYSERDA is the principal provider of low-income energy efficiency services, utility proposals should demonstrate how they will either improve the effectiveness of NYSERDA programs or work in coordination with NYSERDA programs.

This approach will tie utility earnings to (a) greater overall efficiency achievements, (b) the transition toward market-driven achievements and away from surcharge-funded programs, (c) coordination with efforts to reduce peak and improve load factor; and (d) improvement on attribution-based EM&V measures that have proven to be problematic in the context of utility incentives.[100]

*Interconnection*. Staff proposed an EAM for smaller projects of less than 50 kW. Because these projects should be reviewed and approved with limited analysis required, Staff proposed a negative adjustment if 100% of projects are not

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[98] See, e.g., "How Information and Communications Technologies Will Change the Evaluation, Measurement, and Verification of Energy Efficiency Programs," ACEEE Report IE1503, December 2015; "The Changing EM&V Paradigm," Northeast Energy Efficiency Partnerships, December 2015; "Model Energy Efficiency Program Impact Evaluation Guide," USEPA, November 2007.

[99] Case 14-M-0565, supra.

[100] See, e.g., "Accelerating Carbon Reductions from California's Electricity Sector," America's Power Plan, March 2015, pp. 17-30.

processed in a timely manner as required under the Standardized Interconnection Requirements (SIR).[101] Staff also recognized the risk that a potential negative adjustment for interconnections could give utilities an incentive to reduce the overall volume of interconnection applications. In order to avoid this, Staff proposed that a positive incentive should be available to utilities for timely processing of applications in any year in which the total number of approvals is 20% higher than the previous year. Staff also addressed projects greater than 50kW, but recognized that these are more complex and proposed that an EAM be developed, with party participation, around the goals of timeliness and cost of compliance.

The Joint Utilities agree that separate metrics for small and larger projects are reasonable. They oppose the 100% threshold for processing small projects, arguing that even with an automated system 100% is not a realistic standard. The utilities also oppose the 20% increase standard for a positive incentive. With respect to larger projects, the utilities propose that after the latest revisions to the SIR are finalized, an effort to define metrics should be undertaken. The utilities also note that factors such as timeliness are often affected by the customer.

Solar developers including IREC, TASC, and SEIA supported an interconnection EAM and suggested that it should reflect timeliness, cost, access to data, and customer satisfaction. Along with NYC, they suggested that the metric should be symmetrical. AEEI supported the metric proposed by Staff. EDF cautioned that interconnection of some types of distributed generation should not be promoted until emission rules are in place.

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[101] Case 15-E-0557, supra.

*Discussion*

Expediting the interconnection process will promote market development of DERs. Utilities' detailed plans with respect to interconnection improvements will be addressed in the DSIP filings and the revisions to the SIR.

Comments of the parties emphasized timeliness and cost reduction in the interconnection process. Staff's analysis shows that these problems are more pronounced in the complex applications above 50kW in size. Processing of smaller applications presents fewer issues. The straightforward nature of small project approvals, and the relative lack of judgment required, makes these both easier to achieve by utilities, and more amenable to ordinary enforcement of the existing SIR rule. Therefore, we decline to apply an EAM to applications for projects under 50 kW, in order to focus the total potential risks and rewards of EAMs on the greatest need, which is the larger applications.

For projects over 50 kW, the revisions to the SIR recently adopted by the Commission[102] include several standards that could be the basis for performance-based EAMs. These include the 10-day period to review and determine completeness of applications, the 15-day period to complete and return the results of the Preliminary Review/Screening Analysis, and the requirements related to accuracy of cost estimates. Further, we note that a successful interconnection process in the REV context requires three interrelated attributes: high quality applications, timeliness, and reasonable costs. An interconnection EAM must address each of these attributes.

As to the directionality of an interconnection EAM, Staff expressed a concern that negative EAMs for interconnection

[102] Id.

could have counterproductive effects. Specifically, a timeliness metric alone could encourage utilities to skew their consideration of applications, including undue or premature rejections, merely to meet time standards. Negative EAMs could create an unintended incentive for utilities to undermine DER in general, in order to reduce the total number of interconnections they need to process. For that reason, Staff proposed a positive incentive for complying with SIR requirements in the event of year-over-year growth in applications. However, numerous parties objected to this proposal on the grounds that the threshold is difficult to define and that annual growth will be irregular. We agree with those parties and decline to establish an incentive based on annual growth in interconnection approvals. Increased penetration of DER will be a product of other earning opportunities and scorecards discussed in this order.

Another challenge associated with a negative EAM in this category is that it is often unclear who is at fault when an application cannot be processed in a timely way. Instead, the interconnection EAM should be developed to encourage cooperation and efficient pre-application consultations to avoid problems and backlogs in later stages of the process. This is consistent with our outcome-based approach, in which utilities may not have direct control but should be incentivized to collaborate with applicants to produce an effective, efficient result.

Therefore, we will establish an interconnection EAM with the following components:

- A threshold condition based on adherence to the timeliness requirements established in the SIR; and
- A positive adjustment based on an evaluation of application quality and the satisfaction of applicants

> with the process, as measured by 1) a survey of applicants to assess overall satisfaction, and 2) a periodic and selective third party audit of failed applications to assess accuracy, fairness, and key drivers of failure in order to support continual process improvement.

A positive incentive applied to all utilities does not rule out the potential for negative adjustments applied on a case-by-case basis. As discussed above, negative adjustments for the topics treated in this order should generally be reserved for exceptional cases of inadequate effort or performance. In the case of interconnection, this will be considered in the context of individual utility proceedings.

*Customer Engagement and Information Access*. Staff proposed an EAM that gauges utilities' success in implementing an online portal to connect customers with DER providers. Recognizing that development of this portal will take time, Staff proposed an interim EAM around three goals: (1) implementation of a statewide tool to provide utility customers access to their energy information and ability to share it; (2) the percentage of customers using this tool; and (3) successful promotion of demand response and time-variable rate programs.

DER parties including AEEI, Mission:data, TASC and Comverge/EnergyHub agreed that a consumer engagement EAM is a high priority. The Joint Utilities argued that more experience is needed through demonstration projects before specific EAMs on these subjects are established. MI, Nucor, and NYC argued that EAMs are either unnecessary or should at a minimum be symmetrical and tied to actual customer usage rather than mere utility compliance with requirements.

Parties disagreed over many aspects of a statewide customer portal, including its potential value, how long it may take to develop, and how it should be operated.

With respect to the specific interim measures proposed by Staff, DER parties generally supported the measures although many comments suggested alternative measures. AEEI proposed that an engagement metric should be based on the concepts of reach, usage, effectiveness, and feedback. SEIA urged a metric based on customer knowledge and the number of customer requests for information. NYC and MI argued that actual customer engagement must be part of any metric. The Joint Utilities opposed this, arguing that customers' decisions to use engagement tools are beyond the utilities' control.

*Discussion*

Customer engagement and access to data are critical to the development of distribution-level markets and the resulting integration of DERs into system operations, as well as improved ability of customers to manage their bills. The Commission has emphasized the importance of engagement in the Framework Order, the DSIP Guidance order, the Con Edison Advanced Meter Infrastructure order, and the orders related to Community Distributed Generation and Community Choice Aggregation.[103] Customer engagement contributes to almost all of the outcomes

[103] Framework Order, p. 50; Case 14-M-0101, supra, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016), p. 58; Case 13-E-0030, et al, Consolidated Edison Company of New York, Inc. – Electric Rates, Order Approving Advanced Meter Infrastructure Business Plan Subject to Conditions (issued March 17, 2016) (AMI Order), p. 35; Case 15-E-0082, supra, Order Establishing a Community Distributed Generation Program and Making Other Findings, p. 24; Case 14-M-0224, supra, Order Authorizing Framework for Community Choice Aggregation Opt-Out Program (issued April 21, 2016) (CCA Order), p. 22.

that result in PSRs or EAMs; it should be integral to all facets of REV implementation. A utility's satisfactory performance of the DSP function will rely in part on success in facilitating customer engagement.

Customer engagement is also, to a large extent, the responsibility of market participants. The utility should play a facilitating role by providing access to data and by connecting customers with vendors. Both of these principal customer engagement tools have been or may be mandated by the Commission. Utilities are required to develop tools to facilitate sharing of system data and consumer-specific usage data, thereby facilitating customer engagement. These include the ability for ESCOs and DER providers to gain access to data on a time-granular basis (e.g., hourly consumption data). Each of the utilities have created an online marketplace portal to facilitate market access. As part of their business development each utility should evaluate the success of the marketplace and identify whether and when they should be expanded to include all end use consumers. Because customer engagement underlies the majority of the other outcomes that may result in utility earnings, and because the principal customer engagement tools have been or will be mandated, no general EAM is needed in this area.

The Commission, will, however, entertain specific customer engagement EAMs for the adoption and success of innovative utility programs. Such EAMs will provide utilities the opportunity for additional earnings for taking action which affects the behavior of their customers. For example, incentive awards can be provided for customer uptake of programs for opt-in time-of-use rates or a future smart home rate, demand response and energy efficiency programs, and initiatives related to fuel switching (such as electric vehicle adoption and ground source heat pumps). Proposals for EAMs of this nature should include an evaluation of expected customer and system benefits from the programs, and should be calibrated against other anticipated utility incentives from their roll-out.

*Greenhouse gas reductions*

*Achievement of Clean Energy Standard goals*. In a separate proceeding, the Commission is considering a Clean Energy Standard (CES) to achieve the State's target of 50% renewable generation by 2030.[104] Utilities should have earning opportunities tied to reducing the cost of achieving the CES goal. The specific nature of opportunities will depend on policy and implementation decisions that will be made in the CES proceeding.

*Decarbonization of end uses*. The State Energy Plan targets a 40% reduction in greenhouse gasses from 1990 levels throughout the economy. Along with electric production, the highest producers of greenhouse gasses are the transportation and building sectors. The developing electrification of transportation and the ability to convert buildings to geothermal-electric heating and cooling have the potential positive effects of reducing carbon and increasing the efficiency and dynamic capability of the power grid.

The strategy for reduction of greenhouse gasses in the State Energy Plan calls for reducing carbon emissions in transportation and buildings as well as the electric system. As carbon emissions from the electric system are reduced through the CES, NY Sun, and other REV efforts, conversion of cars, trucks, and home and water heating systems to highly efficient electric end-uses will have at least two benefits: first, when properly integrated as active DERs, these end uses will reduce

[104] Case 15-E-0302, supra.

carbon emissions, particularly where charging and pre-heating can occur during off-peak times when the generation mix is increasingly low-carbon[105]; second, conversions will increase total usage and improve system load factor, spreading the cost of the electric system across a greater number of sales units, with resulting savings for customers both in the form of immediate savings and also by reducing long term business risks for utilities.

Staff proposed that end-use conversion should be developed as a scorecard metric. We will include this item on the list of scorecard metrics. Conversion efforts, however, should not await the development of a statewide metric. We encourage utilities to propose programs and strategies to enable and facilitate the beneficial conversion of end-uses. These proposals may contain positive earning opportunities linked to estimated customer savings.[106]

*Affordability.* Recognizing the need for immediate and substantive action to address affordability, Staff proposed an EAM geared toward reductions in both terminations and arrearages. Both terminations and arrearages must be included because an EAM for reducing only one of those could result in increases to the other. Staff also proposed an EAM related to the level of DER participation by low-income consumers.

While acknowledging the underlying problem, parties had numerous objections to Staff's proposal. PULP stated that no utility incentive is needed, and that any resources that

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[105] See, Reply Comments of CEOC, Appendix, "Carbon-Tuning New York's Electricity System: Uncovering New Opportunities for CO2 Emissions Reductions."

[106] To the extent that end-use conversions are already encompassed within a peak reduction/load factor metric, or a customer engagement metric, they should not be subject to a double count.

might fund an EAM would be better dedicated directly toward low-income consumer discounts. PULP further argued that the best way for the Commission to address affordability in the context of REV is to ensure that utility expenditures to implement REV are cost-beneficial. Utilities stated that measuring engagement in DER is premature, and reducing terminations and arrearages will not be feasible unless specific tools are created to achieve these goals. Other parties including NYC and CEOC stated that the proposed metrics will be correlated with exogenous factors that utilities should not be given credit for. MI and Nucor argued that affordability is a problem for all types of consumers and any metric should be oriented toward general rate reductions. AEEI was generally supportive of a DER engagement metric but argued that the range of DER activities needs to be drawn more broadly.

*Discussion*

The Framework Order explained at length how electric customers and utilities face a number of challenging trends that compel the modernization of the utility model. As the REV initiative moves forward, however, we are very mindful that an affordability crisis exists in the present for many vulnerable customers. The low-income affordability proceeding[107] was begun for that reason.

Staff is correct that, in the long term, utility revenues need to reflect incentives to maintain affordability for lower-income customers. For immediate purposes, however, we are persuaded by the arguments of parties that a DER engagement metric for low-income customers is premature and that the goal of reducing terminations and arrearages is best addressed by

[107] Case 14-M-0565, supra.

other means at this time. PULP commented that a specific incentive for affordability is not needed at this time, and that the best way for the Commission to address affordability in the REV context is to manage the rollout of REV in the most prudent and cost-effective manner possible. We will order that the affordability metrics described by Staff should be monitored as scorecards at this time.

In the context of the affordability proceeding, energy efficiency programs will be an important component of an overall strategy to reduce household energy burdens. Utilities can improve their referrals to NYSERDA's low-income efficiency program by identifying high usage customers and customers with high arrearages to be considered for priority treatment. The effectiveness of utility cooperation with NYSERDA in this regard should also be reflected in the scorecard.

As DSP markets develop, we anticipate that a uniform approach to outcome-based EAMs for reducing overall terminations and arrearages, and increasing engagement with DER, will be appropriate in the REV context. In the interim, termination and arrearage metrics will be considered if deemed necessary in rate plans on a case-by-case basis.

## D. Scorecards

### 1. Staff Proposal

Staff proposed that a number of metrics should be maintained as scorecards to measure desired outcomes, particularly where reliable metrics have not yet been developed. Scorecards would measure outcomes but would not have any direct impact on regulated earning opportunities. They would provide transparency to further enable markets, utility planning, and regulatory supervision. Refined scorecard metrics could potentially be used as EAMs in the future.

The scorecard candidates proposed by Staff are:

- System utilization and efficiency: this would encompass load factor, T&D system utilization, fuel diversity, and overall system heat rate;
- DER penetration: this would focus on the penetration of distributed generation, dynamic load management, and energy efficiency as a percentage of total utility load;
- Time-of-use rate efficacy: this would measure the rate of adoption of opt-in TOU rates, and the ability of customers to reduce their bills via these rates;
- Market development: this would track the standard indicators of market health including transparency, ease of access, settlement facilities, and dispute resolution;
- Market-based revenues: this would track the amount, and sources, of utility revenues from platform and value-added services, to reflect the degree of market uptake and the success of utilities in adjusting their business models;
- Carbon reduction: this would track the market penetration of carbon-free sources as a percentage of total load within each utility’s service territory;
- Conversion of fossil-fueled end uses: this would track the adoption rates of electric vehicles and conversion of combustion appliances to high-efficiency electric appliances;
- Customer satisfaction: this would utilize existing indices that measure customer satisfaction, complaint response time, escalated complaint response time, and pending cases; and
- Customer enhancement: this would be a broader index encompassing the affordability metric, customer engagement

in markets, customer satisfaction, and HEFPA compliance rates.

There is wide support among parties for a scorecard approach. The Joint Utilities supported scorecards but cautioned that they could become overly burdensome to track and outcomes outside of utility control should not be used to judge utility performance. MI urged that some of the EAMs proposed by Staff should begin as scorecards until the metrics are better established. Several parties including New York City, CEOC, NYU and EDF argued that carbon reductions should be an EAM rather than a scorecard, especially in light of the 50% renewables goal in the State Energy Plan.

2. Discussion

Scorecards are a widely accepted method of tracking progress, and particularly appropriate for a broad ground-breaking initiative such as REV. The utilities' concern that tracking metrics should not be overly burdensome is a legitimate but manageable concern. Considering the wide range of scorecards put forward by Staff, and the need for further specificity in the actual metrics to be used, this subject should be developed further through a collaborative effort of the parties. The categories proposed by Staff should be used as a starting point and considered presumptively reasonable, but not to exclude other categories proposed by parties, or the reduction of Staff's list if some prove impractical or unnecessary.

Several parties argued that a carbon metric is needed as an EAM rather than a scorecard. Considering the high importance of carbon reduction as reflected in the proceeding to create a Clean Energy Standard (CES) to achieve the State's 50%

renewables goal,[108] this proposal should be considered seriously. As described above, much depends on the nature of the mandate that will be established in the CES, including the extent of utility responsibility and the mechanism for enforcement of the mandate. For that reason, it is premature to determine whether a separate incentive is needed for carbon reduction, until the CES is finally established. In the meantime, the metrics for a carbon reduction measure should be considered along with other scorecard categories.

Staff proposed an EAM related to affordability for low-income customers. For the reasons discussed above, the items in Staff's proposal are best suited as scorecard measures at this time, and household energy burden should also be measured in that scorecard.

An important objective of REV that was only indirectly reflected in the proposed metrics is resilience, i.e. the capability of the system and of individual customers to withstand severe events. Considering the importance of resilience, because of increasingly severe weather patterns and the growing reliance on electric supply in the digital economy, resilience should also be added as a distinct scorecard measure. A resilience metric may consider factors such as the percentage of customers equipped to maintain islanded service during a prolonged widespread outage, or improved utility response capabilities in the sense of system visibility and remote outage management, or resilience as it applies to critical facilities and vulnerable circuits.

[108] Case 15-E-0302, supra.

## E. Other Revenue Issues

### 1. Earnings Sharing Mechanisms

#### a. Staff Proposal

Earnings sharing mechanisms are a component of multi-year rate plans that allow utilities to retain earnings exceeding their target ROE levels, up to a level such as 50 basis points, and then to share earnings beyond that point with customers. The intent of ESMs is to encourage utilities to pursue efficiencies, while removing rewards for steep cuts and ensuring that forecasting vagaries do not become windfalls for shareholders.

Staff proposed that ESMs should be adopted to an outcome-based approach by being linked to outcome matrices. Under Staff's proposal, utilities that meet certain outcome standards would be able to retain a higher percentage of their earnings, while sub-par outcomes would result in a larger share of revenues being allocated to customers.

Parties had a wide range of reactions to this proposal. NYECC and CEOC supported the proposal. MI and Nucor supported the linkage of ESMs to outcomes and MI suggested that the opportunity to earn via ESMs should be the sole means of recovering EAMs. Conversely, the advanced energy parties would not support the use of ESMs if they replaced EAM incentive payments. AEEI noted that modifying the ESMs is not an effective mechanism for encouraging outcomes when a utility is not earning its return. PULP and AARP withheld judgment due to lack of detail as to the specific metrics that would be used. New York City expressed concern that allowing utilities to recover a greater percentage of earnings might come at the expense of customers who have not benefited from the activities underlying the metrics. The Joint Utilities opposed linking ESMs to metrics, arguing that ESMs as currently used are an essential component that properly reflects the risks and rewards of multi-year rate plans.

b. Discussion

Staff's proposal is theoretically sound and consistent with our direction to promote REV objectives and to place a greater emphasis on outcomes. It is reasonable, however, for parties to be concerned that changing the approach to ESMs will disrupt what has become an essential component of multi-year rate plans. Given the range of reasonable concerns raised by parties, we will not require the linkage of ESMs to outcomes as a uniform policy, at this time. In keeping with our current practice, specific revenue adjustments will be excluded from ESM calculations.

The greater potential for Staff's proposal lies in the years after successful experience with platform service revenues and scorecard metrics has been gained. EAMs are an expedient whose scope is administratively determined. Ultimately, the upper bounds of utility earnings should be tied to what they can achieve in customer bill savings and policy objectives. If the potential for higher earnings on a smaller rate base results in bill savings, utilities should be encouraged to achieve this. Rather than immediately tying earning sharing mechanisms to EAMs, as recommended by Staff, our goal will be to eventually tie earning sharing mechanisms to PSRs and to the more systematic metrics that are currently marked for scorecard treatment. This will not be a device to limit earnings potential but rather to expand it.

2. Clawback Reform

a. Staff Proposal

During the course of a multi-year rate plan, a utility can potentially increase its near-term earnings by withholding funds from capital projects that were included in its base rates.[109] For this reason, rate plans include a "net plant reconciliation mechanism" which is normally referred to as the "clawback" mechanism. The clawback provides that earnings from capital programs that fall below approved levels must be returned to customers.

Staff observed that, regardless of the questions around long-term capital bias, REV requires a change in the clawback mechanism because of near-term effects. Under REV, utilities will be encouraged to pursue cost-effective DER alternatives to capital investments. Because these alternatives will often be achieved through operating expenses, the ordinary operation of the clawback mechanism would result in utilities forfeiting their capital earnings with no offsetting compensation, and a risk of absorbing the DER operating expenses that were not reflected in base rates.

For this reason, Staff proposed a change in the clawback mechanism that would allow utilities, when they adopt DER alternatives to capital projects, to retain the earnings on capital that are already reflected in base rates, until rates are reset in the next rate case. These earnings would be offset by the utilities absorbing the operating costs of procuring the DER. At the next rate case reset, the DER expenses would be incorporated into base rates and the earnings associated with the foregone capital project would be removed.

Staff's proposed clawback reform would not only address the inherent disincentive to pursue DER alternatives, but it would provide default protection against DER projects that are not cost-effective, because only if the DER expenses

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[109] This is a near-term opposite of the capital bias that may exist in the longer-term perspective.

are lower than the rates associated with the capital project would it be in the utility's interest to procure the DER.

Parties were generally supportive of this proposal, with some exceptions and concerns. The Joint Utilities proposed that utilities be allowed to retain the capital earnings for a period beyond the next rate case reset, to ensure that the intent of the clawback reform is realized. Other parties such as AEE, TASC, and SEIA supported the reform but observed that it addresses only a narrow set of projects and is not a replacement for more wide-reaching incentives. MI and the utilities both pointed out that the bulk of utility capital investment will continue to be made in conventional infrastructure projects. CEOC and Nucor noted that the clawback reform presents a risk of utilities inflating their initial capital estimates; CEOC proposed that 20% of the net savings be retained by shareholders. New York City agreed that utilities should be able to share in the savings of a cost-effective alternative, but cautioned that the clawback mechanism plays a valuable role and should not be abandoned.

b. Discussion

The Staff proposal will be adopted with modifications. The clawback mechanism in general remains an important component of multi-year rate plans. Staff's proposed reform has a limited application and is not, in itself, a complete solution to issues around capital and operating expenses. It is, however, a very sensible approach to an unintended consequence of the general clawback device. The most serious objection to the clawback reform is that it could provide an incentive for utilities to inflate their initial estimates of capital costs. This incentive exists already in cost-of-service ratemaking, however.

It is countered by the analysis by Staff and parties of the reasonableness of utilities' estimates.

We direct that any multi-year rate plan including a clawback mechanism should also include the reform mechanism as proposed by Staff.[110] In implementing this reform, it is imperative that any retention of earnings on capital must be directly linked to a demonstration of the DER alternative that replaced the capital project.[111]

Consideration should also be given to how this mechanism can reward longer-term savings in a balanced manner as proposed by the Joint Utilities and CEOC. This could involve sharing of savings over a certain number of years rather than Staff's proposal to completely retain savings during the pendency of a given rate plan. Where multi-year rate plans are currently underway, a utility adopting a DER alternative to a capital project may receive comparable treatment upon filing a detailed compliance document demonstrating how an operating expense solution is being used to cost effectively offset and delay a capital investment included in the rate case capital plan.

3. Totex

a. Staff Proposal

A more comprehensive way to address the issue of potential capital bias is simply to eliminate the distinction between capital and operating expenses, for ratemaking purposes.

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[110] As always, a settlement proposal may demonstrate exceptional circumstances that warrant a departure from this principle.

[111] Implementation should also be flexible in consideration of the fact that many capital projects do not see large expenditures closed to plant in service in their early years, which may cause the benefits of the clawback reform to be outweighed by administrative burdens.

This approach combines operating expenses (opex) with capital expenditures (capex) into a single sum of total expenditures (totex).

Staff identified the United Kingdom's RIIO initiative as the most prominent use of the totex approach. RIIO employs a predetermined percentage (typically around 80%) of totex upon which a return is earned ("slow money") and the remainder is recovered on an annual basis ("fast money"). Because the percentage is based on an approximation of actual capital and operating differences, the use of a fixed percentage means that utilities have no incentive one way or another to employ capital versus operating approaches.

Staff noted that differences in accounting standards between the United Kingdom and the United States would complicate efforts to import the totex approach here.[112] Staff invited parties to comment on additional or alternative approaches that could achieve the totex objective.

Party comments on the totex discussion showed a mixed reaction. The Joint Utilities believed several of the objectives associated with the UK's RIIO totex approach identified in the Staff White Paper can be introduced utilizing traditional cost-of-service ratemaking. NFG stated that a totex approach should not be pursued by the Commission due to differences in accounting standards between the US and UK and because UK utilities do not serve as the DSP. The City of New York and Nucor questioned the existence of a capital bias and the need for major changes to address it. AEEI, SEIA, and TASC supported a totex approach, while CEOC expressed concern that changed approaches to cost recovery might lead to overall

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[112] White Paper, p. 43.

increases in costs. Multiple Intervenors reserved judgment pending more detailed development.

AEEI also proposed an alternative, in which alternative utility budgets are prepared based on a traditional capex approach and a modified DER-oriented approach, and some portion of the savings of the DER approach are allocated to utilities.

b. Discussion

Mechanisms that consider efficiency of total expenditures like the totex approach have the potential to eliminate any capital bias that may undermine the economic substitution of DER resources for traditional utility capital expenditures. While the reform of the clawback mechanism addresses capital and operating concerns during the pendency of a rate plan, it does not address the planning process itself. The DSIPs and application of the BCA should result in deployment of the most cost effective solutions over a longer-term horizon. Equal rate treatment of opex and capex would facilitate these efforts. In addition, our management audit program has expanded its reviews of utility capital program planning and operational efficiency to consider how the implications of REV are being reflected in utility capital planning processes.

Even a full adoption of totex, however, would not remove a potential utility bias toward maximizing its own share of total system expenditures. EAMs and PSRs are intended to address these incentives.

Staff has identified technical obstacles to adopting a full totex approach at this time. In addition, parties have identified concerns over how and why totex would be an improvement over current approaches. Totex should continue to be studied, including both the efficacy of totex in addressing utility behavior, and potential means of dealing with accounting standards. The Commission has adopted a totex approach in the limited context of a single procurement.[113] As the United Kingdom gains more experience with RIIO, Staff and parties should evaluate that experience, explore alternatives, and report on their findings in the context of a rate case proposal or a DER program filing.

Utilities can earn a return on some types of REV-related operating investments within the current accounting system. Numerous IT applications will need to be developed and implemented. Rather than developing their own software, many businesses find it more efficient to enter contracts to lease software services over extended periods, typically three to five years. To the extent that these leases are prepaid, the unamortized balance of the prepayment can be included in rate base and earn a return. As utilities evaluate whether to purchase or lease these applications, their ability to earn a return on a portion of the lease investment should help to eliminate any capital bias that could affect that decision.[114]

### 4. Recovery of DSP-Related Investments

#### a. Staff Proposal

Staff discussed the rate treatment of utility investments that will be needed to build DSP functionalities. Recognizing that utilities will be responding to a Commission mandate, and that some of the investments will reflect new directions, Staff addressed the potential risk by proposing that, "following close review of DSIPs, utilities should receive

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[113] Case 14-E-0302, supra.

[114] The decision to lease versus purchase will always be subject to review by the Commission.

assurance … that the initial decision to invest in these capabilities will not be subject to retrospective review."[115]

Customer advocates strongly criticized this proposal. PULP, New York City, Multiple Intervenors, Nucor, and AARP described the proposal as a blanket pre-approval which shifts risk and upends traditional ratemaking. The Joint Utilities argued that assurance of cost recovery will expedite the implementation of REV initiatives. They further argued that pre-approval should cover a range of REV-enabling initiatives such as advanced metering, and that timely recovery of investments might need new ratemaking tools such as surcharges.

b. <u>Discussion</u>

Despite the level of argument around it, Staff's proposal is relatively straightforward and does not represent a major departure from past practice. Staff's proposal addresses the decisions to undertake certain types of investments, but it does not protect utilities from any risk associated with their implementation of those investments. Utilities will still be required to cost effectively manage costs associated with these investments. Staff also plainly stated that approval of DSP projects should come only after careful review of DSIPs, and that implementation should still be subject to prudence review.[116] In these respects, the proposal bears little difference from the approval of a capital plan in a rate case. We adopt Staff's proposal.

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[115] White Paper, p. 68.

[116] The Framework Order made clear that the Benefit Cost Analysis framework is most directly applicable to specific utility procurements and tariff development, while the review of DSP expenditures will require an exercise of informed judgment in appraising costs against a range of potential benefits. Framework Order at 105-106.

Ratemaking always involves a balance in the allocation of risk. Allocation of risk to utilities does not always benefit ratepayers; the level of utilities' risk directly affects financing costs, which ultimately are borne by ratepayers. Where risk can be reduced without any substantial negative impact on ratepayers, it should generally be done. In this instance, the Commission has ordered utilities to undertake REV initiatives, some of which involve new directions in system planning and operation. The Commission has also encouraged utilities to be innovative and responsive to the needs of markets in order best to serve customers. Explicit guidance from the Commission will reduce the perception of financial risk and thereby affect the cost of not only DSP investments but all utility investments.

Approval of investment plans in this context is intended to reduce overall risk, not to shift risk. As one expert has stated, "assuming a front-end review that is no less rigorous than a back-end review, there is no reason to assume that business risk shifts from shareholders to ratepayers."[117] DSIP review will not be equivalent to a retrospective prudence review, but it will not preclude a back-end prudence review if one is warranted. Because utility expenditures are rarely subject to full-blown prudence proceedings, reliance on a front-end DSIP review will not represent any significant shifting of risk.

The City of New York stated that the Commission cannot bind future Commissions. This is true, but Staff has not proposed anything of the sort. The actions proposed here, like any other Commission actions, would require a reasoned

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[117] Hempling, Scott, "Riders, Trackers, Surcharges, Pre-Approvals and Decoupling: How Do They Affect the Cost of Equity?" p. 11.

explanation to be overturned by a future Commission. Because Commission determinations on DSP investments would only occur after thorough review of DSIPs, it is unlikely that a future Commission would overturn them. This is a familiar basis on which utility risk is assessed.

The only significant question to be resolved here is whether pre-approval will apply to general project decisions or to specific project budgets. Specific project budgets should generally be approved in the context of rate cases, although exceptions will occur where the project timing is in conflict with a utility's rate case cycle.

The request of the utilities for special recovery mechanisms is not pertinent to the issue of conceptual approval of REV investments. The appropriate recovery mechanism will be a function of several variables including the timing of rate cases, the type of investment or procurement, and the circumstances of individual utilities.

Staff observed that DSP investments will need to be distinguished from other sorts of investments. This will be relevant where approvals are determined outside the context of a rate case. Such distinctions should be drawn narrowly, i.e. with a presumption that many types of grid modernization would be undertaken whether or not REV required the development of DSP capabilities.

### 5. Long Term Rate Plans

#### a. Staff Proposal

Staff proposed a set of criteria under which rate plans could be extended from three years to five years. These criteria include periodic reviews and maintenance of satisfactory price and earning levels.

According to Staff, extending rate plans has several potential benefits. It would provide stability and predictability of rates while markets are developed; it would allow for multi-year incentives to be achieved; and it would remove the distraction of rate proceedings and enhance focus on implementing changes.

A large majority of parties argued against changing the terms of rate plans at this time. Most accept three years as the optimal term for a negotiated rate plan. Several parties expressed concern that during this REV transition period, oversight, audit, and regulatory structure must be maintained on a regular and transparent basis. Others expressed concern that a Commission preference for longer term plans would give utilities added leverage in negotiations.

b. Discussion

In evaluating this issue, it is noteworthy that the RIIO initiative includes eight-year rate plans, with regular reporting and review, in order to encourage long term efforts to satisfy performance and outcome metrics. We see significant potential for longer-term plans to achieve the benefits described by Staff. At the same time, the concerns expressed by parties are reasonable, especially during this early transitional period of REV.

For that reason, we will not order the development of long term rate plans at this time. Neither will we preclude the possibility of a well-structured agreement among parties, along the lines described by Staff. Although we cannot bind future Commissions in their consideration of negotiated rate plans, our policy and expectation is that any long-term plan that is presented for adoption should either have the active participation and endorsement of a substantial set of non-utility parties, or should convincingly rebut any concerns articulated by parties opposed to that element of the settlement.

## RATE DESIGN

### A. Rate Design: General Approach

#### 1. Staff's General Discussion

Staff analyzed rate design in the context of REV and found that, much like the utility revenue model, current rate design practices fail to provide adequate incentives and value signals that are suitable for a modern electric system. Traditional rate design formulas evolved in an era when modern information technology was not available, and the customer side of the electric system was not widely seen as a participatory resource. With large scale investments occurring on the customer side of the meter, correct value signals are needed so that those investments will be economic both for customers and for the system. Summarizing the need for more precise valuation methods, Staff stated, "The combination of cost, reliability, environmental, and competitive challenges facing the industry require that resources be optimized at the customer end of the system as well as the centralized production end."[118]

The crux of the issue, according to Staff, is that "residential and small commercial customers are not provided with information about the true components of cost or the means to effectively respond to the price signals such information can provide."[119] Rather than simply being a means to recover allocated costs, rate design should be used to send value signals that enable the reduction of total system costs.

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[118] White Paper, p. 11.

[119] White Paper, p. 74.

Price signals and transparency are essential to a healthy market. Rate design for mass market customers has been defined by a tension between fixed monthly charges and volume-based per-kWh rates, neither of which provides an optimal price signal or transparency into true system costs. With improved tools, Staff stated, rate design can move beyond the traditional argument between two inadequate pricing methods.

Staff identified three critical distinctions that must be resolved in order to achieve an optimal rate design:

- Merely changing rate design will not accomplish policy goals unless customers have the tools to respond to improved value signals.
- Increased precision in the rate paid by customers must be matched by increased precision in the compensation to customers for the contributions of DER to the system.
- Policy and equity objectives such as low-income impacts, gradualism, and environmental and social impacts must always be balanced with technical rate design objectives.

To assist in building a rate design that addresses these themes, Staff described two sets of useful distinctions. First is among types of customers:

- Traditional consumers — those customers who do not choose to actively manage their energy usage, or for whom it is difficult to do so.[120]
- Active consumers — those customers who undertake DER measures that allow them to actively modulate their

[120] Consumers who rent their homes, reside in multi-family or mixed-use facilities, and/or do not have individual metering may lack either an economic incentive or practical access to manage their energy usage by investing in DER.

usage in response to rate signals with the purpose of reducing their bills.

- Prosumers — those customers who install or participate in DER including generation or other technologies that allow them to provide services to the grid.

Second, Staff identified the dimensions along which granularity should be developed:

- Temporal — time-differentiating prices that vary in response to marginal price
- Locational — reflecting congestion or capacity constraints in pricing; for example, locational marginal pricing or distribution locational marginal pricing
- Attribute — unbundling rates to reflect the individual attributes embedded in electricity service; for example, energy, capacity, ancillary services, environmental impacts, or others.

2. Staff's Proposal

Staff proposed a set of rate design principles that build on traditional principles to guide rate design decisions for a modern electric system:

- Cost causation: Rates should reflect cost causation, including embedded costs as well as long-run marginal and future costs.
- Encourage outcomes: Rates should encourage desired market and policy outcomes including energy efficiency and peak load reduction, improved grid resilience and flexibility, and reduced environmental impacts in a technology neutral manner.
- Policy transparency: Incentives should be explicit and transparent, and should support state policy goals.

- Decision-making: Rates should encourage economically efficient and market-enabled decision-making, for both operations and new investments, in a technology neutral manner.
- Fair value: Customers should pay the utility fair value for services provided by grid connection, and the utility should pay customers fair value for services provided by the customer.
- Customer-orientation: The customer experience should be practical, understandable, and promote customer choice.
- Stability: Customer bills should be relatively stable even if underlying rates include dynamic and sophisticated price signals.
- Access: Customers with low and moderate incomes or who may be vulnerable to losing service for other reasons should have access to energy efficiency and other mechanisms that ensure they have electricity at an affordable cost.
- Gradualism: Changes to rate design formulas and rate design calibrations should not cause large abrupt increases in customer bills.

The general approach put forward by Staff is to gradually develop a rate design reflecting these principles and REV objectives, with particular emphasis on the finer granularity that is made possible by improved technology. Staff emphasized that gradualism is important not only for customers but also for DER-related industries that have developed around the current system of incentives.

The need for additional analysis of how rate design changes would affect policy objectives argues for a gradual approach. Also, as a practical matter, the current lack of widespread advanced metering capabilities may force a gradual approach over a period of years.

Staff's specific proposals were divided into near-term specific recommendations and long-term directional proposals that will need further process. The near-term recommendations made by Staff were:

- Utilities should file voluntary smart-home tariffs
- Opt-in time of use rates should be improved and promoted
- Rates for large customers should be examined to improve their time variability
- Low-income discounts should be located within a basic usage block
- Standby rates should include a reliability credit and a campus tariff

Long-term recommendations were:

- Analyze potential bill impacts of demand-based and default time-varying charges
- Review cost allocations for potential revisions to standby rates

In addition to changes in customer rates, Staff proposed that a method should be developed for valuing the contributions of DER. This method is applicable generally to markets for DER and specifically to suggested reforms of net energy metering. Staff proposed that NEM for small rooftop installations should be retained, and that monetary credits involved in larger NEM projects should reflect more granular valuations of the value of DER.

3. Party Comments

A large majority of parties supported the principle that rate design should be made more precise. Several parties representing consumer advocates expressed concerns regarding potential adverse impacts on lower-income customers, and environmental advocates expressed concerns over the price signals for energy efficiency and load reduction. What follows is a non-exhaustive summary of party comments related to Staff's general rate design discussion.

TASC generally supported Staff's discussion but noted that the method of achieving granularity matters greatly, and that, for example, there are important differences between a time-of-use approach and a demand-based approach. TASC agreed that rapid changes in government-sponsored programs and subsidies can limit the ability of new industries to develop marketable products. TASC also emphasized that the customer's ability to respond to price signals is a critical factor. TASC supported Staff's characterization of the three types of mass-market customer.

The Joint Utilities emphasized that economic efficiency should be the overriding objective of REV. In the context of rate design, this means that concerns of customer responsiveness are relevant but should not prevent the adoption of the most efficient price signals. They further argued that the economic efficiency of DER should not be generally assumed in establishing rates, and instead should be tested on an individualized basis and demonstrated over time. The utilities opposed the idea that gradualism should apply to existing DER industries; they argued that there is no economic analysis to support that approach. The Joint Utilities agreed with the traditional Bonbright principles for regulation but also supported Staff's proposed update, with one addition: the utilities proposed that economic sustainability across technology and market cycles should be a core principle.

The Energy Democracy Alliance stated that the impacts of rate design changes are hard to determine without more concrete analysis, and that this is exacerbated by the overall number and complexity of REV initiatives.

Vote Solar Initiative (Vote Solar) supported the proposed rate design principles, and particularly those that emphasize customer participation and low-income access. Vote Solar was skeptical that demand charges will send effective price signals to mass market customers, compared with time-differentiated charges.

BlueRock agreed that time and location granularity is the best way to increase involvement of customers in DER. BlueRock emphasized that improved metering will be needed to achieve this.

NYECC supported Staff's general approach and the proposed updated rate design principles. NYECC supported the strategy of encouraging voluntary options in the near term.

The Interstate Renewable Energy Council, Inc. (IREC) agreed that the challenges and opportunities facing the electric system require a reconsideration of traditional rate design methods, with an emphasis on customers' ability to exercise choice in an economic manner.

Exelon agreed that efficient price signals and transparency are critical to the success of REV. Exelon stated that the challenges facing the utility business model make it necessary to change fundamentally the way costs are recovered.

NY-BEST generally agreed with Staff's principles but was concerned that too great an emphasis on gradualism, and a prolonged period of transitional uncertainty, could impair market development.

AEEI supported the development of more granular rates, but cautioned that decisions must be made well in advance of implementation to give providers and customers time to adjust. AEEI argued that for mass-market customers, rate design changes must focus not only on delivery rates but also on default commodity service. AEEI supported the promotion of available opt-in programs in the near term, with emphasis on education and outreach. AEEI strongly agreed that industries that made investments in response to state incentive programs require a gradual approach to changes in order to adjust pricing and business models.

AEEI, TASC, and IREC agreed that Staff's distinction among traditional, active, and prosumer customers provides sound guidance for developing rate design changes.

TASC, AEEI and the Grid Wise Alliance all agreed that rate design should work proactively to avoid uneconomic grid defection, so that the benefits of the "sharing economy" can be realized in the context of the electric system.

The Grid Wise Alliance agreed that transparency in rates is as important as transparency in incentives.

The Real Estate Board of New York (REBNY) agreed that current rates will not serve to focus DER investment where it will be most valuable. REBNY cautioned that a swift move to real-time pricing could be counter-productive, as markets in their present state need price predictability and stability to support investments.

Citizens' Environmental Coalition argued that the regulatory reforms of the 1990s have not had a beneficial impact on low-volume customers, and that it is critical for social and environmental impacts to be considered in any transition.

New York City agreed that there are opportunities to improve rate design, and emphasizes the need for advanced metering to provide more granular information to customers. NYC urged caution, however, in making any generalized changes to mass market rates. The NYC opposed redefining rate classes based on consumers' adoption of DER.

AARP urged caution in changing established rate design principles, and observed that it is unclear whether Staff is proposing a change in emphasis versus a major change in direction.

PULP argued that shifting away from volumetric to fixed or demand charges will be detrimental to most residential customers. PULP opposed redesign of delivery rates based on a theoretical basis of improved price signals; a detailed analysis of bill impacts is needed, and impacts on conservation must also be considered. PULP was opposed to any rate design change that relies on widespread deployment of advanced metering, unless the costs and benefits of metering are included in the analysis of the rate design impacts. PULP also argued that general rate design changes should not be the answer to questions around net metering.

CEOC argued that the cost causation principle should emphasize long-run costs, citing the author of the traditional Bonbright principles. CEOC further noted that the customer orientation of rate reform must include the opportunity for customers to manage their bills.

Multiple Intervenors supported Staff's proposed principles, with the note that the principle of gradualism should apply not only to bills but to rates, because larger customers are more concerned with rates than they are with bills.

Numerous parties had a wide range of comments around the valuation of DER and the future of net energy metering. Those comments are not summarized here, in light of the treatment of that issue in Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources.

4. Discussion

The majority of party comments support Staff's observation that a more refined rate design, with improved price signals and opportunities for participation in DER markets, can benefit consumers and facilitate the accomplishment of REV objectives. We agree. At the same time, we join in the observation that these changes must be consistent with policy concerns regarding sensitivity to overall impacts on consumer bills, with particular regard to the most cost sensitive residential and commercial customers, and achievement of environmental policies.

Accordingly, our approach to rate design will be consistent with our approach to utility revenues. We will harness the opportunities created by enhanced technology and markets to increase value for all customers, through third party participation in grid operations and resulting productivity and efficiency. Because the customer side of the grid must become a system resource, prices must encourage more efficient investment decisions by customers. At the same time, changes will reflect the fact that consumers will need time to adapt and to make investments that allow for full value to be achieved. We will also continue to observe the need to maintain energy affordability for low-income customers.

While efficient cost recovery is the beginning of rate design, rates must also be designed to encourage price-responsive behavior to advance policy objectives. Just as cost-of-service revenues contain implicit disincentives for utilities to embrace reforms, the *status quo* of rate design contains implicit price signals that discourage customers from engaging with DER in a manner that optimizes both customer and system benefits. Improvements in rate design are essential to a modern electric system and the efficient operation of customer-oriented markets. Accurate value signals will enable customers to participate while avoiding uneconomic bypass of the system.

The most prominent concerns regarding reform of rate design were voiced by consumer and clean energy advocates AARP, PULP, NYC, and CEOC. Consumer advocates are opposed to any introduction of mass-market rate reforms without careful consideration of bill impacts and impacts on low-income customers. This is largely consistent with Staff's proposal; Staff noted that further process will be needed to carefully evaluate potential bill impacts before any generalized changes to rate design are adopted.

Beyond the question of bill impacts, the objection of some advocates is that long run marginal costs are avoidable and so should be recovered through volumetric rates. Volumetric rates are more likely to encourage conservation and efficiency, because customers realize greater savings with each unit of usage they avoid.

These are familiar arguments in the context of the opposition between fixed and per-kWh rates. Fixed charges should recover only costs that are invariable with usage, but parties disagree strongly as to which types of delivery system costs fall into the invariable category. As Staff has pointed out, more sophisticated ratemaking tools have the potential to bridge these differences in a manner consistent with fundamental rate design principles and REV policy. Rate design should encourage economic DER and conservation while avoiding the bypass that can occur if the individual customer savings from avoided usage are larger than the system and societal value of the avoided usage. Small value discrepancies and bypass are relatively minor issues in a centralized system with little DER, but they become major issues when customers and third party developers are investing on a large scale in resources that are integral both to the operation and the economics of the system as a whole. The rate reforms initiated here are not intended as a response to the current, relatively small, penetration of DER; rather they are needed to support a high-DER future.

Most of the discussion on rate design reform has centered on residential and small commercial ("mass market") rates. Large commercial and industrial customers (C/I) are no less important to DSP markets. C&I rates however, are already demand-based for delivery and hourly for commodity. Staff notes that some C/I delivery charges could be improved by making them more peak-sensitive. A customer should be encouraged to move its own peak demand to a time that is off-peak for the system (or for the local distribution circuit) when the system savings exceed the cost of shifting. We direct that existing C&I delivery charges should be evaluated in future or pending rate cases to determine whether they can be improved by making them more peak-sensitive and/or by changing the determinants such as peak-to-off-peak ratio that influence customer decisions.

Time-sensitive commodity rates for mass market customers should be considered along with reform of delivery rates. Larger C/I customers of utilities are required to take mandatory hourly pricing for commodity, while mass market customers that have not chosen to select ESCO service typically receive a pass-through of wholesale market prices that has been hedged by the delivery utility.[121] Although many of our rate

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[121] See, e.g., Case 06-M-1017, Proceeding on Motion of the Commission as to the Policies, Practices and Procedures For Utility Commodity Supply Service to Residential and Small Commercial and Industrial Customers, Order Requiring Development of Utility-specific Guidelines for Electric Commodity Supply Portfolios and Instituting a Phase II to Address Longer-term Issues (Issued and Effective April 19, 2007).

design decisions involve delivery rates, granular commodity rates are equally important.

Some ESCO parties argued that only ESCOs should be allowed to offer time-of-use rates to mass market customers. As REV progresses, ESCOs offering value-added services and community aggregation are expected to reduce the number of customers relying on utilities for default commodity service. A key purpose of REV is to increase consumer choice and market innovation. ESCOs will be able to offer options to help consumers respond and take full advantage of granular price signals, as they currently do with larger customers receiving mandatory hourly pricing. When utilities offer granular pricing, ESCOS will have the opportunity to use these price signals to offer budget based products that allow customers to reduce their overall costs through actions such as smart thermostats or other load modifying programs that are simple to administer. We, therefore, will not preclude e the potential for default commodity customers to receive time of use or any other form of advanced pricing signals.

The updated rate design principles put forward by Staff were generally supported by the parties. Three party suggestions in particular warrant consideration here. First, the Joint Utilities suggested adding a principle of business model sustainability. The chief thrust of the principle is that rates should generally not be designed around a particular technology so that technology choices can be determined by price signals in the long term. This is a reasonable proposal and we adopt it. Second, with respect to gradualism, Multiple Intervenors notes that for some types of customers rates are as important as bills, so that the principle of gradualism should apply to rates as well as bills. We adopt this suggestion.

The third suggestion is more problematic and again raises the issue of cost characterization. In the Cost Causation principle, Staff proposed that, "rates should reflect cost causation, including embedded costs as well as long-run marginal and future costs." CEOC proposes that this language should be changed to "… rates that … reflect long-run marginal costs but also recover embedded costs. Fixed charges should only be used to recover costs that do not vary with demand or energy usage."[122]

As we stated above, there is little controversy over the principle that fixed charges should recover only costs that are invariable with usage; but parties disagree strongly as to which types of delivery system costs fall into the invariable category. The correct characterization of different types of system costs has long been a fixture of rate design debates. We will continue to observe the principle of cost causation as REV progresses, but the characterization of costs will evolve. With the growing role of DER in system operation and planning, the variability of more system costs will become tangible. Ultimately the question will be determined in contextual discussions of specific cost categories as DER increases in scale.[123] We will modify the principle proposed by Staff CEOC by adding CEOC's proposed reference to fixed charges and their relation to usage.

With the additions described above, we adopt the Rate Design Principles proposed by Staff. A complete and updated list of the Principles is attached as Appendix A.

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[122] CEOC Initial Comments, p. 45.

[123] Contextual discussion of cost categories will occur in the Value of DER proceeding, in the DSIP process, and in individual rate cases.

Consistent with these principles and the reasons described above, we adopt the policy direction that more granular rate design must be made available to engage customers efficiently in multi-sided DER markets. This policy direction is contingent on the availability of market opportunities and enabling technologies for customers to respond to price and value signals. In addition, improvements in rate design must be coordinated with a plan to reduce the overall energy burden on low and middle-income households, developed in the context of Case 14-M-0565.

We further adopt Staff's recommendation that the near-term focus of rate design changes should be on opt-in programs, as well as utility-specific improvements at the C/I level. While our policy direction is clear, further demonstrations and analyses of bill impacts are needed before generalized demand charges, or default time of use rates, are adopted for mass-market customers.

We direct Staff to consult with stakeholders to define the scope of a study that would analyze the potential impacts of a range of mass-market rate reform scenarios, including time-of-use and demand charges, for delivery and/or default commodity service.[124] The study should be designed to model impacts using New York-specific data, and should consider experience from other jurisdictions.

The policy framework guiding this effort should take into account:

- Integrating REV objectives with rate design principles; a time-variable rate should support

[124] The framework of this analysis will overlap with the analysis of existing opt-in TOU rates ordered below. The analysis of generalized rate design changes, however, must include a substantial focus on impacts on customers that do not participate in DER.

customer response as well as representing efficient cost recovery;

- Potential consequences for: customers participating in DER (both “active” and “prosumer” as defined above); non-participants (“traditional” customers); low-income customers; and utility financial risk as it relates to cost recovery; and
- Prerequisites to implementation, e.g. advanced metering; valuation of DER; outreach and education; and enabling technologies.

Within the general category of time-variable rates, design choices can have a large impact on the effect both for achieving REV objectives and on bill impacts for customers at all levels of participation. For that reason, the scoping effort should consider a range of determinant factors that may contribute to the overall value of a study.[125] These may include:

- Type of costs recovered within particular rate elements or time periods;
- Ratio of peak to off-peak prices;
- Duration of peak or demand intervals;
- Number of peak periods included;
- Seasonal differentials; and

[125] For examples of relevant determinant factors, see, James Sherwood et al., A Review of Alternative Rate Designs: Industry experience with time-based and demand charge rates for mass-market customers (Rocky Mountain Institute, May 2016), L. Bird, J. McLaren, J. Miller, and C. Davidson, “Impact of Rate Design Alternatives on Residential Solar Customer Bills: Increased Fixed Charges, Minimum Bills and Demand-Based Rates,” National Renewable Energy Laboratory, Golden, CO, TP-6A20-64850, September 2015.

- Implementation factors including types of monetary signal, enrollment mechanism, and enabling technologies.

Staff will report to the Commission regarding the scope, feasibility, and deliverables of a potential bill impact study.

Finally, the White Paper discussed at length the subject of compensation for DER as well as its relation to net energy metering. Parties had a great deal of comment on those topics. Because we have initiated a separate proceeding to establish a full valuation methodology for DER, which will also cover questions related to NEM, those topics will not be addressed here, other than to note that principles of full valuation and accurate price signals must apply both to the rates paid by customers and the value received in return for DER services.[126]

B. Standby Service

1. Staff Proposal

Standby tariffs apply to customers that generate much of their power onsite. They reflect the cost of using the distribution grid as a backup; at the same time, standby tariffs are often described as a barrier to the development of distributed generation. A temporary exemption from standby rates for some types of new projects was ordered in April 2015,[127] under the assumption that an improved rate design will be put into place.

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[126] Case 15-E-0751, supra.

[127] Case 14-E-0488, In the Matter of the Continuation of Standby Rate Exemptions, Order Continuing and Expanding the Standby Rate Exemption (issued April 20, 2015).

Staff proposed a combination of near term and long term initiatives. In the near term, distributed generation projects, including existing projects, should receive a reliability credit when they reduce their demand on the utility grid below the contract demand level, for two consecutive summer periods. Staff also proposed that the campus offset rate that is currently in Consolidated Edison's tariff should be applied throughout the state, with improvements that allow the entire campus to be treated as a single unit for purposes of calculating demand, while multiple customers and/or facilities might be located within the campus.

In the longer term, Staff proposed that the method for determining standby rates should be reevaluated in the context of a higher penetration of DER. The method for allocating system costs may need to be revised to account for the networked value of multiple DER systems, and a probabilistic approach to demands for backup availability.

The Joint Utilities did not oppose a review of the method for establishing standby rates. The utilities were concerned about the potential for a subsidy of DER by non-participating customers, and they opposed some of the near-term proposals made by Staff. Regarding the reliability credit, the utilities argued that the credit should only account for the performance of the DG unit itself, and not other means that the customer may employ to reduce demand or the effects of weather and other factors which may reduce customer demand without requiring action from such customers. Regarding the campus tariff, the utilities argued that existing distribution facilities were designed and built to serve the maximum individual demands of the various accounts on the campus, not the coincident peak demand of such accounts.

Staff’s proposals received broad support from other parties, including customer advocates. New York City and Multiple Intervenors both supported Staff’s near term proposals and argued that the longer-term review of cost allocation methods should be expedited. DER industry parties and environmental advocates also supported Staff’s proposals.[128] New York City argued that the four-year exemption should be applied to already-existing projects. Acadia Center argued that standby tariffs should be eliminated after improved pricing and rate design mechanisms are established. TASC observed that DG projects with associated storage systems have less chance of placing demand on the utility and should be exempt from standby rates. CEOC emphasized that outages triggered by fluctuations on the utility side of the system should not be held against the customer. Consumer Power Advocates (CPA) argued that steam standby rates and gas delivery rates also need to be adjusted. The New York Cow Power Coalition observed that some types of generators, like anaerobic digesters, have very high reliability rates that should be recognized with a reliability credit. NECHPI stated that Staff’s near term proposals are at best an interim solution and that more comprehensive reform is needed.

2. <u>Discussion</u>

We agree with Staff and multiple parties that the cost allocation methodology for standby rates needs to be refined. Current standby tariffs were developed more than ten years ago. They are based on negotiated agreements that may no longer represent either the state of the system or the public interest.

[128] Parties supporting Staff’s position included: Acadia Center, AEEI, TASC, NYC, CEOC, Consumer Power Advocates, IGS, Microgrid Resources Coalition, MI, NFG, NYECC, NECHPI, NY Cow Power Coalition, and REBNY.

Second, the development of the current rates did not contemplate the high levels of DER penetration and integration that are anticipated under REV.

Current standby rates are designed to reflect the full cost of delivery under the assumption that customers' onsite generation will not be available during peak time periods. Standby rates are structured as a combination of a customer charge, a fixed "contract demand" charge, and a variable "daily as-used demand" charge. Contract demand charges are designed to recover the costs of "local" facilities that primarily serve the individual customer; i.e. they are tied to the customer's individual peak demand, not the coincident peak demand. Delivery system facilities that are "shared" with more customers are recovered through daily as-used demand charges which apply to the customer's usage at coincident peak times.

The impact of standby rates depends heavily on the percentage allocation matrix that is used to allocate the costs of the local facilities and the shared facilities to the contract demand and daily as-used demand charges respectively. In practice, the higher the "contract demand" charges, which reflect the costs of local facilities, the less potential there is for the customer to reduce its standby costs by avoiding reliance on the distribution system during peak coincident hours.

In reviewing standby rates, several factors must be taken into consideration. When a customer accepts a limitation and agrees to use the distribution system only at off-peak times, it causes little or no incremental capital and operating cost for the utility and therefore the daily as-used demand charges do not apply. Where, on the other hand, the utility is expected to plan for and meet the customer's entire power demand at any time, there are larger potential cross subsidies among customers if stand-by customers are not charged their fair allocation of fixed and longer term marginal costs incurred to meet their needs. A related factor is whether the standby service rates distinguish between new customers adding incremental load with on-site generation for which no capital cost has yet been incurred by the utility, versus an existing customer that decides to add onsite generation.

In addition to those considerations, REV introduces several new factors. Distributed generation that is integrated into system planning and operations will provide system benefits for all customers, and will result in fewer fixed or long term marginal utility costs and more short term operating expenses. Standby tariffs should allow for the potential of a customer actively engaged with the utility and contributing value to the distribution system.

Further, greater levels of DER mean that the risk that all standby demand will occur simultaneously and produce an unplanned coincident peak is lower, so a probabilistic analysis of the likelihood that the DER resource will fail at peak should be considered when allocating costs to standby rate customers. Finally, standby service will increasingly be used by customers that are physically aggregated, in the form of microgrids or campuses, and the coincident peak of the aggregate will increasingly be the relevant determinant of the standby service rate component application.

Another factor to be considered is the potential for uneconomic bypass. If a customer finds the cost of standby service to be higher than the cost of redundant protections, the self-generating customer may choose to disconnect from the distribution system altogether. In that event, the utility's other customers lose the benefit of any contribution that the bypassing customer might have made through a standby rate.

Generally, under REV the approach to standby rates should be dynamic in orientation; in addition to a focus on recovering existing costs, standby rates should facilitate a long term reduction in system costs that benefits all customers.
We will require each utility to make a filing that describes in detail the cost allocation methodology that is currently in use for the calculation of its current standby rates. The filing should include recent studies supporting the methodology and updated values.

The utility filings and the recommendations presented to the Commission should include discussion of several options, including: a rate that rewards customers that engage actively with the utility to provide system value; a reduction in the percentage of costs allocated to the contract demand with a corresponding increase in the allocation of costs to the daily as-used demand charges; a potential distinction between new load and existing load, with a phase-out period for new load status; and a method which first identifies the marginal cost-of-service and then applies an adder for non-capital related cost recovery.[129]

Staff's interim proposals are supported by most parties. The Joint Utilities argued that the reliability credit should take into account only the performance of the DG unit. This argument ignores a central tenet of REV, which is that a variety of DER resources and customer activities should be encouraged, to produce desired outcomes. A customer with a distributed generator that is combined with storage, demand-reducing technology, or any other means of responsive demand reduction, produces reliability just as well as a 100% reliable generation unit. The utilities urged that customers' demand

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[129] This is the method currently employed by Rochester Gas and Electric Corporation.

levels should be normalized for external factors such as weather. This is theoretically correct, but whether it is practical in the context of standby rates should be developed further.

CEOC emphasized that outages triggered by fluctuations on the utility side of the system should not be held against the customer. In recognition of this, and because it is administratively difficult to determine after the fact whether any particular outage was triggered by the customer or by the utility, the Con Edison tariff provides that a customer's performance during each summer period will exclude up to three outage events, regardless of the cause of such events, comprised of no more than five 24-hour weekday periods. This provision will be adopted here at the numerical levels in the Con Edison tariff. As experience is gained with the reliability credit, customers or utilities may petition to change the levels.

The utilities also argued that proposed reforms to the campus tariff related to coincident demand will result in stranded utility investment that was put in place to serve the non-coincident demands of multiple accounts. This argument has merit as related to the current contract demand charges which are designed to recover the costs of local facilities. Those local facilities are closer to a customer's site and were put in place primarily to serve the individual building's load. Therefore, under the current rate structure, contract demand charges should apply to the customer's maximum annual demand of each individual building on the campus. This does not preclude the discussion and development of alternate rate designs that may include a demand charge to campuses that is applied to coincident demands with a corresponding cost allocation.

All electric utilities other than Con Edison shall file tariff revisions to implement the offset tariff and reliability credit provisions as proposed by Staff and described here within 60 days of the effective date of this order. Such provisions will be noticed for comment and brought back to the Commission for determination. For Con Edison, such revisions related to the reliability credit shall be incorporated into its current rate filing and made effective January 1, 2017.

## C. Opt-In Rate Initiatives

### 1. Time-of-Use Rates

#### a. Staff Proposal

Recognizing that generally applicable rate design requires more study and infrastructure deployment, Staff recommended near-term actions to increase adoption of opt-in TOU rates, and gain further information regarding the design and efficacy of TOU rates via demonstration projects. Staff recommended that utilities should be required to submit customer engagement plans to encourage increased participation.

Most parties supported opt-in TOU rates as a near term measure. Acadia Center supported opt-in rates until advanced metering is available, when default rates should be adopted. AARP supported opt-in rates while strongly opposing default or mandatory rates. AARP added that shadow billing is a useful way to develop participation in opt-in rates. EDF stated that default TOU will likely produce much better results but, if an opt-in approach is adopted for an interim period, it should emphasize a variety of approaches, extensive outreach, and bill protection. AEEI urged that utilities should be required to demonstrate the efficacy of different types of rate options. NYC stated that consumer education is the most important variable and that utilities should collaborate with municipalities toward this end. CEOC stated that there is ample information on different types of TOU rates from across the nation. TASC supported an opt-in approach in the near term while cautioning that design options are critically important to success. ChargePoint, Inc. observed that EV charging equipment is already capable of incorporating TOU and need not wait for advanced metering deployment. The American Council for an Energy Efficient Economy (ACEEE) supported opt-in rates. The Energy Democracy Alliance cautioned that impacts on low-income households are critically important and shadow billing should be used to establish impacts. The Joint Utilities agreed with Staff that opt-in TOU demonstration projects are a practical means of gathering data and studying results. ESCO parties argued that only ESCOs should be allowed to offer TOU rates, and that utilities should offer plain service to serve as a benchmark.

b. Discussion

We agree that expanding the use of opt-in TOU rates is a necessary step toward a more comprehensive reform of rate design. Although each utility has a voluntary TOU tariff, the rate of adoption by customers is very low. While nationwide averages of opt-in TOU enrollment rates are approximately 25%,[130] adoption rates for New York utilities range between 0.1% and 1.9%.[131]

Although promotion and education are relevant to adoption rates, design characteristics must also be examined and compared with tariffs of other utilities with greater adoption rates. Design characteristics that may affect the usefulness of

[130] Scheer, "Response to Time Based Rates," Lawrence Berkeley National Laboratory, LBNL-183029, June 2015; Faruqui, Hledik, and Lessem, "Smart by Default," Public Utilities Fortnightly, August 2014.

[131] This calculation does not count the NYSEG day/night differential rate, which has been in place for many years and has an enrollment of over 17%.

the tariff include the duration of the peak period, the ratio between on and off-peak prices, the addition of critical peak pricing, and the availability to customers of tools that enable response to TOU variations.

Each utility should examine its existing TOU rate with references to the design characteristics and practices used by utilities with substantially higher customer adoption rates.

While the redesign of rates is under consideration, each utility should develop promotion and customer education tools, again with reference to best practices in other states. Proposals to increase customer acceptance may include shadow billing to allow customers to compare their existing bills against a TOU option, and temporary bill protections providing assurance that customers will not experience higher bills for comparable total usage. Although improved promotion strategies should be developed, implementation involving substantial expenditures should not be undertaken until revision of design characteristics is complete.

2. Smart Home Rates

a. Staff Proposal

In keeping with the distinction between traditional consumers, active consumers, and prosumers, Staff recommended that prosumers should be served by an opt-in Smart Home rate (SHR) to advance the early adoption of sophisticated home energy management technologies. A Smart Home rate would unbundle price signals to incentivize different types of DER and energy management responses.

AEEI, TASC, CEOC, EDF, Gridwise Alliance, IREC, and SEIA supported Staff’s proposal. New York City and NECHPI stated that more information is needed before a judgment can be formed. The Joint Utilities conditionally supported the proposal but stated that demonstration projects should precede the development of a generally applicable tariff. Gridwise Alliance stated that opt-out rates are greatly preferable to opt-in rates.

ESCO parties supported the concept of a more granular rate but argue that utilities should not be allowed to offer it. NEM, RESA, and BlueRock stated that ESCOs are better situated to offer smart home rates as part of a larger package of customer services. RESA argued that a Smart Home rate would put utilities into direct competition with ESCOs. NEM was concerned that time-variant pricing from utilities will be a gateway for utility offerings of DER services. BlueRock suggested that time-variant pricing can be offered to ESCOs who can bundle them with other services for end-use customers.

b. Discussion

Although the Smart Home Rate is discussed here in the context of demonstration and early adoption, it is the model for a rate design that should become the widely adopted norm as markets mature. An SHR combines time-variable rates with the full value LMP+D compensation that is being developed in Case 15-E-0751.[132] In other words, it combines highly granular time-based rates with location-and-time-based compensation for DER, in a manner that is managed automatically to optimize value for the customer and the system. The ideal SHR participant will combine generation (such as PV), electric vehicle charging, storage, and load management (such as a smart thermostat) with an inverter that allows two-way power flows and reads voltage

[132] Case 15-E-0751, supra.

and other system characteristics.[133] The SHR participant should be able to offer load shifting, peak reduction, voltage and other ancillary support, and automatic response on a time interval specified by the utility.

ESCOs argued that SHRs should only be offered by third parties because they include DER products that utilities are not allowed to provide. In the long term, this argument may have merit, and it should be revisited when the market demand for SHRs is better established. In the near term, there are substantial risks and uncertainties associated with an SHR that may inhibit investment by customers and third party developers. Given the continued evolution of rate design and markets, there is a risk that an early version of an SHR could become superseded, or that DER providers who offer SHR as a service may move on to other business models. The ongoing work of the Value of DER proceeding will also have a substantial interaction with SHRs; early SHRs will inform the development of a full-value tariff, and a full-valuation methodology will eventually become part of the SHR. For these reasons, SHR at this time should be offered on a demonstration basis by utilities, with a hold-harmless provision that assures participating customers that their investments will not be stranded by superseding developments.

Another reason for designing SHRs as demonstrations at this time is that the network values of SHRs may not be achieved by sporadic early-adoption across a wide geographic range, as opposed to a geographically concentrated approach that will

[133] The rate should not, however, necessarily be restricted to only those customers with on-site generation or other specified technologies. Rather, the rate should be designed to accommodate multiple DER technologies and services, but remain relatively technology agnostic in order to encourage outcomes rather than particular technology developments.

maximize both the networked value and the demonstration value of the SHR. Because it is unlikely that a high concentration of early adopters will be found in pre-existing neighborhoods, the ideal setting for such an approach would likely be new development in a high-growth area where a networked set of SHR homes can address the system needs presented by the new growth.

None of these considerations are intended to be binding on the development of an SHR. They are intended to explain why a demonstration approach at this time is preferable to a requirement that SHRs be developed for territory-wide adoption.

Each utility should collaborate with NYSERDA and with third-party developers to identify one or more SHR demonstration projects. Complete uniformity across utilities is not essential in a demonstration context, but working with NYSERDA, utilities should design SHRs that are compatible from the standpoint of DER providers.

## CUSTOMER DATA

### A. Individual Customer Energy Usage Data

Ready access to information regarding customer energy usage is vital to the success of DER markets.[134] For DER developers, information about a potential customer's energy usage is necessary to design products tailored to the consumer's needs. For consumers, data regarding their energy usage is a prerequisite to informed decisions regarding energy usage and purchases. Empowering consumers with tools to easily share that information with vendors whom they select will facilitate market development.

[134] Framework Order, pp. 58-60.

The Framework Order directed consideration of near-term measures to enhance access to customer data. Two technical conferences focused on customer data issues, including technologies and protocols for delivering customer usage information, the conditions under which utilities may charge for providing customer-specific usage information, and privacy issues. Representatives of DER suppliers, utilities and consumers actively participated in those conferences.[135] Parties also submitted written comments regarding the issues addressed in those conferences.[136]

Issues around customer data are (1) whether utilities may charge fees for releasing data, and (2) the types of data to be released and the conditions for release.

1. Utility Charges for Data

a. Proposals

Current Commission policy prohibits utilities from imposing charges upon ESCOs for providing information regarding a specific customer's consumption history and billing information.[137] The Uniform Business Practices provide, however, that utilities may impose incremental cost-based fees,

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[135] Case 14-M-0101, et al., Notice of Technical Conference Regarding Customer and Aggregated Energy Data Provision and Related Issues (issued November 3, 2015); Case 14-M-0101, et al., Notice of Second Technical Conference Regarding Customer and Aggregated Energy Data Provision and Related Issues (issued December 23, 2015).

[136] Comments are summarized in Appendix C.

[137] Uniform Business Practices (UBP), Case 98-M-1343, Section 4(E). A list of the specific information comprising a customer's consumption history and billing information is contained in the UBP Sections 2(a) and 3, respectively. Similarly, Staff proposed in Case 15-M-0180 that utilities may not charge DER suppliers for this customer-specific data.

authorized in tariffs, for an ESCO's request for "customer data for a period in excess of 24 months or for detailed interval data per account for any length of time."[138] Some utilities have tariff provisions for such charges. Staff requested comment from parties regarding how best to allow utilities to recover costs from market participants while encouraging the growth of markets and customer engagement.

Almost all non-utility parties, including AEEI, Mission:Data and NEM, recommended that utilities be precluded from charging customers or vendors for data obtained through sharing tools established by direction of the Commission. CPA recommended that utilities not be able to charge for any customer data, since such charges will create an incentive for utilities to maximize revenue, thereby restricting availability of that data to customers and vendors.

Utilities agreed that a basic level of data should be provided to customers or their designee without charge, and asserted that utilities should be able to set value-based charges for requests for customer information that are above and beyond that basic data set. Utilities claimed that this approach more closely attributes the value of providing premium data services to the customers or vendors who receive them, resulting in fewer costs to be socialized among all customers.

b. Discussion

The Commission's existing policy establishes a reasonable framework regarding utility charges for customer data. Utilities may not charge for basic levels of customer usage data shared with the customer or with vendors authorized by the customer. As argued by NYC and NEM, information should

[138] Id.

be free of charge where the cost of installation and use of utility meters and the information they generate is borne by utility customers as part of regulated rates. Further, precluding utilities from charging for this basic data will reduce barriers to consumer use and is consistent with our objective to facilitate market development.

Charges may be assessed by utilities for information beyond basic customer data. Utilities may continue to charge ESCOs and other vendors for providing monthly customer data for a period in excess of 24 months. Utility charges may also be assessed for data that is more granular and/or more frequent than the basic data described below. As provided in our discussion of PSRs, these charges may be value based, consistent with our interest in having utilities develop market-based revenues.[139] Utilities may propose charges for this data and a fee schedule, as part of their on-going consultations with ESCOs and DER vendors, as required in the recently issued AMI and DSIP Guidance Orders.[140]

2. Basic Data Requirement

a. Proposals

In comments responding to Staff's request, the distinction between a basic data requirement and additional information was central. Parties discussed methods to be used to exchange customer-specific data as well as the specific data which should be provided using those tools. DER developers generally supported the use of tools that are capable of transferring granular usage data in machine readable format.

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[139] Developing value-based charges may require modification of UBP Section 4(E). Utilities should address this issue in tariff filings.

[140] AMI Order, supra.

Utilities noted that many important issues including the datasets that are to be transmitted using these tools, and the associated costs, have not been fully assessed, and that additional stakeholder engagement is necessary to resolve these issues.

Development of data sharing measures that are customer-oriented is already underway. The Commission recently addressed customer data issues relevant to Con Edison's Advanced Metering Infrastructure proposal.[141] Con Edison was directed to implement "Green Button Connect My Data," which is an existing trademark-protected industry-standard protocol that enables customers to obtain their granular energy usage data and share it with vendors they select, as an integral part of its AMI deployment, and to submit additional filings detailing its customer engagement plan and proposed privacy protections applicable to AMI.

In the DSIP Guidance Order[142] utilities with AMI deployment plans were directed to submit a proposed implementation plan, budget and timeline for implementing Green Button Connect My Data or alternate standard that offers similar functionality. Utilities without AMI deployment plans were directed to identify other tools that could be used to improve customer and authorized third party access to customer data in their initial DSIPs.

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[141] Case 13-E-0030, supra; Case 15-E-0050, supra; Case 13-G-0031, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service, Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions (issued March 17, 2016).

[142] Case 14-M-0101, supra, Order Adopting Distributed System Implementation Plan (DSIP) Guidance, April 20, 2016.

The utilities noted that the definition of basic data may change over time in response to changes in technology and customer expectations.[143] Parties generally concluded that changes in the definition of basic data should be identified and addressed as part of the ongoing stakeholder process.

b. Discussion

The basic level of customer data that is to be provided free of charge is defined as the usage for each applicable rate element, including usage bands specified in the applicable tariff.

This is the level of data necessary to render, reconstruct and understand the customer's bill, which will ensure that customers have ready access to information necessary to fully understand how their energy usage affects their energy bill, as well as to understand how energy service offers from vendors may affect their utility bill. Availability of this information, at no cost, to developers who are authorized by the customer will facilitate the developer's ability to identify products which may be of value to the customer.

Customers and vendors they authorize should have free access to recent usage data at the frequency most commonly measured by the customer's meter. For customers with monthly meter reads, this includes 24 months of monthly usage information. For customers with interval meters communicating with the utility, this includes 15-minute interval data on an individual account basis, on a one-day lag.

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[143] We defined basic data in the context of Community Choice Aggregation. Case 14-M-0224, supra; Case 14-M-0564, Petition of Sustainable Westchester for Expedited Approval for the Implementation of a Pilot Community Choice Aggregation Program Within the County of Westchester.

As AMI is deployed, the basic level of customer data should evolve to include near real-time data measured by those advanced meters. The timing of the transition from the availability at no charge of interval data on a one-day lag, to interval data on a near real-time basis, as proposed by MTA, will be considered as part of individual utility AMI plans. Regarding data to be transmitted by "Green Button Connect My Data," the specifics of the data to be shared using that protocol, including the range of datasets and the granularity of that data, are to be developed by utilities with AMI deployment plans, in consultation with ESCOs and DER suppliers. The Con Edison AMI Order requires Con Edison to consult with vendors and file a proposal on these issues as part of its Consumer Engagement Plan filing, due by July 29, 2016. Other utilities with AMI deployment plans are required to consult with vendors and file a proposal on these issues as part of their DSIP filings. In reviewing those filings, we will determine the basic level of data to be provided through the Green Button Connect My Data protocol, for which utilities may not assess charges.

Coupled with our decisions in other orders to require utilities to propose plans, budgets, and timelines for implementing Green Button Connect My Data or other data sharing tools, our policy of free access to basic data will provide the information needed to empower consumers and facilitate market development.

### 3. Charges for Analysis and Assessments

#### a. Proposals

The Notice for the technical conferences asked for comments on the issue of whether utilities may provide usage analysis and assessments to their customers as well as the charges that would be applicable for such products and services. Some parties suggested that utilities should be precluded from providing information, tools, analysis and/or assessments of energy usage information to customers, because these functions can be performed by competitive marketers. Utilities disagreed, citing that they have historically provided and continue to provide customers with a variety of information, tools and analyses. The Natural Resouces Defense Council (NRDC) agreed that utilities should be allowed to assess charges for customized reports and supplemental information, but stated that the charges should be based on costs.

b. Discussion

Consistent with our position on PSRs, utilities should not be precluded from providing analysis and assessments of energy use to customers for a fee. Along with this order, we have taken action in the DSIP Guidance and Con Edison AMI orders to facilitate the ability of customers to share their basic customer data with vendors they select, including firms which provide data analysis and energy usage assessment. Our actions and policies are consistent with a customer-centric, competitively neutral framework in which the customer can choose to obtain energy usage analyses and assessments either from the utility or from a third party. As specified in our discussion of PSRs, utilities will need to file tariffs to charge for data analysis and assessment, demonstrating consistency with the criteria for competitive value-added activity.

4. Protecting Customer Privacy

a. Proposals

Utilities and third-party vendors are currently required to protect customer-specific information which they collect and maintain, and requires an annual third-party assessment of utility practices, systems and programs to protect this information.[144] The Commission also prohibits ESCOs, their employees, agents and designees, from selling, disclosing or providing customer information obtained from a distribution utility, unless authorized by the customer or legal authority.[145] A similar requirement is being considered for application to DER suppliers.[146] The Commission has also recognized that changes in technology and customer expectations may require utilities to revise their protections of customer-specific information, and has directed utilities to file proposed changes to privacy protections to address such changes.[147]

The Notice invited comments on whether privacy principles recently developed by the Department of Energy should be adopted by the Commission, either as a directive or guidance. In 2015, the Department of Energy, in coordination with the Federal Smart Grid Task Force, led a multi-party effort that culminated in a Voluntary Code of Conduct (VCC) regarding the privacy of customer energy usage data.[148] As described in that document, the purpose of the VCC is to describe principles for voluntary adoption that: (1) encourage innovation while appropriately protecting the privacy and confidentiality of

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[144] Case 13-M-0178, In the Matter of a Comprehensive Review of Security for the Protection of Personally Identifiable Customer Information, Order Directing the Creation of an Implementation Plan (issued August 19, 2013).

[145] Case 98-M-1343, Uniform Business Practices, Section 4(F).

[146] Case 15-M-0180, In the Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products, Staff Proposal (filed July 28, 2015).

[147] E.g., AMI Order, supra, p 43.

[148] DataGuard Energy Data Privacy Program, Voluntary Code of Conduct, Final Concepts and Principles, January 8, 2015.

customer data and providing reliable, affordable electric and energy-related services; (2) provide customers with appropriate access to their own customer data; and (3) do not infringe on or supersede any law, regulation, or governance by any applicable federal, state, or local authority.[149]

Party comments emphasized the critical importance of preserving privacy of customer-specific information, for consumer confidence and market development. However, most parties including utilities, Climate Action Associates, IGS, NRDC, and Mission:Data, noted that the VCC is intended to be voluntary, and applicable where detailed rules and regulations do not exist. They cautioned that the VCC contains more ambiguity and flexibility than is appropriate for a regulatory

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[149] The five core concepts of the VCC are:

1) Customer Notice and Awareness. Customer should be given notice about privacy related policies and practices. The notice should be at the start of service and when there is a substantial change in procedure and ownership that may impact customer data. The notice should identify, among other things, the specific types of information to be collected, how it is being used, how the customer can access the data, the circumstances under which it will be shared, and how it will be secured.

2) Customer Choice and Consent. Customers should have a degree of control over access to their customer data. Where data is to be used for new purposes materially different than previously, customers should be able to control use through a consent process.

3) Customer Data Access and Participation. Customers should have convenient, timely and cost effective access to their own data.

4) Integrity and Security. Customer Data should be as accurate as reasonably possible and secured against unauthorized access.

5) Self enforcement management and redress. Entities adopting the VCC should have means in place to ensure that they comply with it.

standard, and they recommended that it not be adopted by the Commission. UIU recognized concerns with the interpretation, compliance and implementation of the VCC, and recommended that the Commission direct that a collaborative be established to make recommendations to clarify these important issues. UIU asserted that the Commission should adopt the resulting document as a rule applicable to all utilities.

b. Discussion

Consistent with current practice, we will continue to require that individual customer usage data can only be released to developers authorized by customers on an opt-in basis. At the same time, we take steps through Green Button and other measures to facilitate these authorizations and transfers of data.

The VCC is an important effort and reflects privacy principles that are consistent with policies of this Commission. As noted by many parties, it is designed to be voluntary and of substantial benefit to entities not subject to direct regulation concerning privacy protections. Our existing requirements applicable to utilities and ESCOs obviate the need for adopting the VCC at this time. We will continue to ensure that customer information is protected as technology and markets evolve, and will consider application of our requirements to DER suppliers that access customer data provided by utilities.

B. Aggregate Data Issues

1. Standardized Reporting of Aggregated Energy Usage Data

a. Proposals

While individual customer data is essential for identifying potential customers and shaping market offerings, aggregated energy usage data is needed for supply procurement and for planning. The CCA Order addressed the availability of aggregated data for the formation of a CCA program.[150] In this Order, we address availability of aggregated data for market participants other than CCA communities.

The Notice for the December 2015 Technical Conference, asked how utilities could prepare and provide electronic access to customer data aggregated by municipality in a standard format and an efficient manner.[151]

In 2012, NYSERDA organized a voluntary utility working group through the Climate Smart Communities (CSC) Coordinator Pilot Program to create a standard "Community Energy Report." National Grid, NYSEG, RG&E, Central Hudson, LIPA, Orange and Rockland, and Consolidated Edison have created a standard Community Energy Report that produced annual aggregate energy consumption data for over one thousand villages, towns, and cities for the years 2010-2012. NYSEG, RG&E, and National Grid have provided updates to these reports since that time.[152]

Building on the Community Energy Report, NYSERDA developed a portal called the Utility Energy Registry (UER) to host the data from the Community Energy Reports. The UER portal maintains an open publishing platform, but also allows utilities to withhold data when required under privacy or security policies. The UER facilitates ongoing policy development and dialog by allowing communities, planners, and policymakers to define desired data types. NYSERDA indicated that the pilot has

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[150] Case 14-M-0224, supra, Order Authorizing Framework for Community Choice Aggregation Opt-Out Program (issued April 20, 2016) (CCA Order).

[151] Case 14-M-0101, et al., Notice of Technical Conference Regarding Customer and Aggregated Energy Data Provision and Related Issues (issued November 3, 2015).

[152] Case 14-M-0101, et al., December 16, 2015 Technical Conference Transcript (filed January 7, 2016).

demonstrated that utilities can provide aggregate community-level data through a standardized process.

The Joint Utilities stated that there can be no "one-size-fits-all" approach to providing aggregated information, and the most efficient way to continue to provide aggregated energy data is to afford flexibility to utilities working with municipalities and building owners. They argued that flexibility is necessary because municipalities, building classifications, geographic areas, political boundaries, and utility service classifications are not standardized, and that rigid formats could impair innovation in designing products and services and the means by which to provide them. Also, they stated that individual requests must be processed to avoid inadvertent release of customer-specific information.

The Municipal Electric and Gas Alliance (MEGA) stated that the UER has already been developed, and upon additional review of the UER, MEGA believes that the UER aggregated energy database is sufficient to inform ESCOs of the available load in a Community Choice Aggregation (CCA) program as part of a request for bids.

DER developers and environmental advocates argued that the increasing consumer engagement will be best realized if market participants have standardized platforms, processes and rules for interacting with the utilities. They asserted that a standard reporting format is needed to allow for geographic comparisons between different utility territories.

b. Discussion

Each utility should continue to work with NYSERDA and should provide aggregated data updates for the Community Energy Reports and the UER. As the CCA Order stated, until fully automated systems are developed to produce and transfer the aggregated data, cost will continue to be incurred by the utility which will manually gather the data.[153]

Utilities should examine methods by which to automate their systems. Once the utilities automate their systems, Staff should reexamine the adoption of the UER portal to make aggregated community-level usage data accessible to all municipalities and developers. In the meantime, utilities should work with NYSERDA to continue updates to the Community Energy Reports, as well as begin to develop potential solutions around issues, such as, reporting standardization, customer privacy, the mode of UER implementation, and the cost of implementation.

2. Charges for Aggregated Energy Data

a. Proposals

The Notice for the December 2015 Technical Conference asked if utilities should be permitted to charge municipalities or other third parties for providing aggregate data and, if so, how those charges should be determined.[154]

The utilities argued that they should be permitted to charge for providing aggregated data because it provides significant value to third parties, and the entities benefiting from the value-added services should pay for the services. NFG stated that either costs should be recoverable from users or utilities should receive full cost-based rate recovery

DER advocates and municipal parties opposed utility charges to municipalities and other third parties for access to aggregate energy usage data. The Association for Energy Affordability (AEA) stated that municipalities should have

[153] CCA Order, p. 45.

[154] Case 14-M-0101, et al., Notice of Technical Conference Regarding Customer and Aggregated Energy Data Provision and Related Issues (issued November 3, 2015).

access to customer data and a fee may be appropriate for private entities. Climate Action Associates supported utilities charging for additional high-value derivative data products on a case-by-case basis.

b. Discussion

Developing and providing aggregated data will impose costs on utilities until fully automated systems are developed. In the CCA Order, utilities were permitted to charge a fee for the data they provide to CCA programs. Utilities wishing to charge such fees were required to file proposed tariffs within 45 days of the date of the CCA Order for Commission Consideration. Charges developed pursuant to the CCA Order should also apply to non-CCA developers.

As the CCA Order stated, charges could be revisited when the data system is automated and utilities' incremental costs are reduced. Each utility, or the utilities jointly, should file a progress report regarding automation efforts September 1, 2016. We will consider placing an end date on the utilities' authority to charge for data, in order to stimulate development of an automated process. These charges will be reconsidered once utilities automate their data systems.

3. Data Privacy

a. Proposals

Staff asked for comment on best practices to protect customer privacy. Although aggregate data is, by definition, not unique to individual customers, under some circumstances the identity of an individual customer can be inferred. Other jurisdictions have adopted rules including a "4/80 rule" that requires data from a minimum of four customers to be reported as long as no one customer's load exceeds 80 percent of the group's energy consumption, and a more protective "15/15 rule" under which a minimum of 15 customers are included in aggregate data with no one customer's load exceeding 15 percent of the group's energy consumption.[155]

The utilities generally affirmed the importance of maintaining the privacy of customer-specific information by safeguarding against providing aggregated data that is not sufficiently anonymous. The utilities opposed, however, a single standard for this purpose, arguing that they already have adequate standards in place that are consistent with generally accepted industry standards.

Other parties presented mixed positions. AEA, the City of New York (NYC) and NFG supported a privacy standard such as the "15/15 rule" or the "4/80 rule". Capital District Regional Planning Commission (CDRPC) and Climate Action Associates recommended that the Commission establish a flexible voluntary code of conduct that would allow, for example, aggregating data upwards to remove personally identifiable information (PII), and/or simply withholding specific data points that fail privacy screens such as the "4/80" example. The Municipal Electric and Gas Alliance (MEGA) stated that customer privacy can be addressed through the use of the UER.

b. Discussion

Adopting a single numerical standard will inevitably result in either over-protection or under-protection in individual cases. The CCA Order provides that utilities shall not provide data for any service class that contains so few customers, or in which one customer makes up such a large portion of the load, that the aggregated information could

[155] See, Colorado Code Regs. 723-3 Part 3 §3031(b)(c).

provide significant information about an individual customer's usage.[156] At this time, utilities should follow their current internal policies in addressing the anonymity issue for ensuring that aggregated data is sufficiently anonymous. In order to make these policies transparent and enforceable, utilities should develop standardized policy statements in the context of the UER development process and each utility should file its policy as a tariff amendment.

Effective protection of data privacy requires flexibility due to the diversity among municipalities, building classifications, geographic areas, political boundaries, and utility service classifications. Utilities should work with municipalities or building owners to evaluate specific requests and only provide information at levels that would not reveal customer-specific information. Utilities will be allowed to withhold data if it is necessary for customer anonymity under a transparent policy. In the case that a municipality does not wish to report its annual aggregated energy usage, the utility shall allow the municipality to opt out of reporting.

## IMPLEMENTATION

Unless otherwise specified, the reforms ordered here should be implemented in the context of rate proceedings, or the DSIP process, as appropriate. Because each utility is at a different stage of its rate plan cycle, and because ratemaking changes need to keep pace with substantive REV measures, some items will require action sooner than the next rate proceeding. Where measures are undertaken outside the context of a rate plan, deferral mechanisms should be employed as defined herein

[156] Case 14-M-0224, supra (issued April 20, 2016).

for PSRs, or otherwise subject to the provisions of existing rate plans.

Several parties have commented that the number and variety of REV-related initiatives is a strain on resources of participating parties. Following standard practice, we will authorize the Secretary to extend deadlines contained in this order as necessary, where requests are reasonable and well-founded.

*Platform Service Revenues*: Utilities may file tariffs, containing the information required above, at any time after the Secretary has established a service list to notify potentially interested parties as described above.

*Earning Adjustment Mechanisms*: Metrics will be established on the schedule described below. Individual utility EAMs will be implemented either in that utility's next rate filing or as provided for in the terms of an existing multi-year rate plan.

- System efficiency: Each utility will file a proposal including peak reduction and load factor targets as described above by December 1, 2016
- Energy efficiency: The Clean Energy Advisory Council will propose metrics and targets by October 1, 2016. Each utility will propose an EAM associated with these metrics and targets by December 1, 2016.
- Customer engagement: Utilities may file proposals as described above at any time.
- Interconnection: Each utility will propose a survey process and EAM by August 1, 2016.
- Clean Energy Standard: Within 90 days of such time as the Commission may adopt a Clean Energy Standard, Staff will initiate a stakeholder process to develop EAMs.

*Clawback reform*: Each utility will propose this in the next rate filing following this order.

*C/I demand charge reforms*: These will be considered for each utility, either in a pending rate case, or pursuant to a filing by each utility by April 1, 2017.

*Data access charges:* Tariffs for aggregated data will be filed pursuant to the CCA order. Tariffs for other charges described in this order may be filed at any time.

*Aggregated Data access requirements*: Each utility will file a data privacy policy statement by October 1, 2016. Each utility will file a progress report on automation efforts by December 1, 2016.

*Scorecard metrics*: Staff will initiate a collaborative process and will issue a progress report to the Commission by May 1, 2017.

*Standby tariffs*:

- Credit: Each utility other than Con Edison will file tariff revisions to implement the offset tariff and reliability credit provisions as proposed by August 1, 2016. For Con Edison, such revisions related to the reliability credit will be incorporated into its current rate filing and made effective January 1, 2017.
- Allocation matrix review: Each utility will file a review and proposed revision by October 1, 2016.

*Opt-in rate design reforms:*

- Each utility will include in its next rate filing a proposal to revise its voluntary time-of-use rates for mass market customers, including an analysis of how the proposed rate compares with rates in other jurisdictions as described above. Each filing will also include a promotion and education tool. For utilities with rate plans that expire after January 1, 2018, a filing will be made by June 1, 2017 rather than waiting for the next rate filing.

- Each utility will propose one or more Smart Home Rate demonstration projects by February 1, 2017.

*Mass market default rate design reforms*: Staff will report to the Commission regarding the scope, feasibility, and deliverables of a potential study of bill impacts, by October 1, 2017.

## CONCLUSION

This order provides directional guidance for long-term reform and a carefully measured set of near-term actions designed to facilitate needed change while maintaining traditional principles of gradualism, equity, and opportunity to earn fair returns on investment.

The Commission orders:

1. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc. and Rochester Gas and Electric Corporation are each directed to file a system efficiency proposal as described in the body of this order by December 1, 2016.

2. Each utility listed in Ordering Clause No. 1 is directed to file an interconnection survey process and proposed Earning Adjustment Mechanism as described in the body of this order by August 1, 2016.

3. Each utility listed in Ordering Clause No. 1 is directed to file a progress report on aggregated data reporting

automation efforts as described in the body of this order by September 1, 2016.

4. Each utility listed in Ordering Clause No. 1 is directed to file an aggregated data privacy policy statement as described in the body of this order by October 1, 2016.

5. Each utility listed in Ordering Clause No. 1, with the exception of Consolidated Edison Company of New York, Inc., is directed to file revisions to its standby service tariffs as described in the body of this order by August 1, 2016.

6. Each utility listed in Ordering Clause No. 1 is directed to file a review of its standby rate allocation matrix and proposed revisions as described in this order by October 1, 2016.

7. Each utility listed in Ordering Clause No. 1 is directed to file one or more Smart Home Rate demonstration proposals by February 1, 2017.

8. Each utility listed in Ordering Clause No. 1 is directed to file revisions to voluntary time of use rates and promotion and education tools as described in this order either in its next rate filing or by June 1, 2017 for utilities with rate plans that expire after January 1, 2018.

9. The requirements of Public Service Law Section 66(12)(b) as to newspaper publication for the tariff amendments described here are waived.

10. The Secretary in her sole discretion may extend any deadline set forth in this order. Any request for an extension must be in writing, include a justification for the extension, and must be filed at least one day prior to the affected deadline.

11. This proceeding is continued.

By the Commission,

(SIGNED) KATHLEEN H. BURGESS
Secretary

**Rate Design Principles**

- **Cost causation:** Rates should reflect cost causation, including embedded costs as well as long-run marginal and future costs. Fixed charges should only be used to recover costs that do not vary with demand or energy usage.
- **Encourage outcomes:** Rates should encourage desired market and policy outcomes including energy efficiency and peak load reduction, improved grid resilience and flexibility, and reduced environmental impacts in a technology neutral manner.
- **Policy transparency:** Incentives should be explicit and transparent, and should support state policy goals.
- **Decision-making:** Rates should encourage economically efficient and market-enabled decision-making, for both operations and new investments, in a technology neutral manner.
- **Fair value:** Customers should pay the utility fair value for services provided by grid connection, and the utility should pay customers fair value for services provided by the customer.
- **Customer-orientation:** The customer experience should be practical, understandable, and promote customer choice.
- **Stability:** Customer bills should be relatively stable even if underlying rates include dynamic and sophisticated price signals.
- **Access:** Customers with low and moderate incomes or who may be vulnerable to losing service for other reasons should have access to energy efficiency and other mechanisms that ensure they have electricity at an affordable cost
- **Gradualism:** Changes to rate design formulas and rate design calibrations should not cause large abrupt increases in customer bills or delivery rate impacts
- **Economic sustainability:** Rate design should reflect a long-term approach to price signals and the ability to build markets independent of any particular technology or investment cycle.

APPENDIX B

State Environmental Quality Review Act

FINDINGS STATEMENT

May 19, 2016

Prepared in accordance with Article 8 - State Environmental Quality Review Act (SEQRA) of the Environmental Conservation Law and 6 NYCRR Part 617, the New York State Public Service Commission (Commission), as Lead Agency, makes the following findings.

| | |
|---|---|
| **Name of Action:** | Reforming the Energy Vision (Case 14-M-0101) Order Adopting Distributed System Implementation Plan Guidance |
| **SEQRA Classification:** | Unlisted Action |
| **Location:** | New York State/Statewide |
| **Date of Final Generic Environmental Impact Statement:** | February 6, 2015 |
| **FGEIS available at:** | http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101 |

**I. Purpose and Description of the Action**

The regulatory initiative launched in this proceeding, Reforming the Energy Vision (REV), aims to reorient both the electric industry and the ratemaking paradigm toward a consumer centered approach that harnesses technology and markets. Distributed energy resources will become integrated into the planning and operation of electric distribution systems, to achieve optimal system efficiencies, secure universal, affordable service, and enable the development of a resilient, climate-friendly energy system. The direction taken by the Commission in this proceeding is consistent with the terms of the 2014 Draft State Energy Plan [Shaping the Future of Energy, New York State Energy Planning Board, 2014] that calls for the use of markets and reformed regulatory techniques to achieve increased system efficiency, carbon reductions, and customer empowerment.

In the attached order, the Commission provides guidance and requires utilities to undertake filings as follows:

1. Data access. A process is established for DER developers to gain access to individual customer data with permission. Standard reporting of aggregate customer data is provided for. Certain basic levels of information will be free of charge, while utilities may charge a fee for provision of more refined data or analysis.

2. Earning opportunities.

(a) Platform service revenues: Platform service revenues ("PSRs") are new forms of utility revenues associated with the operation and facilitation of distribution-level markets. A process is established for the approval of products and services that could generate PSRs, and for the pricing of those services and the allocation of revenues between ratepayers and shareholders. This process will distinguish between monopoly services and services that could be performed by third parties. A set of criteria is established to consider when potentially competitive services should be allowed. The criteria are:

- whether the service facilitates the growth and operation of markets;
- whether there is already a third party market for the service that adequately serves all sectors of the market;

- whether utility economies of scale and/or existing utility expertise are likely to result in cost-effective stimulation of the market;
- whether utility provision of the service is likely to prevent other providers from entering the market; and
- The extent to which a utility has proposed placing its own funds at risk.

(b) Earning Adjustment Mechanisms: Guidelines are provided for the scope and structure of potential incentives, and outcome-based incentives are discussed for four categories:

- System efficiency: Each utility will propose a peak reduction target and a load factor improvement target. Each proposal will meet a list of requirements including targets, an analysis based on the BCA framework, and a proposed incentive for economic savings.
- Energy efficiency: The Clean Energy Advisory Council will develop targets for energy efficiency beyond the existing ETIP and CEF targets. Positive earning opportunities will be developed for utilities based on system-wide outcomes and other forms of savings.
- Consumer engagement: Utilities will be able to propose positive opportunities based on customer savings from innovative engagement programs.
- Interconnection: A positive earning opportunity will be developed based on satisfaction surveys of DER providers regarding utilities' progress in timely and cost-effective interconnection approvals. Satisfactory achievement of a baseline level of SIR timing requirements will be a threshold condition for earning positive adjustments.

(c) Greenhouse Gas reductions: In a separate proceeding, the Commission is considering a Clean Energy Standard (CES) to achieve the State's target of 50% renewable generation by 2030. Utilities should have earning opportunities tied to reducing the overall cost of achieving the CES goal. The specific nature of opportunities will depend on policy and implementation decisions that will be made in the CES proceeding. Closely related, and potentially part of a larger strategy related to the CES, are strategies to engage developers to build electric load, improve load factor, and reduce carbon emissions by encouraging conversion to electric vehicles, geothermal heat pumps, and other efficient and beneficial uses.

3. Competitive market-based earnings: Unregulated utility subsidiaries are authorized to engage in competitive value-added services.

4. Clawback reform: During a rate plan, utilities will be encouraged to displace capital expenditures with third party DER investment where cost-effective.

5. Standby service (near term): Utilities will establish reliability credits for standby customers whose actual demand consistently falls below their contract demand.

6. Opt-in rate design: Voluntary participation in advanced rate design will be encouraged in two ways:

- Opt-in time of use rates: Each utility will examine its existing TOU rates with reference to rates in other jurisdictions that have higher participation; each utility will also develop improved promotion and education tools.
- Smart Home rates: Utilities will collaborate with NYSERDA and third parties to develop Smart Home Rate pilots.

7. Large customer demand charges: Rate cases will examine the existing demand charges applicable to commercial and

industrial customers to determine if they can be made more time-sensitive.

8. Scorecard metrics: A non-exclusive list of ten scorecard measures is adopted, and a collaborative process will be conducted to establish metrics for each measure.

9. Standby service (long term): Utilities will file reviews of the methods and formulas by which costs are allocated to standby service customers.

10. Mass-market rate design: Staff will work with stakeholders to develop an analytic approach to examining bill impacts, for various classes of customers, of a range of default time-varying rate scenarios including time-of-use rates, demand charges, and peak-coincident demand charges.

## II. Facts and Conclusions in the EIS Relied Upon to Support the Decision

In developing this findings statement, the Commission has reviewed and considered the "Final Generic Environmental Impact Statement in Case 14-M-0101 - Reforming the Energy Vision and Case 14-M-0094 - Clean Energy Fund" issued on February 6, 2015 (FGEIS). The following findings are based on the facts and conclusions set forth in the FGEIS.

### A. Public Needs and Benefits

The FGEIS indicates that REV is designed to rethink the regulatory structure of the electricity distribution system, and establish an improved paradigm, to align utility revenues and customer rates with the goals of active customer decision-making and involvement, increased distributed generation, deployment of real-time responsive technology and the use of distributed system platforms to reduce adverse air emissions and to increase system efficiency.

**B. Potential Impacts**

Chapter 5 of the FGEIS describes the expected environmental impacts of the action. The adoption of ratemaking reforms will not of itself create any environmental impacts.

**C. Mitigation**

Chapters 5 and 6 of the FGEIS identify mitigation measures that could address the potential adverse impacts of the action. The reform of ratemaking is not identified as something that would trigger mitigation measures.

**D. Cumulative Impacts and Climate Change**

In aggregate, the clean energy technologies and resources promoted by REV create one common long-term, indirect effect: reducing the use of energy generated from fossil fuels. The environmental impact of a reduction in the use of fossil fuel based energy generation on the human environment is generally positive, but will occur over a long time horizon [FGEIS 5-48].

**III. Conclusion**

The REV program is anticipated to yield overall positive environmental impacts, primarily by reducing the State’s use of, and dependence on, fossil fuels, among other benefits. In conjunction with other State and Federal policies and initiatives, REV is designed to reduce the adverse economic, social and environmental impacts of fossil fuel energy resources by increasing the use of clean energy resources and technologies FGEIS ES-10].

**CERTIFICATION TO APPROVE:**

Having considered the Draft and Final Generic Environmental Impact Statement, and having considered the preceding written facts and conclusions relied upon to meet the requirements of 6 NYCRR 617.11, this Statement of Findings certifies that:

1. The requirements of 6 NYCRR Part 617 have been met; and

2. Consistent with social, economic and other essential considerations from among the reasonable alternatives available, the action is one that avoids or minimizes adverse environmental impacts to the maximum extent practicable, and that adverse environmental impacts will be avoided or minimized to the maximum extent practicable by incorporating as conditions to the decision those mitigative measures that were identified as practicable; and

3. Consistent with the applicable policies of Article 42 of the Executive Law, as implemented by 19 NYCRR 600.5, this action will achieve a balance between the protection of the environment and the need to accommodate social and economic considerations.

**Name of Lead Agency:**
New York State Public Service Commission

**Address of Lead Agency**
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Commissioner Diane X. Burman, concurring:

As reflected in my comments made at the May 19, 2016 session, I concur on this item.