APPENDIX C

Part 1: Comments on July 28, 2015 White Paper

TABLE OF CONTENTS

Page

Entities that Commented on Staff Ratemaking Straw Proposal (with abbreviations)

AARP New York (AARP)
Acadia Center (Acadia)
Acadia Center, Association for Energy Affordability, Citizens for Local Power, Clean Coalition, Environmental Advocates of New York, Environmental Entrepreneurs, Natural Resources Defense Council, Nature Conservancy, New York League of Conservation Voters, New York Public Interest Research Group, Pace Energy and Climate Center, and Sierra Club, filing jointly as Clean Energy Organizations Collaborative (CEOC)
Advanced Energy Economy Institute on behalf of Advanced Energy Economy, the Alliance for Clean Energy New York, and the New England Clean Energy Council (AEEI)
Alliance for a Green Economy, Binghamton Regional Sustainability Coalition, Center for Social Inclusion, Citizens' Environmental Coalition, Citizens for Local Power, Long Island Progressive Coalition, Nobody Leaves Mid-Hudson, and Push Buffalo, filing jointly as The Energy Democracy Alliance (EDA)
American Council for an Energy Efficient Economy (ACEEE)
Association for Energy Affordability (AEA)
BlueRock Energy, Inc. (BlueRock)
Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation (the Joint Utilities)
ChargePoint, Inc. (ChargePoint)
Citizens' Environmental Coalition (CEC)
Citizens for Local Power (CLP)
City of New York (NYC)
Comverge, Inc. and EnergyHub (Comverge/EnergyHub)
Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. (Con Edison/O&R)
Consumer Power Advocates (CPA)
Energy Technology Savings LLC (ETS)
Environmental Defense Fund (EDF)
Exelon Companies, including Exelon Corp. and subsidiaries (Exelon)
Federal Trade Commission (FTC)
GridWise Alliance (GWA)

Hudson River Sloop Clearwater, Inc. (Clearwater)
Institute for Policy Integrity, New York University School of Law (Policy Integrity)
IGS Generation, IGS Solar and IGS Energy (IGS)
Interstate Renewable Energy Council, Inc. (IREC)
Microgrid Resources Coalition (MRC)
Mission:data (Mission:data)
Multiple Intervenors (MI)
National Electrical Manufacturers Association (NEMA)
National Energy Marketers Association (NEM)
National Fuel Gas Distribution Corporation (NFG)
Natural Resources Defense Council, Pace Energy and Climate Center, the Association of Energy Affordability, the Center for Working Families, and the Green and Healthy Homes Initiative, filing jointly as Energy Efficiency for All (EE for All)
New York Battery and Energy Storage Technology Consortium (NY-BEST)
New York Energy Consumers Council (NYECC)
Northeast Clean Heat and Power Initiative (NECHPI)
Northeast Energy Efficiency Partnerships (NEEP)
NRG Energy, Inc. (NRG)
Nucor Steel Auburn, Inc. (Nucor)
NY Cow Power Coalition (NYCPC)
Pareto Energy LTD (Parento)
Public Utility Law Project of New York, Inc. (PULP)
Ratzkin, Andrew (Ratzkin)
Real Estate Board of New York (REBNY)
Retail Energy Supply Association (RESA)
Sierra Club and General Motors (Sierra/GM)
Simple Energy (Simple Energy)
Solar Energy Industries Association (SEIA)
The Alliance for Solar Choice (TASC)
Vanguard Renewables (Vanguard)
Vote Solar Initiative (Vote Solar)

PARTY COMMENT SUMMARIES

July 28, 2015 Staff White Paper on Ratemaking and Utility Business Models

This topical summary of comments was compiled for the benefit of the reader and is not intended to be a comprehensive source of all comments submitted in this proceeding or to reflect any weight given particular comments by the Public Service Commission (Commission) or the Staff of the Department of Public Service (Staff). The full versions of party comments can be found at the Department of Public Service website under the REV case number, 14-M-0101, and have been considered in their entirety by Staff and the Commission.

SECTION I.A INTRODUCTION AND SUMMARY: Introduction

Acadia Center (Acadia):
Acadia supports the REV initiative.

ChargePoint, Inc. (ChargePoint):
ChargePoint supports the REV concept.

Citizens Environmental Coalition (CEC):
CEC argues that REV is a repackaging of 1990's deregulation and that Staff needs to identify the source of new utility revenues and support sufficient energy efficiency targets.

Environmental Defense Fund (EDF):
EDF comments that utilities should be incented to reduce pollution. Pollution should act as a negative factor in calculating LMP+D values. EDF supports gradual introduction of REV and opt-in tariffs. While REV might reduce pollution, it is possible that DER could include polluting sources. RGGI should be modified to include small polluters.

Energy Technology Savings (ETS):
ETS asks that Staff clarify some of the terminology used in the proposal.

Exelon Companies (Exelon):
Exelon generally supports Staff’s position. Basic utility responsibilities remain regardless of regulatory framework. REV should align utility profits to REV goals. Exelon advocates for CO2 regulation and BCA valuation of DER.

National Fuel Gas Distribution Corporation (NFG):
NFG supports the Commission decision to have utilities serve as DSP. As gas distributors, NFG is willing to work on DER projects. NFG also supports RDMs.

New York Energy Consumers Council, Inc. (NYECC):
NYECC states that it is not clear how the proposed incentives and concepts will affect the rate setting process.

Nucor Steel Auburn, Inc. (Nucor):
Nucor believes REV's focus on DER should expand to consider large-scale storage and other peak shaving methods. It’s not clear how much DER is needed to be effective.

Pareto Energy LTD (Parento):
Pareto has two CHP microgrids in NYC and argues that Con Ed should have tapped them as part of BQDM project. Parento stresses the importance of CHP in REV applications.

Ratzkin, Andrew (Ratzkin)
Ratzkin comments that although REV's market goals are worthy objectives, it will require an enforceable mechanism to drive emissions reductions to achieve the State's climate goals.

The Alliance for Solar Choice (TASC):
TASC supports REV goals, customer-centric priorities, access to DER, energy efficiency, and renewable energy. TASC opposes the Commission's decision to utilize the utilities as DSP.

SECTION I.B INTRODUCTION AND SUMMARY: Purposes, Scope and Process of this White Paper

Citizens Environmental Coalition (CEC):
CEC asserts that Staff's proposals are too vague and that REV has too many balls in the air to be effective. CEC also asserts that past ESCO abuses remain unaddressed.

Citizens for Local Power (CLP):
CLP states that the Commission should evaluate the next five years of proposed REV projects in terms of bill impact for various ratepayer classes.

City of New York (NYC):
NYC argues that more development of the record is needed to determine the impact of REV on consumer rates.

SECTION I.C INTRODUCTION AND SUMMARY: Summary of Proposals

Advanced Energy Economy Institute (AEEI):
AEEI is concerned about utilities as market participants in DER. AEEI supports clawback in net plant reconciliation, peak demand focus in rate design, and LMP+D (broad definition of D to include social benefits). AEEI advocates for no unnecessary delays and more energy efficiency.

Citizens Environmental Coalition (CEC):
CEC comments that issues such as low-income, clean energy, security, reliability, and climate resilience need more attention than afforded in whitepaper. As defined, DER could (but should not) include fossil fuels. CEC is opposed to market incentives and questions how long REV will take. Low-income and environmental goals are CEC's highest priorities. CEC argues that the vision of aligning utility's profits with market activity has no basis in fact, and asks how revenues will increase while customer bills decrease. CEC claims REV will change regulators to market monitors and asks how many Staff have the necessary experience to fill that role. CEC argues

that a move to a market-based regulatory model is not guaranteed to succeed.

Energy Efficiency for All (EE for All):
EE for All comments that rate plans should be limited to three years.

Environmental Defense Fund (EDF):
EDF states that Track 2 decisions must be made in context of other related proceedings, and within the environmental regulatory framework. Utility incentives must be consistent with emissions reductions and LMP+D must include considerations of social harms. EDF supports more sophisticated opt-in tariffs.

Joint Utilities:
The Joint Utilities point out that it is difficult to know how market will evolve. Price signals based on long-term avoided costs may not be accurate. Projected long-term benefits must be balanced with known short-term costs.

Microgrid Resources Coalition (MRC):
MRC asserts that DSPs are not needed as middleman between customers and the ISO. As utilities have no experience with eCommerce, customer information should be supplied directly to DER providers.

Mission:data:
Mission:data supports greater access to data in the REV proceeding. Consumers should be provided with secure and convenient access to their energy usage, charges, pricing and account information, both historical information and near real-time information through enablement of the Home Area Network radios. Such data access should be provided to all customers at no cost as part of the basic utility service provided by the DSP, and allow customers to easily and quickly allow access to their data by innovative third-party service providers. Ratepayer funds may appropriately be used to grow the market, but not to unduly favor any particular players. Therefore, Mission Data believes it is critical that the DSP prioritize

establishing an accessible platform upon which consumers may chose the offerings which appeal to them and service their perceived needs.

National Energy Marketers Association (NEM):
NEM is concerned that MBEs will not overcome utility bias against third-party providers. Utilities should act as facilitators for competitive entities providing new services. NEM supports on-bill charge for ESCO value added services, unbundled utility rates and rate designs that will enable third parties to enter the market.

National Fuel Gas Distribution Corporation (NFG):
NFG asserts that there is no indication that third-party financing is cheaper than investments by utilities. Increased risk for utilities will put upward pressure on ROE. NFG supports broad policy objectives that the utilities must meet rather than more specific regulatory framework. Prescriptive, specific performance metrics – whether resulting in penalties or rewards – are not a replacement for policy-driven regulatory oversight. Rate design should help customers manage electricity costs. Low income should be dealt with in its own proceedings. NFG supports revision of stand by tariffs, on a periodic basis and the expansion of the net metering concept to all fuel sources.

New York Energy Consumers Council, Inc. (NYECC):
NYECC **e**xpresses concern with rate plans longer than three years. NYECC also supports net energy metering.

National Energy Marketers Association (NEM)
NEM supports unbundled utility rates and rate design that enables third parties.

Northeast Clean Heat and Power Initiative (NECHPI):
NECHPI argues that lack of specificity on timing makes it impossible to assess progress and that Staff has failed to prioritize goals. NECHIP adds that without comprehensive circuit maps of utility grids, there is no way to perform accurate benefit-cost analyses.

Nucor Steel Auburn, Inc. (Nucor):
Nucor is concerned that time-based rates and added incentives may add to high utility costs.

Pareto Energy LTD (Parento):
Parento complains that Con Ed rejected Pareto's microgrids in designing BQDM, despite the fact that its microgrids operate at half the cost of the macrogrid.

Ratzkin, Andrew (Ratzkin)
Ratzkin states concern that REV is too complicated by the focus on regulatory reform and not broad enough in scope to achieve the State's climate goals. Ratzkin recommends that a separate policy focused squarely on reducing emissions be adopted.

Retail Energy Supply Association (RESA):
RESA supports accurate price signals to customers. Current rates do not accurately reflect costs of commodity. RESA questions how the reasonableness of MBEs will be determined and argues that MBEs should be restricted.

The Alliance for Solar Choice (TASC):
TASC wants current net metering options to remain for residential and small business customers who do not participate in DR programs. TASC supports the study of time of use rates, critical peak pricing, and peak time rebates.

SECTION I.D INTRODUCTION AND SUMMARY: Legal Authority

Citizens Environmental Coalition (CEC):
CEC is not certain that the Commission has authority to undertake REV reform and will be looking into the issue.

Institute for Policy Integrity at NYU School of Law (Policy Integrity):
Policy Integrity argues that the PSL requires the Commission to "promote the public interest, which includes promoting public health and environmental preservation." Citing PSL §§5 and 66(2), Policy Integrity argues that the Commission has the

authority to encourage all persons under its jurisdiction to make long-term plans for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources. According to Policy Integrity, this requires the consideration of social externalities, citing the Commission's 2007 proceeding to establish long-term electric infrastructure plans (Case 07-E-1507). In order to fully achieve these goals, the Commission must approach its ratemaking from the perspective of maximizing net social welfare and properly integrate all significant costs and benefits into the ratemaking process, including environmental externalities.

SECTION II.A LIMITATIONS OF CONVENTIONAL COST-OF-SERVICE RATEMAKING: The Foundation of Traditional Regulation, Efficient Investment, and Innovation in New York

Advanced Energy Economy Institute (AEEI):
AEEI agrees with the Joint Utilities that cost of service should be employed for REV-related expenses. They support modifications to the cost-of-service model, namely the modified clawback mechanism and the use of EIMs, as a means of incenting desired outcomes and desired utility behavior in creating a vibrant DER market.

BlueRock Energy, Inc. (BlueRock):
BlueRock supports effective competition, rather than regulation, as the best means of protecting of the public and insuring technology advancements.

ChargePoint, Inc. (ChargePoint):
ChargePoint agrees that traditional ratemaking structures are outdated and advocates for the Commission to eliminate incentives for a utility to favor its own capital spending over third-party activity that meets system needs at a lower cost to ratepayers. 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.

Citizens Environmental Coalition (CEC):
Noting the problems utilities experienced from previous storms, CEC asserts that metrics are needed to incent utilities to be better prepared. CEC asserts that deregulation of the wholesale power system increased commodity costs and that utilities have no incentive to engage early in proper planning for future.

City of New York (NYC):
NYC agrees that the goals of REV should "bring the goal of dynamic efficiency into balance with other goals of regulation" and into harmony with federal, State, and New York City public policies, including in reducing greenhouse gas emissions and providing affordable energy service to all consumers.

Energy Technology Savings, Inc. (ETS):
ETS agrees that the current approach to ratemaking needs to be revised and a new rate structure must move utilities and third-parties towards the implementation of DER. It is important to eliminate existing financial incentives in the regulations for utilities to favor their own capital spending over third-party investment.

Federal Trade Commission (FTC):
The FTC states that "aligning earning opportunities with customer value" is an appealing way to emphasize the importance of better matching electricity services to customers' preferences. However, the FTC states that the text that fleshes out that heading is too restrictive. The primary problem is that it limits the description of potential benefits from the REV proceeding to price or quantity effects. Other benefits that customers may prefer include power quality, system reliability and resiliency, customer choice, reduced environmental impacts, and innovation. The FTC commends Staff for aligning distribution utility incentives with customer benefits by squarely addressing utilities' incentives to undermine the competition posed by unaffiliated DERs.

Interstate Renewable Energy Council (IREC):
IREC believes a cautious approach is warranted, advising that no compelling reason exists for utilities remaining as large or

having access to as much or more revenue as they have historically. IREC is supportive of finding ways to replace the revenue that utilities would otherwise derive from capital investments, but is troubled by suggestions that utilities should have the ability to get a greater return than they otherwise would in certain cases. IREC sees little reason to allow for a greater rate of return unless it can affirmatively be shown that by doing so customers are getting a proportionally significant reduction in cost.

Joint Utilities:
The Joint Utilities point out that utilities will continue to require large amounts of capital and must be able to raise this capital in the financial markets at reasonable terms and conditions in order to benefit their customers. An explicit commitment by the Commission to full and timely recovery of REV investments based on cost-of-service regulation would help to alleviate any investment community concerns regarding the potential impact of REV on utility risks and financial health, including ROE allowances and equity ratio levels. Any REV-related changes to the Commission's regulatory model should complement cost-of-service ratemaking and not impede the utilities' ability to recover expenditures and investments made to implement Commission directives.

National Fuel Gas Distribution Corporation (NFG):
NFG states that long-term rate plans stifle creativity by locking-in ratemaking concepts and programs. By extending the current "one-size-fits-all" approach the risk of having ineffective or harmful programs would occur, and the ability of utilities to experiment or adapt to changing circumstances would be frustrated. Staff's White Paper correctly identifies that commodity costs are a direct pass through expense for utilities, that these costs represent a significant component of a customer bill, and that currently there are no positive earnings opportunities for utilities if their actions help to reduce costs of supply.

New York Energy Consumers Council, Inc. (NYECC):
NYECC states that it is hard to comment on effectiveness of proposed changes outside of a rate case and without a real

situation for context. NYECC is in accord with Staff that the market growth transformations contemplated by REV will not occur overnight but progress should be incentivized at a pace that will drive customer value.

Northeast Clean Heat and Power Initiative (NECHPI):
NECHPI expresses concern about whether current rate design principles remain intact with REV and if so, which ones would need to be modified.

Nucor Steel Auburn, Inc. (Nucor):
Nucor asserts that further development is needed for MBEs, capital expenditures and EIMs in ratemaking process. In adopting basic ratemaking changes, the Commission must maintain a clear sense of perspective and balance of utility shareholder, consumer and public policy needs.

Retail Energy Supply Association (RESA):
RESA states the Commission must correct the existing utility rate mechanisms, especially the commodity cost component, which do not reflect current market costs and are not transparent.

The Alliance for Solar Choice (TASC):
TASC strongly agree with Staff's views on the shortcomings of cost-of-service ratemaking, and that the multi-sided platform market is a key factor in moving away from this obsolete model. Conventional ratemaking methods should be reformed to "encourage utilities to supplant capital spending with cost effective operating cost or third-party spending…such that utility earnings are based on performance and achievement of outcomes rather than almost entirely on capital spending." The Commission must consider any tax implications resulting from the use of MBEs and other performance-based approaches that could have direct, pass-through impacts on ratepayers.

SECTION II.B LIMITATIONS OF CONVENTIONAL COST-OF-SERVICE RATEMAKING: The Limits of Conventional Cost of Service Ratemaking in the context of REV

AARP of New York (AARP):
AARP indicates that the rates paid by customers for distribution services should reflect the costs of providing such services. Thus, the pricing of delivery service should continue to be based on the utilities' costs and not artificially manipulated to signal customer investment in certain technologies. AARP believes that solar customers and other DER customers should be required to pay their fair share of distribution costs that are incurred on behalf of all customers as it is unfair to shift these lost revenues to other customers who are unable to participate. AARP suggests that cost effective energy efficiency programs and demand response programs can be implemented by utilities without the creation of radical new "markets" or dramatic changes to current regulatory policies, including "pre-approval".

Acadia Center (Acadia):
Acadia disagrees with the Joint Utilities proposed rate making reform to design demand rates using non-coincident peak demand as the customer's billing determinant, asserting that demand charges that are not aligned with system peaks do not provide necessary price signals.

Advanced Energy Economy Institute (AEEI):
AEEI states that using another type of recovery method is likely to result in the financial markets perceiving increased risk in the investments, which will increase the costs of deployment. To the extent platform service revenues materialize, AEEI argues that those revenues can be used to offset the costs of the initial investments. However, AEEI does support modifications to the cost-of-service model, namely the modified clawback mechanism and the use of Earnings Impacts Mechanisms, as a means of incenting desired outcomes and desired utility behavior in creating a vibrant DER market. AEEI notes that without these modifications, cost-of-service ratemaking is unlikely to yield the desired results.

BlueRock Energy (BlueRock):
BlueRock advocates for price signals that reflects cost causation (i.e., basic time-of-use price including potentially environmental adders) and gradual bill impacts. Private sector suppliers (ESCOs and DER Providers) should receive a more granular price signal sooner so they can bundle their rates and services in packages that can both better cater to their customers' needs and more quickly capture technology innovation while implementing DER. ESCOs and DER providers should at least have rate options comparable to what utilities can offer—such is not the case today in the mass markets. When there is a material difference between the revenue recovery of embedded costs and short-run marginal costs, the difference in revenue recovery should be done so as not to distort the marginal cost price signal. Environmental adders and the use of long-run marginal capacity costs are an appropriate way to bridge the gap to the revenue requirement.

Citizens for Local Power (CLP):
CLP is concerned that utilities will be allowed to provide competitive value-added services without adequate consideration of market power issues or whether or not these value-added services could/should also be provided by the competitive market. CLP finds it hard to imagine any service that the utility could provide that does not involve some kind of monopoly advantage.

Clean Energy Organizations Collaborative (CEOC):
CEOC argues that utilities should not be able to earn MBEs for competitive services, and should only be able to earn MBEs for some Platform Service Revenues, including all essential platform services but only a limited number of value-added platform services. If the utility is allowed to engage in competitive services, CEOC contends that there should be minimum requirements to ensure fair competition and separation of the DSP provider from the arm of the utility that would provide competitive services. In response to the comments of the Joint Utilities, CEOC concurs that there is significant uncertainty about MBEs but maintains that this uncertainty can be taken into account during rate cases without making MBEs fully supplementary to the cost of service. CEOC suggests that very

conservative estimates of potential MBEs should be used for determining total revenue requirements. Once actual MBEs are known, utilities could refund ratepayers for excess earnings, or increase revenue requirements to cover any shortfall, in the next rate plan period. Projections of MBEs and their relationship to total utility revenue should be developed through fully-litigated rate case proceedings.

Environmental Defense Fund (EDF):
EDF notes that the experience of two decades of telecommunications deregulation and industry transformation in the United States and Europe has highlighted the many ways in which a platform provider can skew the ability of particular third parties to participate on the platform. The Federal Communications Commission's recent hearings on net neutrality and testimony provided by a range of academic experts may offer an important source of caution about the kinds of protections needed.

Exelon Companies (Exelon):
Exelon notes that the long-term financial health of utilities remains central to the REV evolution. Consequently, cost-of-service ratemaking will likely continue in the future, and enhancements related to REV should not substitute for or impede a utility's ability to recover costs.

Federal Trade Commission (FTC):
The FTC agrees with Staff's discussion about why the cost-of-service approach cannot work well in the context of the REV proceeding. The FTC also agrees with the Staff White Paper's conclusion regarding the DSP operator: "It is critical . . . to eliminate, as much as possible, any structural financial incentive embedded in regulation for a [distribution] utility to favor its own capital spending over third-party activity that meets system needs at lower cost to ratepayers." In general, the FTC commends the White Paper for aligning distribution utility incentives with customer benefits by squarely addressing utilities' incentives to undermine the competition posed by unaffiliated DERs.

Joint Utilities:
The Joint Utilities comment that the proposed REV regulatory model is intended to optimize a portfolio of utility and third-party investments and to encourage innovation throughout the electricity value chain. It is appropriate to adjust the regulatory and ratemaking model to accommodate REV but the goal should be to complement the cost-of-service ratemaking model. There are several ways to complement the existing ratemaking model to accommodate REV, including pre-approval of REV investments, crediting of an appropriate amount of MBEs to utility customers, and providing a meaningful opportunity for utilities to be rewarded through incentives for performance that promotes important REV outcomes. Cost-of-service regulation will continue to be necessary for all investments and expenditures made by the utilities to satisfy their public service obligations and comply with Commission orders including investments and expenditures related to REV. These investments and their cost-of service based recovery should be reflected in current and future rate cases and utility DSIP filings. This is necessary to ensure the continued financial health of the State’s utilities and their ability to attract capital necessary to finance REV and replace aging infrastructure on reasonable terms. The Joint Utilities contend that the parties opposed to cost-of-service ratemaking have not demonstrate how an alternative model will result in the necessary infrastructure to support safe and reliable service at a reasonable cost to customers, and state that the Commission should not rely on MBEs to replace ratepayer funds until it can be shown that MBEs are a stable funding source.

National Fuel Gas Distribution Corporation (NFG):
NFG comments that it is imperative that the process for MBE service charge establishment, refinement and approval be sufficiently rapid and nimble so as to avoid the regulatory process itself becoming a deterrent to market growth and innovation. For stakeholder transparency purposes, utilities could complete a simple standardized form and file it on DMM for a new MBE to take effect. When the form is filed, all parties will receive an instant notification. Within a prescribed time period after the form is filed, parties would have the opportunity to file comments in the case or matter number, to

the extent that they support or object to a MBE. The Commission and Staff will be able to ensure that MBE service charges are comparable and fair throughout New York State by: (1) serving in a monitoring and oversight role, and (2) addressing/responding to comments filed in opposition of proposed MBEs.

National Electrical Manufacturers Association (NEMA):
NEMA notes that specific foundational technologies are needed to facilitate dynamic rates. AMI or its equivalent functionality will play an essential role in enabling dynamic rates and charges, especially time-of-use rates and demand charges. Energy- and cost-saving such as volt/var (volt-ampere reactive) control, volt/var optimization, and conservation voltage reduction should be a prominent part of the NY REV Track Two process to improve grid efficiency and to reduce peak demand.

Northeast Clean Heat and Power Initiative (NECHPI):
NECHPI contends that the Commission should strive to adopt a market-oriented approach as soon as possible that places CHP systems on an equal footing with other distributed-generation technologies. The most crucial aspect of creating a level playing field is defining the tradable grid services (including energy, capacity and ancillary services such as frequency control, voltage stability and upward and downward ramping services) in a way that will enable all resources to compete to provide them. Once a given resource has proven its ability to provide one or more of these services, it should be permitted to provide those services through a distributed-platform marketplace. By refining the definitions of tradable services to expose the value of all services needed by the system, the market can approach true competitive pricing and drive down overall costs of electricity distribution.

Parento Energy, LTD (Parento):
Parento comments that the use of power electronics to enable DG to provide instantaneous VAR and frequency control has been under appreciated in terms of the technology choices for the interconnection of large scale distributed generation. Expanded deployment of a non-synchronous power electronics platform available from multiple suppliers would provide a least-cost resource for the IPEC Plan and BQDM Program and immediately

offer an opportunity to demonstrate a market-based solution without Con Edison ratepayer funding.

Public Utility Law Project of New York, Inc. (PULP):
PULP believes that the Commission should identify the costs and potential bill impacts associated with its ratemaking, rate design, efficiency, and DER program investments and mandates prior to further orders in this proceeding. The regulated distribution or delivery services provided by New York electric utilities should be based on utilities' costs for that service and not artificially manipulated by signaling a regulator's estimate of value to promote customer investments in certain technologies. It would be risky in the extreme to allow utilities to receive cost recovery and additional earnings incentives for a regulatory vision that has yet to be documented as providing value that would exceed well managed and supervised utility programs and services.

Solar Energy Industries Association (SEIA):
SEIA is concerned that focusing on MBEs in this early stage of REV risks the development of a platform designed to help utilities achieve MBEs, rather than a neutral platform designed to enable the DER market. This result would stymie the development of a robust DER market and undermine market confidence. Therefore, SEIA encourages the Commission to focus on developing a neutral platform based on cost-of-service principles, supported with cost-based Platform Service Revenues and with any additional incentives to be provided through Earnings Impact Mechanisms. SEIA is also concerned with the focus on new earnings mechanisms for utilities based on competitive market functions that “complement” cost-of-service ratemaking. As the DSPP, the utility will be providing a monopoly service and therefore should be compensated according to cost-of-service principles. Third parties should provide competitive market products, services and functions.

Alliance for Solar Choice (TASC)
TASC comments that there is no evidence supporting a conclusion that there is any difference in cost of service between net metered customers and other customers in the same class.

SECTION III.A-B ALIGNING CUSTOMER VALUE WITH EARNINGS OPPORTUNITIES: Summary/Market Based Earnings in a Fully Developed Market

Advanced Energy Economy Institute (AEEI):
AEEI is concerned that regulated utilities will be given the opportunity to offer competitive services that would put them at an unfair advantage, owing to their monopoly status. Accordingly, AEEI argues that unregulated affiliates should be allowed limited participation in markets, that utility MBEs should be limited to Platform Service Revenues, and that MBEs be otherwise focused on facilitating and enabling the DER market rather than competing with DER providers. MBEs should not make up a significant portion of utility revenues until the Commission and market participants are confident that the model is working correctly. AEEI states that the utilities should focus on developing platform services that support the integration and growth of DER. Energy efficiency services provided to customers are basic services and not competitive, value-added services. AEEI disagrees with the position taken by some parties that EIMs could largely be replaced by MBEs. Even when DER markets reach sufficient scale to provide meaningful MBEs, it will be nearly impossible to design opportunities for MBEs in such a way that they drive utilities to achieve public policy goals to the same extent as the more direct & explicit approach of using EIMs.

BlueRock Energy, Inc. (BlueRock):
BlueRock recommends rewarding utilities with properly structured EIMs. Such metrics can provide utilities with the incentive to make efficient use of its grid rate base, regardless of the provider. With the proper structural set up, the utility will be indifferent as to whether it achieves an improvement in meeting customer peak demand needs through private investment or increasing its rate base. In contrast, MBEs will encourage utilities to be involved in otherwise competitive markets. MBEs only are achieved when the utility provides (or contracts others to provide on its behalf) the services that could be provided more efficiently in the marketplace by DER providers and ESCOs. Utilities will compete with the private sector and slow the pace

of private capital investment and innovation. Should the Commission decide to allow utilities to provide MBE-type services, then it is strenuously recommended that an element be added to level the playing field to allow ESCO's to likewise support such services. For example, if utilities are able to provide on-bill financing of energy services, then the POR scope should be expanded to include ESCO on-bill financing of energy services.

ChargePoint, Inc. (ChargePoint):
ChargePoint states that it is very important to differentiate between utility services that support and enable competitive markets from those that are (or could be) provided by competitive markets. As a critical first step, ChargePoint recommends that the Staff investigate and discuss which platform services relate to and fit well within the utilities’ core functions and capabilities, and how such services may be used to support the expansion and integration of DER products and services provided through competitive markets. MBE opportunities for utilities should be limited to such platform services, and not to services provided by competitive markets. With respect to EV charging services and network capabilities, the utilities should be authorized to provide supporting services that are within the monopoly utility business function, and the utilities should be encouraged to support third-party services, including network charging, grid integration and demand response. In order to appropriately reward utilities for supporting EV expansion the Commission needs to perform a cost benefit analysis of utility investment in utility-side infrastructure enabling deployment of customer-side EV “smart” charging equipment and services.

City of New York (NYC):
NYC states that relying on MBEs as a key recommendation before fully understanding them could result in harming consumers. The Commission needs to consider the costs, benefits, and burdens on customers and other market participants before deciding on any course of action. NYC expresses concern that consumers will continue to bear the utilities’ full revenue requirements, and they now will be required to bear the added costs of the DER providers.

Citizens for Local Power (CLP):
CLP finds it hard to imagine any service that the utility could provide that does not involve some kind of monopoly advantage. The utilities' hold on the basic data essential for value-added services gives them an anti-competitive advantage, as does their role as DSP. CPL also notes that the competitive marketplace for energy products and services is not a panacea; instead, it is critical to have a robust regime of consumer protections in place before the DSP marketplace is operational.

Clean Energy Organizations Collaborative (CEOC):
CEOC argues that MBEs should not supplant EIMs until they are well established and predictable. The Commission should establish appropriate metrics for determining whether market power exists and clarify what entity will be responsible for monitoring the markets, and what that entity's responsibilities will be. CEOC concurs with AEEI, that "MBEs should not make up a significant portion of utility revenues until the Commission and market participants are confident that the model is working correctly." Uncertainty about MBEs can be taken into account during rate cases without making MBEs fully supplementary to the cost of service. CEOC suggests that very conservative estimates of potential MBEs should be used for determining total revenue requirements. Once actual MBEs are known, utilities could refund ratepayers for excess earnings, or increase revenue requirements to cover any shortfall, in the next rate plan period.

Comverge, Inc. and EnergyHub (Comverge/EnergyHub):
Converge/EnergyHub urges caution on two aspects of Staff's MBE proposal. First, because the utility, in its role as DSP, will be providing a monopoly service to customers and DER providers, access fees to this platform ought to be subject to the same cost-of-service regulation safeguards as those fees associated with basic electric service. Second, Comverge/EnergyHub has concerns that if utilities are expected to generate revenues by providing data analysis, this could limit their incentive to make raw data available to customers and third parties to perform their own analyses. If data analysis is to be included as a possible source of MBEs, clear rules must be implemented to

ensure that third parties can still access raw data at reasonable cost.

Environmental Defense Fund (EDF):
EDF states that the success of MBEs will depend in part on the extent of innovation by third parties who develop new services which they offer, transact, or execute by means of the platform. How that innovation is incentivized, who shares the revenue from innovation, and how the platform remains flexible to evolve over time are important questions that must be studied. Although the future of platform revenues in the electric utility context is uncertain, MBEs offer the possibility of decreasing the burden on captive ratepayers as the source of utility profits, and their existence may be a good indicator that the utilities are succeeding in growing a valuable platform capable of facilitating the public policy goals that lie at the heart of this proceeding. As such, Staff's recommendation to the utilities that they should develop them is well-placed.

Energy Technology Savings LLC (ETS):
ETS comments that the utility should enable market-based and value-added services, but should not directly compete and sell these services. There would be an unfair advantage for the utility selling these services since they have immediate, free access to customer information and in many cases, to the customer directly through the bill. Utilities should be compensated for enabling access to these types of services. MBEs and PSRs seem to be a reasonable way to provide further incentives for the utilities to develop these services and to allow utilities to make money under the new structure. However, as described, it seems as though most of the revenues received by the utilities will come from DER providers and ESCOs. If this is the case, the cost to develop and sell DER to customers will become too high and providers may not seek to provide these services. As DER is introduced into the system, there will be a decreased need for infrastructure investment, which provides benefits for all energy users in the form of lower rates and possible decreased emissions. Since all ratepayers will benefit from increased DER penetration, the costs should not solely be placed upon the suppliers and users of DER, but rather some of the costs should be spread throughout the rate base as well.

ETS supports modifications to the rate structure that will incentivize utility investment in order to enable DER resources to more easily be implemented.

Exelon Companies, including Exelon Corp. and subsidiaries (Exelon):

Exelon believes MBEs, used appropriately where value is added, are an important part of the future utility business model. However, MBEs should be integrated over time with the benefit of experience obtained in pilot programs that demonstrate the MBE programs are proven and reliable. In the near term, MBE should not be imputed as a part of the revenue requirement, as the Commission cannot rely on unproven MBE opportunities to fund essential grid functions. Exelon agrees with Staff that, where appropriate, utilities should be provided opportunities to enhance revenue from 1) performance incentives or 2) the provision of adjacent services, where the utility may be uniquely well-positioned to provide the means for such. Those performance incentives should be bilateral and symmetrical whenever possible. Formula rates (in reality, a form of performance incentive) are also worthy of consideration. Formula rates have been proven to provide a higher degree of financial certainty, regulatory streamlining, and, if designed correctly, customer protection.

Federal Trade Commission (FTC):

The FTC states that a key concept in the discussion of MBE’s is that the DSP operator offers a variety of services to grid users, which include DER investors, owners, and organizers that are unaffiliated with the distribution utility. The White Paper does not appear to address the potential for DSP operators to discriminate against independent providers of services to DER projects. It is unclear whether rules or competitive pressures would compel the DSP operator to compete on an even playing field with the microgrid engineering services offered by independent competitors. The DSP operator’s incentives and range of discretion in accommodating and authorizing microgrid connections to the larger grid could generate credible claims of bias. The FTC urges the Commission to assess whether the MBEs could simply incentivize and enable a DSP operator to discriminate against the unaffiliated firms that provide services to DER projects, even if the distribution utility no longer had incentives to discriminate against the independent DER projects themselves. More generally, the Commission should evaluate whether it is critical to eliminate, as much as possible, any structural financial incentive embedded in regulation for a distribution utility to favor its affiliated DER service providers over unaffiliated, competing DER service providers. EIMs may facilitate effective competition to the extent they seek to counter residual incentives to discriminate against unaffiliated DERs. The use of Scorecards for the same purpose could potentially alert regulators to persistent performance deficiencies that could indicate lingering incentives to discriminate against unaffiliated DER investors, owners, or organizers.

IGS Generation, IGS Solar and IGS Energy (IGS):
IGS recommends that the Commission clarify the nomenclature of MBE, PSR, and EIM, to clearly delineate who pays, who sets the price, and where the dollars flow. PSRs should be always set by the Commission and used to offset the revenue requirement otherwise borne by ratepayers. IGS also recommends that the Commission focus on developing a neutral DSP that enables a robust, transparent competitive market. In order to do this, the Commission should postpone Staff's recommendation that utilities develop competitively set MBE opportunities and instead focus on developing PSRs, with fees set via the regulatory process and revenues generated offsetting revenue requirements otherwise borne by ratepayers. IGS is concerned by the focus in the White Paper on allowing the DSP to leverage monopoly assets to earn revenues through competitive functions and thereby distorting competitive markets. The monopoly utility should not participate in the competitive markets through any other means than a fully separated deregulated entity. After the utility is well on the way to enabling a vibrant marketplace, the Commission should open a separate proceeding to discuss how, if, when, and what safeguards would be required to ensure that the utility does not use its rate based assets for competitive functions. The Commission should focus the initial implementation of REV on developing PSRs, with fees approved by the Commission through a proceeding that allows for due process. Moreover, PSR revenue should offset the revenue

requirement of the DSP (including a reasonable rate of return to the utility for DSP infrastructure), which will reduce the distribution rates that will otherwise be paid by ratepayers. IGS supports promoting REV goals through nondiscriminatory access to the utility bill for non-commodity products until such time as the supplier consolidated billing proceeding is resolved.

Joint Utilities:

The Joint Utilities agree that MBEs could complement the existing ratemaking model and that an appropriate amount of MBEs should be credited to utility customers. However, MBEs are inherently uncertain and cannot be reasonably estimated in advance of the results from demonstration projects and actual experience. Thus, the Joint Utilities take the position that the Commission should continue cost-of-service ratemaking and reject an approach that replaces any portion of the cost-of-service by a projected amount of MBEs. Any REV-related changes should complement cost-of-service ratemaking and not impede the utilities' ability to recover expenditures necessary to support investments and expenditures related to REV. Those parties opposed to cost-of-service ratemaking do not demonstrate how an alternative model will result in the necessary infrastructure to support safe and reliable service at reasonable cost to customers.

While it is unclear which of the MBE services listed in the Staff White Paper will become competitive, it is premature and inconsistent with the public interest to preclude the DSP from offering such services in a nascent market.

Microgrid Resources Coalition (MRC):

MRC generally supports the ability of unregulated (or differently regulated) utility affiliates or subsidiaries of utility holding companies to participate in the market so long as Commission rules are used to prevent differential access to information and tied sales. However, MRC is concerned that some activities in Staff's whitepaper have the potential to create significant hindrances to the goals of REV if undertaken by the utility directly. MRC agrees that if preexisting, ratepayer-funded infrastructure can provide additional services without material additional costs, that some or all of the revenue should benefit the ratepayers. Just because such ratemaking compromises can be made, however, doesn't support a conclusion that they are a wise expedient to adopt more widely. There is a strong risk that utilities will use ratepayer subsidized investment to compete with unregulated businesses to the detriment of competitive markets.

Mission:data:

Mission:data is concerned that MBE's, which may include "data analysis," could conflict with REV objectives addressing "market animation." To date, the services proposed by utilities (such as enhanced data analytics described in the demonstration projects) overlap with product and service offerings provided by non-utility market participants. While Mission: data recognizes that utility-led data analysis solutions may help catalyze the market as a whole, these offerings should not inhibit non-utility data analytic providers from effectively competing in the market. To avoid such a scenario, the Commission should clearly define the "basic" usage data available to consumers and service providers that will be provided by the DSP and ensure that policies and mechanisms are in place to ensure that any utility offerings do not preclude open and fair access to data by consumers and, with proper customer consent, third parties.

Multiple Intervenors (MI):

MI states that MBEs are potentially valuable if managed in a manner beneficial to customers and they result in a corresponding reduction in utility rates. However, MBEs must not result from utilities using their monopoly position to gain an unfair advantage and/or inappropriately exercise pricing power in markets that should be competitive. The Commission should not implement sweeping changes to existing ratemaking practices in contemplation of competitive markets and services that may not exist for many years, if at all. MI comments that MBEs should be limited to new products and services that currently are not paid for through existing rates and should reflect an equitable sharing of revenues between customers and shareholders. The Commission should regulate, actively, the prices that utilities charge for DSP products and services.

National Electrical Manufacturers Association (NEMA):
NEMA asserts that MBEs risk interfering with competition and fees need very careful treatment to avoid suppressing the market. NEMA comments that the platform needs definition and opines that rate reforms won't change utilities' behavior. Most of the possible market-based services that the utilities may offer should be rendered by competitive entities.

National Fuel Gas Distribution Corporation (NFG):
NFG states that MBEs are novel and innovative but need further definition. No differentiation needs to be made between monopoly functions and competitive services. The process for MBE service charge establishment, refinement and approval should be rapid to avoid the regulatory process itself becoming a deterrent to market growth and innovation.

New York Battery and Energy Storage Technology Consortium (NY-BEST):
NY-BEST comments that a level playing field must be ensured. A more clear description of the ownership structure surrounding the DSP is essential to fully evaluate the revenue models being proposed. NY-BEST asserts that platform fees must be competitively neutral and not unduly advantage the utility where competitive services are also available. MBEs should be based primarily on platform service revenues so that the focus is on facilitating and developing the market.

New York Energy Consumers Council (NYECC):
NYECC states that it is necessary to know the scope and sources of MBEs before deciding on rate allocation. Even if MBEs allow earning enhancement without adding to rate base, there should still be reasonable limits on earnings.

Northeast Clean Heat and Power Initiative (NECHPI):
NECHPI believes that the MBE proposals are not sufficiently specified to provide meaningful measures as a step in the implementation of REV market-based objectives. NECHPI does not see the path to the implementation of platform-based markets over time. It is unclear when the DSPs will be set up and running, when services will be well-defined and integrated into utility operations, and how net locational values will be

established. Almost all of the discussion is based on theory, not actual experience. While the demonstration projects will help to a certain extent, most of the demonstration projects are not well-integrated into REV constructs. For this reason, NECHPI believes it is crucial to align REV proceedings with general rate cases.

NRG Energy, Inc. (NRG):
NRG believes that the Commission should place a blanket prohibition on utilities seeking MBEs but states that unregulated affiliates, with appropriate separation, could compete for MBEs. NRG states that if a product or service *can be* provided through competitive means, it *should be* provided by competitive means, using capital that is not part of the utility's rate base.

Retail Energy Supply Association (RESA):
RESA states that the White Paper is vague on the specifics of MBEs and on the standards that would be used to prevent competitive abuses. Standards and guidelines governing the use of MBEs by utilities should be developed. RESA argues that the use of MBEs should be limited to those circumstances where the utility offers to provide a unique or substantive product or service that has real value in the competitive market.

Solar Energy Industries Association (SEIA):
SEIA states that controversy over MBEs and competition will distract from more immediate concerns. Focusing on MBEs in this early stage risks the development of a platform designed to help utilities achieve MBEs, rather than a neutral platform designed to enable the DER market. SEIA encourages the Commission to focus on developing a neutral platform based on cost-of-service principles, supported with cost-based Platform Service Revenues, with additional incentives to be provided through EIMs rather than revenues earned from competitive market functions.

The Alliance for Solar Choice (TASC):
TASC agrees that traditional earning opportunities for utilities are counterproductive to the REV objectives, and should be modified to incentivize behavior that reduces costs, provides customers with greater control over bills, and integrates higher

levels of DER. It is important, however, for the Commission to avoid blurring the line between regulated and unregulated services. Utilities should not simultaneously be positioned as "open access" (DSP role), and "competitive" (value-added) service providers. There is a significant risk of anticompetitive behavior where the entities that are supposed to be offering open-access, platform-based services are also either directly bidding against other services providers or receiving bids from their affiliates. TASC does not suggest that utilities should never be allowed to compete in any competitive markets, or that there may not be transition periods when utilities can offer services for the purpose of jumpstarting competitive markets. It is very important, however that the Commission draw boundaries at this stage of the REV process. TASC believes the Commission should move quickly to develop market rules that will govern DSPs' interactions with DER providers. While EIMs are being contemplated for use prior to the development of full DSP service, TASC is unconvinced that they will provide sufficient incentive for utilities to quickly start leveling the playing field for DER providers, absent other rules or regulations.

SECTION III.C.1 ALIGNING CUSTOMER VALUE WITH EARNINGS OPPORTUNITIES: Modifications to the Utility/DSP Revenue Model; *Capital Expenditures and Operating Expenses*

Acadia Center (Acadia):

Acadia Center emphasizes that a holistic evaluation is essential as part of an investigation that should take place on this issue. In particular, peak demand reduction should be valued with any other co-benefits it may deliver. Also, peak demand reductions that also generate energy savings through energy efficiency should be measured in terms of their total costs and benefits. Energy efficiency and other distributed energy resources that reduce peak demand thus have a potential to play a crucial role in deferring infrastructure upgrades. Further investigation on the impact of load reduction on equipment aging is warranted.

Advanced Energy Economy Institute (AEEI):
AEEI points out that TOTEX has the benefit of setting OPEX and CAPEX equal to each other, allowing the utility to make the most efficient use of all expenditures without the need to compare and substitute different types of expenditures for each other and without the administrative burden to both the utilities and Staff. Utilities should not have a disincentive to use operating resources, or third-party assets in lieu of capital investments where and when they are more effective and efficient. Utilities should be incentivized to deploy/use/encourage third-party DER when it provides system value. AEEI is concerned that clawback mechanism may not go far enough to incentivize the utilities to propose a budget that pursues the most cost effective solutions. Capital plans should be cost effective with clear demonstrable benefits to ratepayers. The depreciation adjustment needs to be calculated so that it is not a disincentive to DER approaches and is consistent with the market-based DER alternative. Staff should develop more detailed analysis and examples that would lay out in greater detail, the cash flows and NPV comparisons of different options. This would enable parties to better understand if the modified clawback mechanism goes too far, not far enough, or is about right. One area in need of clarification by the Commission is the way in which utility OPEX that is subject to the modified clawback is treated after the "reset" of the capital budget at the next rate case.

Citizens Environmental Coalition (CEC):
CEC states that clawback mechanisms should be modified to encourage cost-effective use of operating resources or third-party investment. Disincentives should be removed for renewables and efficiency as preferred alternatives, not for all DER.

City of New York (NYC):
NYC does not agree that there is a bias towards capital investments and disagrees that clawback mechanisms should be abandoned. No adjustments should be made until after due analysis has been performed and vetted, and the likely consequences of the adjustments are known and understood. If a utility can more cost-effectively service its customers via a

third-party solution than its own infrastructure project, the utility should not be penalized for choosing that approach through a reduction in its earnings. The utility should have an opportunity to share in the benefits created by selecting the lowest, or lower, cost approach.

Clean Energy Organizations Collaborative (CEOC):
CEOC does not generally support allowing utilities to earn an incentive rate of return while amortizing all capital and operating costs associated with procuring DER, as incentive rates of return may encourage higher project costs. It supports a modified clawback mechanism that would enable utilities to retain a portion of any savings achieved through investments in DER or through opex rather than through traditional capex. CEOC proposes that a utility be allowed to retain only 20% of the savings. Under any clawback mechanism, there is a risk that capital expenditure budgets will be inflated in order to achieve artificial "savings." Utilities will be required to identify opportunities for DER through their specific DSIP. In order to be effective, a review process must be in place for DSIPs. CEOC agrees with the many parties who noted in their comments that providing utilities with incentives to make cost-effective alternative investments is an important element of the effort to reduce system costs and ensure that customers benefit from REV. Also, determining the correct incentive level will be difficult, particularly since multiple incentives will be combined, so further analysis is warranted prior to modifying the clawback mechanism.

GridWise Alliance (GWA):
GWA supports the statement "structural reforms presented by REV create a need to change the relationship between capital and operating expenses." GWA wishes to underscore the need to adjust the clawback mechanism to better reflect risks to utilities and risks to customers.

Joint Utilities:
The Joint Utilities state that the vast majority of planned utility projects over the next decade are necessary to: replace aging infrastructure; automate the current distribution system; react to new regulatory mandates; and make other foundational

and REV-enabling projects. The Joint Utilities agree with the proposal that utilities should retain some of the savings associated with deferral or avoidance of capital projects. They support modifications of the net plant reconciliation mechanism and believe that utilities should be indifferent to whether the utility or a third party funds a DER-based solution. The Commission should allow the utilities to share the net benefits beyond the primary term of the rate plan. This will encourage the utility to support integration of cost-effective DER into capital decision-making processes and drive long-term value for customers.

Mission:data:

Mission:data opines that clawback mechanisms should be modified to encourage cost-effective use of operating resources or third-party investment.

Multiple Intervenors (MI):

MI generally agrees with Staff's position. The focus should be on reducing costs to customers in a manner that does not harm – and potentially benefits – utilities. For the foreseeable future, REV-related investments and expenses should constitute a small minority of total utility investments and expenses. Rather than change the manner in which all utility capital expenditures and operating expenses are treated in the ratemaking process, changes to the status quo should be limited – at least for now – to those capital expenditures and operating expenses that would be impacted by potential REV-related utility investments.

National Electrical Manufacturers Association (NEMA):

NEMA contends that achieving a level of advanced metering infrastructure or its equivalent functionality will be integral to realizing the Commission's grid modernization objectives. Also, regarding reliability goals, focusing on distribution automation technologies that reduce line losses by quickly locating and isolating faults can reduce outage duration and frequency as measured by CAIDI and SAIFI.

National Fuel Gas Distribution Corporation (NFG):
NFG asserts that a "totex approach" should not be pursued by the Commission due to differences in accounting standards between the US and the UK, where utilities do not serve as the DSP. NFG's reductions in operating expenses over time have been the purposeful result of operational efficiencies, innovation, zero-based budgeting processes, and the utility being a responsible steward of ratepayer funding. There is no need for any additional upside protections against capital spending in excess of forecasts. Excess spending above forecasts has always been subject to review in utility rate cases and adequate protections against imprudent investments already exist. Downward only capital expenditure mechanisms should be eliminated, as they eliminate incentives for the achievement of efficiencies.

Nucor Steel Auburn, Inc. (Nucor):
Nucor states that Staff's recommendations are confusing and inconsistent. The paper discusses an inherent utility bias toward making its own capital investment (adding to rate base) while noting at the same time a short run incentive to reduce or defer capital investments between rate cases. It is the latter concern (chronic capital under-spending relative to approved capital budgets under multi-year rate plans) that has given rise to "clawback" mechanisms. Staff correctly notes that most current utility capital spending concerns maintenance or replacement of existing facilities for which there may be limited opportunities for those investments to be displaced by DER. The carrying charge adjustment approach suggested in the paper is problematic and would needlessly burden rates.

Real Estate Board of New York (REBNY):
REBNY comments that the totex approach, when coupled to Market-Based Earnings, will more closely tie the utility's profit motive to creation of customer value. The Commission should require utilities to share their distribution system capital planning assumptions and schedule, down to the project level in an effort to create transparency.

Solar Energy Industries Association (SEIA):
SEIA agrees with Staff's recommendation for a modified clawback mechanism to remove barriers to utilities choosing third-party

investment paid for with utility opex rather than traditional utility investment that increases rate base. However, this may be insufficient to make the utility indifferent between capital investment and products/services procured from third parties. SEIA encourages the Commission to explore more fully alternative cost-recovery mechanisms (such as the RIIO "totex" approach) that are designed to eliminate structural incentives for utility rate base investment.

The Alliance for Solar Choice (TASC):
TASC comments that clawback reform should be accompanied by forms of PBR that provide explicit and enduring shareholder incentives to reduce peak demand and facilitate clean DER market expansion. The modified clawback mechanism encourages the traditional focus on large capital expenditures as a starting point. The totex approach would result in an ongoing focus on both large and small, and both capex and opex savings as a matter of culture. The clawback mechanism would limit DER investment to replace utility capex and the associated savings. TASC agrees that "Clawback" mechanisms should be modified to encourage cost effective use of operating resources or third party investment. This reform is not likely to significantly reduce utility bias toward "growing rate base though capital expenditures."

SECTION III.C.2.a ALIGNING CUSTOMER VALUE WITH EARNINGS OPPORTUNITIES: Modifications to the Utility/DSP Revenue Model; *Public Policy Achievement, Low-Income Participation*

AARP New York (AARP):
AARP believes that any low-income program should be based upon a comprehensive analysis of the impact on the total bill of a customer, and if it is financed through utility rates, it should only be recovered through a usage based rate component attributable to all customer classes. Any such rate should be evaluated with regard to how it impacts non-participants and the extent of the ultimate rate subsidy. New York's electric rates are already too high. AARP shares many of the concerns expressed by the Joint Utilities with regard to continuing the current net metering policies in New York. Current DER pricing

methodologies creates concerns regarding equity between customers that employ DER and those who do not. It is essential that the Commission protect non-participating customers. AARP believes that solar customers and other DER customers should be required to pay their fair share of distribution costs that are incurred on behalf of all customers. It is unfair to shift these lost revenues to other customers who are unable to participate in solar or DER programs. Furthermore, rate design changes that affect all customers should not be implemented simply to address concerns about DER participation. Rather, the net metering policy should be revised to ensure that all DER customers pay their fair share of distribution services and investments.

Acadia Center (Acadia):

Acadia notes that low-income customers are especially vulnerable when market forces are relied upon to drive energy efficiency investments in low-income neighborhoods. Acadia also points out that the White Paper only explicitly addresses low-income customers who live in master-metered, multi-family buildings as in need of further energy efficiency program assistance. Acadia urges the Commission to develop specific proposals that benefit all low-income customers.

Advanced Energy Economy (AEEI):

AEEI states that the Commission's obligation to make sure that every population is provided access to high quality electric service should extend to new service offerings, not just basic commodity service. A pure market is less likely to serve low-income households because of the perceived lower profits from serving these customers. Low-income families are more likely to live in master-metered buildings, a situation that precludes providing personalized insights to specific customers. To meet these challenges, the Commission needs to actively monitor the provision of energy services across New York State to make sure that no populations are underserved. In addition to low-income households, the Commission should also evaluate services across age groups and ethnic/racial backgrounds. The Track 2 White Paper correctly points out that providing low-income solutions is one area where utility ownership of DER may be appropriate. The Commission should strive to strike a balance by making sure that utilities fill the gap to provide services to low-income customers without overreaching and undercutting the market for companies that focus on the LMI segment and are willing to serve many of these customers. The Commission should also support the expansion of residential sub-metering. Because this will likely lead to families being exposed to energy bills for the first time, such an expansion of metering needs to be paired with a dedicated marketing, education, and outreach budget to smooth the transition. The advanced energy community sees a role for utilities in serving LMI customers, but their participation should not be set up in such a way that precludes third parties and the competitive market from also serving these customers. Ratepayer funds will go further in serving the LMI segment when they leverage rather than supplant private investment. New York has shown ingenuity in developing ways, such as the Green Bank, to leverage private dollars to fulfill public goals. Staff should explore other methods for leveraging ratepayer and private funds such as default insurance subsidies, formation of customer pools that spread and diversify risk, and exploration of other mechanisms to mitigate financial risk and cost of service.

Association for Energy Affordability (AEA):
AEA indicates that well-designed scorecard metrics would provide much needed information on the extent to which utilities are achieving public policy objectives for low-to-moderate income families and encouraging DER investment in environmental justice communities.

BlueRock Energy Inc. (BlueRock):
Until smart meters are more widely available to the mass market (residential and small commercial customers), BlueRock believes an approach proffered by the National Energy Marketers Association, "Demand Response Load Profiles" provides a transitional mechanism so that ESCOs and other third parties are better able to bring cost savings to consumers. It is important that such options be offered to low-income customers as soon as possible because the data shows that low-income customers both respond well to Demand Response and also have better than average load profiles and thus are currently being charged more than their fair share of capacity costs under current rates.

Citizens Environmental Coalition (CEC):
CEC believes that in the near term REV must be aligned with fundamental reform for low-income affordability as well as critically important environmental goals. The majority of the public, not just environmentalists support these goals in multiple opinion surveys. CEC agrees with Staff that there is tremendous opportunity for efficiency represented by the low-income multi-family sector and that the projects discussed are worthwhile. However, it is still absolutely essential that major reform be instituted in relation to the lack of energy affordability for 25% of the New York's population.

Citizens for Local Power (CLP):
CLP welcomes the attention that the White Paper gives to the particular importance of improving low- and moderate-income participation. With regard to low-income participation in distributed renewable projects, CLP notes the superior benefits of local/and community ownership in job creation and economic development over utility ownership. Utilities need not own community distributed renewable projects in order to support low-income participation in them. CLP suggests that utilities that have community development funds could dedicate a portion of those funds to subsidizing low-income participation. Or alternatively, utilities could include specific incentives for customer participation in community solar expansion in a manner similar to how utilities incentivize customer conversions to natural gas.

City of New York (NYC):
NYC states that, before implementation of the Track 2 concepts, it is imperative that the Commission analyze the proposals and recommendations under consideration so as to maintain energy affordability for all consumers. Some of the proposals that have been recommended have the potential to significantly increase rates, especially for low-income, elderly, and infirm consumers – those least able to bear such increased burdens. NYC applauds the recognition in the Track 2 White Paper of the need to ensure that low-income consumers have access to the same opportunities and choices as other consumers so that they too may take advantage of benefits available from DER. It is without

dispute that barriers to low-income consumer participation are significant and in many cases discourage and/or effectively prevent low-income consumers from affirmatively managing their own electric usage and their energy bills. NYC is concerned with an EIM that rewards utility shareholders for actions undertaken by low-income consumers in conjunction with DER providers or others, or based on participation levels in DER programs. Measuring levels of program participation says nothing about the nature or level of a utility's performance or that the utility was responsible for achievement of a certain level. The additional proposal of an EIM tied to terminations and uncollectible expense is inconsistent with the proposals contained in the Staff Report in Case 14-M-0565, Energy Affordability for Low Income Utility Customers.

Clean Energy Organizations Collaborative (CEOC):
CEOC states that market mechanisms must be demonstrated to be effective before they are relied upon. While CEOC applauds Staff's efforts to utilize third parties and market-based approaches to implement DER, it is important to recognize the limits of these approaches, particularly with regard to serving those customers who are harder and more expensive to identify, market to, and serve. Low-income customers are not the only group that is at risk under market-based approaches – many other residential customers, and many small commercial and industrial customers are also at risk. Before relying too heavily on market-based approaches to implement DER, the Commission must determine that they will be sufficient in serving these important customer segments. CEOC supports use of EIMs for affordability, but suggest that this set of metrics include three components: 1) low-income participation rates in EE, DR, DG (especially solar), and TOU programs, 2) reductions in terminations, and 3) reductions in uncollectible expenses. Furthermore, CEOC suggests that participation rates be considered for all rate classes, by type of DER. Metrics based on reductions in residential terminations and bad debt write-offs may be easily measured, but they may be highly correlated with variables outside of utility control, such as the economy. To account for this, reductions in termination and bad debt could be normalized relative to a publically available economic index, such as the unemployment rate. In addition, achieving a

score of better than two standard deviations from the five-year average will likely be very difficult to do; the EIM target should be considered in light of the literature on utility performance improvement in this specific area. Affordability scorecard metrics should be created for annual and lifecycle MWh savings, and for annual and lifecycle bill reductions per low-income participant, by low-income program (EE, DR, solar DG, and TOU). Performance incentive mechanisms, if used, must be carefully designed to avoid increasing burdens on those who are least able to manage them. Well-designed financial incentives can offer relatively low-cost, low-risk ways to monitor and guide the development of the DER market and transition to a clean and efficient electricity industry. CEOC appreciates the Joint Utilities' proposal for a uniform framework for consideration of EIMs and scorecards; such a framework is very useful given the wide range of issues involved here. To the extent possible, metrics should be largely free from arbitrary influence, and should incent outcomes that the utility has some control over. CEOC is not convinced that AMI is needed to achieve the goals of the affordability metric. Further, CEOC has deep concerns regarding "pay-as-you-go" programs.

Energy Democracy Alliance (EDA):
EDA asserts that a shift toward locally owned and locally controlled clean energy resources will have enormous environmental benefits as well as economic benefits, especially if done with an eye toward empowering those who are currently bearing the largest environmental and economic burdens of our energy policy – in particular environmental justice communities, communities of color, and low-income communities.

Energy Efficiency for All (EE for All):
EE for All states that well-designed scorecard metrics would provide much needed information on the extent to which utilities are achieving public policy objectives for low- to-moderate income families and encouraging DER investment in environmental justice communities. EE for All supports the use of EIMs for affordability, but suggests that this set of incentives include three components: 1) low-income participation rates in energy efficiency, demand response, and time of use programs, 2) reductions in terminations, and 3) reductions in uncollectible

expenses. Metrics based on reductions in residential terminations and bad debt write-offs may be easily measured, but they may be highly correlated with variables outside of utility control, such as overall economic conditions. To account for this, reductions in termination and bad debt could be normalized relative to a publicly available economic index, such as the unemployment rate. In addition, achieving a score of better than two standard deviations from the five-year average will likely be very difficult to do; the EIM target should be considered in light of the literature on utility performance improvement in this specific area. Affordability scorecard metrics should be created for annual and lifecycle MWh savings, and for annual and lifecycle bill reductions per low-income participant, and by the deployment of energy efficiency, demand response and other measures in low-income areas.

Exelon Companies (Exelon):

Exelon notes that, as the Commission stated in the Framework Order and Staff reiterated in the White Paper, despite technological change and opportunities for improvement through market mechanisms, electricity remains an essential service imbued with multiple public policy demands. The societal benefit inherent in a reliable, resilient, affordable, and clean energy grid underscores the need to preserve the utility franchise. While the role of the utility may evolve to a more market-based model, there is an underlying need for the continuing ability of the utility to deliver a physical commodity across all classes of customers. Exelon believes that energy efficiency programs, when structured properly and implemented efficiently, enable customers to get the maximum value for their energy dollars. This is particularly important for low-income customers. The White Paper recommends that utility-sponsored energy efficiency should transition from general resource acquisition to targeted and market-based approaches. It is unlikely that these results could be achieved, especially in the short term, without leadership by the utilities and without appropriate cost recovery, including a return on energy efficiency investment.

IGS Generation, IGS Solar and IGS Energy (IGS):
IGS supports Staff's focus on bringing REV benefits to low-income communities but is concerned with the proposal that utilities file additional DER demonstration projects "to test possible programs." IGS would like the Commission to support the efforts of NYSERDA and the Green Bank in providing appropriate incentives to low-income customers, rather than have utilities create test programs. This would enable low-income customers to take advantage of energy efficiency and DER offers made available in the competitive market. IGS contends that Staff's proposal appears to attempt to circumvent the well-founded restrictions in the REV Order by allowing utilities to file wave after wave of demonstration projects.

Interstate Renewable Energy Council (IREC):
IREC comments that when it comes to ensuring that low-income customers continue to receive quality and affordable electric service, special attention must be paid to how it will be provided and by whom. While the Framework Order generally limited the ability of utilities to own DER projects, it provided an exception for utility ownership in underserved communities. While IREC is not opposed to the idea of allowing utilities to participate in this market, it is concerned with a pathway that would provide an exclusive opportunity for utilities. The utility has the advantage of the customer relationship and lower cost of capital, but these advantages do not necessarily mean that the quality of service provided will be superior to, or even on par with, the products and services provided by the competitive market. Thus, while IREC agrees that utilities should be able to serve low-income customers with DER products if it can be shown that there is not an existing market, this should not be an exclusive right. IREC does not want to foreclose the option that low-income customers will be able to take advantage of the creativity, quality and innovation that can come out of a competitive market. Additionally, the White Paper addresses energy efficiency programs for low-income customers, but it does not speak directly to other types of DER programs that could offer significant benefits for these ratepayers, some of which may also be appropriate for utility participation. The "untapped potential" for low-income customers to manage their energy use should not be limited to energy

efficiency measures. Shared renewables programs can provide a good vehicle for engaging customers in better managing their energy use, and can also be a way to leverage private capital and existing low-income subsidies to further reduce bills for these customers. In addition, there are likely ripe opportunities for utility collaboration and participation in such shared renewables programs.

Joint Utilities:

The Joint Utilities agree that low- to moderate-income customers should benefit from new opportunities to engage with DER markets beyond energy efficiency initiatives. Staff, the utilities, and other stakeholders are just beginning to explore ways to give low-income customers access to DERs where the marketplace would not otherwise serve them. Since this concept is relatively new and untested, the Joint Utilities propose that engagement of low- and moderate-income customers in DER programs first be tested in a demonstration project environment where the utilities can gather information, test customer interest, understand the successful channels of engagement, and gain experience administering these programs. To the extent the demonstration projects warrant a wider scale roll-out, a reward-only incentive should then be introduced. The Joint Utilities note that work continues simultaneously within the Low-Income Customer Engagement collaborative in the Commission's Community Distributed Generation Proceeding. The two affordability metrics proposed by Staff are inherently contradictory and will pose challenges both individually and collectively. Reductions of terminations generally drive higher payment arrears, which increase bad debt write offs when an account is closed. More importantly, there are many factors beyond utility control that determine a customer's ability to pay their energy bills, including the state of the economy, the availability of well-paying jobs, fuel costs, wholesale power supply costs, and annual fluctuations in the availability of Home Energy Assistance Program grants. These economic conditions lead to fluctuations in the number of customers falling into arrears, potential terminations, and bad debt write-off as economic conditions change. The Joint Utilities recommend that, prior to adopting any metric, the Commission consider providing new tools and policies that would enable utilities to more effectively manage and reduce bad debt write-offs. Such tools and policies could include: (1) implementing prepayment mechanisms to foster "pay-as-you-go" programs; (2) deployment of advanced metering infrastructure to provide customers with more granular and timely usage data enabling them to consider their energy usage and costs on a weekly basis to help them manage their usage and prioritize their utility payments with other expenditures; and (3) restructuring eligibility rules for assistance programs to eliminate the requirement that a customer must be in arrears and at risk of turn-off to qualify. Experience should be gained regarding the effectiveness of these tools prior to the establishment of a reward only metric reflecting the lack of utility control over these parameters.

Multiple Intervenors (MI):

MI comments that affordability concerns are not limited to low-income customers. If an affordability EIM is adopted it should be focused on rate levels and should encompass all types of customers. 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. MI is concerned regarding the extent to which customers should be required to subsidize residential low-income programs, and how the costs of residential low-income programs should be allocated to, and recovered from, a utility's service classes and individual customers. With respect to energy efficiency programs targeted at residential low-income customers, Multiple Intervenors asserts that such programs should be (i) demonstrably cost effective on an economic basis, and (ii) subject to a budget that makes economic sense and reflects the fact that all or virtually all delivery customers are funding utility energy efficiency programs. In other words, there only is so much capacity for New York utility customers – who already pay some of the highest energy costs in the nation – to fund residential low-income programs. At some point, these issues may have to be addressed by the Legislature. In the meantime, the Commission will need to determine the total amount of funding that is reasonable for residential low-income assistance and energy efficiency programs.

National Fuel Gas Distribution Corporation (NFG):
NFG finds it difficult to meaningfully comment on the proposal to implement of a set of programs targeted at supporting low-income customer usage of DERs, including a measurement of customer participation levels and per customer savings on a dollar amount basis because: (1) the referenced programs do not currently exist, (2) funding for such programs has not yet been authorized by the Commission, (3) there is a possibility that the programming referenced here could conflict with statewide low-income energy programming proposed by NYSERDA's Clean Energy Fund or proposed in utility specific ETIPs, and (4) a policy determination has not yet been made in case 14-M-0565. Before this EIM is considered further by the Commission, a collaborative process should be convened as part of case 14-M-0565 to define the low-income programs referenced in this EIM, as well as definitive, quantifiable metrics that allow for actual measurement. The resources available to fund low-income programs are limited. Designing programs that target benefits to households with the lowest income and highest bills, which are typically the customers with the largest arrears and at the greatest risk of termination, is an effective use of limited resources. An effective low-income program that, over time, reduces collection activity and terminations will result in reduced collection costs and lower write-offs.
NFG supports the notion that low income customers should have the same REV opportunities and options as mass-market customers. The Commission should ensure that decisions made in the REV Proceeding do not have the unintended consequence of increasing energy burdens for low income customers.

Public Utilities Law Project (PULP):
PULP states that while the goals of increased reliability, resiliency and efficiency espoused by REV are laudable, it is to remember that New York's electric costs are among the highest in the United States, and that before taking the steps contemplated in REV Track 2, there must be a comprehensive analysis of what effects these proposed changes will have upon rates. A study of bill impacts, including the impacts of the associated AMI infrastructure that would accompany demand charges and other TOU related rates is vital. The staff proposals on customer engagement and residential rate design present significant risks

to customer affordability for essential electric service. The plethora of interdependent proceedings must be harmonized to lower risk of harmful impact upon all ratepayers and low income consumers in particular. PULP believes that, if Staff's current proposal in 14-M-0565 were to be adopted, the magnitude of risks of negative outcomes to low income residential customers in all other REV proceedings would increase dramatically. On the other hand, more practical and less costly approaches to customer engagement and residential rate design in Track 2 might reduce the funding needed to provide low income assistance from that which PULP estimated in its comments in 14-M-0565, while at the same time allowing for the adoption of PULP's suggested robust eligibility criteria. PULP suggests a more modest and low key approach that is designed to ensure that the potential value of increased efficiency and DER penetration can be delivered to all customers in the form of lower electricity prices compared to the continuation of the current regulatory path; PULP urges gradualism in fact, rather than gradualism in theory.

Vote Solar Initiative (Vote Solar):

Vote Solar disagrees with the Joint Utilities assertion that support for public policy objectives should be delivered through transparent public subsidies and not embedded in utility tariffs. This position ignores the long history of including public policy objectives in rates in general, for instance discounts for specific customer classes. According to Vote Solar, such a position, if applied universally by the Commission, would eliminate low-income discounts. Thus, this type of approach would be detrimental to low-income customers, and all other customers by extension. Vote Solar notes that public policy objectives for DER have been implemented in rates and tariffs in many states, including funding for renewable energy and energy efficiency, and renewable portfolio standards. Vote Solar also points out that other public policy objectives have been included in utility rates and tariffs around the country, such as funding for ratepayer advocates in order to provide expert assistance and, ultimately, protect ratepayers.

SECTION III.C.2.b ALIGNING CUSTOMER VALUE WITH EARNINGS OPPORTUNITIES: Modifications to the Utility/DSP Revenue Model; *Public Policy Achievement, Energy Efficiency*

Acadia Center (Acadia):
Acadia Center appreciates the Commission's commitment to energy efficiency but remains concerned with the proposed transition away from current approaches. Market barriers to energy efficiency are significant and programs targeted at the specific barriers allow for the creation of functioning markets for efficiency. An important first step in setting policy for distributed solar is to understand the value, or benefits, that distributed solar provides.

Advanced Energy Economy Institute (AEEI):
AEEI acknowledges the need for active engagement to make sure that important public policy objectives are being met while the utility system is transitioning to a more market-oriented approach and notes the framework outlined in their comments on the ETIPs filings in proceeding 15-M-0252 regarding the new vision of procuring efficiency in long-term increments as a replacement for traditional utility resources. This will result in an end-state with variety of market participants using a variety of business models to serve the market. AEEI notes, however, that utilities may still play a prominent role in energy efficiency, especially early on and through leveraging their existing relationship with customers to educate and motivate them.

American Council for an Energy-Efficient Economy (ACEEE):
ACEEE strongly agrees that efficiency achievements will need to be increased to meet REV objectives. ACEEE also argues that a specific EIM should be established for energy efficiency.

BlueRock Energy, Inc. (BlueRock):
BlueRock’s proposal, conducive to the policy objectives of various environmental groups and NGOs, would allow for environmental adders and other carbon and environmental impact externalities to be factored into the market entry price, in the context of transparent and a uniformly competitive marketplace.

Citizens Environmental Coalition (CEC):
CEC points out that three northeast states are achieving efficiency levels of 2% and suggests that a more market-oriented approach does not require lowering New York's efficiency goals. CEC states that the absence of clearly stated goals for efficiency of 2% annually suggests the limited confidence Staff has in actually achieving efficiency through market- based approaches. CEC argues that staff's energy efficiency recommendation is weak and lacks accountability.

Citizens for Local Power (CLP):
CLP is concerned that phasing out energy efficiency incentives should not be made a policy goal. Rather, CLP indicates that the policy goal should be the full realization by customers of their energy efficiency potential. There is no evidence to suggest that the market can be relied upon to serve low-and moderate-income residents, who comprise about 40% of all households. CLP notes that middle-income residents and small businesses also face major barriers to making energy efficiency improvements, even though the long-term benefits are significant.

City of New York (NYC):
NYC recommends that the Commission place greater emphasis on reducing carbon emissions via renewable resources and energy efficiency. Both State and City public policies call for substantial reductions in carbon emissions. NYC's policy seeks an 80 percent reduction in carbon emissions by 2050, compared to 2005 levels. The State's policy seeks similar reductions, as well as a 50 reduction in carbon emissions by 2030. NYC states that it is premature to replace net metering with LMP+D. Until the LMP+D construct is completed and incorporated in tariffs that recognize the full benefit of DER, net metering must continue to avoid the disruption of DG development efforts that would contravene the State's energy policies.

Clean Energy Organizations Collaborative (CEOC):
CEOC has concerns with Staff's proposal to transition to more market-based approaches, with goals informed by the ETIP, DSIP, and State Energy Plan processes. Such a transition, although valuable in theory, will take time and movement toward a more

market-based approach must not jeopardize current efficiency initiatives and goals. The Commission should ensure that sustained ratepayer investment in NYSERDA and utility-run energy efficiency programs continues until new market-based approaches have a proven track record of performance. It is also important to guard against backsliding on energy efficiency targets during this transition. The Commission should establish energy efficiency targets in each utility's DSIP. The process should also include periodic studies of, and reports on, the energy efficiency programs within each utility's territory, and should take into account the "bigger-picture" context of how each utility's performance contributes to the State Energy Plan goals. While achieving demand and energy targets is important, utility efficiency programs should, at a minimum, ensure that the basic core efficiency markets are served: (a) low-income: new construction, multi-family, and single family; (b) multi-family (not low-income); (c) residential: new construction, home retrofits, products & services; and (d) commercial & industrial: new construction, prescriptive, custom. CEOC states that utilities should not only be subject to minimum energy efficiency targets, but also pursue energy efficiency aggressively in order to achieve New York's public policy objectives.

Energy Efficiency for All (EE for All):
EE for All notes that because REV markets for DER are in their earliest stages of development, EIMs will be a critical near term policy tool for increasing investment in clean energy. While establishing specific, more aggressive utility targets for energy efficiency will provide the floor for energy efficiency investment and prevent any backsliding against the state's overall energy efficiency goals, EIMs are likely to be the mechanism that drives increased investment beyond the Commission's regulatory requirements. EIMs should take into account both the demand savings (MW) at the local distribution peak, as well as the annual lifecycle MWh savings. In addition, CEOC recommends that participation in energy efficiency programs also be an EIM, defined as the percentage of customers participating in the utilities energy efficiency program per year, by rate class. Given the untapped potential of the multifamily sector, EE for All recommends that Staff establish a

scorecard metric for the deployment of energy efficiency measures in the multifamily housing sector. Affordability incentives should include three components: 1) low-income participation rates in energy efficiency, demand response, and time of use programs, 2) reductions in terminations, and 3) reductions in uncollectible expenses. Metrics based on reductions in residential terminations and bad debt write-offs may be easily measured, but they may be highly correlated with variables outside of utility control, such as overall economic conditions. To account for this, reductions in termination and bad debt could be normalized relative to a publicly available economic index, such as the unemployment rate. Affordability scorecard metrics should be created for annual and lifecycle MWh savings, and for annual and lifecycle bill reductions per low-income participant, and by the deployment of energy efficiency, demand response and other measures in low-income areas.

Environmental Defense Fund (EDF):
EDF would not characterize economic efficiency as a policy objective in itself; economic efficiency is a means to an end, or to multiple ends. EDF explains that although the many objectives of the REV proceeding may be in some tension, economic efficiency can be usefully leveraged to achieve most if not all of them.

Exelon Companies (Exelon):
Exelon is skeptical that utility-sponsored energy efficiency can transition from general resource acquisition to targeted and market-based approaches, especially in the short term, without leadership by the utilities and without appropriate cost recovery, including a return on energy efficiency investment. With respect to alignment with environmental objectives, Exelon supports Staff's suggestion to consider any changes within the context of the State Energy Plan goals and future federal goals. Meeting these stated goals will require maintenance of existing carbon-free clean energy resources, and a mechanism to attract new carbon-free clean energy resources. This requires a single market CO2 price to retain and attract carbon free clean energy resources at the distribution and wholesale level, or consideration of the implementation of the CFAR outlined in the White Paper. Regardless of the approach, the State must move

quickly to appropriately value and implement a carbon methodology to align with New York’s stated climate goals. According to Exelon, emissions reduction policies are central to the Commission’s future ratemaking, and utility financial incentives should be aligned with these and other REV policy objectives. Exelon supports a holistic approach to the State’s goals and energy initiatives to ensure energy, economic, climate, and reliability goals are attained at a reasonable cost and in an efficient manner and will yield resource diversity and decreased GHG emissions. In this holistic approach, REV ratemaking and utility business models cannot be divorced from wholesale competitive market and other reform options available to ensure that existing zero carbon generation resources, relied on by the State to meet GHG targets, remain in operation. Customer value can be aligned with the utility earnings opportunities envisioned by REV. Exelon specifically encourages actions that translate into actual lower carbon dioxide emissions.

GridWise Alliance (GWA):
GWA supports transitioning utility-sponsored energy efficiency from general resource acquisition to targeted and market-based approaches, with goals informed by the ETIP, DSIP, and State Energy Plan processes.

Hudson River Sloop Clearwater, Inc. (Clearwater):
Clearwater strongly supports the reduction of carbon emissions as a policy goal within REV to mitigate climate change.

IGS Generation, IGS Solar and IGS Energy (IGS):
IGS states that 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. IGS recommends that the Commission support the effort of NYSERDA and the Green Bank to address barriers to the participation of low and moderate income communities in the competitive market and should not assume that the utility is the appropriate entity for serving these communities. IGS says that a clear path should be set up to transition utility-sponsored energy efficiency to market-based approaches.

Joint Utilities:
The Joint Utilities believe that the long-term goal to transition utility-sponsored energy efficiency programs from general resource acquisition to targeted and market-based approaches can be effectively addressed through the existing ETIPs and DSIPs. The Joint Utilities are committed to working collaboratively with NYSERDA on this effort. One element of a comprehensive strategy would be to formally define the respective roles of NYSERDA and the utilities regarding the development and implementation of efficiency programs that target low-income customers.

National Fuel Gas Distribution Corporation (NFG):
NFG warns that competitive procurements and longer-duration contracts will not drive down costs of energy efficiency. NFG takes issue the assumption that ratepayer funding could be reduced or eliminated while energy efficiency savings increases. NFG also contends that shortening the program cycle from a four year reauthorization process to an annual reauthorization process would increase the costs associated with administering energy efficiency (both administrative costs for utilities as well as the corresponding quotes received from vendors). Long-term statewide energy and emissions goals, as outlined in the 2015 New York State Energy Plan may be met as long as programs and activities delivered by the utilities and NYSERDA are complimentary and not redundant in nature. NFG is concerned that energy efficiency programs should not transition away from current, and very successful, approaches and argues that Staff's proposed continuum of energy efficiency program evolution will: (1) increase customer confusion in the marketplace, and (2) cause backsliding toward the achievement of statewide energy policy goals by pivoting to unproven programmatic approaches. NFG recommends that the Commission confirm in a future REV Proceeding Order that utility energy efficiency programs should be categorized into one of the four approaches identified by Staff. NFG also requests that the Commission reaffirm that utility programming reside along the resource acquisition end of the continuum and that NYSERDA programming reside along the market transformation end of the continuum.

New York Energy Consumers Council, Inc. (NYECC):
NYECC agrees that increased reliance on market-based solutions should not diminish responsibility to ensure achievement of the Commissions public policies and public interest outcomes. NYECC supports Staff's goals and approach for peak reduction, energy efficiency, and affordability since, if achieved cost-effectively, those goals and approach will result in direct benefits to the overall customer bill. This will provide the utilities with the potential to share savings with customers. Any associated customer bill reductions should be at a minimum commensurate with, but not more than, any EIMs established.

Northeast Clean Heat and Power Initiative (NECHPI):
NECHPI argues that CHP is increasingly being considered as "clean energy" to be supported by policy initiatives in various states. By reducing fossil fuel use, NECHPI explains that CHP-based microgrids can lead to reductions in indoor and outdoor air pollutions and the associated health impacts.

Northeast Energy Efficiency Partnerships (NEEP):
NEEP states that market barriers prevent rate of return from being an effective incentive for energy efficiency projects. Since it is entirely possible that third-party DER developers might not emerge on the timeline envisioned by the REV proceeding, current MWh resource acquisition goals should continue to be supported. Market-based earnings mechanisms should only be relied upon as a replacement for ratepayer funding when MBEs are demonstrated to be a stable and sufficient funding source for energy efficiency savings consistent with the goals articulated in the State Energy Plan. NEEP recommends that an Enhanced Permanent Collaborative be established to help determine the amount of cost-effective energy efficiency that is achievable and the extent to which the utilities are actively procuring cost-effective energy efficiency opportunities.

Public Utility Law Project of New York, Inc. (PULP):
Customers that are focused upon conservation and reducing their energy use in accord with State policy, will be forced not only to pay for the costs of the efficiency measures, but face electric bills that reflect an increasing level of mandates and higher fixed monthly charges. PULP reiterates its concern that

the pace of REV is too quick and that proposed changes are being undertaken without sufficient attention to the costs and benefits of proposed mandates and policies.

Sierra Club and General Motors (Sierra/GM):
Sierra/GM indicates that New York's electric vehicle market is capable of increasing exponentially if complementary infrastructure policies are in place. These policies will ensure EVs can deliver customer savings, a more stable utility industry, increased renewable energy, and cleaner air.

Solar Energy Industries Association (SEIA):
SEIA comments that LMP+D should be designed to achieve the policy objectives of REV, including increased market participation by DER providers, increased customer participation in DER markets, and enabling development of a robust and sustainable DER market.

SECTION III.C.3.a ALIGNING CUSTOMER VALUE WITH EARNINGS OPPORTUNITIES: Modifications to the Utility/DSP Revenue Model; *Earnings Impact Mechanisms, Scorecards, and Outcomes; Industry Context*

AARP New York (AARP):
AARP agrees with Staff's proposal to continue existing safety, reliability, customer-service, and utility-specific performance mechanisms. However, regarding additional EIMS, AARP states that it has serious reservations about "performance based ratemaking" in general, and is aware of negative consequences for consumers when similar policies have been developed in other states. AARP believes that EIMs should be developed cautiously and relied upon only after an analysis of their actual impact on utility behavior and earnings. AARP urges that all EIMS consider rewards and penalties. Staff's proposal lacks details on how an overall customer bill impact metric would be calculated. AARP recommends a pilot program and analytical study to test whether the goals of this approach can be achieved. If EIMs are implemented, they should be linked to annual performance objectives and results, rather than operating on a multi-year basis as a multi-year evaluation would allow a

utility to fail to meet required standards one year and make up the difference in a subsequent year. AARP agrees with concerns raised by the Joint Utilities in regard to the Staff proposed customer bill metric. Requiring a utility to be accountable for charges, taxes and fees that are not within its control is not appropriate for a performance based financial mechanism.

Advanced Energy Economy Institute (AEEI):
AEEI supports the use of EIMs and agrees with Staff's proposal that most should be positive only. The Commission can consider symmetric incentives in the future if they are not achieving desired outcomes. AEEI suggests that EIMs be awarded via fixed sums at predefined performance levels rather than provide them as increases to a utility's allowed ROE.
AEEI proposes that EIMs continue if MBEs do not materialize as expected. Additionally, AEEI prefers that the Commission assume EIMs will stay in place until there is a need to reassess. Long-term EIMs should be contingent on an overall customer bill impact metric. AEEI proposes an EIM for information access by market participants as opposed to customers. EIMs should be designed to reflect the ability of utilities to control the outcomes of the metrics and that design should be standardized across the state. AEEI disagrees with other parties' assertion that EIMs could largely be replaced by MBEs. Even when DER markets reach sufficient scale to provide meaningful MBEs, AEEI does not believe that incentives from those earnings will drive utilities to achieve important policy goals to the same extent that EIMs will. It is a difficult enough task to try to regulate a monopoly in a way that attempts to mimic the benefits of a competitive market – it will be nearly impossible to design opportunities for MBEs in such a way that they drive utilities to achieve public policy goals to the same extent as the more direct and explicit approach of using EIMs.

BlueRock Energy (BlueRock):
BlueRock advocates that EIMs be used to incent utilities to favor private investment, including environmental objectives as part of the EIMs; for keeping a stable, traditional recovery of utility grid meter investments; and for having utility incremental profits come as a share of avoided investments so that average ratepayers are no worse off than they otherwise

would have been under the status quo. The Commission should use EIMs rather than MBEs. With proper set up, utilities will be indifferent as to whether they achieve an improvement in meeting customer peak demand needs, for example, through private investment or increasing rate base. By contrast, MBEs will encourage utilities to be involved in otherwise competitive markets. Utilities should earn profits for facilitating the EIM objectives being met by competitive parties. This proposal complements the goals of the various environmental groups and NGOs who desire to advance their goals by tying fiscal responsibility to shareholder incentives. Environmental adders and other carbon and environmental impact externalities can be factored into the market entry price, in the context of transparent and a uniformly competitive marketplace. Utilities will have the opportunity for equal or higher profits for facilitating competitive third-party DER investments on the customer side of the meter as the utility reduces its commodity supply role. Finally, the utility incremental profits from such facilitation comes as a share of avoided capital investments so that the average ratepayers' bills are no higher than they otherwise would have been.

Citizens for Local Power (CLP):
CLP supports Staff’s proposal to measure and track utility performance and progress in achieving REV and public policy goals. Utilities should provide information on the EIMs and scorecard metrics on their web-based dashboards, updated at least on a monthly basis, and be required to send a printed summary of scorecard results on an annual basis to their customers, ideally as a separate mailing but it could also be included as an insert in the utility bill. CLP states that communicating this information by mail would increase transparency and accountability, as well as customer understanding of what is being required of the utilities and the standards utilities are expected to meet. CLP agrees with CEC and EDA that nuclear power has no place in any measure of utility progress toward a clean, renewable energy system, and requests that nuclear power be excluded from any EIM or scorecard metric.

City of New York (NYC):
NYC states that properly constructed, performance-based regulation could lead to more transparency, enhanced customer engagement, and achievement of the Commission's REV goals. NYC recommends that the Commission review the regulatory models adopted by Ontario and Great Britain, which include a combination of financial incentives and scorecards. NYC notes that Staff's White Paper does not provide any details on EIMs regarding scope, measurement or determination of value. Before any non-financial metrics are included in EIMs, there must be proper baselines, benchmarking to establish targets and performance levels, and review to ensure that the level of any incentives reflect the value of the benefit. NYC also believes that the Commission should decide whether intangible or policy benefits should form the basis of financial rewards or be captured via scorecards. NYC agrees with EIMs that are within the utilities' control and for which incentives should result in improved performance. NYC rejects the recommendation that positive incentives be implemented in the early stages of the DSP market, before baseline measurements have been made and before there has been identification of areas in which improvements are needed.

Clean Energy Organizations Collaborative (CEOC):
CEOC supports Staff's proposed EIMS, however believes that they may need further refinement before implementation. CEOC believes that these details of these mechanisms should be addressed through stakeholder processes in order to ensure that targets are set appropriately, perverse incentives are avoided and rewards to utilities do not exceed benefits net of costs. CEOC agrees that initially, it may be reasonable to provide only positive incentives for certain EIMs, particularly those related to DER investments, except in the case of egregious utility behavior in the form of obstruction, mismanagement, or imprudence. CEOC also proposes a number of additional EIMS, including an EIM related to demand response and dynamic load management instead of a scorecard metric as these are important for helping customers experience system benefits. Those EIMs should reflect participation, defined as percent of customers enrolled per year by rate class, and demand savings (MW) at the local distribution system peak. Additionally, CEOC recommends

scorecard metrics for this category including MW saved as a percentage of utility's total load (including permanent EE load reduction); costs per MW of energy saved, at both the program and portfolio level; cost effectiveness as measured by the Societal Cost test, including non-energy benefits, by program, and presented both as a ratio and net present value; and reduction in non-CO2 pollution, including but not limited to particulates, NOx, and SO2, by program. CEOC recommends an EIM for DG reflecting participation, defined as percent of customers enrolled per year, by rate class. Also, there should be an EIM for MWh generation for each type of DG resource (Combined Heat and Power or CHP, rooftop photovoltaics, etc.). CEOC also would like to see scorecard metrics for this category including geographic, technological, and customer class diversity; number of DG installations by resource type; MWh generated as a percentage of utility's total load (including load offsets); installed capacity (MW) by resource type; program costs per MWh generated by DER, at both the program and portfolio level; cost effectiveness as measured by the Societal Cost test, including non-energy benefits, by program, and presented both as a ratio and net present value; and reduction in non-CO2 pollution, including but not limited to particulates, NOx, and SO2, by program. CEOC also believes that there should be EIMs related to electric vehicles, energy storage, and the carbon free acquisition rate. The fact that practically no metric is entirely within the utility's control should not deter their use. To address concerns stated by some parties' concern about arbitrary influence, the weight given to EIMs could reflect the extent to which they are under the influence of the utility, as determined in an open stakeholder process. CEOC agrees with other parties that more specificity is needed regarding the design of EIMs and scorecard metrics, including precisely how the metrics will be defined and measured, what the targets will be, and what the magnitude of any financial rewards or penalties will be.

Comverge, Inc., EnergyHub (Comverge/EnergyHub):
Comverge/EnergyHub agrees with the use of EIMs and scorecards to incentive utilities to drive efficient grid outcomes. Utilities that implement DR in response to regulatory mandates with only the threat of penalties for non-compliance tend to end up with

more lackluster programs that lack innovative approaches to drive down cost or increase benefits.

Energy Democracy Alliance (EDA):
EDA supports the establishment of EIMs to align utilities with public interest goals. However, EDA does not think that utilities should be rewarded for simply fulfilling responsibilities as regulated monopolies. EDA recommends that the Commission reward utilities for performing better than expected and penalize them for failure to meet established goals. Additional EIMS or scorecards should be developed for Environmental Goals, Local Renewables, Equal Opportunity and Equity Assessment. Additionally, EDA states that nuclear power should not be included in any standard along with renewable. EDA advocates promoting equal opportunity by requiring utilities to report the percentage participation in their online portals of businesses owned by people of color and women and to purchase a certain percentage from minority- and women-owned businesses. Utilities should assess and report annually on how their procurement and investments are supporting economic and racial equity in communities. Metrics could include decreased pollution in environmental justice communities; improved health outcomes due to energy improvements; increased adoption of efficiency and renewable energy by renters and low-income homeowners.

Energy Efficiency for All (EE for All):
EE for All agrees with Staff's proposal to use EIMs, but states that it does not address certain areas of design for these tools including the magnitude of rewards of penalties related to each EIM. The White Paper also does not consider how EIMs may interact with each other. EE for All states that Staff should ensure that these EIMs do not doubly reward or penalize utilities. The Commission should clarify the process for establishing EIMs and scorecards prior to the submission of utility DSIPs and should consider stakeholder input and comment on the further development of these items.

Energy Technology Savings (ETS):
ETS agrees that EIMs will be necessary in the short term to incentive behaviors, however in the long term some EIMs may not

longer be necessary as the market will eventually induce these desired behaviors. ETS agrees with Staff's proposed EIM categories and believes that measuring peak reduction will be one of most important metrics to ensure that REV goals are being achieved. Additionally, ETS believes that monitoring progress regarding functionality and performance of the portal will be crucial as this will be the main vehicle for the incorporation of DER. The portal must be simple to use and provide easy access to customers and third parties to obtain data and interconnect. Furthermore, it is imperative that the portal should be operated in a non discriminatory manner where no utility or provider has a competitive advantage.

Environmental Defense Fund (EDF):
EDF believes that utilities should have incentives aligned with emissions reductions. Utility decisions can contribute to making RGGI reforms attainable and affordable by reducing demand for emissions allowances. Additionally, EDF states that managing emissions from non-RGGI resources must be a part of any regulatory strategy to achieve carbon emissions reductions. Metrics should identify reductions in allowances needed to serve load in a service territory similar to one developed by themselves and the Citizens' Utility Board for use in Illinois, which focuses on GHG reductions associated with load shifting and peak load reductions. To reduce carbon dioxide emissions actually occurring, EDF recommends retirement of RGGI allowances or, if that is not feasible, tightening the cap further based on the reductions in demand that the utility/DSPs have made possible. EDF suggests that the Commission consider an EIM for progress toward the State's 50% renewables goal. The Commission should develop uniform standards for measuring the EIM outcomes in all service territories and take into account the impact of various existing conditions in a utility's service territory when evaluating performance. EDF states that EIMs should relate to items that are within the utilities control and should be objective and measurable with pre-established targets. EDF disagrees with the JU objections to a customer bill impact metric, finding that it should be possible to track any lag between costs and benefits and that the potential for such a lag is part of the reason Staff is proposing for the peak reduction, energy efficiency and affordability metrics to become contingent

on a total bill impact metric at a later time (rather than at the outset). The manner in which compensation is allocated among metrics is critical; the most important consideration when allocating performance compensation among metrics is the risk-reward profile of each EIM as perceived by a particular DSP. If performance-based DSP compensation is not allocated among metrics in a way that reflects these risks, one can assume a DSP will abandon pursuit of some metrics in order to focus on those with the most favorable risk-reward profiles.

Exelon and the Exelon Companies (Exelon):
Exelon notes that successful use of performance metrics requires clearly defined standards of measurement as well as the use of advanced metering. Without these, Exelon states that customers could pay for changes that ultimately do not deliver REV promised customer benefits. Exelon notes concern that failure to "get it right" could lead to wasted capital, increased costs, and lost opportunities to deliver actual value.

Federal Trade Commission (FTC):
The FTC applauds Staff for proposing a portfolio of performance-based rates to better align the financial incentives of distribution utilities with the public policy goals of the REV proceeding. EIMs may facilitate effective competition to the extent they seek to counter residual incentives to discriminate against unaffiliated DERs. The use of Scorecards for the same purpose could potentially alert regulators to persistent performance deficiencies that could indicate lingering incentives to discriminate against unaffiliated DER investors, owners, or organizers. The NY PSC could also take a similar approach to counter a distribution utility's incentives to discriminate against independent firms that compete against the utility's affiliates in providing services to DER projects. The FTC suggests an additional EIMs or Scorecards designed to mitigate incentives to raise the costs of, or otherwise discriminate against, these independent service providers. An EIM or scorecard item should be added to include the value that customers derive from customization of electricity services. Although the Scorecard measures for customer satisfaction and customer enhancement may cover this benefit to some extent, transparency might be better served by creating one or more

Scorecards that focus explicitly on: (1) how advances in DER technology have allowed customers to customize their electric services; (2) how DSP operators have helped inform customers about the potential value of customizing; and (3) how better and more abundant information has allowed customers to better match their preferences for electric services. Yardstick (comparative) EIMs and Scorecards may be attractive initially because they can be easier to develop and administer than quantitative performance measures or standards.

Gridwise Alliance (GWA):
GWA agrees with the implementation of EIMS, particularly EIMs for peak reduction and customer engagement. GWA encourages an EIM for load optimization/peak management and an EIM or scorecard metric for customer education. GWA recommends that metrics be more national in scope, rather than specific to New York State and that they are attainable and adequate to motivate the desired performance.

IGS Generation, IGS Solar and IGS Energy (IGS):
IGS recommends that to minimize confusion in the marketplace and among stakeholders, the Commission should clarify the nomenclature of MBE, PSR, and EIM, clearly delineating who pays, who sets the price, and where the dollars flow. IGS recommends that the Commission open a separate stakeholder conversation to refine the categories and measurement approaches for EIMs. In the interim, EIMs should focus on the building blocks of REV, such as interconnection of DER, customer participation, information access, and targeted participation levels, rather than on REV outcomes. To the extent that the EIMs are focused on REV outcomes, such as peak reduction and energy efficiency, IGS notes that the indicators of whether or not a utility is successful in these EIMs should not be just around the outcome but how the outcome was met. For example, successfully meeting peak reduction EIM should be geared towards whether it was done through market participation rather than through the absolute number of DR that is performed even if the DR provides above market compensation through utility distribution rates. Additionally, IGS believes that all EIMS should be symmetrical to ensure that utilities have sufficient motivation to work towards implementation of the measures.

Institute for Policy Integrity, New York University School of Law (Policy Integrity):
Policy Integrity believes that there should be an EIM related to environmental factors, that there should be symmetric incentives and there should be a menu of earning sharing contracts. Without a link between earnings and environmental performance, shareholders also have little incentive to call for improvements or withdraw their investment from the utility. However, by connecting performance metrics to utility revenues, the Commission can ensure that utilities are motivated to improve performance. Policy Integrity points to Massachusetts Department of Public Utilities, Minnesota Department of Commerce and the Illinois Energy Infrastructure
Modernization Act for examples of states that has structured performance based mechanisms in such a way as to strengthen the connection between performance and earnings. It is important to make sure the utility incentives align with social goals such as reducing carbon emissions, not just with market-based outcomes. Policy Integrity believes that the current Staff proposal, which includes only one environmental scorecard measure, the Carbon Free Acquisition Rate, is insufficient to align the utility incentives with the goals of reducing carbon emissions and also to address broader environmental and health consequences of other pollutants.

Interstate Renewable Energy Council, Inc. (IREC):
IREC agrees with Staff's proposal to implement EIMS and believes that these EIMs are necessary to provide incentives for utility performance that is aligned with customer interests and the goals of REV. EIMs will also ensure that utilities are held to standards of performance that must be met if they are to continue to receive the benefits of a regulated monopoly status. IREC disagrees with replacing EIMs with MBEs for some categories, such as EIMs for basic utility services. While MBEs may provide additional revenue for utilities, it is important that utilities stay engaged in their traditional role of providing safe, reliable and affordable service. IREC believes that "enhanced" returns should be reserved for instances when utilities are truly going above what is otherwise expected. While recognizing that one goal behind the EIMs is to increase

utility incentives for achievement of REV objectives, IREC notes that we must not send a signal that utilities need to be expressly incentivized to provide quality service. IREC therefore thinks that the Commission should consider tying some of the incentive payments to earning-sharing mechanisms which help make sure that the positive incentives only emerge in excess of the allowed rate of return. Finally, IREC agrees EIMs should be adjusted on a regular basis as new information and feedback on the level of performance they incent becomes available.

Joint Utilities:
The Joint Utilities support establishing EIMs but note that many of the proposed EIMS and scorecard metrics are not appropriate as they are not within the control or influence of the utilities or may not be cost effective. The Joint Utilitie proposes an incentive framework to address performance incentives and an initial program of REV incentives. There should be a review of existing performance metrics as they are penalty only and should be modified to be symmetric. The Joint Utilities assert that a total customer bill metric should not be used to determine whether utilities can receive positive-only incentives as two thirds of the total customer bill is dependent on wholesale supply charges, taxes, and fees – all of which are outside the control or influence of the utility. Additionally, the Joint Utilities state that they could be penalized for producing results that are consistent with moving REV forward, but due to the timing of costs and benefits of REV there could be a bill impact. The Commission should establish realistic, transparent, and cost-effective incentives that drive behaviors that achieve policy objectives and produce long-term benefits for all customers and that targets should be established using benefit-cost concepts. Demonstration projects will provide an opportunity to test the market and gather data and can assist in the evaluation of new concepts such as customer engagement and market animation. Particularly at the outset of REV, EIMs and program incentives should be reward-only with conservative targets structured in a way that provides utilities strong incentives to outperform the targets. New performance incentives should be based on real experience with reasonable targets based on a benefit-cost approach to achieve the REV

vision in a cost effective manner. The Joint Utilities note that several parties argue that all incentive metrics should be symmetrical and comment that symmetrical incentives may be appropriate in situations where: (1) the utility has direct control over the outcome; (2) a sufficient performance track record exists to establish a metric; and (3) the metric targets as structured are economically achievable. However, most metrics are not within direct utility control and can only be partially influenced by utility actions. Therefore, they should not be subject to negative revenue adjustments. Additionally, the Joint Utilities noted that as most REV-related metrics will be for new activities, there will be little track record on which to develop metric targets.

Microgrid Resources Coalition (MRC):
MRC agrees with Staff's proposal to continue existing mechanisms, but would like details about the specific areas of service delivery and outcomes and whether these will be EIMs or scorecard items. MRC believes that adequate engineering and technical workers at every utility is a current serious unaddressed need. The discussion around performance based measures tied to financial incentives, EIMs, and Scorecards is confused and contradictory. MRC questions to what extent Staff proposes to keep any regulatory requirements in contrast to only incentives; whether incentives that are monetized are given more weight and prioritization than non-monetized ones; and given that the Benefit-Cost analysis framework proposed gives very little attention to quantifying social and environmental goals, whether it is possible for these goals to receive adequate attention under REV. MRC states that social goals are not aligned with corporate goals solely based on financial rewards as externalities are not adequately accounted for. Additionally, there is no factual analysis to support a financial only perspective.

Multiple Intervenors (MI):
MI is concerned that an increased reliance on incentive ratemaking could enrich utility shareholders at the expense of customers. To the extent that multi-year rate plans are desired, utilities could be accorded "veto power" over incentive mechanisms in negotiations if the Commission requires utility's

consent for the multi year rate plan. Additionally, MI asserts that there is an information imbalance that gives the utilities an advantage. MI strongly opposes Staff's proposal that EIMs are positive only. If customers are required to be financially responsible for new incentives, then utility shareholders should be held to the same standard. MI also strongly opposes a proposed EIM based on peak load reductions that did not account for customer-subsidized programs focused on energy efficiency and renewable generation as utilities are under mandate to implement such programs and customers are therefore paying all of the costs and any peak load reductions that occur as a result of such programs would exist irrespective of the proposed EIM.

National Fuel Gas Distribution Corporation (NFG):
NFG agrees with Staff that EIMS should be examined, and that issues should be assessed in prospective utility rate cases including: (1) an assessment of ratepayer impacts, (2) the degree of utility control over the outcomes, (3) the determination of appropriate basis point levels for each metric, and (4) the establishment of reasonable reporting requirements. NFG further states that to ensure that utility credit ratings are not harmed through incentive ratemaking, the Commission should avoid: (1) penalty incentives, (2) the use of earnings sharing mechanisms, (3) any incentive that adds risk to the utility (e.g., price risk), and (4) ratemaking that adds uncertainty to allowed earnings (e.g., mid-term reopeners, mid-term adjustments, updates, early terminations, etc.). NFG notes that EIMS should not be linked to earnings sharing mechanisms. Such an approach could actually serve as a significant disincentive to utilities, undermining the establishment of and purpose for EIMs. NFG supports the Joint Utilities' position that existing penalty-only performance metrics should be modified to either: (1) allow utility compensation for superior performance, or (2) provide increased symmetry between penalties and rewards. In addition, any such performance metrics can only be adopted with the express agreement of the utility. NFG maintains that EIMs should produce objective, relevant quantitative information on program performance that can be used internally and externally for program monitoring and reporting, strategic planning, budgeting and financial management, performance management, quality and process improvement,

contract management, external benchmarking, public communication, and/or transparency. EIMs should be service territory specific, within control or the meaningful influence of each utility, and should be cost effective for utility customers. NFG believes that EIMs should be established in rate proceedings, and that the adoption of any such performance metrics can only be with the express agreement of the utility.

New York Energy Consumers Council, Inc. (NYECC):
NYECC supports Staff's position on EIMs as long as associated customer bill reductions are at a minimum commensurate, although preferably more than, any EIMs established.

Northeast Clean Heat and Power Initiative (NECHPI):
NECHPI believes that Staff's proposals regarding financial incentives is complicated and will result in greater administrative burdens on the utilities. Staff should rather emphasize the requirements for REV implementation and specific tasks and timelines for circuit mapping than construct an overly complicated, multi-layered rate-reform approach. The proposed EIMs and scorecard metrics seem reasonable, but the EIMs could be stronger and more specific and the scorecard metrics are weighted heavily toward certain technologies. NECHPI notes that the emphasis is repeatedly on statewide system goals, not the key locational, temporal and attribute-based goals of REV. NECHPI also recognizes that until the utilities complete grid mapping and circuit hosting analysis and have implemented advanced metering functionality, there are limits to implementing circuit-specific compensation mechanisms. However, there are risks associated with establishing system-level values which may in fact be over- or underestimated and when implemented on a statewide basis, could dramatically increase, not decrease, utility bills. NECHPI agrees with Staff that issues surrounding DER integration will increase with higher levels of penetration, particularly of variable energy resources, but the Commission should not wait for those higher levels to begin the process of implementing new approaches to tariff design by concentrating on the foundational issues of the value of D and all of the other proposed components of the BCAF. These issues should be a priority of the first order rather than the development of MBEs and EIMs.

NRG Energy, Inc. (NRG):

NRG strongly agrees with the Staff's recommendation that EIMs should be adopted for outcomes. Aligning utility earnings incentives with the creation of a competitive distribution market is one of the most important steps that the Commission can take to make REV a success. In addition to the EIMs Staff recommended, NRG notes that EIMs should apply to the utility's DSP functions that would support the DER marketplace, such as interconnection timelines, information access and transparency, and market development, as well as broader system improvements brought about by competitive means, such as the success of competitive third parties in reducing of peak load, deploying energy efficiency solutions, reducing carbon, decreasing consumption of fossil fuels, etc. NRG states that in each case, EIMs should be aimed at aligning utility earnings with the goal of achieving better competitive outcomes. NRG agrees with Staff that utilities should be rewarded for encouraging activities that provide system value. Directly linking EIMs to activities that can be provided by third parties would incent utilities to encourage the market to provide customer solutions and grid support. Additionally, NRG states that the Commission should not rely on the utilities themselves to develop EIM metrics as utilities may not focus on the creation of a truly open access DSP function, and instead may align their efforts towards meeting self-identified targets that may not track the Commission's goal of creating a self-sustaining distribution level marketplace.

Nucor Steel Auburn, Inc. (Nucor):

Nucor states that performance based mechanisms that exacerbate New York's comparatively high electric rates will be counter-productive. Nucor asserts that the REV model ultimately hinges upon the development of fee-based services that will provide an adequate revenue stream from market participants. Positive only incentives will increase utility earnings on a flat or declining scale, thereby resulting in higher rates. To be sustainable, the REV model must require that all rate incentives combined produce rates that are just reasonable and affordable and that DER deployment must be managed to avoid unnecessary new T&D investment. Nucor states that all of the proposed EIMs should be thorough reviewed and regularly reassessed to attempt to avoid an unintended consequences. Nucor agrees with Staff's proposal that EIMs should concentrate on a small number of outcomes and maintains that any EIM should precisely target Nucor's three core concerns – the cost of establishing and operating the DSP; the requirements of the DSP and DER resources to optimize DER performance to ensure system wide benefits; and the length of time to establish MBE's to offset the missing revenue streams resulting from DER installations.

Public Utilities Law Project of New York, Inc. (PULP):
PULP agrees with Staff's position that existing safety, reliability, customer service, and utility-specific performance mechanisms should be retained. Regarding additional EIMs for peak reduction, energy efficiency, etc., PULP states that the record in this proceeding does not provide support for the use of EIMs where there is existing legal authority for the Commission to order pro-consumer and pro-business behavior. PULP states that there are insufficient details to provide specific comments on Staff's proposal regarding the positive or symmetrical nature of EIMs. PULP questions how the customer bill impact metric would be created and calculated and whether or not there would be true-ups if there were unforeseen circumstances that resulted in strong upward pressure on rates. Additionally, PULP does not agree that EIMs should be established on a multi-year basis. Finally, PULP shares the concerns of the Joint Utilities regarding the DPS Staff s claim of generation supply benefits in the form of lower carbon emissions and lower supply prices for retail customers as a result of many of the recommended Track 2 policies and programs.

Simple Energy:
Simple Energy recommends that EIMS be shaped and improved based on information gained from demo projects as well as from looking at other companies that have created markets that are flexible and interactive. Additionally, Simple Energy cautions against over regulation and also against focusing on perfection which could dampen the momentum of REV.

Solar Energy Industries Association (SEIA):
SEIA agrees that EIMs are an appropriate mechanism to incentive utilities, but notes that the overall goal of EIMs should be to develop a neutral platform that enables development of the DER market. As such, SEIA states that EIMs should be tied to developing the platform that enables the market to create the outcomes expected in REV, rather than being tied to the outcomes themselves. For example, SEIA notes that EIMs should drive infrastructure improvements that will enable DER deployment, reduce regulatory barriers that currently block DER providers and customers, and enable access to information for both customers and providers. It is not sufficient for the utility to demonstrate an increase in energy efficiency deployment or a decrease in peak demand from year-to-year; the utility must also show that those impacts were achieved by customer and third-party actions that were enabled and fostered by the utility. SEIA states that early-stage EIMs should place a heavy emphasis on developing the environment in which customers and third parties can take actions that lead to the desired REV outcomes, with relatively less emphasis on the outcomes themselves. To ensure that utilities are spurred to facilitate development of a neutral and sustainable DSP and DER deployment, SEIA asserts that all EIMs should have both an upside and downside for utilities (or the DSPP, as applicable). The Commission can implement EIMs that are based on utility or DSPP actions rather than factors outside of the utilities' control.

The Alliance for Solar Choice (TASC):
TASC supports Staff's proposal that EIMs should be consistent across all utilities and notes that that consistency will allow comparison of utilities in regards to their meeting REV goals. Specific EIMs may need to be measured differently, such that a utility that is already performing above average would get less proportionate credit for its progress than a utility that is performing below-average. TASC recommends that the Commission establish a minimum level of performance that utilities must achieve in order to earn incentives. Additionally, TASC notes that there should be at least one EIM required for utilities out of each of the near-term categories listed in the Staff proposal. This would ensure that even if the full range of EIMs and their weighting differ between utilities, the utilities have

to accomplish diverse objectives, ranging from peak reduction to affordability. TASC recommends that the Commission implement a stakeholder working group for EIMs that would be facilitated by a non utility entity to consider the EIM categories and how they would translate into meaningful metrics. Utilities' inability to measure certain metrics—or the risk of including confidential information in those metrics—should not result in rejection of an EIM that may have a high impact on the REV vision. Rather, TASC notes that changes to utilities' internal business processes and data collection may be needed in order to implement such EIMs that are central to REV objectives. TASC believes that utilities should be able to earn more incentives if demand growth occurs due to utility success in attracting new manufacturing or facilitating grown in electricity use for transportation. Lastly, TASC believes that incentives should reward utilities for effectively facilitating DER investment, even if the utility is not making a capital or operational expenditure.

SECTION III.C.3.b ALIGNING CUSTOMER VALUE WITH EARNINGS OPPORTUNITIES: Modifications to the Utility/DSP Revenue Model; *Earnings Impact Mechanisms, Scorecards, and Outcomes; Proposed Outcome Metrics*

AARP of New York (AARP):
AARP agrees with the Joint Utilities that the Staff proposed energy efficiency metric does not appear to be based upon a sufficiently thorough analysis of the underlying costs and benefits. Each utility should propose metrics and targets as part of the ETIP process without prejudging whether an EIM or a targeted programmatic incentive is more appropriate as this procedure would provide a forum for energy efficiency experts to weigh the costs and benefits associated with the pursuit of MW reductions (in concert with MWh reductions).

AARP shares the skepticisms raised by the Joint Utilities in relation the Staff proposed load demand reduction metric. While peak demand reductions may benefit consumers, such benefits would be dependent upon the cost effectiveness of achieving those reductions. Demonstration projects and studies that produce evidentiary documentation showing the relationships between the costs and benefits to retail consumers are an important prerequisite to setting any broad goals related to load reduction. Any load reduction goals should be proven to result in lower electric rates for New York consumers overall.

With regard to the development of a portal, AARP states that the Commission should proceed cautiously and only if a demonstration project can prove potential savings, which would be highly dependent upon the ability of utilities and DER providers to offer attractive products and services to consumers. AARP also believes that consumer privacy must be protected, and that no customer specific data should be released to third parties without obtaining that customer’s affirmative consent.

Advanced Energy Economy Institute (AEEI):
With respect to an Energy Efficiency EIM, AEEI agrees with Staff's proposal that attainment of peak reduction targets include at least the currently projected amount of energy efficiency and that at least 10% of the incremental peak reduction be achieved with efficiency programs. This proposal will incentivize the utilities to increase energy efficiency beyond minimum targets and will help to support the progress toward the energy efficiency goals set forth in the State Energy Plan during the transition of energy efficiency delivery. There should be incentives for energy efficiency and peak reduction that apply broadly across utility operations rather than on a programmatic basis as there are multiple avenues across utility operations for achieving goals in these areas. Additionally, AAEI notes that any cost effectiveness study for EE and peak demand reduction, as requested by the Joint Utilities, should take into account the full range of actions that a utility can take for energy efficiency and peak demand reduction, and how these actions might improve cost effectiveness when taken in concert with one another.

AEEI supports Staff’s proposed metrics for interconnection, and agrees with the delineation between projects above and below 50 kW. EIMs should continue or potentially even increase in size and importance, even as MBEs increase, until there is a need to reassess EIMs in general. AEEI agrees with the Joint Utilities that a reward for performance on interconnections should not be “all or nothing” based on whether the utility achieves a perfect score. The Commission should consider a reward structure that begins at achieving an 80 to 90 percent timeliness rating and scales up from there.

AEEI supports including peak reduction as an EIM, but raises several concerns regarding Staff’s proposals. Basing the EIM on a specific number of hours over the course of a year would require load reductions and demand response in many more hours than the target, since the actual peak hours will not be known until after the peak season has passed. The peak reduction EIM should not be based on reducing load during entire days, but instead should be based on reducing load during specific hours of peak days, and that independent forecasts should be used to determine the baseline peak loads which would have occurred absent any peak demand reductions. AEEI agrees with those parties who advised Staff to study the appropriate level of peak demand reduction and ensure that the level passes a benefit-cost analysis.

AEEI generally agrees with the affordability metrics, but suggests broadening the target of lowering bills using DER by including, in addition to DER, other REV-related technologies and programs, such as TOU rates, DR programs, and customer engagement tools and information. Regarding bad-debt write-offs, AEEI notes that customer engagement is an important tool in their prevention, by keeping customers apprised of their spending, providing savings tips, sending alerts for high usage, and similar mechanisms. AEEI supports providing multiple rate options to customers and believes that the Joint Utilities' proposed “pay-as-you-go” programs warrant consideration. Advanced metering, which enables such programs, can also help unlock tools such as high bill alerts that notify customers if they are on track to receiving a bill that is higher than a pre-established threshold.

AEEI is especially pleased to see Customer Engagement and Information Access as an EIM. This is a key enabler of DER markets and linking utility earnings to customer engagement will make REV more successful. It is critical that these metrics not exist in silos and instead are applied through a straightforward, comprehensive framework that tracks the progression of utility engagement from the customer’s perspective. AEEI believes that an effective customer portal of some kind is necessary for the success of REV and for animating markets for DER and new services. Demonstration projects can determine how to make a portal successful. Responding to the Joint Utilities' objections to an EIM measuring customer uptake of TOU rates, AEEI states that while it might be appropriate to reserve the use of a full EIM until TOU rates are revised, the uptake of TOU rates is only partly related to the value to the customer; utility communication strategies play a significant role in the uptake of TOU rates. Utilities also have a significant impact on the value of a TOU rate to a customer through their role in designing those rates.

BlueRock Energy (BlueRock):

BlueRock is concerned that the EIMs as proposed would not be sufficient to truly motivate utilities to gain peak demand reductions from third party DERs. BlueRock lays out a two-part EIM which would compensate utilities for peak-load reductions equivalent to the profit which they would otherwise have made from investing in traditional utility T&D infrastructure (i.e. about 15% of the revenue requirement of such projects), as well as grant the utilities a small portion of the total energy savings resulting from the peak reductions. BlueRock states that its proposed EIM would not only cause the utility to be indifferent to private investment versus a base rate increase, but instead to prefer such investments.

City of New York (NYC):

NYC agrees that one EIM metric should be interconnection timeliness, but disagrees with Staff’s proposal based on increasing interconnection approvals by 20% annually. NYC argues that Staff’s proposal has no factual basis and data has not been collected regarding the baseline amount, therefore there is no way to know if a 20% improvement in the number of approvals is reasonable. NYC proposes that the Commission should require the utility to codify interconnection requirements, dates, and deadlines within its tariffs; collect baseline interconnection process data; perform benchmarking against other utilities; and establish appropriate metrics to measure timeliness, utility responsiveness, project approval rates, and other salient factors not yet identified. If a utility's performance is sub-par compared to its peers, it should be required to improve its performance to a comparable level, potentially subject to negative incentives, before any positive incentives are awarded. As an interim measure, NYC proposes that the Commission should institute a scorecard measure related to interconnection while it develops the EIM metrics as proposed by NYC. NYC questions the reasonableness, propriety, and the utilities' ability to automate interconnection applications.

NYC agrees that the peak demand reduction metric makes sense, however it argues that such a metric should measure the utilities' success in their individual service territories, not on the wider bulk system. Similarly, load factors and increased system utilization should be measured on a utility-by-utility basis. NYC further notes that the peak reduction EIM and energy efficiency EIM may be duplicative.

With respect to affordability, NYC strongly supports the notion that low-income customers should have the same opportunities and options as other consumers but takes the position that developing an EIM related to affordability requires further study. First, a problem needs to be identified for which there is a potential utility solution. Second, the nature of the utility solution must be evaluated to ascertain whether the provision of incentives would provide incremental benefit. Third, if an EIM is determined to be appropriate, baseline data must be collected and reasonable thresholds and targets for improvement developed. Fourth, a cost-benefit analysis must be conducted to ensure that the proposed solution would be cost-effective. Fifth, the incentive levels should be established based on the results of steps three and four. Sixth, a reporting or other mechanism must be included to monitor and measure the utilities' performance. NYC recommends that the Commission refer this matter to Case 14-M-0565 for further development rather than adopt the proposal in the Track 2 White Paper.

As for a metric related to access by consumers to their usage information, NYC and other parties have clamored for such access for years. As noted in the Track 2 White Paper, tools to provide such access already exist. If the Commission decides to adopt a metric for access, it should be tied to the utility's education and outreach efforts, the volume of traffic the portal receives as a result of such efforts, and the purposes for which the information is accessed. Utilities should be rewarded only if their efforts result in increasing customer use of this data for REV-related purposes. NYC also disagrees with aspects of the proposed EIM based on customer engagement. Although customer engagement is critical to the success of REV, the utilities cannot control what consumers do, and rewarding them for actions by others serves no valid purpose. Moreover, EIMs should be used to achieve stretch goals, not relatively administrative acts.

Clean Energy Organizations Collaborative (CEOC):
CEOC recommends the energy efficiency EIM take demand savings (MW) at the local distribution level peak and annual and lifecycle MWh savings into account and that the targets for energy efficiency be set at least as high as those ordered in the Track One Order. Further, CEOC states that although certain, utility-specific adjustments could be applied as appropriate, the utilities should use consistent algorithms and methods to calculate savings. In addition to energy and demand savings, CEOC comments that the energy efficiency EIM include participation in energy efficiency programs, which CEOC recommends be defined as the percent of customers participating in the utility's energy efficiency programs per year, by rate class, adjusted for repeat participation as feasible. CEOC comments that any EIM process should include periodic studies of and reports on the energy efficiency programs implemented within each utilities service territory that assess the way in which each utility's performance contributes to the goals set forth in the State Energy Plan. CEOC suggests the following additional scorecard metrics for energy efficiency: MWh saved as a percent of the utility's total load (including permanent EE load reduction); cost of MWh saved at both the program and portfolio level and disaggregated by type of cost; cost effectiveness as measured by the Societal Cost test, including non-energy

benefits and presented by program both as a ratio and as a net present value; reduction in non-CO2 pollution, including but not limited to NOx and So2, by program; and conversions of fossil fuel combustion appliances to high efficiency electric appliances per year. Finally, CEOC states that Staff should clarify whether the EIM will replace or supplement the utilities' existing positive revenue adjustment for EEPS 2 MWh achievements.

CEOC supports the creation of EIMs for interconnection, however, such EIMs should be further developed though stakeholder processes.

CEOC notes that while peak load reduction is a priority and deserves to have an EIM associated with it, efforts to reduce peak demand should not come at the expense of pursuing aggressive energy efficiency. The peak reduction EIM appears to be redundant with other EIMs and scorecard metrics, and that the target does not appear to be achievable. This EIM should require adjustment for changes in weather and economic conditions, should not have a penalty applied if a utility fails to meet it, and that the amount of financial incentive should be small relative to the other financial compensation available to other EIMs; these proposed changes would mitigate the risk of utilities spending more than is necessary on peak load reduction, as well as avoid overcompensating utilities for outcomes beyond their control. CEOC urges Staff to scrutinize the numbers put forth in the Joint Utilities' comments and set peak reduction targets based on its own assessment of what is cost effective and reasonably achievable. CEOC also states that the metric must be designed to avoid customer fatigue with DR programs. CEOC recommends reducing the relative weight given to EIMs in proportion to a rough measure of the extent to which they are under the influence of the utility, as determined in an open stakeholder process, rather than including only reward incentives.

CEOC supports use of EIMs for affordability, but suggest that this set of metrics include three components: 1) low-income participation rates in EE, DR, DG (especially solar), and TOU programs, 2) reductions in terminations, and 3) reductions in uncollectible expenses. Participation rates should be considered for all rate classes, by type of DER. Affordability scorecard metrics should be created for annual and lifecycle MWh savings, and for annual and lifecycle bill reductions per low-income participant, by low-income program (EE, DR, solar DG, and TOU). Staff should clarify whether the affordability EIM would replace or supplement existing service termination/bad debt revenue adjustments. Responding to the comments of the Joint Utilities, CEOC agrees that eligibility rules should be reviewed to assess whether there are ways to improve access to services before customers are at the point of service termination, but is not convinced that AMI is needed to achieve the goals of the affordability metric. Further, CEOC expresses concerns regarding “pay-as-you-go” programs, stating that such programs may permit utilities to sidestep consumer protections while altering the utility’s incentives to interact creatively and constructively with payment-troubled customers. CEOC agrees with MI that affordability metrics should be formulated so as to incentivize affordability for all customers but argues that affordability for low-income customers is especially important and that metrics should be established to provide a greater incentive to limit rate impacts on those customers.

With respect to an EIM focused on customer engagement, the CEOC parties recommend that the “early indicators” include user-friendly data formats, ideally with automatic generation of charts that show typical summer weekday consumption patterns, or other data that the customer can meaningfully act upon. A scorecard metric should be developed for third-party vendor satisfaction with the utility interface, based on survey conducted by an independent party of all vendors with requests to provide services through tool during one year period. The independent party could be a relevant government agency, such as the New York State Energy Research and Development Authority, or it could be a private company selected by a relevant government agency, such as the Commission Staff. CEOC agrees with other commenters who state that online portals should be launched as early as possible in their development, at which point utilities should log key performance metrics to enable iterative changes to be made early enough to drive successful implementation. It will be important to monitor performance of all metrics, including customer engagement and information access metrics, over time and to make adjustments as needed. TOU engagement should be a separate EIM based on the percentage of customers signed up. Savings per customer should be tracked as a scorecard. Other data that the Commission could consider tracking include the number of customers contacted, marketing media type (in order to improve marketing approaches going forward), and customer awareness and comprehension of TOU rates (based on customer survey results, similar to those used in O&R's service area regarding comprehension of retail choice).

Comverge, Inc., and EnergyHub (Comverge/Energy Hub)
Comverge/Energy Hub supports the concept of a peak reduction metric, but does not support the specific proposal to address the top 100 hours of peak load. Since the top 100 hours are not known to customers or the utility before they occur, demand response program assets could be dispatched for many more than 100 hours, causing demand response participants to leave the program.

Comverge/Energy Hub supports the intent of the customer engagement EIM. Staff should remain open to multiple channels for customer outreach beyond utility portals, to provide for iterative processes to identify and shape utility marketing strategies, and to be mindful that program design is as critical as marketing is in driving mass DER adoption. Portals may not drive huge adoption of residential DR measures. The majority of customers who have participated in bring-your-own device DR programs to date have purchased their devices through other channels such as retail stores or more general-use online shopping websites. Comverge/Energy Hub applauds the adoption of an "open and widely adopted industry standard tool" for data sharing and agrees that "prompt implementation of a statewide tool with accompanied safeguards would be one early indicator of utility effectiveness in increasing customer access to and control over their energy usage data." However it remains unclear, without advanced metering infrastructure capable of recording interval consumption data, what level of data can be shared with customers beyond what is available on their monthly bill.

Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. (Con Edison/O&R):

Con Edison/O&R takes issue with NYC's description of Con Ed's interconnection process for large DG as "extensive, burdensome, redundant or contradictory, and expensive requirements on applicants." Con Ed states that it follows the Standard Interconnection Requirements as approved by the Commission for projects under 2 MW and Con Edison's publicly published procedure EO-2115 that provides the technical specifications for larger DG facilities, both of which are based on standards developed by the American National Standards Institute and reflect state-of-the-art interconnection practices. Large DG projects require a technical process to interconnect on the Company's network system so that their interconnection and operation does not jeopardize the safe and reliable operation of the Company's electric system. Con Ed has a webpage that provides DG customers and vendors with information to navigate the interconnection process, handbooks for both large and small DG and contact information, engineers and project managers available to provide support, and a DG Ombudsman for the specific purpose of assisting customers with interconnection and other DG-related issues. Con Ed notes that it was recently recognized by the Solar Electric Power Association for innovation in interconnecting a large-scale solar project.

Con Edison/O&R is concerned that the peak reduction EIM does not take into account existing customer needs, the consequences of the proposed solutions, the ability and cost to achieve it, or unintended consequences such as stunting economic growth. The avoided T&D infrastructure benefits projected by Staff may not materialize since the bulk system peak hours often do not coincide with the distribution network peak hours which are the main consideration when making demand-related infrastructure decisions on the distribution system. Con Edison echoes the Joint Utilities' proposal for a programmatic approach designed to target distribution system peaks subject to benefit cost analysis.

Energy Democracy Alliance (EDA):

EDA proposes additional EIMs and scorecard metrics that EDA believes will compel utilities and market actors to serve the public interest. Specifically, EDA proposes enforceable renewable energy and energy efficiency targets and recommends financial penalties in instances where a utility fails to meet such targets and financial rewards in instances where a utility significantly exceeds such targets. EDA states that the environmental goals should be tied to metrics set forth in the State Energy Plan or based upon the latest climate science. Finally, EDA recommends that each utility be required to procure energy from a certain percentage of local/community owned energy projects in its service territory.

Energy Efficiency for All (EE for All):
EE for All states that energy efficiency EIMs are likely to play an important role in driving future investment in energy efficiency in the affordable multifamily sector. EIMs should take into account both the demand savings (MW) at the local distribution peak, as well as the annual lifecycle MWh savings. The EIM for lifecycle savings should reward performance beyond regulatory targets. EE for All also recommends that the energy efficiency EIM include participation in energy efficiency programs and that a scorecard metric be established specifically for the deployment of energy efficiency measures in the multifamily sector to address what EE for all characterizes as the untapped potential of that sector. Using GIS data and mapping tools provided by the NYS DEC, a scorecard metric should be established for tracking the installation of specific DER in potential environmental justice areas. EE for All also states that while establishing more aggressive utility targets for energy efficiency will provide a floor for energy efficiency investment and prevent backsliding, it is likely to be the EIMs that drive increased investment beyond the Commission's regulatory requirements. EE for All further states that carefully designed and thoughtfully implemented EIMs could put New York on the patch to achieving the 600 trillion BTU goal set forth in the State Energy Plan.

Energy Technology Savings (ETS):
ETS states that whether or not DER provider participation in the portal, platform, or digital marketplace will be required as a precondition to the interconnection process. Utility progress toward easing the interconnection process should be measured.

Environmental Defense Fund (EDF):
EDF states that other than energy efficiency, the EIMs do not address the State Energy Plan goals, and that the EIM section of the Staff White Paper says little about the environmental outcomes as envisioned in the three primary goals of the State Energy Plan. Further, EDF argues that including carbon emissions reductions in the proposal as a non-earnings-related Scorecard metric is insufficient to capture the quantity of interest in the State Energy Plan, changes in the total amount of CO2. EDF recommends the inclusion of an EIM for reduced number of CO2 allowances required to serve load, which it states better aligns with the State Energy Plan goal. EDF further recommends that the carbon allowance EIM should not be limited to reductions resulting from DER and utility energy efficiency programs, but should capture all utility activities that increase or decrease the need for CO2 allowances and should include a downward adjustments for tons of CO2 emissions attributable to generation resources below 25 MW regardless of whether the generation is sold onto the bulk system, sold back to the distribution system or, used by the customer behind the meter. EDF agrees with the Joint Utilities' assertion that Staff’s proposed energy efficiency EIM would undermine existing energy efficiency programs. However, the shift may not harm cost effectiveness; if the cost of peak power is properly accounted for, particularly the cost of carbon associated with less efficient peak resources, it is possible that an increased focus on peak reductions would be consistent with modifying energy efficiency programs in a way to improve their cost-effectiveness.

With respect to an interconnection EIM, EDF states that the Commission should not begin rewarding rapid interconnection of distributed generation until rules are in place to protect public health and the environment from the emissions associated with these generation resources.

EDF states that the peak reduction EIM is on the right track, but that an additional EIM to incentivize utilities to manage critical peak usage in particular areas may also be appropriate. EDF notes that while the top 100 hours target proposed in the peak reduction EIM would meet a number of goals, it does not meet the distribution system critical peak loads which drive the need for distribution system infrastructure upgrades. EDF takes issue with the Joint Utilities' comments, pointing out that the utilities' influence over system peaks is not confined to NWA projects; rather, it resides in their business models overall. Energy costs are passed through to mass market customers, who can do little to reduce their consumption of the most expensive power without utility companies' support without real-time data access and third party customer support – yet providing mass market customers with tools to reduce their consumption of the most expensive power (such as metering functionality and pricing that would allow them to be aware of especially pricey critical peak power and reduce their consumption of it) or the ability to work with third parties to do the same has not typically been a part of the utilities' business model. The non-coincidence of the bulk system peak does not constitute an argument against an EIM regarding the bulk system peak; rather, it illustrates the importance of establishing a discrete EIM tailored to the system peak to complement the metrics designed to encourage the utilities to contain the overbuilding of their own systems.

Federal Trade Commission (FTC):
The FTC states that the proposed EIM related to customer engagement warrants additional attention as increasing sharing of data can increase risks to consumer privacy.

Interstate Renewable Energy Council, Inc. (IREC):
IREC states that while the two interconnection EIMs proposed by Staff are reasonable starting points, additional consideration of timeliness metrics, interconnection costs, and access to data should be considered by the Commission. IREC argues that customer delays should not end up penalizing the utility, that timeliness should be measured at both the time it takes to complete the review process resulting in an interconnection agreement, and the time it takes the utility to complete any necessary interconnection facilities or system upgrades, and that timeliness of fast track projects and full study projects should be considered separately. IREC proposes to instate an EIM based on two factors: (1) predictability and certainty of the costs of the interconnection study; and (2) the accuracy of

the cost estimate provided by the utility versus the actual costs to interconnect and necessary system upgrades. IREC notes that the Utilities are in control of both of these factors and can control address them through good data sharing and internal processes. IREC also proposes a new factor for the Interconnection EIM related to customer access to grid data and transparency of grid conditions which should be measured through an EIM, or a scorecard at minimum. IREC proposes that a negative EIM could be set to require the delivery of basic data in a timely manner, with positive incentives allowed for the rollout of more sophisticated tools.

IREC strongly supports the use of EIMs to encourage utilities to seek better and more cost effective ways to reduce and manage peaks, however it makes sense for the Commission to identify alternative peak reduction strategies to counteract the loss of revenue that utilities may incur. IREC notes that the calculations used in the White Paper are difficult to follow, and questions why the 3% peak load reduction target was developed. IREC believes that it would also be appropriate for the EIM or the scorecard to encourage the use of DER to achieve the peak reduction target.

With respect to the suggestion that an EIM should be created that gauges the utilities ability to successfully implement an online portal, IREC states that the bar for creating a reasonable online portal seems is too low – creation of a good online portal should be required as a minimum. Like with interconnection and other data access, creating a reasonable method for customers to access information about their energy use is fully within the utilities’ control and should be required. The EIM should instead focus on how many customers actually use the portal to manage their energy use in a way that reduces their bills, as discussed later in the White Paper. Customer engagement may be difficult to track and measure, but the Commission should endeavor to identify more meaningful metrics if there is going to be any positive EIM added in this area.

Joint Utilities:
The Joint Utilities agree that it is appropriate to continue to implement a programmatic incentive as part of the utilities' energy efficiency programs. However, that the annual statewide energy efficiency goal of approximately 55 MW for each of the next five years proposed in the Staff White Paper does not appear to be based on a thorough analysis or a consideration of the underlying benefits and costs. Instead, the Joint Utilities recommend that each utility propose metrics and targets in the ETIP process without prejudging whether an EIM or a targeted programmatic incentive is more appropriate. Such a process will provide a forum for energy efficiency experts to weigh the costs and benefits associated with the pursuit of MW reductions and MWh reductions in a manner that reflects utility-specific circumstances and complies with further incentive guidance to be provided in the Commission's Track Two order. In addition, the Joint Utilities argue that the proposal to measure energy efficiency in terms of peak load reductions would not only undermine existing energy efficiency programs that are measured in terms of kWh reductions over a broader timeframe but also change the costs and cost effectiveness of energy efficiency programs. The Joint Utilities propose that incremental energy efficiency programs focused on demand reduction should be evaluated in subsequent ETIP filings and be subject to the Distributor Cost Test, and state that incremental cost-effective programs could then be implemented with corresponding budget and incentive mechanisms. Finally, the Joint Utilities recommend that targeted incentives for energy efficiency should be positive, only, stating that the outcomes of energy efficiency programs can be meaningfully influenced but are not within the reasonable control of a utility.

The Joint Utilities agree that distinct incentive mechanisms are appropriate for small and large interconnection activities, and that some type of interconnection incentives are appropriate as EIMs. There are a number of customer incentives which are set to expire soon which could lead to increased volumes of near-term interconnection requests – the interconnection EIMs should be positive-only to start, and gradually move to symmetrical. Regarding small interconnections less than 25 kW, the Joint Utilities propose that the timeliness incentive should be based on a tiered structure with increasing rewards as timeliness improves. The Joint Utilities oppose the 20% increase in interconnections metric, stating that the target is likely to quickly become unattainable and is not within the utility's control and ability to meaningfully influence. EIMs for large interconnections should be flexible to accommodate more complex projects, and developers which fail to meet its interconnection requirements at any time should be excluded from the timeliness targets. The Joint Utilities object to any component of the interconnection EIM which would be tied to developers' costs to comply with system requirements.

The Joint Utilities argue that the target set by the peak reduction EIM is not achievable through a normal utility program, and that the Staff proposal establishes an EIM which would motivate utilities to procure peak load reductions at any price and would likely not be cost-effective based on recent prices paid for peak demand reductions through the Indian Point Demand Management Program. If a peak load reduction metric is established, it should be based on an assessment of the degree to which DER deployment can reduce the need for bulk system capacity and lower costs to customers while preserving reliability – these peak load reductions should be addressed primarily through NYISO programs coordinated and complemented by the utilities. Instead of the approach suggested by Staff, the Joint Utilities recommend a programmatic approach to address localized system peaks while considering bulk system value when optimizing program design. These programs would seek a mix of optimized resources which contribute to meeting both network and bulk system peaks to defer distribution-level infrastructure needs. The incentives tied to these programs should be reward-only, both the programs and incentives should be subject to benefit cost analysis.

With respect to "affordability" EIMs, the Joint Utilities point out that Staff, the utilities, and other stakeholders are just beginning to explore ways to give low-income customers access to DERs where the marketplace would not otherwise serve them. Since this concept is relatively new and untested, the Joint Utilities propose that engagement of low- and moderate-income customers in DER programs first be tested in a demonstration project environment where the utilities can gather information, test customer interest, understand the successful channels of engagement, and gain experience administering these programs.

With regard to customer engagement EIMs, the Joint Utilities state that it is not yet apparent whether the first major component of Staff's proposed EIM -- the longer term development of a portal bringing customers, ESCOs and DER providers together -- represents a positive value proposition for customers given that prior efforts both within and outside of New York to implement a statewide energy portal have been costly and unsuccessful. While this objective is clearly relevant and important to REV, the concept has been relatively untested by the Joint Utilities and merits further investigation. The success of the portal should be gauged through ongoing REV demonstration projects and is highly dependent on customer response and the ability of ESCOs and DER providers to offer attractive products and services. The second major component of this EIM measures the utilities' launch of a data sharing tool that will allow customers to automatically share their energy data with selected ESCOs or DER providers. While the Joint Utilities support this proposal in principle, such a tool must be developed with input from participating ESCOs, DER providers, and customers, and should be implemented in a manner that provides benefits and value to customers that justify the implementation costs. The Joint Utilities propose designing metrics once more experience is gained through the various digital marketplace demonstration projects.

Microgrid Resources Coalition (MRC):
MRC does not agree with the targets proposed for either peak load reduction or energy efficiency. MRC proposes that overall goals should be set statewide for all utilities, with some individualization based on the particular circumstances in a particular service territory. MRC states that the target for the peak load reduction EIM should be to eliminate the top 100 hours of peak demand over 5 years, or approximately 20 hours per year.

With regard to the Data Access Portal and to the proposed "Customer Engagement and Information Access" EIM category, the

MRC strongly supports a utility portal that provides prompt, convenient access to customer to view its usage data and the ability for the customer to share that data with DER vendors at the customer's request. The second major utility information function is to catalog the locations on their systems where DERs can make a contribution. This should be a planning function not a requirement by DER providers over and above clerical and electronic document transmission fees would just raise barriers to entry.

Affordability must be addressed comprehensively as part of the low-income affordability proceeding not in individual utility rate cases.

Mission:data:

Mission:data states that the proposal of an EIM should gauge utilities' ability to successfully implement an online portal that supports customer engagement with DER providers, while well-intentioned, does not properly emphasize that the information required to develop such a resource be made available to the marketplace as a DSP function. This is particularly relevant in the case of a customer's usage data, which would be a fundamental component of such a system. The delivery of the information required to operate such a portal should be established as a non-competitive function of the DSP so that all market participants may benefit and innovate for the benefit of all customers. As a platform function, delivery of this kind of underlying information is easily accomplished through application program interfaces, or APIs. Mission:data asserts that the proposed scorecard should include explicit metrics regarding the implementation of data access mechanisms. Metrics be developed that indicate the ability of consumers to have ongoing access to their own historical interval data and real-time meter information using widely adopted standards, the ability of consumers to allow authorized third parties to have ongoing access to their historical interval data and real-time meter information using widely adopted standards, and implementation of application program interfaces, or APIs, for other relevant market information.

Multiple Intervenors (MI):
MI is concerned with the proposed energy efficiency EIM, arguing that the utilities do not assume any risks in administering energy efficiency programs that are funded entirely by customers. MI states that Staff would be at a disadvantage if forced to negotiate an EIM with utilities over specific energy efficiency savings targets due to what MI characterizes as an information advantage possessed by the utilities. In MI's experience, the creation of a regulatory incentive often creates an equal or greater number of perverse incentives. If the Commission decides to implement EIMs focused on energy efficiency savings, it should recognize that it would simultaneously be incentivizing utilities to understate forecasted energy savings and overstate savings attributable to the programs they administer.

MI generally agrees with the thrust of Staff’s proposed interconnection EIM, but with a number of modifications. MI is in favor of expanding the EIM to include metrics based on cost moderation and provision of more accurate interconnection cost estimates. Staff should establish an office dedicated to mediating and resolving interconnection-related disputes between customers, developers, and utilities.

MI recommends that instead of focusing an EIM on peak load reduction, the Commission should institute an EIM based on improvements to system load factors. This would avoid potentially controversial peak load reduction targets and adjustments to those targets, as well as eliminate the possibility that the utilities would be rewarded for an outcome which is entirely or predominantly unrelated to any actions the utilities may have taken.

With respect to the proposed EIM based on increasing affordability for low-income customers, MI states that affordability concerns are not limited to low-income customers. This proposed EIM, if adopted, be refocused on rate levels and encompass all types of customers. Whether REV ultimately is viewed as successful will depend, in large measure, on changes to customers’ rates and bills from this point forward.

The proposed EIMs focused on customer engagement are unnecessary. If, however, the Commission decides that some EIM in this area is needed, it should simplify matters. The Commission should direct utilities to complete an online portal that satisfies certain criteria (including allowing customers to access their energy usage information) within a specified period of time. Utilities that complete the portal early could be provided with a modest EIM, and utilities that fail to complete the portal on-time would be penalized. Once the portal is operational, the Commission could offer a symmetrical incentive (rewards and penalties) based on the number and the types of transactions processed through the portal. After some initial period of time following the start-up of the portal, this transaction-based EIM could be eliminated because PBRs and other MBEs opportunities would provide utilities with ample incentives to ensure that the online portal functions well. If the Commission also wishes to incentivize DR and time-of-use programs, EIMs should focus on participation levels which would include how many megawatts have signed-up for the utility's retail DR programs, and how many new customers have signed-up for TOU programs. Participation is a far more meaningful measure of performance than how many times a utility contacts customers through social media or other avenues merely to promote a program.

National Fuel Gas Distribution Corporation (NFG):
NFG states that the energy efficiency goal included in Staff's White Paper pertaining to targets for electric peak reductions would be counterproductive to natural gas customers and does not apply to natural gas utilities. NFG also state that the electric peak reduction energy efficiency target seems redundant with the Peak Reduction EIM proposed by Staff. Financial incentives should only be awarded on a positive basis, the funding for incentives should be explicitly indentified, and the structure for awarding incentives and the magnitude of incentives should be clearly identified and simple to understand. Finally, NFG recommends that the Commission expeditiously take action to award EEPS 1 and EEPS 2 incentives to assure utilities and other market actors that the Commission will deliver on promised incentive constructs.

NFG notes that while it supports the actions of the Commission to automate processing of small DG projects and increasing interconnection timeliness, it does not support Staff's EIM proposals for natural gas customers and notes that these do not apply to natural gas utilities.

NFG states that it is difficult to comment on the affordability EIM targeted at supporting low-income customer usage of DERs. Before this EIM is considered further by the Commission, a collaborative process should be convened as part of case 14-M-0565.

With regard to the implementation of an online portal that supports customer engagement with DER providers, NFG notes that utilities have a number of robust tools and vehicles to provide mass-market customers with convenient access to their energy usage information, facilitating their ability to share that information with vendors they select. As a result, a newly developed online portal may not be needed at all. The second EIM proposed in this category is the percentage of utility customers using the online portal to share their customer usage data with DER vendors, six months after the portal is made available. Although this information may be useful to determine the uptake of REV initiatives, this should not be an EIM, as performance for this EIM is entirely outside of a utility's operational purview. The third EIM proposed in this category is the extent to which utilities successfully promote demand response and time-of-use programs. This EIM would be counterproductive to natural gas customers and does not apply to natural gas utilities.

Northeast Clean Heat and Power Initiative (NECHPI):
NECHPI raises the concern that given that the three-year ETIP programs seem unlikely to achieve the goals proposed by Staff in its White Paper and that the discussion of the transition to a market-oriented approach to energy efficiency was vague and did not include well-specified tasks and timelines for implementing specific programs. NECHPI states that it is also concerned that the carbon reduction approach included in Staff's White Paper is too simplistic. Without more specificity on the methodologies used to measure two of the scorecard metrics, carbon reductions

and conversions of fossil-fueled end uses, the results will be unfavorable to CHP interests. NECHPI asserts that natural gas-fired CHP can provide significant power output and reduced emissions per unit of output over other distributed-generation technologies. The Commission should align the treatment of GHG emissions reductions across all proceedings.

NECHPI states that Staff's proposed interconnection EIM metrics are inadequate, and argues that the Commission should instead focus on instituting a collaborative stakeholder process to establish best practices for interconnection and on updating the state's Standardized Interconnection Requirements. NECHPI notes that the interconnection process established through its proposed stakeholder process should: (1) implement transparent interconnection rules for all utilities; (2) develop standardized rules covering the entire interconnection process; (3) establish detailed and clear timeliness and compliance assurance rewards and penalties; and (4) use recent interconnection proceedings at FERC, and in California and Massachusetts, as a model for protocols.

NECHPI notes that the Joint Utilities provide ample evidence that peak reduction is an inappropriate metric and is not measurable without circuit-level measurement and monitoring.

NECHPI recommends that customer-engagement metrics be more robust and specific. Additionally, NECHPI states that current TOU rate structures may not represent best practices in dynamic rate design and recommends that the Commission evaluate other dynamic pricing approaches, including TOU with critical peak pricing.

Nucor Steel Auburn, Inc. (Nucor):

Nucor supports a peak reduction EIM adjusted for weather and to accommodate for economic growth, however the utilities should be allowed to adjust their projected base and peak loads to account for year to year changes in economic growth.

The peak reduction EIM as proposed is unnecessarily complicated, and that a more appropriate mechanism would be to directly target improvements in system load factor.

Nucor comments that an "affordability" EIM is wholly unwarranted. All customers, large and small, have a keen interest in affordable rates. Allowing a utility an increased rate of return (which increases all customer rates) for meeting affordability metrics is contradictory on its face. There are many facets of the REV utility-as-DSP process that will place upward pressure on consumer rates.

An EIM for customer engagement and information access is superfluous because utilities will be directed by the Commission order to implement related DSP measures, and an ROE adder is unnecessary.

New York Battery and Energy Storage Technology Consortium (NY-BEST):
NY-BEST supports the concept of incentives for peak reduction and the 3% annual peak load reduction target. NY-BEST urges Staff and the Commission to consider adopting performance incentives that reward utilities for improving system utilization and flattening peak loads. EIMs need to consider ratepayer impacts, the degree of utility control over outcomes, feasibility of the metrics, and financial impacts on utilities. The Commission should adopt interim measures while it fully considers EIMs in order to maintain private project developer and investor interest in the New York electricity market.

Pareto Energy (Parento):
Pareto replied to Con Ed's comments on the Peak Reduction EIM, stating that it is unlikely that the entire state-wide cost of the peak reduction EIM would be $5 million per MW. Taking the Con Edison peak load of 13,322 MW in 2013, it appears that a reduction of approximately 328 MW per year would achieve the objective. According to Con Edison's calculations, the cost to ratepayers for the five-year Peak Reduction EIM would then be $8.2 million. Pareto believes that the use of a power electronics platform for interconnection of existing or planned CHP in Brooklyn and Queens alone would enable the first 369 MW of the Peak Reduction EIM without any need for ratepayer funding. Alternatively, Pareto contends that an entirely market-based approach can finance this upgrade. This is now

possible because the power electronics platform enables fuel efficiencies and the ability to provide least cost energy and control services to the NYISO’s Behind-the-Meter Net Generation Market in a way that mechanical synchronous interconnection cannot.

Public Utility Law Project (PULP):
PULP does not support EIMs in general; the Commission does not need to allow utilities to earn incentives since it has the legal authority to require pro-consumer and pro-business behavior. PULP states that Staff’s proposal to establish a statewide annual MW reduction target for energy efficiency does not appear to be based on any thorough analysis or consideration of the underlying benefits and costs. The proposed measure of energy efficiency in terms of peak load reductions would undermine existing energy efficiency programs such as residential lighting that are measured in terms of kWh reductions over a broader timeframe.

PULP states that Staff s peak reduction EIM proposal does not specify the manner in which peak usage reduction will be monetized in the wholesale market or by whom. Further, Staff does not demonstrate how the proposed programs will result in lower customer electric prices or bills

Solar Energy Industries Association (SEIA):
SEIA notes that the interconnection EIM should be measured by metrics which measure how quickly and efficient the utility handles requests to interconnect DERs, as well as customers and DER provider satisfaction.

SEIA does not support the proposed peak reduction EIM because it may stifle marketplace innovation. A more appropriate way to incentivize the utilities would be to incentivize the building blocks which lead to an outcome, instead of incentivizing the outcome itself.

The customer engagement EIM should focus on facilitating customer engagement with the marketplace and with DER providers, through such measures as the extent of customer knowledge about their DER options and the number of customer requests for information or for DER services. The information access EIM should be focused on the ability of DER providers to gain access to two types of information: 1) planning information regarding optimal locations and the nature of the "need" for DER and 2) real time information (price or other pertinent information) that signals when DER output/load curtailment would be most useful. This can also be measured generally through metrics such as the availability of internet-based information and the level of satisfaction of customers and DER providers in getting timely and accurate information from the DSP.

The Alliance for Solar Choice (TASC):
TASC supports the interconnection EIM in general and proposes that the Commission should measure utility performance on interconnection timelines for both small and large projects as soon as possible. Interconnection performance should be measured based on past performance within each utility, performance benchmarked against other utilities, and also that customer satisfaction in the interconnection process should also be measures. TASC states that this EIM will be most effective as a symmetrical incentive, and that a metric measuring total MW of interconnected capacity should also be added. TASC further requests that in addition to this EIM, a dispute resolution framework should be established to resolve issues around standards and process for interconnection. TASC also supports Staff's proposal to add scorecard metrics to measure performance among utilities but argues that these scorecard metrics should not include contributions from assets owned and rate-based by utilities.

TASC supports an EIM which rewards utilities for reducing payments to the ISO for energy, capacity, and ancillary services during peak demand periods. TASC suggests that the EIM should reward both system-wide peak reduction as well as peak reduction on specific circuits to achieve capital and operations cost efficiency. TASC also proposes three guidelines which should be used in determining a proper peak demand-related incentive: (1) the incentive should be rich enough to motivate utilities to help DER compete against central-station generation; (2) shareholder incentives should be based on reductions in payments from the utility to the NYISO for capacity, energy, and NYISO uplift charges as well as avoided environmental externalities and avoided utility infrastructure; and (3) the EIM could include a reward for peak demand below a certain threshold and cooperating with ESCOs and DER providers. Incentives should be more profitable for utility shareholders than incremental retail electricity rates.

TASC agrees that EIMs for the customer engagement and information access category should be a priority. Customers should be able to share their data electronically with DER providers through an integrated online portal.

SECTION III.C.4 ALIGNING CUSTOMER VALUE WITH EARNINGS OPPORTUNITIES: Modifications to the Utility/DSP Revenue Model; *Earnings Sharing Mechanisms*

AARP New York (AARP):
AARP believes that ESMs should be tied to actual performance. However, lack of any specific performance "index" or information on how ESMs would be calculated makes it difficult for AARP to evaluate the proposal at this time.

Advanced Energy Economy Institute (AEEI):
AEEI states that ESMs should not be the primary instrument for incentivizing utilities as they are not effective for utilities that are not earning their allowed ROE. ESMs also place operating efficiency above other performance goals because the utility must be operating efficiently in order to achieve its allowed ROE. AEEI prefers that REV-related incentives start with EIMs as the primary approach. Because of the way ESMs are structured, operational efficiency will always be the primary incentive provided by ESMs, regardless of whether the utility's allowed portion of retained savings is increased or decreased based on REV performance. In order to receive increased earnings based on EIM performance through an ESM, a utility must already be operationally efficient and earning over its allowed ROE. Keeping the incentives for EIMs and operational efficiency separate will allow Staff to more easily track the performance of and make adjustments to both mechanisms.

Citizens Environmental Coalition (CEC):
CEC argues that greater explanation of the proposal is necessary before it can offer comments.

City of New York (NYC):
NYC expresses concern with the ESM/MBE hybrid approach, stating that utilities will continue to have at least some captive ratepayers because DER may not be available or cost-effective in all areas and for all consumers. To allow utilities to over earn while still seeking recovery of expenses and capital investments above the levels allowed in rates is arguably unjust and inequitable to those captive ratepayers. If utilities are permitted to retain MBEs, a sliding scale should be imposed that limits their ability to recover costs above the levels set forth in their rate plans. As their total earnings increase, the percentage of costs that are recoverable should decrease. There should be some connection between the magnitude of the earnings and the effort expended, and the settings should be utility-specific. In setting ESM enhancements, some consideration to the dollar amounts at issue and whether they are sufficient, inadequate, or excessive to incentivize the utilities is needed.

Clean Energy Organizations Collaborative (CEOC):
Using the performance indicators for both the ESM and the utility compensation packages will send comparable signals to both utility management and utility shareholders regarding the performance expected of them. CEOC generally agrees with Staff’s proposal to tie the ESM to base performance metrics and recommends that base performance metrics be based on an indication of reduced costs, increased system efficiencies or customer participation in DER. The Commission should establish a performance threshold that should be used to determine whether utility management is eligible for utility compensation packages in each year. Linking the ESM to performance will ensure that customers directly experience the benefits of improved performance before utilities obtain amplified earnings for that improved performance. CEOC recommends that the Commission establish a performance threshold, using the same performance metrics that are used in the ESM, to determine whether utility management is eligible for utility management bonuses in each year.

GridWise Alliance (GWA):
GWA concurs with Staff's recommendation. To make REV investments more attractive to utilities, consideration should be given to allowing slightly higher returns on investments and faster recovery for the investments that support the move to the DSP model.

Institute for Policy Integrity, New York University School of Law (Policy Integrity):
Policy Integrity comments that properly designed ESMs can be successful in achieving REV goals. The Commission should review different structural elements of these plans such as performance targets, rewards and penalties, and set them in an integrated manner to ensure that the overall ESM leads to incentives that are consistent with REV objectives. A menu should be offered of gain sharing contracts that have smooth formulas for calculating incentive payments and both positive and negative revenue adjustments.

Joint Utilities:
The Joint Utilities recommend keeping the ESM independent of utility EIMs, Scorecards, and existing performance metrics. The Staff White Paper ESM proposal has the potential for a retroactive adjustment to the stay-out premium. The mechanics behind such an approach are unclear because the stay-out premium is fixed at the beginning of the rate plan as an element of the allowed ROE and rates are then established on a cost-of-service basis to collect that amount. The stay-out premium is related to a specific negotiated rate case timeframe and should reflect the inherent risk of such a stay-out period. The ESM proposal also lacks clarity regarding the basis for determining whether performance is “inferior,” “base,” or “superior.” The primary purpose of an ESM is to incent utilities to create operational efficiencies that allow for a sharing of earnings outcomes between customers and shareholders. Staff’s proposal to link the ability to increase earnings from operational efficiencies to a utility’s performance on unrelated REV outcomes can diminish the effectiveness of all incentive metrics.

Mission:data:

Mission:data states that ESMs should be tied to a performance index.

Multiple Intervenors (MI):

MI generally supports Staff's proposal to link EIMs to ESMs. It would be preferable to customers to "pay" for utility performance out of excess earnings than through additional payments that would result in higher delivery rates. MI questions why inferior outcomes only could result in earnings sharing at the baseline ROE level and not some lower level. If a utility achieves inferior outcomes – potentially under multiple EIMs – earnings sharing potentially should commence at a level below the baseline ROE level. Staff's proposal fails to recognize adequately the harm to customers associated with poor utility performance.

National Fuel Gas Distribution Corporation (NFG):

NFG argues that the Commission should modify its existing ROE calculation methodology in order to more adequately reflect national rates so that utilities in NY can effectively compete for the equity financing needed to support Commission policy objectives. There is evidence that ESMs stifle healthy innovation and provide no meaningful consumer gains over traditional rate regulation. "Indexing" ESMs to performance outcomes would result in utility disincentives, undermining the establishment of and purpose for earnings opportunities and EIMs. A weighting methodology would force the Commission to prioritize REV Proceeding objectives based on their importance. Multiple EIMs would need to be ranked and weighted to ultimately result in a single measure of effectiveness. Absent a weighting methodology, the results of varying EIMs could contradict, compete or conflict with one other.

New York Energy Consumers Council, Inc. (NYECC):

NYECC is in general agreement with Staff statements such as that "ESMs should be directly linked to outcome indices," or that "the net plant reconciliation mechanism should be revised to encourage utilities to supplant capital spending with cost-effective operating cost or third party spending," or that "EIMs should be adopted for a number of performance and achievement of outcomes rather than almost entirely on capital spending." NYECC agrees that "the ESM caps should not represent ceilings on overall utility earnings, if additional earnings can be gained through market-based services and through EIMs," and that "ESM mechanism should complement these other opportunities.

Nucor Steel Auburn, Inc. (Nucor):
Nucor does not object to the application of properly constructed ESMs in utility delivery rate plans. Nucor also agrees that new EIMs should be integrated into rates on an aggregated basis through performance-indexed ESMs and that earnings achieved through market-based services could fall outside an earnings sharing cap, but EIM incentives should remain within such caps.

Public Utility Law Project of New York (PULP):
PULP does not believe there is sufficient information in the record with regard to how such mechanisms might be established, calculated or applied. It would be risky in the extreme to allow utilities to receive cost recovery and additional earnings incentives for a regulatory vision that has yet to be documented as providing value that would exceed well managed and supervised utility programs and services.

Real Estate Board of New York (RESA):
RESA appreciates the emphasis placed on diminishing the importance of rate base return on utility earnings. As outlined by Staff, this measure, when coupled to MBEs, will more closely tie the utility's profit motive to creation of customer value. Consistent with Staff's commitment to transparency, RESA suggests that the Commission require utilities to share their distribution system capital planning assumptions and schedule, down to the project level. This information will be necessary to engage third parties and customers in the development of alternative distribution systems investments that can prove cost efficient and resilient.

SECTION III.C.5 ALIGNING CUSTOMER VALUE WITH EARNINGS OPPORTUNITIES: Modifications to the Utility/DSP Revenue Model; *Capital Expenditures to Implement REV*

AARP of New York (AARP):

AARP opposes Commission "pre-approval" for any utility investment, including "DSP-related capabilities" (the definition for which is still somewhat vague and overly broad). Utilities are currently rewarded with a rate of return for successfully taking on the risk of investment, and are then held accountable for their management decisions. If the risk of investing is removed from utilities (and thus shifted onto consumers), then it will no longer make sense to reward utilities with a rate of return. Cost effective energy efficiency programs and demand response programs can be implemented by utilities without the creation of radical new "markets" or dramatic changes to current regulatory policies, including "preapproval." The Commission should require further pilot programs and demonstration projects before considering any broad-based changes.

Advanced Energy Economy Institute (AEEI):

AEEI states that "DSP capabilities" need to be defined so as to clarify which investments fall within the pre-approval category. AEEI agree with Staff's proposal that CAPEX to develop DSP capabilities should not be subject to retrospective review because such expenditures will be made in response to a Commission mandate and following a review of utility proposals by the Commission. Given that DSP investments are in new areas of technology, it is appropriate to manage risk of utilities and their ratepayers via this pre-approval approach. AEEI notes that "DSP capabilities" needs to be defined so as to clarify which investments fall within the pre-approval category. In general, the definition will comport with the utility-deployed technologies needed to achieve the benefits in the finally approved cost-benefit analysis approach, which, in turn, should also reflect those utility-deployed technologies that result in achieving the EIMs – the capabilities laid out in the market design and platform technology working group final report. The pre-approval should be time-specific and promote prompt implementation and project completion; and should not be indefinite in time span.

City of New York (NYC):

NYC opposes the recommendation that initial utility investment in platform technology should be protected from retrospective review, arguing that it is contrary to decades of Commission precedent. The Commission has a long history of rejecting pre-approval of utility investments but instead gives utilities a reasonable opportunity to recover their prudently incurred costs. If the Commission determines that the utilities' REV- and DSP-related costs were prudently incurred, they will be recoverable in some fashion. If the Commission adopts a pre-approval mechanism, its action must be reflected in the utilities' authorized rates of return. Those rates are based, in part, on the riskiness of the utilities' investments, including their ability to recover both a return of and on those investments. With pre-approval, the risk is significantly reduced, so the required rates of return should be concomitantly lower.

Clean Energy Organizations Collaborative (CEOC):

CEOC agrees with Staff's recommendation that certain investments be given preapproval. This pre-approval "would not supplant the requirement that the utilities' execution of the projects must be prudent," but rather that the pre-approval would be designed only to "address the risk entailed in the decision to undertake these investments." CEOC also agree with Staff's proposal to allow pre-approval only for investments needed to support DSP-related capabilities, but not for traditional utility system expenditures. Preapproval shifts much of the burden of determining the reasonableness of expenditures to the regulators, and much of the risk to ratepayers, and therefore should only be allowed cautiously. In addition, preapproval should only be allowed for costs that (a) have been investigated in a utility's DSIP, and (b) have been reviewed as part of the revenue requirements in a rate case. CEOC also recommend that the Commission allow for pre-approval of the costs of implementing DER. For example, the Commission should pre-approve the costs associated with implementing energy efficiency and demand response programs, where the costs and benefits of these programs have been evaluated and demonstrated in the DSIPs. Pre-approval of REV-related investments provides utilities with greater regulatory certainty, particularly for new types of technologies that utilities have little experience with. Without some degree of regulatory certainty, utilities may be reluctant to take on DSP-related functions and activities outside of their traditional scope. However, as AARP comments, pre-approval also shifts risk to customers. While pre-approval may not be strictly necessary to implement REV, it is likely to significantly speed the rate at which utilities embrace certain REV-related technologies. For this reason, CEOC continues to support the balanced approach outlined in the Staff White Paper whereby limited pre-approval is given, but investments are still subject to a prudency review. CEOC recommends that the Commission give slightly different treatment for utility investments related to AMI. Utilities should provide as clear a case as possible for whether and how AMI should be used as part of their DSIPs, and rather than pre-approving AMI programs, the Commission should provide some regulatory guidance as to the utility's case for AMI. The focus should be on the functionality needed, and not the technology per se.

GridWise Alliance (GWA):
GWA agrees with Staff's proposed recommendation, largely because determining all of the benefits of the REV will be challenging. GWA does not agree with the recommendation or statement in the White Paper that "[w]here 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." GWA believe that demonstrating a project might not be connected to the REV in some way could be quite difficult to demonstrate, as could determining what is being driven by the two-way flow of power.

Interstate Renewable Energy Council (IREC):
IREC anticipates that there are certain investments that the utilities will need to make in their systems in order to enable successful achievement of the REV goals that should be given early authorization. In order to facilitate the integration and management of high penetrations of various DERs, the utilities will likely need to invest in software and hardware that enable more transparency into their existing electric systems. Like

Staff suggests in the White Paper, however, it will be important to carefully distinguish between investments that will be made to advance the goals of REV and those that would have already been done under a business-as-usual approach. In some cases, REV may also require acceleration of certain business-as-usual investments. Just because an investment would have been done otherwise does not mean that it should not be given a path to early authorization if it is important for timely achievement of the REV goals.

Joint Utilities:
The Joint Utilities agree that plans to invest in DSP-related capabilities should be given pre-approval. In addition, the Commission should expand the pre-approval process to include REV-enabling investments that are necessary to implement REV. The Commission should also explicitly clarify that REV-related, incremental expenditures qualify for deferral treatment and will be recovered (to the extent prudently incurred) through surcharge mechanisms, if such expenditures and deferrals are not already unambiguously addressed in existing or forthcoming rate plans. The Commission's review and approval of DSIPs should give utilities assurance of the cost recovery of these REV-related capital investments. With regard to the Staff White Paper proposal that the pre-approval treatment should be provided only to those projects that "would not have been done, absent REV," the Joint Utilities suggest two modifications. First, the Commission should expand the pre-approval process to include REV-enabling and foundational investments (e.g., AMI) that are necessary to implement REV. REV Implementation could be delayed if the regulatory treatment for REV-enabling and foundational investments is not firmly resolved. Second, the Commission should explicitly clarify that incremental REV-related expenditures will be recovered in a timely manner through either existing or new ratemaking tools.

Multiple Intervenors (MI):
MI strongly disagrees with Staff's proposal that utilities' capital expenditures to develop DSP capabilities should be deemed pre-approved and not subject to retrospective review. Staff's proposal conflicts with longstanding Commission precedent. Staff's justification for its proposal -- that

capital expenditures to develop DSP capabilities present a special case due to the novelty of the expenditures and the fact they are responding to a Commission mandate -- should be rejected. While the DSP capabilities desired under REV reflect a change in regulatory focus, utilities are well-versed in making capital expenditures on communication systems and data-related hardware and software. The fact that utilities will be responding to a Commission mandate is not a special case – utilities have been doing so for decades. Staff’s proposed pre-approval of certain REV-related expenditures sends the wrong message. At the end of the day, REV will be deemed a success or a failure based largely (but not entirely) on short-term and long-term impacts on customers’ rates and bills. Providing utilities with a pre-approval of certain REV-related expenditures conveys a clear signal that decisions to invest in REV capabilities are viewed more favorably from other utility management decisions and that such decisions need not even be prudent when made.

Northeast Clean Heat and Power Initiative (NECHPI):
NECHPI believes that private investors are generally risk-averse and seek investment opportunities which reduce risks and increase rewards as much as possible. Private investors have numerous investment opportunities to evaluate against each other, and if a potential investment does not meet certain rigorous criteria, they will pass. Staff's proposals are too broad and their implementation timeframes too vague to ensure that risks are reduced sufficiently to provide an attractive investment environment. Until that time, it is highly likely that most investors will sit on the sidelines until they see more predictability and revenue assurance.

NRG Energy, Inc. (NRG):
NRG largely agrees that it makes sense to pre-approve DSP expenditures, “following close review of DSIPs” and “only in the early phases of REV implementation.” As a totally new endeavor, utilities will be appropriately risk-averse and so should have some comfort that they will not be risking shareholder dollars when investing in platform capabilities. Likewise, the Commission and stakeholders will want to ensure that DSP expenditures are limited to equipment and functionalities that

support the core DSP mission and not related to either non-DSP utility functions or related to 'value-added' functionalities (which should not be allowed, in any event). Pre-approval should not shield the utility from questions of prudence in its implementation of the DSP functions.

Pareto Energy LTD (Parento)
Parento commented that a significant factor in the delayed approval of large projects for interconnection involves the analysis of fault current contribution pertaining to synchronous interconnection. Such concerns do not pertain to non-synchronous interconnection as it entirely eliminates fault current contributions from distributed generation. Nevertheless and despite its successful implementation elsewhere, Con Edison has significantly resisted the adoption of power electronics for non-synchronous interconnection. Pareto Energy advocates that Con Edison should be paid 70 percent of the cost savings from the first project adoption of any improved technology for the interconnection of large-scale distributed generation.

Public Utility Law Project of New York, Inc. (PULP):
PULP states that they oppose the proposed pre-approval plans to invest in DSP-related capabilities. Staff's proposal will transfer risks to ratepayers; likely resulting in higher customer bills. Such a policy would establish a dangerous and unsupported precedent contrary to traditional utility ratemaking policies without any credible evidence that such a policy is needed or would benefit consumers. Furthermore, since any investment that could claim benefits for "reliability", "grid modernization," and "required for DER programs," might qualify for such rate treatment, PULP continues to urge the commission to reject this proposal.

The Alliance for Solar Choice (TASC):
TASC is concerned with Staff's proposal to provide a blanket approval for foundational DSP investments at this stage. Several utilities have already proposed large capital outlays for AMI, and Staff expresses interest in AMI deployment in the White Paper. The ability of competitive markets to provide AMI or AMF and should first be studied, or, alternatively, the Commission should explicitly remove AMI/AMF from this blanket

pre-approval for foundational DSP investments until it explores the least cost methods for deployment. While TASC supports utility investments that support DER expansion and effective integrated distribution planning, TASC opposes any approach that reduced the utilities' obligation to demonstrate prudence by allowing them "pre-approval" of projects. Utilities should be required to demonstrate prudence of investments in advance, and be required subsequently to verify that investments in fact supported the deployment of DERs. Additionally, any pre-approval process should be careful to distinguish projects that utilities are implementing in their role as DSP, versus any efforts they are allowed to undertake in order to compete with third party DER providers.

SECTION III.C.6 ALIGNING CUSTOMER VALUE WITH EARNINGS OPPORTUNITIES: Modifications to the Utility/DSP Revenue Model; *Long-Term Rate Plans*

AARP of New York (AARP):
AARP does not agree with the notion of five-year rate plans. Such a proposal would eliminate the full analysis of investments, expenses and revenues that is required for a rate case, and would further limit the ability for public input into the ratemaking process.

Advanced Energy Economy Institute (AEEI):
AEEI supports the use of long-term rate plans (at least up to 3 years), as they provide stability for utilities, cut down on the cost of administrative oversight and process, and can play an important part in providing utilities with the right incentives to meet REV objectives. When combined with the proposed modifications to the clawback mechanism, the option for utilities to extend the length of their rate plans to five years based on good performance will become an even greater incentive. While concerned about risk to customers and uncertainty at the beginning stages of REV, AEEI believes that these can be adequately handled through reopeners. Earning a return on an avoided capital investment for only three years may be insufficient to incentivize utilities to choose more cost-effective DER solutions. AEEI recommends, however, that Staff

provide more quantitative analysis to help parties better understand the actual financial impacts of the modified clawback mechanism.

Citizens Environmental Coalition (CEC):
CEC does not support longer term rate plans, particularly in the context of potentially fast moving changes under REV. Oversight and regulatory structure must be maintained and increased during these changes, not decreased.

Citizens for Local Power (CLP):
CLP strongly agrees with PULP, AARP and EE for All that rate plans should not be extended for reasons of transparency and accountability in ratemaking. Utilities will likely err on the side of over-estimating the costs of the DSP and other costs related to REV reforms, and there may be unanticipated rate impacts from regulatory reforms that will need to be addressed.

City of New York (NYC):
NYC states that long-term rate plans in New York have led to, among other things, severe underinvestment in critical infrastructure, excessive overearnings, and an inability to properly audit and oversee utility operations and expenditures. Until there is greater clarity and experience with REV, the Commission should require each utility to engage in a rate review at least once every three years.

Clean Energy Organizations Collaborative (CEOC):
CEOC recommends that Staff implement fixed rate plan periods limited to three years, at least for the first few cycles of rate plans, to prevent placing too much risk on customers who are under-served or are experiencing utility revenue over-recovery. CEOC suggests that rate plan extensions should not be permitted at all. Extensions put ratepayers at greater risk, prevent making adjustments that will help the market develop, and can be gamed if utilities are able to unilaterally invoke one. CEOC maintains that any adjustment to ROE should take into account both increases and reductions in risk associated with REV reforms. Reward-only EIMs, for example, would only reduce risk for utilities.

Energy Democracy Alliance (EDA):
As of now, EDA opposes the implementation of long-term rate plans.

Energy Efficiency for All (EE for All):
EE for All recommends that the Commission limit rate plan periods to three years. Waiting four of five years between rate periods will place too much risk on low and moderate income customers. The Commission should investigate utility performance, customer impacts and market development every three years.

GridWise Alliance (GWA):
GWA notes that there is a growing recognition of multi-year rate plans and their benefits. This proposal would allow greater flexibility for utilities to manage resources over a longer period of time, which could facilitate new product development.

Joint Utilities:
The Joint Utilities agree with the Staff White Paper that a three-year rate plan window can be appropriate but any extensions beyond three years should not be based on satisfactory price and earnings levels, adherence to capital plans, or compliance of various performance measures related to REV. Each utility has a statutory right to seek a change in rates unless it has consented to a multiyear rate plan under which it has agreed to forgo the exercise of that right.
The Joint Utilities take the position that the Commission does not have the authority to impose unilaterally multi-year rate plans since the utilities have a statutory right to seek a change in rates, unless they have agreed to forego doing so within the context of negotiated settlement.

Mission:data:
Mission:data comments that 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.

Multiple Intervenors (MI):
MI supports efforts to facilitate settlement negotiations on multi-year rate plans, it is opposed to mandating multi-year rate plans. REV's reliance on multi-year plans will give the utilities too much negotiating power (since Staff will be required to reach a multi-year deal). MI states that Staff claim that the Commission has the authority to impose multi-year plans without utility consent is legally suspect, and, even if true, the Commission and Staff are unlikely to exercise such authority over the objections of the utilities (they note that a multi-year plan has never been imposed unilaterally). MI also cite PSL §66(12), which gives the utilities the right to a determination on a rate filing within 11 months, after a hearing. MI agrees that durations of three years often represent the "sweet spot" in settlement negotiations but disagrees with Staff's proposal that three-year rate plans be coupled with two-year rate plan extensions. Staff has not justified why "utilities should be provided the option to extend such plans beyond three years if performance dictates."

National Fuel Gas Distribution Corporation (NFG):
NFG states that no more than a 2-year term should be allowed. This will provide a nimble platform for both Staff and the utility to respond to current needs. Commission should avoid ratemaking practices that result in uncertainty to allowed earnings. Shareholder uncertainty can adversely affect utility credit ratings, which in turn increases costs of capital for utilities, ultimately resulting in higher rates to utility customers. Rate plans should include symmetrical reopeners and/or terminations that can be exercised based on the discretion of utilities.

New York Energy Consumers Council, Inc. (NYECC):
NYECC states that the question of whether rate plans should be allowed for longer than three years should not be tied only to allowing time for initiatives to be developed and outcomes to emerge without considering other factors. The negotiating power of Staff and Intervenors (and the public's interest) in a rate case shifts decidedly in favor of the utility if the utility knows that the Commission wants a multi-year settlement. In any

event, if a utility wants a five-year rate plan, then it should support such a request in its initial filing.

Northeast Clean Heat and Power Initiative (NECHPI):
NECHPI is concerned with the Staff proposal to increase the utilities' multi-year rate plans from a three- to five-year period. It is extremely difficult to derive reasonably accurate forecasts over such a long time period. It is more important to align the utilities' general rate cases with all of the components of the REV proceeding in order to establish the costs and benefits of all DERs before extending multi-year rate plans to five years.

Nucor Steel Auburn, Inc. (Nucor):
Nucor believes that there simply is no basis for generically presuming outside of an actual factual setting that consumers are better served by multi-year rate plans. Substantial process improvements are required if a multi-year, RAM-based approach is adopted. The ultimate point is that a multi-year, RAM-adjusted rate setting process is different from, but is not an improvement on, conventional rate-setting and certainly does not offer any inherent advantages for the purposes of achieving REV objectives. Implementing REV related performance measures can be accomplished just as readily through existing processes.

Public Utility Law Project of New York, Inc. (PULP):
PULP opposes multi-year rate plans because, among other reasons, the public interest is furthered by increased transparency and accountability in utility ratemaking. Transparency and accountability result in large part from the type of full audit and review, and painstaking analysis of investments, expenses and revenues that is part of a traditional rate case.

The Alliance for Solar Choice (TASC):
TASC agrees with Staff's proposal on long-term rate plans but suggest that the Commission report on the utility's EIMs and scorecard metrics, and request stakeholder input on whether or not to extend rate plans before automatically extending them. Extensions of rate plan periods should be tied to compliance with various performance measures related to REV (including a successful interconnection record, DER penetration, development

of platform capability and success in reducing peak demand). TASC also agrees that the Commission should establish effective tracking mechanisms, true-ups, updates and mid-term adjustments.

SECTION IV.A RATE DESIGN AND DER COMPENSATION: Summary

Blue Rock Energy, Inc. (Blue Rock):
Blue Rock opines that the use of geographically-specific, time-variant prices is an inclusive and accessible democratic way to involve customers and third party DER providers. An adaptation of proven pricing approaches can lead to proper time-variant locational price signals without increasing average prices in distribution areas with significantly different marginal (new construction) cost profiles.

Citizen's Environmental Coalition (CEC):
CEC believes it is essential that the Commission recognize that the deregulation/privatization that was implemented in the 90s adversely impacted especially small energy consumers-residential and small businesses-- with extraordinarily high rates compared to elsewhere in the nation. At the same time measures paid for by consumers, efficiency and renewables, were largely focused on large electricity users in industry and commercial sectors. These inequities must be better addressed starting with the low-income affordability proceeding. There must be differentiation between the value of distributed generation of any type and the value of non-polluting renewables and efficiency. CEC believes it is critically important that improvements be made to the proposed BCA analysis to include social and environmental benefits and costs, and to not solely focus on utility and monetary costs.

Joint Utilities:
The Joint Utilities agree with Staff White Paper that the most important REV objective is economic efficiency, which is achieved by providing accurate and transparent price signals to customers that reflect the costs of serving them. The pursuit of economic efficiency may conflict with other stated REV objectives. Designing rates that reflect the manner in which

costs are incurred will provide customers with the proper price signals to make their electricity consumption and DER investment decisions in alignment with REV goals. Current residential and small commercial rate designs should be modified to provide accurate price signals reflecting the true costs to serve these customers, combined with an increased ability to respond to price signals. Transitioning the recovery of fixed costs away from volumetric charges to either customer or demand charges is consistent with the REV policy to develop an efficient rate design that is fair to all customers. This transition should be implemented in a timely manner with due consideration to short-term customer bill impacts. The Joint Utilities question the Staff White Paper's conclusion that "rate design under REV should enable the reduction of total costs by appropriately signaling value." This conclusion is based on the assumption that DER will provide significant efficiency benefits, which need to be demonstrated over time. Rates paid by customers for distribution services should reflect the costs of providing such services. Thus, the pricing of delivery service should continue to be based on the utilities' costs. "Value" is relevant when establishing compensation by utilities to DERs, but the value to the utility is related to costs that the utility may incur or is able to defer or avoid as a result of integrating DERs. The Joint Utilities disagree that NEM should be retained. It is considerably more important to consistently apply efficient prices and eliminate subsidies than to extend an inefficient and subsidy-rich pricing regime on the basis of simplicity and predictability. The value of D as a pricing concept can be an efficient pricing mechanism only if properly defined and developed. It can prevent DER customers from bypassing responsibility for the fixed costs of distribution service provided to them and shifting these cost obligations to non-participating customers.

Energy Democracy Alliance (EDA):

EDA states that until the various models and plans are developed, it will be difficult for public interest organizations and the public at large to comment on or give input on these items. EDA calls on the Commission to use its broad authority and its resources to foster better public understanding of the complex REV process and to enable public interest organizations (both consumer and environmental advocates) to meaningfully participate on a level playing field with utilities and other for-profit entities in the policy-making proceedings and rate cases. EDA makes the following suggestions: REV must be better publicized and better explained so that it can benefit from consumer and environmental groups input and better serve the needs of the public; intervenor funds must be made available for rate cases and energy policy proceedings so consumer and environmental groups can adequately address the public's interests in these proceedings; community representation and accountability in demonstration projects should be enabled to make sure these projects provide benefits to the public; and community input, accountability and ownership in microgrid projects must be ensured. Utilities should be scored by community groups and local leaders on their public engagement process and outcomes.

Microgrid Resources Coalition (MRC):
MRC emphasizes that not all DER are equal. Some produce MWh on an intermittent basis, and some are dispatchable. The tariffs of the utility of the future, and the markets in which they operate, will need to be able to differentiate among products and services in ways that reflect the value to the system. The best results will come when the utility and its customers, assisted by DER providers, work together in new ways.

New York Battery and Energy Storage Technology Consortium (NYBEST):
NYBEST states that investments in the electric system in the coming years need to be economically efficient while also furthering the policy objectives of REV. Investments must be optimized at the customer end of the electric system as well as the traditional production end, and customers and market participants must 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. 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. NY-BEST believes that the "value of D" concept is at the heart of REV and should be given prominence going forward in joint deliberations. As proposed, LMP+D is too simplistic to appropriately signal the value of energy storage and shifting load to flatten peaks. It does not include the long-term avoided costs for avoided investments in transmission, distribution, and generation. As a near term action, NY-BEST urges the Commission to adopt DPS Staff's recommendation that the utilities should adopt the same software to determine distribution-level marginal costs.

New York City (NYC):
NYC agrees this is an opportunities for improvement compared to the current approach to rate design. NYC supports the goals of providing greater choices to customers, empowering customer engagement through more granular data, and ultimately relying on dynamic interaction between stronger price signals and more effective customer tools to lower the total cost of energy. Some rate redesign may be necessary and/or appropriate to achieve REV goals and implement the proposed new construct, but NYC urges caution regarding any rate redesign. The Commission should not make material rate design changes for any group of consumers without understanding the effect those changes will have on each type of class of consumers. Moreover, the Commission should not adopt rate designs that create gaps or uncertainty in the ability of the utilities to have a reasonable opportunity to collect their revenue requirements. Such risks are likely to lead to deratings, higher borrowing costs, and diminution of service quality and system reliability. REV is intended to reduce costs while maintaining existing high levels of reliability, not increase costs and reduce reliability.

New York Cow Power Coalition (NYCPC):
NYCPC agrees that efficient price signals and transparency are the hallmarks of a healthy market. Fair and rational DER compensation mechanisms which optimize the continuing employment of future Anaerobic Digester Gas (ADG) installations must recognize their unique values-added. The value of "D" for ADG is undervalued. Further, demand charges and standby charges are

unfair when considering the brief and infrequent down-times of ADGs. NYCPC strongly disagrees that different DER compensation policies should be adopted for existing and future installations.

Northeast Clean Heat and Power Initiative (NECHPI):
NECHPI observes that there is little to no discussion of how tariffs can be used to support a variety of services that will be critical to the successful implementation of REV. There are many statements throughout the Ratemaking White Paper that it is now possible to "gather, analyze, and make transparent information much more quickly, enabling the development and exchange of more precise value signals." NECHPI believes that this misrepresents what is possible now and in the foreseeable future and thus, confuses key issues and possible solutions to those issues.

The Alliance for Solar Choice (TASC):
TASC's principle message on the rate design section of the White Paper is to urge caution in regard to proposals to establish demand charges for residential customers. TOU rates are a far superior method to achieve the objectives of the REV process. Utilities throughout the US jumped on a bandwagon to impose high fixed charges or demand charges on residential customers or to customers with on-site generation or net metering and state commissions have generally tended to reject these proposals as they create a wide range of inequities and discourage both energy conservation and distributed renewable investment. This is not to suggest that very modest demand charges, based on distribution system costs attributable to cost of interconnecting individual customers, could not be part of a new rate design paradigm. But TASC firmly resists that idea that there should be a large shift away from volumetric charges as the principle means of recovering utility cost of service. TASC also wishes to strongly support reform of commercial and industrial demand charges so that they reflect customer usage during system coincident peak instead of maximum customer non-coincident usage.

Vanguard Renewables (Vanguard):
Vanguard supports the comments of the New York Cow Power Coalition and emphasizes that pricing considerations should be designed to incent the development of a digester industry in New York state.

Vote Solar Initiative (Vote Solar):
Vote Solar believes that Bonbright's traditional design principles are inadequate for addressing the objectives of the REV, and higher penetrations of DERs in general. Vote Solar is pleased to see the rate design principles of (a) encourage outcomes, (b) decision-making, (c) customer-orientation, and (d) access. While all of the rate design principles are admirable, Vote Solar thinks the aforementioned rate design principles will be especially important to the proliferation of DER in the future. Just as with the Bonbright principles, the rate design principles inherently require a balancing of each of the principles.

SECTION IV.B RATE DESIGN AND DER COMPENSATION: Foundation of Rate Design and DER Compensation in NY

AARP New York (AARP):
AARP strongly objects to the Joint Utilities' suggestion that residential rate designs be modified to transfer the recovery of standard utility costs from volumetric charges to fixed charges or to demand charges. Such a radical shift in rate design policy would disproportionately harm low-usage customers, many of whom are vulnerable customers. From the customer's perspective, these charges send the wrong price signal, because customers with fixed or demand changes will not see corresponding losses in the incentive to participate in energy efficiency and DER investments. Increasing fixed charges and demand charges will reduce the ability of consumers to control their energy bills, and for this reason, are very unpopular.

Advanced Energy Economy Institute (AEEI):
AEEI agrees with the Joint Utilities that economic efficiency in price signals is a critical part of REV, but AEEI diverges on what constitutes an economically efficient price signal. Fixed

charges are not an economically efficient price signal because they do nothing to reduce future costs. Rates should adequately compensate utilities for past investments, but they should also be structured to send signals to consumers to conserve energy, lower peak demand and invest in other forms of DER in a way that avoids and reduces future system costs and also helps achieve other state policy objectives. Fixed charges provide no reward for changes in behavior, and as the fixed portion of a bill increases, the ability to send signals to and incent responses from customers decreases. The dual roles of recovering utility costs and sending price signals to customers need not be at odds with each other, and advanced meter-enabled time-varying rate designs are able to accomplish both; however, fixed rates focus exclusively on recovering utility costs to the exclusion of sending energy efficiency and peak reduction signals to customers.

BlueRock Energy, Inc. (BlueRock):
BlueRock notes there is a potentially significant disparity between the embedded costs and short run marginal costs in distribution networks. Bonbright and others believe that when there is a material difference between the revenue recovery of embedded costs and short-run marginal costs that the difference in revenue recovery should be done so as not to distort the marginal cost price signal. Environmental adders plus the use of long-run marginal capacity costs are an appropriate way to bridge the gap to the revenue requirement. BlueRock's rate design proposals can accommodate multiple objectives in sending a sustainable, long-run price signal that reflects cost causation (including potentially environmental adders) with gradual bill impacts while incenting customers, ESCOs and DER Providers to make economic DER investments.

Energy Technology Savings (ETS):
ETS agrees that it is imperative that charges are billed in such a way that reflects customers' actual usage patterns. The peak demand level to qualify for an interval meter and hourly pricing should be reduced in order to capture more multifamily and smaller commercial buildings. This would provide incentive for these types of customers to manage their energy usage.

Interstate Renewable Energy Council (IREC):
IREC believes the growing complexity of the electric system, along with the new and evolving role of the customer in management and generation of their energy needs, requires reconsideration of traditional rate design methodologies. A better balance could likely be achieved if the rate design toolkit were expanded beyond just fixed charges and per kWh charges and that 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. IREC also reiterates the importance of and its support for gradualism in light of this challenge.

Joint Utilities:
The Joint Utilities agree with Bonbright's principles for rate design.

National Fuel Gas Distribution Corporation (NFG):
NFG supports the Commission's policy in recent years of slowly increasing the fixed customer charge while maintaining a reasonable portion of the total rate in a per unit charge. The key to effective rate design is balancing the method of cost recovery for delivery and commodity. This balance includes the recovery of fixed facility costs through fixed rates such as monthly minimum charges, and the recovery of variable costs through usage-based charges. In addition, NFG supports having standalone components within the delivery adjustment charge to isolate specific impacts of public policy objectives (e.g., energy efficiency programming, accelerated infrastructure replacement, network enhancement, etc.). NFG supports the development of a bill crediting mechanism for the deployment of DER technologies, similar to that used in NEM. Staff is correct that current fuel eligibility requirements for NEM need to be further expanded beyond solar and other renewables. All fuel sources and all DER technologies must be able to participate in NEM. This could be evaluated in the general REV Proceeding, in case 15-E-0082, or as a stand-alone initiative.

New York Energy Consumers Council (NYECC):

NYECC generally supports the Staff proposed rate design principles to guide reform under REV especially "Policy transparency: Incentives should be explicit and transparent, and should support state policy goals;" "Stability: Customer bills should be relatively stable even if underlying rates include dynamic and sophisticated price signals;" and "Gradualism: Change to rate design formulas and rate design calibrations should not cause large abrupt increases in customer bills." Further, NYECC supports near term opt-in rates that give customers options and the ability to adopt technology and receive value from DER, as well as near term improvements to standby tariffs and to existing demand charges for larger customers.

SECTION IV.C RATE DESIGN AND DER COMPENSATION: The Implication of Conventional Rate Design and Current DER compensation in context of REV

Citizens Environmental Coalition (CEC):
CEC asserts that a more to a market-based regulatory model is not guaranteed to succeed.

Energy Efficiency for All (EE for All):
EE for all argues that rate plans should not exceed three years.

Exelon Companies (Exelon):
Exelon agrees with Staff that efficient price signals and transparency are hallmarks of a successful market and that 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. Exelon also agrees with Staff that there is a fundamental need to change the way utility distribution costs are currently being recovered from most of its customers as utilities face new and significant challenges due to declining electric sales growth, the need for increased investment, and new enabling technologies. There is a need for increased

utility investment in delivery infrastructure due to customers' greater reliance on electricity (*e.g.*, internet, computers, cars), the desire to ensure greater reliability and resiliency (post-Super-storm Sandy and Hurricane Irene), general aging infrastructure, advanced metering deployment, higher levels of power quality needed for the digital economy, and a demand for increased grid cyber security. At the same time, new technologies and advanced metering enable more robust usage and allow customers to both generate and use electricity differently. For all of these reasons, electric utilities must revisit their traditional rate structures for delivery service, especially for residential customers.

National Energy Marketers Association (NEM):
NEM supports unbundled utility rates and rate design that enables the participation of third parties. NEM also supports the proposal to derive a proper valuation of DER that appropriately compensates participating customers for the value they provide to the system. In addition to the mechanisms considered in the White Paper for DER valuation, NEM suggests that there should be a rate concession for DER providers that do not use transmission and distribution assets.

National Fuel Gas Distribution Corporation (NFG):
NFG is supportive of Staff's initiative to examine alternative electric rate designs, especially the proper valuation and compensation for DER technologies provided to the electric grid. The reforms envisioned by REV, particularly the development of DSP capabilities and the REV marketplace, open important new avenues for compensating customers or DER providers acting on their behalf, for the system value their DERs produce. Rate design should help customers manage electricity costs. NFG supports revision of stand by tariffs, on a periodic basis and the expansion of the net metering concept to all fuel sources.

New York Battery and Energy Storage Technology Consortium (NY-BEST):
NY-BEST agrees with Staff that there are many risks associated with sending the wrong economic signals that drive inefficient choices, and that potential problems can be addressed by a technology- agnostic design that is more precise, both in

recovering costs and in sending price signals that prompt efficient DER participation by customers. Tariff design should be technology-agnostic. However, rate design and compensation mechanisms implemented under REV should be granular at the circuit where the value of the DER will be realized, not based on system level average values.

NY Cow Power Coalition (NYCPC):
NYCPC states that Anaerobic Digester Generation is a baseload generation technology and should not be subjected to standby and demand charges, as are solar and wind. Removing these charges for ADG would not have a distortive effect.

Pareto Energy LTD (Parento):
Parento points out that BQDM technologies were chosen by Con Ed instead of independent parties.

The Alliance for Solar Choice (TASC):
TASC supports study of time of use rates, critical peak pricing, and peak time rebates. TASC agrees with the majority of views presented by Staff in this section and appreciate the balance struck in the White Paper between DER growth, fixed cost recovery, and the need to prevent grid defection, and ensure that all parties receive fair compensation. Any additional capex authorized by the Commission and added by utilities to the rate base now further exacerbates the problem. Changing granularity of compensation for services provided by DER could reduce costs to the system, but does not resolve the conflict between these priorities. However, MBEs that displace rate recovery of fixed costs, increased DER's instead of utility capex, and a totex regime would reduce the tension among these priorities.

SECTION IV.D RATE DESIGN AND DER COMPENSATION: Framing Proposed Recommendations

AARP New York (AARP):
AARP opposes any changes in rate design that are not implemented on an opt-in basis. Time of Use Rates should be voluntary. If, as Exelon suggests, such rate designs will benefit customers or

result in “lower social costs,” customers will gradually accept and move to such rate options.

Advanced Energy Economy Institute (AEEI):
AEEI believes that rate design discussion should focus on both delivery rates and default service energy commodity rates. As the capabilities of the distribution grid/electricity system are enhanced, applying new rate design approaches, especially time varying rates, to commodity provided through default service may help to spur competitive commodity offerings – either based on more accurate and real-time price signals or providing a more costly fixed price commodity package for customers who value certainty over a particular time period. AEEI agrees with the distinction Staff makes between rates paid *by* customers for electricity service and compensation paid *to* customers whose DER provides value to the system. While compensation for DER services will increasingly be determined by the market, there may remain a regulated component of compensation based on avoided distribution costs and rates. AEEI generally agrees with the three categories of consumer (traditional, active, and prosumer) but notes that an individual customer may cross from one category to another over time, or similar customers at different times may fall into different categories. AEEI supports moving toward increasing granularity and offers three considerations for the Commission. First, decisions on rates must be made well in advance of implementation; second, third parties and others with relevant experience should be engaged to assist or lead customer engagement; and third, unbundling of rates can provide a higher value proposition for customers and DER. AEEI supports the approach of gradually implementing rate design reforms to moderate their impact on customers and the advanced energy companies that have invested in New York in response to previous state policies.

BlueRock Energy, Inc. (BlueRock):
BlueRock appreciates Staff acknowledging how more granular price signals will allow customers or third-parties to reduce costs to better incentivize technology development of more advanced systems. Perhaps more sophisticated time-variant prices (e.g., hourly pricing of the distribution system as well as commodity) could be offered to ESCO's that in turn could use such prices

and bundle with related services in a way that best fits its customers' needs, accommodates available customer resources, and parallels or improves upon the ESCO's business strategy. To achieve this, smart meters for a high proportion of the marketplace will be needed. Until smart meters are more widely available to the mass market (residential and small commercial customers), NEMA's "Demand Response Load Profiles" could provide a transitional mechanism so that ESCOs and other third parties are better able to bring cost savings to consumers. It is important that such options be offered to low-income customers as soon as possible because the data shows that low-income customers both respond well to Demand Response and also have better than average load profiles and thus are currently being charged more than their fair share of capacity costs under current rates.

Federal Trade Commission (FTC):
The FTC believes that the White Paper correctly identifies the importance of accurate and timely price signals as the means to gain the benefits of competitive markets and efficient investment, placement, and operation of DERs. Similarly, the White Paper correctly emphasizes the importance of dynamic prices because costs and prices in the power system vary dramatically over even brief time periods. Particularly with respect to DERs, short-term price signals that include local distribution conditions can be vital in making efficient DER investment, siting, and operating decisions. Advanced electric meters are generally necessary to convey accurate and timely price signals. If the price signals to DER investors, owners, and organizers are timely, accurate, and local, incentives will align with efficient DER investment, siting, and operating levels. By contrast, without accurate price signals, it will be much more difficult to make efficient decisions concerning these issues

Grid Wise Alliance (GWA):
GWA urges the Commission to include transparency in rates as well as transparency in incentives. Incentives will need to be linked to the optimal level of the results that are being incented. The PSC will likely need to sunset incentives that have accomplished their purpose so that they do not result in

"too much of a good thing." In terms of the principle pertaining to reducing "uneconomic grid defection" GWA believes that highlighting the need to pay for grid infrastructure and grid-related services, and the reasons for doing so, is vital. Making the costs and charges involved herein more transparent is imperative as well.

Interstate Renewable Energy Council (IREC):
IREC finds the categorization of customers by Staff intriguing and believes it may be a more appropriate classification than the more traditional rate class designations. Indeed, there is likely a diverse mix of residential, non-residential and industrial customers that fall into the 'active consumer' category, and their unique characteristics and contributions to the system as active consumers may be more meaningful than their specific rate class, especially as it relates to ratemaking, rate design, setting tariffs and/or developing programs going forward. IREC agrees that it is important to keep in mind the different types of customers and to design rates that encourage positive behaviors and enable savings for each type, even if that means needing to differentiate between customers with a wider range of rates or rate-adders. Some questions that may require further evaluation once more specific rate-related proposals are put forth.

Joint Utilities:
The Joint Utilities support a transition away from NEM in the near term to protect non-participating customers. Staff's proposal to expand the concept of "gradualism" to whole industries, such as the solar and energy efficiency industries, will simply serve as a wealth transfer from New York's utility customers to the shareholders/owners of solar and other DER businesses. The Joint Utilities believe all DR programs are essentially "opt-in" programs, which are subject to the customer's perception of value and willingness to participate. Should the Commission incent environmental outcomes at a value above the market value of emissions already captured in the LMP, it should do so in a transparent manner that clearly identifies the basis for and cost to customers of any additional incentives supporting DER. The Joint Utilities state that this is best accomplished through a separate stated surcharge on customer

bills. A rate design that encourages DER deployment is not sustainable because it would impose costs, in the form of cross subsidies of DER installations, to customers unable to or not interested in deploying DER. Improper rate designs could encourage uneconomic investment in DER. The most efficient approach to rate design is clear and accurate price signals that cause those customers who create costs to pay those costs. The Joint Utilities support and recognize the importance of energy efficiency, integration of clean renewable generation, and peak reduction with respect to both REV and overall State energy objectives but do not agree with some parties that rates should be designed expressly to achieve policy outcomes. To the extent that the Commission seeks to support specific public policy objectives, the Commission should do so through transparent public incentives rather than opaque or invisible subsidies embedded in utility tariffs.

Microgrid Resource Coalition (MRC):
MRC points out that all DERs are not created equal and that the ancillary services that are needed by the grid today may not be the ones needed tomorrow. Customers increasingly will be capable of delivering a particular load profile for a day or particular hours providing the DSP with predictability as an alternative to dispatchability. This is not to suggest that dispatchability, DSP3 and NYISO bound DER products can be done away with, but greater predictability reduces the need for dispatchable resources. The tariffs of the utility of the future, and the markets in which they operate, will need to be able to differentiate among these products and services in ways that reflect the value to the system. The best results will come when the utility and its customers, assisted by DER providers, work together in new ways. MRC strongly supports a move to or in the direction of TOU rates for all customers. The value of services to and from a DER-equipped customer will vary substantially with the degree of self-balancing and aggregate demand control that the customer deploys. A sophisticated microgrid can deploy co-generation, renewable generation, thermal and electric storage, fuel arbitrage for thermal loads, and advanced controls, both internal building controls and grid facing controls, to control its load shape. Tariffs and markets must be designed to provide accurate value for services. Net metering may remain effective

for small residential installations, but it is critical that more accurate values be established for larger and more sophisticated installations.

National Fuel Gas Distribution Corporation (NFG):
NFG points out that, although participation rates seem higher in opt-out scenarios, no supporting data or rationale was provided in Staff's White Paper that indicates how many customers never responded, were unaware that they were unilaterally being placed into a new rate classification, or simply did not care about the program enough to opt out. This information is necessary for the Commission to properly consider the potential for opt-out rate designs. National Fuel is supportive of Staff's initiative to examine alternative electric rate designs, especially the proper valuation and compensation for DER technologies provided to the electric grid. It is critical to distinguish between rates paid by customers for electricity service on one hand, and compensation paid to customers whose DER technology provides value to the system on the other hand. In addition, it is important to consider electric rate design impacts for traditional consumers (those that do not actively manage their energy usage), active consumers (those that install DER technologies in order to moderate their usage in response to price signals), and prosumers (those that install DER technologies in order to provide services or generated commodity to the grid).

New York Battery and Energy Storage Technology Consortium (NY-BEST):
NY-BEST understands and supports the need for "gradualism," both to avoid unintended market disruption and to provide time to properly develop valuation mechanisms and markets, but points out that again that a prolonged uncertain transition time could hinder private investment. Specifically, uncertainty in future revenue and market risk may could cause private capital to wait to enter the market. NY-BEST recommends that bridge mechanisms and tariffs, such as the proposed Asset Utilization Tariff be implemented to ensure that progress toward REV goals is not impeded.

New York City (NYC):
NYC agrees conceptually that "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" and advocates working towards opening these avenues. NYC recommends that the Commission first analyze this issue generally, then engage in limited scope demonstration projects to understand and assess the value of alternate rate designs, and fully understand the value DER brings to the marketplace and to different customer classes before fundamentally redesigning rates. NYC supports the more granular use of data and rate designs that spur the development of DER and more efficient use of energy, NYC cautions against a wholesale redefinition of the rate classes. The rate class structure in New York is well-conceived and generally spreads the utilities' revenue requirements among all consumers. If the Commission does decide to base the rate design partly on the level of each consumer's interaction with the DSP market, the Commission should first analyze the dispersion of consumers among the proposed consumer types. REV should be implemented gradually when redesigning rate structures and rate designs.

Northeast Clean Heat and Power Initiative (NECHPI):
NECHPI proposed a Benefit Cost Analysis Framework (BCAF) approach, which helps to establish the value of D. BCAF is important to the ratemaking proceeding because it establishes real, engineering- and economic-driven values at the circuit level; provides a structure for actual measurements of performance by technology or combinations of technologies as well as of GHG and other criteria-pollutant emissions reductions; and allows for the streamlining and full integration of DER interconnection processes into a utility's distribution-planning processes. Once the BCAF foundational work is in place, there can be serious discussion about, and refinement of, the Staff's proposed ratemaking methodologies and compensation mechanisms that reflect the REV vision and fully support the development of platform-based markets.

NRG Energy, Inc. (NRG):

NRG believes with respect to the rates for compensation of DERs, different approaches may be appropriate for different kinds of DERs – e.g., NEM for solar, value-based compensation for reactive power and other services provided by solar smart inverters, locational avoided distribution upgrade costs; or locational energy and capacity for CHP plus avoided substation and other costs. Some DER facilities should be eligible for multiple such revenue streams. While DER compensation based on LMP + D has merit for many larger customer classes, NRG agrees with Staff's recommendation that the Commission should ensure that other payment programs, such as net energy metering, continue to remain available to smaller mass-market customers investing in DERs. The Commission has previously determined that NEM is an appropriate rate for mass-market customers with on-site DERs, as well as for small customers taking part in community shared DG. There is no reason to upset those decisions here. NRG's experience is that customers have an easier time understanding the value proposition of on-site and community shared DER when it can be explained in terms of off-setting their kWh usage.

Real Estate Board of New York (REBNY):

REBNY concurs with Staff's concern that current ratemaking does not focus third party DER investment where it would be most valuable and that a totally market based approach (e.g. real time price based on system value) is too granular as a starting point, because the market requires some degree of price predictability and stability in order to make large investments that will payback over time, and to secure low cost financing. Therefore, as an initial step toward market creation and incentivizing investment into areas of the system with greatest need and value, REBNY supports Staff's recommendation to establish rates that vary with respect to when energy is consumed, where it is consumed, and what services are provided.

Solar Energy Industries Association (SEIA):

SEIA contends that the Joint Utilities recommendation to phase out net metering would be highly disruptive to the growth of the New York distributed solar market, and thus counter to New

York's policy objectives under REV and NY-Sun. The Commission has correctly recognized that there are methods to make the utilities whole for their investments in the distribution grid or in their role as the DSPP through cost-of-service based revenue streams that achieve the public policy objectives under REV. SEIA indicates that these methods include variable rate design such as time of use rates, new revenue structures such as platform service revenues, and EIMs, and decoupling.

The Alliance for Solar Choice (TASC):
TASC agrees with Staff's proposed classification of the three types of consumers: traditional, active, and prosumers. A further segmentation of mass-market customers helps in understanding the value propositions that each of them seek, and the Commission should act to allow each of these segments to maximize these value propositions without discriminatory treatment. With respect to Staff's views on the degrees of granularity, TASC urges the Commission to consider a customer's ability to respond to granular rates with the appropriate DER investment. NEM has been successful to date because it offers customers a reasonably stable and foreseeable value proposition against the default utility rates. Having too-high a degree of granularity would cause too much uncertainty and too little stability in rates would disable the ability of a customer to invest in DERs. TASC applaud Staff's discussion on applying gradualism on multiple dimensions to changes in rates and compensation and is encouraged by the fact that Staff recognizes the potential for rate design to result in grid defection, and that customers with DER may one day need a value proposition to maintain their dependence on the grid. The Commission should consider a customer's ability to respond to granular rates with the appropriate DER investment. NEM has been successful to date because it offers customers a reasonably stable and foreseeable value proposition against the default utility rates. Having too-high a degree of granularity would cause too much uncertainty and too little stability in rates would disable the ability of a customer to invest in DERs.

SECTION IV.E RATE DESIGN AND DER COMPENSATION: Determining the System Value of DER

AARP New York (AARP):
AARP would like to see evidentiary support for such claims about the potential cost effectiveness and the rate impacts that such a transformation would have on residential customer bills. Such evidence should be made publicly available and then be subjected to rigorous stakeholder scrutiny. AARP believes that the Commission should focus on ratemaking changes designed to ensure that all DER customers pay their fair share of essential distribution services that benefit all consumers. Rate design changes that affect all customers should not be implemented simply to address concerns about DER participation. Rather, the net metering policy should be revised to ensure that all DER customers pay their fair share of distribution services and investments.

Acadia Center (Acadia):
Acadia supports the general approach of "LMP+D" to value DER, and emphasizes it is crucial to ensure that "the value of D" includes all relevant ratepayer benefits. Distribution system value should include avoided or deferred infrastructure investments, and it may be appropriate to net out certain infrastructure investments related to DER integration. Overall distribution system value may be determined by category, such as generation capacity or proximity to load. Avoided or deferred transmission infrastructure investments and energy and capacity market price suppression are key ratepayer benefits that must be included, as well as fossil fuel price risk mitigation for certain DERs. The value of emission avoidance needs a more precise definition. In the context of rate design, the preferred method is to include the value of reasonably foreseeable avoided public health and environmental compliance costs as a measure of ratepayer value. To the extent that these compliance costs are not already embedded in market prices, an adder should be developed to include them. Purely external social benefits, above and beyond reasonable avoided compliance costs, need not be included in rate structures and can be considered in the context of incentive mechanisms outside of rate design. These values will likely vary by technology and

even within technologies. Acadia center takes issue with the Joint Utilities contention that the value of D is an upper bound for compensation, and does not support competitive procurement for all DERs in all circumstances, since administrative hurdles, timing, and other procedural challenges may delay development of a multi-directional DER market. Acadia Center concedes the Joint Utilities' argument that LMP+D is temporal, but cautions that this approach is impractical until effective granular pricing is developed. The Commission would benefit from using a long-term estimate of value of long-lived, non-dispatchable DER.

Advanced Energy Economy Institute (AEEI):
AEEI supports the "LMP+D" approach for valuing DER and further note that "D" must be defined broadly to reflect the wide range of DER resources available and their benefits to planning (i.e., investment), operations, and society at large focusing on avoided generation capacity costs, including reserve margin, avoided transmission capacity infrastructure and O&M, avoided ancillary services, and wholesale market price impacts as well as a broad range of system and non-energy benefits. The Commission should retain current net metering compensation for mass-market customers, and let LMP+D be available for customers who wanted to become more active participants. AEEI also supports the current NEM approach for solar less than 2MW and believes this should be considered for other technologies which currently do not get full retail rate compensation for net excess generation. AEEI takes issue with the Joint Utilities presumption that fixed charges are the most economically efficient way to recover fixed costs such as past investments. Although capacity relief for deferring a distribution upgrade provides significant value, the Commission should consider more near-term impacts, such as voltage support, power quality improvements, decreased line losses, and power factor correction. These services are supported by current DER providers, through the use of smart inverters, and maintain that DER is able to lower average loads on transformers and help support power quality, which can increase the lifespan of existing infrastructure where DER is deployed, and not just in locations that are in need of capacity relief.

Association for Energy Affordability, Inc. (AEA):
AEA supports calculating the value of DER based on locational marginal price plus the distribution value, or LMP+D, including an entire range of environmental, public health and non-energy benefits.

BlueRock Energy, Inc. (BlueRock):
BlueRock expects appropriate location-specific price signals at the substation (or targeted feeder level) to incentivize increased appropriate on-site generation, efficiency, and demand response. BlueRock notes that most parties agree that a solid Rate Design leading from cost causation, economic efficiency and gradual bill impacts, and reflecting all of Bonbright's rate design principles is a solid foundation upon which to build. Private sector suppliers should receive a more granular price signal sooner so they can bundle their rates and services in packages that can both better cater to their customers' needs and more quickly capture technology innovation while implementing DER. In the alternative, ESCOs and DER providers should at least have rate options comparable to what utilities can offer.

ChargePoint, Inc. (ChargePoint):
ChargePoint stresses the concept of "gradualism" and that rate design changes not cause large abrupt increases in customer bills. By managing EV charging and other DER, the Commission can avoid grid impacts from increased transportation electrification, and provide demand response by respecting various location and usage characteristics (public, multi-unit residential, and workplace). ChargePoint recommends PSC schedule technical discussions on both EV rate design and the closely related issues of valuing EV charging to better facilitate grid integration and the management of load demand that widespread EV adoption will require.

Citizens Environmental Coalition (CEC):
CEC is concerned that Staff proposes to provide a mechanism for bill crediting other resources-DG and DER- that are not eligible for net metering, however in general REV has been very problematic in not separating renewables from non-renewables, or

clean vs. dirty. In addition, CEC states this section lacks specificity.

Clean Energy Organizations Collaborative (CEOC):
CEOC supports developing estimates of the value of avoiding distribution investments and that the location-based marginal price of energy plus the value of DER ("LMP+D") should be construed as a broad measure "capturing the full range of values provided by distribution level resources," and should include the value of avoided environmental impacts, particularly avoided carbon emissions. CEOC recommends that the value of DER should be based on LMP+D+E, where the "E" refers to environmental benefits, especially the benefits of reducing carbon emissions. CEOC supports the full quantification of load reduction, frequency regulation, reactive power, line loss avoidance, resilience, installed capacity requirements, and emission avoidance when determining the value of DER. In addition, CEOC notes that many responding to the Staff Track 2 White Paper state the value of DER value should include the benefits that accrue to society from DER investments, including avoided air emissions. Staff should calculate the total value of DER that includes the value of bulk transmission services that may be provided by DER, which should be a separate value from the distributional value so that DER providers may be compensated in NYISO markets without double counting. CEOC disagrees with Multiple Intervenors that calculating distribution level marginal costs is premature, and believes that reasonable estimates or proxies are better than ignoring any impact at all. CEOC agrees with Comverge/Energy Hub that long-term price signals may be needed to ensure DER is ready when needed, as well as short-term price signals for operations.

City of New York (NYC):
NYC looks forward to working with Staff and interested parties on analyzing and developing the concept of locational value of DER. The LMP+D construct exists only as a high-level theory and the information needed to make the construct viable and workable (particularly identifying and quantifying "D") does not yet exist. While there may be merit to this construct, it is premature to abandon net metering in favor of it.

Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc. (Con Edison/O&R):
Con Edison/O&R states that the proximity to customer needs and the current-carrying capability of the network, taking into account Con Edison's 'n-2' contingency, mean that DERs do not materially impact power flows outside the local network area: i.e. the benefit of DER in a network requiring reinforcement upgrades decreases as the distance from the system need grows. In addition, the second contingency design means the need for deploying DER resources will likely be based on thermal equipment loadings during primary feeder contingencies, which can occur any time of the year and may not be isolated to high-load days. Con Edison/O&R contends more work will be needed to quantify the extent of opportunities where DER can benefit both the network and system peaks and develop strategies to take advantage of these opportunities, possibly requiring non-linear solutions to calculate power flows and impacts from customer sited solutions. As a result, the need for DER resources within the network portions of the Con Edison system will require different tools to evaluate and value the resources than is the case for the radial portions of the electrical grid. Con Edison/O&R expects to spend capital to build out its modeling and design capabilities as part of REV and ultimately implement a full locational information system to better track DER deployment and enable REV.

Consumer Power Advocates (CPA):
CPA contends that delivery rates for clean DG are greater than the delivery rates for central wholesale generators, and therefore will ultimately raise rates when clean DG is the marginal generator due to the higher fixed costs leading to higher LBMP and hence prices paid to all generators.

Converge, Inc., and EnergyHub (Comverge/EnergyHub):
Converge/EnergyHub asserts that the "LMP+D" valuation should include sufficient granularity in the determination of "D" and to balance short-term price signals of DER operations with long-term price signals of DER investments. Converge/EnergyHub seeks clarification on how "D" is being valued and if its value would be similar to other RTO markets. If based on an RTO market, PSC should consider a forward-capacity market because the cost of

obtaining information about the distribution network to make accurate speculative investment decisions is high and utility planners will not be likely to trust that DERs will show up in sufficient numbers without capital-backed prior commitment.

Environmental Defense Fund (EDF):
EDF supports fair and full valuation of DER based on a time and locational basis, and that the energy supply value of DER on a time and locational basis can be determined by LMP. DER valuation must consider credits valued at a granular location and time basis, the type of service provided, and acknowledge that values change over time and static values should be reexamined to reflect that changing nature. Furthermore, ‘D’ can and should always be valued on a volumetric basis whose single value might not represent true ‘D’ value. EDF argues that: for load reduction, a demand charge based on distribution peak coincident demand that the DER owner can net off of would likely better capture the distribution load reduction benefits of DER and is an important alternative to explore; for frequency regulation and reactive power, services beyond NYISO support should be measured and valued separately with distinct payments to the DER owners supplying these services; for resilience, to the extent that a DER owner is providing resilience services to customers other than herself then these services should be given a separate price tag so that the provider of the resilience services can be rewarded for it (a kWh adder may not be appropriate); for ICAP requirements, it would be more efficient to have an underlying tariff for electric service that would include capacity charges on a kW basis in proportion to the customers’ contribution of the utility capacity requirements; for line loss avoidance, it is appropriate to capture the value of distribution line loss avoidance in a volumetric fashion based on time and location; and for emissions avoidance, the value of emission avoidance needs a more detailed discussion. EDF disagrees with the Joint Utilities' assumption that only the DERs receive the value of the benefits they are providing instead of sharing them with all customers. If DER is compensated for less than the full value, there will be no incentive to invest in DER to the point where marginal value equals marginal cost, which is the socially desirable outcome.

Energy Technology Savings, Inc. (ETS):
ETS contend that demand rates should be more flexible and precise focusing on time-of-day cost causation, simultaneously not penalizing customers utilizing certain types of DER such as storage.

Exelon Companies (Exelon)
Exelon argues that rates designed around a higher proportion of demand charges ($/kW) and/or fixed customer charges ($/customer) would better reflect the distribution system cost structure and thereby ensure adequate cost recovery in a world of low or declining load growth. This new rate structure also would provide more efficient price signals for customers and DER for value provided and received, thereby encouraging economic DER integration and better aligning utility interests with public policy goals. To encourage both realistic and cost-effective change, a benefit-cost analysis that reflects the overall benefits and costs for customers and society should be completed to evaluate DER investment versus traditional utility investment for individual project applications and other proposed REV changes. With utilities serving as the DSP operator, improvements to the operational efficiency and robustness of the distribution grid to incorporate the desired level of customer choice of services and distributed generation must be treated as a foundational investment by the utilities to support the REV framework.

Federal Trade Commission (FTC):
The FTC commends Staff for focusing on the importance of accurate and timely price signals for system efficiency and efficient siting, design, and utilization of DERs. This is the basis for the Smart Home Rate due to increased efficiency and reduced environmental harm, and because it calls for pricing granularity with respect to not only the time of day but also the specific services required to serve a particular customer at a specific location. Further, short-term price signals that include local distribution conditions can be vital in making efficient DER investment, siting, and operating decisions. Even if rate structures migrate toward real-time pricing, the most granular forms of pricing include elements related to the benefits and costs of circuit-level balancing of supply and

demand. By beginning with a dynamic pricing approach and low customer risk, the program may be able to build consumer familiarity with dynamic prices, with less concern for equity effects.

GridWise Alliance (GWA):
GWA suggests that because of the changing nature of supply and demand, all involved should avoid over-building DERs. GWA supports developing time-of-use rates with a delivery add-on and then gradually developing a LMP+D. GWA cautions any heavy moving before FERCs 745 decision is rendered and all affected markets are defined and taken into consideration.

Hudson River Sloop Clearwater, Inc. (Clearwater):
Clearwater advocates for NEM and restoring the full monetary credit for remote net-metered solar projects, with non-demand meters, rather than volumetric credit, since the economics of which are complicated and unreliable.

IGS Energy, IGS Generation, IGS Solar, LLC (IGS):
IGS supports the need to quantify locational value of DER; however, IGS will not take a position because the formula for valuing LMP+D is still under development and contemplates determining the value of LMP+D in a separate proceeding.

Interstate Renewable Energy Council (IREC):
IREC believes if one of the core driving purposes behind REV is to help reduce carbon emissions, the Commission must include environmental and societal benefits of DERs, and the externalities of traditional generation and the positive benefits of certain DERs should be addressed in rate setting. The value of DERs could vary significantly depending upon where the DERs are located on the electric system. Therefore rather than designing multiple different rate structures that would may change, IREC is leaning toward approaches that utilize system information along with rate adders that are available temporally to help drive DERs to locations where they add value. The type of exact performance needed from certain DERs does not lend itself to a basic rate structure as the primary driver of behavior. More nuanced approaches will be necessary to achieve

this performance consistently and reliably over the long-term and short-term system planning and investment horizons.

Joint Utilities:
The Joint Utilities believe the Commission must ensure that the "value of D" is calculated in a fair, objective, and replicable manner and be applied consistently in each application. In many cases, the locational and/or temporal value of D could be zero or even negative if system investments are required to accommodate incremental DERs. The value of D will vary based on the DER technology utilized and any unique attributes that may make its contributions more or less valuable to the distribution grid and this value must reflect the certainty of long-term DER performance. The greatest value DERs can provide to the planning and operation of the distribution system is in distribution capacity relief, i.e., in deferring or avoiding significant capital investments necessary to address prospective reliability needs in locations that are experiencing load growth. The long-term planning value associated with DERs is equivalent to a reservation payment for DERs to be available to the distribution system in specific locations and at a specific time. DERs could also receive compensation for performance when called upon based on a separate short-term value stream and DERs that fail to meet performance obligations would be subject to penalties. DERs also may provide a short-term value to the distribution system in the form of voltage optimization, reactive support, or the reduction of line losses depending on day-to-day, hour-to-hour operational needs, however threshold levels of DER penetration on the distribution system and communications and controls systems must be in place to optimize and measure the performance of DERs. Until more significant levels of DER penetration develop, the Joint Utilities believe that a forward-market mechanism consistent with the cost-effectiveness criteria is the most appropriate means to determine the distribution value of DERs and appropriate compensation. In addition, the Joint Utilities are unconvinced that there is a current software solution to determine distributional-level marginal costs. The Joint Utilities envision using competitive procurement techniques, where practicable, to select resources in a cost-effective manner with the expectation that the benefits accruing from DERs will exceed

the incentives paid to those resources, and that adding 'D' to a NEM credit would be insufficient noting that LMP + D is temporal in nature. Noting that some parties support including the value of externalities in determining the value of LMP + D, the Joint Utilities state that because carbon costs related to RGGI are already reflected in LMPs, it is not necessary to provide a further carbon avoidance incentive for DERs. Should the Commission, in support of public policy objectives, determine that it is necessary to incent environmental outcomes at a value above the market value of emissions already captured in the LMP, it should do so in a transparent manner that clearly identifies the basis for and cost to customers of any additional incentives supporting DERs. This is best accomplished through a separate stated surcharge on customer bills.

Microgrid Resources Coalition (MRC):
MRC contends the value of services to and from a DER-equipped customer will vary substantially with the degree of self-balancing and aggregate demand control that the customer deploys. The potential value may be delivered by simply responding to tariff structures, by committing the DER to respond to dispatch in short-term markets, or by entering into long-term contracts. Tariffs and markets must be designed to provide accurate value for services. Net metering may remain effective for small residential installations, but it is critical that more accurate values be established for larger and more sophisticated installations.

Multiple Intervenors (MI):
MI comments that efforts to calculate the value of DERs using the LMP+D formula could (i) lead to reliance on inaccurate values, (ii) result in the subsidization of DERs by other customers, (iii) materially increase rates and bills for customers, and (iv) be contrary to the public interest. MI also cautions against the premature purchasing or development of software systems to calculate the value of D which are still undefined and vague, as in the value of resilience, and against adopting policies that end up subsidizing DER investments or sending incorrect price signals which lead to unanticipated outcomes.

National Electrical Manufacturers Association (NEMA):
NEMA does not take a position at this time on the merits of the specific ratemaking reforms discussed in the white paper, but expresses support for aligning rates with the dynamic value of electricity to customers which will likely necessitate the need for foundational technologies, especially for confirmation and settlement of DER.

National Energy Marketers Association (NEM):
NEM supports the proper valuation of DERs that appropriately compensates participating customers for the value they provide to the system and suggests that there should be a rate concession for DER providers that do not use transmission and distribution assets.

National Fuel Gas Distribution Corporation (NFG):
NFG supports the development of a bill crediting transactional mechanism for the deployment of DER technologies, similar to that used in net energy metering. Also, current fuel eligibility requirements for NEM need to be further expanded beyond solar and other renewables, and should include all fuel sources such that all DER technologies are able to participate in NEM. NFG is supportive of Staff's initiative to examine alternative electric rate designs, especially the proper valuation and compensation for DER technologies provided to the electric grid. The Commission should establish a broad-based policy objective for valuing DER. The Staff BCA White Paper filed on July 1, 2015, will serve as a first step to aide in this endeavor and will be useful in prospective electric utility tariff filings related to the REV Proceeding.

New York Battery and Energy Storage Technology Consortium (NY-BEST):
NY-BEST argues the "value of D" is central to REV and all involved should agree on fundamental concepts, methodologies and approaches and to set the stage for a phased-in planning cycle to development and implementation. As proposed, LMP+D is too simplistic and near term, and does not take into account valuing and paying for longer term investments. Competitive processes for longer-term contracts for larger resources and installation payments for smaller (e.g., residential) resources could cover

fixed costs based on resource attributes and location to signal where and which resources are most valuable to the system. Tariff structures can be used in addition to incentivize desired operation of the DERs to serve grid needs (e.g., shift peak load, etc.). As a first step, Commission should adopt Staff's recommendation that the utilities adopt the same software to determine distribution-level marginal costs. In addition, NY-BEST concurs that a Cost-Benefit Analysis Framework should form the basis for the 'D' calculations, however the current proposed methodology does not sufficiently capture the benefits of energy storage. NY-BEST believes that rate design and compensation mechanisms implemented under REV should be granular at the circuit where the value of the DER will be realized, not based on system-level average values.

New York Energy Consumers Council, Inc. (NYECC):
NYECC agrees with Staff that while there should be a locational difference for how DER is valued on the system, there should be no locational difference charged to the customer in the delivery charge.

Northeast Clean Heat and Power Initiative (NECHPI):
NECHPI comments that the "value of D" concept is at the heart of REV and should be given prominence going forward in joint deliberations of all involved. Tariff design should be technology-agnostic, but values according to REV need to be granular at the circuit where the true value of DERs reside, not based on system-level average values. Because the LMP+D concept is fundamentally intertwined with the values being discussed in the proposed BCAF as well as those in development in the Community Distributed-Generation Program, the recommended stakeholder collaborative working group could be combined with the stakeholder collaborative working group for the BCAF. NECHPI believes that utility circuit mapping is the only means to establish the value of D meaningfully and in a fully economic fashion and are currently being pioneered by several groups and experts on distribution system planning, such as Integral Analytics. These issues should be a priority rather than the development of MBEs and EIMs before the completion of the foundational work. Aggregation can reduce the risk for individual DERs, increase DER penetration, and can exploit

arbitrage potentials if existing network charges preferentially treat larger devices from the same type or aggregations of devices of different types. Ultimately, DER value depends greatly on how well operating characteristics of DER align with local demand-management needs.

NRG Energy, Inc. (NRG):
NRG agrees in part that DER value can be calculated based on a formula of LMP + D, however the estimation of 'D' needs to capture all aspects of system value drivers, including the distribution level analogues of the bulk power grid's ancillary services, as well as losses, avoided capital and O&M expenditures, ICAP savings, extended lifetimes of equipment, emissions and diversification benefits. NRG supports a Commission effort to establish "zones" within each service territory, grouped into areas where DERs have more or less relative value, and then establishing a set reservation charge for each area, with additional value for DERs that are better able to provide certain needed services, such as volt-VAR balance or active management of thermal constraints. This could be better handled in a collaborative to establish a common method of calculating 'D' across the entire state respecting differences between utility systems.

NY Cow Power Coalition (NYCPC):
NYCPC states that fair and rational DER compensation mechanisms which will help to optimize the continuing employment of and incenting of future ADG installations must recognize their specific and unique values-added. Put succinctly, our "D" – distributive delivery value – has been and continues to be undervalued. NYCPC disagrees with the notion that it would be rational or efficacious to create/adopt different DER compensation policies for existing (legacy) operating anaerobic digesters operations and future installations/operations. If rational DER compensation policies are not in place which would enable the most creative, most competent, most efficient dairy agribusiness people in our State to receive an adequate, appropriate return on their capital and labor investments, future investments in ADGs by dairy farmers or outside investors should not be anticipated.

Pareto Energy LTD (Parento):
Pareto Energy advocates that the new NYISO Behind-the-Meter Net Generation program be the mechanism for establishing the "value of D" and if a collaborative is decided upon, it should include all stakeholders.

Public Utility Law Project of New York, Inc. (PULP):
PULP states that there may be models worth studying and results from other states which are engaging in proceedings to establish a value for renewables, however a LMP+D discussion without identifying the technology is premature. The Commission should identify the costs and potential bill impacts associated with its ratemaking, rate design, efficiency, and DER program investments and mandates prior to further orders in this proceeding. PULP agrees with Joint Utilities that proposed "portal" that would support a market for ESCOs, DER providers, and customers to review and purchase DER products is fraught with the risk of high costs, invasion/erosion of ratepayer privacy, and lack of real benefit to consumers. To the extent DER proposals reflect a theoretical justification based on sending proper "price signals," there is no factual justification for revising distribution or delivery rates for this purpose as these charges send the wrong price signal because customers with high fixed or demand changes will not see any incentive to invest or participate in efficiency and DER investments. Rather, the Net Metering policy should be revised to ensure that all DER customers pay their fair share of distribution services and investments, many of which are being made on their behalf to support further DER investments.

Real Estate Board of New York (REBNY):
REBNY believes the development of "LMP+D" is a key component to ensure a functioning market and whose price signal will communicate the value to market participants and drive market activity towards sections of the distribution system with greatest need. The Commission should initially use well-understood and readily-actionable concepts such as avoided or delayed utility capital investment to value 'D', and then graduate to more sophisticated values.

Retail Energy Supply Association (RESA):
RESA maintains the rate should be implemented in a competitively neutral manner that does not place ESCOs and DER providers at a competitive disadvantage. The requisite infrastructure should be developed and implemented prior to the commencement of such a new rate design.

Simple Energy:
Simple Energy agrees with employing additional DER spurred by positive incentives, cautioning the Commission to not over-monitor what could be an agile process.

Solar Energy Industries Association (SEIA):
SEIA supports valuing DERs based on LMP+D, but urges the Commission to maintain its principle of gradualism in developing and applying LMP+D. Due to the importance and novelty of LMP+D, the Commission should develop LMP+D in a separate stakeholder process. Additionally, SEIA supports Staff's recommendation that the Commission mandate smart inverters on net metered projects moving by enhancing the price signals and incentives for inverter-based DERs to respond to system needs for reactive power and voltage support. SEIA also asks Staff to be sensitive of which stakeholders bear inverter costs as that may impact project economics. In reply comments, SEIA joins with the Alliance for Clean Energy New York, New York Solar Industries Association and Vote Solar to support using LMP+D to inform the valuation of remote net metered and community DG systems, with parity among DER customers, such that community DG customers should not be put at a disadvantage vis-à-vis customers with on-site systems. Development and framework necessities for valuing LMP+D include gradualism, transparency, sufficient notice, identifying best practices, stakeholder input, access to information, and retaining NEM and other full valuation benefits of DER.

The Alliance for Solar Choice (TASC):
TASC believes the definitions associated with "active consumers" and "prosumers" are not detailed enough to determine where a typical residential customer with a net-metered PV system would fall. TASC also inquires whether the calculation of LMP+D should be "vintaged" or would change over the life of a long-

lived asset like a rooftop PV system. The Commission should confirm that all monthly carryover should continue to take place at the retail rate and not as LMP+D and should clarify when and how a smart inverter requirement would be imposed, and who should pay for it. Existing NEM customers should not be required to pay for a smart inverter retrofit. New NEM customers who operate under existing NEM rules should not be required to pay additional costs (beyond the cost of a standard inverter). TASC states there is already a robust market for DER in NY, and it is driven in large part by the State's net metering policy. The biggest threat to DER markets today are the utility proposals do away with net metering and set high fixed charges and demand charges that virtually no mass market customer will understand or be able to react to. TASC disagrees with several Joint Utilities assumptions that the value of DER respect short-term avoided costs since this is in direct opposition to Bonbright principles which emphasize the significant marginal costs are long-run in nature, such as capital or capacity costs.

Vote Solar Initiative (Vote Solar):
Vote Solar looks forward to working with Staff and other interested parties on studying the location-based marginal price of energy plus the distribution delivery value ("LMP+D"). Vote Solar wants clarification on the software systems to be employed, and the "software" be developed and implemented in a transparent process with stakeholder input. The Commission should include the many benefits that accrue to all ratepayers and society in the calculation of LMP+D, such as benefits related to wholesale generation markets that would not be captured in an energy-only wholesale energy price, including capacity costs, or the reduced costs of transmission associated with DER. Vote Solar disagrees with the Joint Utilities' characterization of the benefits of DER to the distribution system as only capacity and other de minimis value; the assertion that compensation should not equal benefits; and the allegation that capacity payments and net metering credits are subsidies.

Northeast Energy Efficiency Partnerships (NEEP):
NEEP comments that it is entirely possible that turn-key, third-party DER developers might not emerge on the timeline—or to the extent—initially envisioned in this proceeding. For this reason, NEEP urges the Commission to continue support for current or expanded MWh resource acquisition goals at least until alternative approaches have been demonstrated to be as effective as current programs.

SECTION IV.F RATE DESIGN AND DER COMPENSATION: Potential Compensation Mechanism Reforms

AARP New York (AARP):
AARP states that the Staff proposal does not reflect the methodology or contain examples of how the LMP+D value would be calculated or implemented by the Commission. The specifics of an actual "formula" should be publicly disclosed and then studied to determine how it would impact utility investment decisions. With regard to net energy metering, AARP believes that the Commission should focus on ratemaking changes designed to ensure that all DER customers pay their fair share of essential distribution services that benefit all consumers. AARP shares many of the concerns expressed by the Joint Utilities with regard to continuing the current net metering policies in New York. Solar customers and other DER customers should be required to pay their fair share of distribution costs that are incurred on behalf of all customers. Furthermore, rate design changes that affect all customers should not be implemented simply to address concerns about DER participation. Rather, the net metering policy should be revised to ensure that all DER customers pay their fair share of distribution services and investments.

Acadia Center (Acadia):
Acadia agrees with the White Paper's cautious approach to reforming net energy metering. Studies have shown that full retail rate net metering for solar generation is generally fair to other ratepayers and the bill crediting mechanism is very important. The next sensible step to take is to use LMP+D to adjust net energy metering credit values for the most

significant categories of projects. These adjustments may only be applied to new projects, and existing projects can be grandfathered. Using a robust measure of ratepayer value to adjust crediting structures is beneficial to DER owners and non-participant ratepayers alike. Changes to the credit calculation may require legislative action. Modest adjustments to NEM credit structures can be made in conjunction with other measures, such as a new "distribution system benefit credit" and an "energy system benefit credit" to compensate for, respectively, distribution system value and any benefits above and beyond the retail generation credit. In addition, new credits can be created for specific categories of projects, such as west-facing solar PV and solar PV that is located in particularly constrained areas of the distribution grid. These credits should be paid for by the appropriate set of customers to which the value accrues, for example only the distribution-related credits should be paid for by the distribution utility. Acadia Center is concerned with the Joint Utilities’ adamant opposition to NEM in general, and NEM for community based distributed generation, in particular, as there is no support for an abrupt termination of a longstanding NEM policy before the DER valuation process is complete.

Advanced Energy Economy Institute (AEEI):
AEEI indicates that the same bill crediting approach should be used for traditional NEM and LMP+D. The timing for when mass-market customers can chose to transition from avoided utility rates to LMP+D compensation should be encouraged and be clearly defined. “Mass-market” customers should also be clearly defined so that customers who do not fall into this category can begin to plan for the (presumably mandatory) transition to LMP+D. AEEI supports the current NEM approach for solar less than 2MW and believes it is worthy of emulation for other technologies in conjunction with the development of new price signals for those items listed above to enable mass-market customers that want to become active participants in the market. However, it is important to recognize that in New York currently, different technologies are compensated differently for net excess generation. Where a technology is compensated for net excess generation only at the wholesale rate, NEM is clearly an insufficient price signal for DER, in the absence of LMP+D as an

alternative. The discussion of "smart inverters" may constitute a significant new requirement that should be supported with a cost/benefit analysis prior to adoption, although in general AEEI recognizes and supports the need to introduce this functionality in order to derive the benefits of DER and to implement LMP+D. AEEI asserts that the Joint Utilities argue for the discontinuation of NEM with no evaluation of the benefits that net metered systems provide to the system. There are certain values of a DG system, such as the avoidance of emissions, which are known with relative certainty and provide a rationale for the continuance of NEM.

Citizens Environmental Coalition (CEC):
CEC supports NEM and its expansion, but recommends significantly raising the caps on NEM to be a significantly larger percentage of peak demand. Also, 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.

City of New York (NYC):
NYC agrees that the use of net energy metering for residential customers should remain in place, but states that Staff's suggestion that the Commission "consider requiring reasonable conditions, including smart inverters, on future net-metered projects" is premature. The State and NYC have a shared interest in increasing reliance on solar power as an alternative to fossil fuels and as a means of reducing system peak demand. Before new conditions are imposed on the solar industry, the Commission should understand the implications of those conditions. Should the conditions impede the growth of solar power, or create barriers to the construction of solar projects, the conditions should not be adopted. NYC disagrees with the Joint Utilities that net metering should be eliminated. Net metering is critical to the continued expansion of solar power, and it is likely that the termination of net metering would cause a dramatic decrease in consumer interest in solar power. Net metering also is a cornerstone of broader, community-based distribution generation programs and projects, and its termination likely would diminish the viability of these important programs. NYC is also concerned that the Joint Utilities proposal regarding demand and fixed charges has the

potential to materially increase energy costs for residential consumers, particularly those least able to afford such increases – the elderly and disabled. Moving more costs into a fixed charge will reduce consumer motivation and interest in reducing energy usage.

Clean Energy Organizations Collaborative (CEOC):
CEOC agrees with Staff that the NEM practices in place today should continue to be used to encourage customers to implement distributed generation resources for their homes and businesses. In particular, the bill crediting mechanism should continue to compensate customers for the generation they provide to the utility system. This mechanism is simple and transparent, and does not create any taxation or regulatory problems by implying that distributed generation customers are selling power to the utility. However, in order to provide NEM customers with price signals that reflect grid distribution and delivery costs, and fair credit that reflects the full value of DER, the amount of credit given to NEM customers should be based on the value of LMP+D+E. This credit should reflect the value of the distributed generation during the hours when it is expected to operate, which can be significantly different than the flat retail rate that is currently used to credit NEM customers. CEOC does not see the need for distinguishing between customer generation that is used to offset customer load and that which could be considered net export generation. It can be very difficult to draw the line between these two types of generation, and if the DG customer is credited at the appropriate value of LMP+D+E there is no reason or need to distinguish between the two. CEOC disagrees with the Joint Utilities' position that the current NEM program significantly overvalues distributed solar generation. Such a statement cannot be made without quantifying the value of LMP+D, and it is quite possible that customers will receive more credit when that credit is given based on the value of LMP+D than they receive under the current regime based on the retail rate.

Comverge, Inc. and EnergyHub, Inc. (Comverge/EnergyHub):
Comverge/EnergyHub states that it will be very challenging to recruit customers into DR programs if, as a prerequisite, they must enroll in highly granular, time-varying rates. Customers

respond well to “risk-free” offers, like an incentive payment for their participation in DR or a peak-time rebate program in which they can only be made better off by their participation. A rate that varies by the hour will be very hard to convince customers to sign up for in large numbers. NEM is not particularly relevant to DR; NEM credits typically reflect an average energy cost which grossly undervalues DR’s contribution to load reduction. Comverge/EnergyHub believes that the “LMP+D” valuation construct must be designed carefully to include sufficient granularity in the determination of “D” and to effectively balance short-term price signals to guide DER operations with long-term price signals to guide DER investments. Utilities should be encouraged to take a central role in coordinating mass market DR programs, while leaving the door open for third-party vendors with direct customer relationships to realize DR value.

Energy Efficiency for All (EE for All):

EE for All supports the DPS Staff recommendation to calculate the value of DER based on locational marginal price plus the distribution value, or LMP+D. In order to capture the accurate DER value, an entire range of environmental, public health and non-energy benefits should be incorporated into this calculation.

Environmental Defense Fund (EDF):

EDF applauds Staff’s approach to rate reform, its proposed gradual evolution toward more granular tariffs while retaining the NEM approach, and its embrace of more sophisticated tariffs on an opt-in basis in the short term while exploring the feasibility of different choice structures for the future. EDF prefers structural solutions that permit scalable results and thus envisions solutions which generate accurate and precise economic price signals without cross-class subsidy. At current penetration levels, NEM could be instrumental in further developing the solar market in the state. Moving forward, the principle of NEM should also remain while the underlying rates become more granular with respect to time, while credits for net exports over time becomes more granular both with respect to time and location, as well as more unbundled with respect to different attributes. EDF disagrees with the Joint Utilities' argument that NEM should be discontinued because it significantly overvalues distributed solar generation and represents a significant subsidy to participating customers and their third-party service providers paid for by non-participating customers. Given the low penetration levels of distributed solar currently in New York, the principle of NEM should still remain while the underlying rates become more granular with respect to time, while credits for net exports over time becomes more granular both with respect to time and location, as well as more unbundled with respect to different attributes.

GridWise Alliance (GWA):
GWA urges the Commission to consider moving NEM customers to TOU+D (time of use + demand) rates. This is consistent with Staff's recommendation regarding the principle of gradualism in rate modifications, i.e., providing signals and greater transparency to customers and the market on what will be important in the future, looking toward LMP+D rates.

IGS Energy, IGS Generation, IGS Solar (IGS):
IGS supports Staff's recommendation that NEM remain in place for mass-market customers and the noted importance of the bill crediting mechanism in NEM. IGS also supports staff's attempts to quantify locational value of DER. Because the formula for valuing LMP+D is still under development, it is difficult to take a position on this issue. IGS, however, looks forward to continuing to work with Staff on the development of LMP+D in a separate proceeding.

Institute for Policy Integrity at New York University School of Law ("Policy Integrity"): Policy Integrity states that the current net metering approach does not maximize the net social welfare because it fails to take into account the real effects—both positive and negative—of DERs. Using a rate that does not take into account the external societal benefits would lead to too little distributed generation penetration compared to the socially optimal level. Not considering the additional costs that distributed generation imposes on the grid due to bi-directional power flows would similarly be inefficient. Thus, unless the retail rates can be modified to reflect all costs and benefits of DERs, the Commission should modify its net metering policy to better compensate DERs for the value they create. Using a more dynamic cost-reflective tariff would not only improve overall system efficiency, but it would also improve the value of distributed generation. Even if the Commission properly calculates the system value of DER as the LMP + D, and even if the value of D reflects all the costs and benefits of DERs including the values that are not related to the distribution system, such as capacity and avoided emissions as suggested by Staff, if these values are not reflected in retail rates with proper granularity, net metering policies will fail to adequately value distributed generation and send efficient investment signals. Therefore, the Commission should consider changing net metering for mass-market consumers contrary to the suggestion of Staff. The Commission should not offer different valuation mechanisms for net metering of distributed solar generation as compared to other types of DERs, since this may inefficiently favor one kind of resource over another. The underlying tariffs for all net metered customers should be the same so that similarly situated distributed generation owners are paid the same price. To the extent that the LMP+D value reflects the true value of the DERs, which includes *all* private and social costs and benefits, and the demand charges help with cost recovery issues, the Commission should not institute a cap on DER interconnection. Pricing based on the true value of DER will be sufficient to guide the market toward a socially efficient level of DER penetration, eliminating the need for an artificial cap.

Interstate Renewable Energy Council, Inc. (IREC):
IREC notes that NEM has been a key tool in enabling hundreds of thousands of customers to better manage their energy use through a readily accessible program that is easy for most customers to understand and participate in. While further discussion regarding the appropriate rate to compensate customers through a NEM program may be warranted, IREC believes that the basic foundational principles of the bill-crediting mechanism should remain in place. IREC agrees that the use of smart inverters will be an important tool to help increase the amount of DERs, particularly, DG that can be accommodated on the electric system. In addition, IREC strongly supports the concept that

the NEM mechanism should be expanded to include different types of DER resources. It may not make sense to apply locational pricing to all DERs. Rather, the Commission will need to evaluate a variety of different price signals along with other tools to help manage the location specific costs depending on the type of DER and the type of customer.

Joint Utilities:

The Joint Utilities disagree with the Staff White Paper's suggestion that NEM should remain in place indefinitely for mass-market customers. The current NEM program significantly overvalues distributed solar generation and represents a subsidy to participating customers and their third-party service providers paid for by customers that cannot or choose not to install NEM eligible on-site generation. Continuation of NEM will slow the development of the robust DER marketplace envisioned by REV. The Joint Utilities support a transition away from NEM in the near term based on a pre-determined formula that preserves the value of their initial investment decision. NEM, in its current form allows certain grid-connected DG customers to benefit from the reliability, stability and other services provided by the utility distribution system without paying the attendant costs of the grid services required to connect them to the grid and service their load and generation. Continued NEM penetration without modification of this subsidy through proper rate design will result in significant rate and bill impacts for nonparticipating utility customers as they are increasingly relied upon to pay for the grid services provided to NEM customers. The Joint Utilities support the use of the LMP + D value to set the compensation for exports from DER, provided that the resources do not receive other subsidies such as capacity payments for distribution support and/or NEM-type credits.

Microgrid Resources Coalition (MRC):

MRC notes that all DER should not be lumped together. However, MRC supports Staff's proposal to move in the direction of TOU rates for all customers. This would tend to reduce differences in the relationship between LMP and the tariff rate to line up with stress on the system, so that customers have the incentive to reduce their usage at times when the system (especially distribution) is stressed and in need of relief. However, the value of services to and from a DER-equipped customer will vary substantially with the degree of self-balancing and aggregate demand control that the customer deploys.

Multiple Intervenors (MI):
MI notes that the Commission has been addressing – and resolving – NEM and remote NEM issues in separate proceedings and MI recommends that such process continue, and that NEM and remote NEM issues only be brought into this proceeding if and when such consolidation has been demonstrated to be necessary. To the extent NEM and remote NEM issues are brought within the purview of this proceeding, their separate examination in other proceedings should cease. The Commission should strive to avoid duplication of effort whereby the same or very-similar issues are addressed in multiple proceedings. Although MI expresses significant concerns regarding how LMP+D may be calculated, and opposes the use of environmental externalities, it finds Staff's proposed distinction between interactive and non-interactive DER to make sense. MI disagrees with Staff's apparent desire to establish distinct DER compensation rules for "residential or small commercial" customers. Customers providing DER-related benefits to the system should be compensated based on the actual benefits provided, irrespective of customer type.

National Energy Marketers Association (NEM):
NEM supports the proposal to derive a proper valuation of DER that appropriately compensates participating customers for the value they provide to the system. In addition to the mechanisms considered in the White Paper for DER valuation, NEM suggests that there should be a rate concession for DER providers that do not use transmission and distribution assets.

New York Battery and Energy Storage Technology Consortium (NY-BEST):
NY-BEST believes that the "value of D" concept is at the heart of REV and should be given prominence going forward in joint deliberations. As proposed, LMP+D is too simplistic to appropriately signal the value of energy storage and shifting load to flatten peaks. LMP+D does not include the long-term avoided costs for avoided investments in transmission,

distribution, and generation. NY-BEST urges the Commission to adopt DPS Staff's recommendation that the utilities should adopt the same software to determine distribution-level marginal costs and initiate a study to calculate avoided LMP + D.

National Fuel Gas Distribution Corporation (NFG):
NFG supports the development of a bill crediting transactional mechanism for the deployment of DER technologies, similar to that used in net energy metering, as well as the continuation of the existing NEM program. Staff is correct that fuel eligibility requirements for NEM need to be further expanded beyond solar and other renewables. All fuel sources and all DER technologies should be able to participate in NEM. NFG supports the Commission's policy in recent years of slowly increasing the fixed customer charge while maintaining a reasonable portion of the total rate in a per unit charge. However, the Commission should refrain from making a policy determination on fixed charges as part of the general REV Proceeding, as this ratemaking element is only discussed in abstract in the Staff White Paper. No concrete proposal or specific change to fixed charges has been presented or identified for the Commission's consideration.

New York Cow Power Coalition (NYCPC):
NYCPC states that statutory net-metering credits may or may not be too low on their face but as implemented and when applied to base load anaerobic digesters (ADG) energy production, without justification or uniformity via the imposition of demand charges, standby charges and excessive interconnection charges, these net-metering credits do not reflect a carefully-thought-out, "granular" assessment of the unique attributes of ADG-produced energy. Put succinctly, the "D" – distributive delivery value of ADG – has been and continues to be undervalued.

NRG Energy, Inc. (NRG):
NRG states that different approaches to compensation may be appropriate for different kinds of DERs – e.g., NEM for solar, value-based compensation for reactive power and other services provided by solar smart inverters, locational avoided distribution upgrade costs; or locational energy and capacity

for CHP plus avoided substation and other costs. Some DER facilities will be, and should be, eligible for multiple such revenue streams. NRG largely agrees with the Whitepaper's recommendation that DER "value" can be calculated based on a formula of LMP + D (where LMP is the NYISO wholesale marginal energy price at a given location on the transmission system). The estimation of 'D', however, needs to capture all aspects of system value drivers, including the distribution level analogues of the bulk power grid's ancillary services, as well as losses, avoided capital and O&M expenditures, ICAP savings, extended lifetimes of equipment, emissions and diversification benefits. The Commission should establish an open stakeholder process focusing on the setting of D, as well as an on-going stakeholder process, with participatory governance, to examine updates and refinements to the 'D' methodology and valuations, as well as other issues related to the structure and functioning of the REV marketplace. NRG recommends that the Commission establish a common method of valuing 'D' across the state, with differences based only on demonstrated and approved differences between utility systems that warrant different methods. NRG also agrees with Staff's recommendation that the Commission should ensure that other payment programs, such as NEM, continue to remain available to smaller mass-market customers investing in DERs.

Nucor Steel Auburn, Inc. (Nucor):

Generally, Nucor supports the Staff effort to ascertain the real economic benefit of verifiable and sustained DER performance on a locational basis, including quantifiable local (distribution) benefits. There are, however, three essential corollaries to Staff's suggested exploration of the "value of D." First, distribution level benefits hinge upon the ability of the DSP to optimize (control) local DER performance, and both DER compensation and DSP rate incentives must emphasize DER system performance optimization. Second, as the White Paper recognizes in its proposed rate design principles, cost causation and allocation must be tightly linked for a more granular process to work. Finally, demonstrable, verifiable, and sustainable DER performance is crucial, and it is appropriate to value and compensate DER based on those performance needs.

Public Utility Law Project of New York, Inc. (PULP):
PULP states that the behavior incentivized traditionally by net metering – i.e., household-scale renewables – removes in part some of the contribution into the grid's carrying costs by those households. In many states, capacity charges or rapidly increasing "basic service charges" result. PULP asserts that whether or not net metering remains one of New York's subsidies for renewable energy, the continued withdrawal of households from supporting the grid will lead to the same problems as are seen with disinvestment in the traditional telecommunications infrastructure. The Net Metering policy should be revised to ensure that all DER customers pay their fair share of distribution services and investments, many of which are being made on their behalf to support further DER investments. The current NEM program should be phased out in the near term through an appropriate rate design that eliminates NEM subsidies.

Solar Energy Industries Association (SEIA):
SEIA supports staff's recommendations to maintain net metering for mass market customers with on-site systems, that NEM bill crediting be used as a mechanism for remote and community DG projects (and other DER), and using LMP+D to help inform the value of credits associated with these systems. SEIA also agrees with Staff that in order to avoid inequities, it is appropriate to ensure that participants in community DG projects receive the same compensation as single-site net metering customers. LMP+D should be applied in a gradual and incremental manner by a transparent process with meaningful stakeholder participation. Any progression of the LMP+D proceeding should be done in close coordination with parallel proceedings, including those on rate design, non-wires alternatives, utility business model reform, and DSPP planning. The Joint Utilities' proposal to phase out net metering is baseless and contradictory to the Commission's objectives under REV, and therefore should be disregarded. Where the value of distributed solar is at issue, the best practice is to undergo a cost-benefit analysis through a transparent process in which all interested stakeholders have an opportunity to provide input. Further, net metering is consistent with the REV objective of engaging customers and enabling investment in DER. Net metering has

proven to be the most effective tool for engaging customers to adopt DER and for financing DER projects. SEIA also opposes the Joint Utilities' support of fixed charges as directly counter to the public policy objectives of REV. Volumetric charges and variable rates allow customers to respond to economically efficient price signals that reflect both short-run and long-run marginal costs and take control of their electricity use, leading to reduced electricity costs for consumers and distribution system relief, especially at peak hours.

The Alliance for Solar Choice (TASC):
TASC asserts that there is no value in changing NEM for mass-market customers with on-site DG at this time. NEM has been a powerful and fair value proposition for customers that leverage existing rate structures. To any extent the Commission has concerns around long-term effects of high-penetration DER, the Commission can mitigate these concerns through MBEs and rate structure changes within reason, while still maintaining NEM in its current form. Staff's discussion around requiring smart inverters is useful, and TASC looks forward to a broader discussion on the standards and use of this technology. TASC believes it is premature to limit net metering only to "mass-market customers." The Commission should clarify that the term "mass-market" includes small commercial customers and make clear that net metering should remain in place for small commercial customers and that LMP + Value of D compensation will be implemented as an optional, but not as a mandatory, replacement for NEM. TASC takes issue with the Joint Utilities' proposal to eliminate the NEM policy, asserting that the position is unsupported and fails to consider the overall benefits of net metering as against the costs.
Similarly there is no basis for the Joint Utilities' claim that NEM will slow development of a robust DER marketplace. There is already a robust market for DER in NY, and it is driven in large part by the State's net metering policy. Net metering is a proven way to enable customers to better manage their electric power costs, expand clean renewable on-site generation in ways that lower system peaks, reduce reliance on fossil fuel generation and reduce the need for central generation, transmission and distribution infrastructure. Net metering is an efficient and administratively simple means to compensate

customers for system and societal benefits of their investment and is a mechanism to which customers have responded. Any attempt to replace net metering with market mechanisms, particularly for mass market customers, will likely impose additional burdens on the Commission to determine appropriate levels of compensation and re-educate customers.

Vote Solar Initiative (Vote Solar):
Vote Solar states that NEM is intuitive and easy for customers to understand. Analyses in Massachusetts, Vermont, and Maine have demonstrated that the benefits of solar exceed the retail rates in those states, which means that the value of the benefits above the retail rate accrue to all ratepayers and society in general. Vote Solar points out that at this point in time, there has been no rationale or data to support the differentiation of treatment for on-site projects. Vote Solar understands the rationale for using the LMP+D valuation to inform the compensation for remote projects. Since remote projects have more siting flexibility than on-site projects, this approach should result in remote projects being located in areas with higher value (and by extension, greater benefits to ratepayers). Without locational value signals, remote projects will most likely be sited at locations with the cheapest development costs, which may not maximize benefits to all ratepayers. Vote Solar supports the development of policies that motivate optimal siting of solar. Locational compensation for remote projects should therefore be investigated. The Joint Utilities have not provided any evidence to eliminate net metering, but rather only conjecture. Until such time that that the utilities (or another party) provide evidence that net metering is inappropriate for New York, Vote Solar supports Staff's recommendation to maintain net metering.

SECTION IV.G.1 RATE DESIGN AND DER COMPENSATION: Potential Rate Design Reforms; *Rate Design Principles for REV*

AARP New York (AARP):
AARP wrote that most of the "proposed rate design principles" recommended by Staff are identical or similar to the traditional rate design principles that have long guided the Commissions

ratemaking decisions. The Commission should be extremely cautious when asked to base its rate design decisions on future costs, the estimation of which are difficult to assume.

Acadia Center (Acadia):
Acadia strongly supports the general rate design principles for REV and believes that electric rates should preserve the consumer incentive to manage his or her energy usage and invest in energy efficiency and local generation. New York's utilities should therefore continue to collect transmission and distribution costs primarily through volumetric rates rather than fixed monthly charges. Fixed charges should be limited to the cost of keeping the customer connected to the grid, such as metering, billing, and service drop. Acadia Center disagrees with the Joint Utilities' assertion that "the transition of fixed cost recovery away from volumetric rates" is in the best interest of consumers. Excessive fixed charges run counter to the consumer-friendly rate design principles that are at the heart of REV.

Advanced Energy Economy Institute (AEEI):
AEEI agrees with the list of rate design principles laid out in the Staff White Paper and suggests the addition of one more: Rates should encourage energy efficiency, integration of renewables, and peak reduction. AEEI also suggests that the principle "Encourage outcomes" include an outcome of reducing customer bills.

ChargePoint, Inc. (ChargePoint):
ChargePoint supports rate design principles as a good starting point for approaching rate design. Rate design needs be considered in conjunction with other REV reforms. This will ensure that programs and policy objectives are complementary and avoid conflicting incentives and messages. For example, the Commission should coordinate programs supporting the expansion of EV charging infrastructure with the development and testing of EV rate options. Mobile loads are different from stationary loads, and it will be critical for the Commission to understand the unique characteristics of mobile loads and the unique opportunities offered by EV resources.

Citizen's Environmental Coalition (CEC):
CEC states that the recommended principles are as a whole not adequate in assuring quality electric services. They are geared primarily to monetary costs while encouraging outcomes, rather than assuring that performance based outcomes are delivered in essential key areas. We are facing major environmental and social issues and rate design must reflect these values.

City of New York (NYC):
NYC agrees that fundamental principles of ratemaking, as enunciated by Bonbright and others, should continue to apply within the REV construct. Cost causation, transparency, and fair value are critical factors to ensuring public confidence and integrity of the rate-setting process. Given the magnitude of the changes to the industry contemplated by the Commission in this proceeding, gradualism is also an essential factor. The Commission should not proceed with implementation, other than the demonstration projects, until appropriate analyses have been conducted and subjected to scrutiny by interested parties.

Clean Energy Organizations Collaborative (CEOC):
CEOC supports Staff's rate design principles related to cost causation, encouraging outcomes, policy transparency, facilitating decision-making, representing a fair value, customer-oriented, stability, access, and gradualism. CEOC recommends modifying the principle of cost causation to read "The Commission should establish rates that, to the extent possible, reflect long-run marginal costs but also recover embedded costs. Fixed charges should only be used to recover costs that do not vary with demand or energy usage." CEOC also states that the principle of customer orientation should be augmented to include: "Rate designs should empower customers with opportunities to reduce their bills by changing their usage profiles and consumption behavior." CEOC strongly opposes the suggestion made by some parties that higher fixed charges would provide more efficient price signals for customers and DER for value provided and received, thereby encouraging economic DER integration and better aligning utility interests with public policy goals. There is no ratemaking or economic principle that dictates that rate design should mirror the utility's cost structure, which is an artifact of historical investments.

Instead, rates should be reflective of long-run marginal costs in order to provide efficient price signals. Fixed charges are accompanied by myriad negative impacts, as has been well-documented in the literature. For this reason, across the country, numerous recent proposals for higher fixed charges have been rejected or significantly reduced.

Environmental Defense Fund (EDF):
EDF opposes the recommendation of the Joint Utilities that fixed customer charges be increased. Fixed charges do not incentivize customers to reduce peak demand, they provide no incentive to the customer to respond in a way that reduces costs over the long run. Furthermore, increased fixed charges would be especially pernicious in the REV context, as they would limit customers' control over their energy bills and thus reduce their incentives to adopt DER of all types. Reduced control over energy bills and reduced incentives for energy efficiency and other forms of DER would undermine key goals of REV. In addition, any increase in fixed charges would raise equity concerns because it would disproportionately burden low-use customers, including apartment dwellers. EDF agrees with Staff that "rate design must take a forward-looking position in order to encourage economic use of DER without encouraging uneconomic bypass." Such a rate design needs to be informed by the principle of cost causation. It is important to identify a rate structure that provides customers with incentives to reduce their contribution to future costs and, consequently, reduces the need for large capital investments. EDF urges utilities to explore which alternatives provide incentives for customers to both reduce their contribution to distribution system costs and adopt DERs.

Grid Wise Alliance (GWA):
GWA commented that in "aligning customer value with earnings opportunities" and "ensuring that customers and market participants receive appropriate value signals" it is important to determine the results being sought at the end, as well as the related characteristics of supply-side, demand-side, and/or load, and make sure all of these are being achieved. Locational marginal prices will change over time, because these characteristics change. With regard to shifting the "balance of

regulatory incentives to market incentives," GWA sees a potential risk of market distortions, though it could be too early to determine. Determining the amount of DG desired or needed will be important. In response to Staff's recommendation that "rate design for mass-market customers should begin to place a greater weight on the peak demand of the customer," GWA states that the overall load factor – and the optimization thereof – are extremely important to consider, rather than just the peak demand here. The load factor and peak demand matter more in the aggregate, than for individuals. Leveraging customer diversity will be important.

IGS Generation, IGS Solar and IGS Energy (IGS):
IGS supports the proposed rate design principles with the exception of the 'Fair Value' principle. With regards to monopoly functions, the Commission should focus on cost rather than value. The term 'Fair Value' refers to a compensation level that is set by competitive markets, indicating in some way a customer's willingness to pay. IGS believes that utilities should have an appropriate opportunity to earn their regulated rate of return; however rate recovery on monopoly assets should be confined to cost-based recovery. Therefore, the Commission should remove or amend this principle to be clear that regulated assets are not to be used in competitive functions.

Institute for Policy Integrity at New York University School of Law (Policy Integrity): Policy Integrity states that in order to ensure that environmental effects are properly considered in electricity use decisions, the rates must fully reflect those environmental outcomes. As externalities, environmental effects are not fully reflected in market prices. Using time and demand-variant pricing does not automatically resolve environmental or health concerns related to emissions. It is important to note that while dynamic tariffs provide more incentives for distributed generation deployment and thus result in a decrease in the energy demanded from the bulk system, unless the externalities are internalized in retail rates, dynamic rates may also cause consumers without distributed generation systems to shift their loads to periods where dirtier plants are on the margin. As peaker plants are often less efficient and dirtier, overall emissions decrease when distributed generation reduces the need for the electricity generated from such plants. However, if time-varying rates shift consumption to other periods, calculating the net effects requires a more careful analysis. Further, as New York State moves forward with plans to comply with the Clean Power Plan, there may be a shift in the times when the fossil fuel fired plants are on the margin, so the idea that peak shaving or peak shifting due to dynamic rates would lead to a reduction in emissions cannot be guaranteed unless the prices reflect the full external damage of emissions. If the temporal dimensions are not taken into account while calculating environmental and health benefits, and if all distributed energy resources are rewarded based on the same average quantity of avoided emissions, then the market incentives will lead to more investment in cheaper distributed energy resources, regardless of whether they are the most beneficial for the society when externalities are taken into account.

Joint Utilities:
The Joint Utilities agree that rates based on the principle of economic efficiency provide customers with the proper price signals on which to base decisions regarding electricity consumption and DER investment. They support the long-standing regulatory requirement that rates should reflect cost-causation, thereby preserving the fundamental requirements of equity and prevention of undue discrimination against any particular user of the electric system. The Joint Utilities agree that rate design has been used to encourage broadly-held policy outcomes, but caution that the “Encourage Outcomes” principle can have unintended consequences. They support the concept of policy transparency in ratemaking and agree that rates should encourage economically efficient decision-making by our customers. The Joint Utilities note a potential inconsistency between the Stability ratemaking principle and the promotion of dynamic or TOU pricing that may become a fundamental requirement for successful implementation of REV. While supporting rate stability as an ideal outcome for customers, the Joint Utilities seek clarity as to how this should be practically achieved in a more dynamic and segmented price signal environment. The Joint Utilities fully support the concept of protecting low-income customers and preventing an outcome in which access to

affordable energy is reduced for low-to-moderate income customers as a result of any changes made to New York's energy policy and agree with the Staff White Paper concept that changes in distribution rates should not "cause abrupt increases in customer bills." In addition, the Joint Utilities propose "sustainability" as a principle, and would require all rate design proposals to reflect the long-term ability for customers to respond and the ability to build out the market in a way to outlast any given technology or investment cycle. Rates are sustainable when they present accurate price signals to customers and adapt to changes in market conditions and evolving customer choices.

Multiple Interveners (MI):
MI agrees that utility delivery rates should reflect cost causation and supports the Commission's current approach of (1) relying predominantly, if not exclusively, on embedded costs for revenue allocation purposes, and (2) considering marginal costs in rate design decisions. Revenue allocation decisions should reflect the cost to serve various service classifications. MI does not oppose efforts to utilize rate design, within reason, to promote certain regulatory policies. Although MI generally supports efforts to improve grid resilience and flexibility, and efforts to reduce environmental emissions, it does not agree that all rate designs that attempt to promote such outcomes are appropriate for ratemaking purposes. MI opposes the creation of non-cost-based subsidies. MI notes that if incentives truly are to be "explicit and transparent," their impacts should be communicated clearly to customers – *e.g.*, through separate line items on bills – and not bundled into opaque, universal surcharges. MI also agrees that rates should encourage economically efficient decision-making. This goal should apply to existing operations and new investments, and MI agrees that utility rates generally should be technology neutral. MI has no objections to the cost-based unbundling of rates such that customers possess increased flexibility to procure the products and services that they desire. On the other hand, MI opposes rate designs that would result in customers subsidizing the market decisions of other customers, or requiring customers to pay additional costs for products and/or services that already are included in their existing rates. With respect to energy

efficiency programs targeted at residential low-income customers, MI asserts that such programs should be (i) demonstrably cost effective on an economic basis, and (ii) subject to a budget that makes economic sense and reflects the fact that all or virtually all delivery customers are funding utility energy efficiency programs.

The Alliance for Solar Choice (TASC):
TASC agrees with Staff's proposed principles of cost causation, policy transparency, decision-making, fair value, customer-orientation, stability, access and gradualism. Non-discrimination should be an additional rate design principle in order to ensure that customers with DER are treated fairly and similarly to customers without DER in similar rate classes. With regard to the "cost causation" principle, TASC acknowledges that rates should reflect embedded costs under regulatory economics principles, but TASC encourages careful consideration of how that principle is applied going forward. Utilities have been and continue to make decisions about operations, maintenance, and infrastructure that are inconsistent with the future development of the REV regime. It may be that, over time, some of these embedded costs can be shifted out of customer rates in favor of value creation through MBEs. TASC encourages the Commission not to enshrine a conservative view of what utility costs might be embedded, or "stranded," as part of the transition to REV.

SECTION IV.G.2 RATE DESIGN AND DER COMPENSATION: Potential Rate Design Reforms; *General Approach*

Acadia Center (Arcadia):
Arcadia strongly supports the general approach to rate design reforms described here, but notes in addition that there is another feedback loop between base rates and DER compensation mechanisms. As base rates become more strongly based on more granular values, the need for special DER valuation mechanisms should diminish.

Advanced Energy Economy Institute (AEEI):
AEEI agrees with Staff's recommendation that the Commission consider rate design reforms that increasingly support REV objectives and markets over time, while reflecting the need for gradualism and infrastructure development in the near term. However, the need for infrastructure development should not present an obstacle to moving forward. Staff's two-tiered approach, distinguishing gradual "base rate" design from more rapid "opt-in" rates may be a way to address both needs. To accelerate adoption of opt-in rate designs, the Commission should require distribution utilities to shadow bill (as is the case in California), or for some of the opt-in demonstration rate changes, the utility could guarantee that customers will be better off than before. A gradual approach for base rates should not become a delay in REV implementation. While studies may have to be conducted and results analyzed before making changes to base rates, AEEI agrees with Staff that more sophisticated rates, such as the smart home rate, can be made available on an opt-in basis. Moreover, infrastructure that offers advanced metering functionalities will need to be developed to achieve robust REV markets and support an evolution in rate design. AMF is a foundational investment, which will determine the shape and pace of REV achievement.

ChargePoint, Inc. (ChargePoint):
ChargePoint strongly recommends that the Commission schedule technical discussions on both EV rate design and the closely related issues of valuing EV charging to better facilitate grid integration and the management of load demand that widespread EV adoption will require. A roadmap for coordinating EV issues will enable the Commission to avoid unintended consequences and take advantage of opportunities associated with this DER resource.

Joint Utilities:
The Joint Utilities support the Staff White Paper's proposed general approach that calls for gradualism with respect to changes in base rates accompanied by more expedient changes to opt-in rates "that give customers options and the ability to adopt technology and receive value from DER."

City of New York (NYC):
NYC fully agrees that greater granularity is essential to the achievement of State and City policy goals and the corresponding REV goals. More granular rates should spur greater consumer understanding, and involvement, increase system efficiencies, and, ultimately, lower energy costs. NYC further agrees with the view expressed in the Track 2 White Paper that abrupt change will do more harm than good, and that a gradual approach be taken by the Commission. NYC supports the need to make rate design changes to implement the REV construct, and that changes should build upon other aspects of this proceeding, including, for example, the development of the DSP, the utilities' distributed system implementation plans and greater penetration of technologies and programs to facilitate and encourage consumer control over their energy usage. NYC looks forward with working with the Commission, Staff, utilities, and other parties on comprehensive redesign of energy rates that preserves energy affordability and reliability while advancing NYC's and the State's greenhouse gas emissions reductions and other policy goals.

Real Estate Board of New York (REBNY):
REBNY agrees with Staff's commitment to a gradual evolution in rate design and transition towards market-based measures so that unreasonable customer impacts are avoided. However, the most important near-term step is for the Commission to establish a rudimentary marketplace and communicate to consumers that they are, whether they realize it or not, market participants. The vast majority of customers, even in the C/I sector, are passive actors with respect to energy and consider the distribution system as solely the provenance of the utility. Changing this paradigm will be the first, and most fundamental, task in underwriting the customer adoption that will be vital to animating a distribution system market. This task, while important, does not need to be difficult. The market can be manifested by the DSP in the form of a website that can serve first as a clearinghouse of information. The development of such a platform, regardless of the particular features and functions, will be an important step in signaling to customers that they are market participants. Furthermore, it will establish the DSP as an entity with which customers interact.

This step will effectively prepare the stage for the roll-out of subsequent reforms and provide a venue for effective communication.

The Alliance for Solar Choice (TASC):
TASC supports the White Paper's approach to rate design reform but believes that fixed customer charges are undesirable, except to collect costs specific to individual customers (e.g., line drops) and should generally not exceed $5-10/month. High fixed charges deviate from long established rate design principles holding that only customer specific costs – those that actually change with the number customers served – properly belong in fixed monthly fees. It also deviates from accepted economic theory of pricing on the basis of long-run marginal costs. The effect of this type of rate design is to sharply increase bills for all low-use customers – including most apartment dwellers, urban consumers, highly efficient homes and customers with DG systems installed – while benefiting larger homes, and suburban and rural customers.
TASC recommends that the Commission find that fixed customer charges for residential customers should be reduced as an early priority for the REV process, with cost recovery initially shifted to volumetric rates— perhaps in conjunction with minimum bills—and eventually (as metering technology allows) to TOU rates. The Staff White Paper refers generally to achieving a shift in cost recovery from fixed costs, but a reform of fixed charges is not, so far, a focus of the REV process. It should be.

SECTION IV.G.3 RATE DESIGN AND DER COMPENSATION: Potential Rate Design Reforms; *Proposed Rate Design Reforms*

AARP New York (AARP):
AARP generally supports voluntary TOU rate programs, and thus endorses an "opt in" dynamic or time-varying rate options, but only if the benefits exceed the costs of such programs. AARP also has serious reservations about performance based ratemaking and the potential that it will result in additional extra charges on consumers. No matter what the justification, the Commission should avoid providing a "bonus" to utilities that

results in making New York energy rates any more unaffordable than those are currently. Another major AARP concern is that the REV process will somehow result in the encouragement of higher customer charges or other mandatory fixed charges. AARP believes that customer charges should be designed for the recovery of nothing more than metering and billing costs and strongly objects to the Joint Utilities' suggestion that residential rate designs be modified to transfer the recovery of standard utility costs from volumetric charges to fixed charges or to demand charges. Such a radical shift in rate design policy would disproportionately harm vulnerable low-usage customers. AARP also objects to the "tools and policies" identified by the Joint Utilities concerning prepayment mechanisms and deployment of AMI. Prepayment programs represent a degraded form of customer service that is often promoted to lower income or other vulnerable customers as a means to retain their essential utility service, thus avoiding the obligations of the utility to comply with the terms of payment agreements and avoiding the obligation to comply with consumer protection rules. AMI technology can be expensive and policies should not be adopted that would significantly increase electric rates and bills without an evidentiary showing that AMI costs will be exceeded by economic benefits to consumers.

Acadia Center (Acadia):

Acadia is encouraged by the proposed study of a three-part rate and peak-coincident demand charges for residential mass-market customers. In the event the demand charges prove too complex for mass-market residential customers, time-varying distribution rates that mimic a peak-coincident demand charge would be the best alternative. Fixed charges should be capped at the costs of connecting the customer to the distribution system; public policy considerations justify fixed charges that are even lower. Acadia Center strongly supports increased facilitation of TOU rates and urges the Commission to adopt a default TOU rate for residential customers on a statewide basis, upon proliferation of AMF. Acadia is encouraged that the Commission intends to maintain policies that favor clean distributed energy resources, including an exemption from standby rates for existing and new technologies. Standby rates present a barrier to DER market animation going forward and should be eliminated once the DER pricing mechanisms are established. Acadia Center concurs with the Joint Utilities' argument that the rate design reform ought to ensure that delivery rates are better aligned with the system costs, but remains concerned with the Joint Utilities' proposal to design demand rates using non-coincident peak demand as the customer billing determinant. Demand charges based on system peak are best suited to provide price signals to the consumers and reflect system costs. All significant rate innovations should be accompanied by advance metering investments that give consumers the information they need to manage their electric consumption and demand and a robust education campaign to ensure maximum consumer benefit and adoption.

Advanced Energy Economy Institute (AEEI):
AEEI supports timely but rapid deployment of AMF. A system coincident peak demand charge should be considered but only if coupled with a robust customer communication and education program. Demand charges can also be coupled with a storage incentive to enhance their effectiveness in reducing peaks. AEEI does not support increased fixed charges, nor do it support demand charges that would become *de facto* fixed charges if customers do not have the ability to modulate demand. AEEI does not support implementation of non-coincident demand charges or approaches that use customer energy usage to approximate demand. Distribution utilities should be required to demonstrate different TVR rates and include options for TVR rate design such as critical peak pricing, peak time rebates, and hourly pricing, such as day ahead or real time prices. AEEI supports the proposed Smart Home Rate, and see it as an opportunity to test opt-in acceptance of more complex rate options, such as day-ahead hourly pricing. Effective customer engagement and education will be critical to the success of TVRs as well connecting customers with in-home "set and forget" devices that allow customers to more easily adapt to the rates. AEEI supports the continuation of low-income discount programs but urges the Commission to require utilities to test current assumptions regarding the impact of TVR on low-income customers. Staff's proposed changes to standby rates are a step forward toward improved rate design which sends accurate price signals and compensates customers for the value they provide. AEEI recommends partnerships with third parties to help communicate

the rate design changes to customers and features on utility websites and customer portals (where applicable) to help implement shadow billing to help customers adjust to new bill structures. The utilities should submit plans to implement the upgraded metering, billing and other systems needed to move forward with immediate and long-term rate designs that will be essential for achieving the REV future. AEEI opposes the suggestion of the Joint Utilities that tiered fixed charges could replicate the impacts of demand billing, arguing that this approach will encounter the same problems that are inherent with all fixed charges: they inhibit customers from being able to control their bills through managing usage and they limit the ability to send price signals to customers to consume in a way that is more beneficial to the system. Customers should pay for their share of aggregate peak usage of capacity as that measure accurately reflects costs.

American Council for an Energy-Efficient Economy (ACEEE):
ACEEE agrees that demand charges should be considered but recommends that demand charges be limited to use during peak period demand hours that most contribute to system costs. Demand charges should be based on the average of several customer peaks during the utility's peak period to give customers an incentive to manage secondary peaks. For residential customers, ACEEE recommends TOU rates rather than demand charges as many of the same objectives can be achieved with well-designed TOU rates. ACEEE supports efforts to expand the promotion of current opt-in TOU rates and demonstrate additional TOU rates. To the extent metering is available, ACEEE also recommends exploration of opt-out TOU rates, as such rates will typically serve many more customers than opt-in rates and provide valuable insights on how such rates work for the majority of customers and not just early adopters.

BlueRock Energy, Inc. (BlueRock):
BlueRock supports a smart home rate and appreciates Staff acknowledging how more granular price signals will allow customers or third-parties to reduce costs to better incentivize technology development of more advanced systems. Some customers modify their electricity use under TVP to lower their electricity costs, but other customers benefit from TVP even

though they do not modify their electricity. Such customers include people who work nights and do not run air conditioning at peak times or include low-income customers without air conditioning. The revenue requirement for customers can also be calibrated based on their current usage patterns – customers' bills go down to the extent they can reduce usage during the high-cost times. Under such rates, the revenue requirement is determined based on average costs and the time variant prices are determined by market prices or marginal costs, including shortage costs. In most utility areas the average zonal capacity costs will be higher than the locational marginal costs so that different customers can see different time-variant locational price signals without major bill distortions. Utilities should move toward a basic TOU price but allow private sector suppliers (ESCOs and DER providers) to receive a more granular price signal sooner so they can bundle their rates and services in packages that can both better cater to their customers' needs and more quickly capture technology innovation while implementing DER. Alternatively, ESCOs and DER providers should at least have rate options comparable to what utilities can offer – such is not the case today in the mass markets, despite what some initial comments may have inferred.

ChargePoint, Inc. (ChargePoint):
ChargePoint states that charging equipment and network services currently available on the market from ChargePoint and other companies is fully capable of incorporating TOU and dynamic rate signals and managing charging in response to such signals and the needs of the grid. There is no need to wait for widespread deployment of AMI in order to effectuate managed EV charging in coordination with EV rates. EV rates for both residential and commercial customers should be implemented now, and dynamic rates should be included in pilot projects. ChargePoint agrees that commercial/industrial rates need to be re-examined and improved.

Citizens Environmental Coalition (CEC):
CEC states that both AMI and the type of smart home tariff envisioned by Staff should be more fully explained. More must be done to correct the current situation for low-income customers. To that end CEC recommends a substantial reduction

the fixed delivery charge for low-income customers and combining this reduced delivery cost with a basic block of energy at reduced cost. Major changes are needed to the Staff proposal in the energy affordability proceedings. Until those issues are reconciled, demand charges should not be considered for low-income customers.

City of New York (NYC):
NYC supports the widespread deployment of AMI to provide more granular and timely energy information to consumers, but states that it is not clear that peak-coincident demand charges are the appropriate tool. The Commission should not incorporate new demand charges into utility rates without first comprehensively studying the issue and understanding how its decisions will affect the cost of electricity for all, particularly for the elderly and disabled who rely on electrically-operated equipment for health or medical reasons. NYC supports the recommendation that the utilities develop plans to engage customers and promote and encourage the use of TOU rates and of of a smart home rate, although more details are needed regarding this rate and how it would be developed and implemented. NYC fully agrees with the recommendation in the Track 2 White Paper that due consideration be given to the potential for adverse impacts of rate design changes on low-income consumers. NYC respectfully urges the Commission not make decisions in this proceeding regarding the nature or magnitude of the low-income discounts, but reserve them for the low-income proceeding. However, the Commission should take steps to ensure that utilities and DER providers pay appropriate attention to the needs of low-income consumers. NYC believes that existing electric standby customers should be allowed to elect the same four-year standby rate exemption established in Case 14-E-0488. The Commission should make this topic a priority and establish a process and expedited timeline for the re-examination and modification of standby rate design. NYC is concerned that the Joint Utilities' position to increase demand and fixed charges has the potential to materially increase energy costs for residential consumers, particularly those least able to afford such increases – the elderly and disabled. Moving more costs into a fixed charge will reduce consumer motivation and interest in reducing energy usage. NYC respectfully urges the Commission to conduct such an analysis

before making any decision to proceed with demand charges or a reallocation of costs to fixed charges.

Clean Energy Organizations Collaborative (CEOC):
CEOC strongly supports, and notes the support of other parties, of expanding TOU rates, and recommends that: (1) TOU rates be designed such that the peak period prices reflect marginal capacity costs as well as marginal energy costs and environmental benefits; (2) peak periods be short enough to enable customers to reasonably shift their usage from on-peak to off-peak or shoulder hours; (3) the differential between on-peak and off-peak rates be large enough to encourage meaningful behavior change but gradually and transparently increased to prevent sudden large changes in customer bills; (4) TOU rate designs with a critical peak price component be investigated; (5) the rate used for consumption of energy and the rate paid for DER generation be separated to avoid perverse price signal; and (6) in the event that an opt-out option is not feasible, an "all opt-in" provision be implemented in which all customers are required to affirmatively opt-in to a rate plan (even if there is a default). CEOC supports Staff's proposal regarding opt-in time variable rates for smart home customers and the recommendation that rates for commercial and industrial customers be improved to better reflect time-differentiated costs. CEOC has concerns that some REV design elements (such as changes to rate structures) could result in increasing energy burdens on low-income and other hard-to-reach populations. CEOC proposes including EIMs that focus on standby rates, until such time as these rates are phased out. Standby rate EIMs should include metrics for time to process applications and the ability to process electric, gas, and steam applications as one. CEOC strongly opposes the suggestion made by some parties that higher fixed charges would provide more efficient price signals.

Comverge, Inc., EnergyHub (Comverge/EnergyHub):
Comverge/EnergyHub states that by pricing electricity in a way that very accurately reflects the cost structure of producing and delivering it, you make it such that consumers acting in their own self-interest necessarily act in the interest of the grid as a whole, in terms of driving lower system cost. However, for the full value of a DR asset to be realized under a

pricing-only regime, the price structure would need to be fully granular. Customers' bills must reflect components such as hourly marginal energy price, contribution to system-wide peak that drives investment in generation capacity, contribution to local circuit peak that drives investment in distribution capacity, marginal losses that they experience at their exact spot on the transmission and distribution network, etc. Comverge/EnergyHub requests that Staff clarify whether tariffs will be structured to allow payment directly to third-party DER providers or whether tariffs would result only in credits on customer bills. If Staff envisions only compensating customers and DER providers via bill credits, this may limit the extent to which third-party DER providers (i.e., DER providers who are not a customer's utility or LSE) can successfully participate in the market. DER tariffs should enable payment directly to third-party DER providers who can then determine how the incentives for their products will be delivered to customers. Comverge/EnergyHub appreciates the idea of a Smart Home Rate, but expects adoption to be relatively low. Highly granular rates would make it harder for DR vendors to recruit customers, but less granular rates would undervalue DR's capabilities and lead to underinvestment. Perhaps several different Smart Home Rate options with different levels of granularity would be appropriate to allow vendors to try to strike this balance. Comverge/EnergyHub also supports Staff's recommendations around TOU rates and associated customer engagement plans. Consideration should be given to adding a critical peak pricing element to TOU programs, which, when coupled with automation, equips utilities with a dispatchable and predictable load resource.

Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc. (Con Edison/O&R):

Con Edison/O&R is exploring alternative rate designs including a gradual shifting of residential and small commercial customer rates from volumetric rates to demand rates when AMI is implemented. Demand rates better reflect the cost of service and provide a price signal that should encourage customer behavior that will help defer or avoid capital investments in network expansions, thereby lowering customer costs. AMI will provide the foundational infrastructure to enable many of the goals of REV. Smart meters associated with AMI will enable customers to install and deploy DERs to participate in DR and other "intelligent" grid opportunities without the current cost and lead-time required to upgrade meters. Furthermore, AMI will drive customer engagement, allowing all customers to evaluate their energy consumption and make informed energy decisions based on their actual interval metering. AMI proposals will allow all customers to reduce their energy costs and help provide distribution benefit by reducing demand and/or on-peak usage.

Consumer Power Advocates (CPA):
CPA comments on steam-commodity standby service in the Con Edison service territory, proposing that the Commission should eliminate contract demand exceedences during hours when the steam system is unlikely to be constrained, establish a bill credit against contract demand similar to what is available for electric service, establish a on-site generation threshold below which standby rates would not apply and establish exemptions to steam standby for efficient CHP projects. Regarding Gas delivery rates for DG units, CPA proposes that the fixed portion of gas delivery rates should be reduced in order to allow competition between DG customers and large central station generation on an equal basis.

Energy Democracy Alliance (EDA):
EDA states that there are mixed reviews and research regarding TOU rates and their impact on low-income households and therefore it calls on the Commission to require the utilities to collect and report data about TOU rates that can be used in future program and equitable policy development (i.e., the impact of different types of TOU rates on low-income households through shadow billing; profiles of the types of households that could benefit from TOU rates).

Energy Efficiency for All (EE for All):
EE for all opposes any increase in fixed charges. A coincident-peak demand charge can, if not properly designed, pose a number of problems for low-income customers. Utilities must determine whether customers, especially low-income customers, have the necessary information and resources to adjust their electricity

usage in response to the demand charge and if they do not, the demand charge should not be instituted until programs and support resources have been established to assist customers with managing their usage. The RIM test is inadequate to protect low-income communities because it measures changes to rates, not bills. The Societal Cost Test, by contrast, considers communal costs and benefits beyond simply measuring prices. EE for All asks that the Commission limit rate plans to a three year period and to modify the clawback mechanism to ensure utilities are given sufficient incentives to choose third-party DER providers while ensuring consumers do not pay more than necessary for this outcome. EE for All further asks that proper steps are taken to ensure a smooth transition from the current EEPS program to a REV market-based model, and that EIMs be designed so as to best capture the energy efficiency potential of the multifamily housing sector.

Energy Technology Savings, Inc. (ETS):
ETS agrees that increasing use of TOU rates will incentivize customers to use energy in a more efficient manner. It is important that the necessary data be provided in order for customers to take advantage of such programs, and that proper pricing and billing allow customers to receive the true benefits of their actions. It is also important that such programs be implemented in a competitively neutral manner. Utilities should not be the only providers of TOU rates, and therefore, other providers need access to required data and billing in order to provide such pricing models. ETS is in agreement that demand rates should be more precise, and reflect the time of day when the costs are actually incurred. It is important that rate design not penalize customers utilizing certain types of DER, such as storage. Rates must be flexible as well in order to accommodate differing types of technology that is now available and may become available in the future. ETS agrees that new technologies should be exempt from standby rates. ETS further notes that it is often more expensive to implement new technologies, and added standby costs could make projects unaffordable.

Environmental Defense Fund (EDF):
EDF believes that more research and testing is important for the development of demand charges that are just and reasonable and that can both allow for the optimal utilization and investment of DER while also ensuring that revenue requirements are met. A demand charge must be connected with peak times (either coincident or non-coincident) in order to provide the correct incentive. Utilities should analyze how changes in demand from the demand charges can lead to distribution system benefits. The Commission should also consider how demand charges affect the incentive to adopt DER. If utilities implement demand charges for residential customers, the demand charges should be applied to all residential customers, not only DER customers. EDF states that opt-out time-variant pricing would likely result in much higher levels of adoption than an opt-in approach. EDF applauds the near term emphasis in smart home rates and agrees that rate design changes should be analyzed for potential adverse impacts on low-income customers. Carefully designed dynamic rates on an opt-in basis can be offered to low-income customers. In order to make electricity bills affordable for low-income households while preserving the incentives for investments in DER, marginal price signals faced by low-income customers need to be preserved. Instead of providing a rate discount which applies to the entire usage amount, confining it to the basic usage block would preserve that marginal price signal. A complementary approach would be to reduce or eliminate the fixed charges for the low-income customers. EDF supports CEOC's recommendation that, in the event that an opt-out TOU tariff is not feasible, an "all opt-in" provision be implemented. EDF respectfully disagrees with NYC's suggestion that the existence of TOU tariffs means that they necessarily are beneficial to customers and that customers should be convinced to switch to them. A better approach would be to improve the choice structure, whether by making high-value time-variant pricing a default where that is feasible or by taking advantage of other behavioral economics insights. Utilities should offer time-variant rates as the default approach to pricing commodity. Ensuring that the commodity price varies based on the time when energy is consumed is not only economically efficient but also environmentally beneficial.

Exelon Companies (Exelon):

Exelon states that distribution rates should be aligned with the underlying cost structure of the distribution network to incentivize high performance. Without rate redesign, price signals in a post-REV environment will be distorted, and higher costs will need to be recovered over smaller sales base consisting disproportionately of customers without the means to invest in DER. Rates designed around a higher proportion of demand charges ($/kW) and/or fixed customer charges ($/customer) would better reflect the distribution system cost structure and thereby ensure adequate cost recovery in a world of low or declining load growth. This new rate structure also would provide more efficient price signals for customers and DER for value provided and received, thereby encouraging economic DER integration and better aligning utility interests with public policy goals. Exelon also supports the Staff proposal to consider demand-based distribution rates for all customer classes, not just commercial and industrial ("C/I") classes and encourages the Commission to consider what has worked well for C/I customers in terms of demand-related charges and apply those lessons to all customer classes. The introduction and use of demand rates will provide customers with the potential for savings by reducing their demands on the distribution system, while ensuring more equitable cost sharing among participating and non-participating DER customers. Exelon, however, opposes voluntary opt-in rate structures in cases where the rate change is designed to improve efficiency or to lower social costs. When rate impact concerns are legitimately raised those concerns can be addressed with phase-in periods rather than by optional opt-in or opt-out rates.

Federal Trade Commission (FTC):

The FTC states that The Smart Home Rate proposal should further help accomplish the REV proceeding's goals of increased efficiency and reduced environmental harm, because it calls for pricing granularity with respect to not only the time of day but also the specific services required to serve a particular customer at a specific location. Accurate price signals could help a customer revise his or her use of energy to reduce monthly power bills quickly and help a customer plan longer-term bill savings through self-supply of some elements of electricity service. The FTC encourages the NY PSC to evaluate the risk/reward differences among various types of dynamic pricing systems for residential and small commercial and industrial customers (who now generally pay flat rates for power). Even if rate structures migrate toward real-time pricing, the most granular forms of pricing include elements related to the benefits and costs of circuit-level balancing of supply and demand. The FTC notes that the Staff proposal regarding standby service is innovative, and may alleviate concerns that the standby rates impede market entry by DERs.

GridWise Alliance (GWA):
GWA believes that the focus of REV should be on gradually moving consumers to dynamic pricing structures, rather than solely to a traditional time-of-use rate structure, for those customers for whom it makes sense. Some portion of the customers may never transition to LMP+D or other dynamic pricing structures. GWA believes that AMF is critical to not only enabling dynamic pricing, but to achieving other key objectives of REV. GWA supports adoption and deployment of all cost-effective options for providing this functionality. Dynamic rates are needed that respond to changes in the supply mix and localized distribution system conditions. TOUs actually might become counter-productive, if they are not sufficiently flexible and adjusted on a regular basis to accommodate changes in demand and supply that will be introduced with DERs. GWA supports the Smart Home Rate proposal but expresses a preference for opt-out over opt-in and, for low-income customers, GWA suggests developing scenarios to model various penetration levels of DG, incorporating the non-dispatchable nature of these resources to the overall optimization of current assets.

Joint Utilities:
The Joint Utilities state that although it would be ideal to establish demand billing determinants based on the customer's peak coincident with the peak in their area of the network, this introduces several concerns including the ability to measure a localized coincident peak, whether this concept can be communicated and understood by customers, and the potential that customers in different parts of the distribution system would have different demand rates. Thus, it is appropriate to design

demand rates using non-coincident peak demand as the customer billing determinant. While movement toward demand charges for delivery service may be desirable, customer charges should be increased to be consistent with customer-related costs. If demand charges are implemented, offsetting reductions should be made to distribution kWh charges and not customer charges. The merits of a demand-billing concept apply equally to all customers regardless of whether or not they are low-income. The principle of gradualism should result in an appropriate phase-in of impacts for low-load factor customers that will be more sensitive to demand charge impacts. The Joint Utilities agree that further investigation is needed to determine the most effective residential offerings. Demonstration projects are the most appropriate means for gathering this data as well as studying the results from other jurisdictions. The Joint Utilities do not oppose a review of the methodology for allocating costs that determine the contract demand and as-used demand components of standby rates but do not disagree with the concept of compensating standby rate customers for reliable DG performance. A reliability credit must be based on metered DG performance, rather than the difference between a standby customer’s contract demand and as-used demand. The Joint Utilities also believe that contract demands should continue to be set in accordance with each utility’s individual tariff provisions. The Joint Utilities disagree with the Staff White Paper proposal to calculate demand charges based on the coincident demand of all accounts within the campus, rather than the individual demands of each account. The local facilities are designed to be able to serve the maximum demand of each account within the campus, not the coincident campus peak, which has no relevance when designing facilities. Those parties that expressed opposition against implementation of demand charges believe that customers may not be able to reduce their bill for demand charges over time. This concern is misplaced as customers do have the ability to reduce their demand charges by altering their consumption and/or deploying DER during peak periods. The Joint Utilities characterize those parties who propose to eliminate standby rates as implicitly favoring cost-shifting from customers who have installed DER to customers who do not. This would not be a reasonable rate design approach based on cost causation.

IGS Energy, IGS Generation, IGS Solar, LLC (IGS):
IGS supports the use of TOU rates as an effective way to send economic signals to customers to change their behavior, but the Commission should clarify that any TOU rates offered by the utilities will not be subsidized. If TOU rates are subsidized through distribution rates, then they are not actually accomplishing REV objectives of using market signals to direct customer behavior in a way that increases system efficiency and reduces the overall cost of the grid. Also, subsidized TOU rates offered by utilities will stifle the ability of the competitive market to develop and offer such products. IGS does not support Staff's proposal that utilities create a TOU program similar to Baltimore Gas and Electric ("BG&E"). BG&E's TOU program provides a non-market based incentive of $1.25 for each kilowatt hour demand reduction, which is equivalent to paying a customer $1250 per megawatt hour. BG&E is able to offer such an excessive non-market based incentive because it recovers the cost of the incentive payments through its distribution rates. To the extent the Commission believes that the utilities should offer TOU or DR products, the utility TOU and DR products *must* stand on their own. Thus the full cost to serve the utility TOU product must be reflected in the TOU rate, and the TOU rate should not receive cost recovery through distribution rates. Further, to the extent the utility offers DR products to residential customers, the only DR compensation the utility should be able to provide to customers is the DR revenues the utilities are able to earn from RTO capacity markets, or other market based revenue. If the Commission finds it reasonable to incentivize DR or TOU offerings by offering payments through distribution rates, such incentives should be made available to all entities that wish to offer DR or TOU products in the market. The Commission should not create utility programs where customers are automatically enrolled in utility DR and TOU products as this will only make it more difficult to compete for non-utility DR and TOU providers. IGS agrees that C&I rates can be improved and states that any demand charge should be based upon transparent and predictable metrics; otherwise customers will not be able to respond and manage their usage accordingly for the benefit of the grid. If a customer is not able to effectively respond to a demand charge in order to reduce their

bill, it will act like a fixed charge and the goals of the REV will be undermined. IGS also supports the review of standby charges to ensure that they do not create a barrier to DER adoption.

Institute for Policy Integrity at NYU School of Law (Policy Integrity):

Policy Integrity states that REV has strengthened New York's role as a leading state modernizing its electrical grid in the face of a rapidly changing energy landscape. The incremental rate reforms proposed will only delay, and could potentially even derail, REV's ambitious vision. As a first step, New York needs to catch up with its peer states in installing advanced metering infrastructure. In conjunction, the Commission should go beyond its transitional plans for an opt-in time-of-use rate and general consideration of demand charges to articulate a clear plan for phasing in more dynamic time- and demand-variant rates that take externalities into account. The Commission should establish a clear timeline for a gradual transition. If the Commission wants to capture all the benefits that a distributed system platform and DERs can achieve, it is imperative that it considers new unbundled and cost-reflective retail tariff rate structures that take externalities into account. Tariffs that provide consumers and producers proper price signals that reflect the actual cost of providing electricity, including the associated externalities outlined in the benefit cost framework, will improve economic efficiency. The Commission should also encourage the development of menus of tariffs similar to the ones developed in other multi-sided platform markets. There is no reason why utilities should offer one time-of-use rate for each class of customers; they should be encouraged to offer a menu of different tariffs for consumers with different preferences for different services. The Commission is rightfully concerned with low-income customers, but trying to keep electricity rates artificially low is not the optimal solution. Direct transfer programs aimed at low-income customers are better policy solutions than distorting the prices. It is important to keep in mind that net social welfare is maximized when the market price equals the marginal private and social cost. Once such a price is established so that the maximum possible net benefits can be realized, distributing this net value among different groups of stakeholders is best done with direct transfer programs that have specific policy goals.

Interstate Renewable Energy Council (IREC):
IREC believes that there should be specially designed rates for customers that are able to install DERs that can help to manage the peakiness of their energy use. Rates should be reflective of some customers' ability to help mitigate the impacts of the peak usage of other customers and should be designed to encourage this grid-beneficial behavior. IREC supports further development of TOU rates and agrees that utilities should be required to implement informational tools and programs that increase customer awareness and understanding of TOU rates. IREC suggests that the Commission continue to research any best practices related to TOU programs and apply any pertinent lessons learned in New York. IREC supports the immediate implementation of a smart home rate and is interested in getting a better understanding of the criteria for such a rate and what level of home performance would be expected and/or required as part of such a rate. IREC suggests that the criteria utilize well-known and existing home energy performance standards to minimize confusion and/or barriers to market adoption. Engaging the real estate and homebuilder trades in program development is also advisable to garner input and buy-in across the applicable sectors.

Microgrid Resources Coalition (MRC):
MRC strongly supports a move to or in the direction of TOU rates for all customers and the Commission's customer centered approach and recognition of the need to increase deployment of third-party capital with the ultimate goal of reducing the total customer bill. MRC also agrees with Staff's position on standby charges. The Commission should consider permitting DERs with sophisticated ability to modulate their demand/production to choose their own level of standby service subject to appropriate penalties if they exceed their chosen limit. There are needed improvements in standards and infrastructure as well. The utility should build its system in anticipation of widespread interconnection of DER that meets specified standards for internal controls. DER meeting those standards should be charged standard rates, not rates based on individual cost

causation, and the last DER to interconnect should not be treated differently than the first. Utilities should be compensated for upgrading the grid to this standard.

Multiple Intervenors (MI):
MI has no objections to the development of a smart home rate, or other time variable rates, for residential customers, provided that such rates are not subsidized by non-residential customers. MI does not oppose – and potentially supports in certain circumstances – an increased reliance on TOU rates for all service classes, including residential customers.
Significantly, MI has concerns regarding the possible cost implications associated with the introduction of advanced metering infrastructure (AMI) and/or advanced metering functionality (AMF) for mass market customers. To date, cost estimates on employing such technology on a wide scale have been in the billions of dollars, and there is no evidence that the benefits to the system outweigh the costs.
If implementation of AMI/AMF is pursued interclass subsidies must be avoided. There are ways to promote TOU rates of various types without advanced meters (*e.g.*, seasonal rates). C/I delivery rates should be based on the utility's costs of providing service. Time-related rate differentials only should be employed where there are legitimate differences in the cost to providing service during the hours in question. MI is willing to explore with utilities and other parties a variety of ways to make C/I delivery rates more precise. MI concurs that gradualism should be employed in implementing rate design changes, and expresses concern regarding timing of standby rate modifications. MI agrees with the concept of the reliability-based bill credit as proposed by Staff, the expansion of the campus offset tariff across the state, and is in favor of enforceable standards to expedite the DG interconnection process. The Commission should ensure that modifications to standby rates are addressed comprehensively and expeditiously. MI also recommends several other standby rate design issues which should be addressed: (1) revenue neutrality; (2) modify the standby rate design matrices; (3) generating unit diversity; (4) daily as-used demand charges during off-peak periods; (5) the standby rate exemption threshold; (6) whether standby rates

reflect the economic diversity that DG customers provide to the system; and (7) elimination of standby rates entirely.

National Energy Marketers Association (NEM):
NEM agrees that greater transparency in utility rates is paramount. Unbundling of utility rates is needed now more than ever. However, a "smart home rate" is the type of service offering that should be made by the competitive marketplace. These types of innovative, competitive rates are enabled by utility rate unbundling that allows ESCOs to compete against the full menu of cost components and by providing ESCOs with timely access to customer data. In no event should these rates be offered by the utility as a gateway to the utility offering behind-the-meter services.

National Fuel Gas Distribution Corporation (NFG):
NFG states Staff's proposed filing requirement for a time-of-use rate customer engagement plan development and of an opt-in mass-market smart home rate should only apply to electric utilities. NFG generally agrees with Staff that rate design changes should be analyzed for potential adverse impacts on low-income customers. The consideration and mechanics of a low-income customer discount should properly be examined in case 14-M-0565. In addition, low-income customer program offerings and REV initiatives should be considered in conjunction with case 15-E-0082, so that: (1) customer offerings do not compete or contradict, (2) customer and market confusion is minimized, and (3) a duplication of efforts does not persist among competing regulatory proceedings and/or initiatives. NFG states that current standby rates force customers to pay charges based on estimates of peak demand, thereby increasing DER costs for customers who are paying for electricity at rates based on maximum usage. This practice directly precludes the adoption of DER technologies. NFG supports the short-term standby rate action items proposed in the Staff White Paper, i.e., the immediate establishment of a customer reliability credit; the expansion of temporary exemptions from standby rates to new technologies; the establishment of campus offset tariff rates throughout NYS and the enhancement of existing campus offset tariff rates; and continued monitoring of the time needed to process standby rate applications and successfully complete

customer grid interconnections. The Commission should refrain from making a policy determination on fixed charges as part of the general REV Proceeding, as this ratemaking element is only discussed in abstract in the Staff White Paper.

New York Battery and Energy Storage Technology Consortium (NY-BEST):
NY-BEST believes that tariff design is critical to the success of REV and advocates that tariffs be standardized, unbundled, granular, flexible, support the deployment of DERs (e.g., storage), and provide sufficient visibility to allow DERs to sign long-term contracts. NY-BEST supports the broader use of demand charges discussed in the Staff White Paper. The introduction of advanced metering functionality will enable movement beyond the historical dispute between fixed customer charges and volumetric rates. As new demand charges are developed through REV, NY-BEST urges staff to recognize the critical role that energy storage plays in addressing peak demand and ensure that energy storage is integrated in the design of these new programs. NYBEST also encourage Staff and the Commission to work to develop interim demand charge programs in advance of the widespread introduction of advanced metering. NYBEST concurs with Staff that further improvements are needed in rate design for C&I customers and encourages the Commission to consider adopting cost-effective incentives for storage and other alternative technologies. This can be done by creating an "Asset Utilization Tariff" that is technology neutral and is based on the cost savings to each utility from reduced ICAP, T&D deferral, distribution system peak load management and energy savings. NYBEST believes that an Asset Utilization tariff would create benefits for the grid, the utility, the customer and third parties. The proposed tariff would also enhance electric system reliability without producing emissions, reduce overall system emissions and increase system utilization rates.

New York Energy Consumers Council, Inc. (NYECC):
NYECC supports near term opt-in rates that give customers options and the ability to adopt technology and receive value from DER and agrees that any transition to a three-part rate requires a detailed study performed, including bill impact analyses under numerous scenarios, including customer non-

coincident peak, system-peak coincidence, localized distribution peak coincidence as well as a range of percentages by which the kWh rate is replaced with the demand charge. NYECC agrees with the need for improvements to existing demand charges for larger customers and Staff's proposals regarding standby rates affording larger customers options and the ability to earn a reliability credit. NYECC also supports further standby rate reforms, including, but not limited to, application of the temporary exemption to new technologies not currently identified in the exemption, expansion of the campus offset rate, and including specific metrics in the processing of standby rate applications at to time and in the ability to process electric, gas, and steam applications as one, in any interconnection EIM.

Northeast Clean Heat and Power Initiative (NECHPI):
NECHPI is skeptical of implementing retail demand charges and does not yet have a definitive opinion about the issue but notes that putting in place AMI is a more immediate step to be taken than coming up with controversial retail rate structures. NECHPI is also skeptical about TOU rates and recommends that any changes should be implemented as pilot programs in specific parts of one of several utility territories. NECHPI states that a smart home rate might make sense in a pilot project form if modeled after National Grid's very successful program in Massachusetts. NECHPI agrees with Staff's observation that 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 LMPD+D" but believes that Staff's standby rate proposal falls short of that approach, does not reflect industry best practices, and is only marginally better than Con Edison's interim solution. NECHPI had hoped for a more innovative approach to standby rates.

NY Cow Power Coalition (NYCPC):
NYCPC disagrees that it would be rational to create/adopt different DER compensation policies for existing ADG operations and future installations/operations. Demand charges potentially measured by an instant of peak usage can be devastating and standby charges are blatantly unfair when considering the brief and infrequent down-times of ADGs. NYCPC supports the

replacement of standby rates with reliability credits and states that such changes in relation to ADG net-metering credits can and should be implemented as soon as possible.

NRG Energy, Inc. (NRG):
NRG believes that the focus here should be on time-differentiated *delivery* rates. NRG disagrees that opt-in TOU rates should be improved with outreach and education, that default TOU rates should be examined, and that utilities should develop TOU rate demonstration projects. Instead, utilities should remain in the basic service role and leave TOU rates to ESCOs, which are capable and willing to serve the commodity supply needs of all customers.

Pareto Energy LTD (Parento):
Parento does not believe that standby charges threaten the economic viability of non-synchronously interconnected CHP projects in NYC. Pareto mentions an article about an independent economic analysis that concluded that the California approach to standby charges was preferable for maximizing the adoption of DG. The article recommended adjusting the marginal cost differential between DG electricity production and purchased utility power as a countermeasure for encouraging the desired level of DG capacity.

Public Utility Law Project of New York, Inc. (PULP):
PULP objects to any rate design proposal that would rely on the widespread deployment of AMI without justification by a costs and benefits analysis and opposes any move to mandatory TOU rates. Rate design changes that would transfer recovery of standard utility costs from volumetric charges to fixed charges or demand charges are not appropriate for most residential customers. Any rate design recommendation must be accompanied by detailed analysis of bill impacts on all residential customers, not merely focusing on "average" bill impacts or usage profiles. The regulated distribution or delivery services provided by New York electric utilities should be based on utilities' costs for that service and not artificially manipulated by signaling a regulator's estimate of "value" to promote customer investments in certain technologies. Customers who purchase or install DER, particularly rooftop solar, should

be required to pay their fair share of distribution services and grid access. PULP also recommends reform of existing low-income programs; reconsideration of the net metering policies; the use of demonstration projects before the implementation of changes in rate design and other mandates; the identification of the costs associated with its various REV-related mandates and orders; and the calculation of the bill impacts associated with REV programs and mandates.

Real Estate Board of New York (REBNY):
REBNY supports Staff's three proposed standby rate reforms, but notes that the Commission should establish an expedited process to address further modifications to standby rates. REBNY also notes that the standby rate exemption order in Case 14-E-0488 is a welcome advance for new DG, but fails to provide relief to existing standby rates customers.

Retail Energy Supply Association (RESA):
RESA states that a 3-part rate (demand, volumetric and fixed charges) will require a detailed Cost of Service study that will unbundle and identify the relevant distribution, capacity and commodity costs and ensure they are allocated to the correct cost bucket. There will be a financial incentive on the part of the utility to maximize the allocation of costs to the fixed customer charge and thus increase the stability of its revenue infusion. It is absolutely vital that the application of the three-part rate be developed and implemented in a manner that is competitively neutral and does not in any way undermine the competitive position of ESCOs providing competitive commodity service. The application of such a three-part rate will not be able to proceed unless and until there is sufficient metering and billing and other related infrastructure in place to support the calculation and implementation of these customer specific rate charges. The use of a three-part rate (or any rate for that matter) can only be useful and accurate if the underlying utility rates reflected in the three-part rate are accurate and consistent with current market costs. The Smart Home Rate should be the province of competitive ESCOs and DER providers rather than the utility. The utility should not be empowered to offer products and services in direct competition (and with ratepayer funding) with independent ESCOs and DER providers —

which have the capability and already offer these types of products.

Solar Energy Industries Association (SEIA):
SEIA supports the concept of smart-home rates and other time variable rates that fit into the long-term vision of REV. However, experimentation with smart-home and other similar rates should be seen as a pilot effort to facilitate learning and early adoption, and should not detract from near and medium term market development efforts. At the same time that dynamic rates are explored, the Commission should remain focused on maintaining net metering and improving time of use retail rates that are more likely to impact customer behavior and drive DER adoption than other more complex rate designs. To the extent that smart home rates are offered, they should be opt-in only and uniform across utilities to the extent possible. SEIA supports Staff's recommendation to improve TOU rates. The Commission should consider moving toward meaningful differences in rates between on- and off-peak times, taking into account the principle of gradualism. Improving TOU rates should be done through a separate stakeholder process to examine and establish principles for improvement. SEIA generally opposes demand charges because they do not effectively incentivize customers to minimize their bills or change their load patterns through DER adoption, and often have the opposite effect, acting as de facto fixed charges that discourage adoption of DER and encourage grid defection. Any study of demand charges needs to focus on the extent to which a customer can respond to the price signal and reduce their bill (i.e. the actual impact of demand charges on customer behavior), and on ensuring that customer demand is measured coincident with the demand on system elements that the Commission seeks to influence. SEIA agrees that standby charges should be reduced. SEIA disagrees with the Joint Utilities' suggestion that customer charges can be implemented to mirror demand charges. The Joint Utilities provide no examples of this approach achieving the objectives of REV, including customer adoption of DER, customer control over electricity use, reduced peak demand, or reduced customer bills. Likewise, SEIA strongly opposes the suggestion that the Commission move away from volumetric charges in favor of fixed charges.

The Alliance for Solar Choice (TASC):
TASC is skeptical that demand charges can be applied to mass-market customers, who have limited ability to respond to these charges. Staff should study demand credits that would incent customers to deploy DER that would reduce their costs to the system and also consider different rate structures and tariffs for different network needs. Any rate structure studied should also take into account the ability of DER to respond to those structures. TASC applauds Staff's discussion around TOU rate structures, and note that staff should allow for broader stakeholder proposals around TOU design. While TASC supports the proposal to study demand charges, it expects the inquiry will find that a shift from volumetric to demand charge collection for residential customers is less likely to meet REV goals, compared to greater reliance on TOU rates. If the Commission wishes to experiment with demand charges for residential customers, it is critical that customers can voluntarily opt-in – demand charges should not be mandatory for residential customers. It is also very important to avoid short duration ratchets. TASC strongly supports the White Paper's proposal for reform of commercial and industrial demand rates, to eliminate non-coincident peak customer usage as a basis for demand charges, and to substitute customer usage that is coincident with system or circuit peak. Standby rates are inappropriate for customers with PV generation systems. Moreover, storage or battery systems should not be subject to a standby charge. TASC states that any future standby rates should be differentiated by system impact. TASC supports the decision to continue the standby charge exemption for on-site generation up to 15 MW and believes that a permanent exemption should be established for intermittent renewable generation and associated energy storage systems. TASC opposes the Joint Utilities' proposal to shift revenue recovery from volumetric to fixed demand charges, noting it is completely out of step with Commission decisions on this topic across the country. Demand charges and increased fixed customer charges significantly reduce customers' incentive to use electricity more efficiently or to install distributed generation resources.

Vote Solar Initiative (Vote Solar):
Vote Solar agrees with Staff's assertion that rates should provide accurate and appropriate value signals but believes that demand charges do not meet this objective as well as time-differentiated energy rates. Until such a time as residential and small commercial customers understand and respond to demand charges, Vote Solar proposes that the Commission only implement time-differentiated energy rates as a mechanism to motivate customers to take action. Vote Solar strongly supports Staff's proposal to analyze any rate design changes for adverse impacts on low-income customers and suggests that low-income customers be allowed to maximize their ability to respond to value signals while protected from unintended consequences. Vote Solar asserts that the Joint Utilities' position on net metering completely ignores the long history of including public policy objectives in rates in general, for instance discounts for specific customer classes. Public policy objectives for DER have been implemented in rates and tariffs in many states, including funding for renewable energy and energy efficiency, and renewable portfolio standards. Vote Solar fully supports Staff's position on net metering. Demand charges are challenging, if not practically impossible, to effectively impact for most small customers by changing their behavior.

PART 2: Comments Following Data Technical Conferences

Comment Summary

First Technical Conference

Advanced Energy Economy Institute (AEEI): On behalf of: Advanced Energy Economy (AEE), The Alliance for Clean Energy New York (ACENY), The New England Clean Energy Council (NECEC): Submitted By: Ryan Katofsky, Senior Director, Industry Analysis

Association for Energy Affordability (AEA): Submitted By: David Hepinstall, Executive Director and Valerie Strauss, Director of Policy & Regulatory Affairs

Capital District Regional Planning Commission (CDRPC): Submitted By: Todd Fabozzi, Director of Sustainability, Albany, NY

Citizens for Local Power (CLP): Submitted By: Susan H. Gillespie, President, Rosendale, NY

City of New York: Submitted By: Kevin M. Lang, Attorney for the City of New York, With COUCH WHITE, LLP, Albany, NY

The Companies: Consolidated Edison Company of New York, Inc. Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, National Fuel Gas Distribution Corporation, New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation: Submitted By*:* Kerri Kirschbaum, Senior Attorney for ConEdison, New York, NY

Consumer Power Advocates: (CPA): Submitted By: Catherine Luthin, Executive Director, Allenhurst, NJ

Direct Energy Services, LLC, Direct Energy Business, LLC, Direct Energy Business Marketing, LLC, and Direct Energy Solar (collectively "Direct Energy"): Submitted By: Angela Schorr Manager, Government and Regulatory Affairs

EnergyNext, Inc.: Represents The Municipal Electric and Gas Alliance (MEGA).

ETS (Energy Technology Savings): Submitted By: Valerie Ross, Sr. Energy Compliance Manager, Summit, NJ

IGS Energy, IGS Generation, IGS Solar: Submitted By: Katie Bolcar Rever, Director, Legislative and Regulatory Affairs, Interstate Gas Supply, Inc. dba IGS Energy, Dublin, Ohio

Metropolitan Transportation Authority (MTA): Sam M. Laniado and Tyler W. Wolcott, Attorneys with Read and Laniado, Albany, NY

Mission Data: Submitted By: Cameron Brooks, President, Tolerable Planet Enterprises, Boulder, CO; and Jim Hawley, Principal, Dewey Square Group, Sacramento, CA

National Energy Marketers Association (NEM): Submitted by: Craig G. Goodman, Attorney & President, and Stacey L. Rantala, Director, Regulatory Services, Washington, DC

National Fuel Gas Distribution Corporation: Submitted by: Michael E. Novak, Asst. General Manager, Rates & Regulatory Affairs, Williamsville, NY

National Grid: On behalf of: The Brooklyn Union Gas Company (KEDNY) d/b/a National Grid NY, KeySpan Gas East Corporation (KEDLI) d/b/a National Grid, and Niagara Mohawk Corporation d/b/a National Grid. Submitted By: Jeremy J. Euto, Senior Attorney II, National Grid, Syracuse, NY

NRDC: Submitted by: Natural Resources Defense Council, Jackson Morris, Director Easter Energy; Urban Green Council, Laurie Kerr, Director Policy; Institute for Market Transformation (IMT), Alissa Burger, Sr. Associate Data and Utillities; and Pace Energy and Climate Center (PACE), Daniel Leonhardt, Sr. Energy Policy Associate

Otego Microgrid Ratepayers (Otego): Submitted by: Stuart Anderson

SolarCity Corporation: Submitted by: Jamil Khan, Deputy Director, Policy and Electricity Markets

Town of Philipstown: Submitted by: Richard Shea, Supervisor

Utility Energy Registry NewYork: Submitted By: Jim Yienger, Principal, Climate Action Associates, Johnsonville, NY

PARTY COMMENTS ON DATA TECHNICAL CONFERENCES

Advanced Energy Economy Institute (AEEI): On behalf of Advanced Energy Economy (AEE), The Alliance for Clean Energy New York (ACENY), The New England Clean Energy Council (NECEC): Submitted By: Ryan Katofsky, Senior Director, Industry Analysis

1. **Enabling customers to share their energy use with vendors they choose.**

Q1. *Are there protocols or alternatives to Green Button Connect that should be considered, and if so, what are the advantages and disadvantages of each alternative?*

The Advanced Energy Community agrees that the Green Button Connect is the appropriate standard to use and that utilities should begin to implement it fully. They note that it has experienced limited deployment and uptake to date. The group strongly recommends that Staff assess the full range of data needs anticipated by all entities, and identify any gaps in the current Green Button specifications. Because Green Button is the only standard that they are aware of, they encourage Staff to watch out for new formats that provide additional functionality or ease to use. The Advanced Energy Community supports the use of open-source protocols for data exchange which will help speed adoption and provide for better interoperability between systems.

Q2. Should vendors seeking to be provided customer data through Green Button Connect, or an alternative protocol, be considered a Distributed Energy Resource Supplier, as defined in Staff's Proposal in Case 15-M-0180? If so, which, if any, of the rules proposed by DPS Staff in that proceeding should not be applicable to vendors seeking to obtain customer data through the Green Button Connect or alternative protocol? If vendors seeking to be provided data through Green Button Connect or alternative protocol should not be subject to the rules developed in Case 15-M-0180, what requirement or oversight should be applicable to those vendors?

The Advanced Energy Community agrees that there should be regulations in place to protect customers and safeguard data;

however, receiving data at a customer's direction is not an appropriate trigger for oversight and regulation beyond existing state and federal consumer protection and data privacy laws and regulations governing all businesses. The group argues that a company that receives data through Green Button Connect or another protocol should not automatically be considered a DER supplier under the Staff's proposed Uniform Business Practices for DERs. In its comments, Advanced Energy Community refers back to the Track One Order which outlined two conditions that would trigger oversight over a DER provider. The group recognizes that one of the criterion under the Order could be broadly interpreted to include data provided through Green Button Connect, a correct interpretation should fit clearly within the boundaries of the Public Service Law and recognize customer choice. Staff's proposal on DER oversight noted that an entity falls under the jurisdiction of the Commission when it sells or facilitates the sale or furnishing of electricity to it residential customers. Advanced Energy Community argue that Green Button Connect does not meet this test nor do many other services that might include data exchange through Green Button Connect or similar protocols.

The group points out in their comments that there are a number of free, web-based apps and other services such as the EPA's Energy Star Portfolio Manager that currently use or are developing compatibility with Green Button connect. Advanced Energy Community believes these types of free services should be encourages as part of market growth, but app developers may be less likely to offer these free services to customers if so incurs a cost to comply with regulatory oversight. In addition, the group sees the decision to share data through Green Button Connect as a customer choice that should not in itself subject the company receiving the data to Commission oversight. The group supports the position that utilities should provide information that is clearly visible to explain that providing data to another company will entail revealing private information. In addition, customers should be advised to review the privacy and data handling policies of the recipient company before sending their information.

Q3. Pursuant to Uniform Business Practices, Section 4 (E), utilities may not change ESCOs for providing customer-specific information including energy consumption history used to market to or enroll customers. Should that requirement also be applicable to customer-specific information provided to ESCOs and other vendors via Green Button Connect or an alternative?

Advanced Energy Community believes that utilities should not charge companies for receiving in near real times, customer usage data through Green Button connect or other similar protocols. The group recognizes that providing this data can generate costs for the utility, however, there should be minimal incremental cost for enabling Green Button Connect over systems that utilities will already need to invest in to enable the customer portal and other systems to support the market for DER.

Q4. What other implementation issues regarding Green Button Connect or an alternative should be addressed and how should they be resolved?

Advanced Energy Community suggests New York look to California for a “lessons learned” for the implementation of Green button Connect to avoid some problems experienced in that state. Three IOUs in California began using Green Button Connect in 2012 but the system is not widely used. The group lists for the following reasons for the slow uptake: lack of awareness; disparity in technical understanding/capability among third party providers, Inter-IOU disparities in data exchange platforms based on interpretation of Green Button and its standards, lack of standard state-wide third party authorization process, and availability of information because Green Button provided only usage data not billing data. The group asserts the Commission should create rules that ensure standard utility implementation of Green Button Connect across New York. Further, utilities should be directed to work with the Green Button Alliance to ensure implementation of Green Button is fully complaint with the standard.

2. ***Providing aggregate energy data to third parties including municipalities for purposes of Community Choice Aggregation and community planning.***

Q1. How can utilities prepare and provide electronic access to customer data aggregated by municipality in a standard format in an efficient manner?

Advanced Energy Community does not have a specific recommendation for a data standard but many companies receives data in CSV format and that is sufficient for most of their needs. Access to direct data is the group’s primary concern.

Q2. Should utilities be permitted to charge municipalities or other third parties for providing this aggregate data? If so, why, and how should those charges be determined?

Advanced Energy Community believes access to aggregated customer data is necessary for companies to be able to propose solutions that service community needs and provide non-wire locations to locations on the distribution grid. However, the group believes that any personal identifiable information should not be provided in aggregated data.

Q3. Should the Commission consider a privacy standard to ensure customer anonymity when aggregate energy data is released to third parties without customer consent? If so, what rule should be adopted? Rules in other jurisdictions include a “15/15 rule” under which a minimum of 15 customers are included in aggregate data with no one customer’s load exceeding 15 percent of the group’s energy, and a “4/80” requiring data from a minimum of four customers to be added as long as no one customer’s load exceeds 80 percent of the group’s energy consumption.

Advanced Energy Community does not have a specific recommendations for aggregated standards but finds the 4/80 does not adequately anonymize customer data and it should be something in between the 4/80 and 15/15 rule. The Commission should not choose something more stringent than the 15/15 rule.

Q4. What other issues regarding providing aggregate customer data to third parties should be addressed and how should they be resolved?

Advanced Energy Community supports access to data to enable advanced EM&V capabilities that are needed to help REV achieve its full potential. The group believes empowering continuous EM&V that quantifies savings in near real-time is important for energy efficiency to transition toward a market based resources. As they outlined in their comments on Utility Energy Efficiency Transition Implementation Plans (15-M-0252), a transition to market-based energy efficiency requires "EM&V 2.0 methods" that include new measurement devices and software that rely on non-participant comparison groups.

Association for Energy Affordability (AEA): Submitted By: David Hepinstall, Executive Director and Valerie Strauss, Director of Policy & Regulatory Affairs

AEA supports the Commission's undertaking in the REV proceeding and sees access to consumer energy use data is central to meeting the objectives of the REV. AEA believes that REV would not be possible or proposed without modern data capabilities and how we use existing data and plan for further developments in its availability requires thoughtful deliberation.

1. ***Enabling customers to share their energy use with vendors they choose.***

Q1. Are there protocols or alternatives to Green Button Connect that should be considered, and if so, what are the advantages and disadvantages of each alternative?

AEA agrees that to enable REV and ensure that REV provide value to customers, access to real-time and easily shared data is essential. Further, AEA states that advanced metering capabilities of providing interval data must be necessary. AEA supports Green Button Connect as is it an existing protocol that can be adopted in New York and provide a consistent approach for vendors and consumers.

However, AEA realizes that Green Button Connect may not be able to completely replace existing EDI protocols because of its shortcoming with billing quality data currently used by ESCOs. AEA remains supportive of moving forward with Green Button

Connect and moving forward a single system capable of providing both billing quality and easy access and use customer data. AEA is not aware of any other good alternative to Green Button Connect but protocols that do surface should provide data in an easy format with compatible electronic information. Green Button Connect provides an important advantage because it is already available.

Q2. Should vendors seeking to be provided customer data through Green Button Connect, or an alternative protocol, be considered a Distributed Energy Resource Supplier, as defined in Staff's Proposal in Case 15-M-0180? If so, which, if any, of the rules proposed by DPS Staff in that proceeding should not be applicable to vendors seeking to obtain customer data through the Green Button Connect or alternative protocol? If vendors seeking to be provided data through Green Button Connect or alternative protocol should not be subject to the rules developed in Case 15-M-0180, what requirement or oversight should be applicable to those vendors?

AEA believes customers permission should be required for vendor access to individually identifiable customer account data because customers should be made aware of what data they are providing to third parties. AEA does not support third parties receiving data automatically being considering a DER provider as defined under the Staff proposal nor be set to a subject of rules. Further, downloading data to a third party for review, analysis or to solicit a proposal should not trigger PSC jurisdiction and therefore, sharing data via Green Button Connect should not be under PSC jurisdiction.

AEA does not agree with all the proposed rules for DER provide oversight or the definition of which providers should be covered by such rules. AEA states that some of the current and future services provided based on customer energy use data are not necessary nor conducive to ensuring consumer access to energy and bill management tools.

Q3. Pursuant to Uniform Business Practices, Section 4 (E), utilities may not change ESCOs for providing customer-specific information including energy consumption history used to market to or enroll customers. Should that requirement also be applicable to customer-specific information provided to ESCOs and other vendors via Green Button Connect or an alternative?

AEA advocates that customers should be provided with their own data as part of basic service at no charge and be free to share their data via Breen Button Connect or an alternative protocol without having to pay a fee. AEA argues that charges for accessing customer data will work against customer engagement in the DER marketplace and detrimental to the Commission's vision.

Q4. What other implementation issues regarding Green Button Connect or an alternative should be addressed and how should they be resolved?

No comments.

2. ***Providing aggregate energy data to third parties including municipalities for purposes of Community Choice Aggregation and community planning.***

Q1. How can utilities prepare and provide electronic access to customer data aggregated by municipality in a standard format in an efficient manner?

No comment.

Q2. Should utilities be permitted to charge municipalities or other third parties for providing this aggregate data? If so, why, and how should those charges be determined?

AEA believes that municipalities should have access to customer data since they are acting on behalf of the public. AEA recognizes that there may be private entities that have received permission to access data from multiple parties and request it in aggregate from, in which case a fee may be appropriate. AEA argues the aggregate data should be made automatic and provided in an ongoing basis for benchmarking and other energy management purposes once the building owner has provided approval.

Q3. Should the Commission consider a privacy standard to ensure customer anonymity when aggregate energy data is released to third parties without customer consent? If so, what rule should be adopted? Rules in other jurisdictions include a "15/15 rule" under which a minimum of 15 customers are included in aggregate data with no one customer's load exceeding 15 percent of the group's energy, and a "4/80" requiring data from a minimum of four customers to be added as long as no one customer's load exceeds 80 percent of the group's energy consumption.

AEA supports a privacy standard for aggregate energy data disclosed without customer consent. The standards should protect customer privacy while ensuring quality data to third party providers. AEA suggests the 4/80 is preferable because it is more useful for a wide range of buildings with tenants and a wider range of applications. No more stringent standards should be adopted.

Q4. What other issues regarding providing aggregate customer data to third parties should be addressed and how should they be resolved?

No comment.

Capital District Regional Planning Commission (CDRPC):
Submitted By: Todd Fabozzi, Director of Sustainability, Albany, NY

CDRPC supports the establishment of an independent non-profit, such as "The Energy Registry," as it was proposed during the December 16, 2015 Technical Conference panel. The Energy Registry is based on the Utility Energy Registry (UER) platform. In addition, CDRPC supports the idea of a bridge organization that can work with stakeholders and the utilities, in continuing in the delivery of local energy metrics for community planning.

In regard to aggregate energy data, CDRPC recommends that the Commission focus on creating voluntary and flexible codes of conduct for utilities on privacy, regardless of whether the data is sold or provided free-of-charge. Also, CDRPC believes that the Commission should encourage the utilities to engage in the open-market and participate in voluntary efforts like The Energy Registry for supporting community sustainability.

CDRPC commends the National Grid, NYSEG and Central Hudson for already participating in the UER platform through the Climate Smart Communities Program. The data that they have provided from 2010 to 2014, is the backbone of the Capital Region Sustainability Plan, and the Capital District 2010 Regional Greenhouse Gas Inventory. Also, it has been incorporated into many other energy and climate plans.

Citizens for Local Power (CLP): Submitted By: Susan H. Gillespie, President, Rosendale, NY

1. ***Enabling customers to share their energy use with vendors they choose.***

Q4. What other issues regarding providing aggregate customer data to third parties should be addressed and how should they be resolved?

CLP is concerned that ESCOs or other third-party providers will seek to benefit financially from customer data in ways that are aimed not at providing “ancillary services” to the customers, but at enriching the ESCOs and third-party providers at the customers’ expense, by either selling their information or engaging in marketing efforts that are unrelated to energy improvements benefiting the customer. CLP requests that any permission to use customer data be accompanied by a clear and unambiguous prohibition against the marketing and sale of customer data by ESCOs to third parties, or their use outside a specific range of purposes. To be effective, CLP believes the prohibition must be accompanied by legally enforceable sanctions that are significant enough to be a real disincentive. In addition, beyond monetary penalties, ESCOs should also be faced with the possibility that the privilege of accessing consumer data could be revoked altogether.

2. *Providing aggregate energy data to third parties including municipalities for purposes of Community Choice Aggregation and community planning.*

Q1. How can utilities prepare and provide electronic access to customer data aggregated by municipality in a standard format in an efficient manner?

CLP believes the information provided to the municipality should be as detailed in terms of location and time (including interval data) as the utility is able to provide without revealing customer-specific information. In addition, it must be sufficient to allow the municipality to make an initial assessment of local demand, resources, and opportunities, and identify key uncertainties and risks for the future CCA.

CLP provides an illustrative list of data as a sample of the kids of information that municipalities may require. The list includes: aggregated customer usage data, by political district, going back at least several years, load/system data sufficient to indicate where the introduction of DER is most economical, and load data and general system data sufficient to indicate where DER will be most beneficial in terms of reducing system strain and peak load. CLP states that to the extent that utilities do not have access to needed data, they should work with requesting municipalities to provide the closest approximation available to them at the time.

Q2. Should utilities be permitted to charge municipalities or other third parties for providing this aggregate data? If so, why, and how should those charges be determined?

CLP argues utilities should not be permitted to charge municipalities for providing aggregate data the municipalities need to plan for and introduce CCA. CLP believes that charging for the upfront planning data will decisively prevent most municipalities, particularly those in rural New York or with large low- and middle-income populations, from undertaking the necessary planning for a CCA 2.0, thus severely limiting the adoption of this more comprehensive, REV-compatible type of energy reform across the State. Whereas, CLP believes wealthier counties or towns may be confident about launching a CCA program without a plan, such an approach will not appeal to the poorer communities that make up the vast majority of our populace. CLP strongly supports Cameron Brooks of Mission: Data when he argued at the technical conference that individual customers should have the right to access their energy information "as part of basic service with any implementation investments included in base rates accordingly." CLP argues much of this data is already being provided by the utilities to ESCOs at no cost, and it would be wrong to introduce fees for municipalities to access services that are currently being provided free to commercial entities.

CLP supports points made by Kevin Lang, representing New York City at the technical conference that municipalities are different from ESCOs and should receive preferential treatment when it comes to data access. CLP also agrees with Mr. Lang that "for public purposes, the data should be provided for free" not only to municipalities but to other customers as well.

Q3. Should the Commission consider a privacy standard to ensure customer anonymity when aggregate energy data is released to third parties without customer consent? If so, what rule should be adopted? Rules in other jurisdictions include a "15/15 rule" under which a minimum of 15 customers are included in aggregate data with no one customer's load exceeding 15 percent of the group's energy, and a "4/80" requiring data from a minimum of four customers to be added as long as no one customer's load exceeds 80 percent of the group's energy consumption.

CLP refers to their earlier filing in case 14-M-0224.

Q4. What other issues regarding providing aggregate customer data to third parties should be addressed and how should they be resolved?

CLP is surprised by the limited amount of detailed information that is available to our utility about the state of the transmission and distribution grid at any given time and that a utility should have to rely on phone calls from customers to know that there is an outage, or send an employee out to measure the load level at a particular substation seems out of step with technological developments. CLP believes that the ability or inability of the utility to "read" and evaluate the state of the grid at any given moment has serious ramifications for its ability to respond to natural or man-made threats and also for its ability to support the decentralization of energy generation, including the creation of advanced CCAs. CLP looks forward to the reviews of the DSIPS filings on advanced metering infrastructure (AMI), and to further analysis of how AMI can best be applied at the system (e.g. at substation or feeder) level. As National Grid's Jeff Martin noted in his remarks, the ability to gather and provide data on system usage and grid dynamics is basic to the kind of locational pricing envisioned by Track 2 of the REV.

CLP suggests the PSC to consider creating a State-wide data exchange, as argued by Dan Leonhardt of Pace Energy and Climate Center and Jennifer Manierre of NYSERDA. CLP notes the Energy Demographic Tier example presented by Jim Yienger of Climate Action Associates indicates that it is possible for a third party, in cooperation with the utilities, to gather the needed information and make it accessible to the public in usable formats on a uniform State-wide basis.

City of New York: Submitted By: Kevin M. Lang, Attorney for the City of New York, With COUCH WHITE, LLP, Albany, NY

1. ***Enabling customers to share their energy use with vendors they choose.***

Q1. Are there protocols or alternatives to Green Button Connect that should be considered, and if so, what are the advantages and disadvantages of each alternative?

The City of New York (The City) offers no comment.

Q2. Should vendors seeking to be provided customer data through Green Button Connect, or an alternative protocol, be considered a Distributed Energy Resource Supplier, as defined in Staff's Proposal in Case 15-M-0180? If so, which, if any, of the rules proposed by DPS Staff in that proceeding should not be applicable to vendors seeking to obtain customer data through the Green Button Connect or alternative protocol? If vendors seeking to be provided data through Green Button Connect or alternative protocol should not be subject to the rules developed in Case 15-M-0180, what requirement or oversight should be applicable to those vendors?

The City stresses the need to stimulate industry innovation and create flexible and adaptive markets while simultaneously protecting consumers from potential marketplace abuses. The City has long supported stringent guidelines and Commission oversight when residential consumers, especially low income consumers, are adversely affected by the retail marketplace including, for example, predatory practices of ESCOs. The City believes the same basic principles are applicable here, and the City incorporates its comments to the DER Oversight Proposal by reference herein. The City does not advocate for any one specific rule advanced by DPS Staff in the DER Oversight Proposal, but reiterates its support for some form of Commission oversight.

The City argues the Commission should protect consumers, especially low income consumers, to prevent third-party vendors from exploiting data about their energy usage to their detriment. In addition, the Commission should recognize that residential and commercial consumers require different levels of protection, especially as they pertain to third-party vendor access to consumer energy usage data. The City suggests the Commission should account for the nature of the third party and how it intends to use the data. For example, the same rules should not and need not apply to municipalities seeking data for benchmarking and planning purposes and to DER providers seeking to sell energy-related products or services to consumers.

Q3. Pursuant to Uniform Business Practices, Section 4 (E), utilities may not change ESCOs for providing customer-specific information including energy consumption history used to market to or enroll customers. Should that requirement also be applicable to customer-specific information provided to ESCOs and other vendors via Green Button Connect or an alternative?

The City opposes the imposition of any charges to consumers for access to information about their individual energy usage from utilities. This information was developed as part of the utilities' regulated businesses, the costs of which were borne by consumers through the electric rates they pay. The City states whether the means of providing such information is via Green Button Connect or any other alternative, the costs of designing and implementing the interface presumably will be built into the utilities' rates and borne by its customers and adding charges on top of those costs is not appropriate.

Furthermore, the City argues that saddling customers with additional costs will discourage them from using the data to make meaningful energy efficiency investment decisions, and is contrary to both the public interest and the energy policy goals of REV and the City.

Q4. What other implementation issues regarding Green Button Connect or an alternative should be addressed and how should they be resolved?

The City believes that any discussion about the costs of implementing Green Button Connect should be based on solid market information and transparent as possible. The City is concerned utilities may provide inflated values for system implementation which obfuscates the discussion and blocks progress on effective data solutions. The City respectfully request that, where possible, any discussion of the costs of Green Button Connect implementation be well informed by groups with experience in its implementation.

2. ***Providing aggregate energy data to third parties including municipalities for purposes of Community Choice Aggregation and community planning.***

Q1. How can utilities prepare and provide electronic access to customer data aggregated by municipality in a standard format in an efficient manner?

The City believes it is important that consumer energy usage data is accessible in a standard format, and usage procedures and rules are consistent across the State. The City is concerned that differences among utility service territories could create barriers to competition, impose unnecessary costs on consumers, and inhibit achievement of REV and its underlying public policy goals.

The City points out one particular tool that would be useful in standardizing energy usage data is EPA Portfolio Manager which is presently used by building owners throughout New York City to comply with Local Law 84. The City states the EPA Portfolio Manager is an interactive resource management tool that enables users to track and assess energy and water use across a portfolio of buildings with dozens of metrics such as consumption, cost, and operational use details. In addition, the EPA Portfolio Manager also allows users to compare a building's performance against similar buildings, national medians, and other benchmarks. As a nationally-recognized standard for municipal benchmarking of energy usage data, the City notes EPA Portfolio Manager represents a viable means of standardizing energy data exchange across the state.

The City requests the Commission consider the EPA Portfolio Manager platform as a viable means for the purposes of aggregating customer data, and it should direct utilities to adopt the platform for those purposes. In addition to facilitating standardized energy data exchange, adopting EPA Portfolio Manager (or a similar platform) would make the State's standards consistent with nationally-recognized data exchange standards. Creating harmony between the State's standards and those applicable elsewhere would help to attract DER providers and other competitive entrants by allowing them to directly apply their already-developed information technology systems in New York.

The City respectfully submits that the New York utilities should be able to incorporate EPA Portfolio Manage into their systems as other utilities throughout the country. The City states many of those utilities provide automatic uploads to EPA Portfolio Manager free of charge. By comparison, Con Edison charges $102.50 per data request, and it provides that data in a manner that requires the customers to manually transcribe it into EPA Portfolio Manager. The City states this transcription requirement creates significant opportunity for errors, and it is an unnecessary requirement.

The City the point outs that low cost third party solutions are available and in the event any utility suggests that it could not implement data uploads to EPA Portfolio Manager or another similar system, the PSC should closely scrutinize the basis and reasonableness of such assertion.

The City also offers the following comment in the interplay of EPA Portfolio Manager and the Energy Department's Green Button initiative – the EPA Portfolio Manager has implemented a "Download my Data" function whereby customers with EPA Portfolio Manager accounts can download their electric meter data in the Green Button XML file format, which then can be used for third-party vendor purposes. However, EPA Portfolio Manager does not allow a customer to download Green Button data from a utility and then upload it to EPA Portfolio Manager.

Q2. Should utilities be permitted to charge municipalities or other third parties for providing this aggregate data? If so, why, and how should those charges be determined?

The City is opposed to any utility charge to municipalities and other third parties for access to aggregate energy usage data for public purposes. Such a charge would be against the public interest, and it would severely hamper the City's energy efficiency planning efforts. Instead, the City states that aggregate energy usage data should be provided to municipalities upon request, and at no cost. Likewise, data should be provided free-of-charge to customers and building owners for benchmarking purposes. The City offers no opinion at this time as to whether private parties seeking aggregate data for commercial purposes also should be permitted to obtain the data at no cost. The data may have commercial value that could be used for the benefit of consumers to offset some of the costs associated with REV. At the same time, this revenue potential must be weighed against the potential for advancement of consumer benefits that could arise from the provision of such information to DER providers and others for no charge.

The City uses aggregate energy usage data for benchmarking purposes pursuant to LL 84, which is similar in form and function to benchmarking ordinances in the cities mentioned above. The City is concerned that its efforts will be subverted if it, or a building owner, is required to pay every time it wishes to obtain this data because a utility fee for data would create a significant barrier to effectuating the City's and the Commission's energy efficiency policies and climate action planning and be entirely contrary to REV's goals. The City is also concerned because it already faces significant obstacles to LL 84 in the form of existing utility fees for benchmarking data from Con Edison because it charges building owners a fee for aggregated building data for both electric and gas consumption, at a rate of $102.50 for each property. The City claims this obstacle has led to poor quality data for LL 84 purposes. Because such programs are designed and intended to serve the public interest, the City requests the Commission should encourage participation, not discourage by allowing the imposition of unnecessary fees. The City respectfully urges the Commission to mandate that utilities provide aggregate energy usage data to building owners and municipalities for benchmarking purposes upon request and at no cost.

Q3. Should the Commission consider a privacy standard to ensure customer anonymity when aggregate energy data is released to third parties without customer consent? If so, what rule should be adopted? Rules in other jurisdictions include a "15/15 rule" under which a minimum of 15 customers are included in aggregate data with no one customer's load exceeding 15 percent of the group's energy, and a "4/80" requiring data from a minimum of four customers to be added as long as no one customer's load exceeds 80 percent of the group's energy consumption.

The City does not support imposing an aggregation threshold on data collection for whole building benchmarking ordinances like LL 84. The City states that privacy standards such as the 15/15 rule and the 4/80 rule are important in commercial settings to protect individual consumers. In addition, this issue does not arise where municipalities like the City use the aggregate energy usage data strictly for public purposes and benefits, such as benchmarking and generally promoting energy efficiency. The City argues that, imposing an aggregation threshold on data collection only degrades the quality of information needed for initiatives like LL 84 where granular per-building energy efficiency data is most needed. Because of the manner in which the data is then used, the City's concerns about disclosure of consumer-specific information are greatly diminished. Further, municipalities already have procedures and policies in place to protect consumer information, and those policies and procedures easily can be extended to protect any aggregate usage data that could be tied to individual consumers. The City expresses no opinion at this time on the validity or workability of an aggregation threshold on data collection in regard to CCA programs.

Q4. What other issues regarding providing aggregate customer data to third parties should be addressed and how should they be resolved?

The City states the Commission should ensure that any standardized energy data is compiled in a format that is easy for consumers to understand and the corresponding interface must be simple and intuitive, be able to collect and quickly process user requests, match meter, account, and energy data to buildings, and submit this data back to the consumer, municipality, or other requestor, as appropriate. The City is concerned that without a clear, simple interface, consumers will be dissuaded from using the system and unable to maximize the benefits that can be derived from their usage data, particularly information that will help them use energy more efficiently. The City disagrees with the utilities that the existing Electronic Data Interchange ("EDI") platform would be sufficient. The City states that EDI is a system by which ESCOs and utilities electronically exchange retail access data, but the information it provides is not in a consumer-friendly or easily understood format and it is not appropriate for the purposes being contemplated by REV. In addition, the Department of Energy speaker observed, what is needed is an innovative platform designed for consumers and future needs, not an aged platform that was intended for a very different purpose. The City is confident that Con Edison and other utilities will be able to accomplish the task in a cost-efficient manner and produce an intuitive and effective interface through which customers can access their energy usage data.

The Companies: Consolidated Edison Company of New York, Inc. Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, National Fuel Gas Distribution Corporation, New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation: Submitted By: Kerri Kirschbaum, Senior Attorney for ConEdison, New York, NY

The Companies believe that a variety of issues need to be carefully evaluated as these processes move forward, including, but not limited to, identifying the data set to be provided, the mechanism to share the data, data security and customer privacy guidelines, and what data points represent a basic service versus a value-added service. Equally important is the need to develop data sharing processes that are customer-driven. Customers who wish to provide their data to third parties should be required to make an affirmative choice to provide their data and should be educated on what that affirmative choice means for the disclosure of their data so that any release of customer data is done with the customers' full knowledge and consent. These issues are complex and likely will evolve over time for many reasons, including market evolution.

The Companies will need to evaluate current systems and processes for data sharing and potentially invest in new systems and processes in order to meet new requirements.

Responses to Questions in the Notice:

Q: Are there protocols or alternatives to Green Button Connect that should be considered, and if so, what are the advantages and disadvantages of each alternative?

As the Joint Utility Initial DSIP Comments articulated, access to customer-specific data, which was the topic of the first panel at the Technical Conference, "whether by customers or third parties, is determined by multiple factors, including but not limited to the meter infrastructure, customer service systems, and website capabilities unique to each utility. The prospect of changes to the current state of data access necessitates careful consideration of the needs of each utility's service territory and the potential value for customers." This fact was clearly evident at the Technical Conference where there was extensive discussion related to utility implementation of the United States Department of Energy's Green Button Connect ("GBC") protocol for providing customers and third parties access to customer-specific data. For a variety of reasons, utilities are in different positions when it comes to evaluating GBC. Con Edison and O&R are currently in a position that they can give serious consideration of GBC. One significant reason for this serious consideration is that Con Edison and O&R are currently moving forward with Automated Metering Infrastructure ("AMI") deployment in their respective service territories, and so GBC functionality would provide both customers and third parties far more granular usage information than currently exists for mass market customers. Additionally, GBC is a secure nationwide protocol, based on modern technical protocols (*i.e.* REST APIs, Oauth 2.0, XML). The GBC protocol is also consistent with Con Edison and O&R's new digital service platforms and provides a clear customer-driven authorization process.

Other utilities do not foresee implementing AMI as quickly, if ever. For these companies, the benefits of GBC may not be as tangible because interval data will not be available for mass-market customers. In those instances, there may be other methods for transferring customer data that may be appropriate and will continue to be evaluated. If and when other utilities evaluate the installation of AMI, GBC or other data transfer protocols may be assessed.

The Companies note that there are outstanding issues to resolve before ultimately making a decision to move forward with GBC implementation. These issues are discussed below in response to the last question related to GBC. However, the Companies note that they continue to benchmark with other utilities that have implemented GBC. Based on the Companies' evaluation to date, and the administrative complexity and cost of GBC implementation, and because some utilities may not consider GBC viable at this time or in the foreseeable future, the Companies believe that any utility that decides to implement GBC should do so in a phased approach. This phased approach would begin with GBC implementation first with respect to customer usage data. Other aspects of customer profile information create added complexity and cost and it is unclear at this time what other data customers, third parties, or the Commission have determined to be necessary, relevant, useful, actionable, and cost-effective. Therefore, to the extent utilities move forward with GBC implementation, they should first provide protocols related to customer usage information and evaluate other features later.

Q. Should vendors seeking to be provided customer data through Green Button Connect, or an alternative protocol, be considered a Distributed Energy Resource Supplier, as defined in Staff's Proposal in Case 15-M-0180? If so, which, if any, of the rules proposed by DPS Staff in that proceeding should not be applicable to vendors seeking to obtain customer data through Green Button Connect or alternative protocol? If vendors seeking to be provided data through Green Button Connect or an alternative protocol should not be subject to the rules developed in Case 15-M-0180, what requirements or oversight should be applicable to those vendors?

Vendors seeking to be provided customer data through GBC should be considered a Distributed Energy Resource Supplier ("DERS"). The Commission clearly contemplated that such vendors be subject to oversight in its February 26, 2015 *Order Adopting Regulatory Policy Framework and Implementation Plan* in the REV Proceeding. There, the Commission stated: "In the case of DER providers, there will be two distinct criteria, once DSP market tools have been developed, used to establish when a service is the "furnishing" of electricity subject to jurisdiction. First is the acquisition of customer data by any means established under the Commission's authority." Therefore, vendors obtaining customer information through GBC should be subject to the oversight proposed by Department of Public Service Staff ("Staff") in Case 15-M-0180. The Companies note that the Joint Utilities filed comments on the Staff Proposal and incorporate those comments by reference here.

The Companies note two important features of those comments. First, the Companies reiterate their comment that monitoring and compliance of DERS should be conducted by Staff in a manner similar to what is currently done for ESCOs, and believe this issue is best resolved within the context of that proceeding and with the information currently on the record therein. Second, any party receiving customer information, individual or in aggregate, and whether purchased or provided at customer request, should commit and be held responsible for not sharing that information with other parties. That commitment may take the form of regulation/standards of business conduct or non-disclosure agreements, or UBPs.

Q. Pursuant to the Uniform Business Practices, Section 4(E), utilities may not charge ESCOs for providing customer-specific information including energy consumption history used to market to, or enroll, customers. Should that requirement also be applicable to customer-specific information provided to ESCOs and other vendors via Green Button Connect or an alternative?

The entirety of Section 4(E) of the Uniform Business Practices reads as follows:

No distribution utility or MDSP shall impose charges upon ESCOs or Direct Customers for provision of the information described in this Section. The distribution utility may impose an incremental cost based fee, authorized in tariffs for an ESCO's request for customer data for a period in excess of 24 months or for detailed interval data per account for any length of time.

This section clearly contemplates that ESCOs can be charged for customer data for a period in excess of the past 24 months or for providing detailed interval data. Indeed, both Con Edison and O&R have provisions in their Commission-approved Tariffs related to such charges and, in fact, ESCOs have paid such charges. Therefore, the assumption inherent in the question posed in the Notice is not entirely complete because it does not recognize that the Commission does, in fact, permit utilities to charge for certain customer information.

Moreover, Section 4(e) is consistent with the Companies' position related to the provision of customer data to customers or their designees. That is, a basic level of data should be provided to customers or their designee without charge. In reference to utilities charging for aggregated data, utilities, should they desire, should be allowed to set value-based charges for requests for customer information that are above and beyond the basic data set. This is very similar to what the Uniform Business Rules contemplate, with the exception that the Uniform Business Rules state that the charge should be cost-based. The Companies believe that such charges should not necessarily be cost-based, consistent with many REV concepts. For instance, the July 28, 2015 *Staff Whitepaper on Ratemaking and Utility Business Models* explains that "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."

At the Technical Conference, several stakeholders advocated that utilities should provide as much customer information as possible, in as near real-time, and with as much granularity as possible, for no charge to all customers and vendors. As stated above, the Companies believe that a base level of data should be provided at no charge but that additional data could be provided for a value-based fee. This is more equitable as it more closely attributes the value of providing premium data services to the customers or vendors that receive them, resulting in fewer costs that must be socialized among all customers. It should be noted that both the basic level of data provided at no charge and what additional more granular data provided for a fee may, in fact, evolve over time as technology, customer expectations, and necessity dictate.

Q. What other implementation issues regarding Green Button Connect or an alternative, should be addressed and how should they be resolved?

The Companies identified several outstanding issues that must be evaluated related to GBC implementation during its presentation at the Technical Conference. For instance, each of the utilities are evaluating the cost of GBC implementation in their service territories, which includes consideration of expected adoption rates, as well as how to phase implementation and potential fee structures for premium data services. The Companies must consider a variety of implementation details that will influence the cost of adopting GBC in their respective service territories. Because GBC is a data sharing protocol and not a specific software product, there are multiple approaches to implementing GBC. Regardless of the acquisition method, the cost of GBC is not clear-cut and the multiple ways in which the software can be obtained and implemented add a layer of complexity to the evaluation process.

Additionally, there are many other details of GBC implementation that the Companies must consider, including: the type of data to be included in the initial phase of implementation and the complexities associated with providing multiple customer profile data points; the timeliness of the data (one-day lag or real time); the granularity (hourly, fifteen-minute, five-minute interval); the quality of the data (billing data or meter data); and the amount of request options for customers to choose (ongoing, one-time historical, temporary authorization). At the Technical Conference, certain ESCOs explained that they have had issues with other utilities that have implemented GBC and the quality of data provided. The Companies believe that the GBC protocols can lay the foundation for authorization and data transfer and that the protocols can be developed in such a way as to satisfy these concerns and provide billing level usage data. The Companies must also consider the different types of third parties that may be utilizing GBC, including ESCOs, DER providers, consultants, and customers, and, importantly, whether and how to continue the use of existing methods of data provision given the costs and complexity of maintaining multiple systems.

Q. How can utilities prepare and provide electronic access to customer data aggregated by municipality in a standard format, in an efficient manner.

There are a variety of reasons that a municipality or its designee may request aggregated energy consumption information from utilities. For instance, a municipality may request such information as part of a Community Choice Aggregation program or as part of its own energy planning purposes. Additionally, as the Notice acknowledges, in certain circumstances, buildings owners request such information from utilities. The most efficient way to continue to provide this data is to afford flexibility to utilities working with municipalities and building owners. Strict rules or formats for providing this data could harm innovation in designing products and services and the means by which to provide them. Flexibility is necessary because municipalities, building classifications, geographic areas, political boundaries, and utility service classifications are not standardized. The Companies, working with municipalities or building owners, must evaluate specific requests and only provide information at levels that would not reveal customer-specific information. There can be no "one size fits all" approach to providing aggregated information.

Q. Should utilities be permitted to charge municipalities or other third parties for providing this aggregate data? If so, why, and how should those charges be determined?

Utilities should be permitted to charge for providing aggregated data. As part of REV, utilities are encouraged and tasked to develop fee-based services where they can add value to third party business models. The aggregated information being sought from the Companies provides significant value to the third parties (*i.e.*, aggregators, DERS, municipalities, and ESCOs) that are requesting the data and responding requires substantial administration. Further, the information requested is often unique to the requestor and must be developed by the utility with significant effort and at significant cost. Charging for this type of service is consistent with the general principle of a competitive marketplace, whereby the entities benefiting from the Companies' value-added services should pay for such services. Such fees for providing aggregated data have, in fact, already been accepted by the Commission in the case of the Sustainable Westchester Community Choice Aggregation Pilot Program. Appropriate fees and fees structures will be evaluated by the Companies and interested stakeholders as the REV process moves forward and, in particular, in the Supplemental DSIP.

Q. Should the Commission consider a privacy standard to ensure customer anonymity when aggregate energy data is released to third parties without customer consent? If so, what rule should be adopted? Rules adopted in other jurisdictions include a "15/15 rule" under which a minimum of 15 customers are included in aggregate data with no one customer's load exceeding 15 percent of the group's energy consumption, and "4/80 rule" requiring data from a customer's load exceeds 80 percent of the group's energy consumption.

The Companies are committed to the privacy of customer-specific information. As such, the Companies work with municipalities, building owners, and other third parties to safeguard against providing aggregated data that is not sufficiently anonymous such that a particular customer or customer's information can be ascertained. Municipalities, building owners and other third parties also should be required to maintain the privacy of this information. As noted above, however, flexibility is key to providing aggregated data. For the reasons briefly stated above, and discussed at length during the Technical Conference, the Companies do not recommend a standard related to anonymity.

Consumer Power Advocates (CPA): *Submitted By: Catherine Luthin, Exec. Director, Allenhurst, NJ*

CPA supports the Commission's efforts to define secure data protocols that respect customer privacy. In our view, customer data is customer property. As such, it should always be available to customers and their identified agents and to their vendors or contractors with permission only. Moreover, customer identifying information must never be disclosed without the customer's specific consent.

CPA also believes that data must be available to customers in a conveniently usable form. That means it should be downloadable from utility supported platforms at all times at the customer's option, in formats that are usable in widely available software. Utilities should not charge for this service, nor should they be allowed to sell customer specific data. Any use of data by utilities as a revenue generating resource will ultimately create an incentive to restrict the availability of that data from all other parties, including customers. Any restriction on the customer's access to his or her own data will only discourage the development of innovation and market based solutions to energy use problems.

Finally, it is important that customer data be available to agents and consultants identified by the customer on the same basis as available to the customer. The New York's energy systems are becoming increasing complex, and many customers, including some of the most sophisticated consumers, may not have the specific skills and knowledge necessary to optimize the value of these new opportunities. In these circumstances, it is essential that customers have available to them the advice of third party experts, including consultants who do not have a direct interest in energy sales transactions. It is critical for customers to have the best advice from disinterested experts if they are to understand the full potential value of these new opportunities. Absent the knowledge provided by expert advisors, many consumers will not achieve the promised benefits of REV. In the worst case, the least knowledgeable customers will be the victim of misleading or even fraudulent business practices.

Direct Energy Services, LLC: *Direct Energy Business, LLC, Direct Energy Business Marketing, LLC, and Direct Energy Solar (collectively "Direct Energy"): Submitted By: Angela Schorr, Manager, Government and Regulatory Affairs*

Direct Energy supports the comments filed by The National Energy Marketers Association ("NEM")(see NEM comments below) pursuant to the Aggregated Energy Data Technical Conference.

Direct Energy believes that consumers and ESCOs should have access to energy usage information. For ESCOs, the data should be provided on a timely basis, and it should be suitable for billing. If the data is delayed and it is not billing quality, an ESCO will not be able to bill that customer properly, thus potentially putting the ESCO in breach of contract.

Direct Energy states that no utility in a restructured market has elected to use the Green Button as the exclusive method of providing energy data to ESCOs. Prior to the approval of the Green Button, Direct Energy states that the Commission should ensure that the data provided to ESCOs should be appropriate quality, suitable for billing and it should be provided on a timely manner. Such data can be used to develop and offer innovative products and services to New York customers.

While the Green Button may be excellent as a customer-facing platform--intended to increase consumer engagement in energy usage management--, however, it has not been used as a platform for the types of data that ESCOs require to offer time of use or other innovative products. Additionally, the method in which the consumer has to designate third party access has been a very manual process in which the customer has to designate each account individually. This creates a burdensome and clumsy process for customers because it creates at least a three-step process to receiving time of use or other interval data-enabled products and services: 1) the customer signs a contract with an ESCO for such product or service; 2) the ESCO receives the customer's authorization to access the customer's interval data; 3) the customer must create an account or sign on to Green Button and designate the ESCO as an authorized third party. If the customer signs a contract that requires interval data access but later forgets to create an account with Green Button or misidentifies the appropriate third party to receive access to the customer's interval data the entire process breaks down. The Commission should make sure that the process is easier for customers, in choosing products and services that suit customer needs.

Direct Energy also agrees with NEM's suggestion of implementing a dual process that utilizes EDI for sharing monthly billing quality data and provides non-billing quality data on a next day basis via FTP. As a baseline, ESCOs should be provided with hourly, interval, billing quality data on a monthly basis via EDI. Hourly interval data should be provided through a web portal or email the next day. A progressive, phased approach to providing ESCOs with access to customer energy usage data should begin with access to hourly interval data, moving to shorter intervals (15 minutes), and ultimately, providing real time data access or as close to real time data access as is practicable.

EnergyNext, Inc.: Represents--The Municipal Electric and Gas Alliance (MEGA)

EnergyNext, Inc. represents the Municipal Electric and Gas Alliance (MEGA). MEGA is a not-for-profit Local Development Corporation that manages aggregated procurement of energy products and value-added services for 36 county governments among more than 275 municipal entities in the state. MEGA also serves some residential and commercial customers. MEGA was created by local governments to serve local governments, and it makes decisions solely for the benefit of its participants.

It is the opinion of MEGA that free access to aggregate energy data is in the public interest and is already feasible using an existing database, the Utility Energy Registry. Access to this database will enable municipalities to engage in the REV process and accomplish energy planning goals, as well as provide the basis for planning and implementation of Community Choice Aggregation (CCA) programs.

Responses to questions in the Notice:

Q. How can utilities prepare and provide electronic access to customer data aggregated by municipality in a standard format, in an efficient manner?

It is fortuitous that through the efforts of Climate Action Associates in the role of NYSERDA contractor for the Climate Smart Communities Program, a database, the Utility Energy Registry (UER), has already been developed. All major utilities voluntarily provided the aggregate energy data for 1,300 cities, towns and villages across the state. These data are in a standardized format by consumption rate class and accessible in aggregate by community, zip code or county. Upon additional review of the UER, and based on experience from other CCA markets, including Illinois, MEGA believes that the UER aggregated energy database is sufficient to inform qualified ESCOs of the available load in a CCA Program as part of a Request for Bids.

Q. Should utilities be permitted to charge municipalities or other third parties for providing this aggregate data?

MEGA's view is that utilities should not charge municipalities, or third parties acting on their behalf for aggregate energy data. Free access to centralized and standardized data will be efficient for both utilities and municipalities. In the specific case of the development of the UER, Climate Action Associates was supported by Regional Greenhouse Gas Initiative (RGGI) monies. As the funding was in public interest, we believe that municipalities should not have to pay a second time to access their aggregated energy data. MEGA is grateful that through the initial development of the UER, utilities were willing to provide these aggregate energy data voluntarily and without charge and we encourage them to continue to do so. Providing these aggregate data in monthly intervals, on an annual basis is likely to be more efficient for both utilities and municipalities than generating and responding to data requests from municipalities, consultants and/or ESCOs. MEGA looks forward to the ongoing development of the UER in 2016.

At the technical conference it was reaffirmed for MEGA that many stakeholders, including NYSERDA, Mission Data, Department of Energy and Climate Action Associates agree with our position that aggregated energy data are in the public interest and should be made available at no charge.

Q. Should the Commission consider a privacy standard to ensure customer anonymity when aggregate energy data is released to third parties without customer consent?

Many of the questions and concerns surrounding customer protections and privacy can be easily addressed through the use of the UER for sharing aggregate energy data. If one of the rate classes within a given city, town or village does not meet the '15/15,' '4/80' or other privacy rule, the data will simply not be made available through the database. In this case, the need for customer consent would not be required as the aggregate data provide the desired anonymity.

Another value of the data existing in the UER, is that it is possible for an analysis to be undertaken to determine how many discrete groups of data would not pass a given set of privacy rules, such as the '15/15'or '4/80' rules. Undertaking such an analysis may properly frame the scale of the issue related to anonymity with aggregate energy data.

ETS (Energy Technology Savings): Submitted By: Valerie Ross, Sr. Energy Compliance Manager, Summit, NJ

ETS believes that individual customers and third-party DER providers must have access to energy usage information in order for them to determine which products and services would be most beneficial for energy management purposes. This access must be the starting point for the further development and implementation of energy management products and services, DER and increased customer engagement. Without such access to data, many customers will not be able to take advantage of the many energy management offerings that may be available to them.

ETS agrees with the suggestion made at the Technical Conference held on December 16th, that there may be a need for a combined solution including both an EDI like component for data communication with third parties requiring detailed, real-time access to billing quality data, and a Green Button type of solution for simpler customer access to their own energy usage information. ETS also believes that it is important to be sure all possible alternatives are explored before making a decision as to what types of solutions, and which vendors would be best suited to handle the requirements for data access in the future. There may be different requirements for the various customer classes, and diverse types of DER providers that will be utilizing the data. Any proposed solution must provide efficient and effective access to the necessary data without creating barriers to entry into the DER market, while also providing a competitively neutral solution. While Green Button is potentially a useful solution for certain purposes, at present, it does not seem to present a viable option for all purposes since it does not present billing quality data, which would be needed for many DER products.

Enabling customers to share their energy use data with vendors they choose.

While the Staff document, which provides an overview and proposed questions indicates that a Green Button Connect type of solution would provide customer identifying information, billing history and load profile in order for vendors to prepare an offer reflecting customer specific information, ETS believes that further information would be required. DER providers will need real-time access to billing quality data in order to have the necessary information to prepare offers tailored to their potential customers. The process to access this data must be simple, and similar to that which exists today for ESCO's requesting access to their customers' historical usage information. Third parties wishing to access the data should be required to obtain customer consent, which must contain a full and accurate description of the types of information to be released and how it will be used. Additional action must not be required by the customer, or the process may become too cumbersome for some, and the evaluation of appropriate DER products and services for the customer may not continue.

The Staff document also poses a question as to whether vendors requesting customer data through Green Button Connect, or an alternative protocol, should be considered Distributed Energy Resource Suppliers, as defined in Staff's Proposal in Case 15-M-0180?1. ETS believes that vendors should not be considered Distributed Energy Resource Suppliers simply because they request access to customer data. The data may prove that there is no viable energy management solution for the particular customer, and the process may end after the data is considered. It would not be efficient to apply many potential DER regulations to third party providers that may or may not ultimately fall under the definition of a Distributed Energy Resource Supplier. If a DER solution is found to be pertinent after the data is examined and compared to the offerings of the third party, then the DER regulations would become applicable to the dealings between the parties, provided the transaction itself is within the scope of the regulations.

Staff also poses the question as to whether or not the utilities should be allowed to charge vendors for data accessed via the mechanism developed under this proposed solution. ETS suggests that the utilities not be allowed to charge vendors for access to this data as this should be part of the services available to all utility customers. At any point, any utility customer may decide to explore energy management products and services to reduce their energy bill. This data access process will be available to them at such time, and therefore, they should share in the expenses incurred in order to make this process available to them. Since this option will be available to all customers, expenses for these services should be shared by the customer base and should be included on the distribution side of the utility bill.

IGS Energy, IGS Generation, IGS Solar (IGS Energy or IGS):
Submitted By: Katie Bolcar Rever, Director, Legislative and Regulatory Affairs, Interstate Gas Supply, Inc. dba IGS Energy, Dublin, Ohio

IGS believes that the Commission should promulgate rules that allow for access to consumer energy usage data, and not create undue burden for third party providers that utilize energy usage data to provide products and services to customers. If access to energy consumption data is unduly restricted, fewer products and services to enable more efficient energy use will be available to customers, there will be less competition, and ultimately the goal of REV will be undermined. If a provider of energy products and services cannot get access to customer energy consumption data, or must jump through a number of burdensome hoops to get that data, a company cannot tailor products and services to meet the customer’s specific usage patterns. For these reasons, the Commission should not place undue restrictions on the customer energy usage data that is available to registered third parties.

Certified third party providers should have access to consumer data in order to facilitate customer engagement.

Enabling consumers to have easy access to their data is an important step in customer engagement. Also, third party providers should have access to this data because they can develop and offer products and services that empower New Yorkers to make more informed energy choices. Without third party access to consumer data, the majority of consumers will not be able to engage on their energy use – and will not be very interested in engaging. If access by third party providers to consumer data is either overly burdensome or restricted to a few select providers, innovation will be restricted if private companies perceive that true competition is not possible and therefore do not participate in the market.

IGS believes having consumer data available to all eligible third party electricity providers is critical to creating a marketplace that both ensures consumer protection and data privacy while also enabling competitive markets that develop innovative products and offer them at a scale that will increase the efficiency of the overall electricity system.

IGS Recommendation:

Similar to Ohio and Pennsylvania, the Commission should make consumer lists, including twelve to twenty-four months of usage data and load factor, available to all eligible energy companies ("ESCOs"). Customer lists that include high-level customer consumption data enable ESCOs to offer products and services to customers to help them better manage their energy consumption. For instance, with customer lists that contain annual load factor and consumption data an ESCO can easily identify customers that are well suited for demand response or energy efficiency in order to make appropriate offerings to customers. Further, by seeing in advance high-level customer energy consumption data, an ESCO may be able to identify whether a customer is a good candidate for distributed generation.

Contacting every single customer to get affirmative consent to receive high level customer consumption data is overly burdensome, and ultimately will lead to less energy efficiency, demand response and distributed generation in New York. States such as Ohio and Pennsylvania already provide certified competitive suppliers with lists of high level annual customer energy consumption data, and this practice has not caused any harm or undue burden on customers.

The Commission can certainly put appropriate practices and protections in place to ensure customer data is protected. For instance, the Commission can only make this data available to registered ESCO's over which the Commission has jurisdiction, and require those ESCOs to not disclose that data to any third party. Further, the Commission can include on the list only high level annual and monthly consumption data and load factors, and require customer affirmative consent for disclosure of more granular data such as hourly and daily consumption. The Commission could also give customers the option to opt-out of the customer lists if the customers do not want their energy consumption made available to ESCOs.

Finally, if the Commission is not comfortable with making this available for both mass market and commercial and industrial customers, then it should begin with commercial and industrial customers.

IGS Recommendation:

If the Commission chooses not to make lists with consumer electric consumption data available to registered ESCOs, then the Commission should minimize transaction costs associated with obtaining consumer consent and ultimate third party access to the data. For example, the Commission should not require the customers to fill out a separate form, aside from the customer contract, to authorize disclosure of energy usage data to a third party provider. A third party provider should be able to get access to customer usage data by including a provision in the contract authorizing the electric utility to disclose the data to ESCOs.

Any payment for consumer data that is derived from a monopoly asset should be based on cost-of-service.

One of the issues discussed at the December 16th technical conference was whether third party providers and consumers should pay for accessing data, and if so, how should this price be set. IGS is not opposed to paying an appropriate amount to access consumer data. However, this price should be regulated by the Commission and set on a cost-of-service basis, and not as a 'market based earning' opportunity for utilities. It is critical to the success of REV that the Commission not allow utilities to earn competitive returns on cost-of-service assets. Consumer data is clearly an asset that the utility has due to its monopoly status and any fees associated with having access to this data should be set on a cost-of-service basis.

IGS Recommendation:

The Commission should define what consumer data is provided free of charge. For any other data, the Commission should clearly state that this shall be provided on a cost-of-service basis and offset revenue requirements.

Metropolitan Transportation Authority (MTA): Sam M. Laniado and Tyler W. Wolcott, Attorneys with Read and Laniado, Albany, NY

The MTA supports the Green Button Connect platform, or its equivalent, which appears to address the MTA's need for simple, unencumbered access to its own energy consumption data. The MTA also strongly believes that the "basic" level of energy consumption data available to large commercial consumers without a charge or fee should consist of near real-time data (up to a 15-minute lag), using advanced meters that report usage every 5 minutes.

The MTA is a very large consumer of electricity, being billed by NYPA for approximately 6.9 million kilowatts and 2.9 billion kilowatt hours in 2014. The MTA is very interested in exploring the potential for energy and demand savings throughout its system that serves the MTA Service Area. The MTA has engaged an energy management firm to implement its Energy Management System ("EMS") that is designed to monitor and manage the MTA's energy consumption across all MTA agencies, with the goal of informing operations, demand response, energy conservation efforts and bill auditing. That effort is hampered, however, by the lack of real-time energy consumption data. The implementation of Green Button Connect could be a giant step forward to providing near real-time data. And, considering the breadth of the MTA Service Area, facilitating easy access to its own consumption data would help MTA realize the full potential for demand management, environmental, and cost benefits for millions of New Yorkers.

The Commission Should Move Forward with Implementation of Green Button Connect or Its' Equivalent.

The MTA requires easy access to its own real-time energy consumption data to accomplish the goals of its EMS and provide multiple benefits for residents within the MTA Service Area. By adopting the Green Button Connect platform, or its equivalent, as the minimum standard for demand and consumption data access, at least in the Con Edison service territory, the Commission would help the MTA effectively implement their energy efficiency and demand management programs.

The MTA is participating in the review of Con Edison's Advanced Metering Infrastructure ("AMI") Proposal. The AMI Proposal was unclear on what percentage of customers, if any, would have access to their own, near real-time consumption data. Significant consumers of electricity such as itself require real-time or near real-time (up to a 15-minute lag) consumption data every 5 minutes—an interval currently contemplated by Con Edison's AMI Proposal for commercial customers—to effectively manage their loads.

Making interval data available to the customers in near real time, as defined in the preceding sentence, should be *considered basic access for large energy users, and provided at no additional cost to the energy user.*

In addition, Con Edison's AMI Proposal relies on a company-run web portal to provide consumers access to their own consumption data. The MTA requested a revision to the AMI Proposal that would allow its data to be pushed to or accessed directly by its EMS.

According to some presenters at the Data Technical Conference, Green Button Connect could provide access to near real-time data on a 15-minute interval to the user or its authorized representative. Therefore, implementing Green Button Connect, or its equivalent, should eliminate any uncertainty about the level of access provided by the AMI Proposal.

In addition, adopting Green Button Connect would eliminate the need for large consumers, such as the MTA, to negotiate individualized data access arrangements. With Green Button Connect, the MTA's EMS should have access to real-time consumption data without further action. Also, there should be no charge for authorized third-party access to this level of data.

Moreover, Green Button Connect should eliminate the need for utility-run web portals to facilitate consumption data access. According to one presenter at the Data Technical Conference, customers must have the unilateral power to access their own data and authorize the data's flow. Green Button Connect would provide this unilateral power, and eliminate the need for utility web portals. As another presenter opined, utility web portals are inconvenient and essentially useless in this modern age. These portals provide Electronic Data Interchange ("EDI") data, which, according to Green Button Connect proponents, is insufficient. EDI data is, according to these proponents, ill-suited for consumers because formatting, extraneous information, and poor timeliness make the data unusable.

The Commission Should Adopt a Policy That Mandates Access to Near Real-Time Energy Consumption Data Free of Charge.

The MTA proposes that the Commission await acting until the specifics of the “basic” level of access for Green Button Connect, or any new platform, are clarified. Parties cannot meaningfully represent their interests without this information.

The MTA strongly believes that the free, “basic” level access must consist of 5-minute interval, near real-time consumption data for large energy users. The MTA and other large energy users require near real-time data, not subject to a 24-hour reporting delay, to manage their demand and efficiency programs. It makes no sense to ask ratepayers to invest significant funds in a new system, whose benefits would be realized by its full utilization, and then deter that utilization by imposing charges for its use.

Con Edison points out that the realization of benefits of the AMI strongly depends on the level of customer engagement. For example: Con Edison AMI smart meter initiative will help meet the REV objectives of providing products, technology, and incentives for customers to actively participate in energy markets, control energy use, and take control of their monthly bill. AMI directly enables future engagement with the Company’s customers, a primary goal of the REV initiative. With the appropriate data systems and web presentment in place, customers will have the opportunity to leverage the interval meter data made available by AMI to evaluate their energy consumption and make informed energy decisions.

Con Edison added that it “plans to develop various customer products and services that only become possible with the two way connectivity and granular usage information provided by smart meters.”

In essence, the MTA strongly believes that charging customers for access to real-time interval data violates the spirit of the REV energy initiatives and related demand-side programs administered by the New York Independent System Operator (“NYISO”). In the Data Technical Conference, Con Edison argued that charging for more granular and extensive data requirements was analogous to a cell phone companies charging for larger data packages. This analogy is misplaced and inapplicable to the facts at hand. The data the cell phone company is selling is the product the customer is purchasing.

The cell phone company provides the same level of tools for network support and immediate access to usage information regardless of the data plan the customer purchases. In the cell phone service case, the data is the actual product consumed by the customer, whereas in the AMI case, the data is a *tool* customers need to manage the actual product delivered by Con Edison.

In addition, utilities often provide incentives to customers to encourage behavior that reduces energy demand and usage. There is no benefit to New York or its citizens from giving an individual cell phone customer more data volume. On the other hand, the AMI data provided to Con Edison customers on a real-time basis facilitates the ability of these customers to more effectively and efficiently monitor and control their demand for and consumption of electricity, and, thus, provides cost and environmental benefits to the electric system and to the general population. For example, the NYISO is currently preparing a new Behind-the-Meter Net Generation tariff that will allow net generators to sell capacity into the NYISO market. To be effective, customers participating in this program will require 5-minute or less interval meter data. It does not make any sense to discourage participation in this program by charging customers for access to this data.

Mission Data: Submitted By: Cameron Brooks, President, Tolerable Planet Enterprises, Boulder, CO; and Jim Hawley, Principal, Dewey Square Group, Sacramento, CA

Mission:data believes that empowering consumers with convenient access to their energy data with the ability to quickly and conveniently share that data with third parties of their choice will bring substantial benefits to consumers in New York and will advance the objectives of the REV initiative.

Energy usage in homes and buildings makes up 41 percent of total primary energy use in the U.S., and 69 percent of total electricity use. Optimizing efficient operation of buildings, and efficiency investments can be a complex undertaking for individual customers. In the residential and small commercial sectors served by some of our members, where individual loads are smaller, the challenge has been particularly difficult. Today, software and information technologies can automatically be applied to energy-use decisions and customers can be readily informed of actions they can take to save energy. This new capacity can reduce transaction costs while still providing customized, actionable information, increasing consumer confidence in efficiency or renewables. Energy management software products and services represent one of a number of exciting consumer resources for saving energy that have emerged as information technologies have evolved.

Because the most compelling new energy management technologies depend increasingly upon consumers having access to their energy usage and pricing data, Mission:data agrees with the Commission that a leading priority in this proceeding must be "[e]nhanced customer knowledge and tools that will support effective management of their total energy bill." Placing the power of data in the hands of consumers and their chosen service providers enables substantial efficiency gains and reductions in carbon pollution while fueling compelling clean energy and high-tech jobs.

Mission:data and our member companies therefore strongly support a central objective of this proceeding: providing consumers with convenient access to their own energy data and mechanisms to share that information with service providers of their choosing.

Benefits of Consumer Data Access

The members of Mission:data share a simple vision: that consumers should have access to the best available information about their own energy use, what it costs them and the ability to share that information with the companies they trust and value.

Providing consumers with robust data access mechanisms and affirmative policies will lay the foundation for achieving three critical objectives: (1) empowering consumers; (2) scaling clean and efficient energy technologies; and (3) promoting economic development.

1. Consumer Empowerment: As noted in the REV OIR, consumers have unique interests, including energy savings, comfort and environmental considerations. New technologies increasingly offer consumers the means to recognize and respond more than ever to price signals and to cost-effectively generate and save energy in ways that were unavailable until recently. As such, policies should provide consumers with access to their own usage information to use as fits their particular needs and interests. Such a policy framework is consistent with federal policy, best practices from other states and long-standing NARUC resolutions that seek to provide consumers with "the benefits of the deployment of the smart grid promises."

2. Energy Efficiency: The research literature shows that providing consumers access to their energy usage information can drive significant savings in energy usage and demand response. Improving data access policies will increase the ability of New York to achieve significant improvements in energy efficiency, both through regulated programs and offerings from the private sector that are outside of traditional programs.

3. Economic Development: Mission:data includes within its membership companies that are actively developing products and services to help consumers save money and energy and participate more fully in energy markets. Several of our companies are based in New York State. Ensuring that data access policies are given full consideration will help drive a robust market for energy management services within New York and position this state for economic leadership in this sector.

The REV Initiative seeks to establish new market-driven solutions and overall "market animation." Data solutions are fundamental to any functioning marketplace. Without the working knowledge of their own energy profile provided by a robust data-access framework, there is no way for consumers to meaningfully engage in a market and take advantage of the offerings.

Furthermore, functioning markets allow consumers not only to reveal, but, indeed, to discover their own preferences. As a notable scholar of innovation recently observed about the UK's electricity market (a market that has served as an inspiration for this proceeding), "One crucial aspect of consumer benefit that is underappreciated is the effect of innovation on the benefits that consumers enjoy." This is because, "In dynamic markets with diffuse private knowledge, neither entrepreneurs nor policy makers can know *a priori* which goods and services will succeed with consumers and at what prices. Similarly, consumers' preferences are not fixed and known, either to others or even to themselves. Consumers learn their preferences through the process of evaluating available choices in a marketplace, and analyzing the relative value of those tradeoffs over time. The set of available consumer choices itself changes due to entrepreneurial activity."

In short, we don't know what consumers want because they themselves have not yet discovered what they want. A functioning marketplace, enabled by robust data, is required for that discovery.

Therefore, Mission:data proposes three fundamental framing questions for the inquiry related to customer and aggregated energy data provision:

1. Should an affirmative data access policy and framework be established?

We believe the Commission can and should establish a policy that affirms that consumers have a clear right to access the best available information about their energy use, including interval details where available, real-time information directly from the meters with HAN communications and the corresponding details of bill charges and tariff information. Consumers should be able to share that information with whomever they choose, which means that it is machine-readable, adheres to industry standards and can be delivered through secure and convenient web service protocols; and, finally, this basic level of service – which is exactly what consumers are getting in every other sector of the economy – should be delivered as part of basic utility service, with any implementation investments included in base rates accordingly.

To date, the Commission has not established, within the context of the REV Initiative, a clear framework for what data consumers will be entitled to as part of basic service. As a result, there is ambiguity with regard to what information consumers and market participants can expect from the platform market envisioned.

2. What steps can be taken today to implement that framework, even if only part of the larger vision?

We believe the Commission can and should find that benefits will come from immediate implementation of consumer data access protocols. Even in the absence of advanced metering functionality, there is value today for consumers to be able to quickly, easily and securely share information about their energy use with service providers and renewable energy developers.

3. What are the appropriate boundaries between basic consumer service, neutral platform services and competitive markets?

We believe the Commission should clarify what information is provided to consumers as part of basic service, what information will be available to market participants from a competitively neutral platform provider and what services are considered competitive services. We believe that currently this ambiguity may hinder the development of a robust marketplace as envisioned by REV.

As further general remarks, we offer the following observations:

There is broad consensus on the record in support of consumer data access.

Indeed, nowhere within the record have any parties posited that consumers should not have access to their data and the right to share that information with their chosen service providers. While there may be differences with regard to how to address privacy concerns, the investments required and design of the markets, there is no evidence within the record that any party has argued against consumer access to their own information as anything other than their fundamental right.

Consumer Data Access is consistent with federal policy and previous Commission action.

Federal policy has consistently supported consumer data access. In particular, the 2007 Energy Independence and Security Act, declared that, "It is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a Smart Grid," including "Provision to consumers of timely information and control options…."

Direct action and funding supporting data access is found with the National Broadband Plan, American Recovery and Reinvestment Act of 2009 and the Green Button Initiative.

Similar, the Commission determined in a 2009 investigation regarding advanced metering systems that, "AMI systems must have the ability to provide customers direct, real-time access to electric meter data. The data access must be provided in an open, non-proprietary format."

Action is available to the Commission today

We believe that the Commission has several pathways available for immediate action that would bring benefits to consumer today. Our coalition includes companies that offer energy efficiency, bill management, load control, detailed disaggregation and other services in markets across the country today. In consumer markets today, millions of customers are benefiting from products like intelligent thermostats and services available from control software and analytic tools. These digital technologies offer innovations at the edge of the grid that were not possible before and the value of the corresponding economic and environmental benefits raises the opportunity cost of not establishing a strong, forward-looking open data framework.

There is no reason why consumers in New York today should not enjoy simple, convenient access to their energy information. Even without the enhanced granularity that will come from future advanced metering functions, there are services and benefits today available to consumers from having convenient access to their basic monthly bill data and the ability to share that with their chosen and trust partners.

Responses to Questions in the Notice:

Q. Are there protocols or alternatives to Green Button Connect that should be considered, and if so, what are the advantages and disadvantages of each alternative?

Green Button Connect is available today and should be implemented.

While we do not believe that the Commission should prescribe one single standard for data access, and we do not believe that Green Button Connect is a panacea for all data needs, we do believe that it offers an implementation pathway many years in the making, with strong industry and government support, and currently being used in other states with millions of customers.

There is absolutely no reason why consumers in New York shouldn’t enjoy the same level of access as consumers in other states, notably California and – in the near future -- Illinois.

Green Button was developed by utility industry leaders based on the “Common Information Model” developed by the collaborative efforts of industry leaders. Because the foundations of the standard are based from an international data model with strong industry support, it enhances the interoperability of the solutions available. We also note that, in addition to direct interoperability, there is also an industry infrastructure that has developed around the Green Button, including groups like the Green Button Alliance, which offers certification, and the Smart Grid Interoperability Panel, which is continuing to develop standards solutions. Further, federal agencies such as the National Institute for Standards and Technology (NIST) have and continue to support industry adoption of Green Button.

Electronic Data Interchange (EDI) is insufficient for the modern marketplace.

The most commonly referenced alternative standard appears to be Electronic Data Interchange (EDI). While EDI may serve existing functions quite well and we do not propose that it should be eliminated, we believe it is important to recognize that EDI was developed decades ago, long before the web services used as common practice today. As a result there is a "looseness" in the standard that increases implementation costs and can introduce variances from one utility to the next; it is not available for direct-to-consumer applications; it introduces privacy and security risks by mixing personally identifiable information and its file transfer process; and, quite simply, it's just the wrong tool for the job in 2016.

Green Button Connect is required for data access to be "convenient" in the modern economy.

With regard to Green Button, there two different "flavors" of data access considered – Green Button Download – a one-time file transfer that requires a manual intervention from the customer and Green Button Connect, which provides an ongoing stream of information for the consumer and solutions providers. This ongoing access allows the kind of "set-it-and-forget-it" customer participation that is what most people consider "convenient" in the modern world.

Q. Should vendors seeking to be provided customer data through Green Button Connect, or an alternative protocol, be considered a Distributed Energy Resource Supplier, as defined in Staff's Proposal in Case 15-M-0180? If so, which, if any, of the rules proposed by DPS Staff in that proceeding should not be applicable to vendors seeking to obtain customer data through the Green Button Connect or alternative protocol? If vendors seeking to be provided data through Green Button Connect or an alternative protocol should not be subject to the rules developed in Case 15-M-0180, what requirements or oversight should be applicable to those vendors?

Data analytics and other data-enhanced services are not regulated functions.

We do not believe that vendors *with whom the consumer has elected to share information* should be considered Distributed Energy Resource Suppliers, as defined. Data-enhanced products and services are not regulated utility functions and should be treated accordingly.

To animate markets, particularly to enable young companies to participate in this market, it is important to avoid requirements that could impose significant barriers to entry. California has adopted a framework under which such vendors must acknowledge that they have reviewed and agreed to abide by privacy and security requirements established by the Commission. Once vendors affirm this (as well as providing contact information and demonstrating technical capability), and presuming they are not on a list of vendors barred by the Commission from receiving consumer usage data, the utility provides customer usage data to the vendor as authorized by the consumer. If a vendor engages in a pattern or practice of violating Commission rules, the Commission, after due process, can order a utility to cease providing data to the vendor.

Q. Pursuant to the Uniform Business Practices, Section 4(E), utilities may not charge ESCOs for providing customer-specific information including energy consumption history used to market to or enroll customers. Should that requirement also be applicable to customer-specific information provided to ESCOs and other vendors via Green Button Connect or an alternative?

No additional fees should be imposed on consumers with regard to their data.

Yes. We believe it is entirely appropriate to include restrictions on indiscriminate fees. As stated previously, we believe it is consistent with REV principles, existing Commission directives and other state and federal policy that basic consumer data regarding energy usage and associated charges should be provided to the consumer as part of basic utility service. Any implementation costs should be included within the corresponding rates. It is particularly important to recognize that any fees are borne by the consumer, plain and simple. If there is a fee on Green Button Connect – the most convenient way for a consumer to share information – then it's simply a fee that increases their cost unnecessarily and chills the development of the markets New York is attempting to animate. .

Q. What other implementation issues regarding Green Button Connect or an alternative, should be addressed and how should they be resolved?

Implementation costs should be immediately identified and evaluated.

Comments in the record, notably from utility parties, have suggested that implementation costs of providing consumer data access would overwhelm potential benefits. Comments to this effect were reiterated at the December 16, 2015 Technical Conference in Albany. Consolidated Edison suggested that "Our benchmarks are twelve to eighteen months for implementation and cost anywhere from $5 million to $19 million."

Given the fact that nearly $23 billion is spent every year purchasing electricity in the State of New York, we are curious to understand a more detailed assessment of the costs and benefits. In New York's residential market alone, every improvement of 1% represents approximately $100 million of customer benefit. This can be achieved without AMI or other advanced metering. Results of studies using Green Button functionality in California (where AMI is deployed) are demonstrating significant consumer benefits that, if extrapolated, dwarf the costs of Green Button Connect implementation.

To date, there are no cost estimates or cost-benefit assessments offered within the record of this or any other proceeding before the Commission. The conclusion that implementation costs may exceed benefits strike Mission:data as premature, at best.

We further note that commissions that have engaged in an assessment have determined that the benefits far outweigh the costs.

Finally, we would observe that it should not be difficult to quickly get cost estimates since nearly every major industry vendor has made public statements about their ability to support Green Button quickly and easily.

Therefore, we propose that the Commission should not accept at face value assertions that costs are not justified by potential consumer benefit. As we have noted, we believe the Commission can and should require immediate data access from all utilities within their jurisdiction. At a minimum, the Commission should require specific, on-the-record implementation cost estimates be provided.

As part of those estimates, we highlight that it is critical to distinguish between:

- Costs associated with delivering secure web services and third-party authorization (similar to major services like Google, PayPal, Yahoo and the others); and

- Costs associated with the particular data standard used to package the information.

Many of the costs, we believe, are attributable to the former. That is, costs estimates should allow the Commission and other parties to determine whether there are incremental costs associated with the data standard. Our experience to date suggests that costs properly attributable to modernizing information infrastructure are improperly attributed to the particulars of Green Button or other data configurations. We believe this improperly inflates the cost estimates.

All advanced metering implementation should include clear implementation of data access

We recognized that the Commission is currently considering proposals for advanced metering systems. We believe it would be imprudent for any advanced metering systems to be approved or implemented *without* clear requirements and associated budgets for provision of consumer data access.

No service offerings should be approved without a clear data access framework and protocols.

Within the REV proceeding and in associated advanced metering proposals, utilities have proposed to offer data-rich services and offerings without establishing corresponding mechanisms for consumers or service providers to have access to basic consumer information. These products and services include subscription services, enhanced data analytics and access to Green Button Connect functionality.

Charging additional fees *without* providing clear access to information in an open market context only serves to introduce costs that limit customer choice and undermine the "market animation" goals established within REV.

As we have stated previously in this proceeding, while we recognize that utility-led data analysis solutions may help catalyze the market as a whole, we believe that these offerings should not inhibit non-utility data analytic providers from effectively competing in the market. To avoid such a scenario, the Commission should clearly define the "basic" usage data available to consumers and service providers that will be provided by the DSP and ensure that policies and mechanisms are in place to ensure that any utility offerings do not preclude open and fair access to data by consumers and, with proper customer consent, third parties.

The Commission should establish clear delineation between classes of products and services.

As we have noted, we believe there is an ambiguity with regard to what products and services will be included as part of basic service, as platform functions or as competitive services. We believe this ambiguity is eroding the ability of parties to find common ground and consensus. With regard to data in particular, we propose that the Commission clarify the boundaries between three domains:

1. Basic: As stated, we believe consumers should have access to sufficient usage and cost data to develop the most meaningful profile of their usage and what it is costing them. We submit that minimum level of customer information – usage, cost and real-time information – is assumed as a minimum-level function in any description of a "smart" or "modern" grid. Further, electricity remains the

only sector of the economy where this is somehow considered novel or forward-looking in the year 2016. (For example, consumers have been able to download financial information into analysis software and online services – e.g., Quicken or Mint.com – for decades.) This should be part of basic service and any costs should be addressed through traditional cost recovery mechanisms;

2. Platform: What services are required to successfully operate the system and its platform capabilities? Are any of these value-added services that can be offered by the platform provider in a competitively neutral fashion. If so, we presume the associated fees levied on market participants would be determined in a cost-of-service manner similar to basic consumer rates.

3. Competitive: What are competitive services? Clearly, we believe that partnering with consumers to meet their needs is an area where competitive products already exist and so we question the need for the utility to accelerate the market. We also question whether they are in some way better positioned that others to lead the innovation and market animation REV seeks.

Clear boundaries between competitive services and platform functions are required. As we have noted, demonstration projects include products – like a subscription to enhanced data analytics – that are available today from companies in open markets. But these companies are precluded from working with customers in New York State because the data are available only through utility channels and not through a competitively neutral platform.

Off-line discussions that are not part of the official record seem to suggest that data-rich services – like enhanced analytics – should somehow be “reserved” to support utility market-based earnings (MBE’s) and to augment declining utility revenues. This seems misguided. We implore the Commission to be mindful of the proverbial monkey paw trap, where a firm grasp on the small prize forfeits the much greater benefits available from innovations and open markets.

The very goal of economic regulation in general is to simulate this competitive result. The President of NARUC, addressed his colleagues last year and mused on this central paradox of regulation, which is that "competition, if it could work…would work better than we do. That is a humbling thing," he concluded. And he continued by imploring his colleagues to explore where markets are available today for new technology and to be vigilant in the face of "parochialism and rent-seeking behavior." In this context, we agree that it is important for the Commission to effectively determine that utility participation in service offerings is value-additive and not merely an economic gain without reciprocating any benefits back to society through wealth creation.

This concern about the impacts to fair competition is echoed by parties on the record in this proceeding and raises important questions about the ability of the utility to simultaneously execute its neutral system operation functions – the "platform" services – while also participating in competitive markets. This is why some clarification is required immediately with regard to what services consumers can and should expect.

Mission:data requests the Commission to consider the following:

- Customer usage and price information has been demonstrated in studies and in practice to reduce overall energy consumption, reduce peak lead energy usage, save consumers money and create environmental benefits.

- Utilities across the country have implemented systems that effectively, securely and affordably provide consumers with access to their own energy data according to common standards.

- The lack of data access has been identified by staff and working group participants as a barrier to effectively achieving "market animation" and other REV goals.

- Potential benefits appear, *prima facie*, to far exceed implementation costs.

Based on these observations, Mission:data urges the Commission to:

 Adopt a clear policy that affirms that:

1. Consumers have a clear right to access the best available information about their energy use, including interval details where available, real-time information directly from the meters with HAN communications and the corresponding details of bill charges and tariff information.

2. Consumers should be able to share that information with whomever they choose, which means that it is machine-readable, adheres to industry standards and can be delivered through secure and convenient web service protocols; and, finally,

3. This basic level of service shall be delivered as part of basic utility service, with any implementation investments included in base rates accordingly.

 Require immediate implementation plans from all utilities that provide timelines and cost estimates for achieving such "best available" consumer data access.

 Incorporate data access protocols within any and all proposal for advanced metering equipment of functionality.

 Provide clear delineation between three classes of service with regard to consumer data – basic, platform and competitive.

National Energy Marketers Association (NEM): Submitted by: Craig G. Goodman, Attorney & President, and Stacey L. Rantala, Director, Regulatory Services, Washington, DC

NEM shares the Commission's vision that "consumers should have ready access to their energy usage information and should be able to easily share that information with vendors they select." NEM offers recommendations specifically directed at how to provide ESCOs with access to more timely and granular consumer energy usage data so that ESCOs have the tools to develop innovative, time-of-use and other smart meter-enabled products and services. Also, NEM explains the deficiencies in the Green Button Connect protocol, and the non-billing quality data it provides, from an ESCO perspective.

Green Button began as a White House initiative in 2011 to provide consumers with electronic access to their energy usage information. It was envisioned that consumers would able to download their own detailed energy usage information with a simple click of the "Green Button." With that data, consumers would be able to utilize online tools, or "apps," to help them better manage their energy usage. Green Button is available with two capabilities. Green Button Download My Data allows the customer to download its own energy consumption data to its own computer, providing a one-time snapshot of historical data. Green Button Connect allows customers to automate the secure transfer of their own energy usage data to authorized parties. Green Button Connect provides a more on-going stream of data. However, it is not billing quality data.

NEM believes that the Green Button was not designed to be a solution to provide ESCOs with access to energy usage data that is needed to animate a suite of time-of-use and other smart meter-enabled products and services. The Green Button data stream is not fully automated, it does not provide billing quality data and does not provide data in daily intervals. Our members report that in other restructured states that considered it, those states determined not to use the Green Button protocol for the dissemination of energy usage data to competitive energy suppliers.

NEM believes that a streamlined mechanism must exist by which ESCOs can obtain billing quality data for all of their customers (with customer authorization), without having to make multiple requests for data for each individual customer. ESCOs should be provided with hourly, interval, billing quality data on a monthly basis via EDI. Non-billing quality data should be provided on a next day basis via FTP or email the next day. A progressive, phased approach to providing ESCOs with access to customer energy usage data should begin with access to hourly interval data, over time moving to shorter intervals (15 minutes), and ultimately, providing real time data access or as close to real time data access as is practicable.

One of the specific customer energy usage data elements that ESCOs should be provided with is the AMI indicator, so that ESCOs know the utilities' plan for deployment and placement of meters. With this information, ESCOs can properly tailor their marketing efforts and offer appropriate, eligible products to the correct customers that have AMI meters installed in their homes.

Distributed Energy Resource Providers

In Case 15-M-0180 regarding Commission oversight of Distributed Energy Resource Providers, the Staff proposed a set of Uniform Business Practices – Distributed Energy Resource Providers (UBP-DERS). Staff included a proposed Definition Section in the proposed UBP-DERS, including the terms "Distributed Energy Resource" and "Distributed Energy Resources Supplier."

The proposed definition of "Distributed Energy Resource" is as follows:

A broad category of resources including end-use energy efficiency, demand response, distributed storage, and distributed generation. DER will principally be located on customer premises, but may also be located on distribution system facilities.

The proposed definition of "Distributed Energy Resources Supplier" is as follows:

A supplier of one or more DERs. Suppliers may choose to provide DERs as stand-alone products or services, or may choose to bundle them with energy commodity. Entities which sell both DER and energy commodity are both DERS and ESCOs.

NEM believes that the proposed definitions of "Distributed Energy Resource" and "Distributed Energy Resources Supplier" are worded very broadly, potentially encompassing activities and entities that have not historically and should not prospectively, be Commission-regulated activities or entities. Limiting oversight to those transactions that constitute the sale of DER services into the DSP markets would appropriately limit jurisdiction to activities that take place on Commission-jurisdictional markets.

Further, NEM believes that the utilities should not be permitted to charge ESCOs and other vendors for customer-specific information that is provided via Green Button Connect or an alternative. The customer-specific information belongs to the customer, not the utility. The utility should not be permitted to construct artificial barriers to third party providers being provided with access to information. Utilities recover the costs of metering and metering infrastructure from ratepayers. Customers have paid utilities for the installation and use of the meters and the information those meters generate. As a result, customers should be able to authorize third party providers to have access to their information, and the access should be free of charge. Charging ESCOs and other vendors for energy usage data would result in a double payment to the utility for the information. Moreover, the utilities already enjoy an unfair competitive advantage given their superior access to customer data. Requiring third party providers to pay for the data under these circumstances will make it more difficult for them to develop innovative value-added products and services and will increase their costs of offering DER products into the marketplace. This will needlessly increase costs to consumers and artificially limit the availability of DER products to them.

Finally, the REV goal of increasing consumer engagement in a host of DER products and services will be best realized if market participants have standardized platforms, processes and rules for interacting with the utilities. This includes a standardized, automated mechanism for providing ESCOs with access to customer energy usage data. Such a standardized, automated mechanism should provide timely access to more granular data. Otherwise, market participants must develop individualized systems for interacting with each of the utilities, subject to utility-specific requirements, all of which will increase the cost of doing business in the State. For example, Texas uses a statewide data clearinghouse that is centrally managed by ERCOT, called SmartMeterTexas.com, to provide competitive suppliers with secure and timely access to customer energy usage data. Given the pending utility applications for metering upgrades, implementing a statewide data clearinghouse to coordinate ESCO access to meter data would be particularly appropriate, cost-effective and efficient.

National Fuel Gas Distribution Corporation (Distribution or the Company): Submitted by: Michael E. Novak, Asst. General Manager, Rates & Regulatory Affairs, Williamsville, NY

As a gas-only utility, Distribution is differently situated from every other major utility in New York State, because the primary focus of the REV proceeding is concerned with the electric industry. Similarly, the discourse concerning Distributed Energy Resources ("DER") products and Suppliers has focused upon retail electric customers. Distribution understands the potential Advanced Metering Infrastructure ("AMI") provides in terms of changing the nature of electricity customer energy data. Given the daily/hourly pricing structure of the wholesale electric market, interval metering may provide for thousands of usage points annually, thereby playing a significant role towards achieving various REV-oriented objectives, including the potential for emergence of a DER products market. Since the monthly/daily pricing structure of the wholesale gas market does not provide a basis for the implementation of AMI, the nature of gas customer energy data appears unlikely to expand beyond the traditional 12 monthly usage points annually.

Community Choice Aggregation ("CCA") has a broader focus and at least with respect to the provision of energy supply, appears equally applicable to retail gas and retail electric customers. As such, Distribution views the provision of customer energy data, whether at an individual account level or at an aggregated level, as an adjunct to the development of CCAs.

Distribution currently provides all customers with access to their energy data, at no charge, through its web-based historic bill calculator. While this tool was designed in the context of competitive retail energy markets, access to customer data (including usage data) is provided whether or not the customer procures their supply service from an Energy Services Company ("ESCO"). With respect to the development of CCAs, Distribution already provides, and plans to continue to provide, aggregated usage data to municipalities seeking to aggregate customers. Since 2000, several municipal aggregation groups have operated under Distribution's existing tariff services. Distribution, through its course of conduct, clearly supports: 1) providing customers with access to their energy data, and 2) providing aggregated data to municipalities interested in customer aggregation. The main issues of concern to Distribution center upon the means of providing customers access to their data, the means of providing municipalities with aggregated customer data, and ensuring that proper regulation and oversight is in place to properly protect customer information.

Responses to Questions in the Notice

Q. Are there protocols or alternatives to Green Button Connect that should be considered, and if so, what are the advantages and disadvantages of each alternative?

Distribution plans to implement a new billing system during spring 2016 and at this point is unable to prepare a detailed cost estimate until the new system is implemented, post implementation stabilization work is completed, and until the Company gains some operating experience under the new environment. Based upon preliminary analysis and investigation, the implementation costs presented by Consolidated Edison at the Technical Conference appear to be a reasonable gauge of the costs Distribution might incur, if it were to implement Green Button Connect. Installation of AMI for approximately 500,000 gas accounts could add tens of millions of additional cost to the Green Button Connect implementation cost estimate.

Given that only 12 usage points are present for Distribution's customers, limiting the Green Button implementation to "Download My Data" would be less costly than implementing Green Button Connect, but essentially duplicative of the functionality currently provided by Distribution's current historic bill calculator. To replicate the full functionality of "Download My Data," Distribution could enhance its historic bill calculator to forward usage data in a standardized format to DER Suppliers ("DERS").

Some parties advocate utilizing Green Button as a standardized interface for customers and DER Suppliers, and that doing so is essential to achieving REV-oriented objectives. Distribution disagrees, and points out that with the exception of interval data, the data that would be available though Green Button is already available through New York's Electronic Data Interchange ("EDI") Standards. Distribution is not suggesting that customers would have to implement EDI to access their data, since existing web-portals such as Distribution's historic bill calculator provide that functionality today. The proposition that a standard format will be beneficial to customers is misleadingly attractive because for gas and electric service, the typical customer only deals with one or two utilities. It should also be noted that no evidence has been presented as part of Cases 14-M-0101 et al. that suggests that customers are even interested in obtaining their usage information, regardless of a standardized format. Rather, the majority of customers within New York are unaware of REV and DER offerings.

Distribution is suggesting, however, that requiring DER Suppliers to utilize EDI is not a barrier to entry. Several EDI Service Providers offer services that access EDI transactions through more user-friendly formats such as web pages (for transaction entry) and/or provide responses in common office productivity software formats such as Excel spreadsheets. Since ESCOs will also have the opportunity to provide DER services, the implementation of Green Button or an alternative format at the supplier/service provider level, imposes unnecessary costs onto these market participants because they already access this data via EDI.

Distribution believes that the Commission should not mandate Green Button implementation on gas utilities, as the United States Department of Energy's ("DOE") Green Button website specifically states that "households and businesses can use Green Button to access their own energy usage data from their electric utility." This statement, by DOE itself, is an indicator that Green Button functionality, or its equivalents, may not be cost effective or suited for gas utilities. However, should the Commission mandate use of Green Button, Distribution proposes that rather than requiring direct real-time access to utility system through an Applicable Program Interface, that utilities have the option to implement through a third-party Green Button provider (here-in-after, "Green Button Store") that offers customers access to their utility data for a nominal fee. The Green Button Store would collect account indentifying information from the customer and translate[14] it from Green Button's data format into an 814HU EDI request. Distribution would respond the next business day[15] with an 867HU response providing the customer's usage data (up to 24 months). The Green Button Store would translate the usage data into Green Button's format and follow the customer's instructions concerning to whom the data should be forwarded.

The cost to Distribution for such an approach is very small (i.e., no more than what the Company incurs when an ESCO enters Distribution's competitive market, and comparable to the costs incurred when Distribution began to exchange analogous data with the New York State Energy Research and Development Authority ("NYSERDA") via EDI). Distribution also believes it's possible that multiple Green Button Store outlets could emerge as a competitive service because presumably DER Suppliers would find value in sales channel differentiation. This approach might also help determine a quantifiable, competitive market value for the data.

Q. Should vendors seeking to be provided customer data through Green Button Connect, or an alternative protocol, be considered a Distributed Energy Resource Supplier, as defined in Staff's Proposal in Case 15-M-0180? If so, which, if any, of the rules proposed by DPS Staff in that proceeding should not be applicable to vendors seeking to obtain customer data through the Green Button Connect or alternative protocol? If vendors seeking to be provided data through Green Button Connect or an alternative protocol should not be subject to the rules developed in Case 15-M-0180, what requirements or oversight should be applicable to those vendors?

Distribution supports having vendors seeking to be provided customer data through Green Button Connect, or an alternative protocol, be considered a DER Supplier.

Distribution believes that Staff's Proposal in Case 15-M-0180 may unintentionally create gaps relative to analogous requirements applicable to ESCOs under the Uniform Business Practices ("UBPs"). A better course of action would be to incorporate the intent of Staff's Proposal in Case 15-M-0180 into the existing UBPs, and apply the resulting rules to ESCOs and DERS contemporaneously; many of whom will be the same entity.

Q. Pursuant to the Uniform Business Practices, Section 4(E), utilities may not charge ESCOs for providing customer-specific information including energy consumption history used to market to or enroll customers. Should that requirement also be applicable to customer-specific information provided to ESCOs and other vendors via Green Button Connect or an alternative?

Yes, except as noted above in response to question 1. While ESCOs and other vendors may use customer-specific information, permitting these parties to charge others for access to this information is not consistent with of the underlying restriction on utilities, and potentially undermines customer data privacy.

Q. What other implementation issues regarding Green Button Connect or an alternative, should be addressed and how should they be resolved?

Distribution has no specific issues at this point but reserves the right to respond to issues raised by others in response to the Notice.

Q. How can utilities prepare and provide electronic access to customer data aggregated by municipality in a standard format, in an efficient manner?

While it can be presumed that providing municipalities with electronic access to customer data (aggregated by municipality in a standard format) is a technical design matter and would be efficient, if there is no demand for such data, the technological solution will be cost ineffective and wasteful. Distribution's observation from the Technical Conference is that this request would serve no purpose other than filling in data gaps for a preconceived notion of how municipal aggregation should take place.

Standardization is most useful when there is a high volume, repeat request for a particular type of data. Statements made at the Technical Conference that utilities are being overwhelmed by requests from municipalities are unfounded. As mentioned above, Distribution received two municipal aggregation inquiries during 2015; only one of those reached the stage where it was appropriate to provide aggregated customer data to the municipality. Distribution believes it is far more cost effective to provide utilities with flexibility to respond to requests for specific types of data, and that the availability of the data should be limited to those municipalities who request such data. Given the current level of interest in municipal aggregation, data can be provided in a password-protected Excel spreadsheet in the normal course of business. Should the level of interest grow to the point where the number of requests from municipalities becomes unmanageable, the proposal can be revisited.

Q. Should utilities be permitted to charge municipalities or other third parties for providing this aggregate data? If so, why, and how should those charges be determined?

So long as Distribution is able to maintain flexibility with respect to its current practice of providing aggregated data to municipalities on an as-requested basis, the Company sees no need to charge a fee for the provision of this information. Distribution does not have a conceptual objection to charging municipalities or other third parties for access to aggregated data. However, given the inapplicability of REV-oriented objectives to the gas market, fees for access to aggregated gas data are not practical. Distribution asserts that aggregate gas data has relatively little, if any, value compared to aggregate electric data. Furthermore, charging fees for aggregated gas data would likely create an impediment to the development of CCAs. As such, Distribution believes it should receive full cost-based rate recovery for the implementation of Commission directives, with respect to the provision of aggregated gas customer data. In turn, the Company would not charge municipalities or other third parties for provision of aggregated data. Alternatively, Distribution would be willing to develop and charge fees, to the extent that the Commission provided Distribution with full cost-recovery through a tracker mechanism, against which any data fees would be credited.

Q. Should the Commission consider a privacy standard to ensure customer anonymity when aggregate energy data is released to third parties without customer consent? If so, what rule should be adopted? Rules adopted in other jurisdictions include a "15/15 rule" under which a minimum of 15 customers are included in aggregate data with no one customer's load exceeding 15 percent of the group's energy consumption, and a "4/80 rule" requiring data from a minimum of four customers to be added as long as no one customer's load exceeds 80 percent of the group's energy consumption.

Distribution supports the Commission's adoption of privacy standards such as the "15/15 rule" or the "4/80 rule," but believes a regulatory process, whereby a municipality can seek waiver of such rules (e.g., upon consent of the affected customers), may be appropriate. Distribution adds that having a flexible definition of municipality is the best means to ensure customer privacy concerns are met when aggregated data is provided. For example, an individual municipality, such as a suburban or rural town that cannot meet the "15/15 rule" or the "4/80 rule," should have the flexibility to aggregate their municipality with other interested municipalities to produce an aggregation group that satisfies these rules.

Q. What other issues regarding providing aggregate customer data to third parties should be addressed and how should they be resolved?

Distribution has no specific issues at this point but reserves the right to respond to issues raised by others in response to the Notice.

Finally, Distribution recommends that the Commission consider the differences between gas and electric service provided to customers, as well as the applicability of REV objectives to each industry. Further, Commission determinations should leverage existing data infrastructure, business practices and rules that were built for the competitive market, continue to be proven effective in a number of Commission proceedings, and that have been enhanced over the past 20 years.

National Grid (Company): On behalf of: The Brooklyn Union Gas Company (KEDNY) d/b/a National Grid NY, KeySpan Gas East Corporation (KEDLI) d/b/a National Grid, and Niagara Mohawk Corporation d/b/a National Grid. Submitted By: Jeremy J. Euto, Senior Attorney II, National Grid, Syracuse, NY

National Grid agrees that access to data is an important part of these interactions, and that careful consideration of issues involving customer and third-party access to data is essential to meet customer expectations with regard to data privacy, protection of personally identifiable information and cybersecurity. National Grid believes flexibility is essential in identifying cost effective means for utility customers to access, utilize, and share data and for determining optimal means to meet customer expectations with regard to safeguarding customer privacy.

Q. Are there protocols or alternatives to Green Button Connect that should be considered, and if so, what are the advantages and disadvantages of each alternative?

National Grid believes access to energy consumption data can be of value to customers, associated building owners and managers, Energy Service Companies (ESCO's), governing agencies, and DER providers. The Company supports elements of the Green Button Connect ("GBC") protocol, and we have already taken steps to provide Download My Data (DMD) service through our website. While other secure data sharing protocols have been and continue to be used for specific purposes (e.g., web services, point to point file transfers, EDI, etc.), the Company found support and discussion of GBC format at the Technical Conference very encouraging. The fact that GBC is evolving as a nationwide standard using current protocols providing a high level of customer data protection makes it a viable option for utilities, basic and advanced customers, and innovative market service providers. As the Joint Utility Initial DSIP Comments suggest, access to customer-specific data is determined by multiple factors, including but not limited to the meter infrastructure, customer service systems, and website capabilities unique to each utility.

` Further, the Joint Utility Initial DSIP Comments advocate flexibility, noting that possible changes to the current functionality for data access "necessitates careful consideration of the needs of each utility's service territory and the potential value for customers."

t is clear that utilities in New York and across the country are in different positions in evaluating and implementing elements of GBC. For National Grid, other protocols, such as the existing online account access and EDI, continue to be most appropriate for specific applications. While National Grid has already embraced and offered GBC "download my data" functionality, the Company is not currently pursuing implementation of GBC "connect my data" as an alternative to provide an additional means of means of data sharing with customers and third parties. This decision reflects the current data set available to National Grid's mass market customers (i.e., that do not have access to interval data) and adequacy of existing functionality to share the types of data currently available to National Grid mass market customers (e.g., monthly usage data, bill and usage history, etc.). This could change in connection with expanded deployment of automated metering infrastructure ("AMI"), which National Grid is in the initial stages of investigating for its electric service territory in upstate New York.

Q. Should vendors seeking to be provided customer data through Green Button Connect, or an alternative protocol, be considered

a Distributed Energy Resource Supplier, as defined in Staff's Proposal in Case 15-M-0180? If so, which, if any, of the rules proposed by DPS Staff in that proceeding should not be applicable to vendors seeking to obtain customer data through the Green Button Connect or alternative protocol? If vendors seeking to be provided data through Green Button Connect or an alternative protocol should not be subject to the rules developed in Case 15-M-0180, what requirements or oversight should be applicable to those vendors?

National Grid strongly concurs with the Commission's assertion in the February 26, 2015 REV Order that, "the acquisition of customer data by any means established under the Commission's authority," would subject an entity that provides DER to the Commission's rules governing DER providers. Under this approach, data sharing protocols, such as Green Button Connect (or any protocol for that matter), adopted by the Commission would subject providers of DER acquiring customer data via such protocols to rules or regulations adopted by the Commission governing DER and DER providers. This is consistent with comments filed in Case 15-M-0180 on September 25, 2015, wherein the Joint Utilities, including National Grid, asserted that "DER oversight should apply to DERS or other third parties, including rate and other consultants, that acquire customer data by any means established under the Commission's authority." National Grid also fully supports continued development of rules and standards that will support efforts such as those being pursued in REV demonstration projects.

Q. Pursuant to the Uniform Business Practices, Section 4(E), utilities may not charge ESCOs for providing customer-specific information including energy consumption history used to market to or enroll customers. Should that requirement also be applicable to customer-specific information provided to ESCOs and other vendors via Green Button Connect or an alternative?

The data provisions contained in the Uniform Business Practices ("UBP") were specifically designed to support and promote the competitive energy supply business for qualified providers. The question suggests that utilities may not charge ESCOs for providing customer specific information, however, Section 4(E) of the UBP expressly permits distribution utilities to impose "incremental cost based fees, authorized in tariffs for an ESCO's request for customer data for a period in excess of 24 months or for detailed interval data per account for any length of time." This section clearly contemplates that ESCOs could be charged for say, detailed interval data, such as that contemplated under GBC connect my data. As is the case with the sharing of certain data to promote retail access (contemplated under Section 4(E)), the Company believes that a standard or "base" set of data from an online web portal, EDI or protocol such as GBC should be provided without additional charge to customers and qualified vendors. However, there will be situations where customers and vendors will request or require more extensive data or data not conforming to a standard or "base" specification. In these situations utilities should be permitted to charge customers and/or third parties requesting such data to cover costs incurred to accommodate their request.

Q. What other implementation issues regarding Green Button Connect or an alternative, should be addressed and how should they be resolved?

The Company believes that development and support of the advanced GBC connect my data functionality would be a substantial undertaking and would require a linked AMI strategy to prove beneficial for advanced applications. While the company supports AMI as important to achieving goals of REV, a business case for AMI needs to be developed recognizing service territory dimensions of size, geography, customer density, and demographics.

There are likely many development and implementation issues regarding GBC that the Company has not yet begun to address. The presentations and discussions at the Technical Conference were useful in exposing the fact that while GBC is a nationwide standard there are many fundamentals yet to be decided upon.

One factor which will be critical to explore is the "billing quality" of data available through a protocol such as GBC. While the Company's current GBC download my data service provides post-billing data, more advanced GBC functionality would likely be sourced through a utility’s Meter Data Management (MDM) tool or a central meter data repository. Meter data sourced at frequent intervals through these sources may not be “billing quality”.

Another factor will be the data privacy and protection standards used with a protocol such as GBC. Certain guidelines and advice given to the Company have been incorporated into its data privacy policies but initiatives such as GBC will require careful consideration and application of these policies.

Q. How can utilities prepare and provide electronic access to customer data aggregated by municipality in a standard format, in an efficient manner?

The Company has experience with municipal data needs for aggregated customer data in other jurisdictions and recommends that the Commission require municipalities submit a detailed “Aggregation Plan” for review and approval prior to execution of such plan. The Aggregation Plan should include a detailed description of the requirements to facilitate the aggregation including:

- Parameters of price point (e.g., whether pricing is guaranteed to be below the utility price)
- Green power offer
- Consumer protections
- Term of aggregation
- Opt-in or opt-out process
- Education plan for consumers
- Electric service agreement
- Termination plan

National Grid recognizes that different entities may have different needs for aggregated data. This can include community choice aggregation, or other efforts involving municipalities and building owners. The Company believes that flexibility is required when dealing with requests for data associated with aggregation efforts, to reflect the diversity of customer demographics, geographic areas, political boundaries, and utility service classifications. Further, utilities should be permitted to review and respond to individual requests in a manner that meets customer expectations for data privacy.

Q. Should utilities be permitted to charge municipalities or other third parties for providing this aggregate data? If so, why, and how should those charges be determined?

Utilities should be allowed to charge for services. At a minimum, National Grid believes customers and entities benefitting from the aggregation should bear the costs to compile and share the necessary data. Another factor weighing in favor of charging aggregators for data, is the potential cost incurred to respond to their requests. The Company's affiliates are currently providing aggregated customer data to several municipalities in Massachusetts. The process used to accommodate these aggregations is not automated, and manual steps to address populations of just 12,000 customers have proven difficult and time consuming. To handle such efforts for our New York service territories would require development of a more automated process to increase capacity and accommodate more frequent and larger requests. As noted previously, the Company believes appropriate fees and fees structures should be addressed by interested stakeholders in the context of the DSIP and Track 2 REV proceedings.

Q. Should the Commission consider a privacy standard to ensure customer anonymity when aggregate energy data is released to third parties without customer consent? If so, what rule should be adopted? Rules adopted in other jurisdictions include a "15/15 rule" under which a minimum of 15 customers are included in aggregate data with no one customer's load exceeding 15 percent of the group's energy consumption, and a "4/80 rule" requiring data from a minimum of four customers to be added as long as no one customer's load exceeds 80 percent of the group's energy consumption.

While the Company is committed to providing data necessary to support such programs, it is also very sensitive to the protection of customer data privacy. So as not to stifle innovation, the Company does not believe a one-size-fits-all rule or standard for privacy needs to be adopted by the Commission at this time. The Company believes that its own data privacy policies are already consistent with generally accepted industry standards, and though we continue to monitor and adjust our practices as appropriate, no further changes are required at this time.

NRDC: Submitted by: Natural Resources Defense Council, Jackson Morris, Director Easter Energy; Urban Green Council, Laurie Kerr, Director Policy; Institute for Market Transformation (IMT), Alissa Burger, Sr. Associate Data and Utillities; and Pace Energy and Climate Center (PACE), Daniel Leonhardt, Sr. Energy Policy Associate

Energy usage data is much more than simply a compilation of numbers. This data is information. Properly assembled, such information creates opportunities for increased knowledge and action. In turn, this knowledge can assist consumers and other key stakeholders in making critical decisions regarding energy usage and supply alternatives, including energy efficiency and other distributed energy resources.

The PSC itself recognizes this fact. In its Order initiating the Reforming the Energy Vision (REV) proceeding, the Commission identified five policy objectives. In enumerating these objectives, the Commission lists first "Enhanced Customer knowledge and the tools that will support effective management of their total energy bill". The foundation for both this knowledge and these tools is timely customer access to high quality usage data. Indeed, access to energy usage data is also critical to the achievement of the Commission's other REV policy objectives. Users of the information extend beyond "customers", such as prospective tenants selecting among different buildings, as well as mortgage lenders or property insurers considering a building's energy usage profile in their decision making.

Through provision of this information, the market participants in the building sector will be better able to adopt the necessary measures to achieve New York's ambitious but achievable State Energy Plan goals on efficiency and greenhouse gas reductions (23% efficiency improvement in buildings and 40%

reduction in GHG emissions by 2030). We recommend that the PSC consider the following specific measures:

Recommendations Regarding Customer-Level Aggregated ("Whole Building") Energy Usage Data

1. Prioritize the Building Owner Use Case.

National Grid recommends that the Commission focus first on assuring that building owners can obtain usage information they need to measure, benchmark, and manage the energy usage in their buildings.

The Notice references building owners' need to obtain information about the energy use in their buildings, but does not highlight this critical question with sufficient specificity. Building owners need whole-building usage information (at least on a monthly basis) in order to manage the energy use in their buildings, obtain benchmarking results, provide prospective tenants with information about energy use, and more. New York utilities must have clear and express direction to deliver the whole-building usage information to owners, subject to sensible terms and conditions. The terms and conditions needed for utilities to deliver information to building owners can and should be implemented in a priority manner, separately from regulatory solutions to address other use cases, such as customers sharing information with vendors, and utilities sharing information with other parties. Delivering information to building owners raises discrete questions.

Moreover, the problem is amenable to known solutions already implemented by many utilities in other states, and we describe such policies below.

2. Direct Utilities to Deliver Aggregated "Whole-Building" Usage Data to Building Owners.

The PSC should direct New York utilities to deliver whole-building usage summary information to building owners if the building includes two or more meters and if additional conditions are satisfied (such as providing notices to included customers).

It is necessary to first define aggregated building usage information (ABUI) or "whole building" usage information. Many buildings have multiple separately metered customers, such as office buildings with many tenants or apartment buildings with tenants with their own utility accounts. In these buildings, the owner requires a summation of all the utility usage across all meters in order to know how much usage occurs in a given time. The total utility usage is the basis for a benchmarking score and provides a baseline to identify anomalies that can cause usage spikes. (ABUI is a single number, such as 105,000 kWh in June 2015.)

Any policy to deliver summary information must be tailored to resolve any privacy risks and considerations of the included customers (e.g., tenants in the buildings). ABUI is not customer information and contains no individual customer information. If the ABUI total (e.g., 105,000 kWh) is aggregated usage from several customer meters, it is very difficult for the owner to use the information to "re-identify" the usage of any included customer. For a discussion of specific reasonable terms and conditions that the PSC might consider, see "How Utilities Can Give Building Owners the Information Needed for Energy Efficiency while Protecting Customer Privacy," *Electricity Journal*, November 2015 (attached as appendix A).

To help facilitate compliance with New York City's annual benchmarking requirement for large buildings, we understand that Con Edison, National Grid, and PSEG Long Island have been delivering whole-building usage information to building owners using reasonable terms and conditions.4 These policies, however, should be institutionalized, expanded to include automatic uploading of the data (see Section 3, below), and these data should be available to all building owners around the state. While Con Edison, National Grid and PSEG Long Island are currently providing building owners with whole-building usage information, they are not yet providing automatic upload/web services, which is needed. Market participants will be better able to establish tools and uses for such information with greater certainty around the information availability.

3. Direct Utilities to Implement Systems to Enable Direct and Automatic Upload of Aggregated Building Usage Information.

The PSC should direct utilities to implement systems to enable direct and automatic upload of whole-building usage information in the formats needed for use in standard benchmarking systems, including EPA's Energy Star Portfolio Manager. At a minimum, utilities should implement such systems for customers and buildings located where mandatory benchmarking requirements are in place.

Building energy benchmarking increases adoption of efficiency investments and spurs the efficiency market. Implementing systems that allow for automatic data delivery to systems such as Portfolio Manager would drastically reduce data entry errors inherent in manual data entry and facilitate owners' building energy benchmarking, which is a crucial, foundational step for building owners to make informed decisions about investing in energy efficiency measures in their buildings, and in certain localities, required by law. Automatic uploading reduces the burden of benchmarking on building owners and would greatly facilitate benchmarking throughout the state. Benchmarking energy use allows building owners to measure a building's comparative energy performance over time and allows owners to compare their buildings to others of a similar size and type in their location and across the country. It provides owners with an energy performance baseline, helps them to target their efficiency investments, and allows them to verify savings.

Many utilities around the country provide aggregated building energy use information to building owners, including (among others): Avista (Washington), Baltimore Gas & Electric (Maryland), Commonwealth Edison (Illinois), Enwave Seattle (Washington), Eversource (Massachusetts), PECO (Pennsylvania), Pepco (District of Columbia), Puget Sound Energy (Washington), Rocky Mountain Power (Utah), Seattle City Light (Washington), and Washington Gas (District of Columbia). Providing clear direction to do so in New York State would bring New York utilities in line with those utilities. In October 2015, the California legislature passed AB 802 requiring, in part, owners to report benchmarking results for all commercial and residential buildings with more than five units to a statewide repository, and requiring utilities to deliver the requisite information to owners. The National Association of State Energy Officials also recently passed a resolution supporting state adoption of policies facilitating whole building energy data access, transparency and benchmarking. Mandatory benchmarking programs are now underway in a growing number of cities and states across the country, with more to come.

Creating a requirement for utilities to automatically upload usage information to systems such as EPA's Energy Star Portfolio Manager will further enable benchmarking initiatives and requirements throughout New York by improving the quality of data and reducing the cost of obtaining such data, especially in terms of time, for building owners. Expanding benchmarking will increase the opportunities for utilities and market participants to increase efficiency efforts and will help achieve the state's climate and energy goals.

4. Direct Utilities to Examine Policies and Processes for Building Owners to Obtain Individual Tenant Usage Information.

The PSC should direct utilities to examine policies and processes for building owners to obtain individual usage information of tenants with the tenant's permission. The express goal of this directive is to encourage utilities to modernize their policies and procedures so that building owners, tenants, and the utilities can accomplish the needed information exchange with reduced paperwork burdens, time delays, and costs.

In many apartment buildings, energy usage information at the unit-level is necessary for the owner to consider energy related repairs and improvements. In subsidized housing, the unit-level information allows for accurate calibration of utility allowances to enable an owner to recoup the cost of efficiency-related work.

It is reasonable and expected that utilities would require customer permission to share the individual customer's usage information with the building owner. However, many utilities have antiquated policies in place that require building owners to obtain permission using a utility-provided paper form and to obtain a “wet-signature” and then send or fax the form to the utility for every tenant in the building. Even with automated functions (such as “Green Button Connect My Data”11), the approval may hinge on each tenant/customer taking action. This process can be, in practice, a barrier to the owner obtaining the needed customer information, which could result in lost efficiency opportunities.

We recommend that the PSC direct utilities to implement policies and procedures that will enable building owners to obtain usage information in a more streamlined manner. One option to explore is to allow utilities to rely upon tenants conveying requisite permission in a lease document. Another option is to authorize the utility to “pre-qualify” owners or operators for large numbers of offices or apartments, which would allow the utility to rely on the building owner’s representation and warranty that it has obtained the tenant’s permission, assuming the owner has met certain preconditions. This will relieve the utility of the burden of examining every lease document for the requisite language and signatures.

Recommendations Regarding Community-Level Energy Data

1. Require the Development of a System that Easily Provides Access to Aggregated, Community-Level Data.

We recommend that the Commission act to assure the development of a data system that allows a geographic rollup of individual customer data with appropriate privacy protections. Access to aggregated, community level data by local jurisdictions is critical to the success of REV. Moreover, such data is equally important in facilitating other important state initiatives, such as the New York State Community Partnership and the Five Cities Energy Plans.

In its presentation at the Technical Conference, NYSERDA described these aggregated, community-based data as “exploratory data” to distinguish it from more customer specific “implementation data”. We concur with NYSERDA’s recommendation that this aggregated, community-based data should be made available at no cost to communities and the public through a single, easily accessible portal. NYSERDA correctly points out that access to such data is in the public interest. This aggregated data should minimally be available annually. Ideally, in time it can be produced on a quarterly or even monthly basis.

Working with the utilities and organizations like NYSERDA and NYPA, the Commission should facilitate the development of a standard reporting form and assure the quality and consistency of these data to allow for easy geographic comparisons between different utility territories. The availability of such community-based aggregated data will be a valuable tool for the Commission, NYSERDA, and interested stakeholders to track and measure progress under both the Clean Energy Fund and the utilities' energy efficiency programs, especially market transformation efforts, and to facilitate program adjustments and target future assistance.

Otego Microgrid Ratepayers (Otego): Submitted by: Stuart Anderson

Otego believes that getting consumers to switch to renewables will be easier if data is available. Otego states how difficult it currently is for contractors trying to market renewable energy in New York. Stuart Anderson writes for Otego, and he states that, his household is home to no less than 23 combined years of education at Cornell, Colgate and MIT, so analysis of technical issues is not a problem for them; but trying to make a logical, mathematically informed decision about energy in their home during the planning process was literally impossible. Ultimately, they tore out oil-fired space and water heating and "replaced" them with electric water heating, a geothermal heat pump drawing heat from a new pond, and 10kw of photovoltaics on the roof—grid tied. They had no way to determine in advance if what they were doing was properly scaled. After the installation, data was difficult to come by….they literally went around with a clip board every day and wrote down what was happening with the equipment; without their own logs, they would have been essentially blind for another year. NYSEG has just recently altered their billing format to include information on net metering accumulation; thank you for that, but there's so much more happening in that meter that they cannot access.

Otego believes that the utilities are incentivized to horde information. REV as currently written, provides utilities with a powerful incentive to discourage the distribution of data to persons and entities interested in establishing microgrids. Under current REV guidelines, in the event that some portion of the grid is not included in a microgrid by some combination of local governments and/or third parties and/or investors, the responsibility for developing that area to microgrid standards—including islanding—defaults to the regional utility. The utility will install DERs to support islanding, and these DERs are required to be "clean". As the Big Lie promulgated in the 2015 State Energy Plan declares that natural gas is a "clean" energy resource, and as utilities are required to consider investment and operating costs in their selections of equipment, the utilities will in effect be mandated to install gas-fire turbine generators at such locations.

Otego strongly recommend that the PSC direct the Staff to develop provisions for wresting control of tie-in data from the utilities and make that data available to developers in a timely and complete fashion. Also, the PSC could inform the Governor and the State Energy Board that natural gas does not merit its "clean" energy designation…..possibly a bridge too far.

SolarCity Corporation: Submitted by: Jamil Khan, Deputy Director, Policy and Electricity Markets

SolarCity supports Mission Data comments. SolarCity considers customer and aggregated data access, along with interconnection improvements, a fundamental barrier that must be resolved before there can be progress on the more far reaching reforms within the Reforming the Energy Vision proceeding. Streamlined access to data will advance the goals of REV, including market animation, customer engagement, DER and energy efficiency growth, peak load reduction, emissions reduction and customer affordability.

The comments submitted by Mission Data contain clear and vital recommendations for the Commission with respect to customer data access. Customers have the right to access and share their own electronic data in a clear format and with the simplest process. While other industries excel at customer data transparency, utility customers generally still do not have the most basic information that could inform their consumption, behavior, and investment decisions. Customers are also unable to share this information easily. SolarCity encourages the Commission to swiftly adopt the principles and proposals put forward by Mission Data.

Town of Philipstown: Submitted by: Richard Shea, Supervisor

Support CCA. CCA can be an important tool for meeting New York State's energy goals, and at the same time, they can contribute to economic development. Also, CCA can afford transparency and accountability in energy decision making and ensure adherence to state procurement regulation that protect consumers. To form a CCA, municipalities need access to granular data (not just aggregated data) before the CCA program is created. Because it will help in the planning and implementation strategies for including renewable energy and energy efficiency goals. Also, it will better position to seek the financial resources needed to build out distributed energy resources over a period of years or decades.

Utility Energy Registry NewYork: Submitted By: Jim Yienger, Principal, Climate Action Associates, Johnsonville, NY

Climate Action Associates designed the Utility Energy Registry as a pilot project under the Climate Smart Communities (CSC) Regional Coordinators Pilot Program supported by NYSERDA. It reports that a market-driven approach to producing aggregate community-scale energy demographics tested during the Climate Smart Communities pilot has been successful. All utilities that they approached voluntarily engaged, including National Grid, NYSEG, RG&E, Central Hudson, ConEdison, O&R and LIPA. According to Climate Action Associates, this collaborative model effectively engaged planners and utilities in the process, and subsequently produced data for thousands of communities.

With the CSC Regional Coordinators Pilot Program now closed, Climate Action Associates is working with stakeholders to establish “The Energy Registry” (TER) as an industry-driven non-profit approach to foster continuous innovation in community energy demographics, much like the Green Button. Basically, the organization would facilitate an ongoing dialog with stakeholders to continuously define energy demographics, and would then work with utilities to help them publish their data to communities and to the public openly and free of cost through a central portal such as the Utility Energy Registry.

Climate Action Associates recommend first allowing utilities to engage voluntary market mechanisms like the TER, to determine if needs are being met. Industry-led approaches are far more cost-effective, and are more responsive for innovating standards in the face of an ever changing complex data environment. For example, energy policy innovators can engage the TER process to work with utilities and other stakeholders to create market-sizing demographics necessary to support policies during design. Furthermore, like Green Button, community data issues cross state boundaries and there will be interest nationally to standardize energy demographics.

In cases where a voluntary approach is not creating data acceptable to certain stakeholders, Climate Action Associates believes that, at that time, it makes sense for the Commission to engage and create a resolution.

Responses to three Questions in the Notice:

Q. How can utilities prepare and provide electronic access to customer data aggregated by municipality in a standard format, in an efficient manner?

Climate Action Associates agree with NYSERDA that energy demographics, especially those for public access, are best standardized and published to a central platform for consumers. This is a win-win all around.

Q. Should utilities be permitted to charge municipalities or other third parties for providing this aggregate data? If so, why, and how should those charges be determined?

The utilities have already provided demographic data free of charge, and that there is a good chance they will voluntarily continue to do so as communities continue to desire their help.

These public-interest products will assist utilities in being involved in community energy planning activities, and can serve as a gateway for them to engage communities on utility projects and programs.

Although TER would only support open and free data, Climate Action Associates support utilities charging for additional high-value derivative data products on a case-by-case basis. In the matter of Community Choice Aggregation (CCA), certain market sizing metrics (if not today) will likely evolve to be open demographics simply to cost-effectively meet widespread public interest demand. However, transactions needed to set up a CCA/ESCO may involve a series of labor intensive data services the utility could provide an ESCO or community on a cost basis.

Q. Should the Commission consider a privacy standard to ensure customer anonymity when aggregate energy date is released to third parties without customer consent?

Recommends that the Commission establish a flexible voluntary code of conduct that enables utilities to move forward. There are many approaches available, such as, aggregating data upwards to remove personally identifiable information (PII), and/or simply withholding specific data points that fail privacy screens such as the "4/80" example. Energy demographic data is low risk and the vast majority of data points developed during the CSC Regional Coordinator Pilot Program project would pass these screens, so even in some data must be withheld the set is still very rich.

Comment Summary
Second Technical Conference Held January 20, 2016

Citizens for Local Power (CLP): Strongly supports that utilities should be obligated to provide municipalities and their third-party consultants with aggregated data on energy usage at no cost. Aggregated data is essential for municipalities planning to create a Community Choice Aggregation (CCA), both for purposes of energy purchase and to plan and implement the more advanced form of CCA known as "CCA 2.0," which includes DER buildout. Municipalities introducing CCA 2.0 need to undergo a preparatory planning and evaluation phase before proceeding to form the CCA. As CLP has argued elsewhere, most municipalities in New York State, especially rural towns and villages and cities with large low-income populations, are not in a position to pay upfront for the data they need to explore the feasibility and undertake the implementation of an advanced CCA 2.0.

As Klaar de Schepper of Bright Power pointed out, utilities are already able to provide a significant amount of data to customers (and municipalities) without creating "fancy online platforms"; hence "there should be no extra charge to customers or the service companies they hire to…get access to this data." We agree with Ms. de Schepper that the data should not be delayed in expectation that more detailed data will be available in the future, for example following AMI implementation (pp. 48-49).

We agree with EnergyNext's Gordon Boyd (on behalf of MEGA), based on EnergyNext's extensive experience with CCAs serving tens of thousands of people in Illinois, that "the aggregate data for a municipality ought to be provided for free by the utilities" (p. 57). We also agree with Mr. Boyd's stress on the value of such data not only as the essential basis for moving forward with concrete projects, but also as part of mobilizing communities to become educated about, and to participate in energy planning. An informed public is as essential to "market animation" as it is to the reform of the energy system writ large.

Finally, we agree with the statement of Michael Murphy, of Con Edison and Orange & Rockland, who stated that basic level data should be provided for free (p. 76), and with Jennifer Spinosi of DirectEnergy, who affirmed that "We really don't think that municipalities should be paying to get their aggregated data" (p. 89).

What is important is that utilities are compelled to provide municipalities with all the non-personally-identifiable data that is at their disposal, promptly and in a standardized form. Municipalities that are considering implementing CCA 2.0 require this aggregated data both to investigate the initial viability of CCA and to develop a roadmap that lays out their future path to realizing the long-term economic and environmental value of DER investment.

CLP suggests that all data required to plan and implement a CCA should be provided without charge.

In the context of this striking degree of unity on the need for basic data to be made available at no cost – a matter we believe will decide the future viability of CCA in most of New York's communities – CLP particularly seeks clear confirmation from the PSC that the CCA demonstration "pilot" that is currently underway in Westchester County under the oversight of the PSC (Case 14-M-0564) does not provide a precedent in regard to payment for utilities' aggregated data. The "pilot," which is sponsored by Sustainable Westchester (SW), is the first CCA to be created in New York State. It includes significant upfront one-time data charges. For the success of CCA 2.0 State-wide, it is critical that this model not be generalized.

Thus, in a Petition of Sustainable Westchester dated April 23, 2015, in response to the PSC's Order Granting Petition in Part (dated February 26, 2015), Con Edison and NYSEG notified the PSC that they intended to impose the following charges: 1) a non-refundable administration fee of $.07 per record charged to SW; 2) a combined subscription and data service fee of $0.65 per record, billable by the Companies to the ESCO, and 3) a fee of $.35 per record to execute any additional request that may be made to the Companies" (p. 3).

Importantly, the Petition by Con Edison and NYSEG makes crystal clear that the charges they intend to levy are not intended to be precedential. The filing explicitly states that "because the SW CCA has been approved as a demonstration project, the fees below can and should be evaluated as the demonstration project moves forward. For this reason, the fees should not be afforded precedential value and should not be construed as being applicable to any other demonstration projects or CCA programs that may develop elsewhere in the

Companies' service territories…" – or, presumably, in the service territories of other utilities operating in New York State.

The upfront charges potentially associated with these agreements would certainly be prohibitive for upstate municipalities and it is quite clear that the per-customer fees imposed by Con Edison and O&R in Westchester would put CCA out of reach of most New York communities.

The experience of the California CCA projects that are underway in Sonoma County, Marin County, and San Francisco supports the importance of providing upfront aggregated data free or at most at reasonable cost. In California, data is provided either at no cost or at charges that are considerably less than those proposed by Con Edison and NYSEG. The most expensive aggregated data report currently available from PG&E costs $920.

The Technical Conference included a lot of discussion about whether utilities should continue to rely on the old, but reliable EDI system, and/or should introduce newer, more sophisticated data communication systems based on RESTful APIs, which offer better options for communicating with customers. CLP does not have a strong position on this question. We do, however, urge the PSC to use its powers to compel the utilities, as regulated monopolies, to provide communities with the data they need without delay and without waiting for a decision to be made about what future systems will be adopted. Utilities need not wait for the introduction of new functionalities to provide essential information to the public they were created to serve.

Finally, CLP would also like to draw attention to the discussion, during the January 20 Technical Conference, of Smart Meter Texas, a statewide information clearinghouse on energy that was cited by Ms. Spinosi, among others (pp. 99-102). CLP believes that this is the best approach for New York. A statewide clearinghouse would, among other things, provide standard and consistent formats for data availability. This would greatly facilitate the opening up of the DER market across different utility territories, as well as in areas where more than one utility is active. We urge the PSC to seriously consider this option. The demographic database introduced by Mission: Data at the December 16, 2015, Technical Conference on data provision, developed under the oversight of NYSERDA with assistance from Google technicians and the voluntary cooperation of New York utilities, offers a tantalizing glimpse of what could be possible if the PSC – benefiting from and building on the potential value inherent in the fact that New York has a single ISO – insists on the creation of a State-wide energy database or information clearinghouse.

Should the PSC decide *not* to require a State-wide energy database or information clearinghouse, CLP believes that it is of paramount importance for the PSC to develop, or cause the utilities to develop, State-wide standards and a unified set of parameters to ensure that data will be consistent and comparable across utility territories. Perhaps the Con Edison/ O&R demonstration project that is currently underway, working with OPower, which seeks to develop a freely available web platform combining RESTful APIs and Green Button Connect, can provide the prototype for a system that the State’s other utilities can build on, using a cooperative approach. In this context, we would like to point again to the NYSERDA-sponsored Energy Demographic Tier developed by Climate Action Associates and presented by Jen Manierre at the December Technical Conference – a project demonstrating that it is indeed possible, in New York, for a third party, in cooperation with the utilities, to gather the needed information and make it accessible to the public in usable formats on a uniform State-wide basis.

The cost of all such developments should be borne by the utilities (rate-based) or paid for out of public funds generated by the SBC. In the interest of proceeding in an efficient, State-wide manner, we suggest the latter option as more appropriate

Climate Action Associates LLC (CAA): Submitted By: Jim Yienger, Principal, Johnsonville, NY

Q. What are utility best practices in the U.S. regarding providing municipalities with their aggregated data load, including data transfer process and cost associated with transfer? Under what conditions should utilities charge for providing aggregated data information, including raw data, analysis, and assessments?

We believe the best model is in New York. The Utility Energy Registry (UER), implemented under the Climate Smart Communities program is the best model in the United States for providing municipalities with aggregated non-PII data load. This model simultaneously promotes standardization, process automation, high quality data, and eliminates burdensome transactions. It has been widely appreciated by communities as noted in the comments submitted by the Capital District Regional Planning Commission dated January 11, 2016. It also has the benefit of already having been developed and implemented in New York by utilities here.

We also note that the Metropolitan Washington Council of Governments (MWCOG) has been implementing a similar, though less formal, model to the UER. MWCOG serves the District of Columbia and numerous communities in Maryland and northern Virginia. It reached out to utilities and asked them to voluntarily report granular aggregate non-PII energy data by community and zip code. Like in New York, all utilities approached voluntarily agreed and have been supplying data to MWCOG for redistribution to communities for the last four years. This example, along with the UER work in New York, demonstrates that facilitated, centralized, and voluntary data production of community aggregate non-PII data is tractable nationwide even in the absence of regulation.

Utilities should be permitted to charge for aggregate data when providing that data would not be compensated for under traditional rate-based cost recovery. This is consistent with DOE DataGuard (Page 10) that states:

"*Allows the Service Provider to recover costs for Aggregated Data requests that are different from the method or format in which it generally offers aggregated data, represents the fulfillment of multiple requests, or is not based on commonly used data formats or standards*"

In New York, because the UER project defines common data formats, UER participation will offer a natural line for utilities to demonstrate to the market what they may be willing to produce systematically as part of routine operations versus what will constitute a custom service subject to additional cost recovery.

Q. As the Commission considers how its privacy requirements should be revised to reflect technology and market changes, should the Commission adopt the US DOE's DataGuard program as high level guidance regarding data privacy?

DOE DataGuard is a voluntary code of conduct intended to support utilities where detailed rules and regulations do not exist. It defines consensus principles, but is not a detailed technical implementation process for each state in every condition. Therefore, in this case, the Commission could provide utilities a window of time to create and submit custom Data Codes of Conduct that address key provisions. Many may opt to start with DataGuard as a foundation and modify it, or they may adopt it as is.

For aggregate data, DataGuard is an excellent resource. It lists privacy risk factors for aggregated data but correctly does not attempt to define exact actual numerical thresholds when preparing data. We believe that utilities are capable of creating detailed methods to manage data risks themselves. For example, in the case of the MWCOG cited above, PEPCO implemented an account aggregation threshold of five accounts across geographic aggregations.

East Coast Power & Gas, LLC (ECP&G): Submitted By: Natara G. Feller, Attorney, Brooklyn, NY

ECP&G supports Community Choice Aggregation ("CCA"). In order for CCA programs to truly succeed, and maximize participation from competing ESCOs, it is essential that the supporting infrastructure provide aggregated customer data in a simple, easy to understand format, and made available to ESCOs responding to RFPs for CCA at no cost.

The January 20th Technical Conference raised many critical questions and provided new information about the type and amount of data required for municipalities that seek to introduce Community Choice Aggregation. ECP&G supports Gordon Boyd's opinion, expressed at the Technical Conference, that aggregated data should be provided for free to ESCOs in an easy to understand and workable manner. This data would not include customers in an existing relationship with an ESCO. Access to this data would ease the financial burden on ESCOs while providing them with the critical information needed to most effectively serve customers.

ECP&G also lends its support to the previous comments of National Energy Marketers Association ("NEM") and Direct Energy Services, LLC ("Direct"), that ESCOs need usage data that is accurate and timely, eventually moving to real time data access. This data should be provided with hourly, interval, billing quality data on a monthly basis via EDI, and should be free, regardless of how that information is provided to the ESCO.

Additionally, ECP&G supports MEGA's view that utilities should not charge municipalities, or third parties acting on their behalf, for aggregate energy data. This will advance the objectives of both REV and community choice aggregation.

IGS Energy: Submitted By: Katie Bolcar Rever, Director Leg & Reg. Affairs, Dublin Ohio

Providing consumers access to their own energy data, and vendors access to customer-specific data with customer authorization.

Utilities should not charge to provide customers with access to their own basic energy data. This should be standard information that is freely available to all consumers.

Utilities should also not be the 'gatekeepers' to consumer data, allowing certain select third party vendors, chosen by the utility, to analyze consumer data which can be used to offer products to customers. This would lead to an oligopolistic market where only a small handful of select large companies have streamlined access to consumer data and can analyze this data and innovate products and customer engagement.

Even if the providers or installers of such products and services would be competitive providers (i.e. non-utility) utilizing only one company to serve a product portfolio via the utility platform is still anti-competitive and will stymie product development. Access to the utility platforms, and customer data, should be made available on a competitively neutral basis to all companies that are willing to pay reasonable fees and subject themselves to consumer protection rules.

Customers have different types of usage patterns, and different products will be most effective at helping different customers to adjust their usage and respond to price signals from the grid. To achieve the REV vision, the Commission should develop processes for third party vendors to have streamlined access to consumer data in order to allow them to analyze the data, innovate products and services, and target the products to fit the specific needs of individual consumers.

To the extent that utilities charge third parties for access to consumer data, such charges should be based on cost-of-service, overseen by the Commission, and used to offset revenue requirements that would have otherwise been borne by all ratepayers – otherwise known as Platform Service Revenues or 'PSRs'. Utilities should not use consumer data or any analytics of consumer data to establish Market-based Earnings (or 'MBEs'). Utilities have unique access to consumer data because of their status as a state sanctioned monopoly. For these reasons it is important to put appropriate protections in place to ensure utilities do not abuse their market power and a competitive market is established for REV type products.

Privacy and Security Issues Concerning Customer Data

A. Opt-Out Customer Data Lists

IGS recognizes that the assumption going into the technical conferences is that third party vendors would only have access to consumer data on an opt-in basis. We strongly support robust consumer protection in order to ensure that third party vendors act responsibly and operate in the best interest of customers. We posit, however, that with appropriate consumer protections, the Commission should provide third party vendors with access to consumer data on an *opt-out* basis, enabling third parties to provide more robust consumer engagement by targeting products to consumers that are tailored to their unique needs.

States such as Pennsylvania and Ohio provide certified Energy Service Companies ('ESCOs') with customer lists that contain such data and we have not seen issues of abuse arise. Further, in states such as Pennsylvania and Ohio, certified ESCOs are able to utilize customer lists with high level energy consumption data (e.g. monthly consumption and capacity tags) to identify energy efficiency and demand response opportunities for customers up front, resulting in more efficient and targeted enrollment of customers in energy efficiency and demand response products.

IGS would support additional oversight on third parties that wanted such access, including certification requirements, in order to ensure that these third party providers do not share the data with any outside entities and use the data to only offer relevant products and services. Further, any certified entity wishing to receive customer lists with high level energy consumption data should be subject to strictly enforceable agreements prohibiting sharing of customer consumption data with third parties. As stated in our previous comments, if the Commission is not comfortable offering this for residential consumers, it could start with the commercial and industrial segments which tend to be more sophisticated energy users.

B. DataGuard

IGS agrees with many of the parties at the technical conference who said that it is not appropriate to adopt DataGuard in whole cloth. For one, DataGuard does not allow for the ability to provide consumer data on an 'opt-out' basis.

Additional Issues on Access to Consumer Data

IGS would like to take the opportunity in this 'catch all' question to highlight the importance of appropriately adjusting an ESCO's NYISO settlement statement to reflect the actual usage of the customer in order to facilitate REV objectives.

Currently residential customer usage is profiled meaning residential customers are assigned capacity tags based on the average residential demand for the class, as opposed to assigning capacity based the individual customers demand. Further, for non-interval metered customers, NYISO settlement statements only reflect profiled electric consumption based on the average time of use for the customer class, and not actual time of use of the customer. Unless utilities begin using actual residential customer demand data to calculate residential customer bills ESCOS and DER providers will not be able to develop innovative products and services to allow a customer to monetize grid-enhancing behaviors and investments.

In other words, utilities should cease profiling customer energy, capacity and transmission usage. ESCOs have the ability to offer customers products and services (either demand response or distributed generation) that will reduce their usage during peak demand hours (usually between the hours of 4:00 pm and 6:00 pm). But customers (and their ESCOs) will not get "credit" for their efforts to the extent that customer bills and supplier NYISO settlement statements are performed based upon load profiling methodologies. For example, when a utility performs settlements and billings based upon profiling methodologies, a customer that shifts their energy usage to off-peak times may have the same capacity peak load contribution and hourly energy usage as a customer that turns on all their appliances when the grid is most stressed. Thus under the current billing methodology there is no incentive for the customer to shift energy consumption to off-peak periods because the customer gets no credit for doing so.

To the extent upgrades in the utility metering and IT infrastructure are required to begin utilizing actual customer usage for billing, IGS believes this is a worthy investment. The utility of the future should be billing customers based on the customers actual granular usage patterns (and not profile based on class averages) as this will only help to promote more efficient use of energy and gird infrastructure.

Finally, IGS emphasizes the importance of enabling third parties to have streamlined access to consumer data – with appropriate consumer protections – in enabling the REV vision. The role of third parties in animating and engaging consumers cannot be under estimated, and the Commission should guard against oligopolistic outcomes where utilities and a few 'chosen' third parties are able to analyze consumer data and engage consumers in order to offer products to customers.

Joint Utilities (Collectively "National Grid"): Submitted By*:* Kerri Kirschbaum, Senior Attorney for ConEdison, New York, NY

I. Providing customers data, and customer-specific data to vendors with customer authorization

The Utilities supported providing customer data to both customers and third parties; agreed that sharing energy consumption information can enable customers to better manage their usage and assist third parties to develop tailored offerings to customers; and explained that the method for providing customer-specific and aggregated data must be determined by evaluating a variety of factors for each utility, including, but not limited to, meter infrastructure, customer service systems, website capabilities, and service territory.

Con Edison and O&R, based on an evaluation of the factors above, as well as other factors, have specifically evaluated representational state transfer application program interfaces ("RESTful APIs") as a means of enabling customer-driven data sharing as well as usage data transfers to interested energy service companies ("ESCOs"). Con Edison and O&R support the use of RESTful APIs because they are capable of transferring granular usage data (including both billing-quality data and raw meter data) in machine readable format and are used extensively across industries. Additionally, Con Edison has recently proposed implementation of Green Button Connect My Data, a nationwide standard for data exchange that relies on RESTful APIs. One of the many important factors driving this proposal is

Con Edison and O&R's proposals to implement Advanced Metering Infrastructure ("AMI") throughout their respective service territories and a planned complete redesign of Con Edison and O&R's website and digital customer experience.

Other utilities may not be in the position to propose implementation of Green Button Connect My Data protocol or RESTful APIs, especially in terms of their stage of AMI adoption. For example, as a gas-only utility National Fuel may never be in a position to implement AMI system-wide if no more than a relative handful of customers place value on the information beyond its market usefulness. Given the many factors to consider when determining how best to provide customers with access to their data, and share customer data with customer consent, each utility should be permitted to carefully evaluate the appropriate methods for providing data to their respective customers and third parties and the means by which data is made available, i.e., Electronic Data Interchange, RESTful APIs, or any other technology.

The Joint Utilities also incorporate by reference the reply comments submitted by Con Edison, O&R, Central Hudson, Niagara Mohawk Power Corporation d/b/a National Grid, NYSEG and RG&E to Staff's Distribution System Implementation Plan ("DSIP") Guidance proposal, filed on January 6, 2016. In those comments, the Joint Utilities noted that "stakeholder engagement is necessary to reach consensus on which customer data and system information provide value to customers and/or third parties, assure customer privacy and system security, and can be provided by the utilities at reasonable cost. The provision of customer data and system information will likely require a prioritization of efforts and a staged approach to close capability gaps that exist today." Because the issues highlighted during the Technical Conference are complex and cannot be resolved all at once, the Joint Utilities note that resolutions to these issues will necessarily evolve as the market evolves. The Joint Utilities therefore recommend continued collaboration on data access and sharing as part of the Supplemental DSIP stakeholder process.

With respect to whether utilities may charge a fee for certain customer-specific or aggregated data, the Joint Utilities again point to the January 13, 2016 utility comments. A basic level of data should be provided to customers or their designees without charge. Utilities should be permitted to set value-based charges for requests for customer information that are above and beyond the basic data, which is more granular and/or frequent. The Joint Utilities believe that such charges should not necessarily be cost-based, consistent with REV Track 2 concepts outlined by Staff in the July 28, 2015 Staff White Paper on Ratemaking and Utility Business Models ("Staff White Paper"). The Staff White Paper explains that "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 is more equitable as it more closely attributes the value of providing premium data services to the customers or vendors that receive them, resulting in fewer costs that must be socialized among all customers. The basic level of data provided at no charge to customers and their designees will continue to be defined. However, it should be noted that both the basic level of data provided at no charge and the kind of granular data provided for a fee may, in fact, evolve over time as technology, customer expectations, and necessity dictate. Further, differences in utility service territories8 and whether the information provided pertains to gas or electric service may also play a role in determining whether the cost of providing data should be socialized or borne by those who place a premium on the content.

Finally, at the Technical Conference, it was suggested that utilities be precluded from providing information, tools, analysis and/or assessments for customers. The Joint Utilities strongly disagree. The Joint Utilities have historically provided and continue to provide customers with a variety of information, tools, analyses, calculators, etc. to help customers better manage their energy use and make informed decisions about energy services. Customers should have the choice whether to obtain such information from their utility or from a third party.

II. Privacy and Security Issues Concerning Customer Data and DataGuard

The Notice also requested that interested parties comment on whether the Commission should adopt DataGuard, a voluntary code of conduct related to a commitment to protecting the privacy of customer energy usage data by utilities and third parties. The process of developing the voluntary DataGuard was a multi-year utility industry facilitated by the DOE in collaborative with the Federal Smart Grid Task Force, and the final concepts and principles were released in January 2015. DataGuard describes principles for voluntary utility and third party adoption that it claims: (1) encourages innovation while appropriately protecting privacy and confidentiality, (2) provides appropriate customer access to their usage data, and (3) does not infringe upon applicable laws or regulations. The Joint Utilities believe there may be value in many of the high level principles outlined in DataGuard that the Joint Utilities can support. However, after a preliminary review of DataGuard, the Joint Utilities oppose any Commission action that would take a code of conduct intended to be voluntary and make it mandatory, even at a high level, as a guidance document. DataGuard's strength is as a voluntary, flexible tool – the very aspects that make it broadly applicable to different organizations make it inappropriate for use as a specific regulatory requirement.

A. The Commission must holistically review DataGuard in combination with other rules, policies and procedures.

The Joint Utilities take customer privacy and data security very seriously and work diligently, through systems, policies and programs, to maintain security and customer privacy. It is important to note that while both of the Technical Conferences in these proceedings have been focused primarily on customer-specific energy usage information and aggregated usage information, the Joint Utilities' privacy policies and procedures govern far more information, including payment information, status of participation in utility low income programs, system information, employee information, and other customer-specific data points. Utility policies and procedures have developed over time considering all varieties of information and in accordance with applicable state and federal law, as well as Commission policies and orders. Each of the Joint Utilities have implemented privacy policies and apply best practices available in various privacy frameworks, including National Institute of Standards and Technology ("NIST") Privacy Principles, Generally Acceptable Privacy Principles ("GAPP"), and others.

The Commission has also previously addressed the privacy of customer data. For instance, in August 2013, in its *Order Directing the Creation of an Implementation Plan* in Case 13-M-0178, the Commission required all New York State utilities to undertake a comprehensive review of their protection of personally identifiable customer information. This review included having a third party annually assess the utilities practices, systems and programs. In addition, there have been several other orders and policies from the Commission related to privacy of customer information, including its December 3, 2010 *Order on Rehearing Granting Petition for Rehearing* in Case 07-M-

0548, and Staff REV demonstration project reports, discussing the need to keep customer energy usage data confidential. The Joint Utilities strive to protect this information appropriately. Beyond Commission jurisdiction, the Joint Utilities recognize that the Federal Trade Commission, as well as other state and federal agencies, can investigate and take enforcement actions against companies related to consumer protections and privacy-related matters. Therefore, when considering the merits and details of DataGuard, the Joint Utilities and the Commission must also take into careful consideration existing state and federal laws, rules and regulations, as well as Commission policies and orders.

Importantly, it appears that the drafters of DataGuard were keenly aware of these complexities and the potential for overlap of rules, regulations, and policies. Indeed, DataGuard specifically described itself as primarily a document that can be useful to entities not subject to regulation by applicable regulatory authorities. Given the extensive regulatory paradigm under which the Joint Utilities operate, as well as the potential for overlap and/or conflict in varying rules, regulations, and procedures, DataGuard should be evaluated in a context where all data security and privacy-related issues are fully considered. Utilities must review all the systems, standards, policies and procedures they have in place to determine how DataGuard might enhance their existing frameworks for data protection.

B. DataGuard should remain a voluntary code of conduct.

DataGuard is a voluntary code of conduct that appears to have been written with a deliberate level of ambiguity and flexibility that allows entities room to interpret its provisions in a reasonable manner. The most critical ambiguity in DataGuard is the lack of clarity around the definition of primary versus secondary purpose. DataGuard applies different policies for the exchange of information based on whether the exchange has a primary or secondary purpose. DataGuard defines primary and secondary purpose as follows:

> **Primary Purpose**
> The use of Account Data or Customer Energy Usage Data (CEUD) that is reasonably expected by the customer: (1) to provide or reliably maintain customer--initiated service; and (2) including compatible uses in features and services to the customer that do not materially change reasonable

expectations of customer control and third party data sharing.

Secondary Purpose
The use of Account Data and CEUD that is materially different from the Primary Purpose and is not reasonably expected by the customer relative to the transactions or ongoing services provided to the customer by the Service Provider or their contracted agent.

Based on these definitions, it is unclear whether many of the utilities' current practices would be considered primary or secondary uses. Moreover, there may be uses that develop as part of REV and the DSIP process that may be considered secondary purposes under DataGuard, requiring a customer-controlled consent process and opportunities to opt out. This may be inconsistent with current or anticipated Commission initiatives. This potential inconsistency was echoed during the Technical Conference by Navigant, a proponent of DataGuard:

> Today probably an end customer would view a primary use of data as mainly around billing and service maintenance outage and restoration, those kind of operational uses. But as DER becomes more mainstream, more widely dispersed on the grid, it becomes more of a requirement to meet things like clean power plans. I think you could make the case that sharing data for information on valuing DER on the grid could become a primary source of data, versus a secondary source that it may be today. (Technical Conference Transcript, p. 126, l. 11-19).

Additional examples of concerns with ambiguity in DataGuard are described below. For instance, it requires that "contracted agents" have contractual obligations "comparable" to those of the service provider. It is unclear what is meant by "comparable" and until the definition is clarified, the utilities are unable to evaluate all existing agreements with third parties and vendors – including recently-signed agreements related to REV demonstration projects – so that contractual obligations match those ultimately required. DataGuard also requires that notice about privacy-related policies be sent at service startup, on some recurring basis (annually), upon customer request, and when a significant change in procedure or ownership occurs. However, "significant change" is not defined. Moreover, DataGuard requires that the consent process be "cost-efficient," which is subjective and unclear.

These ambiguities can lead to confusion and difficulty in interpreting DataGuard. If the Commission adopts DataGuard as even high-level guidance, the ambiguities pose an unacceptable risk to entities that will be required to comply with the DataGuard. Therefore, before DataGuard is considered for adoption as even a high level guidance document, there must be a review and discussion as to how the Commission and the parties would define ambiguous terms and phrases in DataGuard.

There may also be significant compliance costs associated with DataGuard. The Commission, stakeholders, and utilities would need to evaluate each aspect of the detailed provisions of DataGuard, review the ability and cost of compliance, review the process and cost associated with modifying practices, and the potential need to modify existing contracts with vendors. For instance, DataGuard requires that utilities maintain records identifying what customer data has been shared, when it was shared, with whom it was shared and maintain that information for as long as it exists in the third parties system. If the utilities are required to comply with DataGuard, they should be permitted full cost recovery for any system or process changes required to comply with DataGuard.

C. DataGuard's notice requirement to customers could result in customer confusion.

DataGuard's notification obligations require that its adoptees "provide[] complete, accurate, and timely notice to customers whose Customer Data may have been compromised while within the Service Provider's control or within the control of the Service Provider's Contracted Agent, and remedy[] those condition which led to the breach." (4.0.d). This standard is greater than the standards included in New York State law for breach notification and in fact, greater than the obligations imposed by any state or the federal government. The Joint Utilities do not believe that notifications should be provided when data *may* have been compromised. Continued notification of non-events could result in customer confusion in that a utility may send out a notice of potential compromise only to retract it to say that there was no compromise. Notification should be limited to instances of an actual compromise, not for a potential compromise.

Finally, the Joint Utilities should not be required to adopt DataGuard at this time. Prior to any action related to adopting DataGuard, there should be a collaborative effort to evaluate the specific details of DataGuard holistically along with all other existing laws, rules, regulations and orders to determine appropriate data privacy standards for New York State. If the Commission does adopt DataGuard at this time, a reasonable implementation period (i.e. 2-5 years) should be established so that the utilities can appropriately evaluate DataGuard and utilities should be permitted cost recovery for implementation costs and ongoing monitoring costs associated with DataGuard.

Local Power Inc.: Submitted By: Paul Fenn, President, Comptche, CA.

Q. Should vendors seeking to be provided customer data through Green Button Connect, or an alternative protocol, be considered a Distributed Energy Resource Provider, as defined in Staff's Proposal in Case 15-M-0180? If so, which, if any, of the rules proposed by DPS Staff in that proceeding should not be applicable to vendors seeking to obtain customer data through the Green Button Connect or alternative protocol? If Vendors seeking to be provided data through Green Button Connect or an alternative protocol should not be subject to the rules developed in Case 15-M-0180, what requirements or oversight should be applicable to those vendors?

Local Power Inc. agrees with the City of New York that as a rule, the Commission should create two different sets of rules and procedures for access to confidential customer data – one for commercial entities or market participants providing services for purposes of obtaining a profit, and another distinct set of rules for local governments such as Community Choice Aggregations, that are formed democratically for a public purpose:

"In formulating an oversight construct, the Commission should recognize that residential and commercial consumers require different levels of protection, especially as they pertain to third-party vendor access to consumer energy usage data. The Commission also should account for the nature of the third party and how it intends to use the data. For example, the same rules should not and need not apply to municipalities seeking data for benchmarking and planning purposes and to DER providers seeking to sell energy-related products or services to consumers." (New York City, COMMENTS OF THE CITY OF NEW YORK ON AGGREGATE ENERGY USAGE DATA, January 13, 2016, p.3). California's CCA data rules adopted by the California Public Utilities Commission (CPUC) in December, 2004 (D.0412-046, December 16, 2004, Mailed 12/21/2004), provide that, whereas any other party seeking customer data must obtain the express permission of customers in order to collect data, CCAs may obtain the same aggregate and detailed confidential data at cost from utilities based upon written request, without any restrictions, provided they sign nondisclosure agreements.

The CPUC's reasoning was that CCAs are governed by local elected officials and subject to state public meeting laws, that use the data to benefit the public, are already entrusted with a variety of forms of confidential data by state and federal governments, and may be trusted to keep electricity end-use data confidential, subject to a Commission requirement that each CCA official or government agent that handles confidential data be required to sign a standard nondisclosure agreements with the utility releasing it. CCA commercial counterparties are not allowed to see the confidential parts of received CCA data until the CCA opt-out period has commenced, signaling the participation in programs that define "choice" through a local public decision followed by an opt-out process, rather than an affirmative marketing choice of each consumer.

In the state's CCA law, AB117, also written to augment DER developments, the California legislature contextualized access to data in the need not only to operate CCAs, but to investigate them, pursue and negotiate them, and launch them, meaning *access to detailed data early on is important for designing programs in advance of contracting them out to service providers.*

CCAs must have certain types of information in order to plan their procurement strategies, assess the viability of offering energy services, and to contact customers, anticipating the needs of CCAs for certain types of customer data and information, as outlined in AB117:

> "All electrical corporations shall cooperate fully with any community choice aggregators that investigate, pursue, or implement community choice aggregation programs. Cooperation shall include providing the entities with appropriate billing and electrical load data, including, but not limited to, data detailing electricity needs and patterns of usage, as determined by the commission, and in accordance with procedures established by the commission." (California AB117 - Chapter 838, Section 366.2(c)(9)), 2002).

In its discussion of the question, the CPUC said AB 117 is clear in its intent to require the utilities to provide CCAs all customer and usage data that is relevant to CCA operations even before the CCA begins offering service. In addressing the informational needs of CCAs, Section 366. 2(c) (9) provides that the utilities shall "cooperate" with CCAs that "investigate or pursue" CCA programs. Because a CCA is most likely to "investigate or pursue" CCA programs before it begins offering service, we read the plain language of the statute to mean relevant information must be provided on demand, without distinguishing between a customer who is still with the utility or a customer of the CCA or between the time a CCA is created and the time it provides service. By law, CCAs are entitled to receive certain types of information as long as they are investigating, pursuing or implementing a CCA program.

CCAs also need the confidential part of the end-use meter data for the simple launch of programs, namely the names and addresses and billing information for customers to undertake the opt-out enrollment process that defines CCA.

"Section 366.2(c)(13) (A) supports this finding in its requirement that CCAs provide opt-out notifications to prospective customers prior to cut-over. Although Section 366(2)(13)(B) gives the CCAs the option to request utility assistance with the notifications, each CCA must assume ultimate responsibility for the notices. The CCA cannot satisfy this responsibility without access to customer names and addresses. Thus, if the Legislature had intended for customer information to remain with the utility, it would have not required the CCA to issue the opt-out notices." (CPUC, Decision D.04-12-046, December 16, 2004, p.50.)

***Q. How can utilities prepare and provide electronic access to customer data aggregated by municipality in a standard format, in an efficient manner*?**

The kinds of data needed for a CCA preparation consist of two elements: aggregate data that is needed for early phase evaluation of overall program economics, and detailed data needed during the RFP or negotiation phase prior to implementation plan preparation for DER program design. Many of these are lacking in PG&E's tariff, but should be required standard items on New York state utility CCA data tariffs in addition to any special requests, in order to reduce transaction costs for the utilities and minimize the payment burden on local governments implementing CCA. The types of data that should be included on New York utilities' CCA data access tariffs should include the following forms of data:

A. Aggregate Power Data (free of charge)

1) Aggregate monthly usage (kWh) by rate schedule: energy consumption (kWh) for the most recent 60 months of complete information for each customer class for a given period of time for each municipality in CCA service territory that is in the utility service area.

2) Aggregate monthly usage (kWh) by zip code within a city code.

3) Where applicable, residential, small commercial, large commercial and government kWh usage aggregated according to Time of Use (TOU; in cases where historic data is available) rates or other meter-specific rates, and further separated by summer/winter peak, partial peak, and off peak periods and summer/winter period, as available.

4) Designation of which rate schedules are included as "non-commercial" in the utility's Market Supply Adjustment Mechanism since five years prior to the data request.

5) Estimation of peak coincident and non-coincident demands by sector for the CCA's service territory.

6) Number of service agreements in each rate schedule within the CCA service territory.

7) The number of customers by class, including indication of numbers in each class that are currently provided electric and/or gas supply service from an ESCO.

8) The aggregate gas and electric usage of all customers, by class served, for the 60-month period preceding the request.

9) The system peak hour, or hours, that determines capacity buying requirements, and to the degree that it is available the aggregated load factor by class served for the 60-month period preceding the request.

10) Total kWh loads of utility customers and customers receiving ESCO service, first on a monthly basis and second,

annually on a rate schedule basis within the CCA service territory, for the past sixty months.

11) Annual aggregate spending by utility customers and customers receiving ESCO service for energy supply for the past sixty months.

B. Power System Data

1) System-wide residential and non-residential load shapes by New York Load Zones and New York Control Area designations for the most recent sixty months for which the utility has complete information.

2) Standard system average load profiles by rate class, also referred to as Dynamic Load Profiles and Static Load Profiles, within the CCA service territory.

3) Data fitting the CCA service territory's annual usage to New York ControlArea load shapes; estimation of peak coincident and non-coincident demands.

4) Distribution grid data that could impact the siting of distributed generation or demand-side assets, in a GIS format including shape-files and any associated datasets.

5) All electricity usage data, account address and telephone number, latitude and longitude of meter and meter number at the shortest time-interval recorded by interval meters on all Central Hudson distribution systems within Ulster County in the past sixth months, including substation dynamic load data, latitude and longitude of meter and meter number.

C. Customer-Level Data: ELECTRIC (reasonable cost-based charge)

1) Customer-specific information from the current billing periods, as well as the prior sixty months, consisting of the following: account name, account address, account telephone number, meter number, latitude and longitude with zip code, monthly/bimonthly kWh usage, monthly maximum demand where available, Baseline Zone, low income residential participation (Home Energy Assistance Program or HEAP), End Use Code (Heat Source), Service Voltage, Medical Baseline, Meter Cycle, Bill Cycle, Level Payment Plan and other plans, HP Load and Number of

Units, monthly rate schedule for all accounts within the CCA service territory.

2) Mapping of customer rate schedules to rate classes.

3) All monthly unbundled rate components and charges for each meter.

D. DER Power Build-Out Data

1) Quarterly or monthly aggregated participation data for the utility's energy efficiency programs.

2) All energy efficiency program data for each customer (by account number, service ID number, address, latitude/longitude, etc.), listing all recorded activity and information, including but not limited to on-site or online audits, benchmarking, retro-commissioning, and energy use analyses and efficiency recommendations, and paperwork filed by customers or contractors, and financing information, as well as any associated data sets such as building information on tenant/owner occupancy, square footage and year built, and/or rebate code and measure tables, as available.

3) Demand response program participation, when available, and all relevant metrics recorded for these programs.

4) The type of interconnection agreement and all relevant metrics associated with customers who have already interconnected distributed generation to the distribution utility's distribution grid.

California Public Utilities Commission Regulations Governing Utility CCA Data Access Tariffs

We recommend California's approach both in law and the CPUC's adopted rules. In order to ensure unlimited CCA access to data, the CPUC decided that CCAs are "entitled to any and all billing data that is reasonably useful to the CCA, including detailing electricity needs and patterns of usage:

"In addition to its requirement that utilities provide information to CCAs before and after they initiate operations, AB 117 specifies the types of information the utilities must provide to CCAs. Section 366. 2(c)(9) refers to "appropriate billing and electrical load data, including, but not limited to, data detailing electricity needs and patterns of usage.” The statute specifically refers to “billing” data as distinct from “electrical load data.” We are not aware how aggregated or masked billing data could satisfy the statutory requirement.

Again, the plain language of the law means that the CCA is entitled to any and all billing data that is reasonably useful to the CCA. It also refers to information “detailing” electricity needs and patterns of usage.” (Decision 04-12-046, December 16, 2004, p.51)

The CPUC even provided for CCAs to request data beyond detailed meter data and aggregate data, and established a complaint procedure for CCAs when utilities refuse based on their participation in retail energy markets and need for competitive secrecy:

“We also agree with PG&E that confidential information about a utility’s market, market strategies, procurement efforts or contracts (as addressed in R.04-04-003) is probably not among the types of “appropriate” information to which CCAs are entitled. If a CCA seeks such information and the utility objects to its provision to the CCA, we will consider this disclosure on a case-by-case basis in this proceeding. Hopefully, as PG&E suggests, we will ultimately have a list of the types of information that are automatically available to CCAs and the types of information that would not be available to CCAs. This list can more readily be developed after the utilities gain experience with the CCA program.”

The CPUC anticipated utility noncooperation, threatened to enforce rules with penalties, and clarified that utilities may not decide what data is deemed “relevant,” which is left to CCAs to decide:

“Finally, we state our intent to enforce the law with respect to its requirement that the utilities “cooperate” with CCAs in the provision of all relevant information, a term which we interpret broadly. The utilities may not determine what information is “relevant” to CCA operations as long as the utility is reimbursed for the reasonable costs of providing the information. While we welcome the utilities’ tariff proposals for the secure and cost-effective sharing of information, we will not tolerate utility actions or delays that may affect the provision of information to CCAs or CCA services to customers.” (p.53).

Q. Should utilities be permitted to charge municipalities or other third parties for providing this aggregate data?

We agree with Citizens for Local Power that utilities should not be permitted to charge for aggregate data:

"Utilities should not be permitted to charge municipalities for providing aggregatedata the municipalities need to plan for and introduce CCA…. Charging for the upfront planning data will decisively prevent most municipalities, particularly those in rural New York or with large low- and middle-income populations, from undertaking the necessary planning for a CCA 2.0, thus severely limiting the adoption of this more comprehensive, REV-compatible type of energy reform across the State. Whereas wealthier counties or towns may be confident about launching a CCA program without a plan, such an approach will not appeal to the poorer communities that make up the vast majority of our populace. Rural towns and cities with large low- and middle-income populations are very unlikely to take the step of forming a CCA without a plan that demonstrates concretely how DER can contribute to their reliability, resilience, and economic development at a cost that is affordable or at least can be expected not to exceed the costs of doing nothing."

(COMMENTS OF CITIZENS FOR LOCAL POWER ON THE TECHNICAL CONFERENCE REGARDING CONSUMER AND AGGREGATED ENERGY DATA PROVISION AND RELATED ISSUES, January 13, 2016).

As indicated above, the California Public Utilities Commission adopted the principle that utilities could only charge for the "reasonable cost" of preparing the data – which turned out to be no charge for aggregate data, and transactional charges for transfers of multiyear histories of meter-read data charged by the request rather than the account, reflecting the fact that the request or transaction causes the cost, not the number of accounts or number of years of data requested, that incurs costs.

Local Power Inc. recommends adoption of a per request pricing structure, an example of which is Pacific Gas & Electric's data tariff, which provides aggregate data free of charge, and charges detailed data based on cost at fairly reasonable (though not insignificant) rates. While Local Power Inc. would like more data to be made available than PG&E's current tariff for DER purposes, this tariff does provide a normative sense of how certain kinds of data are priced based on the transaction or cost of preparation of a cd containing data exported from one or more utility databases. Following is the current list of PG&E's charges for data it currently makes under its current CCA-INFO tariff:

"APPLICABILITY: This schedule applies to: 1) Community Choice Aggregators (CCAs) who participate in Community Choice Aggregation Service (CCA Service), as defined in electric Rules 1 and 23; 2) communities who wish to explore CCA program implementation, and 3) eligible entities under California Public Utilities Code Section 331.1 that are considering CCA service.

TERRITORY: The entire PG&E service territory.

RATES:

1. Aggregate monthly usage (kWh) by rate schedule. No charge for the first request PG&E will provide the CCA with energy consumption (kWh) for the most recent 12 months of completed information for each customer class for a given period of time and a given city. PG&E will aggregate monthly usage by rate schedule. Additional requests for this information will be provided at the CCA's expense. (See Item 6, below.)

2. Annual proportional share of energy efficiency funds for a CCA's proposed territory as defined in the CPUC's energy efficiency policy manual - No charge

3. System wide residential and nonresidential load shapes by climate band for the most recent year for which PG&E has completed information - No charge

4. Standard system average load profiles by rate class also referred to as Dynamic Load Profiles & Static Load Profiles posted to PG&E's website. Available at no charge at PG&E's website

5. Quarterly or monthly aggregated participation data already tracked for CPUC reports (for energy efficiency programs). Available at no charge at PG&E's website.

6. Aggregate monthly usage (kWh) by rate schedule, first request is at no charge (See Item 1, above) Per request $207.00.

7. Aggregate monthly usage (kWh) by zip code within a city code - Per request $207.00.

8. Public Goods Charge customer payment by city code - Per request $350.00.

9. Number of service agreements in each rate schedule within a CCA’s territory or proposed territory - Per request $207.00.

10. Mapping of customer rate schedule to rate class. No charge

11. Estimated annual generation revenues by CCA territory - Per request $207.00.

12. Estimation of peak coincident and non-coincident demands. Items 1 and 3 provided to customer.

13. Fitting CCA annual usage to climate band load shapes; estimation of peak coincident and non-coincident demands - Per request $696.00.

14. Total annual kWh loads of bundled and direct access customers on a monthly basis and secondly on a rate schedule basis within the CCA’s territory - Per request $920.00.

15. Aggregated residential annual kWh usage for a particular year in a format by tier for each rate schedule. For the TOU rates, provide further separation by summer/winter peak, partial peak, and off peak periods and summer/winter period - Per request $920.00

16. Customer-specific information from the current billing periods as well as prior 12 months consisting of the following billing information: meter number, service agreement number, name on agreement, service address with zip code, mailing address with zip code, telephone number, email address where available, monthly kWh usage, monthly maximum demand where available, Baseline Zone, CARE participation, End Use Code (Heat Source), Service Voltage, Medical Baseline, Meter Cycle, Bill Cycle, Balanced Payment Plan and other plans, HP Load and Number of Units, monthly rate schedule for all accounts within the CCA’s territory, per request. In addition, PG&E will provide the CCA the following additional information regarding customers currently enrolled in its CCA service: current and historical billing information for non CCA Services provided by PG&E or other service providers (provided on acd rom/zipped file). Per request $920.00.

17. Customer-specific information consisting of: service agreement number, monthly interval meter data where available, and rate schedule for all accounts within the CCA's territory, per request (provided on a cd rom/zipped file). Per request $920.00".

(Pacific Gas & Electric, "Electric Schedule E – CCAINFO Sheet 1," Revised Cal. P.U.C. Sheet No. 32786-E, Filed August 29, 2013).

Q. Should the Commission consider a privacy standard to ensure customer anonymity when aggregate energy data is released to third parties without customer consent?

Local Power Inc. recommends that the Commission adopt a policy framework similar to California's, which is the only state with CCA laws and regulations designed to support DER such as energy efficiency and renewable distributed generation. The data rules in all other CCA states (OH, IL, NJ, MA) reflect their lack of concern about DER and their singular focus on conventional grid-supply, RECs and discounts. California, which like New York is focused on DER development, made very deliberate decisions to entrust CCAs, unlike other "third parties" such as commercial suppliers, and ESCOs, with confidential end-use meter data, and to exempt CCAs only from rules restricting commercial party access to customer data. (Rulemaking R.03-10-003 had two major decisions, Phase I and II in 2004 and 2005, with the data rules adopted in the first Phase decision).

The California Public Utilities Commission decided that CCA's local democratic deliberation adopting CCA by ordinance in public hearings constitute customer consent under this form of choice: that "the customers for whom the CCA seeks information have implicitly agreed to permit the CCA to aggregate their energy requirements and offer service." (Decision 04-12-046, December 16, 2005, p.50). The CPUC, moreover, makes a clear distinction that CCAs are not mere "market participants" like ESCOs that may not be trusted not to abuse confidential data, and need the data in order to realize the potential benefits of CCA through program design to make fully *informed decisions regarding energy procurement, service requirements and resource planning decisions*:

"We believe AB 117 assumes, as we do, that CCAs can be entrusted with confidential customer information. Unlike energy service providers offering direct access, CCAs are government agencies. As long as some basic protections are in place, the risks of providing confidential information to these entities is outweighed by the dictates of the statute and the potential benefits CCA customers would realize only if CCAs have the information they need to make fully informed decisions regarding energy procurement, service requirements and resource planning decisions."

In order to address utility concerns, the CPUC decided to require CCA mayors or chief administrators to sign a letter attesting to the CCAs intent to investigate or pursue status as a CCA:

"To help assure that cities and counties do not seek information casually, we will require as a condition of receiving utility information that the mayor or chief county administrator sign a letter attesting to the city or county's intent to "investigate" or "pursue" status as a CCA." (p.50).

The CPUC specified that the data should not be merely aggregated or masked data, but the detailed, confidential customer data for which all commercial parties have always required written customer consent to collect, and which is needed specifically for purposes of marketing their services and tailoring those services to customer needs:

"Use of such specific terms reflect the Legislature's intent for CCAs to have information that is neither masked nor aggregated, to the extent such information is required by CCAs that would reasonably "investigate, pursue or implement" a CCA program. This approach is consistent with our understanding that CCAs may need specific usage information in order to market their services and tailor those services to customer needs. We are not convinced by utility testimony that city and county tax rolls will provide the kind of information CCAs need to accomplish those ends." (p.52)

The CPUC required utilities to provide all relevant usage information, load data and customer information to CCAs under nondisclosure agreements for any data that is not masked or aggregated, with use limited to local energy programs:

"We direct the utilities to provide all relevant usage information, load data and customer information to CCAs. The CCA shall sign nondisclosure agreements for any confidential information that is not masked or aggregated.

We will also require that all notices relevant to CCA programs inform customers that the utility may share customer information with the CCA and that the CCA may not use the utility's information for any purpose other than to facilitate provision of energy services." (p.52)

The CPUC provided for utility indemnification:

"We agree with PG&E and SDG&E that the utilities should be permitted to include language in their tariffs that CCAs indemnify the utility from liability associated with release of customer information, as long as the utility provided the information responsibly and according to Commission rules, orders and approved tariffs. Utilities should inform customers who complain about the release of customer information that California state law requires the release of that information to CCAs." (p.52)

Finally the CPUC suggested that while utility data might be limited to aggregate data at first at the beginning of a CCA process (such as deciding whether to consider CCA), the detailed confidential data must be provided by the time an implementation plan is being developed, which would be well in advance of program launch:

"It may, however, be reasonable for utilities to provide aggregate data by customer type or geographic area at the beginning of the process, when a potential CCA is investigating whether to pursue becoming a CCA, whereas more detailed customer and billing information is warranted when the CCA is developing its implementation plan." (p.53).

Q. What other issues regarding providing aggregate customer data to third parties should be addressed and how should they be resolved. Customer-Level Data: GAS DATA

While CCA for natural gas has not been the particular focus of comments, it is in the scope of these proceedings and included under Governor Cuomo's CCA policy:

"Development and exploration to allow Community Choice Aggregation in New York to benefit residential and small commercial customers and lower energy costs. Community Choice Aggregation involves the aggregation of gas or electricity load by municipalities. Participating municipalities could negotiate with energy services providers to contract for the community's energy supply. These contracts may offer attractive and stable prices as well as other public benefits. CCA programs will support the deployment of renewable generation, energy efficiency programs, home energy management, and other distributed energy resources." (Governor Cuomo Press Release, "Governor Cuomo Announces New Clean Energy Initiatives to Grow Economy and Protect the Environment," DECEMBER 12, 2014).

CCA of natural gas service is a similarly important opportunity for the development of heating DER for such as IP thermostats and renewable onsite heating systems to supplant natural gas services, which are both large monthly bills for consumers with high volatility, and considerable greenhouse gas emissions.

Accordingly, the following gas data should be made available on utility tariffs, with a similar principle of no charge for aggregate data and reasonable cost charged for detailedend use meter and system data requests:

1) Natural gas consumption and billing data for all customers located within the service area boundaries of the CCA service territory, including account name, account address, latitude/longitude, account telephone number, customer/meter data, consumption data at the most granular interval available, monthly bills with unbundled charges, and all data necessary to calculate those charges.

2) Clarification and datasets used to associate gas meters with electric meters at the building level and customer level.

CONCLUSIONS

Provision of data to CCAs should be unlimited and provided at cost within one month of request, with setup of utility CCA MDMA services required.

To sum up the major points, there are five basic questions to answer about CCA data access rules.

- First, do CCAs warrant special, privileged access to confidential customer data above the levels allowed to other market participants, subject to signing nondisclosure agreements. **The answer is yes.**

- Second, do CCAs need unlimited access to just aggregate data, or also to detailed whatever confidential end-use meter data or any other distribution system data they deem appropriate, from investor-owned utilities?

The answer is, CCAs need both aggregate and confidential end-use meter data, as well in some cases distribution system and substation data, and should be unrestricted in their prerogative to decide what data they require for their programs.

• Third, when do they need it? Do CCAs need detailed end-use meter data in advance of program launch, or once customers are enrolled in programs?

The answer is, they need all the data in advance of program launch, in order to package their DER programs to assess feasibility of DER technology choices to match both aggregate and meter-specific customer demand patterns bbetween businesses and residents, night and day. In order to design complex, multi-site, small footprint technologies that define DER, CCAs need to be able to plan and request bids from suppliers based on analysis of a robust data set.

• Fourth, do CCAs need a live 24/7 or 8760 hour/year MDMA access to data on all confidential end-use meters, interval meters, time of use meters at existing locations, as well as all distribution and substation and system meters within their jurisdictional boundaries?

The answer is yes, once operational, for purposes of both monthly billing and also for operating integrated DER within a live operational (Demand Response) environment in which interoperability between DER sites and power procurement need to be coordinated at a real time desk, and data indicating levels of system load and customer load monitored and controlled.

• Fifth, what should CCAs pay for aggregate data, or for detailed end-use meter data?

The answer is, they should pay no fee for aggregate data, and for detailed end use meter data should pay for only the utility’s cost of preparation.

Mission Data Coalition: Submitted By: Jim Hawley and Michael Murray, Sacramento, CA

Q. What are utility best practices in the U.S. regarding providing customers with access to their own energy data in a

manner that customers understand and which facilitate an informed purchase decision? What information, tools and assessments are available for residential customers? Under what conditions should utilities charge for providing this information, including raw data, analysis and assessments?

A number of jurisdictions and utilities across the country have developed best practices to ensure convenient customer data access in a manner that animates markets and promotes innovation. As the Commission knows, there are two distinct interfaces by which data can be provided to customers: (1) historic (interval) usage, bill, and tariff data provided by utilities to third parties such as DER providers, preferably through a national standard format and RESTful web service such as "Green Button Connect My Data," also known by its technical name, the Energy Services Provider Interface ("ESPI"), a principal advantage being that consumers can obtain data and energy saving tools automatically without having to purchase equipment; and (2) real-time data provided through the Home/Premises Area Network ("HAN") radio contained in the smart meter and provided directly to a consumer, typically a gateway or other HAN device capable of receiving the signal from the consumer's meter. Our comments address best practices with respect to both interfaces.

As a preliminary matter, Mission:data strongly believes it is critical to avoid imposition of any utility charge or fee for standard usage, cost, and tariff data made available to consumers and third parties of their choice. A large part of the total value proposition of advanced metering infrastructure ("AMI") – perhaps 40% of the total benefits of AMI -- represents consumer value from demand-side savings, and the IT improvements needed to provide customers access to their data represent a small fraction of the total cost of an AMI deployment. Before implementing AMI infrastructure, data access through RESTful web services, better access to machine readable meter readings, cost, and tariff data will start removing costly and time consuming obstacles to energy benchmarking and measurement and verification.

Charging consumers or third parties for data when ratepayers have already shouldered the cost of AMI will deter consumers from adopting data-enabled technologies -- essentially reintroducing costs and frictions that technology has largely eliminated -- and put third parties at a distinct market disadvantage compared to utility-provided offerings. Consumer access to meter data should be provided as basic utility service, without charge to consumers, as is the case in states like California, Colorado and Texas.

Mission:data is encouraged that the Consolidated Edison (ConEd) representative clarified on the record that ConEd's intent is to offer Green Button Connect: "Green Button Connect will help us -- as part of our plan, to … connect with third parties on a machine-to-machine basis" and that ConEd will provide "a base set of data for no charge… that data will likely be hourly day-to-day behind."

As to the granularity of data provided without charge, Mission:data notes that Texas has required 15-minute meter intervals and urges that as more granular data becomes available it should also be made available to consumers without charge. This decision as to the granularity of data to be provided as basic utility service is critical to market animation and enabling the development and scale of cost effective energy management services for consumers. First, the interval provided should be enough to enable a third party to reconstruct the customer bill. Second, it should match the interval required by NYISO to settle demand response transactions. Finally, it should be at least as granular as the interval used for demand charges. For example, if demand charges are based on 15-minute interval usage, interval data provided through the meter should be at least as granular as 15 minutes so that consumers can access affordable products to avoid or reduce demand charges.

An additional consideration is that the granularity provided should support techniques such as disaggregation – the use of algorithms to determine what devices in the home or building are being used. Disaggregation represents a key tool in supporting more powerful energy savings. Hourly data supports only the most basic disaggregation: shorter intervals enable disaggregation of appliances at greater detail. (The most powerful data for disaggregation is the usage data provided in intervals every few seconds, typically through the HAN.)

With respect to current best practices for data access through either of the interfaces described above, Mission:data recommends adoption of the following best practices:

a. Best practices to enable access to interval data

i. Establish a simple registration process. Because market animation depends on lowering barriers to market entry, the third party "registration process" -- the process for determining a third party's eligibility to receive interval data on behalf of consumers -- needs to be simple and avoid putting the utilities in a "gatekeeper" role or imposing liability on them once a consumer has authorized data sharing.

The Commission should establish the rules governing third party eligibility to receive interval data. Mission:data recommends adoption of rules similar to those used in California, initially proposed by Southern California Edison, which require simply that third parties provide each utility (1) the third party's basic contact information; (2) an acknowledgement that the third party has reviewed the Commission's privacy rules; and (3) a demonstration of the third party's technical capability to interconnect with utility systems for securely receiving the data. Further, no third party may receive data if it is on a Commission list of third parties barred from receiving such data. These simple rules promote innovation and vigorous competition that will afford consumers wide choice.

ii. Enable simple customer authorization processes. The authorization process -- i.e., the process by which consumers authorize a utility to share their energy data with a specific third party of their choosing -- should be as convenient and simple for the customer as possible and accommodate multiple processes: via the utility's website, telephone, email and text message. The easier it is for customers to engage with DER providers, the more animated the marketplace will be. In addition, if the Commission wishes for customers to be apprised of their rights to rescind authorization or file formal complaints against a third party, the Commission should issue standardized authorization language that all utilities must display to customers, as is being developed in Illinois. Variations in authorization language or vagueness in Commission orders will inevitably lead to implementation problems and utility reluctance to proceed.

The best practice of ESPI's authorization process allows for two possibilities. In the first case, the customer visits the utility's website, logs in with his/her credentials, selects a third party from a list of registered companies, and clicks to authorize that third party. In the second case, the customer begins at the third party's website, logs in with his/her credentials with the third party, clicks a link that says "authorize your utility company here" (or something similar), is redirected to the utility's website to provide a login and password, and then is returned to the third party's website to complete the process. This latter case is similar to how Facebook, Twitter, LinkedIn and other services provide a user experience for simple authentication and authorization with third party websites. It is important to note that these two cases are equally secure – one is not inferior to the other in terms of security or authenticity.

The best practices of authorization processes include non-web-based methods as well. An authorization on paper could still enable a third party to access usage data through ESPI, for example; web-based authorization and ESPI are not incompatible. Paper-based authorization processes might be necessary to accommodate customers without computers, certain business customers, or others who do not have an online utility account established. One can imagine any number of authorization processes involving faxes, text messages, or emails in which customers affirm their intention of sharing usage data with a third party. What is important is not so much the medium (paper, fax, text, etc.) but rather that the customer’s identity is reasonably determined. If the utility has the customer’s cell phone number on file, then texting a four-digit temporary key to the cell phone could be used to establish identity. (In that case, the customer would enter the temporary key in the third party’s website, and the third party would transmit the key to the utility for validation.) Therefore, while we encourage the Commission to require, at a minimum, the utilities to implement the ESPI authorization processes described above, we believe there are other methods that can and should be sanctioned that provide flexibility to different customers while assuring that the authorization is not fraudulent.

Finally, Mission:data notes that Commission rules should envision continuing improvements for customer convenience: for example, the process should be flexible enough to allow customers the ability to authorize multiple accounts and meters at one time. And the imposition of arbitrary limits on the period of authorization should be avoided so that the authorization may last as long as the customer desires to use the service without risk of interruption, as California and Colorado permit.

iii. Allow third party led authorization. To make things simple and convenient for consumers -- essential to the scaling of energy management and realization of large-scale energy savings -- third parties should be able to lead the authorization process on behalf of a customer. In other words, a third party should be able to present a utility with information about a customer (name, address, account number, etc.) and the customer's authorization, and those two elements should be sufficient to gain access to usage data.

One of the barriers to market animation in several other states is that the authorization process is clumsy and difficult when utilities have no incentive to make it simple. Third parties, on the other hand, have every incentive to quickly and easily sign up new customers. It therefore makes sense for third parties to be able to present a customer's consent to the utility on the customer's behalf. For example, the utility could create a location on its website where registered third parties that provide customer identifying information (information which could not be obtained *without* valid consent, such as the combination of zip code, account number, etc.) are immediately authorized and begin receiving data via ESPI.

Third party led authorization has been adopted for retail energy providers in Illinois and other states. The challenge for Commissions with respect to third parties not subject to Commission regulation involves how to ensure that third parties do not violate customer privacy or misrepresent customer consent. In this regard, Mission:data believes that the models provided through the U.S. Department of Energy's Data Guard program or through regulatory solutions such as those adopted by California, which contain similar privacy protections – whereby the Commission can enforce rules through its power to direct utilities not to share data with third parties engaging in a pattern or practice of violations – are worthy of the Commission's attention. These are discussed in more detail below.

b. Best practices to enable access to real-time data.

To ensure that customers have the option to receive real-time data through the HAN, utilities deploying AMI should immediately offer HAN functionality using ZigBee, certified by the ZigBee Alliance. Independent certification by the ZigBee Alliance is important because adherence to the standard ensures technical interoperability. ZigBee is widely adopted and used in California, Illinois, Oklahoma and Texas, and we note that the AMI vendor recently selected by ConEd and Orange and Rockland Utilities – Silver Spring Networks – provides this capability. Other proprietary radios or protocols should not be relied upon for the HAN, as they severely limit the choice of consumer devices. Furthermore, the ZigBee radios contained in the meters should be delivered with all of the necessary firmware and security certificates to function in the field as soon as possible after deployment.

Furthermore, with respect to enabling customers to receive real-time data through the HAN, Mission:data recommends that the device "pairing" process is easy for consumers and that the testing and certification process for HAN devices should be centralized and streamlined to minimize barriers to entry.

i. Centralize device certification. A HAN device should be able to work if a consumer moves to new utility territory in the same way that a Bluetooth device adhering to national standards can be used with any phone, anywhere. In states early to adopt smart meters with HAN radios, the challenge has been that there is no centralized testing and certification process, leaving utilities to individually test and certify a multitude of devices, an unnecessarily repetitive and costly process. (Some testing labs charge $6,000 per device, a very expensive proposition for vendors who must certify each version of a HAN device, and sometimes for each firmware upgrade.)

The obvious solution is for a nationwide testing and certification process that is honored by every utility, and, in the absence of that, a single, state-wide testing and certification process honored by each of New York's utilities. The California Commission directed the utilities to collaborate on just such a process. New York should do the same. Mission:data recommends coordination with the commissions of California and Illinois to the extent practicable so that a single, uniform process can be implemented.

ii. Make it easy for consumers to pair devices. It is critical that customers who purchase a gateway or other HAN device be able to easily "pair" it with their own meter so that it can receive real-time usage data. The goal should be to enable instantaneous pairing with a self-service portal on the utility website. Rather than waiting days or weeks for a utility to process a form, the customer should be able to instantly connect any HAN device of his/her choosing and begin using it immediately. This is critical to achieving broad adoption and scale. In California, utilities have been required since January 2015 to support an unlimited number of HAN activations and PG&E in particular has embraced a self-service process through its website. In Illinois, Commonwealth Edison is currently using a manual process whereby the customer must phone the utility, but expects to transition to an automated process as well. In Texas, a single web portal (www.smartmetertexas.com) was established to enable self-service pairing by customers throughout all competitive areas in the state.

Furthermore, utilities should be required to provide an Application Programming Interface ("API") for DER providers to pair and manage HAN devices on behalf of their customers. If a solar installer, for example, provides HAN gateways to its customers, that solar installer should be able to automatically request pairing by making an API call. With potentially dozens or hundreds of customers going solar every day, an automated API will be essential to streamlining this process.

Q. Do existing practices and tools regarding customer-specific usage information provide customers, as well as vendors, receiving usage information with customer authorization, accurate information in a timely manner, and if not, what improvements can and should be made?

Real-time data read directly from the meter via the HAN provides the same quality of data (and in fact can provide much more granular data) as that read by the utility via the AMI network. As to interval data, Mission:data points the Commission to our discussion on Page 2 as to the need for intervals supplied to support disaggregation and critical services such as enablement of customer demand response.

As to improvements that can and should be made, Mission:data has previously urged the Commission to provide customers and third parties with access to tariff and bill data in an electronic format, through the same web service gateway as meter data. Customers do not find presentation in kilowatt-hours compelling. Instead, they want to know how much money they will save. Access to tariff and bill data is important so that services can provide information to consumers on the exact bill impacts of their energy decisions. Currently, bill data is either entered manually, or machine readable bill data is reverse engineered by scraping pdf bill images, retrieved by companies authorized by customers to automatically log in to the utility provider's website with their own login and password. Not only are these ways of retrieving data not cost efficient, they are also prone to error. Additionally, customers should not have to share their own login info to give consultants access to utility bill images and usage history, as is currently the case. The solution is a portal for third parties that does not include customer banking information. Customers should be able to delegate access to third parties and manage permissions from either their own online account or through the third party-led processes described earlier for data retrieval via RESTful web services.

Q. As the Commission considers how its privacy requirements should be revised to reflect technology and market changes, should the Commission adopt the U.S. DOE's DataGuard program as high level guidance regarding data privacy?

Facilitated by the Department of Energy's Office of Electricity Delivery and Energy Reliability and the federal Smart Grid Task Force, and developed by a working group that included AEP, Southern Company, Edison Electric Institute, Green Mountain Power, and Xcel Energy, the DataGuard program is a voluntary standard intended to provide "customers with appropriate access to their own Customer Data" and assurances that utilities, their contractors and third parties will protect the privacy of consumer personal information and individual energy use.

DataGuard provides a mechanism to ensure that third parties authorized to receive customer usage data from utilities -- but who are not themselves subject to commission jurisdiction -- can be required to abide by basic privacy rules and be held accountable for violations. DataGuard encompasses the Voluntary Code of Conduct ("VCC") including five high-level requirements that

(1) the customer be provided notice and awareness of how his or her customer data ("Customer Data" is defined as a combination of individually identifiable data and usage data) will be used and shared;

(2) the customer have control of her Customer Data and the choice to share Customer Data with third parties via a consent process that is "convenient, accessible, and easily understood" and free of charge;

(3) the customer should have access to her Customer Data and the ability identify and have corrected possible inaccuracies;

(4) Customer Data should be accurate and secured against unauthorized access; and

(5) Utilities and third parties commit to enforcement mechanisms to ensure compliance.

Under the Data Guard program, third parties voluntarily agree to abide by the VCC principles in the collection, handling and disposition of Customer Data. Third parties who violate these public commitments are subject to enforcement by the Federal Trade Commission or for claims of misrepresentation or unfair business practices under state law.

Generally speaking, the VCC principles of empowering consumers with access to their own energy data – and choice about whether and with whom they share that information -- is consistent with the growing trend in privacy rules to give consumers access to the information collected about them. At the technical conference, concern was expressed that aspects of the DataGuard principles are vague and in need of further refinement. Mission:data agrees that some of the principles would benefit from clarification, but notes that DataGuard is intended to "provide companies with a consumer-facing mechanism for demonstrating their commitment to protecting consumers' data and thus increase consumer confidence." Mission:data does not believe it should be treated as a regulatory tool or that adoption must be a pre-condition to access through Green Button Connect.

As a general recommendation, Mission:data urges the Commission to avoid unique privacy requirements that would delay data access or add unnecessary costs to solutions developed for a national market and develop approaches consistent with those adopted in other states like California or Colorado. With respect to enforcement, the Commission may wish to also consider the approach adopted by California which provides that any third party engaging in a "pattern and practice" of violating privacy rules risks loss of its ability to access utility data by virtue of the Commission's oversight over utilities.
In California, an enforcement framework establishes that utilities and third parties receiving data: (1) must provide consumers meaningful, clear, accurate, specific, and comprehensive notice regarding the collection, storage, use, and disclosure of individually identifiable energy usage information, (2) must disclose to consumers each category of covered information collected, used, stored or disclosed by the covered entity, and, the purposes for which it will be collected, stored, used, or disclosed, (3) must provide to customers upon request access to their covered information, (4) may share, with few exceptions, individually identifiable covered information only with customer consent, or under a "chain of responsibility" approach whereby parties that receive covered information may disclose such information without

consent to another party only for a primary purpose and only if the contract requires that party to adopt restrictions no less restrictive than those adopted by the providing entity; and (5) must ensure that the covered information they collect, store, use and disclose is reasonably accurate and complete and use reasonable safeguards to protect it.

The rules do not regulate the consumer's own decision as to with whom to share data, and the rules do not hold the utility responsible for policing the acts of entities who receive information. But the Commission holds a huge stick to ensure compliance: the Commission can order utilities to terminate data sharing with third parties who the Commission has found exhibit a "pattern and practice" of violating privacy rules.

One last point is that if the New York Commission were to reconsider implementation of a data exchange as proposed in its Phase 1 Straw Proposal, it would need to ensure that participants who access data through such an exchange can be held accountable if they misuse customer data. In such a case, the Commission might consider participation in the Data Guard program as an option to direct regulation for third parties desiring to participate.

Q. What other issues regarding access to customer and aggregated energy data by ESCOs, other vendors of DER products and services, and other third parties for the purpose of furthering REV objectives, should be considered by the Commission at this time?

Data quality is important to facilitate new products such as demand response. In California, initial decisions such as D 13-09-025 did not address data quality in detail. IOUs are required to notify third parties whether customer usage and pricing data is, or is not, revenue quality. "Revenue quality" is generally understood to mean the usage readings that are used to generate bills. Data become "revenue quality" after the validating, editing and estimation ("VEE") process.

Unfortunately, the Commission's lack of specificity regarding data quality, and the IOUs' resulting regulatory filings documenting their ESPI implementation, led to protests by Mission:data. The IOUs explained that backhauled data from the previous day are not necessarily revenue quality right away, but rather bills must first be generated in order for data to be deemed revenue quality. The problem for third parties was that settlement of demand response or ancillary services with the

Independent System Operator ("ISO") require revenue-quality data. If the IOUs did not provide revenue-quality data through ESPI, then an entire class of services that save ratepayers money and that were originally envisioned as consumers of data through ESPI would be jeopardized.

The issue of revenue quality has yet to be definitively resolved by the Commission, but the IOUs have filed their responses to the protest. We would like to draw the New York Commission's attention to PG&E's amended advice letter dated August 14th, 2014, in which PG&E (i) pledges to use the "Quality of Reading" ("QoR") flag in the ESPI specification, with a QoR value of 19 to mean "revenue quality"; (ii) will transmit any data updates automatically to authorized parties; and (iii) affirms that third parties can request historical data multiple times (in order to get the highest-quality data possible) at no charge. In particular, we would draw the Commission's attention to Attachment 2 of PG&E's amended advice letter, because it contains a succinct, thoughtful and technically workable description of how data quality should be tagged for customers of different types. See http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4378-E-A.pdf

Natural Resources Defense Council: Submitted By: Jackson Morris, Laurie Kerr, Alissa Burger, and Daniel Leonhardt.

Prioritize delivery of whole-building information to building owners. We urge the Commission to prioritize the most critical use case: delivering whole-building information to building-owners for energy management and benchmarking.

Across the country, benchmarking is an increasingly prevalent policy mandate and energy management tool. In addition to being adopted by many building owners (when the information is available), it is required by ordinance or statute in at least 15 cities, one county, and two states. New York City is a national leader, with a local law requiring whole-building data for benchmarking of large buildings for the past five years and counting.

Existing benchmarking requirements in New York cover an enormous building area. Under Governor Cuomo's 2012 Executive Order 88, state-owned and managed buildings over 20,000 square feet are required to benchmark. In addition, the New York City law applies to over 15,000 properties and more than 23,000 buildings, representing more than 50 percent of the city's gross floor area – an area of approximately 2.6 billion square feet, or more than all the square footage in Chicago. And with building-owner compliance rates in New York City at approximately 85 percent, benchmarking programs are yielding very valuable data that can help shape building owner action, city policy, and Commission and utility decisions. Properties reporting in all years from 2011 to 2013 – covering over 650 million square feet – showed significant performance improvements, with Total Source Energy Use dropping by 6 percent over two years.

Given the importance of benchmarking in achieving our energy efficiency goals and the success of existing benchmarking efforts in New York, we strongly encourage the Commission to ensure that the necessary data-provision framework and data aggregation policies are in place to preserve and promote access to whole-building data for energy management and benchmarking.

Thus, we encourage the Commission to first address, as a high-priority matter, a directive to utilities to give building owners the information and tools needed to manage the energy use in their buildings and to facilitate building energy benchmarking. The Commission should ensure this directive is in place before it turns to address the many other issues raised. As we stated in our previous comments, dated January 13, 2016 ("January 2016 5 Comments"), knowledge gained from properly assembled energy usage data "can assist consumers and other key stakeholders in making critical decisions regarding energy usage and supply alternatives, including energy efficiency and other distributed energy resources. . . . Building energy benchmarking increases adoption of efficiency investments and spurs the efficiency market." A recent report by IMT, *The Benefits of Benchmarking Building Performance*, describes the various associated benefits derived from benchmarking.

While utilities in New York City have been providing whole-building data to many building owners to facilitate benchmarking compliance for several years now, it is important for the Commission to make the data delivery formal and systematic across the state.

Automatic uploading of whole-building data. We urge the Commission to direct utilities to implement systems to *automatically* upload aggregated building information to benchmarking systems (such as EPA's Energy Star Portfolio Manager) to help streamline benchmarking efforts and ensure accurate and comprehensive reporting.

Building owners as a unique class. The Commission should establish building owners as a unique category of information recipients, separate and distinct from "customers" and separate and distinct from the general category of third parties and vendors. As more fully discussed in our January 2016 Comments, building owners have a unique position with respect to customers who reside in, or have offices in, the owner's building.

Process of continual improvement. The Commission should seek to establish a process of continual improvement for utilities' information delivery, and not view information improvements as a one-time directive. Utilities, stakeholders, and the Commission, should have an effective process to periodically examine the sufficiency and usefulness of utility information delivery methods and content. This is especially important in light of the pace of technology change and the changing nature of customer usage. One option is the formation of an advisory group of key stakeholders to enable utilities and the Commission to respond to new opportunities as they arise.

Responses to Specific Questions

What are utility best practices in the U.S. regarding providing customers with access to their own energy data in a manner that customers understand and which facilitates informed purchase decisions?

We offer the following recommendations for Commission consideration, derived from our experience and the experience of many utilities delivering usage information and reports to residential and commercial customers.

1. ***Identify energy management as the primary purpose of information delivery.***

a) Customers. Any initiative to deliver better information to customers about their own usage should occur with a clear statement of the purposes to be accomplished. For example, a primary purpose of the traditional utility bill is providing customers with a clear description of the amount due and elements of the total customer charge. We suggest that a primary purpose for new initiatives should be to deliver information to customers and building owners that enables energy management by the recipient of the information. Over time, utilities can innovate to fulfill the stated goals and may offer information analytics to large customers, such as average night-time usage, average weekend-usage, start-up time, and shut-down time, just to name a few examples.

b) Building owners and operators. Delivering "whole-building" energy usage data should facilitate building energy benchmarking. As discussed in our January 2016 Comments, "[t]he PSC should direct New York utilities to deliver whole-building usage summary information to building owners if the building includes two or more meters and if additional conditions are satisfied (such as providing notices to included customers)," formalizing the standard used by both Consolidated Edison and PSEG Long Island for provision of whole-building data for five years now. In addition,

> The PSC should direct utilities to implement systems to enable direct and automatic upload of whole-building usage information in the formats needed for use in standard benchmarking systems, including EPA's Energy Star Portfolio Manager. At a minimum, utilities should implement such systems for customers and buildings located where mandatory benchmarking requirements are in place.
>
> Implementing systems that allow for automatic data delivery to systems such as Portfolio Manager would significantly reduce data entry errors inherent in manual data entry and facilitate owners' building energy benchmarking, which is a crucial, foundational step for building owners to make informed decisions about investing in energy efficiency measures in their buildings, and in certain localities, required by law. Automatic uploading reduces the burden of benchmarking on building owners and would greatly facilitate benchmarking throughout the state.

In our January 2016 Comments we included examples of a number of utilities around the country that are providing aggregated building energy use information to building owners. Utilities that currently use Energy Star Web Services to automatically exchange data with Energy Star Portfolio Manager include: PG&E, Seattle City Light, Puget Sound Energy, Clark Public Utilities, Southern California Edison, Southern California Gas, Sacramento Municipal Utility District, San Diego Gas & Electric, Xcel Energy, Pepco, Pacific Power, PECO, Rocky Mountain Power and Commonwealth Edison.

Integrate building information into data platform and provision.

For New York utilities to deliver meaningful information and analytics to customers about their own usage (e.g., EUI, and how a customer's usage compares to other occupants' usage), it will in many cases require a combination of utility usage information and building characteristic information, such as square footage, number of units, and what centralized systems exist (e.g., space heating and/or cooling systems, water heating, etc.) in the building. Assembling or accessing information about buildings must, therefore, be an element of any utility's long-term strategy to deliver meaningful and actionable usage metrics and information to customers and building owners. For example, one can imagine a usage report for residents of multifamily buildings comparing one resident/customer's usage against averages of other residents/customers in similar buildings.

With respect to how a utility implements any plan to provide information and tools to users (i.e., whether a utility builds the capacity to deliver better information or engages a vendor to do so on its behalf) will depend on many factors. If a utility engages a vendor to deliver usage information, we note the importance of the utility retaining the right to use all information about customers and their buildings if the information was assembled or acquired with customer funds, so that the information is available to the utility and regulators for a range of purposes and reporting.

What information, tools, and assessments are available for large business customers?

This question is an important one. Information and tools that large business customers (e.g., owners and operators of large buildings) have adopted on their own for the purpose of energy management should inform the Commission and utilities about the kinds of information and tools utilities might consider providing to customers and building owners. In addition, information and tools that are widely used by building owners (e.g., Energy Star Portfolio Manager) may be harnessed by utilities to provide added value to owners and customers.

We recommend the Commission expressly include owners of multifamily residential buildings in the category of "large business customers" for questions related to information and tools for energy management. Owners of multifamily buildings often have substantial energy usage for common areas and central cooling, heating, and ventilation systems.

We understand that many large customers engage firms to deliver usage reports for their buildings – both commercial offices and multifamily buildings. This may involve installation of additional metering devices on certain equipment, or in some cases, a device to replicate the usage recorded at the main meter. These firms provide reports and data-visualization tools that illustrate the kinds of reports utilities could offer to commercial and multifamily customers and building owners. We are not suggesting utilities replicate these functions or deliver the full suite of reporting or services, but rather that certain basic tools might be delivered by the utility to customers and building owners at a cost that is much more efficient than relying on individual owners to contract for such services and install duplicative metering.

For examples of the kinds of data visualization tools and reports that owners of commercial and multifamily buildings could find valuable for purposes of encouraging energy management, see:

- WegoWise (located at: https://www.wegowise.com)
- Brightpower (located at: http://www.brightpower.com/)
- Agilis Energy reports (located at: http://agilisenergy.com/energy-analytics-solutions/)
- Optimization Reports by Aquicore – (located at: http://aquicore.com/products/optimization/)
- First Fuel (located at: http://www.firstfuel.com/platform/)
- Reports from SkyFoundry (located at: https://www.skyfoundry.com/file/34/Information-Alchemy---Turning-Operational-Data-Into-Value.pdf)
- Real Time Energy Management Report (located at: http://www.nrdc.org/business/casestudies/files/tower-companies-case-study.pdf)
- Report from Lawrence Berkeley Labs (located at: http://eis.lbl.gov/pubs/energy-management-package.pdf)

We also understand that some utilities have implemented online tools that deliver usage information to large commercial and multifamily customers, such as the "CEO Online" tools available to PEPCO customers in the Washington, DC area. The recent report from Mission: Data *Got Data? The Value of Energy Data Access to Consumers*, also provides useful background, discussion and recommendations. Available at: http://www.missiondata.org/news/2016/2/2/got-data-report-shows-benefits-of-consumer-access-to-their-energy-data.

As discussed in our January 2016 Comments, one of the basic, foundational tools for customers to manage energy use in large buildings is Energy Star Portfolio Manager. Portfolio Manager, a widely used benchmarking system, uses aggregated building energy use data and user inputs on the building's systems, size and other characteristics to give owners an energy performance baseline for a building. This provides a very simple indication of energy performance and allows owners to target efficiency investments, and verify savings from those investments. Portfolio Manager is an excellent example of the kind of existing system that utilities could harness, by delivering information directly to it on behalf of the customer.

Under what conditions should utilities charge for providing this information, including raw data, analysis, and assessments? AND 1B. Under what conditions should utilities charge for providing aggregated data information, including raw data, analysis, and assessments?

Impact evaluations and assessments have shown that utilities can deliver usage information to customers in a more effective way than the current practice and in a cost-effective manner – doing so produces energy efficiency that is of greater value than the cost involved to deliver the reports.

As a general matter, such cost-effective functions should not have user fees associated with them. Charging a fee is counter-productive. Delivery of the information creates value for all customers. At the same time, we recognize certain expanded data functions, custom reports, and integrations to third-party systems can have an additional cost to the utility.

We recommend that the Commission define two categories of information reports and tools:

The first category ("Category 1") would be information for which no user fees should be charged. This category should include at least all basic usage information included in utility bills today and all applicable usage information and rate information needed to understand the amount due. Basic charts and visualization tools using raw interval data, and the interval data itself, from the utility's meters should also be included in this category. The Commission should also include in this category all whole-building usage reports needed for standard benchmarking systems, such as Energy Star Portfolio Manager or similar tools. No fees should apply to such essential information.

The second category ("Category 2") could include customized reports, supplemental information and tools, and certain integrations that are not essential and for which a user-fee might be reasonable. We include in this category custom reports and data visualization tools that are targeted to a small number of large customers or building owners and not used by a large number of properties. For tools in this category, utilities would be permitted to charge a user fee to defray the costs of providing the service, so long as any fee does not exceed a cost-based fee for the function provided.
As a general matter, utilities should provide free-of-charge to municipalities aggregated information needed for governance and planning, including information required to create municipal greenhouse gas inventories, with exceptions for unusual or custom requests.

We reiterate our support for utilities to implement systems that allow a geographic "roll-up" of individual customer data into community-level reports, subject to appropriate privacy protections. Access to aggregated, community level data by local jurisdictions is critical to the success of REV. Moreover, such data is equally important in facilitating other important state initiatives, such as the New York State Community Partnership and the Five Cities Energy Plans. This aggregated, community-based data should be made available at no cost to communities and the public through a single, easily accessible portal.

Do existing practices and tools regarding customer-specific usage information provide customers, as well as vendors receiving usage information with customer authorization, accurate information in a timely manner, and if not, what improvements can and should be made?

No. Utilities should examine their processes to improve how they deliver information to three important users of the information: i) the customer, ii) building owners (with customer authorization for customer-specific information), and, iii) vendors and service providers. As discussed in our January 2016 Comments, the Commission should prioritize the building owner use case and should direct utilities to deliver aggregated whole-building usage information to building owners, which does not include personally-identifiable information, as well as to implement systems to enable direct and automatic upload of aggregated building usage information. When information is aggregated, it should also include a list of all utility meters that contributed to the reported consumption. We note that there are a number of positive developments in place – such as implementation of "Green Button Download" that establishes a standard data protocol – but more is needed.

As also described in those comments, important improvements are needed in how utilities secure and document that building owners have customer permission to obtain certain information sets, such as individual usage as opposed to whole-building monthly data. We encourage the Commission to direct utilities to establish a streamlined method for building owners to evidence customer permission to obtain such information sets (i.e., individual customer usage, as opposed to aggregated whole-building monthly usage totals). One option to explore is to allow utilities to rely upon tenants conveying requisite permission in a lease document. Another option is to "pre-qualify" owners or operators for large numbers of offices or apartments, which would allow the utility to rely on the building owner's representation and warranty that it has obtained the tenant's permission, assuming the owner has met certain preconditions. This will relieve the utility of the burden of examining every lease document for the requisite language and signatures.

As the Commission considers how its privacy requirements should be revised to reflect technology and market changes, should the Commission adopt the US DOE's DataGuard program as high level guidance regarding data privacy?

It is essential that the Commission provide utilities with clear guidance and direction for sharing usage information with various recipients and in different scenarios that provides legal and regulatory certainty for the practices involved.

We recommend that the Commission does not adopt the US Department of Energy (DOE)'s DataGuard program at this time, at least not until the needed regulatory framework is clearly established. The DataGuard materials are intended to give utilities a way to communicate certain "best practices" with their customers. It is a voluntary way for utilities to potentially increase customer trust. There might be a time and place for utilities to adopt the DataGuard program, but it is not a substitute for the guidance and directives New York utilities need to fulfill the requirements discussed in these proceedings.

As described in our January 2016 comments, any policy governing provision of energy data must be tailored to provide utilities clear guidance on resolving reasonable privacy concerns. Energy usage information aggregated of at least two accounts is the approach that has been working successfully for two New York utilities for the past five years.

For a discussion of specific reasonable terms and conditions on privacy that the Commission might consider, we recommend "How Utilities Can Give Building Owners the Information Needed for Energy Efficiency while Protecting Customer Privacy," *Electricity Journal*, November 2015 (attached as appendix A to our January 2016 Comments).

Finally, we encourage the Commission to focus first on the following high-priority items before turning to address other matters related to energy usage information:

a) Prioritize giving utilities necessary guidance and direction to assure building owners receive whole building usage information required to benchmark their buildings with tools such as Energy Star Portfolio Manager;

b) Direct utilities to implement systems to enable direct and automatic upload of aggregated building usage information in the formats needed for use in standard benchmarking systems, including Energy Star Portfolio Manager;

c) Direct utilities to examine policies and processes for building owners to obtain individual tenant usage information; and,

d) Require provision of aggregated, community-level data to municipalities and the public at large.

NYS Department of State's Utility Intervention Unit (UIU):
Submitted By: Erin P. Hogan, Director, and Kathleen O'Hare, Albany, NY

UIU Recommends the Commission Adopt the United States Department of Energy's DataGuard Code of Conduct.

The United States Department of Energy (DOE), in collaboration with industry stakeholders, recently established a framework for accessing, using, and sharing customers' energy usage and related data, which is presented in the DataGuard Energy Data Privacy Program, A Voluntary Code of Conduct (DataGuard Code of Conduct). While this framework is considered voluntary at the federal level, DOE envisioned that state public service commissions may use DataGuard Code of Conduct to inform their privacy regulatory proceedings. UIU has carefully studied the privacy framework and suggests the Commission require that the DataGuard Code of Conduct be mandatory for all utilities, ESCOs, and Distributed Energy Resource Suppliers (DERS). This requirement should be incorporated into the Uniform Business Practices (UBP) for ESCOs, as well as the yet-to-be-adopted UBP for DERS. The Commission should also apply the DataGuard Code of Conduct to all the utilities in the State so that all energy providers follow the same rules respecting customer data privacy.

Rochester Gas and Electric (RG&E) and New York State Electric and Gas (NYSEG) have already adopted the principles of the DataGuard Code of Conduct,8 and while they are not yet 100 percent in alignment, the companies are looking carefully at how to incorporate each section in their data security and privacy procedures. UtilityAPI, an energy data infrastructure company, also generally supports the Dataguard Code of Conduct and spoke about its steps toward compliance at the Second Technical Conference. However, Con Edison, Orange and Rockland, Central Hudson, and National Grid expressed several concerns with the prospect of adopting it. These utilities recognized the merit of the DataGuard Code of Conduct's basic principles but noted that some sections of the DataGuard Code of Conduct are ambiguous and had concerns with compliance and implementation. To address these concerns, UIU suggests that the Commission establish a collaborative, to be held within 60 days of an Order in these proceedings, to make recommendations and ensure that the duties imposed on utilities, ESCOs, and DER providers by the DataGuard Code of Conduct are clear to all parties.

During the collaborative, UIU would propose mechanisms to ensure that consumers understand and are aware of the protections provided. While some terms and details may need to be expressly defined in the collaborative, DataGuard's Code of Conduct offers a helpful framework. The Code of Conduct's first core concept, Customer Notice and Awareness, requires the service provider to notify the customer about the specific types of data that is collected, used and secured, at a high level and in easy-to-understand language. This notice also must be in font no smaller than 14 point to ensure it is not lost in fine print. Further, the notice should be available in at least the top six non-English languages spoken by limited English proficient individuals in New York, as well as one or two additional languages prevalent in those areas of New York with growing populations of refugees whose primary languages fall outside the State's top six languages. The notice of consumer data sharing should be in plain language before the translation and should be written at a sixth grade reading level in every language in which it is provided. Notice on customer data collection should be given on a recurring basis, either annually or quarterly or where there has been a change in the use or collection methods of customer data. As suggested by the DataGuard Code of Conduct, these disclosures should require affirmative consumer consent and be "convenient, accessible, and easily understood."

UIU supports the guidelines established in the DataGuard Code of Conduct's second core concept, Customer Choice and Consent. Customers should be provided with notice and the opportunity to accept or decline the use of their energy use data for secondary purposes. One such secondary purpose may include online behavioral targeting. The Federal Trade Commission has defined online behavioral targeting as "the tracking of a consumer's online activities over time – including the searches the consumer has conducted, the web pages visited, and the content viewed – in order to deliver advertising targeted to the individual consumer's interest." Studies have shown consumers are wary of behavioral targeting; a Pew Research Center study found 68% of internet users "disapprove of search engines and websites tracking their online behavior for the purpose of ad targeting." Behavioral targeting is currently a popular way to reach customers, but in the case of establishing informed consent to collect personal energy data, it is important customers are offered clear information on how this data may be used, including if it would be used to develop targeted ads for the customer.

Code of Conduct Must Aggressively Protect Consumer Information

The DataGuard Code of Conduct aggressively protects consumer information. Just because a consumer consents to data collection in one circumstance should not mean that the consumer consents to data collection in all future circumstances. The DataGuard Code of Conduct's suggestion for notification at times where the customer has the ability to make a choice, such as push notifications for software downloads, makes sense. To make implementation of this guideline clear, UBPs adoption of the DataGuard Code of Conduct should include a few specific examples of times where such notification should be provided.

As discussed in the DataGuard Code of Conduct customers should have access to their data in a "reasonably convenient, timely, and cost-effective manner." UIU suggests the service providers be offered the opportunity to develop a data-access platform through smaller pilot projects, so that the Commission may choose the best option for use by all service providers. Creating this platform will benefit service providers as well as customers, as energy data access will help the customer make informed energy choices and potentially lower their bill by using the data to make energy efficient choices. This also aligns with some of the goals set forth in the Reforming the Energy Vision Proceeding such as "empowering New Yorkers to make informed energy choices." To ensure cost-effectiveness of service providers' approaches, UIU suggests Department of Public Service ("DPS") Staff conduct a cost-benefit analysis to determine which costs, if any, would be appropriate for the service providers to recover.

The DataGuard Code of Conduct's integrity and security provision offers strong guidelines to inform the creation or modification of a standard plan of action all service providers must follow in the event of a customer data breach. If not already established, each provider should develop a comprehensive data breach incident response plan to be reviewed by interested parties and DPS Staff, followed by Commission review and final approval. In the event of a data breach, a company's costs associated with repairing the damage should be borne by the company. Since the company's breach has harmed its ability to provide adequate and reliable services to its customers, ratepayers should not bear the cost of a data breach beyond what they will already have to endure, including the risk of identity theft, fraud, etc. Utilities, ESCOs, and DER providers should also bear the cost associated with helping consumers protect themselves against fraud by providing victims with free credit monitoring and insurance services for the year after the data breach has occurred.

Minimizing Customer Data Breaches Will Help Minimize the Strength of the Secondary Market for Consumer Data

Customer data security breaches affect millions of New Yorkers every year, but energy companies can take steps outlined in the DataGuard Code of Conduct to minimize the chances of a data breach occurring, which will provide benefits for companies as well as New York residents. In 2015, 979 businesses reported data security breach issues to the New York State Division of Consumer Protection. These issues affected approximately 5.5 million New York State residents.26 In the United States, a study conducted from January 2014 to March 2015, found that the average organizational cost of a data breach was $6.53 million. The average cost per capita of an energy data breach was $132.28 These breaches harm customers even when their costs are not directly tracked and charged to ratepayers, as data is frequently sold through secondary markets, increasing customers' exposure to identity theft.

A 2014 RAND Corporation study found that black markets for customer data are growing in size and complexity. The report also noted attackers will continuously innovate and change the tactics they use to retrieve data. A recent Intel Security report found that a payment card number with the three-digit security code could be worth $5 to $30 in the secondary market depending on the amount of additional information that is included with the number. While each individual set of data may not have a high value, a breach of a utility's or other energy provider's data system may yield millions of data sets thus making energy data systems a lucrative target for potential attackers. By adopting the DataGuard Code of Conduct and enacting a clear data security plan with an incident response system, companies can insure consumers are better protected from the risks of data breaches. By minimizing data breaches, companies can make personal data theft a less lucrative market, and decrease the availability of such data.

The Future Foundation's Study on Consumer Privacy Attitudes Is Inapplicable.

The Commission should not rely on the Future Foundation/DMA/Acxiom study, "Data Privacy: What the Consumer Really Thinks" (Future Foundation Study), which the Retail Energy Supply Association presented at the technical conference, as an indicator of New York State consumers' preferences on energy data sharing. The Future Foundation Study is based on a survey of UK residents, and does not evaluate any of the studies focused on American residents, which are more relevant. New York customers may not have the same views as UK customers regarding privacy and energy data. The Future Foundation Study included a question based on European Union (EU) data protection regulations, which may inform how comfortable UK customers are with sharing their data, but is not applicable to New York customers. Furthermore, the Future Foundation asked only general questions about customer attitudes on data privacy, and so lacks the specificity that would be required to inform energy data privacy policy.

Customer preference scholarship includes several more relevant studies the Commission could consider. For example, a study released by Pew Research Center on January 14, 2016 questions a representative sample of American adults on a variety of privacy and information sharing scenarios, including smart thermostats. The Pew Study showed many Americans are willing to share personal information in exchange for tangible benefits. Customers are wary of how information is used once given to a company, and the study found customers believed smart thermostats were an unacceptable tradeoff by a 55% to 27% margin. The comments people shared in the Pew Study suggests customers may need reassurance from companies that their personal data will not be distributed to third parties without an explanation and their consent; a primary concern customers had with smart thermostats was who would get information on their "habits of coming and going."

UIU suggests that the Commission investigate more relevant studies and consider the survey methodology such as the study's sample size, representational statistics, and questioning methodology to determine if the study results are representative of New York consumers. During the course of this survey review, the Commission should pay particular attention to the design of the questionnaire because a response to a question asking "Do you have an objection to sharing energy data?" may be significantly different if the question were framed as follows: "Do you have an objection to sharing data that could be used to target your behavior?" Survey responses can inform the collaborative's discussion of appropriate language to include in the Customer Notice and Awareness section of the DataGuard Code of Conduct utilities, DER providers, and ESCOs adopt. Customers should have a clear understanding of the costs/benefits of their privacy decisions and companies should recognize the value of the information customers are providing. With more knowledge about customer energy trends, companies can assist customers with strategies to improve their energy efficiency, which will also be beneficial to the company.

Otego Microgrid Ratepayers: Submitted By: Stuart Anderson, Otego, NY

The REV plan as currently configured will allow utilities to organize and operate microgrids on any portions of the grid that are not serviced by third party microgrid developers. There are many portions of the grid which, for various reasons (including geographic dispersal, lack of major load centers, and overlap with portions of multiple civil divisions) will quite likely receive very little or no attention from third party developers; microgrids in these regions will likely default to utility control. The utilities will, under the current definition of "clean" energy, be allowed to install gas-fired generation on each of these microgrids in order to satisfy the islanding requirement; as a result, broad areas of the grid will become reliant on gas-fired distributed generation. In the current cheap gas environment, and with gas suppliers and users allowed to externalize so much of their costs, the utilities will have great difficulty justifying investments in renewable energy alternatives: gas will dominate the distributed generation system in New York State.

Under the aforementioned circumstances, the utilities will have enormous incentives to discourage third party developers from establishing microgrids; a simple and effective way for utilities to squelch third party developers would be to withhold, delay, impair, obfuscate, frustrate, and/or ignore information requests from third party developers regarding suitable locations for distributed renewable generation to access the grid. Utilities would also, by controlling the flow information, have the ability to favor some developers over others. (This is NOT a criticism of the utilities—they are protecting their shareholders; this is an observation on how the energy ecosystem can be expected to work.)

We suggest a solution to this problem: do not make utilities responsible for providing grid access data to developers; rather, require the utilities to provide the necessary data to a database manager within the Department of Public Service, and charge the database manager with all responsibilities relating to the distribution of said information. In such an arrangement, the utilities will be responsible only for the accuracy of the data; the DPS database manager will be responsible for vetting information applicants and for delivering data to approved applicants in a timely fashion.

While satisfying the REV objectives of reliability and minimized operating costs (at least in the current cheap-gas environment), the broad adoption of gas-fire distributed generation is in direct conflict with the REV goals of reduced greenhouse gas emissions and moving away from reliance on our predominant energy source, fracked gas. Allowing the DPS, rather than the utilities, to control the distribution of information on grid access will provide an important shift in the execution of the REV's distributed generation strategy, away from gas and in favor of renewables.

Pace Energy and Climate Center: Submitted By: Radina Valova, Attorney

Pace recommends that the Public Service Commisison ("PSC") investigate requiring each utility to build a common application program interface ("API") for all customer usage information and other specified fields (e.g., kwh, kw, rate class, meter number, address) for use by customers and by third parties subject to a permission protocol to be defined. A common API for customer data ("front end portal") would reduce costs and service provider's barriers to entry, strengthen the capacity of all participants to track market performance, and increase privacy protections. The permission protocol would assure that only customers, or users with the permission of the customer, have access to their usage information.

More advanced metering and data gathering technologies will be deployed over the coming years and these will enable a far greater level of granularity in analysis of consumption data.

Customers, and other stakeholders, will want to gain access to that data in readily useful ways. These ways will differ by customer type: residential, commercial, and industrial; sub-groups within each type will have different perspectives on energy billing and management. However, customer needs will not differ substantially from one utility *territory* to another. For customers with a presence in multiple utility territories, as well as for the state and municipal governments, data consistency will be beneficial. Development and enforcement of privacy and security, also of great importance, are best addressed in a single standardized portal rather than separately across all individual utilities.

Enabling customers to gain access to granular usage data and providing data visualization tools will require the deployment of a number of components:

- A publically facing website for all accounts with security and privacy controls in place
- Applications to render data visually
- Development of data export algorithms for use in outside software packages and

platforms (e.g., MS Excel, Energy Star Portfolio Manager)

- Call center(s) to provide customer support
- Database architecture, management, and support
- Physical infrastructure (data centers, servers, networks)
- Data retention and archiving functionality
- Customer feedback, quality assurance, and new feature development
- Business continuity planning, disaster recovery processes, and redundant infrastructure

All of these components benefit from economies of scale. Having six different solutions, one at each major utility (plus numerous smaller ones), could over time result in higher costs (or lower functionality).

None of the six electrical utilities in NYS currently provide a modern system for robust interval meter data reporting and export. While utilites provide *some* of the functionality (e.g. they have a customer facing website for basic billing functions), development of additional functionality and construction of back-end infrastructure to support it are still required. This is the case even if the utility deploys advanced metering infrastructure (“AMI”). Clearly there can be overlap with AMI deployment, but data gathering for grid operations and consumption monitoring is not the same as creating a useful customer facing data reporting system.

SPECIFIC ADVANTAGES

A single front end system offers advantages to customers, data service providers, energy service companies (“ESCOs”), and utilities.

Core Competencies - Utilities are focused on, and experienced with, managing electric and gas infrastructure. Development of robust "big data" customer facing websites is not a core competency. The burden on utilities will be to design data query and reporting interface functions so that customers can retrieve consumption and billing data through the portal and use it with third-party service and technology products. This project would be better executed in the hands of an information technology ("IT") services firm. The portal unburdens the utilities from taking on this responsibility. Centralization is also avoid the diversity of systems that would be developed if each utility contracted with a different IT services firm to provide this functionality.

Utility Remains System of Record - The system should be designed as a portal for multiple streams of data and information. The burden on utilities will be to design data query and reporting interface functions so that customers can retrieve billing data through the portal and use it with third-party service and technology offers. There are numerous examples of multiple data platforms being integrated into a web portal seamlessly for users. Below are several examples:

- Many people have investment/brokerage accounts with the same firm that they use for retail checking/savings accounts. Such systems fall under two different types of regulation and are typically hosted on completely different sets of IT infrastructure; yet customers can access both through the same portal with the same login.

- Medical insurance companies subcontract their online pharmacy to an outside provider but users can order prescription refills from what is, from their perspective, their insurance carrier's website.

- Travel websites such as Expedia do not store airline ticket prices and availability in their own systems. When users run a search, the site connects to Sabre (and potentially additional similar systems depending on the airline) to render the data according to the search parameters the user laid out.

- Credit reporting agencies such as Experian are not constantly polling banks and credit card companies for account balances. But when a credit report is run, there's a common protocol in place to allow the relevant data to be shared with them to generate a credit report. And this is done with tightly prescribed privacy controls.

Consistent Privacy and Security Controls - Privacy and security controls are more easily designed, deployed, monitored, and enforced using a common portal system design.

Unification of Data Formats - A common format for obtaining and receiving utility information lowers the barriers to entry for ESCOs and technology companies specializing in data analysis, allowing them to develop a single data importation platform rather than six different variations. In addition, many commercial, multifamily, governmental, and industrial customers will have facilities and accounts in several different utility territories. This is true even for local governments as political boundaries and service territories do not always coincide. A common format enables centralized and consistent analysis across their portolios.

Less Burdensome on Smaller Utilities - Some of the costs of developing these systems scale with the number of customers a utility has, but certain costs are fixed. These fixed costs will exert a disproportionate pressure on operating costs for smaller utilities. A centralized system would mean fixed costs are shared on a pro rata basis, lowering the burden on smaller utilities.

Statewide Aggregation is Seamless - Analysts of data usage statistics by the Independent System Operator ("ISO"), state government, and other stakeholders (such as research entities) will have a robust and normalized statewide set of data at their disposal on an on-going basis (subject to appropriate privacy and disclosure rules). This can enable numerous benefits such as:

- Improved and more timely feedback on the effects of energy policy changes, new incentives, and tariff modifications
- More robust data archive to show system trends over time with greater granularity of time intervals than currently possible
- Enable a straightforward comparison of previously customer groups in different regions and new investigative endeavors

Data Reporting and Benchmarking Compliance - The portal will serve purposes beyond customer data access and these will multiply its benefits.

The number of municipalities that enact energy reporting and benchmarking regulations is likely to grow. A single front end portal can make compliance with such regulations far less burdensome allowing for better program implementation and higher societal benefits.

Additionally, the system's administrator can serve as subject matter experts and advise municipalities on how best to craft the reporting requirements to meet their goals.

Removes Perverse Incentives - Because of the costs and complexities involved in developing an IT system such as this, there is the risk of some utilities taking a "wait and see" approach, seeing a last mover advantage by looking at other systems and being last to implement new functionality. Their customers could be left without advanced functionality while this process unfolds. Centralized development ensures that all utilities in the state benefit equally from the system's development.

Consistent and Cheaper Customer Enrollment and Education - Any new system will require customer educational materials. A single centralized system means that only one such set of guides, FAQ's, instructional videos, etc. needs to be developed.

Future Proofing - Data reporting standards and best practices are going to evolve over time. The same is true for IT infrastructure. A centralized system means that upgrades, new features, testing, and customer feedback can be conducted more cheaply and rolled out statewide once complete.

Finally, Pace believes that a central front end portal for consumer use data will reduce costs, reduce service provider barriers to entry, and strengthen the capacity of all players to track market performance, while also strengthening privacy protections. We recommend that the PSC evaluate the full costs and benefits of implementing such a central repository.

Renewable Highlands: Submitted By: Michelle Smith, Cold Spring, NY

We believe Community Choice Aggregation (CCA) is a powerful tool for accomplishing our primary goals, as well as facilitating community input, cost savings, pricestability and local economic growth. Therefore, Renewable Highlands is actively studying the feasibility and design of a CCA in our geographic area. We have already received public support from the City of Beacon and Town of Philipstown, and are working with other sizeable municipalities. During this process we have identified two key issues we hope the PSC will address to facilitate formation of CCAs in line with the state's REV objectives. These are:

(1) **Geographic Area**: We think it essential that a CCA be able to operate irrespective of political boundaries (e.g. across county lines). A primary rationale for this is to facilitate scale within the area covered by a single utility, because utility and county borders are generally not aligned. Other reasons include geographic proximity, media coverage areas and existing collaborations between municipalities, which often cross county lines. For similar reasons, we also think the rules should facilitate collaboration between smaller CCAs on energy procurement.

(2) **Renewable Energy and Price Volatility Mandates**: For CCAs to better meet REV objectives with respect to resilience and renewable energy growth we believe that, while absolute price should be a focus area for selecting energy service companies, it should not be the only criteria. Selection criteria should also give suitable weight to renewable energy sources and limiting price volatility over time.