STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

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

# STAFF WHITE PAPER ON RATEMAKING AND UTILITY BUSINESS MODELS

JULY 28, 2015

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# I. INTRODUCTION AND SUMMARY

## A. Introduction

On February 26, 2015, in its Reforming the Energy Vision (REV) proceeding, the Commission issued an Order Adopting Regulatory Policy Framework and Implementation Plan in this proceeding (the "Framework Order").[1] The Framework Order articulated a vision for the future of the electric industry in New York that is customer-centric, focused on reducing the total energy bill to New York customers, and fully integrated to ensure optimal resource choices are made. Among other components, the Framework Order requires New York's electric utilities to provide distributed system platform (DSP) services to enable third-party providers of distributed energy resources (DER) to create value for both customers and the system.

The Framework Order recognized that utilities must retain their universal service obligations to maintain a delivery system that provides reliable, resilient power at just and reasonable rates. The Commission was also clear that the changes contemplated in REV must ensure that the State be able to achieve or exceed its goals to protect the environment through increased use of energy efficiency and renewable energy, coupled with market enabling measures that integrate those

[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).

resources in a manner that achieves both economic and environmental sustainability. New York's State Energy Plan corroborated this statement, establishing that New York will achieve, by 2030, a 40% reduction in greenhouse gases and 50% of electricity from renewable sources.[2] As recognized in the plan, reforming ratemaking approaches so utility interests are appropriately aligned with achieving these targets is essential.[3]

The Commission found that significant technological innovation in software and hardware systems that improve the intelligence and flexibility of the delivery system, and similar advances that have significantly reduced the cost and increased the value of DERs, present the opportunity to fundamentally improve how utilities meet their service obligations. The Commission stated that business-as-usual is no longer a viable option for meeting its statutory responsibilities to New Yorkers.

Utilities now have the ability to capture the value of third-party supplied customer-sited resources and a smarter grid to improve the reliability, resiliency, and value of the system. When enabled by adequate information and pricing, DERs can drive greater system efficiencies, facilitate the integration of 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.[4]

The Commission further recognized that simply ordering utilities to use DER as an integral element of their operations would not be sufficient to realize these potential benefits. The intent of REV is to harness markets to achieve innovative

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[2] "The Energy to Lead: 2015 New York State Energy Plan," Vol. I, p. 112.

[3] Id., p. 60.

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

and cost-effective solutions, with utilities facilitating those markets both in their system planning and in day to day operations. Financial incentives and economic signals must be in alignment with this goal.

New York’s current practice of decoupling utility revenues from volume of sales has made utility finances less sensitive to higher penetrations of DER, but there remain significant disincentives for utilities to take affirmative actions to increase the development and use of third-party capital and services that support DER penetration and system value.

Utilities’ earnings are heavily dependent on their capital expenditures, and the long-term security of their earnings is based on the assumption of a growing or stable sales base. Further, utilities cannot earn a return on operating expenses, except by cutting them. Optimally integrating DERs may, though, require increases in utility operating expenses and decreases in capital spending. Consequently there is a financial misalignment between the utilities’ economic interest, the interests of third-party DER providers and other service providers, and customers.

The Framework Order states that a comprehensive reform of ratemaking practices to address this and other misalignments will be “critical to the success of the REV vision.”[5] There are two principal reasons for this. First, while the Commission has wide latitude to determine compensation schemes to ensure fair and reasonable prices for customers, it must provide utilities an opportunity to earn a fair return on their investments. Utilities will continue to need to raise large amounts of capital, and it is in the interests of customers and shareholders that investors retain high confidence in the manner

[5] Framework Order, p. 10.

in which the State oversees the relative risks and rewards of the regulated enterprise.

Second, the ratemaking paradigm should be used to encourage, not deter or delay, the realization of customer benefits through optimal investment in and management of the system including the deployment and use of DER. Misalignment between utilities’ financial interests and operational changes or transactive obligations that improve economic and efficient energy delivery, including support of the continued growth of DER penetration, introduces friction that is detrimental to the successful achievement of REV’s objectives and its attendant benefits. Accordingly, the focus of the ratemaking reforms discussed in this white paper is to identify mechanisms that will reduce or eliminate this friction and achieve the desired alignment of interests.

The pace of the comprehensive ratemaking reform discussed in this white paper cannot be predicted at this time. The objective should be to develop the right set of opportunities that encourage utilities to shift as quickly as is practical towards the realization of the DSP market. The recommended approach is to provide positive incentives in the early stages, but to carefully monitor utility activity and impose negative adjustments if needed to accelerate progress.

### B. Purposes, Scope, and Process of this White Paper

In that context, the purposes of this white paper are to 1) describe the limitations embedded in current ratemaking practices in the context of REV, 2) describe the direction of comprehensive ratemaking and business model reforms, and 3) make recommendations for near-term reforms where possible.

The scope of this white paper is limited to ratemaking issues, including the utility business model and earnings opportunities, the ratemaking process, and rate design. The ratemaking analysis is, of course, a significant element of the comprehensive set of issues the Commission is addressing through REV. As such, this whitepaper is informed by, and informs, the various other initiatives actively underway as part of REV. This set of initiatives, along with comments from parties, is part of the record that the Commission can rely on to determine how to best proceed.[6] Other initiatives that are closely coordinated with the Staff’s analysis and recommendations include:

- The development of a benefit-cost analysis framework;
- The development of an approach to calculate the full value of DER to the distribution system;
- The recommendations of the Market Design and Platform Technology (MDPT) working group, which will inform Staff’s guidance for utility Distributed System Implementation Plans (DSIPs);
- On-going inquiries for improved rate design for low-income customers;
- The review of the New York State Energy Resource and Development Authority's (NYSERDA) Clean Energy Fund filing;
- On-going consultant studies being undertaken to 1) examine the benefits and costs of net energy metering (NEM), and 2) develop approaches to appropriately value the multi-sided market aspect of the modern utility model as part of ongoing regulatory and pricing reform; and
- REV demonstration projects.

[6] The matters that the Commission is reviewing as part of REV extend beyond this list and include other issues such as its inquiry into oversight of Energy Service Companies (ESCOs) and DER providers and improved dispute resolution and development of the digital marketplace, and further speak to the comprehensive nature of the beneficial changes that the State will realize through REV. Those that are listed in the document are more directly related to the Commission’s ratemaking determination.

The many proceedings and initiatives related to REV are necessary to allow for focused development of the complex issues at hand, and thereby provide parties and the Commission the opportunity to fully develop the issues and record. In an effort to continue to support parties in participating in REV, the Staff is undertaking an effort with NYSERDA so that both agencies' websites can be used as vehicles to provide clear information to interested parties and individuals.

This white paper reflects extensive outreach and public comment.[7] It is a continuation of a process that started in December 2013, when the Commission ordered Staff to begin a process to examine our regulatory paradigms and markets.[8] Staff issued a Report and Proposal on April 24, 2014, and the Commission initiated the present proceeding. On May 1, 2014, a 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. Staff has also conducted focus group meetings related to this paper, with representatives of customer advocacy, environmental, service provider, utility, and government interests.

The ratemaking reforms proposed and discussed here are designed to elicit discussion and debate, and will continue to evolve through an interactive process. The process and the Commission's record for its ultimate policy determinations will

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[7] Staff was assisted in the preparation of this white paper by Rocky Mountain Institute, the Regulatory Assistance Project, and the New York State Energy Research and Development Authority.

[8] 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).

be informed by both written comments on this white paper and other stakeholder processes focused on specific topics. The Commission’s decisions will also be informed by the ongoing work in the implementation of the Framework Order. At the conclusion of this white paper, a summary of proposals and next steps is provided.

## C. Summary of Proposals

### 1. Principles and Framework

The proposals included in this white paper reflect several foundational principles:

- **Align earning opportunities with customer value —** A driving purpose of REV is to leverage the power of markets to reduce the total customer bill by increasing deployment of non-regulated third-party capital, and by supporting utility reliance on DER as an integral grid resource. Therefore, the ratemaking paradigm must create alternatives to the current financial and institutional incentives and provide opportunities for utilities to earn from activities that achieve their service obligations in a manner that supports reductions in the total customer bill.
- **Maintain flexibility —** It is not possible to predict how quickly the market will evolve, so there must be sufficient flexibility built into the regulatory model to enable it to adapt as the market develops. The Commission expects that the demonstration projects required by the Framework Order will provide important information to ensure regulation is well calibrated to support REV’s objectives.
- **Provide accurate and appropriate value signals —** The success of the REV market is highly dependent on customer engagement and DER value identification. Further, by modifying when and how they use power, customers can reduce their individual bills while at the same time supporting a lower cost system in New York. Thus, it is crucial that the rate design and value signals provided to the market and to customers—reflecting both long-term avoided costs and real-time value—supply the information and compensation necessary to support anticipated market activity and customer interest.

- **Maintain a sound electric industry -** Because of the critical importance of maintaining an operationally and financially sound electric industry, forward-looking changes must be grounded in the present and governed by the principle of gradualism.
- **Shift balance of regulatory incentives to market incentives –** Metrics and regulatory incentives to support foundational investments, activities, and outcomes that will drive future success are initial measures that serve as a bridge. Regulatory incentives are generally less efficient and more costly than market-driven incentives, and over time some of the regulatory incentives proposed here may become unnecessary and will be supplanted by more valuable and efficient market driven financial benefits. Regulatory incentives should remain in place as long as they are needed and effective.
- **Achieve public policy objectives –** As the Commission stated clearly in the Framework Order, even while technological change has brought about significant opportunities for improvement through market mechanisms, electricity remains an essential service imbued with multiple public policy demands. Superstorm Sandy and other major climatic events that New York has experienced over the last several years demonstrate the growing need for reliable, resilient, affordable, and clean energy. The ratemaking principles and changes proposed here reflect the public policy objectives that surround power delivery, including, but not limited to, ensuring system reliability and security, protections for low-income customers, and actions to support attainment of the State’s environmental goals.

Based on these principles, the reforms discussed in this white paper fall into three categories: 1) utility business model reforms including opportunities for market-based earnings (MBEs); 2) incremental ratemaking reforms to the utility revenue model; and 3) rate design reforms to reflect the needs of the evolving energy marketplace.

This discussion proposes some reforms for immediate adoption, while others require further development that should be initiated immediately for future adoption, and will grow in importance. Because many of the planned outcomes of REV will take time to develop, ratemaking incentives and earnings opportunities will follow the practical realities of REV implementation. The critical task is to incentivize the near-term activities that will promote the development of full-scale markets. Among others, these include making data more accessible, developing platform capabilities, and engaging customers with the goal of near-term reduction in system peak and control of customer bills.

### 2. Utility Business Model Reforms

As DSP capabilities and DER markets develop, utilities will have the opportunity to increase revenues earned from serving as a platform for customers and DER providers to employ DERs and manage customer bills, thereby participating in achieving system efficiency and other policy objectives. Increased MBEs will have the dual benefit of 1) encouraging utilities to support access to their systems by DER providers who can improve the economics of the system and add value to end use customers, and 2) offsetting required base revenues derived from ratepayers.

New approaches that are tied to successfully driving desired outcomes, including greater use of performance incentives, should be initiated and applied to a range of policy objectives built around market, customer, and environmental goals. Current performance incentives should be maintained, and new performance incentives, referred to here as earnings impact mechanisms (EIMs), adopted.[9]

The current net plant reconciliation mechanism, which discourages the use of cost-effective third-party and operating resources, should be reformed. Earnings sharing mechanisms

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[9] The existing performance incentive for energy efficiency, however, should be modified. See discussion, infra, sections III.C.2.b and III.C.3.b.i.

(ESMs) should be tied directly to outcome indices. To allow time for initiatives to be developed and outcomes to emerge, allowing rate plans longer than three years should be considered.

These approaches will offer utilities the opportunity to thrive in a changing environment if they succeed in meeting customer-oriented objectives. As the role of utilities changes in response to market developments, the relative balance between base rates, performance incentives, and MBEs will change as well. Market activities that reduce overall system costs will both reduce the total customer bill and support alternative revenue streams for utilities. Indeed, when utility performance and revenue contribution demonstrate that MBEs provide the required incentives to support sustainable and beneficial market growth, the need for regulator-specified EIMs and attendant regulatory risk, may prove redundant and may be eliminated.

The eventual shift in balance from traditional regulatory incentives to MBEs opportunities will complete the transition to a business and regulatory model where utility profits are directly aligned with market activities that increase value to customers. System costs can be reduced and, to some extent borne, by participants who benefit directly from the market, resulting in fewer costs that must be socialized among all ratepayers. This will promote both equity among customers and the incentive for utilities to encourage and facilitate innovation in the market. It will also focus the role of regulators on supervising markets rather than on determining incentive levels. Policy-driven metrics such as carbon reduction and other less market-driven values will continue to be implemented through regulatory measures.

Timing of these ratemaking changes will be consistent with the broader schedule for REV implementation. The pace of change, however, will not be dictated by regulation alone. All markets, and particularly technology markets, evolve at speeds that are often unpredictable and frequently faster than anticipated. The Commission, utilities, and stakeholders should be in a position to respond to market developments and should not be rooted in a particular set of expectations.

### 3. Rate Design and DER Compensation

In addition to establishing MBEs and performance incentives for utilities, the Commission should ensure that customers and market participants receive appropriate value signals. 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. As the distinction between consumer and producer begins to dissolve through increased reliance on DER, it becomes even more important for customers to receive value signals that allow them to make optimal investment choices. For that reason, a number of rate design reforms are proposed here that balance the general policy concerns of equity, efficient price signals, and encouragement of DER.

Rate design reform should be carefully phased, taking into account two types of timing concerns: the time needed to assess potential bill impacts and foster customer acceptance; and the time needed to develop information and infrastructure capabilities to implement an improved rate design. Through gradual reforms, rate design for mass-market customers should begin to place a greater weight on the peak demand of the customer, which is closely related to the cost of the system and which can be managed by the customer to control their electricity costs. Rate reforms to support low-income customers should follow the recommendations of the current low-income rate proceeding,[10] and should incorporate a usage block structure to maximize opportunities for low-income customers to participate in DER.

While many of the rate design reforms proposed here will take time to further design and implement, that should not delay action by those customers who have the desire and capability to respond to more granular value signals now. A “smart home rate” should be made available for those customers who want to begin participating as active consumers.

The demand-based rates of larger commercial and industrial (C/I) customers can also be improved to more closely align rates with system costs while enabling more efficient management of bills. Standby service tariffs that apply to customers with self-generation should be revised to include a campus netting tariff and a reliability credit that can be earned by demonstrating reduced reliance on the distribution grid for two successive peak seasons.

Compensating customers for DER requires consideration of two inter-related issues. The first is the form of the transaction. Today, the transaction takes the form of a reduced bill for energy that is not consumed, either at a specified credit in the case of demand response (DR), or at the retail rate for DER that does not respond to a utility request but instead is net energy metered. The convention of NEM has proven a very successful tool to support the growth of the solar industry, and Staff recommends that it continue to be used. Further, a bill-crediting transactional mechanism, similar to that used in NEM, should be considered for DER resources, beyond those to which NEM already applies, that transact with the

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

system either through actions that respond to DSP requests for service, or through the ability to inject power into the system.

The second issue, recently discussed by the Commission in the Community Distributed Generation Order,[11] is the level of compensation that these resources should be provided. The level of compensation should be more accurately defined for larger projects. The current convention of crediting at the average retail rate may be either too little or too much based on the nature of the resource and its location. Through the calculation of the full value of DER to the system[12] the utility will be able to determine the total economic value of the resource and this economic value can then be used as the basis of the credit.

### D. Legal Authority

As a matter of policy and law, electricity must be available to all at a just and reasonable price. The Commission determined in the Framework Order that its core statutory mandate compels a new approach in the face of the challenges and opportunities facing the state's utilities.[13]

The regulatory mandate stems from the monopoly nature of electric delivery service. Where risk is undertaken in the performance of a public utility service, it is compensated with an opportunity to earn a fair return. Under normal circumstances, this is the risk-reward balancing that drives much ratemaking. Where the expectations of utility performance

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[11] Case 15-E-0082, Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program, Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015).

[12] See, infra, section IV.A.

[13] Framework Order, p. 2.

are changed, as they are with REV, the incentives or disincentives entailed by ratemaking practices should be changed as well.

Ratemaking is essentially an instrumental function; its goal is to advance statutory and policy objectives in the most equitable and efficient manner. The Public Service Law (PSL) grants the Commission wide discretion in the methods that it uses to satisfy the policy objectives of safe, reliable, and environmentally responsible service at just and reasonable prices. Courts have affirmed this discretion in numerous contexts.[14] This includes crafting measures to address competitive and potentially disruptive trends,[15] and adopting proactive responses to new technology trends.[16]

Because utilities are obligated to provide service at regulated rates, the United States and New York Constitutions provide them protection from confiscatory regulation. Here again, regulators enjoy wide latitude in the methods used and the range of end results achieved. The U.S. Supreme Court has stated that a utility's return "should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital,"[17] but that there are "various permissible ways in which any rate base on which

[14] 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).

[15] County of Westchester v. Helmer, 296 A.D.2d 68, 74 (3d Dept. 2002); Multiple Intervenors v. Public Service Commission of the State of New York, 154 A.D.2d 76, 80 (3d Dept. 1990).

[16] Kessel v. Public Service Commission of the State of New York, 136 A.D.2d 86, 97, 99-100 (3d Dept. 1987).

[17] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

the return is computed might be arrived at."[18] Expanding on this standard, the Court more recently explained that "circumstances may favor the use of one ratemaking procedure over another [and t]he Constitution within broad limits leaves the States free to decide what rate setting methodology best meets their needs in balancing the interests of the utility and the public."[19]

The ratemaking reforms recommended here represent pragmatic adjustments to current practice. They are designed to achieve the policy objectives articulated in the Commission's Framework Order in a measured and balanced way. They will be implemented in a deliberate and gradual way to maintain support for existing investment while promoting efficient investment to meet the changing needs of the industry and customers going forward.

## II. LIMITATIONS OF CONVENTIONAL COST-OF-SERVICE RATEMAKING

### A. The Foundation of Traditional Regulation, Efficient Investment, and Innovation in New York

Four attributes of regulation distinguish public utilities from other parts of the economy: 1) control of entry, 2) setting of prices, 3) prescribing the quality and conditions of service, and 4) the obligation to serve.[20] Where the utility has an obligation to serve and sole control over the means of providing service, the regulator must set prices that are just and reasonable for customers and provide the utility an opportunity to earn a fair return on its investment. In the absence of markets to drive cost efficiency and innovation, the regulator must try to simulate the incentives, risks, and rewards of

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[18] Id.

[19] Duquesne Light Co. v. Barasch, 488 U.S. 299, 310 (1989).

[20] Alfred Kahn, The Economics of Regulation: Principles and Institutions (John Wiley & Sons 1970).

markets while meeting the policy and legal requirements that come with the obligation to serve.

Emerging technologies and capabilities, as well as new policy goals in the modern age, require updated approaches to electricity regulation. A recent formulation of this task delineates regulatory priorities as:

- **Operational efficiency—**Deliver electricity to customers at the lowest reasonable cost while providing acceptable reliability and performance.
- **Dynamic efficiency—**Induce efficient investments in innovation so that utilities are able to meet future demands at the lowest reasonable cost.
- **Consumption efficiency—**Customers should bear the incremental cost that their decisions impose and be given appropriate incentives. Prices should be set at the lowest level consistent with system cost recovery.
- **Other policy objectives—**Where utilities are expected to support other policy goals, they should do so in a cost-effective, minimally distortive manner.[21]

Many of the reforms discussed in this white paper are designed to bring the goal of dynamic efficiency into balance with the other goals of regulation. As the Framework Order makes clear, future demands on the electric system require a rethinking of many aspects of the current regulatory structure.

### 1. Overview of Cost-of-Service Ratemaking

The traditional goals of ratemaking have typically been met using a cost-of-service approach. Although there are hundreds of variations in practice, what follows is a simplified description of the basic cost-of-service regulatory approach still largely in effect in New York today.

[21] "The Future of the Electric Grid: An Interdisciplinary MIT Study" (2011), pp. 176-177.

Utility costs are divided into two principal categories: rate base (asset base) and operating expenses. The rate base largely consists of the un-depreciated balance of capital investments, plus deferred regulatory assets. Each year, the utility's rates include the annual depreciation or amortization of the assets, as well as an allowed return on investment based on the cost of capital. Operating expenses are the non-capitalized portion of the utility's costs, and rates are set to allow full recovery in the same year that operating expenses are incurred. In combination, the return of and on rate base plus operating expenses represents the utility's revenue requirement, i.e., the "cost of service" that should be recovered via rates.[22]

After establishing the utility's revenue requirement, the regulator must design rates to allocate the cost among various types of customers. First, costs are allocated to customer classes (e.g. residential, commercial, and industrial) and then a rate is designed for each customer class. Rates for many customers, and especially for residential and small commercial (mass-market) customers, are set based on average costs. That is, the customer pays a single, volumetric rate that reflects the average cost to provide service to the class over time. By definition, average cost pricing does not reflect the marginal cost to the system attributable to an individual customer's usage.

The rates set by the regulator remain in place until they are changed in a new rate proceeding. Until that time, some portion of any reduction in operating expenses below the rate allowance is kept by the utility to encourage efficient operations, and further reduction is shared with customers to

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[22] This simplified description omits income taxes and items that are passed through or reconciled such as commodity costs and property taxes.

discourage under-spending. On the other hand, unplanned overspending is absorbed by the utility. When a new rate case is completed, the allowed revenue requirements and associated rates are reset to reflect the most recent estimate of costs and appropriate risk-related return on equity (ROE).

In a traditional regulatory environment of regular rate cases and conventional utility-scale investments, cost-of-service ratemaking provides utilities with the opportunity to earn stable returns. Indeed, over the past ten years, New York utilities have been able to earn returns on equity that are on average equal to or above their allowed returns. Credit rating agencies have viewed New York utilities as having relatively low business risk due to their focus on transmission and distribution (T&D) operations. The rating agencies also note that New York's regulatory policies include stabilizing cost-recovery mechanisms that are credit-positive. Between the state's low-risk regulatory approach and mechanisms designed to allow New York utilities to actually achieve their authorized returns on equity, utilities have had little difficulty issuing debt and equity at reasonable terms. This result will continue under the package of reforms discussed in this white paper.

### 2. Historical Concerns and Improvements to the Cost-of-Service Approach

The cost-of-service approach worked reasonably well for many years in a climate of growing demand and centralized infrastructure. It has always been vulnerable, however, to a critical question: what incentive does the utility have to modernize and improve long-term efficiencies?

The classic cost-of-service formula provides limited incentive, and in fact substantial disincentive, for innovating and reducing long-term costs for customers. Any near-term benefits the utility enjoys from operating efficiencies are quickly reset into rates, reducing revenues in the long term. Similarly, reductions in capital spending could provide modest near-term earnings benefits but reduce company size and rate base in the long term. There is little financial incentive, short of direct mandates from the regulator, for the utility to undertake the effort, cost and risk involved in improving operations once rates are established. If operating efficiencies require upfront spending that is not included in a rate plan, the utility is at risk that these expenses will have the effect of reducing net income.

Another difficulty with the cost-of-service approach is information asymmetry in the rate-setting process. Utility managers typically have far better information than regulators do, regarding both their future spending needs and any opportunities to improve efficiencies. While this does not inhibit recovery of past expenses, it makes it extremely difficult to estimate future costs in a manner that balances objectives for quality of service, efficient investment, and innovation, while providing optimal incentives for cost minimization.[23] As a result, service may cost more than it would if utilities were better motivated to modernize and improve long-term efficiencies.

It is important to note, of course, that utilities have other reasons to improve service, including public service responsibility and professionalism, and there have been many incremental improvements in system design and operation over the years, despite the inherent disincentives of the ratemaking system.

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[23] Jean-Jacques Laffont and Jean Tirole, A Theory of Incentives in Regulation and Procurement (1993).

The New York Commission has been a leader for decades in exploring and developing improvements to the traditional cost of service approach. Key reforms over the past decades have included:

- Fully forecasted test years that reflect expected changes in revenues, investments, operating expenses and new programs which help ensure strong cash flow and access to capital at lowest reasonable cost,
- Multi-year rate plans that increase the near term benefit to the utility of operating efficiencies,
- ESMs that encourage the utility to achieve efficiencies and share the benefits with customers,
- Performance metrics related to safety, reliability, customer service, emergency responsiveness, and energy efficiency that link earnings directly to outcomes, and
- Decoupling sales from revenues to allow utilities to encourage energy efficiency and distributed generation (DG) without losing revenues.

The greatest change in the traditional framework, adopted by New York, many other states, and the federal government, has been the deregulation of electric generation and energy sales. Due to technology and communication improvements, utilities no longer need to operate on a vertically integrated basis. Instead, intra- and inter-state markets for electricity have been in operation for nearly twenty years. This has improved the efficiency of the bulk power system and has also brought third-party capital into the market, reducing the amount of customer dollars at risk.

New York utilities continue to be obligated to obtain commodity supply for customers as a default provider. They are also obligated to enter into hedges that reduce the risk of price volatility to customers. However, commodity costs are a direct pass through expense for utilities. While they are a significant component of the customer bill, there are no positive earnings opportunities for utilities if their actions help reduce the costs of supply. The utilities also retain a small residual risk of the Commission finding that the utility either over-hedged or under-hedged commodity volatility and therefore imposed unnecessary commodity risks to customers. Due to ongoing practices of continuous Staff and Commission review of hedging practices and the high bar of demonstrating imprudence, the risk of disallowance is not significant.

### B. The Limits of Conventional Cost of Service Ratemaking in the Context of REV

#### 1. Deterrents to DER and Market Participation

While New York has shown leadership on ratemaking issues, the context of REV compels further changes to the cost-of-service approach. There are several traits inherent in the traditional model that present deterrents for utilities to implement REV. In addition to the historical question of whether cost of service provides the utility an incentive to modernize, a more recent question is whether the cost-of-service approach continues to work when essential aspects of the natural monopoly are not aligned with or are potentially threatened by beneficial technology and market developments. Alfred Kahn asked the first question, and anticipated the second, when he asked, “Might [utilities] be natural monopolies in some static, efficiency sense but ‘unnatural’ ones in terms of the prerequisites for innovation and growth?”[24]

The cost-of-service approach is insufficient in the face of the accelerating technology and market trends the Commission has identified. The Commission is requiring utilities to fulfill their statutory obligations in fundamentally different ways.

[24] Kahn, supra, p. 12.

Market and regulatory models must support individual customers in using power most efficiently and reward utilities in promoting system wide optimization and efficiency. Current models do not accomplish this and in fact create disincentives, which means that both the total demand and the load profiles that drive delivery and wholesale power costs are economically inefficient.

Unlike competitive companies whose long-term increase in profitability is driven by growing revenues and controlling costs, utilities' earnings are largely a function of increasing investment and controlling short-term expenses. Utilities do not have a sufficient incentive to use third-party capital to provide service to customers, particularly when this reliance has the effect of increasing their operating expense.

Placing the customers' interests in total bill management, including reliance on DER, at the center rather than the fringes of the utility's operating and business models, means that third-party and customer capital and market risk need to be added dimensions to how utilities meet their monopoly service functions. By allowing DER providers to contribute services and capital that result in greater value, innovation, and DER penetration onto the system, utilities' capital requirements and associated returns from traditional cost-of-service regulation may be reduced, and utilities will necessarily incur additional expenses to accommodate these changes. In other words, to achieve the benefits to customers that REV-enabled reform contemplates, utilities will need both mechanisms to recover the expenses they incur to support the developing market and opportunities to earn on them.[25]

[25] As the Commission stated in the Framework Order, DER is not expected to wholly replace bulk power generation, renewable and conventional, or transmission investments. Rather, by making demand more efficient and increasing its use as a

The conventional regulatory approach prevents the utility from profiting in the long term through the most efficient use of operating resources or through reliance on third-party capital contributions. If utility capital costs are the primary means to achieve utility earnings, then to the extent that market investments could displace utility investments, utilities will have a disincentive to encourage efficient market developments.

This misalignment is exacerbated by the fact that many of the desired outcomes under REV will rely on utility operating costs in the form of DER procurements, and capital spending by others. The conventional rate treatment of utility capital and expenses is in conflict with a reformed energy vision of reliance on third-party cost contribution and a desired shift toward utilities focusing on greater productivity via operating expenses to grow their own earnings. It is critical therefore to eliminate, as much as possible, any structural financial incentive embedded in regulation for a utility to favor its own capital spending over third-party activity that meets system needs at lower cost to ratepayers.

### 2. Discontinuity Between Cost-of-Service Ratemaking and Multi-Sided Markets

The activities anticipated under REV underscore the shortcomings of conventional cost-of-service ratemaking, and imply that new revenue models are needed that correspond to the

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balancing resource, the Commission envisions that the entire integrated system and retail and wholesale markets will become more efficient and the relative needs for bulk power and retail level investment will be more apparent. As a result both utilities and third parties should expect that with more information and accurate and comprehensive pricing, there will be greater value and investment certainty throughout the system.

expanded responsibilities the utilities will take on to provide DSP functionality.

The DSP market envisioned by REV has many of the hallmarks of a multi-sided platform market with the utility functioning as the platform provider.[26] Platform markets are familiar in the modern economy, including in financial markets, credit card services, video game systems, and many internet businesses. In these markets, transactions take place in a triangular rather than linear exchange, in which buyers, sellers, and the platform provider each interact with two or more other parties rather than one counterparty exclusively.[27] The platform provides the technology, protocols or structure through which users can interact.[28]

The cost-of-service approach fails to provide financial incentives for a modern utility operating as a platform. REV envisions that the utility will use several market facing and operational mechanisms to modernize the electricity delivery business, including reliance on third-party investments where appropriate, and providing value added services that reduce the transaction costs of DER entry and increase the volume of DER on the grid. Further, as will be discussed in Section IV, REV promotes the development of price signals that allow DER providers and customers to receive full value from their DER assets, thereby encouraging even greater levels of investment.

In contrast to a platform-based market structure, the conventional utility model follows the framework of a

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[26] See, for example, Claire M. Weiller and Michael G. Pollitt, “Platform Markets and Energy Services,” Working Paper, (University of Cambridge, Energy Policy Research Group 2013).

[27] T.R. Eisenmann, G. Parker and M. Van Alstyne, "Strategies for Two-Sided Markets," Harvard Business Review (October 2006).

[28] Andrei Hagiu and Julian Wright, "Multi-Sided Platforms," Working Paper (Harvard Business School 2011), pp. 12-24.

traditional industry, characterized by products that follow a linear path from supply to consumption, with end users as the sole bearers of cost. That market model no longer fits the modern electric industry. As the Framework Order envisioned, the DSP marketplace will feature a proliferation of DER offerings in the form of DG, storage, micro-grids,[29] load management and energy efficiency offered by third parties that the DSP will be able to rely on to support its reliability function and provide value to customers. Third-party DER providers will use the platform services of the DSP to obtain access and information that identifies the best locations for investment, pricing signals that indicate the real-time value of the investment, and other services that help reduce transaction costs.[30]

The concept of the utility as a platform provider aligns well with recent literature on the value of networks.[31] One of the characteristics of a true network is that the value of the particular good is enhanced through multiplicity. That is, a good is more valuable if it is part of a system of many goods. Three examples are wireless communication networks, internet search engines, and online shopping. In the case of wireless, the value of a wireless phone and the network is enhanced through growth of usage, services on the phone like email and texting, and interoperability between networks. For this reason, wireless providers support the ability to call and text over each other's systems.

[29] Micro-grids can be an example of how the DSP as a platform will also support the development of adjacent platforms that enhance customer value in the network.

[30] Customers will continue to obtain commodity and reliability through the utility or an ESCO.

[31] Eisenmann et al., 2006, supra.

Similarly, in the case of search engines and on-line shopping, value to customers comes from the ability to easily find desired services, and the value to service providers is the information that the search engine uses to help locate potential buyers. Among other things, these resources have demonstrated value through their ability to provide information that matches buyers with sellers, reduces transaction expense and improves customer value.

These examples are analogous to the type of value that a full-scale DSP will supply to the retail markets. First, the value of a DER market will grow with penetration and as DER providers create new products and services for customers over time. A single DER provider that helps a customer to reduce 100 kW of demand for one hour during peak will help that customer reduce their energy cost but might have little impact on price or reliability on the larger system. However, if the same customer is part of an aggregated portfolio that accounts for 25 MW of reliable load reduction over longer periods, that customer can produce substantial pricing and investment effects that will benefit both the customer and a broader group of users.

Moreover, DER providers can now and will increasingly provide more than load reductions. For the grid to operate reliably, both the New York Independent System Operator (NYISO) and individual utilities must be able to match supply with demand as well as maintain voltage and system stability. In a customer and demand oriented system that integrates both traditional generation and DER resources, the utilities and the NYISO can coordinate to co-optimize these resources and deliver reliable service to customers at a much lower price. There is a significant multiplier effect for individual DER providers when DERs can be operated in concert with other resources. Just as in other networks, the value that the utility offers as a DSP will be enhanced by growing the participation in the network and offering services that support interoperability and reduced transaction costs.

As we have seen in other networks, the multitude of service offerings, value streams, and adjacent networks and platforms that will be developed under REV will evolve as the market matures. REV demonstration projects, currently under development, can and should be used as a source for developing these opportunities.

Under the current cost-of-service approach, there is no established way for a utility providing DSP functionality to be compensated for services offered to DER providers, further illustrating the lack of appropriate incentives in the current ratemaking and pricing constructs and underscoring the need for a new revenue model. 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.

## III. ALIGNING CUSTOMER VALUE WITH EARNINGS OPPORTUNITIES

### A. Summary

Neither the utility business model nor market growth transformations contemplated by REV will occur overnight. Particularly during the early stages of this transformation, it is critical that the Commission retain strong oversight of the continuing monopoly nature of the business, supply clear expectations of desired outcomes, and have the mechanisms in place to measure success and alter the course if deemed necessary. At the same time, the proposals in this white paper are meant to collectively incentivize progress at a pace that will drive customer value.

There is no single component of regulatory reform that will yield the comprehensive outcomes that REV contemplates. Achieving those comprehensive outcomes can be ensured in part by creating earnings opportunities for utilities at each point where they can produce increased customer value—including capital efficiency, operating cost efficiency, peak reduction, and enabling customers to manage their bills. Therefore, Staff recommends a combination of financial incentives that consist of new MBEs opportunities, practical adjustments to conventional ratemaking methods, and concrete targets with new positive-only, symmetrical, and bidirectional earnings impacts. This combination allows early gains around overall cost reduction as well as continued assurance that public policy goals are met.

The combination of market facing opportunities and traditional regulatory oversight are necessary to instill the broad based confidence that REV requires, place the State firmly on the path to industry modernization, and provide the Commission the transparency necessary to determine how best to adjust the regulatory formula as the market matures and less regulatory intervention is needed.

New MBEs can come in several forms. In addition to their conventional functions, utilities in the role of platform providers will be able to earn revenues from various value-added services provided to market participants, for example, micro-grid engineering. As a network provider, utilities should enable interoperability and open sourcing as much as feasible throughout the system to gain the greatest value for customers without compromising the security, safety and reliability of the overall network.

Conventional ratemaking methods should also be reformed to orient utility earnings toward the outcomes of successful markets and achieving policy goals. ESMs should be directly linked to outcomes indices. The net plant reconciliation mechanism ("clawback") should be revised to encourage utilities to supplant capital spending with cost-effective operating cost or third-party spending. EIMs should be adopted for a number of distinct outcomes such that utility earnings are based on performance and achievement of outcomes rather than almost entirely on capital spending. Scorecards with no direct revenue impact should be used for planning, transparency, and accountability.

## B. Market-Based Earnings in a Fully Developed Market

### 1. Platform Service Revenues, Customer Enhancements, and Synergy Opportunities

The utility as a platform presents opportunities for new utility services and associated revenues, which will supplement existing rate-based utility revenues. As markets develop liquidity and volume, utilities should be expected to derive a growing share of earnings from MBEs in exchange for value-added services that they provide to the market.[32]

The makeup, mixture, and pricing of MBEs will be driven more by market forces and innovation than by regulatory requirements. Examples of likely market-based services in the electric industry could include, but should not be limited to: 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; and advertising. Examples of customer enhancement and adjacent value-added synergies include energy services financing, engineering

[32] See, e.g., Weiller and Pollitt, supra.

services for micro-grids, and enhanced power quality services. A primary vehicle anticipated for utility MBEs will be "platform service revenues" (PSRs). PSRs are revenues that utilities, in their capacity as DSP providers, will earn from market participants. The first set of demonstration projects filed with the Commission reveal early examples of these types of opportunities.

Alternative revenue streams are not new for regulated utilities. For example, Georgia Power offers bundled communication services, and Con Edison and Pacific Gas & Electric offer co-location with wireless facilities.[33] Green Mountain Power offers a number of advanced energy options including heat pump services. These innovative types of revenue streams allow utilities to use their assets for the benefits of both shareholders and customers.

What will be new in REV is the diversity and scale of revenues potentially available from MBEs, and the way in which MBEs support the policy goals of REV. Utilities will be able to diversify their business and protect against the concern of lost sales from, and potentially stranded investments in, conventional business units as more third-party investment enters the system. Platform services can aggregate services from otherwise separate industries, such as electricity and home security, while connecting customers to the product options that are best suited for them.[34]

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[33] See Case 09-M-0329 - Petition of Consolidated Edison Company of New York, Inc. and AT&T Mobility LLC for Authorization for AT&T's Existing Wireless Equipment to be Attached to Con Edison's Electric Transmission Facilities (Tower K-34) Pursuant to Section 70 of the Public Service Law. See also, Steven Propper, "Alternate Utility Revenue Streams: Expanding Utility Business Models at the Grid Edge" (GTM Research 2015).

[34] Sangeet Paul Choudary, Geoffrey Parker and Marshall Van Alstyne, "The Rise of the Platform: How today's connected

Electric utilities are particularly well suited to provide platform services, because one of the aspects of multi-sided markets is that they allow spare resources of various participants to be optimized. The load balancing performed by utilities for a hundred years is taken to a new level when customer-producers are able to invest and use resources most efficiently by sharing their capabilities and needs across the platform, enabled by service providers and aggregators.

### 2. Benefits of the MBE Model

MBEs should be an important part of the utility business model in a fully developed REV environment. Along with performance incentives and traditional cost recovery, MBEs will be a part of a utility's total revenue stream and will be particularly important as an opportunity to increase earnings without adding to base rates. MBEs will serve numerous policy and financial objectives, including to:

- **Facilitate market entry and participation**—DER providers and ESCOs experience high transaction costs in identifying and recruiting customers. The platform will enable market entry at greatly reduced cost. Utilities' opportunity to earn from increasingly wide use of the platform will provide an incentive to make access to the platform and to customers as simple as possible.

- **Offset rate impacts of DSP capital and operating expenses**—Charging participation and transaction fees to those who utilize the platform will be a means of sharing the platform costs between participating customers and the general customer base while total system costs are reduced.

- **Unlock potential system value**—The addition of MBEs to utility business models will not represent a reshuffling of existing costs and benefits. It represents new value created by the DSP platform and DER market activities.

users are powering a seismic shift in business models" (Platform Economics 2015).

- **Allocate DSP-related capital and operating costs between market participants and non-participants**—Customers who receive more service and value from the platform should pay a higher portion of the platform costs. Such costs should be offset by the increased value those customers receive, and should not become a barrier to entry. These costs should generally be charged to the DER provider, and will in turn be included within the transaction value of the DER provider to the end-use customer. In this manner, delivery rates charged by the utility to customers will remain the same, regardless of whether the customer’s actions take the form of a traditional consumer, an active consumer, or a prosumer.

- **Provide incentives for utilities to meet the needs of customers and DER service providers**—Efficient implementation of REV will require effective operation of the DSP platform, which should result in utilities earning revenues from platform users. This will both advance the goals of market participants and improve utility earnings without adding costs to ratepayers.

- **Provide incentive for utilities to serve REV objectives**—Effective operation of the platform by utilities will serve not only the private interests of market participants but also the public objectives of REV. In that way, the opportunity for utilities to enhance earnings through platform operation will benefit all customers.

- **Provide incentive for utilities to innovate and encourage innovation in the market**—MBEs will be earned not only through effective performance of basic DSP functions. 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.

- **Supplement utility revenues as third-party market share increases**—One of the principal goals of REV is to create a utility business model that embraces market and technology changes that would otherwise be viewed as competitive threats. This is accomplished in part by outcomes-based ratemaking reforms, but will be enhanced by the opportunity to earn MBEs where market activities are both expanded and predictable.

- **Reduce uneconomic grid defection**—MBEs will be earned from activities that are providing system value. In this manner, by utilities working with market participants to produce greater grid-connected value, available grid services will be of greater value than that achievable from grid defection.

3. Pricing and Revenue Sharing

In multi-sided markets, the platform is defined in part by deciding which aspects of the market to open to third parties for competition and product development, compared to which aspects are exclusively maintained by the platform provider (i.e., the utility).[35] Platform markets are also distinguished by particular pricing structures that reflect the multi-sided nature of transactions. Unlike traditional transactions, in which products and services flow in one direction to customers while payments flow exclusively in the opposite direction, suppliers in platform markets frequently elect to pay service charges to the platform itself in order to gain efficient access to the market and to customers. The determination of appropriate charges, and the balance between what service providers pay versus end users, is a matter of significant research and consequence for market outcomes.[36]

Establishing both the right level and application of service charges is critical to gaining market success. Charges that are set too high or leveed on the wrong actor can have the effect of unnecessarily slowing growth of the market and depriving customers of its attendant benefits. On the other

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[35] Thomas R. Eisenmann, Geoffrey Parker and Marshall Van Alstyne, Opening Platforms: How, When and Why?, Working Paper (Harvard Business School 2008).

[36] See, e.g., Eisenmann, et al., 2006, supra; Andrei Hagiu, "Two-Sided Platforms: Product Variety and Pricing Structures," Journal of Economics and Management Strategy, Vol. 18, Number 4 (Winter 2009).

hand, charges that are set too low or where service is given to DER providers at no cost, necessarily means that the costs of implementing REV may not be optimally shared between market participants and customers who gain only indirect benefits. NYSERDA has engaged consultants to further assess the issue of service charge development, and their work will be available for consideration by the Commission and parties.

Demonstration projects offer a particularly rich opportunity to explore the opportunities and challenges surrounding MBEs, and to provide real-world experience to inform their design. Several of the demonstration projects filed on July 1, 2015 will directly inform the development of MBEs, such as Con Edison's Clean Virtual Power Plant and Iberdrola's Community Energy Coordination or Flexible Interconnect.[37]

Utilities and DER providers should use these demonstration projects as vehicles to develop business models that use MBEs as a component of compensation and earnings. As REV progresses, and following the Commission's guidance in initiatives such as community aggregation and community DG, utilities should be encouraged to develop charge structures that can support market growth and fair cost allocation.

The understanding and use of MBEs as a component of the modern utility business model will take both time and experience, and the regulatory process must be sufficiently flexible to accommodate both of these elements. While utilities should be encouraged to work with DER providers to develop these innovative approaches, there are also several significant regulatory components that should inform how service charges are

[37] Determinations on specific demonstration projects are still pending. References to demonstration projects in this paper reflect the project as proposed and do not imply approval.

applied and the treatment for recovery under traditional regulatory constructs.

A critical factor in the ratemaking treatment of new revenue sources will be the extent to which the revenues derive from functions that only the utility can provide as part of its monopoly functions, versus the extent to which they represent competitive services. 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. Earnings opportunities from competitive functions should depend on the extent to which utilities place shareholder funds at risk. In other words, if the activity is essentially competitive (e.g. advertising) but is made possible by a combination of ratepayer-funded infrastructure investment and at-risk operating expenses, a suitable allocation method will need to be developed.

As an example of current practice, regulated natural gas delivery companies earn revenues from selling pipeline capacity that is not needed to serve their native load. Revenues from these capacity releases are typically shared, in New York, with 85% of proceeds to ratepayers and 15% to shareholders. In this instance, the initial investments were rate based and minimal shareholder risk is involved, so the shareholder portion represents an incentive to optimize sales while ratepayers receive the bulk of the revenues. The Commission will need to determine the circumstances in which a sharing mechanism should be applied, whether a single revenue sharing allocation or multiple ones should be used for allocation of service charge revenues, and in all cases what level of sharing is appropriate.

Many services generating MBEs will be competitive in the sense that DER providers could use non-utility resources to accomplish the same function. Utilities will have an incentive to maintain high service quality, or risk losing this business to other providers. Some services such as platform access will be exclusive to the DSP function and will be subject to greater oversight. Regardless of the nature of the service, the Commission will need to ensure that service charges are not discriminatory. Also, the rapid dispute resolution process under development as required in the Framework Order will be used to facilitate resolution of any concerns of discriminatory or otherwise unfair practices by utilities.

Particularly in the early days of implementation, the introduction of service charges must be transparent and subject to Commission oversight. Regardless of whether they are for services that are new and competitive in nature or are derived from their monopoly functions, utilities must maintain the appropriate level of transparency in their service charge development and provide the opportunity for stakeholders to comment. This will be equally true for when charges are first established and when they are modified.

The Commission must ensure that charges for similar services are set in a manner that is comparable and fair throughout the State. At the same time, the process for service charge establishment and rules for recovery and retention of earnings must be sufficiently rapid and nimble so as to avoid the regulatory process itself becoming a deterrent to market growth and innovation. Given that the introduction of MBEs is less familiar in the industry, the Commission will need to determine the appropriate approach to regulating that allows market forces to operate while at the same time ensuring fairness and transparency. The Commission has experience with this form of light regulation in other aspects of its regulatory oversight, and guidance can also be found through approaches in other industries.

Appropriate considerations for these issues will be informed by currently ongoing consulting efforts for NYSERDA. Stakeholders should provide input on how best to establish the structures for the development of and regulatory treatment of MBEs. Staff will combine these inputs with early lessons from the demonstrations to recommend a set of guidelines that can then be offered for further comment and Commission approval. In so doing, Staff will consider the role of demonstration projects, utility-wide pilots, or other similar approaches in facilitating regulatory approval.

Finally, reliance on MBEs as a significant element of utility revenues will develop as REV markets attain full-scale and platform pricing grows from initial market development into a fully operational market. Encouraging the use of MBEs accomplishes three purposes: it (1) provides important information on how best to calibrate service charges to achieved desired market entry and outcomes; (2) provides the Commission the opportunity to learn how to approach MBEs that are derived from investments that would otherwise be entirely assigned to customers, and over time become a reliable source of continued earnings that offset revenue requirements; and (3) provides opportunities to utilities to further grow their business and provide value to shareholders from competitive DSP services. Because technology-driven markets have a tendency to evolve faster than regulators predict, the Commission should be prepared to respond and should not be wedded to a particular timetable that might slow the pace of adoption.

### C. Modifications to the Utility/DSP Revenue Model

While utility MBEs are established and grow over time, other modifications to utility ratemaking are needed to immediately support development of DSP capabilities and to orient utilities to achieve REV objectives. Two general areas of regulation are available for near-term measures promoting progress toward REV objectives: specific outcome-based financial incentive mechanisms, and changes to general ratemaking methods. Both types of incentive changes are recommended in this proposal.

The informal comments of many parties cautioned against abrupt changes in established ratemaking methods. Both consumer advocates and utilities expressed concern that the balance could be tipped in the wrong direction unless reforms are carefully considered and justified. For these reasons, the approach recommended in the near-term is to make incremental ratemaking changes that minimize inherent financial incentives against third-party engagement in DER, and provide incentives that will direct utility actions toward enabling increased DER penetration.

These changes serve as a bridge to more comprehensive reform in two ways. First, in response to parties' concerns, the recommended changes represent the minimum needed to effectuate REV, but could lead to greater reforms as necessary. Second, they are a bridge toward a fully established market-based structure that relies more heavily on platform revenues and market-enabling services and less on regulatory interference as a mechanism to drive innovation and customer benefit.

### 1. Capital Expenditures and Operating Expenses

New York utilities spend billions of dollars annually on infrastructure and maintenance.[38] The potential for DER to mitigate these expenditures is most clear where growth-driven new facilities are planned. However, much of the current spending is used to maintain or replace existing facilities, where the potential for DER is less obvious and the opportunity for substitute actions requires detailed analysis and potential modification of utility operations. Some types of maintenance and replacement schedules may be subject to deferral or alternative approaches, while many will not be. Utilities must have earnings incentives that prompt the optimal choices among capital, operating, and third-party DER options.[39]

Current ratemaking provides earnings primarily through a return on rate base. Choices between capital and operating options can be influenced when short-term earnings are increased by cutting operating expenses. Thus, utilities have inherent interests in growing rate base through capital expenditures. Utilities may also have other business motivations to favor capital spending, unrelated to finance, such as firm size or operational control.

Several parties question whether the perceived financial bias favoring capital is real, arguing that increased rate base is attractive only if there is confidence in the ability for earned returns on capital to exceed actual costs of capital. In this view, if earned returns equal the cost of capital, the utility should be financially indifferent. The distinction between rate base and deferral accounting is also significant

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[38] The Framework Order cited current NYISO estimates of $30 billion in capital spending over the next ten years.

[39] Examples of possible targeted areas for cost reduction are described in Appendix D.

here. Utilities tend to favor physical assets over regulatory assets, even if both are carried at the cost of capital, as they perceive physical assets to be less risky.

Regulatory lag, in some cases, may also affect behavior because a utility may have a near-term financial interest in reducing capital investment. Concerns have arisen in the past when utilities have cut capital expenditures to enhance near term earnings, at the expense of long-term quality of service. Over the last decade, long-term rate plans have introduced net plant reconciliation mechanisms (referred to here as “clawbacks”) to remove the earnings benefits of capital expenditures that fall below forecasted levels. The purpose of the clawback is to prevent utilities from delaying needed capital projects for the sake of short-term earnings.

Regardless of whether a capital bias has been demonstrated in the course of ordinary business, the structural reforms presented by REV create a need to change the relationship between capital and operating expenses. At a minimum, utilities should not have a disincentive to use operating resources or third-party assets in lieu of utility capital investment, where the former are more efficient and effective. Utilities should have an incentive to encourage third-party investment in DER to the extent the DER provides system value.

One approach to begin to address this issue is to modify the existing clawback mechanism such that it does not discourage utilities from relying on operating expenses or third-party investments to displace capital projects, and utilities are given a better incentive to make the most cost-effective choice between capital and operating expenses. Clawbacks are now standard components of rate plans, providing that if a utility does not spend its entire proposed capital budget, then the carrying charges (return and depreciation) on unspent amounts embedded in rates will be refunded to customers.

The clawback should be revised so that carrying costs may be retained by the utility where a project in the capital budget has been supplanted by DER or operating expenditures in a cost-effective manner. This would allow the utility to retain some or all of the earnings benefits of the capital it did not spend.

Where a utility spends operating expenses to address system needs, the utility would recover the expenses by reducing a portion of its projected capital spending. In effect, this would ensure that the project is cost-effective, as the operating expenses to achieve the DER should be lower than the carrying costs on capital that was displaced.[40] For this reason, the clawback should be modified so that the utility, at a minimum, could be indifferent to whether the utility or a third party funded the DER. In this way, the utility and customers share an interest in maximizing efficient third-party investment in DER to supplant capital spending.[41]

At the time of the utility’s next rate case, the capital budget would be reset, and avoided carrying costs on the supplanted project (net of on-going third-party DER expenses) would result in lower rates. Under this formulation, a utility in a multi-year plan has a strong incentive to find cost-effective alternatives to capital projects, but the utility would not receive a long-term increase in rates. Long-term incentives would be provided by MBEs and EIMs.

[40] An exception to this situation might occur where traditional utility operating expenditures on maintenance may produce multi-year benefits but are not capitalized.

[41] This reform would also potentially improve the utility's cash flow, since capex will be avoided and replaced with lower cash expenses.

As a hypothetical example of how this would work, consider a utility whose DSIP identifies a capital project that can be supplanted by DER. A $3 million capital project would have an annual rate impact of approximately $500,000, of which approximately $350,000 covers rate of return on debt and equity and the remainder is depreciation expense. If the need for the project can be deferred by spending $200,000 per year on DER, the utility can procure the DER and retain the difference of $300,000, until the next rate case. In the next rate case, the $500,000 carrying charge on capital is removed from rates and the lower $200,000 procurement expense is inserted. The net result for ratepayers is neutral during the initial period, and savings of $300,000 per year after the reset of rates. Under the conventional clawback in this scenario, the utility would spend the $200,000 on the DER without any rate recovery, and also have to forfeit the entire $500,000 representing carrying charges on the capital project that was not built. That approach leaves the utility with a strong disincentive to pursue the cost-effective DER.

Another complementary approach would involve operating expenses that are used to develop or enable DER that do not offset near term capital spending. If utilities are able to see operating resources as an earning opportunity on a par with capital spending, they will have no disincentive to procure DER. In the case of Con Edison’s Brooklyn-Queens Demand Management (BQDM) project, the Commission determined that all capital and operating costs should be amortized over a ten-year period with carrying charges and an incentive adder.[42]

[42] Case 14-E-0302, Petition of Con Edison for Approval of Brooklyn Queens Demand Management Program, Order Establishing Brooklyn/Queens Demand Management Program (issued December 12, 2014), p. 19.

The topic of capital bias has been taken up by other jurisdictions. Of particular note, the UK's RIIO structure uses a "totex" approach to address the distinction between capital and operating expenses. The totex approach is an accounting strategy under which capital and operating expenditures are treated as equivalent and recovered under the same formula. The formula sets a ratio of "slow money" to "fast money", with slow money being amortized at cost of capital and fast money recovered on an annual basis. The ratio, typically 80% slow to 20% fast, is applied regardless of the actual ratio of capital and operating expenditures.

Adopting the totex approach in New York would face significant obstacles, given differences in accounting standards between the United States and the UK.[43] Moreover, even if rates

[43] There are two reasons why full adoption of a totex regulatory approach may not be practical given differences in accounting standards between the United States Generally Accepted Accounting Principles (US GAAP) and the International Financial Reporting Standards (IFRS) used in the UK. First, in the UK the regulatory asset value is an amount set by the UK regulatory body, which is not based on original cost. In comparison, under US GAAP and New York regulation, utilities are permitted recovery of assets based on original cost less depreciation. Second, under US GAAP, utilities are permitted to use deferral accounting under Accounting Standards Codification (ASC) 980. Under IFRS deferrals are not permitted. In 2014, utility assets in New York included over $4 billion of regulatory assets, or 24% of utility equity. Adoption of an alternate approach such as totex could expose utilities to a write-off of these regulatory assets, since a totex approach will hinder a utility's ability to demonstrate that specific recovery of these assets is being provided through rates. Deferrals are not permitted under the UK system, and an inability to book deferrals would inhibit approaches under REV that would require utilities to defer and earn a return on certain DER-related operating expenses. It could also increase earnings volatility and increase the cost of capital.

were based on regulatory totex values, public financial statements would still be presented in conformance with traditional accounting standards, and utilities and financial managers would be held accountable on that basis, reintroducing the distinction between capital and operating expenses. A more fundamental issue, however, is that UK distribution utilities do not perform the platform provider functions planned in the DSP model proposed for REV. While RIIO is a leading example of the reform of regulated services, it does less to encourage a transactional grid structured as a platform-based market.

Whether the issue being addressed is described as capital bias or as a disincentive to use operating resources, RIIO's totex approach is intended to make the utility somewhat indifferent to the type of expenditure, and this indifference is an objective of REV as well. Modifying the clawback mechanism is necessary to correct an existing misaligned incentive, but may not be sufficient to fully address the objective. Stakeholders should comment on additional approaches that could achieve the outcomes of the totex approach.

2. Public Policy Achievement

As has been consistently noted, the reforms proposed in REV are oriented toward developing cost-effective, market-based solutions to reduce total customer bills to reduce the need for regulatory intervention as a means to achieve this objective and other public policy goals. However, increased reliance on market-based solutions does not diminish responsibility to ensure achievement of public policies and public interest outcomes that are fundamental to the Commission's statutory authority. Standards and economic measures that require utilities to ensure that electric service is reliable and secure and that they are well prepared to address weather and cyber related threats remain critical. While REV will provide utilities with enhanced options to meet these objectives, utilities will retain the overall obligation for safe, reliable and secure service. The Commission should retain existing performance metrics related to these core activities.

Other crucial public policy objectives concerning the protection of the interests of low-income customers and continued gains in energy efficiency do, however, require additional emphasis and near term intervention to ensure their continued success.[44]

### a. Low-Income Customer Participation

In order to encourage cost-effective market participation and third-party capital, the Framework Order specified that utilities should not own DER projects except under limited circumstances. One of the circumstances for utility ownership is in underserved communities where market opportunities are not present or being developed.[45] The intent of this provision is to ensure that low-income customers are not deprived of the opportunities to take advantage of DER benefits due to lack of independent commercial interest,[46] and to provide a vehicle for partnership and enhancement of DER participation and

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[44] Framework Order, pp. 77, 88.

[45] A petition for rehearing or clarification of this exception, filed on March 31, 2015 by Alliance for a Green Economy, Binghamton Regional Sustainability Coalition, Citizens Environmental Coalition and Citizens for Local Power, is currently pending before the Commission.

[46] As the Commission observed, it is also highly sensitive to the concerns of the environmental justice (EJ) communities that they not experience increases in local fossil-fuel emissions due to higher levels of DER penetration. Accordingly, the programs that are discussed herein should be used as a vehicle to decrease harmful local emissions for the benefit of the specific EJ communities and their neighbors.

opportunity. National Grid's Neighborhood Solar demonstration project is an example of a cooperative approach to developing DER in low-to-moderate income communities.

Utilities should also encourage new developments in energy efficiency designed to enable full participation by low-income customers who may live in master-metered multiple dwelling premises. While low-income discounts provide a baseline of affordability, there is untapped potential for low-income residents to affirmatively manage their own electric usage and therefore their electric bills. Barriers to low-income participation in energy efficiency measures include rental arrangements that prevent or deter implementation of energy efficiency measures, insufficient information about energy usage or deployment of tools to manage usage, lack of awareness of opportunities, and inadequate availability of capital.

Potential solutions to overcome these barriers are being actively developed by stakeholders.[47] For example, a cooperative model suggested by the Brooklyn Alliance for Sustainable Energy (BASE) and the New York City Environmental Justice Alliance (NYC-EJA) could unite community-based organizations in low-income communities into a cooperative to pool their usage reductions, creating a demand reduction resource of value to the utility. Increasing energy efficiency in the affordable

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[47] For example, the national Energy Efficiency for All Coalition includes the Natural Resources Defense Council, Association For Energy Affordability, Pace Energy and Climate Center, the Center for Working Families, West Harlem Environmental Action, Enterprise Community Partners and the Green and Healthy Homes Initiative. Optimal Energy, Potential for Energy Savings in Affordable Multifamily Housing (May 2015). Additionally, Rocky Mountain Institute’s Low-Income Energy Affordability Program (LEAP) is working in New York with the aim of mobilizing community voices in the design and priorities for the management of energy in their neighborhoods, towns, and cities.

multifamily sector is a cost-effective way to reduce energy consumption and provide low-income customers tools to manage their own usage and to monetize those reductions.

The development of business models to ensure that low-income communities gain the full potential of REV requires a focused effort. Consistent with the Framework Order, the Consumer Advocacy staff, through the office of Consumer Services, will continue to engage with NYSERDA, the utilities, and interested stakeholders including representatives of the affected communities to develop 1) the models that are discussed in this white paper, and 2) other solutions that can be deployed to meet the Commission’s objectives. Demonstration projects could be used to test possible programs.

The Consumer Advocate’s Consumer Advisory Council[48] has proven to be a valuable resource to identify issues of concern and develop solutions that can materially benefit low-income customers. A focused effort that can incorporate the experience of these entities and expand them with the ideas of others has the potential of yielding practical solutions that utilities and DER providers will be able to implement throughout the state. The effort Staff will continue and expand will result in the identification of programs utilities should implement, and the adoption and uptake of these programs should be included as part of an affordability EIM discussed later in this white paper.

b. Energy Efficiency

The Framework Order reiterated the Commission’s commitment to energy efficiency, and noted that its approach was meant to

[48] Consumer Advisory Council members include the City of New York, the Association for Energy Affordability, the Utility Intervention Unit, the Public Utilities Law Project, AARP, and New York Public Interest Research Group.

"achieve greater market-wide efficiency savings with less need for direct ratepayer support" by leveraging market mechanisms that combine resource acquisition with third-party activities.[49] The Framework Order further determined that funding for utility efficiency programs should transfer from a surcharge mechanism to the utilities' operating expense allowance, and that energy efficiency programs should transition to a more market oriented approach that complements the market transformation strategy developed by NYSERDA.[50]

While a key objective is to create a vibrant market resulting in greater levels of energy efficiency by making efficiency an attractive business opportunity, maintaining minimum targets is important to ensure sustained effort and demonstrated commitment. Therefore, overall efficiency targets will not be reduced. Rather, the Framework Order stated that efficiency achievements will need to be increased to meet REV objectives. Achieving more efficiency without adding to ratepayer charges requires a change of approach, and as an early step, utilities filed Efficiency Transition Implementation Plans (ETIPs) for 2016 and for 2017-18 on July 15, 2015. These plans represent an initial step towards determining targets going forward, with additional input to be provided via the DSIP process, as discussed below. The Commission also revised

[49] Framework Order, p. 76.

[50] In the June 19, 2015 order authorizing gas efficiency programs, the Commission determined that for both gas and electric utility efficiency programs, only costs associated with utility personnel working directly on energy efficiency programs should be recovered through base rates as part of the utilities' operating expense allowance, and established an Energy Efficiency Tracker, a surcharge mechanism to recover the remaining costs associated with the implementation of utility energy efficiency programs.

program restrictions to give utilities more flexibility in meeting targets.

In order to fulfill the Commission’s objectives in the long term, utility-run or utility-sponsored efficiency programs should progress along the spectrum of the following four approaches, and the relative weight of the approaches should shift as other elements of REV implementation proceed. The four approaches are, in sequence: 1) resource-acquisition programs similar to current Energy Efficiency Portfolio Standard (EEPS) programs that achieve MWh savings in the most cost-effective way but with an increased targeting of MW reductions to add customer value, 2) resource acquisition programs or market-supplied programs targeted to specific distribution system needs identified in DSIPs, 3) utility resource acquisition programs designed to support market transformation strategies, and 4) market-driven measures that benefit from market transformation strategies and DSP-enabled markets.

The first of these approaches is a more flexible version of the current EEPS approach with a MW component. Like other elements of REV, the transition in approach to utility efficiency programs should be phased and should provide reasonable continuity to vendor communities that have developed to serve the Commission’s programs. Near-term programs, covered by the 2016 ETIPs and to some extent subsequent years, are expected to predominantly consist of general resource acquisition programs to meet assigned MWh targets, but with an orientation toward MW reductions in order to add customer value and reduce bills.

Interim-period utility programs should be targeted to meet distribution system needs. This approach builds on the first by using utility DSIPs to identify areas where durable reductions in demand through energy efficiency programs will have value to the distribution system.  Utility efficiency programs in this phase should transition toward a bidding process or other procurement mechanism that allows energy efficiency service providers to meet those needs.  One approach would be to utilize multi-year contracts administered by utilities that have the potential to meet energy efficiency targets and reduce the total customer bill by avoiding the need to purchase more expensive capacity and energy from the wholesale markets.  Through the use of longer-duration contracts and competitive procurements to obtain these services, utilities will be complimenting the market transformation efforts of NYSERDA as contemplated in the Clean Energy Fund proceeding, and help drive down the costs of energy efficiency achievements.  As in the case of other aspects of REV, utilities should have an incentive to share in these benefits to further align their economic interests with those of the customers and third-party DER providers.

Once more market oriented and customer benefiting approaches are established, the level of economically achievable energy efficiency will continue to grow and, rather than see it as a fulfillment of a regulatory mandate, utilities will be able to incorporate energy efficiency into their base business model both as a source of earnings and an improved measure to meet their overall obligations to customers.  Through the additional tool of improvement in rate designs that provide better price signals to customers, providers will further be able to pursue energy efficiency opportunities that support customer needs without the need of utility payment schemes.

This transition in utility efficiency programs will have implications for outcome-based incentives, including carbon reduction.  When third parties and market transformation are relied on to meet efficiency goals, metrics that include efficiency gains will be more outcome-based and will not be tracked to specific MWh obtained by individual utility resource acquisition programs.

As described, targets for these programs will be established first through the ETIPs, and subsequently as a product of the DSIP process in which system needs and DER opportunities are identified. State Energy Plan goals, and compliance with anticipated federal carbon reduction requirements, will inform all of these processes.

### 3. Earnings Impact Mechanisms, Scorecards and Outcomes

#### a. Industry Context

The outcome-based ratemaking proposed here is a variation of what is broadly referred to as performance-based regulation (PBR). PBR is the subject of increasing attention for regulation of electricity markets as a means of better aligning earnings with performance.[51] Various forms of PBR have been studied or implemented in U.S. electricity markets such as Illinois, Massachusetts, and Minnesota, as well as in Canada, Europe, South America, Australia, and New Zealand.

PBR has also been explored in other regulated industries including telecommunications and healthcare, and is a familiar concept in other areas of the competitive economy, where setting of product prices, and frequently whole industries’ business

[51] Regulatory Assistance Project, “Performance-based regulation for distribution companies” (December 2000); David Malkin and Paul A. Centolella, “Results-Based Regulation: A Modern Approach to Modernize the Grid” (GE Digital Energy 2013); Jim Lazar, “Performance-Based Regulation for EU Distribution System Operators” (Regulatory Assistance Project May 2014); Melissa Whited, Tim Woolf and Alice Napoleon, “Utility Performance Incentive Mechanisms: A Handbook for Regulators” (Synapse 2015).

models, are oriented around the constant improvement of value to customers.

Elements of PBR have been adopted or proposed in electricity markets, including New York, for years.[52] As noted previously, New York electric utilities, including PSEG-LIPA, utilize performance metrics including outage duration, number of outages, customer service, safety, and various metrics targeted to particular needs identified for individual utilities. Earnings exposure for regulated electric company operations, by rate plan, range from total negative incentives of 263 basis points to total positive incentives of 45 basis points including positive incentives for energy efficiency.[53]

PBR plans tend to employ performance incentive mechanisms (PIMs) and/or scorecard-based performance metrics to evaluate performance. This proposal will use the term EIMs, which differ from PIMs in that PIMs are not necessarily monetized. The term PIMs is used here to reflect its common usage in industry reports and some other jurisdictions. PIMs are designed to balance anticipated costs and benefits from the actions they seek to elicit, are developed with stakeholder input, and can evolve over time to incorporate practical learning from experience and to improve outcomes achieved.[54]

Three key themes emerge from an assessment of how other jurisdictions have considered or employed PIMs:

- **Expansiveness of metrics** — Historically, PIMs have been relatively narrowly focused and designed to encourage

[52] Sonia Aggarwal and Eddie Burgess, “New Regulatory Models” (Prepared for the State-Provincial Steering Committee and the Committee on Regional Electric Power Cooperation March 2014).

[53] A table of existing performance mechanisms is found in Appendix C.

[54] Whited, et al., supra, provide an overview of performance incentive mechanisms, including suggested design principles, which is a useful reference for ongoing development of PIMs.

specific outcomes or applied to isolated projects for purposes such as cost control or safety. Increasingly, as in the case of Minnesota and the United Kingdom, PIMs are being considered more broadly to address a variety of desired outcomes such as environment and social outcomes.

- **Whether to monetize or simply track metrics** – Different jurisdictions also take different approaches to monetizing PIMs. PIMs may not be monetized, but rather simply tracked via a scorecard if the metrics are difficult to measure accurately, less familiar, or if there is a desire to move incrementally towards PBR. Metrics without direct financial consequences may still have motivating effects. A hybrid is also possible.
- **What portion of revenue to put at risk** – There is also an important choice around what portion of earnings to tie to PIMs. Most jurisdictions to date have made PIMs relatively small in magnitude, but some are considering tying increasing portions of utility revenue to performance.[55]

b. Proposed Outcome Metrics

Two types of metrics should be considered for New York utilities: those that have direct earnings impacts, and those that are measured but not monetized (i.e., via scorecards). There are several reasons to use both EIMs and scorecard metrics. The new directions in REV give rise to a wide range of desired outcomes. Attaching an earnings impact to every desired outcome would be difficult and would distract from the central priorities. It will be most effective to concentrate earnings impacts on a relatively small number of outcomes that have the greatest potential to influence changes in the utility model and development of the market in the near term. Also, the use of a scorecard allows the development of metrics and an assessment of their relative effectiveness as a measure or cause of change without necessarily affecting earnings or customer bills. A scorecard measure can be refined over time and, eventually,

[55] Lazar, supra.

might be converted into an EIM.[56] A scorecard can also be used as a public, transparent measure of progress in attaining important outcomes.

i. EIMs

On June 4, 2014, a list of 26 outcomes in five different categories was presented to parties for comment. Parties had divergent opinions about the ratemaking options, but the outcomes themselves were generally well accepted. The chief comment of parties on the outcomes was that prioritization is needed.

The specific EIMs proposed here represent near-term prioritization. They reflect the comments of many parties in this proceeding and the observations of Staff concerning the near-term goals that can have the greatest positive influence on customer bills and the developing REV marketplace. These outcomes and associated EIMs should be incorporated in the initial rate filings approved following the Commission's Order in this proceeding.

EIMs should be seen as a supplement to the service charges that the Commission will otherwise allow utilities to charge for the market enabling activities discussed in this white paper. Because the EIMs proposed here are new and should be viewed as a positive motivation towards REV development, the Commission should limit EIM application in the near-term to enhancement of utility allowed rates of return. If necessary, in subsequent stages of development or utility rate cases, the Commission may either find that any particular EIM is no longer necessary and has been supplanted by market-based activities or, alternatively

[56] This technique has been used in telecommunications regulation. See Case 97-C-0139, Proceeding on Motion of the Commission to Review Service Quality Standards for Telephone Companies, Carrier to Carrier Performance Metrics Report (dated April 2015).

that negative revenue adjustments should be added to further motivate utility focus and success.

Specific EIM categories recommended for near-term implementation are identified below. Staff invites parties to comment on proposed EIM categories as well as the specific suggested measurements or methods to develop such measurements.

- **Peak reduction**—Reducing peak demand on the bulk electric system, and thereby improving system efficiency, are major objectives under REV that will bring immediate benefits. The goal of this EIM would be a decrease in each utility's peak load from one year to the next, in order to improve efficiency and reduce the top 100 peak load hours over a five-year period. The statewide load associated with the top 100 peak load hours is approximately 14% of the peak load or 4846 MW in 2013. Reduction of this peak could save customers billions of dollars per year. The annual target of an EIM can be tied to achieving a 3% reduction in peak load each year, and the baseline would be the average load of the top 10 peak load days of the calendar year that the metric first goes into place. On an annual basis the baseline will need to be adjusted for known weather related or economically induced changes to load growth and peak load contribution.[57] In order to allow for a flexible approach to implementation, the annual target could be used as a scorecard with the financial incentive measured over a longer period.

  Existing programs are expected to contribute toward this goal. On an annual statewide basis, the New York Sun program is projected to achieve 188 MW; combined heat and power incentives will achieve 23 MW; and current peak-shaving DR programs 29 MW. Capacity savings from energy efficiency programs are more difficult to estimate, because efficiency targets are primarily stated in terms of megawatt-hours. Current estimates are as high as 185 MW per year. 425 MW of annual peak shaving from current

[57] To be clear on this point, the Commission recognizes the important role of utilities in spurring economic growth in the State. To prevent unintended consequences, the Commission should allow the utilities to adjust projected base load peak from year over year changes in their load that reflect economic growth and associated increases in electric usage and contribution to peak.

programs would leave an incremental balance of 545 MW per year to achieve the 14% goal.

- **Energy Efficiency**—The attainment of the peak reduction targets should include at least the currently projected amount of energy efficiency. In this way, current efficiency targets will be met in a manner that also has the benefit of reducing peak. In addition, at least 10% of the incremental peak reduction balance of 545 MW should be achieved with efficiency programs. This will have the effect of increasing efficiency beyond current targets. Commission action on this EIM, though, should be made with consideration for utility-proposed efficiency metrics that will be provided through the on-going ETIP process.

- **Customer Engagement and Information Access**—The overall success of the REV market depends on the ability of customers to learn about measures they can take to manage their overall energy bill, the ability of DER providers and customers to access data about their own electricity usage so that solutions can be developed, and the ease of effectuating a transaction between and among customers, utilities, and DER providers. Staff has identified several mechanisms that can be translated into an EIM in this area.

  First, an EIM should gauge utilities' ability to successfully implement an online portal that supports customer engagement with DER providers, thereby lowering transaction costs. For example, utilities should be rewarded for successfully developing and deploying a portal that allows customers to easily and quickly access DER provider or ESCO websites, and this metric can be a useful early indicator of utilities' value-added role in linking customers and DER providers. This measure should reflect utilities' success in designing the customer portal in a manner that leads to customer action. For example, utilities could incorporate analyses of their customers' usage, demographic, and other information, and combine it with behavioral insights to create customer experiences on the portal that result in customer action.

  Recognizing that the customer portal will take some time to develop a robust set of functionalities, a second element of this EIM should equally weight three indicators of expanded data access and customer engagement in the time interval before the portal is operational.

A key objective is to provide mass-market customers with convenient access to their energy usage information, and facilitate their ability to share that information with vendors they select. Open and widely adopted industry standard tools are designed for that purpose, and prompt implementation of a single statewide tool, with accompanying safeguards, would be one early indicator of utility effectiveness in increasing customer access to and control over their energy usage data.

Another early indicator of customer engagement is the percentage of utility customers using this tool to share their customer usage data with DER vendors, six months after it is available. This measures how well utilities have informed customers of the benefits of accessing and sharing customer-specific usage data.

A third early indicator of customer engagement is the extent to which utilities successfully promote DR and time-of-use (TOU) programs.[58] Most utilities are launching DR programs in the summer of 2015, and already have opt-in TOU rates, and are expected to promote those programs using a wide range of outreach and marketing vehicles including Internet marketing, e-mail, and direct mail. A metric of utilities' success in promoting these options is the number of customers contacted with messages promoting DR programs. This metric should reflect each of the primary marketing vehicles, including outgoing emails and social media messages regarding DR programs. The number of customers contacted is only a first indicator of customer engagement, and this metric should also reflect the ability of utilities to evaluate and improve their marketing efforts, and ultimately the effectiveness of utility marketing efforts over time measured as number of customers participating in DR and TOU programs.

- **Affordability**—The purpose of this measure is to gauge utility progress towards increasing affordability for low-income customers, and it includes two parts. First, utilities should be evaluated based on their implementation of a set of programs targeted at supporting low-income customers' use of DERs to lower their bills. Subsequently,

[58] 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).

utilities should be evaluated based on participation levels and per-customer savings associated with these programs.

Second, the affordability EIM should be oriented toward the total amount of terminations and uncollectible expenses. Using terminations alone as a metric is insufficient, as the steps taken to avoid terminations can encourage an increase in arrears or bad debt. Staff has proposed earnings-based incentives related to reductions in residential terminations and bad debt expense in recent rate cases.[59] The process of establishing targets for such an incentive should follow the same approach as has been used to establish performance-based ratemaking incentives for other elements of measuring quality of service:

- o Establish the average number of residential terminations and bad debt write-offs for the last five years, and the standard deviation.
- o The utility can earn a positive incentive if it scores better than the average, minus two standard deviations for residential terminations and bad debt. A partial incentive could be awarded for achieving one of these targets, provided the other is at or below the average level.

- **Interconnection**—The Framework Order established a schedule for utilities to develop capabilities that will allow them to process more interconnection requests in a timely manner. Automated processing of numerous applications for smaller DG projects will both speed up those projects and also enable greater focus on larger projects that might require more analysis. The interconnection EIM should come in two parts. The first part would measure timely approval of applications of 50kW or smaller, and should be based on 100% timeliness as defined by the Standardized Interconnection Requirements. Positive incentives should be available in years where the total of interconnection approvals has increased by at least 20% from the previous year. This will help to ensure that an interconnection timeliness metric does not run counter to the objective of increasing DER penetration.

[59] See Cases 14-E-0318 & 14-G-0319, Central Hudson Electric and Gas Rates; and Cases 14-E-0493 & 14-G-0494, Orange and Rockland Electric and Gas Rates.

> The second part of the metric would apply to projects greater than 50 kW. Because these projects can present more complexity and need for analysis, timeliness and cost of compliance are both important and should be part of a metric, while some flexibility for the utility should be provided. The process should be more oriented toward developing workable solutions rather than simply identifying obstacles, and utilities should have an incentive to help produce solutions.

As previously noted, existing performance mechanisms that are related to safety, reliability, customer service, and utility-specific needs should generally be retained in the near term.[60] The changes being enacted by REV, including the greater capability and use of DERs, are expected to provide utilities with additional resources and capabilities to meet some of these existing goals, particularly around reliability and resilience. As part of the evolving regulatory environment, some of the existing metrics, such as stray voltage testing, should be examined for their continued need, if utilities are far exceeding the regulatory standard and an EIM is therefore no longer necessary.

There remain a number of implementation issues to work through in establishing EIMs. Important factors include ratepayer impacts (of both the incentives and the desired outcomes), the degree of utility control over the outcomes, the novelty and confidence-level in the metric, and impact on utilities' financial opportunities.

The degree of control that the utility exercises is relevant but should not be definitive.[61] A primary purpose of

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[60] See Appendix C.

[61] This is not a new principle. For example, prior to the decoupling of sales from revenues, utility earnings were strongly influenced by customer behavior over which utilities had little control.

EIMs is to align utilities’ profit motive with market-driven outcomes. By its nature, market activity will not be fully within the control of the utility, yet utility performance can have a significant influence over results.[62]

Many EIMs should be established on a multi-year basis. In contrast with existing reliability and customer-service standards, REV outcomes in the initial phase are more oriented to building long-term market structures, and the pressure of annual goals may interfere with this development. This practice is consistent with approaches adopted elsewhere, including the United Kingdom and Illinois. Multi-year metrics should be accompanied by interim reviews and reporting.

The categories of EIMs should be established by the Commission for all utilities, consistent with REV objectives. The method of measuring performance for EIMs should also be uniform across utilities. The specific EIMs adopted for each utility, however, as well as the relative weight of individual EIMs, should be considered in individual utility cases. The relative importance of outcomes may vary considerably among utilities and among service territories.

The amount of basis points at risk must be large enough to incentivize the desired outcomes. At this time there is no formulaic approach to this issue, either for individual EIMs or for the aggregate. A uniform approach across all utilities is preferred, but in early years, basis points should be established in individual cases on a utility-by-utility basis. As increased experience with EIMs enhances the precision of the metrics and the predictability of achievement, the number of basis points at risk and their relation to baseline returns on equity will be refined. Calculation of EIM adjustments might

[62] For this reason, this general initiative is called “outcome-based” ratemaking rather than “performance-based” ratemaking.

also involve a dead band within which a small variance above or below the target has no effect.

While most existing performance mechanisms are based on potential negative revenue adjustments, new EIMs can utilize either positive, symmetrical, or bi-directional adjustments.[63] There is no need for all EIMs to be subject to the same directionality. Factors unique to individual EIMs may determine the appropriate treatment. The direction of incentives is also related to the number of basis points at issue. A positive-only or positively weighted bi-directional approach might indicate that a relatively small number of basis points should be used.

As noted, Staff's recommended approach is to allow time for desired outcomes to develop, while prompting immediate action to develop the underpinnings of a market. For the first set of rate proceedings involving these new EIMs, Staff recommends positive incentives only. Staff notes two exceptions to this general approach. The EIMs for data access and interconnection should be symmetrical, with potential negative adjustments for non-attainment. Each of these is largely within the utility's control to achieve, and can easily be tracked and calculated. In addition, as noted in the MDPT recommendations, with regard to data access, specifically, the Commission should require that the utilities provide customer information as part of any advanced metering infrastructure program.

The EIMs for peak reduction, energy efficiency, and affordability initially should be subject only to a positive incentive. Because this group of goals, if achieved cost-effectively, will result in direct benefits to the overall customer bill, a positive earning potential for utilities will result in shared savings with customers. The rationale for

[63] A "bi-directional" adjustment is one in which the amount of a positive or negative weighting is not equal.

positive-only incentives is based on the assumption of associated customer bill reductions. Therefore, maintaining positive-only EIMs beyond the first round of rate cases should be predicated on the development of a metric to gauge that reduction. Such a metric must assess overall customer bill reduction in comparison to business-as-usual, rather than to current bills. Utilities should jointly propose a metric to be used to measure overall customer bill impact as it relates to evaluating the continuation of positive-only EIMs.

EIMs should be measured over a multi-year period to allow utilities time to develop outcomes. The addition of symmetrical negative and positive outcomes, or new EIMs, can be developed in further proceedings if desired outcomes are not occurring at a reasonable pace. In the event that the utilities do not achieve the targets through the positive-only incentives in the initial years of implementation, negative earnings risks can be added.

The source of funds to compensate utilities for incentives earned must also be established. The conventional method is to establish accounts that are reconciled in the utility’s next rate proceeding. An alternative approach is to link incentive payments directly to earning-sharing mechanisms, so that positive incentives could only take the form of earnings in excess of the allowed return. This approach would provide for incentive earnings without affecting rates, and would be coupled to a traditional incentive to maximize operating efficiencies. On the other hand, it would dilute the effect of EIMs, and might run counter to the goal of encouraging operating resources as a potential profit center. Staff therefore recommends the conventional method be used.

In shaping positive incentives, utilities should be able to propose alternative mechanisms. For example, a straightforward basis point approach would be the default mechanism, but a shared savings approach could also be considered.

Finally, as previously expressed, all incentives should be viewed as a temporary mechanism that drives but does not become the market solution. As markets develop into full scale, the need for EIMs, positive and negative, that are oriented toward building DSP capabilities and market activity will be superseded by the maturation of other earning opportunities such as PSRs. In this transition, regulatory targets will be replaced by market-driven outcomes.

ii. Scorecards

Scorecards will be measures of performance that do not have any direct earnings impact.[64] They would be applied to broader outcomes of general importance, and to novel types of measures for which reliable metrics have not yet been developed. Scorecards would serve three distinct purposes: 1) public, transparent mechanism to track progress on important outcomes; 2) providing information for system planning; and 3) refining metrics for potential use as future EIMs. The total of scorecard measures should reflect what is needed to provide a broad view of outcomes. For reference, Illinois, Ontario and Puerto Rico are each pursuing measurement and reporting for some metrics prior to establishing financial incentives.[65]

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[64] Scorecards could have an indirect earnings impact if they are used as outcome indicators under the Earnings Sharing Mechanism discussed below.

[65] Whited, et al., supra; Ontario Energy Board, “Performance Measurement for Electricity Distributors: A Scorecard Approach” (March 5, 2014).

Proposed scorecard metrics include:

- **System utilization and efficiency**—Advanced metrics to define system utilization in a broad context should be developed, including T&D utilization, fuel diversity, and overall system efficiency. System load factor is a useful indicator, but must be defined broadly to include desirable outcomes that can potentially contribute to a durable positive load factor across the entire system. These include energy efficiency, DG penetration, and DR participation. The amount of generating capacity with very low capacity factors is a strong indicator of poor system efficiency on a broad scale, but unless located in a load pocket, would be difficult to attribute to any individual utility.

- **DG, energy efficiency, and dynamic load management (DLM) penetration**—Building a market for DER requires a critical mass of market penetration to attract market participants and to establish scale for platform investments. This metric would focus on the penetration of DG, energy efficiency, and dynamic load management (DLM) as a percentage of a utility's total load (including load offset by onsite generation and permanent load reduction achieved through energy efficiency). A target for installed DER penetration should account for the time needed to achieve this outcome. The scorecard should take into account the aggregate penetration of DG, DLM, and energy efficiency activity in the utility service territory. DER developed by third parties without the benefit of utility incentives should also count, as third party capital investment is a desired outcome.

- **Opt-in time-of-use rate efficacy**—New York’s utilities all have existing opt-in residential time-of-use rates, and these represent an important early opportunity for customers to manage their bills while at the same time developing more effective approaches to customer engagement. This scorecard metric should include two distinct but related parts. First, the number of customers who adopt the TOU rate. Second, customers’ ability to reduce their bills by responding to the TOU rate, measured as the range of and average customer savings for those customers who have adopted the TOU rate.

- **Market development**—There are a number of widely used indicators of market health. These include transparency, ease of access, settlement facilities, and dispute resolution. A scorecard should be developed for continuous monitoring of progress toward achieving liquid markets.

- **MBEs use**—The amount of market-based revenues a utility receives is a critical indicator of market uptake. It is equally important, especially in the near term, for the particular sources of MBEs to be critically evaluated, for purposes of transparency, monitoring progress, and determining needed improvements. Utilities should report total revenue from platform services and other sources of MBEs, and should identify the particular sources including any sources developed through demonstration projects.

- **Carbon reduction**—Each utility should be monitored for its Carbon Free Acquisition Rate (CFAR), taking into account carbon-free sources of generation sponsored by utilities as well as third parties for the benefit of load within the utility footprint, and energy efficiency penetration. The development of this measure is, of course, dependent on the issues pending in the Large Scale Renewables proceeding. One potential way to calculate the CFAR would be to use the following formula:

  CFAR = [(Contracted and Owned MWhs of Bulk Renewables, Nuclear, Hydro) + (Clean Behind the meter MWhs) + (energy efficiency MWhs)+ (Any Other Load Reduction)] {divided by} [(MWhs of Load) + (MWhs of DR) + (MWhs Energy Efficiency)]

- **Customer Satisfaction**—REV ultimately relies on engaged customers making informed decisions. Responsiveness to customer concerns is critical to engagement. The Customer Service Response Index is an existing metric that measures four items: customer satisfaction, complaint response time, escalated complaint response time, and pending cases. Like the affordability metric, this should be established by using a five-year average and standard deviation. As described below, at a later phase this index should be combined with others to create a broader metric that incorporates more REV-specific customer issues.

- **Customer Enhancement**—This measure would combine the affordability EIM with other indices such as levels of customer engagement in markets, prompt provision of utility service, customer satisfaction scores, and Home Energy Fair Practices Act compliance rates.

- **Conversion of fossil-fueled end uses**—This would measure the adoption rates of electric vehicles and conversions of combustion appliances to high-efficiency electric appliances (e.g. ground-coupled heat pumps), as well as their times of usage and extent of participation in DSP offerings. These measures can be leading indicators of the introduction of programs that can further improve durable load efficiency and affordability.

### 4. Earnings Sharing Mechanisms

ESMs are a component of multi-year rate plans, which are in standard use in New York. They allow utilities to retain earnings above the baseline ROE, up to a pre-determined level (e.g., 50 basis points). Beyond that level, earnings are shared between utilities and customers, and at higher levels savings are dedicated entirely to customers. This type of mechanism encourages utilities to cut costs and increase efficiencies, while removing rewards to utilities for making steep cuts that might hurt customers' interests. It also ensures that major unforeseen developments and vagaries in forecasting do not become windfalls to utility shareholders.

ESMs can be adapted to an outcome-based ratemaking approach. The sharing formula can be indexed to utility achievements, so that the utility's share of earnings is directly dependent on achievement of Commission objectives including affordability. This addresses the concern that utilities might cut spending in a long-term rate plan in order to increase earnings at the expense of service or otherwise compromise other REV objectives.

Indexing ESMs to performance will help to ensure that savings in operating expenses do not come at the expense of REV objectives. Equally important, the ESM caps should not represent ceilings on overall utility earnings, if additional earnings can be gained through market-based services and through EIMs. The ESM mechanism should complement these other opportunities.

In early years, ESMs should be tied to a performance index that aggregates the new EIMs with existing performance standards. These could be aggregated into three performance levels: base, superior, and inferior. In the longer term, ESMs could be tied directly to specific metrics in a more complex formula.

The acceptable or base performance scenario should be structured in the way that is commonly used at present. If the utility meets base performance metrics, it is allowed to retain the first tranche of earnings, and share subsequent levels in a declining proportion, with additional earnings above a specified level inuring entirely to customers.

If a utility achieves superior outcomes, the level at which sharing begins would be increased (i.e. the dead band would be widened). This would allow greater earning potential for the utility without increasing rates.

If a utility achieves inferior outcomes, the level at which sharing begins would be decreased, potentially down to the baseline ROE level. This would give the utility a strong incentive to achieve greater performance, and would ensure that measures taken by the utility to increase earnings are not at the expense of performance.

Following is an illustration of how ESMs tied to performance might be structured:

| | ESM | | |
|---|---|---|---|
| | Scorecard Performance | | |
| **ESM Proposal for REV** | **Base** | **High** | **Low** |
| Allowed ROE | 9.00% | 9.00% | 9.00% |
| Stay out Premium | 0.10% | 0.20% | 0.00% |
| Cap for Sharing Earnings | **9.10%** | **9.20%** | **9.00%** |
| Utility Retention | 0.25% | 0.75% | 0.00% |
| Sharing Cap | **9.35%** | **9.95%** | **9.00%** |
| | | | |
| First Level of Basis Points | 0.50% | 0.75% | 0.25% |
| First Sharing Threshold | **9.85%** | **10.70%** | **9.25%** |
| Customer Sharing % | 50.00% | 25.00% | 75.00% |
| Utility Sharing % | 50.00% | 75.00% | 25.00% |
| | | | |
| Second Level of Basis Points | 0.75% | 1.00% | 0.25% |
| Second Sharing Threshold | **10.60%** | **11.70%** | **9.50%** |
| Customer Sharing % | 75.00% | 50.00% | 90.00% |
| Utility Sharing % | 25.00% | 50.00% | 10.00% |

5. Capital Expenditures to Implement REV

Capital expenditures to develop DSP capabilities, e.g. communication and data management hardware and software, present a special case due to the novelty of the expenditures and the fact they are responding to a Commission mandate. Following close review of DSIPs, utilities should receive assurance from the Commission that the initial decision to invest in these capabilities will not be subject to retrospective review.

REV implementation plans detailed in DSIPs will inform utilities' overall capital plans. The Commission will need to take a balanced approach to pre-approving DSP spending in light of the overall bill impacts anticipated under the utilities' overall spending plans.

Pre-approval would not supplant the requirement that the utilities' execution of the projects must be prudent, but it will address the risk entailed in the decision to undertake these investments. This form of partial pre-approval to support a cost-based recovery should only be used in the early phases of REV implementation. Depreciation schedules for these investments should also consider the relatively short period of usefulness of many technology investments.

This approach requires a distinction between DSP expenditures and ordinary system expenditures. In most cases this will be a simple distinction; e.g., a conventional transformer replacement would not be eligible for this treatment while development of DSP platform technology would. Where the line between DSP and conventional spending will be most difficult to draw is in grid modernization projects such as sensors and automatic reclosers. Where a project may have been undertaken even in the absence of REV and distributed markets, the Commission should not provide pre-approval without a specific showing by the utility that the project would not have been done, absent REV.

Spending prior to approved DSIPs will need to be governed by the terms of utilities' current rate plans. Rate recovery for demonstration projects has already been addressed by the Commission. It is not anticipated that large capital expenditures will be needed prior to the DSIP process. In the event that a utility intends to commit large capital implementation expenditures not contemplated within its rate plan, a pre-approval petition should be filed. Deferral of recoveries should be subject to the deferral provisions of the existing rate plan.

### 6. Long-Term Rate Plans

Multi-year rate plans have been in use in New York for decades. The Commission has developed a number of mechanisms to drive efficiency and performance in this context.[66] REV presents additional reasons for longer-term plans. Utilities, customers and market participants will benefit from the stability and predictability of a multi-year plan as REV markets are developed. Long-term plans developed in the DSIP process can be implemented within the span of a single rate plan. Utilities will be better able to focus on developing DSP capabilities and if they are not diverted into time-consuming and contentious rate proceedings. This will expedite progress toward achieving multi-year EIM metrics.

Long-term operational plans come with the caution that the longer the rate plan, the more uncertain is the forecast for the later years of the plan. This applies not only to the setting of base revenues but also to the establishment of incentive measures. As discussed in the recommendations below, a longer-term plan should be accompanied by a well-considered set of tracking mechanisms, annual true-ups, updates, and mid-term adjustments. Further, it is important that long-term plans not become a vehicle for maintaining the status quo.

The typical term for a negotiated multi-year rate plan has been three years. Plans consisting of three-year terms should be retained but utilities should be provided the option to extend such plans beyond three years if performance dictates. Two-year rate plan extensions which would allow rate plans to potentially be in effect for up to five years should be considered. Any extension beyond three years should be

[66] See, for example, the discussion in the DPS Staff Report and Proposal issued in this proceeding on April 25, 2014.

accompanied by interim reviews, scorecards, and performance metrics as described here.

The baseline rates for a long-term plan should be established through a conventional revenue requirement review. In later phases of REV, the Commission should consider benchmarks or price indexing formulas or models as part of the process for setting baseline rates.

Current multi-year plans include a variety of performance measures to ensure that spending cuts are not made at the expense of service. These measures include tree-trimming targets and various safety-related initiatives. These measures should continue to be included in rate plans under REV.

Other mechanisms that should continue are the periodic recovery and reset of volatile items that are not under the utility’s control, e.g., storms and property taxes. In order to improve cash flow, an automatic recovery/passback mechanism for deferrals could be included when net cash deferral levels meet a threshold, positive or negative. The details of the mechanism should be negotiated in long-term rate plans and consider the impact on ratepayers. These deferrals would be subject to future audit.

Extension of a plan from three to five years should be tied to satisfactory price and earnings levels and adherence to capital plans. Extension should also be tied to compliance with various performance measures related to REV. These gateway measures include the development of platform capabilities, a successful interconnection record, and DER penetration in the service territory, and system efficiency improvements. Continuation into the latter years of the plan would be allowed if utility performance met targeted gateway levels.

Following an initial round of rate plans under REV, high-performing utilities may be eligible for longer-term rate plans.

Long-term rate plans are generally subject to being reopened if necessary. Where a utility exhibits poor performance combined with high earnings, the plan should automatically be subject to general reopening. Where poor performance is not accompanied by high earnings, reopening of targeted issues might be warranted for remedial actions.

Parties have raised concern that utilities will have negotiating power if they know a multi-year plan is required. This is true only if the Commission lacks the authority to impose a multi-year plan. Under the PSL, the Commission can adopt a multi-year plan with or without the consent of the utility or other parties.[67] There is a question whether a utility rate filing in the middle of a multi-year plan imposed by the Commission requires a full rate-case-style hearing. In any event, expectation of a long-term plan must not have the effect of providing negotiating leverage to any party in position to block a long-term plan.

Important to note in the context of multi-year rate plans is the fact that the Commission retains sufficient legal authority to ensure that rates set under a multi-year decision remain just and reasonable. Multi-year rate plans typically include language to the effect that “the Commission retains the power to act on the company's rates if events affect the envisioned range of earnings levels or equity costs so as to render the company's return unreasonable or unnecessary for the

[67] Section 72 of the PSL establishes a three-year limit on certain types of rate plans, but this limit does not apply to rate plans established after a hearing pursuant to PSL §66(12). For example, in one instance, a term of ten years was established. Case 01-M-0075, Niagara Mohawk Power Corporation, Opinion and Order Authorizing Merger and Adopting Rate Plan (issued December 3, 2001). See also, Matter of Kessel v. PSC, 136 A.D.2d 86 (3rd Dept. 1988).

provision of safe and adequate service."[68] The Commission also routinely offers the opportunity for public hearings, albeit usually expedited in some fashion, concerning reconciliation filings and/or subsequent staged filings under multi-year plans. Therefore, the Commission has the authority to avoid "stale" rate orders and ensure that rates remain just and reasonable, while at the same time promoting long-term rate plans.

## IV. RATE DESIGN AND DER COMPENSATION

### A. Summary

Rate design is the process of determining how a utility's revenue requirement will be recovered from customers.[69] Rate design sends price and value signals that influence customer actions; the cumulative effect of many customer decisions ultimately affects the cost of the system. Rate design must try to prevent undue disproportionate or inequitable impacts on different customers within classes, and take into consideration policy objectives along with technical cost causation analysis. For those reasons, rate design requires a balancing among multiple objectives, principles, and interests.

Traditionally, rate design has focused on the allocation of system costs to customers, assuming a uni-directional electric system designed around inelastic demand, with one-sided transactions between utilities and customers. While this approach has been effective historically, technological advances mean that the assumptions behind that approach no longer hold in their entirety. The increasing proliferation of DERs and customers' technology-enabled abilities to actively manage their

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[68] Id.

[69] For technical purposes, "rate design" is subsequent to "revenue allocation" in which the utility's total revenue requirement is allocated among the various customer classes.

own loads allow for a bi-directional electric system in which demand itself can be a resource, and where multi-sided transactions between utilities, DER providers, and customers are possible.

Therefore, rather than simply allocating costs, rate design under REV should work toward enabling the reduction of total costs by appropriately signaling value. The goals of REV now call upon consideration of mechanisms that compensate customers for the benefit their DERs provide to the system. These approaches—including NEM, DR tariffs, and others—must similarly balance multiple objectives, including New York’s policy commitments to energy efficiency and renewable energy.

Historically, both rates and DER compensation mechanisms have been designed in an environment of imperfect information, partly because residential and small commercial customer meters deliver incomplete information, and also because the allocation of costs to those customers depends on projections, averaging of costs, and categorizations of fixed and variable costs in a process that is imprecise by nature. Now, however, it is possible to gather, analyze, and make transparent information much more quickly, enabling the development and exchange of more precise value signals.

The varied trends facing the industry as well as the policy objectives put forth by REV compel a thoughtful consideration of potential reforms to rate design and DER compensation mechanisms. A large amount of investment will be made in the electric system in the coming years, by utilities and increasingly by third parties, DER providers, and end use customers. Those investments need to be economically efficient while also furthering the policy objectives of REV. That means that investments must be optimized at the customer end of the electric system as well as the traditional production end, and requires that customers and market participants have sufficient information and value creation potential to make the best choices about how they purchase and use power, and how they invest in and use DER.

The crux of the issue 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. Similarly there is an incomplete understanding of the full value that DERs provide to the system, and thus insufficient information on which to base investment and usage choices. This situation requires us to better determine how customer behavior contributes to the entire bill, the disaggregated cost of delivery service, and conversely the benefit that should be provided to the customer in terms of total cost avoidance or reductions to the distribution system by DER, which the Commission has referred to as the "value of D".[70] The value of D when added to the location-based marginal price of energy (LMP) will constitute the full value of DER to the system, or the LMP+D. Pursuant to the Commission's direction in the Community Distributed Generation proceeding,[71] the Staff will engage with parties to develop this value.[72]

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[70] Case 15-E-0082, Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program, Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015), p. 31.

[71] Id., p. 32.

[72] To avoid confusion, it is important to distinguish LMP+D from other similar concepts. "Distribution locational marginal price" or DLMP is sometimes used to refer to a granular calculation of time- and location-specific costs on the distribution system. As applied here, LMP+D is a broader measure capturing the full value of DER, including energy (LMP) and the full range of values provided by distribution-level resources (D).

Closely following the determination of the value of D is the consideration of what mechanisms are best suited to convey that value. At present, the chief mechanism for translating system values into compensation for DER is NEM. NEM has proven to be highly successful at promoting the development of clean energy resources at the customer level. The simplicity and predictability of NEM should be retained, and the valuation of NEM credits for larger projects should be more fully realized through application of LMP+D.

The current mass-market rate design, like current cost-of-service ratemaking, fails to encourage optimal realization of the potential of DER. Rate design that combines a fixed customer charge and a flat, volumetric per-kWh charge is insufficient to support market participant or customer action to reduce peak and optimize usage. At the same time, fundamental changes to mass-market rate design require a very deliberate process including scrutiny of potential bill impacts. Therefore, Staff makes a set of rate design proposals to be further developed and analyzed prior to Commission action. Changes to mass-market rate design are linked with changes in metering. In proposing new metering functionalities, utilities should be required to explain how they will enable time varying and attribute unbundled rates, and propose demonstration projects around the efficacy of time varying rates.

While changes to rate design for all customers will require more process, customers and market participants who have the desire and capability to provide value to the system should be enabled to do so. Therefore, an opt-in “smart home rate” should be designed and implemented as quickly as possible. Finally, Staff suggests a series of immediate reforms targeted at C/I customers, standby rates, and low-income customers, detailed below.

### B. The Foundation of Rate Design and DER Compensation in New York

A foundational set of rate design principles was articulated by James Bonbright in 1961 and are still commonly in use today:[73]

- Rates should be practical: simple, understandable, acceptable to the public, feasible to apply, and free from controversy in their interpretation.
- Rates should keep the utility viable, effectively yielding the total revenue requirement and resulting in relatively stable cash flow and revenues from year to year.
- Rates should be relatively stable such that customers experience only minimal unexpected changes that are seriously adverse.
- Rates should fairly apportion the utility's cost of service among customers and should not unduly discriminate against any customer or group of customers.
- Rates should promote economic efficiency in the use of energy as well as competing products and services while ensuring the level of reliability desired by customers.

On numerous occasions, the New York Commission has articulated the need for a balancing of standard rate design principles. For example, the Commission has stated that "cost should be the primary determinant of rates and . . . marginal cost is the proper measure of cost for rate design purposes,"[74] and that, "in establishing competitive and non-competitive rates, a number of important public policies must be balanced

[73] James C. Bonbright, Principles of Public Utility Rates (1961). Different articulations of rate design principles have been developed in various sources.

[74] Cases 27215, 27216, 275387, and 27539, Niagara Mohawk Power Corporation – Electric Rate Design, Opinion 80-18, Opinion and Order Determining Just and Reasonable Rates (issued May 7, 1980).

and considered in establishing rate levels and designs."[75] Among these policies are customer impact, gradualism, and environmental protection.[76]

Rates are designed for general classes (e.g., residential, small commercial) because it is generally not feasible or beneficial to tailor rates to individual customers. Rates in New York are designed differently for larger C/I customers than they are for lower-usage residential and small commercial (mass-market) customers. Mass-market rates are designed to be simple, whereas C/I customers' delivery rates are more complex and more closely tied to the costs that individual customers place on the system.

C/I delivery rates are based on peak usage, and those above certain thresholds (e.g., 300 kw peak demand) are billed for energy commodity on an hourly basis, which is tied to the actual system cost during that hour. This rate design allows the usage patterns of individual customers, and therefore the costs placed on the system, to be reflected in individual bills.[77]

The residential class, although it consists of a mix of different customers with widely varied usage, is treated within one rate classification and charged with one rate formula. The basic formula consists of a fixed monthly customer charge, plus a charge per kWh used.[78] Small apartments, large houses,

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[75] Case 00-M-0504, Proceeding on Motion of the Commission Regarding Provider of Last Resort Responsibilities, the Role of Utilities in Competitive Energy Markets, and Fostering the Development of Retail Competitive Opportunities - Unbundling Track, Statement of Policy on Unbundling and Order Directing Tariff Filings (issued August 25, 2004).

[76] Id., pp. 18 n. 57, 37.

[77] Although it is more precise than mass-market design, C/I design still stands in need of improvement as described below.

[78] Many utilities also employ adjustment clauses and surcharges that are typically collected on a per-kWh basis.

vacation homes, homes with high peak usage, and homes with low peak usage are all charged under the same formula. The customer sees one price, although the reality is that actual system costs vary greatly by the time, location, and peak demand of the customer's usage.[79] One reason for this simple approach to mass-market rates is that today's utility meters for these customers do not measure peak usage or time of use.

An important feature of New York's current practice is the principle of gradualism. In rate cases, where the analysis indicates that a particular customer class should be assigned a higher share of total costs, the Commission employs a gradual approach to moderate the impacts, by limiting the extent of the cost shift that occurs in any given year.

New York's policy in recent years has been to slowly increase the fixed customer charge while maintaining a large portion of the rate in a per-kWh charge. Low-income discounts, energy efficiency programs funded through a System Benefits Charge, and net metering for clean generation are added to the balance to meet particular policy objectives.

This approach to the balance of fixed charge and per-kWh charge is the result of the tension between two opposing views. Some argue that basing rates on the number of kWh consumed, while a correct approach for energy commodity, is incorrect for delivery rates. In the near term, the cost of maintaining distribution service to a home is largely independent of the total energy usage at that home. That is, the cost of wires, poles, and transformers will not change in the short term regardless of how many kWh the customer uses in a given month.

[79] Exceptions to the homogeneity of rates are found in the seasonal differences employed in residential tariffs of Con Edison and Orange & Rockland.

Others argue that system costs are variable in the long run and rates based on long run variable usage may provide the best method of cost causation as well as the most economic incentive to invest in DER. Proponents of this view also make policy arguments that charging based on volume increases the incentive customers have to use energy efficiency measures, or to install photovoltaics, to reduce total demand on the grid. An additional policy argument is that many lower income customers are also low-volume users, so a volume-based rate allows them to control bills and reduces utilities' uncollectible expenses.[80]

A better balance could likely be achieved if the rate design toolkit were expanded beyond just fixed charges and per-kWh charges. The cost of maintaining the distribution system is variable in the long term and potentially in the short term through better use of DER and other mechanisms to improve system intelligence. These costs are most affected by the combined peak of all customers on a circuit (i.e., circuit coincident peak demand).[81] Because mass-market meters do not measure peak demand, however, this important cost factor is not currently reflected in rates.

Beyond rate design, compensation that customers receive for the value their DERs provide to the system is generally limited to NEM, and in some cases, demand tariff-based payments for load reductions via DR. Net metering compensates customers not by

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[80] It is not always true that low-income customers are also low-volume customers. For example, low-income customers who heat with electricity may be high volume users.

[81] "Circuit coincident peak demand" means the peak level at the moment of highest total usage among all the customers on a circuit. "Customer non-coincident peak demand" means the peak demand of an individual customer, regardless of when it occurs. For example, Customer A may have an individual peak demand at 8 a.m. while the peak demand on the circuit might occur at 4 p.m. For purposes of system costs, the usage of Customer A at 4 p.m. is more relevant than the usage at 8 a.m.

paying them a price for services and power production but rather by relieving them of an obligation to pay rates. To the extent that generation is netted against usage, this is identical to the value stream that customers receive from any portion of on-site generation that reduces their consumption.

## C. The Implications of Conventional Rate Design and Current DER Compensation in the Context of REV

Several aspects of the changing electricity system and of REV make it necessary to reevaluate conventional rate design and DER compensation mechanisms. Together, these factors imply valuable opportunities, as well as a risk of negative impacts for customers if rate designs are not optimized. These include:

- REV will result in much greater adoption of DERs, many of which may displace more traditional infrastructure investments. The decisions supporting the investments should be as economically sound as possible in order to effectively lower total cost.
- The customer end of the grid will be treated as a core resource on par with centralized resources; this elevates the need for better price signals.
- Implementation of the DSP market and its enabling technology will result in greatly enhanced information that will enable a more precise rate design.

Efficient price signals and transparency are hallmarks of a successful market. Rate design and compensation mechanisms that accomplish these will help to optimize the investment in and use of DER, thereby reducing total system costs and customer bills, not only for customers with DERs. Conversely, rates that are bundled and mask the underlying costs of service will not facilitate efficient decisions.

The balancing of multiple objectives and principles inherent in current rate design gives rise to a debate as to economic efficiency with respect to DER. Whether the rates are too favorable or not favorable enough, a sharp increase in DER penetration could cause any imbalances to have a much larger effect. This is important even for customers who do not employ DER. The balancing in current rate design applies to a range of customer types and usage patterns, but the wide-scale adoption of DER will widen this range even further. Customers will have more individuated load profiles, and any disparate impacts of applying a homogeneous rate to an increasingly heterogeneous customer class will become more pronounced.

Strategies that were adopted to promote clean DER from a state of near-zero penetration may not be optimal for DER that is widespread and mainstream and will need to rely on consistent and accepted valuation methods. If the monthly bill reduction from a DER investment depends in part on avoiding a share of distribution costs, then two types of uneconomic bypass may occur. On one hand, customers who install DG and continue using the grid may avoid their appropriate share of system costs, leaving other customers to pay the balance. The other form of bypass, however, is the exact opposite. If fixed customer charges are so high that a customer can only avoid delivery charges by exiting the system altogether, then any share of distribution charges that the customer might have been willing to pay in order to remain connected is lost. Where the cost of building redundant capability and exiting the system is lower than the price of staying connected, exiting the system may represent uneconomic bypass. These are examples of the risk of sending the wrong economic signals that drive inefficient choices.

Each of these potential problems can be addressed by a technology-agnostic rate design that is more precise, both in recovering costs and in sending price signals that prompt efficient DER participation by customers. DER investment should produce net beneficial results for both the participating customer and the system as a whole. This can be achieved by improving both the compensation for DER services provided to the grid, and recovery of grid costs properly assigned to the DER customer.

Adopting a rate design and compensation mechanism based on a more precise calculation of system value should greatly improve the proper valuation of DER. This will provide greater confidence in the market, and will make investment decisions in DER more stable and predictable.

Some of these issues have been raised and addressed to varying degrees in other parts of the United States and internationally, and several key themes and tensions have emerged:

- **Increasing granularity**—In the face of increasing DER penetration, there is a trend towards increasing the granularity of the rates that customers see. This is largely in recognition that, with the growth of DERs and new information capabilities, it is becoming less costly and more beneficial to accommodate greater differentiation among customers through increased choices in how they use, pay for, and are paid for, grid services.
- **Unbundling rate attributes**—There is much discussion over unbundling rates into their various value attributes, such as energy, capacity, ancillary services, and others. This has in part been driven by the growth of net-metered solar PV and some stakeholders’ concerns that costs and benefits of net-metered facilities should be more accurately accounted for. At the same time, ancillary services and other reliability benefits provided by DER are uncompensated because of the lack of unbundling.
- **Reflecting DER value**—Some stakeholders argue that DERs are under-valued and under-utilized as part of the system. In response, there is a significant trend towards attempting to better assess the value that DERs provide and developing appropriate mechanisms to monetize that value.
- **Managing complexity vs. simplicity**—As rates increase in granularity they are likely to become more complex. At the same time, increasing complexity conflicts with the long-

standing goal to make mass-market rates simple and understandable. A number of proposals have been made that attempt to strike a balance, and the role of aggregators is clearly at the center of enabling that balance and managing increasing complexity on behalf of customers. That is, customers themselves may not need to see complex rates if a service provider or aggregator sees and manages complexity for them.

## D. Framing Proposed Recommendations

### 1. Scope of Recommendations

Three framing points for this discussion are critical to clarify at the outset. First, the focus of the discussion here applies to delivery rates, which are distinct from energy commodity rates. Commodity prices are established in markets run by the NYISO,[82] and through bilateral contracts. Where customers still purchase energy commodity from utilities, the underlying commodity costs flow through, although the Commission can influence efficiency by applying a TOU factor. Delivery rates have a stronger state regulatory component, because the Commission is responsible for establishing both the underlying revenue requirement and the rate design. Introducing elements of market efficiency into distribution system operations and corresponding delivery rates, while improving performance on policy goals embedded in regulation, is the challenge of REV.

Second, especially given the market envisioned by REV, it is critical to distinguish between rates paid *by* customers for electricity service on one hand, and compensation paid *to* customers whose DER provides value to the system on the other hand. As the DSP market develops, compensation will increasingly be determined by market forces, reflecting market prices for power and transactions between DER providers and

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[82] Distribution level activities under REV will affect these prices but will not control them.

customers contracting with each other. There is a crucial regulatory component, however, because DER compensation will also be determined based on avoided locational, non-locational, and time-based costs on the distribution system and purchased from the wholesale market. The discussion below describes potential rate reforms and the process for developing appropriate compensation mechanisms separately.

Third, beyond conventional rate classes, it is useful to make a distinction among three types of customers as regards DERs. Each of these customer types may interact with the grid and the DSP market in different ways, and each should be considered in the context of rate design under REV:

- **Traditional consumers** – Those customers who do not choose to actively manage their energy usage, or for whom it is difficult to do so.[83]
- **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.

### 2. Considerations for Rate Design and DER Compensation Proposals

In developing the proposals in this white paper, Staff considered several fundamental design choices, including:

#### a. Providing Appropriate Options to Meet Customers' Varying Needs

Rates can be designed to be 1) mandatory for all customers, 2) default for all customers but giving customers the ability to

[83] Customers 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.

“opt-out” to a basic rate, or 3) elective for customers, giving customers the ability to “opt-in” to that rate design. There has long been debate about the relative merits of opt-in vs. opt-out options, especially for more sophisticated rates.

Evidence from around the country shows that customer participation rates are much higher in opt-out scenarios, even though per customer response, for example to a TOU rate, may be higher when customers opt in. For example, a recent report assessing TOU programs across multiple utilities showed average enrollment levels of 28% when TOU was opt-in, as compared to 85% when TOU was opt-out.[84] Similarly, a 2013 Lawrence Berkeley National Laboratory (LBNL) report found 11% opt-in participation vs. 84% for opt-out.[85]

The choice of approach requires a careful consideration of the benefit of a particular rate design both in terms of its accuracy in recovering utility costs and the behavioral signals it sends to customers, versus its acceptability to customers, which may evolve over time. Critical variables are the extent of outreach and education to customers, and the extent of the opportunity to manage bills or reduce environmental impact that is presented by the opt-in program. Further insight into this choice will be provided by demonstration projects and by the opt-in TOU efficacy scorecard metric.

b. Approaches to Sending Pricing Signals

Value signals can be sent either via the rates customers are charged for the electricity they use, or via the

[84] Ahmad Faruqui, Ryan Hledik and Neil Lessem, “Smart by Default,” Public Utilities Fortnightly (August 2014).

[85] Annika Todd, Peter Cappers and Charles Goldman, “Residential Customer Enrollment in Time-based Rate and Enabling Technology Programs” (LBNL, June 2013).

compensation customers are offered for the service their DERs can provide, or both. For example, TOU rates and DR tariffs are two ways of approaching one objective, namely, to encourage customers to reduce or shift usage to reduce system or outage costs. TOU rates impose charges based on the cost of receiving service at any particular time, thus rewarding a customer for shifting usage, while DR pays a customer for relieving a burden. From the standpoint of system management, TOU rates rely on voluntary customer behavior, while direct load management has the value of DSP or utility control.

Historically, rates have been the primary tool for sending pricing signals, and much of the industry-wide discussion has centered on modifying rates to better match system costs. There has been comparatively less emphasis on sending signals via tariffs or other mechanisms that provide an incentive or reward for providing service or voluntarily shifting demand. NEM is the most common form of compensation for DER service, and “value of solar” tariffs are a variation of this mechanism. An example of an emerging model focused more on load modification as compared to DG is Baltimore Gas & Electric’s Peak Time Rewards program that provides a $1.25/kWh saved rebate during peak events.[86] Like opt-in programs, there is some evidence that this type of reward program has greater customer acceptance, but lower overall effect than opt-out programs.[87]

The rate versus compensation distinction is also important in the treatment of locational values. Distribution rates do not vary by location on the system, although the marginal cost of providing service can be location-specific. Providing

[86] Baltimore Gas & Electric Company, “Supplement 508 to P.S.C. Md. E-6: Rider 26—Peak Time Rebate” (filed September 4, 2012).

[87] Ahmad Faruqui, Ryan Hledik and Jennifer Palmer, “Time-Varying and Dynamic Rate Design” (Regulatory Assistance Project and The Brattle Group July 2012).

customers payments for service, based on avoided long-term costs, can capture locational value without having to reflect locational value in distribution rates.[88]

The reforms envisioned by REV, particularly the development of the DSP market, open important new avenues for compensating customers, or DER providers acting on their behalf, for the system value their DERs produce.

### c. Enabling the Appropriate Degree of Granularity

The rapid growth in adoption of DERs has made apparent the deficiencies inherent in bundled, volumetric pricing and has opened up a broad conversation about the merits of making rates more granular along three primary dimensions:[89]

- **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.

A variety of rate options have been considered along each of these dimensions, ranging along a spectrum from less granular to more granular.  For example, time-varying rates can range from relatively low-granularity two or three block TOU rates to high-granularity real-time pricing.  By and large, experience

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[88] Energy prices established through the NYISO are location-specific, but not at the granular level of individual distribution circuits.

[89] Rocky Mountain Institute, "Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future" (August 2014).

around the country has favored simpler options, reflecting the desire for simplicity and understandability for customers. However, emerging models like value of solar tariffs are proposing increasing granularity, especially in situations where third parties and aggregators can manage the complexity on behalf of the customer.

### d. Applying Gradualism on Multiple Dimensions

Gradualism refers to the approach of gradually implementing rate design reforms so as to moderate the impact and minimize sudden changes for customers.  The principle of gradualism should apply not only for customers but also for whole industries, such as solar and energy efficiency providers, that have responded to state policies and developed businesses in the state.  Any changes affecting these industries should provide ample time for businesses to adapt and plan for new forms of opportunity.[90]

For the same reason, rate design changes should be oriented toward investments going forward, versus investments already made.  To the extent possible, customer investments already made under assumptions of a program such as NEM should not be disrupted.

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[90] “Boom and bust” government policies can foster “a legacy of increased regulatory uncertainty and reduced investor confidence. . .” Richard Schmalensee and Robert N. Stavins, “The SO2 Allowance Trading System:  The Ironic History of a Grand Policy Experiment,” Journal of Economic Perspectives, Vol. 27, No. 1 (Winter 2013), p. 117.  This “wreaks havoc with the business confidence necessary for the long-term investments required to develop new and improved products.” Jesse Jenkins, et al., “Beyond Boom and Bust:  Putting Clean Tech on a Path to Subsidy Independence” (Brookings Institution April 2012), p. 37.

e. Maintaining a Dynamic Outlook

As the costs of self-generation decline and the feasibility of grid defection increases, rate design analysis becomes more complex. Rather than simply allocating the costs of maintaining the system among a stable group of customers, rate design must also be concerned with avoiding uneconomic bypass of the system. As described above, if the only way that a customer can avoid any distribution charges is to avoid them all by exiting the system, then remaining customers will absorb the cost contribution that the exiting customer would otherwise have made. Rate design must take a forward-looking position in order to encourage economic use of DER without encouraging uneconomic bypass.

## E. Determining the System Value of DER

Making effective reforms to rate design and to DER compensation mechanisms requires a strong foundational understanding of the system value that DERs can provide. The Commission spoke directly to this issue in its July 17, 2015 order in the Community Distributed Generation proceeding.[91] The system value of DER is divided into two components: the energy value, and all other values associated with distribution-level resources. The energy value in New York is established by power markets and is called the LMP. The distribution delivery value

[91] Case 15-E-0082, Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program, Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015).

(i.e., value of D) can be added to the LMP to create “LMP+D”—the full value of a DER on a time and location-specific basis.[92]

Determining LMP+D is particularly important in the context of REV, because REV markets will be multi-sided; they will consist of transactions among customers and service providers, and also transactions between utilities and prosumers or DER providers acting as intermediaries on their behalf. For purposes of the utility transaction, it is essential to quantify the distribution system value that DERs can provide. It is also essential that the market have access to data and price information on an appropriately dynamic basis.

While the LMP is already well established and transparent, the value of D is not. Values can include load reduction, frequency regulation, reactive power, line loss avoidance, and resilience. Other values not directly related to the distribution system are installed capacity requirements (ICAP) and emission avoidance. Software to determine distribution-level marginal costs should be adopted by New York’s utilities.

The Commission’s July 17, 2015 order on a Community Distributed Generation program requires the Staff to initiate this determination. As found by the Commission, the calculation of avoided LMP+D will be aided by ongoing proceedings developing the Benefit and Cost Analysis Framework for DER. Staff will initiate this study and work with interested parties, including the utilities and DER providers as soon as practicable.

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[92] This development will follow a path already established in wholesale energy markets. Wholesale markets were based on contract paths plus wheeling, until location-based pricing was established. Matching prices with the marginal cost of production has greatly improved.

F. Potential Compensation Mechanism Reforms

NEM applies to small solar and other clean energy projects less than 2 MW, and functions by crediting NEM customers at the retail rate for 100% of the generation they produce. NEM is established in statute,[93] and has been expanded and refined in numerous Commission decisions. At present, the total amount of generation eligible for net metering in any utility's service territory is capped at 6% of that utility's 2005 peak load,[94] with some utilities reporting total applications that approach or exceed the cap. As part of the community distributed generation proceeding, the Commission has ordered Staff to report on the status of interconnection applications and make recommendations as to caps within any individual utility service territory in order to ensure market growth is not disrupted.[95]

NEM has been an important and effective tool in fostering the growth of New York's solar industry. As the Commission has stated, concerns about the potential diseconomies of NEM are inconsequential at the currently low levels of penetration.[96] A large-scale expansion of DER, however, would increase the debate around these concerns.

Input from the DER industry makes clear that the simplicity and predictability of NEM is very important in engaging customers and providing certainty to investors. Staff does not believe that there is any value in changing NEM for mass-market

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[93] PSL §66-j.

[94] Case 14-E-0151, et al., Petition of Hudson Valley Clean Energy, Inc. for an Increase to the Net Metering Minimum Limitation at Central Hudson Gas & Electric Corporation, Order Raising Net Metering Minimum Caps, Requiring Tariff Revisions, Making Other Findings, and Establishing Further Procedures (issued December 15, 2004).

[95] Case 15-E-0082, supra, pp. 34-35.

[96] Framework Order, p. 25 n. 54; Case 14-E-0151, supra, p. 13.

customers with on-site DG at this time, subject to further development based upon the following observations.

First, the future of REV markets depends on DER facilities that have the technical capability to interact with the utility to optimize system operations. Current net-metered facilities have little incentive to install this capability, and the failure to install these capabilities in new projects represents an opportunity cost for the system. For example, smart inverters can increase the total amount of solar generation that can safely be interconnected to a circuit. When LMP+D valuation is established, customers will have a stronger incentive to install interactive capabilities. In the meantime, rather than increasing the installation of non-interactive DER, the Commission should consider requiring reasonable conditions, including smart inverters, on future net-metered projects.[97]

Once a process is in place for determining full and specific values of DER, the Commission may determine that it is not necessary or practical to apply it to all forms of DER. For example, current ratemaking practice does not differ the unit rates applied to customer classes for delivery service, regardless of the customer location, and this practice should be continued. While there should be a locational difference for

[97] See, e.g., "Advanced Inverter Functions to Support High Levels of Distributed Solar" (National Renewable Energy Laboratory, November 2014). Both California and Hawaii are considering smart inverter requirements in order to increase the amount of PV that can be accommodated on individual distribution circuits. See California Energy Commission, Rule 21 Smart Inverter Working Group; Public Utilities Commission of Hawaii, Docket No. 2014-0192, Instituting a Proceeding to Investigate Distributed Energy Resource Policies, Hawaiian Electric Companies' Motion for Approval of NEM Program Modification and Establishment of Transitional Distributed Generation Program Tariff (January 20, 2015), Appendix 1.

how DER is valued on the system, there should be no locational difference charged to the customer in the delivery charge.

In those instances where the DER that the customer deploys only supplies a portion of their total electricity usage over the course of a month and the customer does not actively participate in a utility program, there is no significant credit paid to the customer by the utility. Rather, the customer simply avoids a portion of the electric bill. In this circumstance, even when the "value of D" as a service to the grid can be calculated, the reduction of the customer's bill should continue to be based on the average cost of service. That is, NEM as it is currently constructed should remain applicable.

Conversely, where the customer actively participates in a utility's DR program, or through some other means interacts with the grid as an active consumer or a prosumer, the full value of the DER should be calculated based on the LMP+D and should inform the level of compensation paid. In this case, the NEM bill crediting mechanism should continue to be employed.

Similarly, where the customer exports to the grid either through a remote net metering or community distributed generation program, the full value of the DG should inform the level of credit paid. For residential or small commercial participants in a community DG project, if the value of the full DG credit is less than the amount the customer would have been paid if the DG were located at the customer's home or place of business, then the Commission may determine that further adjustments should be made to avoid inequities within and among a customer class. A participant in a community DG project should not receive less compensation than a single-site net metering customer.

### G. Potential Rate Design Reforms

#### 1. Rate Design Principles for REV

Taking into consideration Bonbright's traditional rate design principles described above and the ways in which REV changes both objectives and capabilities for improvement, Staff proposes that the Commission adopt the following rate design principles to guide reforms under REV:[98]

- **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.

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[98] Jim Lazar and Wilson Gonzalez, "Smart Rate Design for a Smart Future" (Regulatory Assistance Project July 2015); Cal. PUC Rulemaking 12-06-013, Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and Sand Diego Gas & Electric Company and Transition to Time-Of-Use Rates (July 3, 2015); Rocky Mountain Institute, "Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future" (August 2014).

- **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

2. General Approach

The Commission should consider a set of rate design reforms that collectively follow on the above-mentioned principles. These reforms will increasingly support REV objectives and markets over time, while in the near-term reflect the need for gradualism and accompanying infrastructure development to support future rate design reforms.

Over time, rates should begin to reflect greater granularity in time and unbundling of attributes. More granular rates will not only produce better price signals but also will enable DER providers, acting on behalf of customers, to optimize the deployment and operations of DERs to maximize value to both customers and the grid.

At the same time, an abrupt shift into complex rates would be counterproductive, causing confusion and customer resistance. For that reason, Staff proposes a two-tiered approach. Any changes to base rate design should be gradual, and would require extensive analysis of potential customer impacts, while in the near term opt-in rates should be established that give customers options and the ability to adopt technology and receive value from DER. Improvements to standby tariffs and to existing demand charges for larger customers should also occur in the near term.

The rate design proposals made here are divided into the following categories: 1) mass-market, 2) C/I, 3) low-income customers, and 4) standby service. Each of these categories presents separate issues and opportunities, as well as distinct timing and implementation issues related to customer expectations and technological capabilities. All of the categories, however, affect REV objectives and it is important to consider them in the aggregate. It is also important to consider them in conjunction with other ratemaking reforms discussed above, particularly as they relate to the overall financial risk and opportunity of utilities and overall impact on customers.

Within each of these categories, Staff's proposals focus primarily on 1) immediate implementation to remove imminent barriers or capture obvious opportunities, or 2) interim and longer-term implementation for rate designs that support REV but require further design and analysis, represent more significant changes for customers, or would be enabled by additional infrastructure. Staff expects a continued conversation about the evolution of rate design as REV unfolds and infrastructure enables additional options.[99]

Design of utility rates paid by customers is directly related to design of DER compensation and markets as described above. Providing granularity and sophistication in market pricing could reduce the level of granularity needed in base rates, although more sophisticated rates can be made available

[99] Consistent with the Framework Order, this assumes that advanced metering functionalities will be developed as a necessary prerequisite for REV markets. The timing of that development, and the choice of technology, may be determined mostly by other efforts such as the MDPT working group, DSIPs, and rate cases. The application of these technologies to rate design highlights the important question of which types of advanced communication can provide utility-grade metering. This raises the further question of what "utility-grade metering" means in the context of ubiquitous digital markets.

on an opt-in basis for those customers who prefer to optimize against a cost signal than interact with a market.

### 3. Proposed Rate Design Reforms

#### a. Introduction of a Demand Charge For Study, Comment, and Discussion

The introduction of advanced metering functionality will enable movement beyond the historical dispute between fixed customer charges and volumetric rates. Because long-run distribution marginal costs are driven by coincident peak on a circuit-by-circuit basis, customers' usage at system peak provides the most accurate measure of system costs. And, unlike fixed customer charges, peak demand can be managed by customers via DR, energy efficiency, and/or DG. Therefore, the incorporation of a peak-coincident demand charge in place of some portion of the kWh and fixed customer charges is put forward here for comment and further development. As part of the proposed transition to a three-part rate (volumetric charge, demand charge, and fixed customer charge), the fixed customer charge should be formulated to reflect only the costs of distribution that do not vary with customer demand or energy consumption.

It is crucial to note that this change is not proposed as a mere reallocation of costs among customers. It is proposed as part of a broader strategy to reduce long-term system infrastructure needs, encourage the optimal development of DER, discourage uneconomic bypass of the distribution system, and maintain affordable rates for all customers.

Any transition of this magnitude would require detailed study, including bill impact analyses under numerous scenarios, and Staff suggests this analysis should be undertaken as soon as possible. Relevant scenarios should include charges based on customer non-coincident peak, system-peak coincidence, and localized distribution peak coincidence. Scenarios should also include a range of percentages by which the kWh rate is replaced with the demand charge, e.g., 25% kWh and 75% demand. Factors to be considered include impacts on low-income customers, incentives to adopt DER,[100] and potential impacts on different categories of customers such as individually billed customers in multi-family buildings.

Because a transition to a demand charge would require upgraded metering, it could not be implemented on a wide scale in the near term. The analysis of demand charges can be conducted in parallel with the development of advanced metering functionality. Further, to the extent that utilities propose advanced metering functionality in their DSIPs, Staff proposes that utilities be required to describe how that functionality will enable more granular rates and price signals, including demand charges and TOU rates as discussed in the following section.

### b. Facilitation of Time-Of-Use Rates

Because the cost of generating electricity varies greatly by time of day, TOU rates better reflect costs and encourage customers to participate in reducing overall system costs.[101] Examples from around the country have demonstrated the efficacy

[100] The total per-kWh element of a customer's combined bill should be considered with reference to the externality value calculated in the Benefit-Cost process and should not, in any event, be lower than that value.

[101] Case 26806, Proceeding on Motion of the Commission as to Rate Design for Electric Corporations, Opinion No. 76-15 (issued August 10, 1976).

of TOU rates,[102] and other states are weighing the merits of an increasing focus on TOU rates, including as the default.[103] Each New York utility has a residential TOU rate, on an opt-in basis. For most utilities, the level of participation in the rate is low.[104]

In the near term, the focus of action should be on 1) increasing participation levels in existing opt-in TOU rates, and 2) gaining further experience with the design and efficacy of TOU rates via demonstration projects. To the first point, utilities should be required to implement informational tools and programs, in collaboration with third parties, that increase customer awareness of TOU rates, help customers understand the potential savings benefit from a TOU rate with enabling DER technology, and make it easy to enroll. Staff proposes that

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[102] Studies on TOU rate rollouts and pilots in North America have shown significant peak reduction savings ranging from just under 0% to about 47%. TOU rates coupled with enabling technology such as in-home displays, energy orbs and programmable and communicating thermostats exhibit higher peak load reduction impacts than without. Also, peak load reduction impacts are seen to increase as the peak to off-peak price ratio in TOU rates increases. See Ahmad Faruqui and Jenny Palmer, "The Discovery of Price Responsiveness – A Survey of Experiments involving Dynamic Pricing of Electricity" (2012), pp. 5-9.

[103] See, Mass. D.P.U. 14-04-B, Investigation by the Department of Public Utilities upon its own Motion into Time Varying Rates, Anticipated Policy Framework for Time Varying Rates (June 12, 2014); Cal. PUC Rulemaking 12-06-013, Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and Sand Diego Gas & Electric Company and Transition to Time-Of-Use Rates (July 3, 2015).

[104] The greatest current participation is in the day/night differential rate previously offered by New York State Electric & Gas, which was instituted decades ago to encourage electric heating, and in which 133,000 customers still participate. Aside from that rate, the greatest participation of residential customers in voluntary TOU is Orange & Rockland with 1.9%. No other utility exceeds 1% in participation.

utilities submit customer engagement plans that describe how these types of tools will be made available. To the second point, demonstration projects provide an important opportunity to validate the potential customer benefits of a TOU rate, and to investigate how TOU rates should be designed to maximize participation and benefit. Utilities should propose demonstration projects focused on TOU rate design.

TOU rates should be designed in a manner that is compatible with dynamic load response tariffs.[105] One way to accomplish this is to design time-sensitive rates in terms of basic time blocks, with dynamic load response tariffs designed in a more granular way to allow for active load optimization.

Like demand charges, TOU rates depend on advanced metering functionality that is not generally in place today. As discussed above, utilities should describe how proposed advanced metering functionality will be designed to enable the widespread use of time-varying rates.

### c. Develop a Smart Home Rate

A gradual approach to changes in mass-market rates should not prevent customers who are willing and able to begin participating in energy markets as active consumers from doing so. For that reason, a faster track approach should be made available on an opt-in basis.

Participation levels in opt-in rates have historically been low, both in New York and in other jurisdictions. The new opportunities created in REV, coupled with customer education and a growing awareness among customers of potential to enhance clean energy while managing bills, should result in greater participation.

[105] Case 14-E-0423, Proceeding on Motion of the Commission to Develop DLM Programs.

One option for a more sophisticated mass-market rate is a smart home rate, in which granular price signals are unbundled to reflect costs associated with underlying dimensions of electricity delivery, including commodity energy, delivery costs, and possibly certain ancillary services, and have significantly more temporal granularity. A well-constructed smart home rate would provide a technology agnostic rate mechanism to incentivize greater system efficiency through behind-the-meter management. Through direct management by customers, automated controls by on-site DER, or possibly supported by third-party intermediaries, customer loads could respond to day-ahead or other price signal. On an opt-in basis, a smart home rate would allow interested customers and service providers to develop more advanced in-home energy management systems.

#### d. Improve Commercial/Industrial Rate Design

Rate design for larger customers is already more advanced than for mass-market customers, but further improvements are needed. Demand rates should be more precise, reflecting the time of day in which costs are incurred. Current non-coincident demand rates can have the effect of inhibiting a customer from shifting load to off-peak times. For example, a customer investing in storage to purchase off-peak power and utilize it at peak times might face an increased demand charge due to the shift in usage to the off-peak time.

Because there is a larger variety of rates at this level, C/I rates must be examined on a utility-by-utility basis. Each utility should examine its C/I rates for opportunities to improve their reflection of time values, and should propose any changes in its next rate filing.

### e. Improve Solutions for Low-Income Customers

Any rate design changes should be analyzed for potential adverse impacts on low-income customers. Because there is a separate proceeding to establish a uniform low-income discount approach,[106] the first stage of REV rate design should be to incorporate any determination in that proceeding.

The ability of low-income customers to participate in DER will be increased if the low-income discount is focused on basic usage levels. The economics of a DER project will be most affected by the variable portion of the rate. For that reason, and consistent with the Staff Report on energy affordability,[107] the low-income discount should be supplemented or modified by locating it within a basic usage block. This will place the economics of DER for the low-income customer on a par with other customers, making it easier for the low-income customer to achieve further savings by reducing usage through efficiency or another form of DER.

Further provisions for low-income customers should be considered in reference to developments in the current low-income customer case and the customer affordability scorecard, as well as the community DG initiative.

### f. Revise Standby Service Tariffs

Standby rates apply to larger customers that generate much of their power onsite. They reflect the cost of using the distribution grid as a backup. Standby rates are often described as a serious barrier to expansion of DER, and have

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

[107] Case 14-M-0565, supra, Staff Report (filed June 1, 2015).

been the subject of a recent Commission order.[108] In that order, the Commission expanded a current exemption from standby rates, for a period of four years, with the intention that an improved rate design will be implemented that will eliminate the need for further standby rate reform.

The issue of standby rates is closely related to net metering and to the general rate design issue of fixed versus variable rates. In each case, the responsibility of a customer for the cost of the customer's reliance on the distribution grid is at issue. As explained above, however, that analysis must be dynamic and look to the potential for different types of uneconomic bypass. The cost of remaining connected to the grid should generally be lower than the cost of building redundancy and independence into a self-generation system.

REV contemplates a larger number of self-generation projects as well as a greater ability to realize system values. This prompts a revisiting of standby rates. The methodology for allocating costs that determine the contract demand and as-used demand components of standby rates should be reviewed in this new context, in conjunction with the method for calculating LMP+D described above.

For immediate purposes, a reliability credit should be created, based on the experienced difference between a customer's contract demand and as-used demand.

The contract demand for a standby customer is currently set based on one of two methods, depending on the utility: either (1) the customer sets its own contract demand amount, in kW, subject to a penalty if that contract demand amount is exceeded; or (2) the utility sets the customer's contract demand based on

[108] 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).

the maximum non-coincident demand, in kW, that the customer could draw from the utility's system.[109]

Staff proposes that customers should have the option which of these methods to use, and that the experienced difference between contract demand and as-used demand should generate a credit against the contract demand charge.

The credit would be earned by reliably reducing load below the contract demand, over two consecutive summer periods. The credit would be equal to the difference between the customer's Contract Demand in kW, and the customer's highest kW demand recorded on the customer's revenue meter (net of generation) during the previous two consecutive full summer periods during peak hours, multiplied by the Contract Demand Delivery Charge per kW in effect during the year in which the credit is determined.

This proposal can be applied to existing customers with at least two consecutive summer periods of available interval data. Customers that do not yet have data available may determine their own maximum anticipated demand, net of any load reductions or generation assets, for use in the above formula.

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[109] Where the customer sets its own contract demand amount, the customer is subject to a penalty equal to the contract demand exceedance multiplied by the contract demand rate, multiplied by 12. Once an exceedance penalty has been charged to customers who set their own contract demand amount, the contract demand is set to the new maximum peak demand. Dead bands can be employed for small, temporary exceedances of the contract demand where a penalty will not be charged, but will result in setting the contract demand going forward at the higher level. Where the utility determines the customer's contract demand, there are no contract demand exceedance penalties. In the event that the customer exceeds the contract demand as set by the utility, the new higher level of contract demand is used going forward.

This proposal would allow standby customers to supplement their DG unit with any form of DER to ensure load reduction to either achieve their chosen contract demand or earn a credit. This will make it more likely that standby customers will reliably stay off the utility grid during peak conditions. Customers who set their own anticipated maximum net on-peak demand will be incentivized to set a reasonable, conservative, and reliable maximum net on-peak demand since exceeding this demand would result in the inability to earn credits until two consecutive summer periods of interval data is available.

In addition to the reliability credit and revisiting cost allocation, several other standby rate reforms should be considered:

- The temporary exemption from standby rates should apply to new technologies not currently identified in the exemption.
- The campus offset rate currently in Consolidated Edison's tariff should be applied throughout the state and revised in two ways: rather than calculating a separate demand for each account within the campus, the coincident demand of all accounts within the campus should be used; and the offset tariff should be available for multiple customers within the same building.
- The interconnection EIM could be amended to include metrics specific to the processing of standby rate applications, accounting for the time to process, and the ability to process electric, gas and steam applications as one.

#### g. Timing and Implementation of Rate Design Changes

In addition to the concerns of gradualism discussed above, there are technical issues that must be addressed as part of any major rate design reform. Upgraded metering is needed to implement a demand or TOU charge. Cost and installation schedules need to be considered and synchronized with the broader REV roadmap. Utilities' billing systems must be revised. Following these developments, a period of shadow billing is advisable to test assumptions regarding bill impacts and to develop customer acceptance. Staff recommends that the Commission should adopt the immediate-term rate design proposals described here, and should order follow-on processes leading to the adoption of rate design proposals at the appropriate times.

## V. SUMMARY OF PROPOSALS AND STRUCTURE OF COMMENTS

This white paper describes new opportunities for utility earnings, possible changes to current ratemaking practices, and reforms to rate design and pricing structures that, collectively, can achieve REV objectives. A summary of proposals and key issues is provided here.

Staff proposes that:

1. Utilities should develop MBEs opportunities, and should further analyze potential revenue streams from platform services.
2. PSRs and other MBEs in a full-scale market should supplant some or all EIMs.
3. Formulas for sharing platform revenues between utility shareholders and customers should be developed, with attention to the extent of shareholder risk and use of regulated resources, and market alternatives.
4. Clawback mechanisms should be modified to encourage cost-effective use of operating resources or third-party investment.
5. Utility-sponsored energy efficiency should transition from general resource acquisition to targeted and market-based approaches, with goals informed by the ETIP, DSIP, and State Energy Plan processes.
6. Existing safety, reliability, customer-service, and utility-specific performance mechanisms should be retained subject to evaluation as needed.
7. EIMs should be developed for peak reduction, energy efficiency, customer engagement and information access, affordability, and interconnection.
8. Initial EIMs should represent a mix of positive and symmetrical adjustments. Longer term positive EIMs

should be contingent on an overall customer bill impact metric, which should be proposed by utilities.

9. EIMs should be established on a multi-year basis, accompanied by interim reviews and reporting metrics, unless it is demonstrated that single-year mechanisms are preferable on a case-by-case basis.

10. Scorecard measures should be developed for system utilization and efficiency, DG, energy efficiency, and dynamic load management penetration, carbon reduction, market development, MBEs use, opt-in TOU rate efficacy, customer enhancement, customer satisfaction, and conversion of fossil-fueled end uses.

11. ESMs should be tied to a performance index.

12. Plans to invest in DSP-related capabilities should be given pre-approval, where appropriate.

13. Three-year rate plans should be retained with an opportunity for two-year extensions to allow rate plans to be in effect for up to five years. Any extension beyond three years should be accompanied by interim reviews, scorecards, and performance metrics.

14. A method of calculating the value of DER, based on a formula of LMP+D (location-based marginal prices plus distribution value) should be adopted.

15. Net energy metering (NEM) should remain in place for on-site projects of mass-market customers. Remote and community projects should continue to use the bill crediting mechanism of NEM and an improved method of calculating credits for net export should be developed, based on LMP+D.

16. The Commission should adopt the proposed rate design principles.

17. Utilities should file tariffs for opt-in smart home or other time variable rates.

18. Opt-in TOU rates should be improved with outreach and education, and default TOU rates should be examined. Utilities should develop TOU rate demonstration projects. Utility proposals for AMI/AMF should include a demonstration of the value of AMI/AMF for TOU rate improvements.

19. Each utility should examine its commercial and industrial rates to improve their reflection of the value of time variability.

20. Consistent with the Staff report on energy affordability, application of the anticipated low-income discount should be supplemented by locating it within a basic usage block.
21. Bill impact analyses should be performed for potential demand charge scenarios; these analyses should include impacts on low-income customers.
22. Standby rates should be reviewed and modified to include a reliability credit and a wider application of the campus tariff.

Parties may file comments in any form, but to expedite the processing and evaluation of comments it is strongly preferred that party comments follow the table of contents. In order not to confuse the comment outline with the recommendations listed above, the table of contents is replicated below, with parenthetical references to each of the recommendations above. In this way parties can comment on the specific recommendations within the framework of the table of contents.

# A. Acronym List & Glossary

| **ACRONYM** | **TERM** |
|---|---|
| ASC | Accounting Standards Codification |
| BQDM | Brooklyn-Queens Demand Management |
| CFAR | Carbon Free Acquisition Rate |
| CHP | Combined Heat and Power |
| C/I | Commercial and Industrial |
| DER | Distributed Energy Resources |
| DG | Distributed Generation |
| DLM | Dynamic Load Management |
| DR | Demand Response |
| DSIP | Distributed System Implementation Plan |
| DSP | Distributed System Platform |
| EEPS | Energy Efficiency Portfolio Standard |
| EIM | Earnings Impact Mechanisms |
| ESCO | Energy Services Company |
| ESM | Earnings Sharing Mechanisms |
| ETIP | Efficiency Transition Implementation Plans |
| HEFPA | Home Energy Fair Practices Act |
| ICAP | Installed Capacity |
| IFRS | International Financial Reporting Standards |
| kW | Kilowatt |
| kWh | Kilowatt-hours |
| LMP+D | Location-Based Marginal Price of Energy + Value of Distributed Resources |
| LMP | Location-Based Marginal Price |
| MBE | Market Based Earning |
| MDPT | Market Design and Platform Technology |
| MW | Megawatt |
| MWh | Megawatt-Hours |
| NEM | Net Energy Metering |
| NYISO | New York Independent System Operator |
| NYSERDA | New York State Energy Research and Development Authority |
| PBR | Performance-Based Regulation |
| PIM | Performance Incentive Mechanism |
| PSL | Public Service Law |
| PSR | Platform Service Revenues |
| PULP | Public Utility Law Project |
| ROE | Return on Equity |
| REV | Reforming the Energy Vision |
| T&D | Transmission and Distribution |
| TOU | Time-of-Use |

This glossary contains the definitions of certain frequently used terms in the companion Staff White Paper as those terms are used therein.

- **Allowed return** – The amount provided by a regulator in a utility’s rates to compensate the utility for the cost of the utility’s investor provided capital, which is expressed as a percentage. The allowed return also could be a reference to the overall rate of return associated with all investor provided capital including common equity, as well as the interest expense on debt and preferred stock dividend rate.

- **Arrears** – Overdue amounts under the terms of the utility’s tariff owed to the utility by its customers.

- **Basis points** – A common measure for denoting small changes in interest rates. One hundred basis points is equivalent to one percentage point (1.0%). One basis point is equivalent to one one-hundredth of a percentage point (0.01%). Positive or negative revenue adjustments are often set by reference to the number of basis points on equity.

- **Benefit-cost analysis (BCA)** – A BCA is a systematic and analytical comparison of the gains and losses that would derive from a specified project or program. A BCA is used to aid in deciding whether to implement such projects or programs, or to choose among alternative projects or programs. (For a more detailed discussion in the REV context, see the Policy Framework Order, February 26, 2015, pp. 122-5.)

- **BCA Framework** - The BCA Framework is the set of guiding principles, and estimation methods and sources, to be used by electric utilities in investment, process, and purchase decision-making, specifically in the context of their DSIPs and future DER tariff designs. (For a more detailed discussion, see the “Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding,” 14-M-0101 July 1, 2015.)

- **Capital expenditures (“capex”)** – Funds spent to acquire or upgrade the physical assets like plant, property, equipment (including transmission and distribution infrastructure), or industrial buildings. Conventional cost-of-service regulation as applied in New York provides a return of, and on, capital costs over a multi-year period.

- **Clawback mechanism -** A mechanism that ensures that utility underspend for capital expenditures is captured for the benefit of ratepayers. Also known as the "net plant reconciliation mechanism."

- **Coincident-peak** – Demand from a customer's facility that coincides, in time, with the time that system-wide electricity demand is at its peak.

- **Cost-of-service (COS) ratemaking** – A ratemaking process whereby the regulator sets utility rates at a level that allows the utility to recover its forecast cost of service to provide service to customers. The utility's cost of service is the sum of its operating expenses, depreciation expenses, property and income taxes, and a reasonable return on its capital expenditures (property) devoted to public service.

- **Critical peak pricing (CPP)** – Pricing that occurs when the utility anticipates high wholesale market prices or power system emergency conditions to address critical events (e.g., a heat wave or a power plant failure) that may cause a significant increase in the price of electricity to reflect system conditions. In comparison to a critical peak rebate, CPP signals the need for load reductions through increased prices paid by customers rather than incentive payments to customers.

- **Critical peak rebate (CPR) –** A demand response program that provides load relief when critical events (e.g., a heat wave or a power plant failure) are called by the utility. Participating customers receive payments for reducing electricity usage during the event relative to the amount they normally use. In addition, participating customers that adopt approved electric metering equipment receive an incentive payment.

- **Deadband** - A deadband is a zone that is established in a utility rate plan where no action occurs if the financial amounts at issue fall within the zone's established boundaries. For example, as applied to earnings sharing mechanisms, the deadband is the area above the established specific target return on equity where the utility retains all earnings regardless of its variance from the specific target number.

- **Demand charge** – A charge to energy users based on a measure of each user's peak demand in a specified period (often calculated on a monthly basis). The charge provides a mechanism to recover costs associated with infrastructure and maintenance expenses used to deliver energy in periods of peak demand. Demand charges are currently applied to large customers in New York, but could be expanded to others including mass market customers.

- **Demand response -** A tariffed program that provides customers with an opportunity to play a significant role in the operation of the electric grid by reducing or shifting their electricity usage during peak periods in response to time-based rates or other forms of financial incentives.

- **Demand-side management (DSM)** – A tariffed program, where the utility can pay customers to reduce their load in a responsive and measurable manner through the customers' energy efficiency and demand response measures. DSM capacity is typically cheaper and easier to procure than traditional generation

- **Digital marketplace** – A digital marketplace is a web-based customer portal providing customers and vendors opportunity to transact business via an internet or telecommunications connected device or platform (e.g., mobile phones, social media marketing, display advertising, search engine marketing).

- **Distributed energy resources (DER)** – A class of energy technologies that include energy efficiency, and distributed generation. DERs are engaged at the low voltage, distribution level of the electric grid, either on the customer-side or utility side of the meter.

- **Distributed generation (DG)** – Any distributed energy resource that generates electricity. Examples include combined heat and power production units, photovoltaic cells, and small wind turbines.

- **Dynamic load management (DLM)** - The process of using on-call demand (e.g., load reduction, dispatchable storage, distributed generation) to reduce peak load or to address a system contingency or system emergency.

- **Distributed System Implementation Plan (DSIP)** - A multi-year integrated operating plan filed with the Commission by each utility.

- **Distributed System Platform (DSP)** - The new energy platform or marketplace that the local utility will coordinate among smart grid technology, distributed energy resource providers and ESCOs.

- **Earnings sharing mechanism (ESM)** – A mechanism that allows the utility’s customers to share in any earnings that exceed a pre-designated level.

- **Earnings impact mechanism (EIM)** – A specific performance-based incentive that has financial impacts and that aligns a utility’s financial interests with desirable outcomes.

- **Energy service company (ESCO)** – A lightly regulated business entity, other than the utility, that sells electric commodity/energy service (delivered by distribution utilities) and related services to users.

- **Home Energy Fair Practices Act (HEFPA)** - Article 2 of the Public Service Law, sometimes known as the “utility customer bill of rights.” HEFPA details residential ratepayers’ rights regarding the provision of electric and gas service in New York State. HEFPA outlines specific rights customers have regarding billings, deposits for service connection, notification of service termination, cold weather safeguards, the PSC “hotline” and a help line that handles unresolved billing or service complaints. HEFPA also has special provisions for the blind, low-income customers; individuals 62 and older and customers with crucial health related problems. All providers of electric and gas service, including regulated utilities and non-regulated energy service companies, are required to comply with HEFPA’s provisions.

- **Interconnection** – The wiring system and components necessary to connect a distributed generator to the utility delivery system to ensure safe interoperability.

- **Load factor** – The ratio of average load over a period to the maximum or peak load in that period. Load factor provides a measure of how “peaky” system load is and may indicate the degree of asset utilization on the grid; a higher load factor correlates with higher utilization of grid infrastructure.

- **Market based earnings (MBEs)** - Utility earnings derived from facilitating the creation and transaction of value-added services by active users of the DSP.

- **Mass Market** – The mass market consists of a utility’s residential and small commercial customers.

- **Multi-sided market** - Economic platforms that serve two or more distinct user groups that value the extent of each other’s participation. Such dependent valuations are known as “network effects.” Participation in the market occurs between user groups over an intermediary platform, which often has prescribed technology standards, market rules, and pricing structures.

- **Net energy metering (NEM)** – A tariffed service that enables customers’ meters to register both the amount of energy they receive and the energy they send back to the grid, which results in offsets to the customer’s energy bill and credits for net exports to the grid.

- **Network effects** – A distinguishing characteristic of multi-sided markets. A network effect exists when the value derived from a platform by one distinct user group increases as the size of overall participation in the market grows. For example, a certain credit card (the platform) becomes more valuable to consumers as the number of businesses accepting that credit card grows. Similarly, the value of that credit card to businesses grows as the number of consumers using it grows. As producers and ESCOs using the DSP platform grow, and provide new services through the platform, the platform should become more valuable to consumers actively engaging with the platform. Similarly, as the number of consumers actively engaging with the DSP platform grows, the value that producers, ESCOs, and innovative service providers derive from the platform should grow.

- **Non-coincident peak** – Maximum demand of an individual facility occurring within a specified period (e.g. daily, monthly, or annual). Non-coincident peak demand does not necessarily coincide with the time that system-wide electricity demand is at its peak.

- **Non-wires alternatives** – Alternatives to traditional utility infrastructure (e.g. substations, poles and wires), such as DER, that can serve system needs at reduced total costs.

- **Operating expenses (“opex”)** - The utility’s day-to-day costs (e.g., insurance, wages and materials) to run its business. Typically, operating expenses are accounted for within a single rate year.

- **Outcomes-based ratemaking** – A variation of performance-based regulation, which places greater emphasis on market-driven outcomes and the utility’s performance in enabling those outcomes.

- **Physical assets –** The utility’s property, plant and equipment, which are used for its business, held for the production of income and included in its rate base.

- **Peak demand** - The maximum level of operating requirements (production) placed upon the system by customer usage during a specified period of time (thirty-minute peak, one-hour peak, one-day peak, and annual peak are common points of reference). Peak demand measurements may be determined for an operating segment of the utility, such as a customer class; for a specified service area, such as a distribution circuit; or for the entire utility distribution service, depending on intended use of the data.

- **Performance-based regulation (PBR)** – An alternative to conventional cost-of-service ratemaking that aligns a utility’s revenue and profits with performance relative to specific benchmarks or pre-determined factors. PBR schemes tend to employ performance incentive mechanisms (PIMs) and/or scorecard-based performance metrics to evaluate performance.

- **Performance metrics -** Metrics that track individual utility performance on pre-determined factors that may serve to achieve targeted goals.

- **Platform service revenues (PSRs)** - Revenues generated by the utility from multi-sided markets that are effectuated by the utility’s employment of a DSP platform and its development of a network of customers (consumers, ESCOs, and producers) enabled by using such a platform. PSRs are one type of market based earnings that will be available to utilities.

- **Prosumer** – A utility customer who installs portfolios of DERs including generation or other technologies that allows customer to provide services to the electric distribution grid.

- **Real-time pricing** – Electricity pricing that varies frequently over a day relative to changing electricity costs.

- **Reconciliation mechanism** – A risk-reducing mechanism that reconciles actual expenses with expense levels assumed in rates. This is typically applied to uncontrollable expenses.

- **Regulatory assets** – Specific costs or revenues that the regulator allows a utility to defer, subject to limitations, on its balance sheet, to be recovered or paid at a later time.

- **Return on equity (ROE)** – In rate regulation, the ROE is an amount of money that a utility is allowed to collect through its rates to provide a return for the equity invested by the utility's shareholders. The ROE is applied to the equity component of rate base and is grossed up for income taxes.

- **Scorecard** – A tracking mechanism with no direct revenue impacts, by which the Commission can track progress on PBR outcomes.

- **Smart Home Rate** – An opt-in rate that can be used to unbundle price signals to reflect costs associated with electricity delivery (e.g., time and location) and attributes including commodity energy, delivery costs, and possibly certain ancillary services.

- **Standby service** - Electric utility service that serves customers when their on-site generation is not operating or when it is operating but is insufficient to meet the customer's load requirements.

- **Terminations** – The act by which a utility disconnects a customer's service due to the customer's failure to pay bills.

- **Third party** – Refers to entities other than the utility that invest in DER and provide value-added services to end-users or the grid.

- **Time-of-use (TOU) rates** – Rates that vary based on system costs at different times, and that encourage customers to reduce their electricity usage during peak periods when electric prices relative to off-peak prices are higher.

- **Total expenditures (“Totex”)** – A ratemaking approach that makes the utility indifferent to distinctions between capex and opex, thereby eliminating the utility’s preference to capitalize expenditures.

- **Transactive grid** – A software-defined, low-voltage distribution grid that enables market participation by DER bidding generation of negawatts (reduction reduction) or kilowatts (energy injection). The transactive grid is the convergence of technologies, policies, and financial drivers in an active prosumer market.

- **Uncollectible expenses** – Expenses that occur when the utility writes off customer arrears.

- **Utility earnings** – The utility’s net income, or the money that remains available solely for utility use after subtracting all of appropriate utility expenses, losses and taxes from its collected total revenue.

- **Utility revenues** – The amount of money collected by the utility from all sources, including but not limited to, its direct provision of service to customers.

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# C. Summary of Existing Performance Incentive Mechanisms

**Summary of New York Electric Utility**
**Positive/Negative Revenue Adjustment Areas [1,2]**

| Company | CHGE | Con Edison | NMPC | O&R | NYSEG | RG&E |
|---|---|---|---|---|---|---|
| Rate Case | 14-E-0318 | 13-E-0030 ext. | 10-E-0050 | 14-E-0493 [3] | 09-E-0715 | 09-E-0717 |
| | ($'000s) | ($'000s) | ($'000s) | ($'000s) | ($'000s) | ($'000s) |
| Value of 10 Basis Points (BPs) | $660 | $14,450 | $3,300 | $610 | $1,250 | $800 |
| **Negative Revenue Adjustments (NRAs) [4]** | **BPs** | **BPs** | **BPs** | **BPs** | **BPs** | **BPs** |
| a) Customer Service Performance | 46.1 | 27.7 | 46.1 | 24.6 | 72.0 | 62.5 |
| b) Reliability Service Performance | | | | | | |
| 1. CAIDI | 30.0 | 6.9 | 18.2 | 20.0 | 56.0 | 62.5 |
| 2. SAIFI | 30.0 | 6.9 | 18.2 | 20.0 | 56.0 | 62.5 |
| 3. Other | 0.0 | 82.4 [5] | 24.2 | 0.0 | 0.0 | 0.0 |
| c) Stray Voltage (per measure/per year) | 75.0 | 75.0 | 75.0 | 75.0 | 75.0 | 75.0 |
| ***Total NRAs*** | | | | | | |
| ***Basis Points*** | ***181.1*** | ***198.9*** | ***181.7*** | ***139.6*** | ***259.0*** | ***262.5*** |
| ***Dollars ($'000s)*** | ***$11,950*** | ***$287,375*** | ***$59,950*** | ***$8,515*** | ***$32,375*** | ***$21,000*** |
| **Positive Revenue Adjustments (PRAs) [6]** | | | | | | |
| a) Energy Efficiency | | | | | | |
| 1. EEPS2 max MWh (total-not annual) | 33.3 | 8.1 | 45.3 | 20.3 | 29.6 | 28.3 |
| 2. MW Incentive | 0.0 | 13.8 | 0.0 | 0.0 | 0.0 | 0.0 |
| b) Residential Service Terminations/Bad Debt | 5.0 | 0.0 | 0.0 | 9.2 | 0.0 | 0.0 |
| c) Customer Additions | 0.0 | 0.0 | 0.0 | 5.0 | 0.0 | 0.0 |
| ***Total PRAs Excluding ESM Provisions*** | | | | | | |
| ***Basis Points*** | ***38.3*** | ***21.9*** | ***45.3*** | ***34.6*** | ***29.6*** | ***28.3*** |
| ***Dollars ($'000s)*** | ***$2,531*** | ***$31,642*** | ***$14,950*** | ***$2,108*** | ***$3,700*** | ***$2,266*** |
| **Earnings Sharing Mechanism (ESM) Provisions [7]** | | | | | | |
| 1. Deadband | 50.0 | 60.0 | 0.0 | 60.0 | 90.0 | 90.0 |
| 2. Level 1 - Threshold Potential | 25.0 | 32.5 | 50.0 | 30.0 | 37.5 | 37.5 |
| 3. Level 2 - Threshold Potential | 10.0 | 12.5 | 25.0 | 15.0 | 0.0 | 0.0 |
| Final Threshold: ROE Greater than/ Co. Share | 10%/10% | 10.75%/10% | 11.3%/10% | 10.8%/10% | 11.65%/15% | 11.65%/15% |
| Potential Sharing per ESM (BPs) | 35.0 | 45.0 | 75.0 | 45.0 | 37.5 | 37.5 |
| Potential Sharing per ESM ($'000s)) | $2,310 | $65,025 | $24,750 | $2,745 | $4,688 | $3,000 |
| ***Total PRAs Plus ESM Provisions*** | | | | | | |
| ***Basis Points*** | ***73.3*** | ***66.9*** | ***120.3*** | ***79.6*** | ***67.1*** | ***65.8*** |
| ***Dollars ($'000s)*** | ***$4,841*** | ***$96,667*** | ***$39,700*** | ***$4,853*** | ***$8,388*** | ***$5,266*** |

[1] Data is current as of July 2015.

[2] In addition to the revenue adjustments in this table, all companies have a symmetrical sharing mechanism around property taxes; NYSEG and RG&E have a positive incentive around labor savings; and Con Ed has a sharing mechanism associated with Municipal Infrastructure support.

[3] Per the Orange & Rockland Joint Proposal (issued June 5, 2015).

[4] NRAs are deducted from utility revenues when the utility fails to achieve pre-specified performance targets.

[5] The "Other" category for Con Edison's reliability mechanism has a maximum NRA potential of $119 million/84.2 bps, which reflects: remote monitoring system reporting ($50 M), major outages ($30 M), intrusion detection ($24 M), program standards ($9 M) and overduty circuit breakers ($(

[6] PRAs are added to utility revenues when the utility achieves pre-specified performance targets.

[7] ESMs enable a utility to retain a portion of earnings that exceed the authorized return, generally as the result of its ability to manage costs.

# D. Cost Reduction Opportunities

The following discussion provides qualitative examples of possible targeted areas for cost reduction on the grid.

**Transmission and Distribution Investment**

Non-wires alternative projects, including targeted demand management programs, help reduce customer peak demand for electricity and avoid costs associated with transmission and distribution infrastructure investment. Peak demand can be reduced by energy efficiency, demand response, distributed generation or other forms of DER including energy storage. Reduced demand can result in the deferral of new substations, transformer upgrades, and feeder reconductoring. These projects and programs can also be used to buttress utility system reliability to minimize or avoid power outages, which adversely impact the economy due lost productivity, spoiled products, or even loss of life.

**Line Losses**

Enhanced system visibility and control will allow for the better placement and operation of distributed energy resources and distribution system equipment, such as capacitors and load tap changer (LTC) transformers, to reduce distribution line losses. Losses come from the current through the resistance of conductors. Some of that current transmits real power, but some flows to supply reactive power. Since line losses are a function of the current squared ($I^2$), reducing current levels on lines with DER and distribution system equipment used for VAR support significantly reduces losses.

**Volt/VAR Optimization (VVO)**

The concept of Voltage/VAR management or control is essential to electrical utilities’ ability to deliver power within appropriate voltage limits so that customers’ equipment operates properly, and to deliver power at an optimal power factor to minimize losses. For utility operations, VVO solutions provide a higher level of visibility into system operating parameters, including integrated distributed energy resources, and a greater degree of control to optimize energy efficient and reliable electricity delivery. The ability to optimize power factor, in combination with DER utilization, is a key driver in a utility’s ability to minimize losses. VVO also provides environmental benefits since the utility has to generate less power to serve the same demand, resulting in less coal or natural gas burned, and therefore fewer $CO_2$ and other air emissions.

**Conservation Voltage Reduction (CVR)**

Conservation Voltage Reduction (CVR) is a specialized usage of VVO, which has numerous potential benefits. This type of VVO solution can be used to flatten voltage profiles and then lower overall system voltage while staying within the specified ANSI voltage limits. VVO serves to optimize voltage along a distribution line, while the purpose of CVR is to reduce the total voltage on a distribution line to decrease electric demand. In the absence of VVO and DER at the grid edges, the utility will be required to increase voltage at a substation to maintain a minimum voltage at the end of the distribution line. By controlling voltage along the entire length of the line and optimizing the placement of DER for voltage support, the utility can decrease voltage from the substation and simultaneously decrease energy usage as a consequence of the reduced voltage.

Utilities can institute CVR to further reduce voltage for the purpose of reducing overall system demand by a factor of 0.7-1.0% for every 1% reduction in voltage. From a customer perspective, this reduces the energy they consume. CVR and DER reduce the amount of power the utility needs to generate or purchase from a generator. There are benefits associated with reduced utility operating costs, however the bulk of the benefits from CVR are realized when it is implemented to defer investment in new generation capacity or to address reduced capacity due to old generating assets being taken offline. Generation capacity benefits can be significant, especially when load growth is small since investments can be deferred for longer periods.

**Fault Location, Isolation, and Service Restoration (FLISR)**

Fault location, isolation, and service restoration (FLISR) combines hardware, software, telecommunications, and grid engineering to decrease the duration and number of customers and of distributed energy resources affected by any specific outage. FLISR is one of the more attractive applications within distribution automation (DA) and can noticeably improve utility performance metrics, such as the customer average interruption duration index (CAIDI) and the system average interruption frequency index (SAIFI), and ease the integration of more DER onto the grid. Improved CAIDI and SAIFI indicators can lead directly to improved customer satisfaction. Successful implementation will detect fault locations with greater precision and decrease time and cost to find and repair the fault along a line, thus allowing DER to continue to operate and provide customer and system benefits as discussed in the above four areas. Additional benefits include avoided outages (reducing truck rolls) and reducing what would have been an hour outage down to minutes for most affected customers by isolating faults and maintaining/restoring power through automatic line switching.