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Wellinghoff Case

BEFORE THE STATE OF NEW YORK

DEPARTMENT OF PUBLIC SERVICE

PROCEEDING ON MOTION OF THE COMMISSION IN REGARD TO REFORMING THE ENERGY VISION

CASE NO. 14-M-0101

COMMENTS OF JON WELLINGHOFF, STOEL RIVES, LLC AND KATHERINE HAMILTON AND JEFFREY CRAMER, 38 NORTH SOLUTIONS, LLC

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EXECUTIVE SUMMARY

Opening up the regulatory system in New York to competition through the creation of an Independent Distribution System Operator ("IDSO") will (1) enable distributed energy resources to be fully deployed while improving the utilization of existing grid resources; (2) allow for greater consumer choice and participation in the electric grid of the future; and (3) spur the development of a more transactional energy framework for the distribution system that can realize lost value through the emergence of an entirely new energy market model. Our recommendations ask that the Public Service Commission open a new proceeding to consider this regulatory option; require that utilities submit a plan for how they would turn operational management of their assets over to an IDSO; develop a system of monitoring and analysis to ensure that consumers and the grid benefit from the new structure; and propose an operations system that ensures reliability and safety of the electric grid in New York.

I. INTRODUCTION

As the state of New York looks toward increasing the utilization factor of its current resources while keeping consumer prices down and allowing for more innovation on its electric grid, the Public Service Commission ("Commission") has asked two key questions in its order instituting a proceeding for Reforming the Energy Vision ("REV")[1]:

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

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

These questions and consideration of how best to answer them provide enormous opportunities for the state of New York and its electricity consumers.

To that end, we propose a model similar to that established for transmission entities nearly two decades ago. Just as traditional management of the grid by vertically integrated utilities was inadequate to support the changing needs of the transmission grid, we posit that management of the New York distribution system by utilities alone will not be sufficient to sustain a resilient, clean, least cost, and innovative grid. This is evidenced by the rapid growth in distributed energy resources ("DERs").

DERs consist of demand response, energy efficiency, energy storage, advanced communications technologies, and all forms of distributed generation including solar, wind, fuel cells, and co-generation and waste heat recovery that are on the customer side of the meter. There may, in fact, be many additional technologies, applications, and behavioral incentives that will provide distributed resources in the future. It is now widely recognized that distributed resources, as owned or under the control of the consumers who are also distribution system customers, are capable of providing valuable services to the larger grid, including energy, capacity, and ancillary services in a manner consistent with and in some cases superior to conventional central station generation.[2] As a result, the state regulator can no longer depend on the distribution utility to fully support these DERs given the inherent conflicts that arise between the owner of the distribution asset and the entities interconnected to or desiring to interconnect to that asset for purposes virtually identical to transmission assets. In the current construct, a consumer providing services to the grid is not compensated as a resource; the utility currently has total control over access and use. Opening up this market would enable far greater consumer and third party access and ability to become resources to the grid.

Thus, while the Commission staff has recommended a Distributed System Platform Provider ("DSPP") model for distribution utilities, our proposal would remove the owner of the distribution system from this "gatekeeper" role and instead install an Independent Distribution System Operator ("IDSO"). This IDSO would be selected competitively based on criteria determined by the Commission. This single

[2] FERC explicitly recognized this in Order 755 that requires higher compensation for fast response regulation services-typically provided by DERs such as batteries and demand response- than is provided to slower responding regulation services from traditional central station generators.

change would then allow for innovative and entrepreneurial third parties to have the ability to fairly and fully participate as providers in a truly competitive distribution energy market. We believe that opening up the system to competition through the creation of an IDSO will (1) enable distributed energy resources to be fully deployed while improving the utilization of existing grid resources; (2) allow for greater consumer choice and participation in the electric grid of the future; and (3) spur the development of a more "Transactive Energy Framework" for the distribution system (as the bulk power system experienced as a result of FERC orders referenced above) and allow for realization of foregone value[3] and the emergence of a whole new class of energy market entrants.

II. PRECEDENT

On April 24, 1996, the Federal Energy Regulatory Commission ("FERC") issued Order 888, creating the foundation for competitive wholesale markets.[4] Three years later, FERC issued Order 2000[5] that established Regional Transmission Operators ("RTO") and clarified independent regionally operated transmission grids to ensure reliability, protection of the public interest, and lowest prices for consumers, while stimulating continued innovation. This rule required that each public utility that owned, operated, or controlled facilities for the transmission of electric energy in interstate commerce make certain filings with respect to forming and participating in an RTO.

FERC codified minimum characteristics and functions that a transmission entity had to satisfy in order to be considered an RTO with the goal of promoting efficiency in wholesale electricity markets and ensuring that electricity consumers pay the lowest price possible for reliable service. Minimum characteristics and functions for an RTO were set forth to ensure the most efficient, reliable, and cost-effective operation of the grid. Order 2000 allowed regions to open the bulk transmission system to competitive access that reduced market prices through demand response; reduced congestion costs with the ability to better interconnect with the grid and to better plan and build new transmission; and facilitated the integration of multiple types of resources (wind, solar, and fast-response regulation from advanced energy storage) to help lower costs and drive down market prices. This construct also allowed

[3] Foregone value here refers to various grid services provided by DERs – generation, efficiency, ancillary services, for example--that can only be fully realized operationally within the system and compensated for when actively managed and controlled. In the case of traditional net metered distributed solar, energy delivered into the distribution system in surplus of the customer load, particularly during peak load, offers no recognized incremental monetary or operational value for either the customer or the system.
[4] See Order No. 888, 61 FR 21,540 (May 10, 1996)
[5] See Order No. 2000, (December 20, 1999)

for regional dispatch of high quality resources that increased overall system efficiency, a benefit we expect would occur at the state level with the IDSO.

We use the RTO formation not as the solution but simply as a structural example. We believe additional benefits would accrue from full deployment of DERs at the distribution level through the creation of an IDSO. The IDSO would allow New York to have increased control of planning, asset investment, and system integration, while retaining the benefits of that structure for its own consumers.

III. IDSO STRUCTURE

The primary distribution assets—such as poles, wires, transformers, and switches--will remain under the ownership of the distribution utility that will also have the primary responsibility to maintain and upgrade the system subject to existing state laws that make adequate performance a condition of keeping the franchise. The operation of the system would be turned over to the IDSO that would coordinate the operation of that system with the operation of the bulk-electric system in the state. The IDSO and the ISO may in fact be the same entity.

Independent operation of the distribution system through an IDSO would accommodate and encourage additional competition that could in turn reap significant consumer benefits. The basic structure would consist of requiring the existing investor-owned distribution systems currently under the Commission's jurisdiction to turn the operation of their distribution systems over to an independent third party entity designated by and based on merits set forth by the Commission. The distribution-system asset owner would continue to maintain the distribution assets and perform the billing function to its customers for distribution service. While the Commission would retain responsibility for ensuring a system planning process is in place for resource adequacy and other key goals set forth by the state of New York, the distribution utility would also continue to be responsible for upgrades to the system (such as voltage control and other distribution grid improvements) and be allowed to earn a return on those investments to the extent they could be shown by the utility to be prudently incurred and used and useful.

The IDSO would be responsible for the daily operation of the system, the connect and disconnect of customers and distributed generation and customer storage systems, and general system planning. It would review existing rules for these services and establish open, transparent, and non-discriminatory procedures to provide these services. The IDSO would be in charge of customer data and meters and establish open, transparent, and non-discriminatory procedures for access to aggregated data sets that could be used by third parties to provide DER services to customers in the distribution system.

DERs, including distributed generation, demand response, and energy efficiency, would be owned by the customer behind the meter or may be owned by a third party. But the distribution system owner would be prohibited from providing DER products and services in their territory directly or indirectly—through itself or through an affiliate. And any provision of information to DER providers regarding distribution system customers would have to be through the IDSO on a non-discriminatory basis. The IDSO would provide for development of all rules and tariffs regarding the use and operation of DER within the system and would do so on a non-discriminatory open access basis. The business model of the IDSO will be an important and complex question to answer going forward, but we do not address this issue here since the business model will depend on the specific structure.

We understand the sensitivities distribution utilities will have in allowing an independent entity to coordinate and control its assets allowing for rapid growth of third-party DERs, but we believe there are achievable pathways that can benefit both distribution utilities and third-party DER providers.

This proposed structure would prevent monopoly ownership and control and enhance competition while creating as much market certainty as possible to all participants. A correctly devised and implemented independent distribution system operation would: (1) provide increased savings and control by consumers; (2) allow for distribution system owners to adequately recoup their costs; and (3) stimulate innovation on the electric grid. In concept, the IDSO would provide a solutions-oriented approach that, at a minimum, allows independent system control, non-discriminatory rates, appropriate control of operations, and the ability to provide reliable service.

Additional criteria for the structure of the IDSO include:

a) Ensuring that the IDSO is truly independent with a governing board that has no financial interests in conflict with the IDSO;

b) Giving discretion in determining services needed, provided certain criteria are met;

c) Conducting a collaborative process;

d) Having an open architecture, flexibility in approach and design of market mechanisms, and the ability to adjust with technology and market evolution;

e) Having the ability and transparency to aggregate demand side resources and feed them into the wholesale market;

f) Maintaining a program of clear data analysis, a reporting function, and market information and monitoring with cost and benefits benchmarks;

g) Having a transparent and fair access and interconnection process and charges; and

h) Being chosen based on merits and qualifications as defined by the Commission.

IV. WHY IDSO FOR NEW YORK?

While the staff recommendation sets forth the DSPP model, we believe there are other models that could benefit and should be considered for New York. In fact, Rana Mukerji, Senior Vice President of New York Independent System Operator ("NYISO") was quoted in an article titled "Reinventing the Grid" in *Public Utilities Fortnightly* in which he states,

> "There would be an entity, the [independent] distribution system operator (DSO), which would coordinate the distribution players. The DSO would have a purely regulated, goal-driven paradigm. It would offer a nondiscriminatory, open access structure for both supply and demand resources to compete in the distribution space. The DSO's other role would be to aggregate distribution resources and feed them into the ISO market."[6]

Mujarki goes on to describe what a market in New York could look like where supply and demand would be elastic and function in real time—transparently and seamlessly—based on economic signals. "The DSO would manage the load shape, hour by hour and minute by minute, and provide a framework for different players to compete, aggregate, and feed resources into the wholesale market," states Mujarki.

Although this construct is not the same as that proposed by the Commission staff, it should be considered as a viable alternative subject to the same criteria set forth above. In addition to support from NYISO, others have been thinking about this concept and proposing a similar framework. Another piece in *Public Utilities Fortnightly* by Farrokh Rahimi and Sasan Mokhtari of Open Access Technology International, Inc. (OATI), [7] describes the DSO model as a "transactive" framework that extends trading to end-use consumers, or "prosumers", a term used often by Commission Chair Audrey Zibelman. The GridWise Architecture Council defines "Transactive Energy" as "as set of economic and control mechanisms that allows the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter."[8] The transactional value of energy would be based on quantity, value, time, and location. And as Rahimi and Mokhtari point out, "for the Transactive Energy paradigm to work effectively across the various layers of power system operation as well as among prosumers, the traditional role of the operator of the distribution system must be expanded to ensure it can effectively function as a reliability custodian to maintain distribution system integrity while facilitating transactive operations."[9] In our proposed model, the IDSO assumes a full conversion from the

[6] *Public Utilities Fortnightly*, March 2014, "Reinventing the Grid", by Michael T. Burr http://www.fortnightly.com/fortnightly/2014/03/reinventing-grid

[7] *Public Utilities Fortnightly*, June 2014, "From ISO to DSO", by Farrokh Rahami and Sasan Mokhtari, http://www.fortnightly.com/fortnightly/2014/06/iso-dso

[8] "GridWise Transactive Energy Framework", GridWise Architecture Council, October 2013, Section 3.2, Page 9.

[9] *Public Utilities Fortnightly*, June 2014, "From ISO to DSO", by Farrokh Rahami and Sasan Mokhtari, http://www.fortnightly.com/fortnightly/2014/06/iso-dso

existing utility model to this transactive system.

Achieving such a marketplace where DERs behind the meter communicate on the same level as bulk power systems will take time. But without an independent entity managing the operation of the distribution system, we believe that the inherent conflict between the owner of the distribution assets and the entities interconnected to or desiring to interconnect to that asset will prevent distributed energy resources from realizing their full operational and market potential.

V. CONSUMER ENGAGEMENT

Key to enabling a more efficient, cleaner, and less costly system that allows for innovation, will be including the consumer as a true partner. Given that smart meters have started proliferating in parts of New York, granular energy-consumption data are being gathered by utilities but should be made available to consumers and their designated third parties to allow for a greater understanding of how energy is used and where the potential savings lie. Senators Mark Udall (D-CO) and Ed Markey (D-MA) recently introduced a bill in the United States Senate[10] that would make data access a national policy; New York should adopt consumer data access at the state level as well. As data become more granular and instantly available through smart grid and building energy management systems, consumers will need to have control—or give third parties control—over that information to take full advantage of DERs. Access to data will enable consumers to identify areas for potential energy savings and to invest in technologies and solutions that will help them reap those savings.

Rate options like--Critical Peak Pricing, Peak Time Rebate, Time-of-Use, Dynamic Pricing—may not give consumers as much flexibility as they will want given the granularity of data and ability of DERs to respond in real time to economic signals. Simple, yet infinitely flexible pricing based on performance at a given time will be most valuable to consumers.

Another consumer consideration is with large consumers that participate in DERs —whether with demand response, energy efficiency, or ancillary services — directly or through their own provider. Consumers that are aggregated by DER providers to provide grid resources should not be forced into a DSPP construct with a utility when a competitive third party -- like an energy service company ("ESCO") -- might be equally or more efficient and cost-competitive. In addition, these consumers should not be penalized for delivering these DER services to the grid with surcharges levied by the utility. The ISDO construct will allow for these consumers to have the greatest ability to provide services to the grid while managing their energy use and creating their own paths to save energy.

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[10] Access to Consumer Information Act or E-Access Act, S. 2165 introduced March 27, 2014. Summary: https://www.ase.org/resources/summary-e-access-act

An example from a large customer points to the need for a structure independent of the utility: first, the customer pays for energy efficiency investments; the customer then applies for rebates; the customer then pays an amount much greater into the energy efficiency program line item than the limited rebate received; then often the customer rate increases per kilowatthour because they are using less energy have moved into a new rate bracket; then the utility fights in a rate case to be made whole for the energy it did not sell; and, finally, the utility requests an incentive credit for promoting energy efficiency. This case may sound extreme but it points to the perverse incentive structure in the current utility construct. Having the IDSO manage these programs will remove those burdens and costs while empowering the consumer who is able to aggregate multiple DER across an independent party--the IDSO--rather than relying on the utilities to provide services that are working, in effect, against their best interest.

VI. DISTRIBUTED ENERGY CONSIDERATIONS

For New York, the IDSO model creates an incredible opportunity for technologies and applications that have been researched and developed in a rich ecosystem of state laboratories, start-ups, clean energy companies, and financial institutions. Solar, wind, and hydropower can work in concert through smart grid technologies with energy efficiency (including management and controls), demand response, energy storage, CHP, and microgrids to take full advantage of the regional clean-energy sector while providing the greatest savings for consumers in New York. With the IDSO model, it will be unnecessary to establish complex energy settlement accounting rules in an effort to reconcile multiple loads and resources for the utility. Technologies like energy storage that fall into a gray area where applications can look like load or resource (since energy storage can both inject and absorb energy—both of which can be valuable services) should be able to be valued for their full set of benefits, and that can best be achieved with the IDSO construct.

VII. RECOMMENDATIONS

Initiate Proceeding

As the next step in the REV process, we recommend that the Commission convene a proceeding to determine the appropriate entity or entities to become the IDSOs for the New York distribution utilities. That process should assess the operational, planning, and process capabilities of the entities considered. The Commission should determine whether the NYISO would consider becoming the IDSO on a contract basis to the state, and if so, the Commission should consider how the IDSO functions could be integrated into the current functions of the NYISO.

Utility Plans

Simultaneous with the convening of a proceeding to investigate the IDSO options, the Commission should order each entity under the Commission's jurisdiction who owns, controls, or operates facilities used for distributing electric energy within the State of New York to develop and submit a plan to the Commission as to the necessary steps to turn the operation of their distribution system over to an IDSO designated by the Commission.

Benefits Analysis

Critical to ensuring that both consumers and energy providers in New York are benefiting from a competitive distribution model will be establishing an analytic framework for calculating all of the costs and benefits associated with such a system. Continuous monitoring and verification of this process will be necessary to allow for adjustments to be made that protect consumers and system operators.

As the REV proceeding suggests, we also recommend that the Commission estimate potential quantitative benefits in cost savings as well as less easily quantified benefits that include better use of existing assets and institutions, new market mechanisms, technical innovation, and less rate distortion. These system changes should enable all distribution system buyers and sellers of electricity to have open access to the distribution system, while ensuring an orderly and fair transition that maintains the integrity and reliability of the electric grid and existing infrastructure.

The IDSO should calculate benefits of technologies and their applications on the system with respect to the following values:

a) Greenhouse gas emission reduction

b) Social cost of carbon

c) Reduced need for additional grid build-out and generation purchase

d) Generation, capacity, and ancillary services provided

e) Increased overall efficiency of system

f) Increased resilience and reliability

The following costs should be considered as well:

a) Stranded assets on existing system

b) Reduced load and associated lost profits from that reduction

c) Implementation of climate mitigation and facility hardening

d) Cybersecurity and privacy provisions

Whether or not the costs and benefits of behind-the-meter assets are calculated for ratemaking purposes, there should be an explicit recognition of a consumer's right to self-generate and offset internal load with that generation. In addition, any cost calculations should be offset by the value of additional incentives available on the state and federal level, such as tax credits and bonus or accelerated depreciation.

VIII. OUTCOMES

We believe that with a fully competitive distribution model, New York can enjoy enormous benefits of a cleaner, more innovative grid and provide a template for other states to follow. As the state works toward meeting the greenhouse gas emission targets set forth in the Clean Air Act 111(d) rule[11], this model will enable full deployment of the cleanest resources available. In addition, the bulk-power system operated by NYISO that will be increasingly populated with cleaner, potentially more valuable resources will be able to interact with DERs in such a way that maximizes the value of the bulk-power resources. DERs will in effect function as "virtual power plants" that can be fully integrated with the existing bulk power system.

IX. CONCLUSION

In conclusion, we believe the Commission should seriously consider the IDSO construct laid out here, opening up a new proceeding to gather additional information for the record, requiring utilities to develop comprehensive energy plans for the transition, and analyzing the entire value stream for DER to ensure that consumers in New York can take advantage of all benefits afforded by those resources. We remain convinced that this model will give utilities the ability recoup their investments, give consumers savings, and allow distributed resources to participate in a competitive market. The result will be a cleaner, more efficient, interactive grid in New York that can serve as a national model for other states to emulate.

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[11] Environmental Protection Agency draft rule: http://www2.epa.gov/sites/production/files/2014-05/documents/20140602proposal-cleanpowerplan.pdf

Kristov Discussion

USD School of Law
Climate and Energy Law Symposium
November 7, 2014

Panel One: The Utility of the Future

"Distribution System Operator Models and Regulatory Questions They Raise"

Presentation by Lorenzo Kristov, Ph.D.

Principal, California Independent System Operator

The proliferation of diverse, distribution-connected energy resources (DER) is challenging traditional utility operating, planning and business paradigms in a number of ways.

Distribution system operation will no longer be simply the delivery of energy from central station generators to end-use customers. With high penetration of DER, distribution utilities must maintain reliability with more variable, multi-directional energy flows coming from potentially thousands of small, independently operated generating and storage facilities and micro-grids.

Distribution planning will have to go beyond conventional planning for incremental load growth, to ensure reliable integration of rooftop and community solar, electric vehicles, smart buildings, smart campuses and smart cities. Moreover the adoption of these new modes of energy supply and use is being driven at least as much from the bottom up - by end-use customer demands, local climate action plans, and more powerful, less expensive enabling technologies - as it is from the top down by policy-based directives and incentives. In the context of increasing climate volatility and cyber security concerns, local jurisdictions and state regulators are seeking to implement more local approaches to reliability and resilience to systemic disturbances.

In the business realm, the volumes and prices of commodity energy will continue to decline due to the combined effects of low marginal cost renewable energy and increased penetration of behind-the-meter solar arrays. Before long most rooftop solar installations will be combined with energy storage, even further reducing end-use customers' need to rely on the utility for energy supply. Thus utility business models based on continued growth of kilowatt-hour sales do not seem to offer a secure future.

One potentially viable approach to these challenges is for utility distribution companies to re-formulate themselves as distribution system operators (DSOs). At present there are several different DSO models being discussed across the industry, which means the field is very fluid and opportunities are ripe for utilities to develop DSO models that work for their service areas. Under almost any DSO design, however, there will be fundamental functional requirements to operate the distribution system in the new high-DER environment, and these in turn will drive needs for investment in electrical and communications infrastructure for the distribution system. Thus a utility business model centered on providing a reliable distribution network, in a manner that accommodates the different needs and desires of residential customers, large installations like medical and university campuses, business enterprises and municipalities, would seem to offer a potentially viable future.

At the same time, the DSO concept raises regulatory questions that will need to be resolved. One set of questions has to do with the significance of the transmission-distribution interface in the high-DER electricity system. Traditionally the transmission-distribution substation, where the high-voltage meshed transmission network meets the lower-voltage radial distribution circuits, has been a pretty clear boundary for operational, planning, market and jurisdictional purposes. As the industry moves to a high-DER structure with new DSO entities, the future of these boundary functions will require some re-thinking.

Van Nostrand Paper

KEEPING THE LIGHTS ON DURING SUPERSTORM SANDY: CLIMATE CHANGE ADAPTATION AND THE RESILIENCY BENEFITS OF DISTRIBUTED GENERATION

James M. Van Nostrand[*]

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Abstract: *Hurricane Sandy (ultimately downgraded to "Superstorm" Sandy by the time it hit the coasts of New York and New Jersey in late October 2012) was the most lethal and destructive hurricane in 2012, resulting in 285 deaths, $68 billion in damages, and 8.5 million utility customers in the eastern U.S. losing power. Superstorm Sandy provided a "wake up call" for electric utilities on the need to adopt a different set of long-term planning tools to improve*

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the resilience of the electric system to cope with the anticipated extreme weather events of the future. The experience of Superstorm Sandy provides a case study of the system resiliency benefits of distributed generation (DG) resources and microgrids, and valuable lessons that can be learned as utilities plan for increasingly frequent extreme weather events of the future.

This article examines legal and regulatory tools that can be used to encourage electric utilities to move in the direction of a DG-based model, and focuses in particular on the Con Edison rate proceeding in New York. In that recently concluded proceeding, utility regulators had an opportunity to consider a "traditional" approach proposed by the utility—featuring transmission and distribution infrastructure investments—alongside a competing view of a "utility of the future" offered by environmental parties, geared toward a more resilient system that integrates DG resources and microgrids. In a precedent-setting order issued by the New York Public Service Commission (PSC) on February 21, 2014, the PSC required Con Edison to make significant investments "to enhance system reliability, to achieve a higher level of storm hardening and resiliency in the face of anticipated climate change and sea level rise." Con Edison was directed to take specific steps to use DG resources as an alternative to traditional infrastructure, to facilitate DG installations in its service territory, and to develop an implementation plan for microgrids in its service territory. More broadly, utilities in New York were directed to integrate predicted impacts from climate change into their long-term system planning processes.

The article also examines other legal theories that can be used in utility regulatory proceedings to move utilities toward a new utility paradigm that features DG resources, including the prudent investment standard, the doctrine of "used and useful," and the requirement to set "cost-based" rates.

I. INTRODUCTION

Hurricane Sandy (ultimately downgraded to "Superstorm" Sandy by the time it hit the coasts of New York and New Jersey in late October 2012) was the most destructive hurricane in 2012 and the second costliest storm in U.S. history, resulting in $68 billion in damages and 286 deaths.[1] The storm had a diameter of almost 1,000 miles, and produced a storm surge of 14 feet at the Battery in lower Manhattan that was at least three feet higher than previously reported storm tides.[2]

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[1] Ejaz Kahn, *10 Most Destructive Hurricanes in U.S. History*, WONDERSLIST, available at http://www.wonderslist.com/10-destructive-hurricanes-u-s-history/; Aon Benfield, *Annual Global Climate and Catastrophe Report, Impact Forecasting 2012*, available at http://thoughtleadership.aonbenfield.com/Documents/20130124_if_annual_global_climate_catastrophe_report.pdf, at 24.

[2] New York Pub. Serv. Comm'n, Case 13-E-0030, Consolidated Edison Company of New York, Inc., Testimony of Electric Infrastructure and Operations Panel, available at

About 8.5 million utility customers in the eastern U.S. lost power during Sandy, and more than 650,000 homes were damaged or destroyed.[3] Apart from the sheer magnitude of the disaster in terms of fatalities and destruction, Superstorm Sandy provided a "wake up call" for energy providers, and electric utilities in particular: a different set of long-term planning strategies to improve the resilience of the electric system to cope with the anticipated extreme weather events of the future is urgently needed. One strategy is expanding the role for distributed generation (DG) resources.

The electric utility industry in the U.S. (and in most developed countries) generally features large, central generating stations that produce the electricity, which is then transmitted along high-voltage transmission lines to local distribution systems where it is delivered to end users.[4] This article describes how DG resources, which are small-scale generating resources located near and connected to the electrical load being served, with or without grid interconnection,[5] offer an alternative that has attractive features for coping with climate change.[6] Although DG resources also may have advantages as tools to reduce greenhouse gas (GHG) emissions,[7] this article will focus primarily on the

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http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A3EFED44-5E61-42B6-9348-7AB59BAA8CB5}, at 14-15.

[3] *Id*. at 15; Doyle Rice and Alia Dastagir, *One Year After Sandy, 9 Devastating Facts*, USA TODAY, Oct. 29, 2013, available at http://www.usatoday.com/story/news/nation/2013/10/29/sandy-anniversary-facts-devastation/3305985/.

[4] Joel E. Eisen, *Distributed Energy Resources, "Virtual Power Plants," and the Smart Grid*, 7 ENVT'L & ENERGY L. & POL'Y J. 191, 192 (2012) ("Over the past 100 years, we have created an electric grid that is a complex network of large, fossil fuel-fired power plants located far from end users, with high-voltage transmission lines and lower voltage distribution lines carrying electricity to millions of consumers.")

[5] NYS 2100 COMMISSION, *Recommendations to Improve the Strength and Resilience of the Empire State's Infrastructure*, available at http://www.governor.ny.gov/assets/documents/NYS2100.pdf [hereinafter NYS 2100 COMMISSION REPORT], at 182 ("Distributed Generation (DG): Small electrical power generators installed in homes, businesses, and office buildings, that can supply power to a location when grid power is not available.")

[6] Eisen, *supra* note 4 at 193 ("Given the urgency to address climate change, [distributed energy resources] have become especially important as part of a portfolio of solutions to reduce fossil fuel use (and resulting GHG emissions) in the electricity sector of the economy and adapt to the changing climate.")

[7] DG resources, if fueled by renewable resources (solar, wind, biomass and geothermal), can be an effective climate change mitigation strategy when used to displace the GHG emissions produced by large, centralized coal, oil and natural gas-fired plants. Kyle Siler-Evans, Ines Lima Azevedo, M. Granger Morgan & Jay Apt, *Regional Variations in the Health, Environmental, and Climate Benefits of Wind and Solar Generation*, PNAS, available at http://www.pnas.org/content/110/29/11768.full. Even non-renewable DG resources, such as high-efficiency natural gas-fired CHP, or cogeneration, can provide GHG reduction benefits through

advantages of implementing DG resources as an adaptation strategy capable of improving the resiliency of the electric system in the face of the increasing frequency of extreme weather events.[8] Extreme weather events, sea level rise, and increasing temperatures create potential threats to utility infrastructure and the delivery of electricity.[9] The article describes how a more distributed power grid, utilizing DG resources, would avoid some of the systemic vulnerabilities of the centralized large grid, which has inherent exposures as a result of being regionally interconnected.[10] The experience of Superstorm Sandy provides a case study of the system resiliency benefits of DG resources, and the lessons that can be learned as utilities plan for increasingly frequent extreme weather events.

The impact of Superstorm Sandy on the electric utilities operating in the region was unprecedented;[11] extensive power outages affected the region for days. However, many commercial and industrial facilities and educational institutions in the area (including Princeton University's campus in New Jersey and New York University's campus in lower Manhattan) were largely able to maintain operations, due to on-site DG facilities, primarily cogeneration or combined heat and power (CHP) facilities.[12] DG resources can improve the resilience of the

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increased energy efficiency achieved by integrating electric power generation with heating and cooling loads. EPA, *Combined Heat and Power Partnership, Basic Information*, available at http://www.epa.gov/chp/basic/index.html.

[8] The National Climate Assessment states that "[e]xtreme weather events and water shortages are already interrupting energy supply, and impacts are expected to increase in the future." U.S. GLOBAL RESEARCH PROGRAM, *Climate Change Impacts in the United States, Chapter 4, Energy Supply and Use*, available at http://nca2014.globalchange.gov/report/sectors/energy, at 114.

[9] NYS 2100 COMMISSION REPORT, *supra* note 5 at 20.

[10] U.S. DEPARTMENT OF ENERGY, The Potential Benefits of Distributed Generation and Rate-Related Issues that May Impede Their Expansion, available at https://www.ferc.gov/legal/fed-sta/exp-study.pdf [hereinafter DOE STUDY] at 2-3. ("Outages caused by faults and failures in generation are rare. While transmission faults are somewhat more common, 94% of all power outages are caused by faults and failures in the distribution system.") *Id*.

[11] One news report noted the "unprecedented confluence of hurricane-force winds and record-high storm surges," which resulted in a "historically large" response from utilities. Jon Hurdle, *After Sandy, Utilities Face Biggest Restoration Challenge*, BREAKING ENERGY, November 6, 2012, available at http://breakingenergy.com/2012/11/06/after-sandy-utilities-face-biggest-restoration-challenge/

[12] As noted in the NYS 2100 COMMISSION REPORT, CHP or cogeneration facilities were "able to keep the lights on during the hurricane using microgrids." NYS 2100 COMMISSION REPORT, *supra* note 5 at 101. A combined heat and power (CHP) system is a DG resource that uses an on-site electrical generator, typically fueled by natural gas, to provide electricity and thermal energy (usually in the form of steam or water) to a single large building or, in the case of a microgrid or district energy system, to a campus or group of facilities. After capturing heat that would otherwise be wasted as a byproduct of electricity generation, a CHP system converts that heat into useful thermal energy for space heating, cooling or other processes. EPA, *Combined Heat and Power Partnership, Basic Information*, available at http://www.epa.gov/chp/basic/index.html.

electrical grid and mitigate the impacts of an outage by enabling critical facilities to maintain essential operations.[13] If the electrical grid is experiencing an outage, DG systems can be configured to "island" from the grid, thereby maintaining uninterrupted power supplies to utility customers within a "microgrid."[14] That was the experience from Superstorm Sandy, where the use of microgrids and DG resources enabled power to be provided to pockets of utility customers in the face of widespread outages of central power plants and the associated transmission and distribution (T&D) systems.[15]

Notwithstanding the lessons learned from Superstorm Sandy regarding the potential role of DG resources in enhancing utility system resiliency, the response of both Consolidated Edison Company of New York (Con Edison)—the utility serving New York City—and Public Service Electric & Gas Company (PSE&G)—the largest utility serving New Jersey—was to propose substantial rate increases to cover the expenditures to "harden" the utility system and reinforce the traditional central generation model (and associated T&D systems).[16] Con Edison's rate request in New York included a commitment to spend $1 billion in "storm hardening structural improvements" over the next four

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"Capturing and using the waste heat allows CHP systems to reach fuel efficiencies of up to 80%, compare with about 45% for conventional separate heat and power." ICF INTERNATIONAL, *Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities*, March 2013 [hereinafter ICF REPORT], available at http://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_critical_facilities.pdf, at 4. CHP systems generally do not operate independently from the electrical grid, as the grid is necessary for (1) supplemental power to meet peak electricity needs, and (2) backup power when the CHP system is unavailable because of maintenance or an outage. *Id*. Because the supply of natural gas is generally not dependent upon electricity from the grid, a CHP system can continue to operate during an outage on the grid, thereby ensuring that the host facility will be able to maintain essential operations. *Id*. In the case of the NYU campus, for example, the CHP system was able to "keep the larger buildings and core of the Washington Square campus heated and powered throughout the storm and in the weeks that followed, while surrounding buildings were cold and dark." NYS 2100 COMMISSION REPORT, *supra* note 5 at 101.

[13] Eisen, *supra* note 4 at 193 (Distributed energy resources "help the electric grid by increasing grid reliability and resilience, making the grid less vulnerable to prolonged power failures.")

[14] Microgrids are small distribution systems that can interconnect and coordinate a number of DG resources into a network capable of serving all or a portion of the energy needs of a cluster of users. NEW YORK STATE ENERGY AND RESEARCH DEVELOPMENT AUTHORITY, *Microgrids: An Assessment of the Value, Opportunities and Barriers to Deployment in New York State*, (2010, available at www.nyserda.ny.gov at S-1. Depending upon their configuration, microgrids can be "islanded" to operate independently from the utility grid. NYS 2100 COMMISSION REPORT, *supra* note 5 at 95 ("'Microgrids' refers to clusters of homes and buildings that share a local electric power generation and/or energy storage device while disconnected from the utility grid.")

[15] NYS 2100 COMMISSION REPORT, *supra* note 5 at 101.

[16] *See infra* text accompanying notes 17- 18.

years.[17] PSE&G, for its part, proposed an "Energy Strong" program to spend $3.9 billion over four years to harden its system by, among other things, protecting switching and substations, strengthening its pole distribution system, and undergrounding overhead distribution lines.[18]

An alternative approach would embrace the resiliency to climate change provided by DG resources and related innovative technology. In contrast to the "business as usual" filings of Con Edison and PSE&G, a better approach would involve a fundamental re-examination of the manner in which electric utility service is delivered, with a focus on measures that improve the resilience of the grid. Rather than relying on traditional methods to prepare for the next major storm based on the weaknesses exposed by the last one, a better solution may be to realign the priorities of a utility's major capital expenditures toward investing in the "utility of the future"—a utility designed to withstand the extreme weather events that are likely to occur decades into the future.[19] A key attribute of the "utility of the future" is the ability to integrate widely dispersed DG resources and widespread deployment of microgrids, both of which work to reduce the dependence on the traditional model of large centralized generating stations and extensive (and vulnerable) T&D networks.

This article focuses on legal and regulatory tools that can be used to encourage electric utilities to move in the direction of a DG-based model. One such tool is using general rate proceedings as forums to challenge the "business as usual" approach typically followed by utilities.[20] This article focuses in particular

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[17] New York Pub. Serv. Comm'n, Case 13-E-0030, Consolidated Edison Company of New York, Inc., Letter from Craig S. Ivey, President, Con Edison to Jeffrey C. Cohen, Acting Secretary, New York PSC, Jan. 25, 2013, available at https://www2.dps.ny.gov/ETS/jobs/display/download/2997631.pdf, at 1.

[18] New Jersey BPU Dockets EO13021055 and GO13020156, PSE&G, available at http://www.pseg.com/family/pseandg/tariffs/reg_filings/pdf/EnergyStrong.pdf, [hereinafter PSE&G FILING], Petition at 4.

[19] The National Climate Assessment notes that "U.S. energy facilities and systems, especially those located in coastal areas, are vulnerable to extreme weather events." U.S. GLOBAL RESEARCH PROGRAM, *Climate Change Impacts in the United States, Chapter 4, Energy Supply and Use*, available at http://nca2014.globalchange.gov/report/sectors/energy, at 115. The impacts of extreme weather events "are expected to increase in the future." *Id*. at 114.

[20] The "business as usual" approach is illustrated by Con Edison's January 2013 rate filing (*supra* note 17) and PSE&G's "Energy Strong" filing (*supra* note 18), where the rate relief was directed toward spending on traditional T&D infrastructure rather than investments in energy efficiency and DG resources, which have been characterized as "peripheral elements of the electric system." New York Pub. Serv. Comm'n, Case No. 07-M-0548, *Order Approving EEPS Program Changes*, Dec. 26, 2013, available at http://www3.dps.ny.gov/W/PSCWeb.nsf/All/06F2FEE55575BD8A852576E4006F9AF7?OpenDocument. In its December 2013 order in the Energy Efficiency Portfolio Standard (EEPS)

on the Con Edison rate proceeding in New York, where utility regulators had an opportunity to consider the "traditional" approach proposed by Con Edison alongside a competing view of the "utility of the future" offered by environmental parties, which featured less investment in T&D infrastructure in favor of DG (including high-efficiency cogeneration in particular), as well as smart grid investments to empower consumers to reduce their reliance on the grid.[21] Another such tool is the authority of regulatory agencies to direct utilities to take climate change adaptation into account in long-term system planning.[22] In New York, for example, the Columbia Law School Center for Climate Change Law and a number of other environmental and public interest organizations filed a petition with the New York Public Service Commission (PSC) in December 2012 requesting that the PSC use its regulatory authority to require all utility companies within its jurisdiction to prepare and implement comprehensive natural hazard mitigation plans to address the anticipated effects of climate change.[23]

In addition to these tools, there are legal theories that can be used in utility regulatory proceedings to push utilities toward a new utility paradigm that takes advantage of the resiliency benefits of DG resources. One such theory is the prudence standard in utility ratemaking,[24] which can be used to challenge expenditures by utilities on T&D infrastructure. Because DG resources allow the generation to be located closer to the load, some spending on T&D infrastructure may be shown to be unnecessary if DG resources represent a more cost-effective solution.[25] Another legal theory involves the doctrine of "used and useful," which would preclude a utility from earning a return on assets that are "excess" to its needs in providing utility service to the public.[26] Because DG resources are smaller in scale, utilities can more precisely match their generating resources with

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proceeding, the New York PSC commenced a "comprehensive inquiry and redesign" of the regulatory model necessary to support "customer-based technologies as a core source of value to electric customers." *Id.* at 2, 21.

[21] *See infra* Section III.A.

[22] *See infra* Section III.B.

[23] New York Pub. Serv. Comm'n, Matter No. 12-02754, *Petition on Natural Hazard Planning*, Dec. 12, 2012, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A7D27EFB-2CE0-4ABE-8D22-B9D629B9C3BE} [hereinafter COLUMBIA PETITION]

[24] *Duquesne Light Company v. Barasch*, 488 U.S. 299, 309 (1989) ("Under the prudent investment rule, the utility is compensated for all prudent investments at their actual cost when made (their 'historical' cost), irrespective of whether individual investments are deemed beneficial or necessary in hindsight.")

[25] *See infra* Section III.C.

[26] *Denver Union Stock Yard Co. v. U.S.*, 304 U.S. 470, 475 (1938).

their customers' electricity demand.[27] As a result, regulators have a basis for disallowing the excess generation that often results from reliance on the traditional model of large, centralized generating facilities. Finally, utility regulatory commissions, in setting "cost-based" rates, should be encouraged to reflect in those rates all the benefits of DG resources. The Energy Policy Act of 2005 required DOE to conduct a study of the benefits of DG and the rate-related issues that impede its expansion;[28] DOE's February 2007 study identifies many of these benefits.[29] States have a wide degree of latitude in setting "cost-based" rates,[30] and they should be encouraged to exercise this authority in favor of DG solutions.

II. DG AS A CLIMATE CHANGE ADAPTATION STRATEGY: SUPERSTORM SANDY AND THE SUCCESSES OF DG RESOURCES

A. The Impact of Superstorm Sandy on Utility Systems in the Northeast

Prior to Superstorm Sandy, electric utilities operating in the Northeast had experience with the dangers posed by storms and other extreme weather events. In 2011, for example, Hurricane Irene left nearly 4 million homes and businesses without power between Folly Beach, North Carolina and Portland, Maine.[31] In New York City, over 70,000 Con Edison customers lost power as a result of Hurricane Irene, and the numbers were even higher on Long Island (over 320,000 customers) and in New Jersey (412,000 customers).[32] In New York, a substation operated by Con Edison located near the East River in southeast Manhattan survived a storm surge of 9.5 feet during Hurricane Irene.[33]

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[27] As described in Section III.D. *infra*, DG resources provide the ability to install additional generating capacity in smaller increments.

[28] Energy Policy Act of 2005, Section 1817.

[29] DOE STUDY, *supra* note 10.

[30] *Re California Pub. Util. Comm'n*, Order Granting Clarification and Dismissing Rehearing, 133 FERC ¶ 61,059, 2010 WL 4144227 (FERC, 2010) ("[S]tates are allowed a wide degree of latitude in establishing an implementation plan for Section 210 of PURPA, as long as such plans are consistent with our regulations. Similarly, with regard to review and enforcement of avoided cost determinations under such implementation plans, we have said that our role is generally limited to ensuring that the plans are consistent with section 210 of PURPA.") 133 FERC at ¶ 61,266.

[31] Chris Kahn, *Hurricane Irene Power Outages: Electricity Blackouts Affect 4 Million Homes and Businesses*, HUFFINGTON POST, Aug. 28, 2011, available at http://www.huffingtonpost.com/2011/08/28/hurricane-irene-power-outages_n_939441.html.

[32] Jen Chung, *Power Outages In NYC Region As Hurricane Irene Arrives*, GOTHAMIST, Aug. 28, 2011, available at http://gothamist.com/2011/08/28/power_outages_in_nyc_region_as_hurr.php

[33] Jeff Donn, Jonathan Fahey, Dave Carpenter, *NYC Utility Prepped for Big Storm, Got Bigger One*, ASSOCIATED PRESS, Oct. 31, 2012, available at http://bigstory.ap.org/article/coned-prepped-big-storm-got-even-bigger-1.

In anticipation of Superstorm Sandy, Con Edison shut off power to sections of lower Manhattan in order to better protect underground equipment,[34] and planned its defense measures based on the record 11 foot storm surge recorded in 1821.[35] Con Edison did not expect the design limit of 12.5 feet to be threatened.[36] But Superstorm Sandy created a 14 foot storm surge that flooded into the East River substation and destroyed underground equipment, leaving about 250,000 customers without power as "the blinding flash of an explosion lit the most famous skyline in the world, then plunged the bottom third of Manhattan into darkness."[37] The area below 39th Street in Manhattan was renamed by some as "SoPo," or "South of Power," after five days without power.[38]

Superstorm Sandy caused five times more outages in the Con Edison service territory than Hurricane Irene, and represented the worst natural disaster in Con Edison's history.[39] As a result of Superstorm Sandy, about one-third of Con Edison's customers—1,115,000 out of 3.3 million—lost power.[40] In order to restore power, Con Edison and its associated crews had to replace 140 miles of electric cable and respond to damages at 30,000 different locations.[41] In a single week, Con Edison used a six-month supply of utility poles and transformers.[42] Con Edison was able to restore service to 98 percent of the affected customers within 12 days.[43]

In some regions of New York, power was not restored for two weeks or more.[44] As noted in the *NYS 2100 Commission Report*, "[m]any of the power plants, substations and other electric system infrastructure in the downstate region of New York are clustered in or near coastal areas, making them vulnerable to the

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[34] Cara Buckley, William Rashbaum, *Power Failures and Furious Flooding Overwhelm Lower Manhattan and Red Hook*, N.Y. TIMES, Oct. 29, 2012, available at http://www.nytimes.com/2012/10/30/nyregion/red-hook-residents-defy-evacuation-warnings-drinks-in-hand.html?_r=0.
[35] Donn, *supra* note 33.
[36] *Id*.
[37] *Id*.
[38] NYS 2100 COMMISSION REPORT, *supra* note 5 at 81.
[39] Con Edison, *Superstorm Sandy, 2013 State of the Company*, available at http://www.conedison.com/ehs/2012-sustainability-report/engaging-stakeholders/reliability/superstorm-sandy/index.html#gsc.tab=0.
[40] New York Pub. Serv. Comm'n, Case 13-E-0030, Testimony of Electric Infrastructure and Operations Panel, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A3EFED44-5E61-42B6-9348-7AB59BAA8CB5} at 15.
[41] Con Edison, *Superstorm Sandy*, *supra* note 39.
[42] *Id*.
[43] *Id*.
[44] NYS 2100 COMMISSION REPORT, *supra* note 5 at 81.

type of flooding encountered" as a result of Superstorm Sandy.[45] Long Island's electrical system experienced "widespread devastation and outages of record number and duration"; 1.1 million, or 90 percent, of Long Island Power Authority's (LIPA) customers experienced outages.[46] Over the course of its efforts to restore service, LIPA replaced more than 4,500 poles and 2,100 transformers, and repaired approximately 400 miles of distribution lines; 44 substations were impacted by Superstorm Sandy.[47]

In New Jersey, Superstorm Sandy affected about 2 million of PSE&G's customers, and was described as the "largest and worst storm" in the utility's history.[48] As compared with Hurricane Irene, Superstorm Sandy involved more than twice the number of customers, with over 90 percent of PSE&G's customers losing power.[49] 96 electric substations, or 39% of PSE&G substations were affected, and 51 out of 154 transmission lines, or 33% of lines, totaling 1,517 miles in length, were interrupted.[50] In PSE&G's service territory, 355 of its sub transmission lines (totaling 2,499 miles in length) were interrupted, 320 miles of conductor were replaced from Newark to Pittsburgh, and 2,427 utility poles, 1,022 transformers, and 1,282 overhead and underground distribution circuits were damaged.[51] PSE&G estimated the cost associated with the restoration of its distribution and transmission system following Superstorm Sandy and the subsequent Nor'easter to be approximately $250 - $300 million.[52]

B. Utility Rate Filings in the Aftermath of Superstorm Sandy: The Need for "Storm Hardening"

Within three months of Superstorm Sandy's destruction, Con Edison filed a request for a massive rate increase with the New York PSC, with the "vast majority of the expenditures . . . relat[ing] to lessons learned from Superstorm Sandy about the vulnerability of Con Edison's system to extreme weather

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45 *Id*.
46 *Id*.
47 LONG ISLAND POWER AUTHORITY, *Update on Hurricane Sandy*, Nov. 19, 2012, available at http://www.lipower.org/newscenter/pr/2012/111912-update.html.
48 New Jersey BPU Dockets EO13021055 and GO13020156, PSE&G, Petition, available at http://www.pseg.com/family/pseandg/tariffs/reg_filings/pdf/EnergyStrong.pdf, at 2.
49 *Id*.
50 PSE&G OUTLOOK, *Special Edition: Superstorm Sandy*, December 2012, available at http://www.pseg.com/info/retiree/pdf/Outlook_1212_Sandy.pdf, at 2.
51 *Id*.
52 PSE&G, *PSEG Estimates the Utility's Cost of Superstorm Sandy Restoration*, Dec. 4, 2012, available at http://www.pseg.com/info/media/newsreleases/2012/2012-12-04.jsp#.Uo0LMKMo670.

events."[53] Con Edison's filing letter made its case by focusing on "the need for investments and preventative measure to further strengthen critical infrastructure designed to reduce the impact of future major storms on [the utility's] customers."[54] Con Edison committed to spending $250 million on "storm protection measures" over the next two years, and the filing included approximately $1 billion in "potential storm hardening structural improvements over the next four years that are intended to reduce the size and scope of service outages from major storms, as well as to improve responsiveness and expedite the recovery process to better serve [the utility's] customers."[55] The measures for storm hardening of critical infrastructure incorporated "strategic undergrounding and flood protection projects."[56] These projects involve installation of flood walls to protect electric and steam equipment, raising the elevation of critical equipment in anticipation of higher flood levels, upgrading gas system equipment, and accelerating the schedule for installing submersible equipment.[57] Apart from these "storm hardening" projects, Con Edison also proposed plans to improve the "flexibility" of the electric distribution system.[58] These plans involved installing additional switches and "smart grid" technology as well as reconfiguring certain networks in an effort to minimize the impact of storms on customers.[59]

Con Edison's filing did not provide itemized support for the $1 billion in "storm hardening" expenditures, which consisted of $800 million for the electric system, $100 million for the natural gas system and $100 million for the steam system during calendar years 2013, 2014, 2015 and 2016.[60] With respect to

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[53] New York Pub. Serv. Comm'n, Case 13-E-0030, Testimony of Jackson Morris, Pace Energy & Climate Center, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={81F2C4EB-EE3C-4921-B0F5-C5F4C6E24EF3} [hereinafter MORRIS TESTIMONY], at 5.

[54] New York Pub. Serv. Comm'n, Case 13-E-0030, Letter from Craig Ivey, President of Consolidated Edison Company of New York, Inc. to Jeffrey C. Cohen, Acting Secretary, New York Pub. Serv. Comm'n, Jan. 25.2013, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={B81F8F41-1051-4A89-877C-81C0DB7FB629}, at 1.

[55] *Id*.

[56] *Id*.

[57] *Id*.

[58] *Id*.

[59] *Id*. "Smart grid" generally means "computerizing" the electric grid, through computer-based remote control and automation. DOE, OFFICE OF ELECTRICITY DELIVERY & ENERGY RELIABILITY, *Smart Grid*, available at http://energy.gov/oe/technology-development/smart-grid. This automation technology allows the utility to control remote devices—such as integration of DG resources—from a central location. *Id*.

[60] New York Pub. Serv. Comm'n, Case 13-E-0030, Testimony of Robert Mucillo, Con Edison, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={3F1A34F7-1985-4A66-9D83-418CA43076CB}, at 71-72.

electric system expenditures, the filing identified various "storm hardening" projects, including $63.5 million for Central Operations over 4 years;[61] $90.5 million over 4 years for "capital projects that improve distribution system performance when storms occur";[62] $240 million over 4 years for transmission and substation work;[63] and $215 million in 2013 and 2014 for distribution storm hardening work.[64] With respect to remaining "storm hardening" projects included in Con Edison's $1 billion figure, the utility proposed implementation of a surcharge mechanism that would provide for rate recovery of costs associated with "storm hardening" projects and programs, as identified by Con Edison during periodic filings over the 4-year period.[65] The surcharge mechanism would provide a return on and reimbursement of such investments, in addition to incremental operating and maintenance costs, sales taxes and other operating costs that arise because of a storm hardening project or program.[66]

The response of PSE&G was to file a proposed "Energy Strong Program" with the New Jersey Board of Public Utilities (BPU) on February 20, 2013.[67] The rate request sought recovery for 5 years of the Program, representing an investment of $1.703 billion for electric delivery and $906 million for gas delivery, and associated gas and electric operations and maintenance expenses.[68] The full *Energy Strong Program* represents an investment of $2.762 billion for electric delivery and $1.08 billion for gas delivery over a ten-year period.[69] According to the filing, the purpose of the *Energy Strong Program* is to "harden electric and gas infrastructure to make them less susceptible to damages from extreme wind, flying debris and water damage in anticipation of . . . changing weather patterns."[70] The *Program* is designed to "improve the durability and stability of PSE&G's energy distribution infrastructure, making it better able to withstand the impacts of hurricanes and other severe weather events, and enabling a faster response to customers and outages than would otherwise be feasible."[71] The *Program* investments will also "increase the resiliency of PSE&G's electric

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[61] New York Pub. Serv. Comm'n, Case 13-E-0030, Testimony of Electric Infrastructure and Operations Panel, Con Edison, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A3EFED44-5E61-42B6-9348-7AB59BAA8CB5}, at 18.
[62] *Id*. at 19-20.
[63] *Id*. at 36.
[64] *Id*. at 40.
[65] Testimony of Robert Mucillo, *supra* note 60 at 75-77.
[66] *Id*. at 76.
[67] PSE&G FILING, *supra* note 18, Petition at 1.
[68] *Id*. at 4.
[69] *Id*.
[70] *Id*. at 1.
[71] *Id*.

delivery system, allowing it to recover more quickly than it would otherwise be able from damage to any of its components or to any of the external systems on which it depends."[72]

To allow prompt recovery of the costs associated with the *Energy Strong Program*, the PSE&G filing sought recovery of *Program* costs through an "Energy Strong Adjustment Mechanism," which would include a separate rider on the utility bill for recovery of the costs associated with the *Program*.[73] Costs recovered would include depreciation/amortization expense (to recover the cost of the *Program* Assets over their useful lives), return on the net investment at the weighted average cost of capital, operation and maintenance expenses related to implementation of the *Energy Strong Program*, and certain administrative expenses.[74] Much of the *Energy Strong Program* is devoted to "hardening of the electric delivery infrastructure."[75] In addition to these "system hardening" expenditures, PSE&G proposed two sub-programs "to increase resiliency of the electric delivery infrastructure."[76]

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[72] *Id*. at 1-2.
[73] *Id*. at 4.
[74] *Id*. at 32.
[75] *Id*. at 5. The first sub-program for "system hardening" is station flood and storm surge mitigation for 21 substations affected by Superstorm Sandy and 13 affected by Hurricane Irene and prior water intrusion events, at a cost of $1.678 billion over 10 years, and includes three mitigation options: (a) installation of flood walls, (b) raising and replacing the substation, or (c) relocating the substation. *Id*. at 5-10. The second is higher outside plant design and construction standards, including upgrading about 5 percent of the existing 4 kV, or 130 miles of overhead construction to 13 kV standards, at a cost of $65 million over 5 years; 5 percent of the existing 26 kV, or 60 miles of overhead construction, to 69 kV standards, at a cost of $60 million over 5 years; and about 10 miles of open wire overhead construction replaced with overhead spacer cable, at a cost of $10 million over 5 years. *Id*. at 10-12. The third sub-program is strengthening pole infrastructure, through targeted investment in enhanced guying systems, larger diameter poles, reduced spans between poles, and potential use of non-wood and composite materials poles, at a cost of $105 million over 5 years. *Id*. at 12-14. Fourth, rebuilding backyard poles lines, by relocating backyard pole lines to the public right of way, at a cost of $100 million over 5 years. *Id*. at 14-15. Fifth, targeted undergrounding to mitigate storm impacts, including approximately 20 miles of overhead construction for conversion to underground construction where the undergrounding will provide substantial benefits, at a cost of $60 million over 5 years; replacement of approximately 75 ground level pad-mounted Automatic Transfer Switches, at a cost of $8 million over 5 years; and replacement of approximately 200 pad-mounted transformers with fully submersible equipment, at a cost of $8 million over 5 years. *Id*. at 15-17. The sixth sub-program involves relocation of operations centers and the emergency response center, which are located below sea level, to a higher floor elevation, at a cost of $15 million over 2 years. *Id*. at 17-18.
[76] The first sub-program, "Advanced Technologies," would improve "system visibility," through microprocessor relays and Supervisory Control and Data Acquisition (SCADA) field equipment, expanded use of microprocessor (i.e., computer-based) relays on distribution feeders or circuits

PSE&G subsequently scaled back the scope of its *Energy Strong Program* from $2.762 billion to $1.22 billion under a settlement reached with other participants in the Energy Strong filing, which was approved by the New Jersey BPU on May 23, 2014.[77] Under the settlement, PSE&G will invest up to $1 billion ($600 million for the electric system and $400 million for the gas system) over three years, with recovery of the investment through the Energy Strong rate recovery mechanism.[78] PSE&G will invest an additional $220 million in its electric system, with those amounts subject to recovery through a base rate case rather than through the Energy Strong rate recovery mechanism.[79] The $1.22 billion total investment under the settlement comprises $620 million to raise, relocate or protect 29 electric switching and substations;[80] $350 million to replace and modernize 250 miles of low-pressure cast iron gas mains in areas that previously flooded or are located in FEMA flood zones;[81] $100 million for "system reconfiguration strategies" to create redundancies in the system to reduce

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and installation of SCADA field equipment in every substation, at a cost of $250 million over 10 years, and through a Distribution Management System (DMS), which will visualize, control, collect and analyze all monitored points from each distribution station through the development and implementation of feeder and substation automation, at a cost of $50 million over 10 years. *Id*. at 18. Other elements of the "Advanced Technologies" sub-program include improvements to communication networks to better address storm impacts, including a high-speed fiber optic network (cost of $73 million over 10 years) and satellite communications (cost of $3 million over 5 years). *Id*. at 20. The utility also proposes to improve its system for storm damage assessment, including an advanced DMS to incorporate additional data sources such as outage information, intelligent fault indicators, potential future deployment of Smart Meters and AMI and add-on analysis applications such as load flows and state estimations for data accuracy, at a cost of $15 million over 10 years. *Id*. at 21. Also included as part of "Advanced Technologies" are enhanced storm management systems, through development of an integrated mobile plant damage filed application to capture plant damage information, such as location, asset information and picture, and electronically transfer that information back to the OMS system, at a cost of $50 million over 4 years. *Id*. at 21-22. Finally, PSE&G proposes to install expanded communications channels, to enhance its ability to communicate storm-related information to customers, at a cost of $10 million over 3 years. *Id*. at 22. The second sub-program focused on improving resiliency is "Contingency Reconfiguration Strategies," which increase the sections in the present loop designs utilizing smart switches, smart fuses and adding redundancy within the loop scheme, at a cost of $200 million over 5 years. *Id*. at 22-23.

[77] New Jersey BPU, Docket Nos. EO13021055 and GO13020156, In the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Energy Strong Program, Order Approving Stipulation of Settlement, May 23, 2014, available at http://www.state.nj.us/bpu/pdf/boardorders/2014/20140521/5-21-14-2I.pdf.

[78] *Id*. at 5.

[79] *Id*.

[80] *Id*., Stipulation at 10. This investment will be made over five years rather than three years. *Id*. at 5.

[81] *Id*., Stipulation at 12.

outages;[82] $100 million for "advanced technologies" to deploy smart grid technologies for improved monitoring of system operations and enhanced ability to respond more quickly to needed system repairs;[83] and $50 million to raise and harden five natural gas metering stations that were flooded during Superstorm Sandy.[84] In approving the settlement, the New Jersey Board found that "hardening" was necessary for certain of PSE&G's switching and substations, and that acceleration of certain investments in other areas of the electric system would "help with overall reliability" and "improve storm response measures."[85]

C. The Performance of DG Resources during Superstorm Sandy

Following Superstorm Sandy, the consulting firm ICF International prepared a report highlighting the role of DG resources, and CHP facilities in particular, in enhancing the resilience of critical infrastructure facilities during the extended power outages caused by Superstorm Sandy.[86] "Critical infrastructure" facilities were defined to include "those assets, systems and networks that, if incapacitated, would have a substantial negative impact on national or regional security, economic operations, or public health and safety."[87] The *ICF Report* includes fourteen "case studies" where CHP facilities improved system resiliency through "mitigating the impacts of an emergency by keeping critical facilities running without any interruption in electric or thermal service."[88] The report noted that, depending upon how the CHP system is configured, it can continue to operate independently from the electricity grid, thereby "ensuring an uninterrupted supply of power and heating or cooling to the host facility."[89]

Included in the case studies were four microgrids operated by educational institutions, where the campuses essentially disconnected from the grid and relied on self-generated power and heat. The Washington Square Campus of New York University was served during Superstorm Sandy by a 14.4 MW combined cycle CHP system installed in 2010.[90] The electricity generated supplies 22 campus buildings, while the steam is used to produce hot water for 37 campus buildings and meets all the space heating, space cooling, and hot water needs for these

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[82] *Id*., Stipulation at 11.
[83] *Id*., Stipulation at 11-12.
[84] *Id*., Stipulation at 12. This investment will be made over five years rather than three years. *Id*. at 5.
[85] *Id*. at 7.
[86] ICF REPORT, *supra* note 12.
[87] *Id*. at 2, citing Patriot Act of 2001, Section 1016(e).
[88] *Id*. at 4.
[89] *Id*.
[90] *Id*. at 29.

buildings.[91] Although the system does not cover the entire NYU campus, the larger buildings and core of the Washington Square campus were able to maintain heat and power throughout the storm and days thereafter.[92] The University's CHP system went into "island" mode when the local grid went down, and became isolated from the utility grid.[93] In addition to providing electricity, heating, and cooling to the core of the campus, the University's CHP system made it possible for NYU and New York City officials to establish a command post on the campus.[94] Princeton University in Princeton, NJ has a district energy facility that produces electricity, steam, and chilled water for its campus; the system consists of a 15 MW natural gas-fired CHP unit that typically provides about half of the electricity needs and all of the steam needs on the campus.[95] During Superstorm Sandy, the University was able to maintain essential services due to the CHP plant.[96] As in the case of the NYU campus, Princeton disconnected from the utility grid and relied on its CHP system to power most of its campus, with the plant meeting most of the energy needs during the two-day period (Monday evening to Wednesday evening) when grid power was unavailable.[97] In addition to providing an electricity supply, the CHP system provided uninterrupted steam and chilled water service to the Princeton campus.[98] Two other college campuses had similar experiences. The College of New Jersey in Ewing, NJ, with its 5.2 MW gas turbine, also went into "island mode" when the grid went down, and remained isolated from the grid for about a week until utility infrastructure issues could be resolved.[99] Salem Community College in Carney's Point, NJ, disconnected its 300 kW microturbine from the grid on Sunday morning, October 28, and it operated continuously until the morning of November 1, allowing the American Red Cross to open a disaster relief shelter in the DuPont Field House in Davidow Hall on Sunday evening.[100] Eighty-five individuals took advantage of the disaster relief shelter during the storm.[101]

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[91] *Id*.
[92] NYS 2100 COMMISSION REPORT, *supra* note 5 at 101.
[93] ICF REPORT, *supra* note 12 at 29.
[94] *Id*.
[95] *Id*. at 16.
[96] *Id*. It should be noted that non-critical loads (*i.e*., the administration building and some classrooms) were curtailed; the University's average load is 20 MW versus the 15 MW output of the CHP unit. *Id*.
[97] *Id*.
[98] *Id*.
[99] *Id*. at 18.
[100] *Id*. at 19. The three 100-kW microturbines provide about 80% of the electricity needs and all of the heating and cooling needs to Davidow Hall. *Id*.
[101] *Id*.

Several hospitals equipped with on-site DG resources also functioned normally during Superstorm Sandy and its aftermath. South Oaks Hospital in Amityville, NY, disconnected from the LIPA grid on the evening of October 28 and remained in "island mode" for about fifteen days.[102] By relying solely on its 1.25 MW natural gas-fired reciprocating engines, the hospital was able to provide critical services for two weeks.[103] In Greenwich, CT, Superstorm Sandy caused a seven-day power outage in the area surrounding Greenwich Hospital.[104] Because of its 2.5 MW reciprocating engine CHP system, however, Greenwich Hospital was able to maintain normal operations throughout the outage.[105] The Christian Health Care Center (CHCC) in Wyckoff, NJ is equipped with a 260 kW microturbine and three emergency backup generators.[106] During Superstorm Sandy, the CHCC experienced only a brief loss of power, and was able to operate for 97 hours off the grid.[107] The CHP system was able to meet all the power, heat and hot water needs of the CHCC residents.[108]

With the benefit of on-site DG resources, one of the largest cooperative housing developments in the country, located in The Bronx, NY was able to maintain heat and power for its 60,000 plus residents during Superstorm Sandy.[109] Co-op City covers over 330 acres in the Bronx, and includes 14,000 apartments (located in 35 high-rises and seven clusters of townhouses), three shopping centers, six schools (three grade schools, two middle schools and one high school), and several parking garages.[110] Since 2011, it has been served by a 40 MW natural gas-fired combined cycle CHP plant that provides about 95% of the electric and thermal needs of Co-op City.[111] Although the onsite cogeneration facility was installed primarily to achieve energy savings, its ability to operate independently from the electrical grid during Superstorm Sandy enabled Co-op City to avoid the power outages experienced by the areas surrounding it.[112]

On Long Island, a district energy CHP system providing thermal energy to Nassau University Medical Center and Nassau Community College was able to continue operating throughout the storm and its aftermath, without any

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102 *Id*. at 13.
103 *Id*.
104 *Id*. at 14.
105 *Id*. at 14.
106 *Id*. at 15.
107 *Id*.
108 *Id*.
109 *Id* at 21.
110 *Id*.
111 *Id*.
112 *Id*.

operational issues.[113] The 57-MW CHP system, operated by Nassau Energy Corporation, enabled Nassau Community College to establish an emergency shelter during Superstorm Sandy, which served over 1,000 individuals for up to a month and a half.[114] The system was also able to continue supplying power to the Long Island Power Authority.[115]

Another form of critical infrastructure—data centers providing hundreds of companies with office telecommunications support—benefitted from on-site DG resources during Superstorm Sandy. The Public Interest Data Center at 50 West 17th Street in Manhattan, with its 65 kW natural gas-fired microturbine-based CHP system, was able to remain fully operational even though power to the building and the adjacent area was out for over two days.[116] Finally, a major manufacturing facility was able to remain open and continue operating with minimal disruption during Superstorm Sandy, due to the backup power from its CHP system.[117] The Sikorsky Aircraft Corporation in Stratford, CT is equipped with a 10.7 MW gas turbine that supplies 84% of the facility's power needs and 85% of the facility's steam heating needs.[118] The facility's CHP system did not experience any disruptions during Superstorm Sandy, and 9,000 Sikorsky employees were provided with food and amenities notwithstanding the power outages experienced in the local communities.[119]

D. The Concept of Electric System Resilience

The concept of "resilience" has broader applications outside the context of an electric utility system. For example, C. S. Holling introduced the word resilience into the ecological literature in 1973 as a way of drawing a distinction with the concept of stability, which he described as the ability of an ecosystem to return to equilibrium after a disturbance.[120] According to Holling, resilience measures the persistence of ecosystems, and their ability to absorb a disturbance while still maintaining relationships within the ecosystem.[121] Other authors

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[113] *Id*. at 25.
[114] *Id*.
[115] *Id*.
[116] *Id*. at 20.
[117] Vignesh Gowrishankar, Christina Angelides & Hannah Druckenmiller, *Combined Heat and Power Systems: Improving the Energy Efficiency of Our Manufacturing Plants, Buildings and Other Facilities*, NATURAL RESOURCES DEFENSE COUNCIL (April 2013), available at http://www.nrdc.org/energy/files/combined-heat-power-ip.pdf, at 5.
[118] ICF REPORT, *supra* note 12 at 31.
[119] Gowrishankar et. al, *supra* note 117 at 5.
[120] C.S. Holling, *Resilience and Stability of Ecological Systems*, ANNU. REV. ECOL. SYST. 1973.4 at 14.
[121] *Id*.

measure resilience according to the time it takes for a system to return to a stable state following a disturbance.[122] Some authors suggest that two separate variables are involved in defining resilience: resistance, which measures the size of a disturbance necessary to cause a change in structure, and recovery, which measures how quickly the system returns to its original structure.[123]

The concept of resilience is increasingly being mentioned in the context of infrastructure and essential services in the wake of recent extreme weather events.[124] The *NYS 2100 Commission Report*, for example, defines resilience according to a system's ability to endure "shocks and stresses" and still perform its essential functions.[125] The *Report* also mentions the second concept associated with resilience, which is the ability to "repair and recover" following a "stress" event.[126] The recent decision of the New York PSC in the Con Edison case

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[122] Lance H. Gunderson, *Ecological Resilience-in Theory and Application*, ANNU. REV. ECOL. SYST., 31:426 (2000) available at http://www.annualreviews.org/doi/pdf/10.1146/annurev.ecolsys.31.1.425. Resilience has also been defined as "the capacity of an ecosystem to absorb disturbance without shifting to an alternative state and losing function and services." Isabella M Côté and Emily S. Darling, *Rethinking Ecosystem Resilience in the Face of Climate Change*, PLOS BIOL 8(7): e1000438. doi:10.1371/journal.pbio.1000438 available at http://www.plosbiology.org/article/info%3Adoi%2F10.1371%2Fjournal.pbio.1000438.

[123] *Id*.

[124] In *The End of Sustainability*, Robin Kundis Craig and Melinda Harm Benson express the view that effective mitigation of climate change has failed, and that the concept of "resilience" is a better means of addressing future challenges. Melinda Harm Benson & Robin Kundis Craig, *The End of Sustainability*, SOCIETY & NATURAL RESOURCES; AN INTERNATIONAL JOURNAL, DOI: 10.1080/08941920.2014.901467 (2014). ("[A] resilience approach would reorient current research and policy efforts toward coping with climate change instead of increasingly futile efforts to maintain the existing state of being.") *Id*. at 4.

[125] NYS 2100 COMMISSION REPORT, *supra* note 5 at 24.

[126] *Id*. In contrast to resilient systems, those that are more vulnerable were described in the Report as lacking diversity or being stretched to capacity. *Id*. The NYS 2100 COMMISSION REPORT identified several features that are common to most resilient systems, which included "having spare or latent capacity (redundancy); ensuring flexibility and responsiveness; managing for safe failure (building resistance to domino effects); and having the capacity to recover quickly and evolve over time." *Id*. Infrastructure resilience also comes into play in the context of security efforts; the Homeland Security Critical Infrastructure Task Force defines "resiliency" to mean "the capability of a system to maintain its functions and structure in the face of internal and external change and to degrade gracefully when it must." HOMELAND SECURITY ADVISORY COUNCIL, *Report of the Critical Infrastructure Task Force*, January 2006, available at http://www.dhs.gov/xlibrary/assets/HSAC_CITF_Report_v2.pdf, at 12. Under this concept, resilient infrastructure systems "will be less likely to collapse in the face of natural or manmade disruptions and will limit damage when disruptions do manage to inhibit the full functionality of the system." *Id*. *See also*, Brad Allenby and Jonathan Fink, *Toward Inherently Secure and Resilient Societies*, SCIENCE 12 August 2005: Vol. 309 no. 5737 pp. 1034-1036 for further exploration of the concept, available at http://www.sciencemag.org/content/309/5737/1034.full.

defined resiliency as going beyond the "hardening" of existing utility infrastructure to reduce the impact of severe storms.[127] Adopting the definition from the *NYS 2100 Report*, the *PSC Order* defined resilience as "the ability of a system to withstand shocks while still maintaining its essential functions."[128]

The Department of Energy and the President's Council on Economic Advisors examined the economic benefits of grid resiliency, and noted that the cost of weather induced outages ranges from $25 to $70 billion annually.[129] According to their report, the costs arising from grid outages include lost economic output and wages, delays in production, inconvenience, lost inventory due to spoilage, and damage to the grid itself."[130] The report recommended continued investment in grid modernization and resilience in order to mitigate these costs over time, which would potentially save billions of dollars and reduce the hardship suffered by millions of Americans arising from extreme weather events.[131]

DG resources in particular have been identified as contributing to the resilience of electric utility systems; a 2002 report of the National Research Council identified the vulnerabilities of the electric system to intentional disruptions, and noted the potential role of DG resources in achieving "an intelligent, adaptive power grid."[132] According to the NRC report, an advantage of having smaller, distributed resources closer to the load centers is creation of a "more flexible grid" that would enable "islanding to maintain key loads,"[133] as illustrated by the successful operation of microgrids following Superstorm Sandy, noted above. The NRC report urged utilities to recognize the "improved security" provided by DG resources when they consider future investments in the grid.[134]

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[127] New York Pub. Serv. Comm'n, Case 13-E-0030, Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, February 21, 2014, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-E-0030, [hereinafter PSC ORDER] at 63, note 47.

[128] *Id*. Similarly, when the Department of Energy and the President's Council on Economic Advisors examined the economic benefits of grid resiliency, they defined a more resilient grid as "one that is better able to sustain and recover from adverse events like severe weather." *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages*, available at http://energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf., at 5.

[129] *Id*.

[130] *Id*. at 3.

[131] *Id*.

[132] NATIONAL RESEARCH COUNCIL, *Making the Nation Safer—the Role of Science and Technology in Countering Terrorism*, The National Academies Press (2002).

[133] *Id*.

[134] *Id*.

The *DOE Study* similarly identified the potential role of DG resources in improving resilience.[135] While acknowledging that the greater number of smaller-scale power plants in a DG-based system would increase the number of targets vulnerable in an attack, the *Study* observed that a smaller number of customers would be affected under such a system.[136] The *DOE Study* also noted the reduced vulnerability when utility customers are able to "island" themselves in microgrid arrangements, which are particularly important in the case of "critical infrastructure facilities."[137] The *DOE Study* defined these facilities to include hospitals, public safety buildings, telecommunications facilities, and natural gas and oil delivery systems."[138] The *DOE Study* described DG as a "viable means" for improving the resilience of the electric grid, based on actual experiences where DG resources maintained a power supply to critical facilities in the face of widespread power outages.[139] According to the conclusions of the *DOE Study*, improving the resilience of the grid can prevent a variety of losses, including economic losses and loss of life.[140]

III. PROMOTING DG RESOURCES IN UTILITY REGULATORY PROCEEDINGS

A. Advocating for the "Utility of the Future"

In response to Con Edison's January 2013 rate filing, a group of environmental non-governmental parties (NGOs) intervened in the New York PSC proceeding to "offer a different perspective" on the issues raised in Con Edison's rate filing.[141] The NGO Parties, comprising Environmental Defense Fund (EDF), Natural Resources Defense Council (NRDC), Pace Energy and Climate Center (Pace), and Columbia Law School Center for Climate Change Law (Columbia), observed that "the vast majority of the expenditures" driving Con Edison's request for rate relief related to the demonstrated vulnerability of Con Edison's system to severe weather events, based on the experience of Superstorm Sandy.[142] According to the NGO Parties, a danger in having a "single issue"—the impact of Superstorm Sandy on Con Edison's system—drive a rate proceeding is that focusing too much on responding to the last storm may foreclose "a thoughtful, deliberate examination" of the investments that should be made in order to design more forward-looking utility systems that would be "resilient under conditions that are likely to exist for the next thirty or forty

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[135] DOE STUDY, *supra* note 10 at 7-3.
[136] *Id*.
[137] *Id*.
[138] *Id*.
[139] *Id*. at 7-12.
[140] *Id*.
[141] MORRIS TESTIMONY, *supra* note 53, at 4.
[142] *Id*. at 5.

years."[143] The NGO Parties undertook to articulate this different approach for Con Edison's system that would take into account this objective of resilience, along with reliability, environmental integrity, and economic efficiency.[144]

The NGO Parties offered testimony in several specific areas. Pace's testimony addressed DG resources, microgrids and the role of energy efficiency.[145] The testimony of EDF focused on enhancing the resilience of Con Edison's T&D systems through, among other things, advanced metering infrastructure (AMI) and smart grid investments.[146] NRDC in its testimony addressed electric vehicle charging and time of use rates,[147] while Columbia's testimony described projected increases in temperature and sea level rise as well as increased frequency and intensity of heat waves, coastal flooding, and other extreme weather events.[148] Collectively, the NGO Parties purported to offer "elements that should be included in 'building a 21st Century resilience strategy' for Con Edison."[149]

Of particular relevance to this article is the testimony on DG resources and microgrids offered by Pace. The Pace witness was a co-author of the *ICF Report* discussed in Section II.C. above,[150] and his testimony featured a number of the case studies from the report illustrating how several educational, commercial and industrial facilities throughout the Northeast were able to "power through" Superstorm Sandy because of the availability of onsite DG resources, and CHP in particular.[151] Based on the "critical role" that DG resources and CHP facilities

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143 *Id*. at 6.
144 *Id*.
145 *Id*. at 2. *See also* testimony of Thomas G. Bourgeois, New York Pub. Serv. Comm'n, Case 13-E-0030, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-E-0030 [hereinafter BOURGEOIS TESTIMONY].
146 MORRIS TESTIMONY, *supra* note 53 at 3. *See also* testimony of Paul Centolella, New York Pub. Serv. Comm'n, Case 13-E-0030, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-E-0030.
147 MORRIS TESTIMONY, *supra* note 53 at 3-4. See also testimony of Luke Tonachel, New York Pub. Serv. Comm'n, Case 13-E-0030, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-E-0030.
148 MORRIS TESTIMONY, *supra* note 53 at 4. See also testimony of Professor Radley Horton, New York Pub. Serv. Comm'n, Case 13-E-0030, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-E-0030.
149 MORRIS TESTIMONY, *supra* note 53 at 15.
150 ICF REPORT, *supra* note 12.
151 BOURGEOIS TESTIMONY, *supra* note 145 at 6-8.

played in continuing to provide service to essential facilities during Superstorm Sandy, the witness maintained that the resilience of Con Edison's system could be improved if DG resources played a more prominent role in Con Edison's long-term strategy.[152] In the view of this witness, however, Con Edison devoted "very little attention" in its filing to the deployment of DG or CHP, and focused instead on "conventional and established measures" that would "harden" its system and strengthen its critical infrastructure.[153]

The Pace testimony noted the slow rate of DG penetration in Con Edison's service territory.[154] As compared with the goal of 800 megawatts of new, clean DG resources within New York City by 2030 as set forth in PlaNYC,[155] Con Edison identified only about 150 MW of baseload DG currently installed in its service territory, with 75 MW of new installations expected by 2017.[156] Con Edison estimated that there would be only 500 MW of installed DG by 2030, about 40 percent short of the PlaNYC goals.[157] Pace identified a number of reasons for the "unacceptably low levels" of DG penetration in Con Edison's service territory, including the failure of Con Edison's existing distribution planning process to contemplate DG solutions and Con Edison's "failure to enthusiastically encourage and to accommodate DG within its service territory."[158] According to Pace, by not incorporating DG resources into its planning process, Con Edison "is missing a huge opportunity" to improve the resilience of its distribution system as well as capture system and societal benefits.[159]

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152 *Id*. at 9.
153 *Id*. at 9-10.
154 *Id*. at 19.
155 THE CITY OF NEW YORK, *PlaNYC: Update 2011, A Greener, Greater New York*, available at http://nytelecom.vo.llnwd.net/o15/agencies/planyc2030/pdf/planyc_2011_planyc_full_report.pdf, 115 (2011). PlaNYC 2030, which was released in 2007, is a long-term planning effort initiated by the Bloomberg administration to (1) prepare New York City for an additional million residents, (2) strengthen its economy, (3) address climate change, and (4) enhance the quality of life. *See* http://www.nyc.gov/html/planyc2030/html/about/about.shtml.
156 New York Pub. Serv. Comm'n, Case 13-E-0030, Testimony of Electric Infrastructure and Operations Panel, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-E-0030, at 364.
157 *Id*.
158 BOURGEOIS TESTIMONY, *supra* note 145 at 20.
159 *Id*. As specific examples of Con Edison's "apparent unwillingness to accommodate DG within its service territory," Pace cited the experience of the Durst Organization and its skyscraper at One Bryant Park in Manhattan, where Durst on two separate occasions was forced to seek relief from the New York PSC in response to attempts from Con Edison to increase the electricity and natural gas charges related to the CHP facility located at One Bryant Park. *Id*. at 20-21. Pace also noted

As part of the NGO Parties' vision of the "utility of the future," Pace presented a number of policy recommendations designed to force Con Edison toward more aggressively implementing DG and microgrid solutions.[160] Among other recommendations, Pace urged the New York PSC to adopt rate incentives that would reward Con Edison financially if it played a role in facilitating the development of clean DG, CHP or microgrid projects within its service territory.[161] Pace also proposed that in the case of "high-efficiency" CHP, the price of gas delivered by Con Edison could be reduced to cover only the commodity cost of the gas (and not the transportation costs).[162] Another element proposed by Pace was the elimination of standby tariffs for qualifying projects.[163] To encourage utility-owned DG resources, Pace urged the PSC to consider adopting a program that would authorize Con Edison to earn higher rates of return on its investments in DG resources.[164]

With respect to microgrid development, Pace observed that progress has been "slow due to a lack of any formal statutory or regulatory guidance and high transactional costs," and urged "affirmative action by New York State lawmakers and/or regulators."[165] In the meantime, Pace recommended that Con Edison help overcome transactional impediments by standardizing the process for interconnecting microgrids, such as by developing a standard design template and by broadening the eligibility for the "campus style" interconnection successfully employed in the case of New York University.[166] Pace urged the PSC to require Con Edison to "issue a report demonstrating how it is integrating microgrids as a

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Con Edison's proposal to delay replacing a number of over-duty circuit breakers in Manhattan, a situation often cited as a barrier to DG interconnection; according to Pace, these are the investments that "make the system more amenable to CHP/DG penetration," and should be accelerated rather than slowed. *Id*. at 24.

[160] *Id*. at 27-28.

[161] *Id*. at 15.

[162] *Id*. at 16.

[163] *Id*.

[164] *Id*. The Pace testimony noted that a utility has a financial disincentive to promote DG resources as alternatives to T&D investments, given that the T&D investment upon which a utility earns a return would be reduced or eliminated. *Id*.

[165] *Id*. at 26. It should be noted that the New York State Legislature in 2013 passed a law requiring NYSERDA to develop recommendations regarding the establishment of microgrids. SECTION 1 OF PART T OF CHAPTER 58 OF THE LAWS OF 2013. The Memorandum accompanying the legislation states that "[h]ad New York State constructed microgrids to protect hospitals, first responder headquarters such as police and fire stations, emergency shelters, schools, water filtration plants, sewage treatment plants and other infrastructure, the extent of the damage caused by Super Storm Sandy would have been tremendously mitigated." *Id*. The Memorandum further states that "[t]he extent of severe damage caused by recent storms demonstrates the tremendous benefits of having microgrids in place to protect critical public health and safety infrastructure." *Id*.

[166] BOURGEOIS TESTIMONY, *supra* note 145 at 26.

resiliency measure by summer of 2014."[167] Pace also urged the PSC to create a "microgrids collaborative" that would address the recommendations of a forthcoming study on microgrids prepared by the New York State Energy and Research Development Authority (NYSERDA).[168] The Collaborative would be required to report back to the PSC and identify "tangible projects" that would be commenced in 2014.[169] Convening a collaborative prior to issuance of the NYSERDA study facilitates locating a microgrid within an area affected by storm damage so that a "center of refuge" can be created.[170]

In response to the testimony and proposals of the various parties to the rate proceeding, Administrative Law Judge Eleanor Stein convened a collaborative group in early July 2013 to consider, among other things, the utility's storm hardening proposals and ways of building "flexibility" into Con Edison's designs.[171] The collaborative formed four working groups that considered, among other things, the need to modify future design standards to reflect climate change and its effects, and alternative strategies to make the grid more resilient, including microgrids, DG resources, energy efficiency, demand response, and alternative metering technology.[172] Con Edison agreed to conduct a "Climate Change Vulnerability Study" that, among other things, would reflect the latest thinking on climate change, as well as identify the likely effects on infrastructure design standards.[173] More generally, Con Edison committed to consider resilience objectives as it designs, installs, operates and maintains its facilities and equipment.[174] A Phase II working group was formed to consider alternative strategies for achieving resilience (other than through "storm hardening" projects).[175] This working group identified several potential approaches to achieve resilience, including DG resources, microgrids, energy efficiency, demand response, electric vehicles, energy storage, and rates based on time-differentiated

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[167] New York Pub. Serv. Comm'n, Case 13-E-0030, Initial Post-Hearing Brief of Pace Energy and Climate Center, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-E-0030, at 27.
[168] *Id*. at 27-28.
[169] *Id*..
[170] *Id*. at 28.
[171] New York Pub. Serv. Comm'n, Case 13-E-0030, Storm Hardening and Resiliency Collaborative Report, December 4, 2013, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-E-0030, [hereinafter RESILIENCE COLLABORATIVE REPORT] at 6.
[172] *Id*. at 7.
[173] *Id*. at 9.
[174] *Id*.
[175] *Id*. at 23. The working group focused on alternative resiliency strategies is Working Group 2. *Id*.

pricing.[176] It should be noted that the recommendations comprising these potential approaches to resilience correspond closely to the solutions urged by the NGO parties in their collective testimony in the proceeding.[177] The goal of this working group was to develop a proposal for the PSC regarding alternative resilience solutions.[178]

Apart from the collaborative process dealing with storm hardening and resiliency issues, the parties to the rate proceeding pursued settlement discussions of the other rate case issues on a parallel track.[179] On December 31, 2013, a settlement agreement among most of the parties to the proceeding, including the NGO Parties, was submitted to the PSC.[180] The *Joint Proposal* includes a recommended rate increase over the two-year rate plan period that reflects the findings of the Resiliency Collaborative with respect to Con Edison's proposed storm hardening expenditures.[181] It also recommends that the PSC direct the continuation of the Resiliency Collaborative, including the collaborative discussions of the working group focused on alternative resiliency strategies.[182]

Additionally, the *Joint Proposal* contains agreements with respect to DG issues.[183] Con Edison identified significant load growth in the Brownsville section of Brooklyn requiring "significant capital investment in order to maintain reliability," and committed that it would use "non-traditional programs," facilitating the use of DG resources to reduce its investment needs.[184] Con Edison responded to Pace's criticism regarding the delay in replacing "over-duty circuit breakers," which Pace had identified as an investment that would make it easier for Con Edison's system to accommodate DG resources.[185] In the *Joint Proposal*, Con Edison committed to pay the cost of purchasing and installing fault current mitigation technology where an over-duty circuit breaker condition exists or will

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[176] *Id*.
[177] See text accompanying notes 118-122 *supra*.
[178] RESILIENCE COLLABORATIVE REPORT, *supra* note 176 at 23.
[179] New York Pub. Serv. Comm'n, Case 13-E-0030, Joint Proposal, December 31, 2013, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-E-0030, [hereinafter JOINT PROPOSAL] at 3.
[180] *Id*. at 1-2.
[181] *Id*. at 51. In addition to the two-year rate plan for electric rates, the JOINT PROPOSAL provided three-year gas and steam rate plans. *Id*. at 2-3.
[182] *Id*. at 52.
[183] *Id*. at 96-97.
[184] *Id*. at 38. As stated in the PSC ORDER, "Con Edison will pursue a plan to address significant load growth in the Brownsville section of Brooklyn with distributed resources as an alternative to traditional infrastructure." PSC ORDER, supra note 127 at 4.
[185] BOURGEOIS TESTIMONY, *supra* note 145 at 24.

exist with the addition of DG, up to a total of $3 million annually.[186] With respect to the deployment of microgrids within its service territory, Con Edison agreed that within six months of the release of the NYSERDA microgrid study, it would file an "implementation plan" with the PSC and would convene a collaborative to consider, among other things, whether its tariff should be modified to enable multiple customers to collectively offset the output of a DG facility against their usage.[187]

The PSC received testimony regarding the *Joint Proposal* at a January 14, 2014 evidentiary hearing, and on February 21, 2014 issued an order adopting the *Joint Proposal*.[188] The *PSC Order* acknowledged the prominent role of Superstorm Sandy in the proceeding, stating that "Superstorm Sandy drove home the urgency not only of emergency preparedness, but of advance planning for the impacts on the utilities of New York State of extreme weather events exacerbated by a changing climate."[189] The *PSC Order* characterized the expert testimony offered by the NGO Parties in the proceeding as "urging a comprehensive and longer-term approach" to the investments associated with storm-hardening, noting that the nature of infrastructure investments is that they will likely last "for most of this century."[190] The *Order* describes the NGO proposals as "advocate[ing] generally for a broad definition of resiliency . . . to include equipment on both sides of the meter."[191] The *PSC Order* noted the findings of the New York City Panel on Climate Change regarding the likely impact of changing climate conditions on the ability of Con Edison to provide reliable utility service and the consensus of the Resiliency Collaborative that a utility system should be designed to "better withstand more frequent, violent storms and larger storm surges."[192]

The *PSC Order* adopted the recommendation in the *Joint Proposal* to continue the Resiliency Collaborative process.[193] Along with these efforts to improve the utility's adaptive capabilities, the *PSC Order* urged a continued commitment to climate mitigation measures—in the form of efforts to reduce carbon emissions.[194] The *Order* noted the "broad support among the parties for these capital investments that are intended to enhance system reliability, to

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[186] JOINT PROPOSAL, *supra* note 184 at 96.
[187] *Id*. at 97. This would expand the opportunities for microgrids beyond the single customer campus, such as in the case of New York University's Washington Square campus, to a microgrid involving multiple customers.
[188] PSC ORDER, *supra* note 127 at 73.
[189] *Id*. at 62.
[190] *Id*.
[191] *Id*. at 66.
[192] *Id*. at 62.
[193] Id. at 67.
[194] *Id*. at 67.

achieve a higher level of storm hardening and resiliency in the face of anticipated climate change and sea level rise."[195] The *Order* observed that the result of these investments should be lower costs to customers in the future due to "greater efficiencies and stronger, more resilient systems."[196]

The *PSC Order* directed a fundamental change in the manner in which Con Edison plans for future capital investments, and requires analysis of alternative resilience strategies, including microgrids.[197] In this new approach to a cost/benefit analysis, Con Edison is required to consider "[t]he risks and probabilities of future climate events, the expected useful life of assets, the impact of outages of various duration on affected customers, and the potential risk to critical facilities."[198] The objective of such an analysis is to facilitate a comparison of the "traditional utility system" and alternative approaches.[199] Con Edison was directed to quantify these considerations to the extent possible.[200] In describing the approach to the public, Con Edison announced in early February 2014 that it would begin conducting an economic analysis that would attempt to "quantify the benefits of preparing its infrastructure for the impacts of climate change."[201]

With respect to the application of the PSC's findings to utilities other than Con Edison, the *PSC Order* expressly broadened the obligation to address climate change considerations to include all New York utilities.[202] The *Order* urged New York utilities to "familiarize themselves with scientists' projections for local climate change impacts on each service territory,"[203] and "to integrate these

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[195] *Id*. at 24.
[196] *Id*.
[197] Id., at 67-68. The PSC ORDER directed Con Edison to "develop and apply a cost/benefit analysis approach for future capital investment that differs from a typical utility capital expenditures analysis and assesses the relative benefits of existing utility infrastructure and alternative resilience approaches such as microgrids."
[198] *Id*. at 68.
[199] *Id*.
[200] *Id*.
[201] Andrea Vittorio, *Con Edison to Calculate Economic Benefits of Preparing Utility for Climate Change*, DAILY ENVIRONMENT REPORT, Feb. 11, 2014, available at http://www.bna.com/con-edison-calculate-n17179882024/. The utility spokesman added that "electric utilities have not quantified the costs of climate change impacts, or the benefits of avoiding such costs, because that kind of economic analysis is 'tough to do.'" *Id*.
[202] PSC ORDER, *supra* note 127 at 71.
[203] *Id*. The PSC ORDER noted that climate change impacts would differ from utility to utility: "other coastal and estuarine utilities also face sea level rise and storm surges, while all the State's utilities face challenges such as Hurricane Irene and Tropical Storm Lee, Nor'easters, floods, severe winds, increased ambient heat, and extreme heat events." *Id*. at 71-72.

considerations into their system planning and construction forecasts and budgets."[204]

The *PSC Order* was noteworthy in several respects. First, the PSC largely rejected the "business as usual" approach offered by Con Edison, which responded to Superstorm Sandy by proposing massive, traditional investments in T&D infrastructure to "harden" the system against future storms.[205] In its place, the PSC enunciated a strategy much more focused on improving the resilience of the utility grid, which may depart from T&D infrastructure investments depending upon the outcome of an innovative cost-benefit analysis that Con Edison must apply to its future capital investments.[206] The *Order* points out that stronger, more resilient systems should result in the lowest rates to customers in the long term.[207] Second, the *PSC Order*, by adopting the *Joint Proposal* and the specific commitments therein, recognized the valuable role that DG resources and microgrids can play in improving the resilience of a utility system in the face of future extreme weather events.[208] The *PSC Order* requires Con Edison to take specific steps to pursue integration of DG resources in its service territory and to investigate the feasibility of microgrid installations.[209] Third, the PSC adopted broader policies directing all utilities to integrate climate change adaptation into their long-term system planning.[210] Given the long-lived nature of infrastructure facilities, the *Order* directs that these investments be based on strategies

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[204] *Id*. at 72. It should be noted that following Superstorm Sandy, Section 66 of New York's Public Service Law was amended to increase the role of the PSC with respect to oversight over and enforcement of emergency plans. New York Pub. Serv. Comm'n, Case 13-E-0198, Order Approving Electric Emergency Plans, (issued Aug. 16, 2013), available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-e-0198&submit=Search+by+Case+Number, at 2. Section 66(21)(a), as amended, specifies the contents to be included in emergency plans, requires annual filing of emergency plans by utilities, and requires the PSC to review and approve the utility filings. *Id*.

[205] PSC ORDER, *supra* note 127 at 24.

[206] *Id*. at 67-68.

[207] *Id*. at 24.

[208] *Id*. at 70.

[209] *Id*. It should be noted that the PSC subsequently instituted a new proceeding, *In Regard to Reforming the Energy Vision*, to explore, among other things, the role of distribution utilities in a system based on deployment of DG resources. New York Pub. Serv. Comm'n, Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Instituting Proceeding* (issued April 25, 2014), available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101&submit=Search+by+Case+Number, at 2. A Report and Proposal prepared by the Department of Public Service staff, attached to the Order Instituting Proceeding, presents a possible new utility business model in which DG resources become a "primary tool in the planning and operation of electricity systems." *Id* at 4.

[210] PSC ORDER, *supra* note 127 at 71-72.

promoting resilience to withstand future climate change and sea level rise, rather than historical experience.[211]

B. Requiring Climate Change Planning by Utilities

Another legal tool available to encourage utilities to consider the climate change adaptation and mitigation benefits of DG resources is imposition of a requirement, either through a regulation or administrative order, that utilities engage in a process of long-term planning that considers the risks posed by climate change and the measures available to utilities for mitigating those risks. In December 2012, a group of environmental and civic organizations in New York petitioned the New York PSC for just such a regulation.[212] Led by the Columbia Law School Center for Climate Change Law, the petitioners urged the New York PSC to require utilities in New York to consider how future extreme weather events may affect their infrastructure and their ability to provide utility service, and to develop plans for mitigating those risks.[213] According to the petition, Superstorm Sandy demonstrated that "infrastructure that has historically been safe from extreme weather events cannot be assumed to be safe from future events."[214]

In support of its request, petitioners cited the remarks of Governor Andrew Cuomo, who had urged that an anticipated increase in "extreme weather type situations" be taken into account in "reforming" the region's infrastructure.[215] Petitioners also noted Mayor Bloomberg's statement in the New York City Panel on Climate Change 2010 Report, where the Mayor observed that it is less expensive to plan for climate change "than rebuilding an entire network after a

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[211] *Id*. at 72.
[212] COLUMBIA PETITION, *supra* note 14 at 1.
[213] *Id*., Petition at 1. The other petitioners were Earthjustice, Environmental Advocates of New York, Natural Resources Defense Council, New York League of Conservation Voters, pace Energy & Climate Center, Riverkeeper, Inc., and Municipal Art Society of New York. *Id*. at 9.
[214] *Id*. at 3.
[215] Ken Lovett, *Hurricane Sandy Death Toll In NY At 26; Gov. Cuomo Blames Climate Change For Increase In Storms*, N.Y. DAILY NEWS, Oct. 31, 2012, available at http://www.nydailynews.com/blogs/dailypolitics/2012/10/hurricane-sandy-death-toll-in-ny-at-26-gov-cuomo-blames-climate-change-for-inc. Governor Cuomo further stated that "I think part of learning from this is the recognition that climate change is reality. Extreme weather is a reality. It is a reality that we are vulnerable. And if we're going to do our job as elected officials, we're going to need to think about how to redesign, or as we go forward, make the modifications necessary so we don't incur this type of damage. For us to sit here today and say this is a once-in-a-generation and it's not going to happen again, I think would be short-sighted." *Id*.

catastrophe."[216] Echoing this observation, the Petition stated that smart planning could indeed reduce the costs of future extreme weather events.[217]

As legal authority supporting the requested relief, petitioners relied on the general responsibility of the New York PSC to ensure that New York utilities provide "safe and reliable service."[218] They cited Section 5[2] of the N.Y. Public Service Law in particular, which requires the PSC to encourage "corporations subject to its jurisdiction to formulate and carry-out long-range programs . . . for the performance of their public service responsibilities," and Section 66, which requires electric corporations to submit "storm plans" for review and approval by the PSC.[219] Pursuant to this authority, the PSC requires electric utilities to prepare emergency response plans for storms and storm-like events.[220] The Petition stated that "[e]valuating risks to existing infrastructure and taking account of future climate predictions are essential to ensuring safe, secure and reliable access to utility services for the residents and businesses of New York."[221]

According to the Petition, natural hazard mitigation plans should include four main elements. The first is incorporation of both hazard mitigation and disaster response planning efforts, including an evaluation of infrastructure.[222] Second, the plans should not be based on historic observations, but should incorporate future predictions of climate.[223] According to the Petition, "[a] common weakness in existing natural hazard mitigation planning is its failure to account for the predicted severity of future storms and its reliance on historic trends . . . when available evidence indicates that storm surge and rainfall will be greater in the future than what has been seen historically."[224] A third requirement is that utilities coordinate with each other and with state and city officials, with an opportunity for all stakeholders to have input.[225] Finally, the plans should be

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[216] Michael Bloomberg, *Forwards to Climate Change Adaptation in New York City: Building a Risk Management Response*, ANNALS OF THE NEW YORK ACADEMY OF SCIENCES, 1196, 2010 Report of the New York Panel on Climate Change, 24 May 2010, http://onlinelibrary.wiley.com/doi/10.1111/j.1749-6632.2009.05415.x/pdf.
[217] COLUMBIA PETITION, *supra* note 23 at 4.
[218] *Id*. at 5. Section 30 of the N.Y. Public Service Law, which applies to residential gas, electric and steam services, states that "continued provision of [such services] to all residential customers without unreasonable qualifications or lengthy delays is necessary for the preservation of the health and general welfare and is in the public interest." *Id.*
[219] COLUMBIA PETITION, *supra* note 23 at 5.
[220] *Id*., citing 16 NYCRR Part 105.
[221] *Id*.
[222] *Id*. at 6.
[223] *Id*.
[224] *Id*. at 7.
[225] *Id*. at 6.

reviewed at regular intervals to reflect new information on climate predictions and to assess the adequacy of mitigation efforts.[226] According to the Petition, plans meeting these requirements "would prepare utility infrastructure throughout the state for future extreme weather events, which are expected to be more severe than those seen in the past, and to ensure the reliable provision of vital service to New York citizens."[227]

No formal action has been taken by the New York PSC on the Petition.[228] In response to the Petition, the PSC's acting secretary issued a letter noting that Governor Cuomo in his State of the State Address had "identified the need for storm hardening and resilience planning in response to climate change." The letter also stated that PSC Staff was in the process of considering the approaches to infrastructure planning that would serve the "best interests of ratepayers" over the long term."[229] As a practical matter, many of the issues raised by the Petition were included as part of the Con Edison rate proceeding then pending before the New York PSC.[230] In its testimony to the New York PSC, for example, the witness for the Environmental Defense Fund urged the PSC to require Con Edison to develop a long-term plan that focuses on enhanced grid resilience and address the "potential impacts of climate change, including storm surge, sea level rise, more severe storms, and extreme heat."[231] The testimony claimed that historical climate experience was no longer valid as a basis for long-term planning.[232] Columbia Law School's Center for Climate Change Law also filed testimony in the proceeding, and criticized Con Edison's "storm hardening efforts" for focusing

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[226] *Id*.
[227] *Id* at 8.
[228] *See* New York Pub. Serv. Comm'n, Matter No. 12-02754, *Petition on Natural Hazard Planning*, Dec. 12, 2012, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=12-02754&submit=Search+by+Case+Number
[229] Letter from Jeffrey C. Cohen, Acting Secretary, New York Pub. Serv. Comm'n, to Anne R. Siders, Associate Director, Columbia Center for Climate Change Law (Jan. 16, 2013), available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={33FC06DC-93B3-411A-AB3B-FD5603B7FD65}.
[230] New York Pub. Serv. Comm'n, Case 13-E-0030, *Consolidated Edison Company of New York, Inc*., available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-E-0030.
[231] New York Pub. Serv. Comm'n, Case 13-E-0030, Environmental Defense Fund, Direct Testimony of Paul Centolella, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={53AEAB04-79AF-480D-92BD-79FE1E12E138}, at 5.
[232] *Id*. at 8, citing New York City Panel on Climate Change, *Executive Summary of Climate Change Adaptation in New York City: Building a Risk Management Response,* ANN. N.Y. ACAD. SCI. 1196 (2010) at 8.

too much attention on storm hardening based on the weaknesses exposed by Sandy rather than planning for the future impacts of climate change, such as projected sea level rise.[233] Columbia, along with Natural Resources Defense Council, Pace Energy & Climate Center, and the City of New York, addressed this shortcoming, at least in part, by entering into a stipulation with Con Edison requiring the utility to use updated flood plain maps in developing its capital investment design standards for resilience- or storm hardening-related capital improvement projects.[234] The Stipulation refers to Federal Emergency Management Agency (FEMA) Preliminary Work Maps issued in June 2013, and requires Con Edison to account for the impact of future climate change for projects located within the 100-year floodplains by designing them to withstand the level of a 100-year flood plus three feet.[235]

As discussed in the preceding section, the issues raised in the Con Edison proceeding were resolved in accordance with a *Joint Proposal* adopted by the New York PSC in its order issued in February 2014.[236] Although the PSC noted in its order that the settlement by its terms is specific to Con Edison, the PSC also addressed the applicability of climate change impacts to other utilities by expressly broadening the obligation to address these issues to include all utilities.[237] As noted in the preceding section, New York utilities were urged to examine projections by scientists regarding local climate change impacts, noting that climate change impacts would differ from utility to utility.[238] By requiring utilities "to consult the most current data to evaluate the climate impacts anticipated in their regions over the next years and decades" and "to integrate these considerations into their system planning and construction forecasts and

[233] New York Pub. Serv. Comm'n, Case 13-E-0030, Columbia Center for Climate Change Law, Post-Hearing Brief, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={C7889A83-F9B7-4072-8DCF-75741788D8BB}, at 8. According to Columbia, "Con Edison's current planning procedures are focused on storm mitigation based on historic, experienced, events rather than projected future events." *Id*.

[234] New York Pub. Serv. Comm'n, Case 13-E-0030, Stipulation, July 19, 2013, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={207C8972-2BE0-4BC3-8B12-420E99B70C10}, at 2.

[235] *Id*. The stipulating parties also agreed "on the value of increasing the resiliency of Con Edison's infrastructure," and agreed "to advocate to the Commission ratemaking treatment and cost recovery for resilience- or storm hardening-related capital projects" that were consistent with the terms of the Stipulation. *Id*.

[236] PSC ORDER, *supra* note 127 at 73.

[237] *Id.* at 71.

[238] *Id*.

budgets,"[239] the *PSC Order* granted the essential elements of the relief requested in the Petition.

C. The Role of the Prudence Standard

The prudence standard in utility ratemaking can also be an effective tool in utility retail rate proceedings to promote the integration of DG resources in utility system planning. Prudence has been described as "an essential constituent" of utility regulation.[240] When an electric utility seeks to increase its rates, it bears the burden of proof to demonstrate that the expenditures underlying the proposed rate increase are "reasonable and prudent."[241] As stated by the New York Court of Appeals, the burden of proof is on the utility "to justify its conduct" and to demonstrate that it "acted reasonably, under the circumstances at the time."[242] In the context of justifying significant capital expenditures, a utility seeking to fulfill this burden of proof generally must show that it followed a "reasonable decision making process" in arriving at its proposed course of action and responded in a reasonable manner, taking into account the facts that the utility knew or should have known at the time.[243] The prudent investment standard has been described as "an analog of the common law negligence standard" for utility regulators in determining whether utility investments should be excluded from rate base."[244] The burden on the utility is to demonstrate that the investment was "necessary and appropriate," or "resulted in no additional costs."[245]

To satisfy the burden of proof that a capital expenditure is necessary and reasonable—and therefore recoverable in rates—a number of states have required a utility to demonstrate that it identified and evaluated alternatives to the particular investment. The Kentucky Public Service Commission, for example, requires that a utility seeking a certificate of convenience and necessity for construction of electric facilities "must demonstrate that a thorough review of all reasonable alternatives has been performed."[246] That review necessarily involves consideration of whether such alternatives may result in a lower cost over time to

[239] *Id*. at 72.
[240] *Long Island Lighting Co. v. Pub. Serv. Comm'n of State of N.Y.*, 523 N.Y.S. 2d 615, 620 (1987)
[241] *Re Cent. Vermont Pub. Serv. Corp*., 5132, 1987 WL 257812 (May 15, 1987) at *566.
[242] *Long Island Lighting Co*., *supra* note 240 at 620.
[243] *Gulf States Utilities Co. v. Louisiana Pub. Serv. Comm'n*, 578 So. 2d 71, 85 (La. 1991), citing *Re Cambridge Electric Light Co*., 86 P.U.R. 4th 574 (Mass. D.P.U. 1987).
[244] *Gulf States Utilities Co*., *supra* note 209 at 84-85, citing *Appeal of Conservation Law Foundation*, 127 N.H. 606, 507 A.2d 652, 673 (1986).
[245] *Id*. at 85, citing Union Electric Co., 40 F.E.R.C. 61,046 (FERC 1987); *Long Island Lighting Co. v. Public Serv. Comm'n of New York*, 134 A.D.2d 135, 523N.Y.S.2d 615 (3rd Dept. 1987); *Re Central Vermont Pub. Serv. Comm'n Corp*., 83 P.U.R.4th 532 (Vt. P.S.B. 1987).
[246] *In the Matter of Kentucky Power Co*., 2013 WL 5592919 (Ky. P.S.C.), *16.

utility ratepayers; while selection of a higher-cost alternative does not necessarily indicate "wasteful duplication" under the Kentucky statute, the Kentucky PSC has adopted "the principle of least-cost [as] one of the fundamental foundations utilized when setting rates that are fair, just, and reasonable."[247] The Washington Utilities and Transportation Commission (WUTC) similarly requires evaluation of alternatives as part of a utility's *prima facie* case to demonstrate the prudence of a resource acquisition. In a 1993 decision involving Puget Sound Power and Light Company, the WUTC directed that the utility, for each of its resources acquisitions, identify the resource alternatives that were available to it at the time it made the decision to contract for the resource at issue.[248]

With respect to the evaluation of DG resources as an alternative to utility investments in T&D infrastructure, the California Public Utility Commission expressly requires the three investor-owned utilities subject to its jurisdiction to evaluate DG resources as possible alternatives to distribution system upgrades.[249] In Minnesota, a utility seeking to construct transmission lines must demonstrate that the electrical demand cannot be met in a more cost effective manner.[250] Among the possible alternatives for satisfying the transmission needs, the utility must consider the possibility of upgrading its existing energy generation and transmission facilities to operate more efficiently, or investing in load-management programs and DG resources.[251]

Based on this precedent under the prudent investment standard, utility expenditures on T&D infrastructure can be challenged in rate proceedings, if it can be demonstrated that use of DG resources may result in a lower-cost alternative for the utility than additional investments in T&D infrastructure. The contention is that because DG resources allow the generation to be located closer to the load, some spending on T&D infrastructure may be subject to disallowance, as unnecessary expenditures, under the prudent investment standard. An example of such a challenge is the testimony of Pace in Con Edison's 2009 electric rate

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[247] *Id*. The PSC also stated that the "least-cost principle" is incorporated within KRS 278.020(1), which is the statute requiring a certificate of convenience and necessity for construction of electric facilities. *Id*.
[248] *In re Puget Sound Power & Light Co*., UE-920433, 1993 WL 500137 (Sept. 21, 1993) on reconsideration in part sub nom. *Re Puget Sound Power & Light Co*., UE-920433, 1993 WL 601269 (Dec. 15, 1993) at *101.
[249] *In re Elec. Util. Res. Planning*, D.04-12-048, 2004 WL 3057972 (Dec. 16, 2004) at *31, citing D.03-02-068 (2003).
[250] *In the Matter of the Application of Otter Tail Power*, 2007 WL 2505697 (Minn. Off. Admin. Hrgs.) at *17.
[251] *Id*.

proceeding.[252] In that proceeding, Con Edison sought an increase in its electric rates of $854 million.[253] The largest single driver of the rate increase was "infrastructure investment," which accounted for $170 million, or about one-fifth of the request.[254] Given the extent to which investments in T&D infrastructure was driving the need for Con Edison to seek rate relief, Pace intervened in the case "to explore[] the extent to which Con Edison considers using additional investments in DG, whether utility-owned or customer-owned, as a means of avoiding or delaying investment in T&D infrastructure."[255]

Pace's discovery focused on whether Con Edison evaluated the deployment of DG resources as an alternative in the various T&D infrastructure projects proposed for rate recovery in Con Edison's filing.[256] According to Pace's testimony, Con Edison claimed to have explored various opportunities for mitigating the infrastructure investment, including demand reduction and energy efficiency.[257] In an attempt to satisfy its burden to demonstrate the reasonableness of its proposed T&D infrastructure expenditures, Con Edison apparently followed a "least cost evaluation process" that included various "least cost options." The options included the installation of additional equipment; looking at demand-side options in the area, such as targeting energy efficiency programs; transferring some of the electrical load to a nearby substation having excess capacity; or building a new substation.[258] Pace expressly inquired about Con Edison's evaluation of DG as part of this "least cost evaluation process." Con Edison's response was that because DG was technically included as part of its "Targeted DSM Program," the list of activities included as evaluated "least cost options" actually did include DG.[259] Noting that there was no participation by DG providers in Con Edison's Targeted DSM Program—which Pace claimed was due to the "restrictive parameters of the program"—Pace stated it was "hollow" for Con Edison to hold out this Program as a true evaluation by Con Edison of DG resources as cost-effective alternatives to T&D investment.[260] Citing the results of its discovery, Pace disputed that Con Edison was actually integrating DG

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[252] *New York Pub. Serv. Comm'n*, Case 09-E-0428, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=09-e-0428&submit=Search+by+Case+Number.

[253] New York Pub. Serv. Comm'n, Case 09-E-0428, Testimony of Thomas G. Bourgeois, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={C8A02A51-D2C3-4861-9839-3CFAAB10467E} at 9

[254] *Id*.

[255] *Id*.

[256] *Id* at 18.

[257] *Id*.

[258] *Id*. at 18-19.

[259] *Id*. at 19.

[260] *Id*.

resources into its T&D planning process as a possible alternative.[261] As its requested relief, Pace asked that Con Edison be required in future proceedings to show as part of its burden of proof for recovering T&D costs in rates that it evaluated DG resources as an alternative to making additional investment in T&D infrastructure.[262]

The issues raised by Pace were addressed in a settlement agreement among Con Edison and the other parties to the rate proceeding.[263] Under the Joint Proposal filed with the New York PSC on November 24, 2009, Con Edison agreed to convene a DG Collaborative to investigate a number of DG-related issues that arose in the case. These issues included a "physical assurance" requirement imposed on DG resources seeking to participate in Con Edison's DSM program, the extent to which Con Edison included DG resources in its long-range electric plan, the terms under which Con Edison provides electric service to a campus facility where an on-site DG resource provides all or part of the customer's electrical or thermal requirements, and quantifying the value of using DG resources to defer infrastructure investment.[264] The DG Collaborative was assigned the task of developing protocols for Con Edison's T&D planning process that incorporate the possible use of DG resources as a means of providing load relief, with the express requirement that DG resources were to be considered on a comparable basis with other measures.[265] The Collaborative was also charged with exploring options for funding investments in DG resources in those situations where they could be deployed as alternatives to T&D investments.[266] The Joint Proposal specified that the types of DG to be considered by the Collaborative include wind, solar, combined heat and power (CHP), micro-CHP, energy storage, and other alternative technologies.[267] The Joint Proposal was adopted by the New York PSC in March 2010.[268]

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[261] *Id.*
[262] *Id.*
[263] New York Pub. Serv. Comm'n, Case 09-E-0428, Joint Proposal, November 23, 2009, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={16AFDDC3-0F68-45B9-B27C-DFA48744B3A2}.
[264] *Id.* at 57.
[265] *Id.*
[266] *Id.*
[267] *Id.*
[268] New York Pub. Serv. Comm'n, Case 09-E-0428, Order Establishing Three-Year Electric Rate Plan, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={60F5E842-B7B6-43CC-A589-8C16347B59FD} at 39.

The DG Collaborative convened on April 12, 2010, and held eleven meetings over the succeeding six months.[269] On November 2, 2010, Con Edison filed the Report of the DG Collaborative with the New York PSC.[270] One of the issues in the DG Collaborative was the "physical assurance" requirement under which Con Edison effectively imposed a 100% reliability requirement for DG resources connected to its system.[271] This requirement meant that either the customer with DG resources had to isolate its load from the grid and rely solely on the DG resource, or the customer must be willing to shed load if the DG resource was out of service.[272] This was seen as a barrier to DG resources, inasmuch as Con Edison was imposing a reliability requirement on the resources greater than it expected from its own system.[273] As a result of the DG Collaborative process, there was some movement by Con Edison, which promised to "relax" the physical assurance requirement "in some very limited circumstances."[274] Con Edison also committed that over the twenty year period of its Electric System Long Range Plan, it would "seek to integrate energy efficiency, DG, and demand response ("DR") to further the goals of deferring new infrastructure investment."[275] Con Edison further acknowledged that while "traditional infrastructure investments are one way to address capacity and reliability constraints on the system . . .[i]n some cases, demand side solutions may be more effective and will also help meet [Con Edison] objectives to reduce the impact of energy distribution and use on the environment."[276]

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[269] New York Pub. Serv. Comm'n, Case 09-E-0428, 2010 Distributed Generation Collaborative Report, November 2, 2010, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={B731E2D5-83A9-4954-9F15-694699915503} [hereinafter DG COLLABORATIVE REPORT] at 2.
[270] *Id*.
[271] *Id*. at 4.
[272] BOURGEOIS TESTIMONY, *supra* note 145 at 12.
[273] New York Pub. Serv. Comm'n, Case 09-E-0428, Testimony of Thomas G. Bourgeois, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={C8A02A51-D2C3-4861-9839-3CFAAB10467E} at 13.
[274] BOURGEOIS TESTIMONY, *supra* note 145 at 12. *See also* DG COLLABORATIVE REPORT, *supra* note 269 at 4-5.
[275] DG COLLABORATIVE REPORT, *supra* note 269 at 5.
[276] *Id*. at 6. Notwithstanding these statements by Con Edison in the DG Collaborative Report, Pace testified in the 2013 Con Edison rate case that "the DG Collaborative was unsuccessful in getting Con Edison to think any differently about integrating DG into its long-term planning process." BOURGEOIS TESTIMONY, *supra* note 145 at 12. Pace observed that Con Edison's "DG Strategy," as enunciated in the DG Collaborative Report, is "passive rather than proactive." *Id*. at 13. As described by Pace, "the results of the DG Collaborative are that Con Edison will continue to 'study' the issue for the next few years, take another five years to develop an 'implementation strategy,' and maybe after 10 years customers will see streamlined interconnections, two-way communications, and the possibility of microgrids." *Id*. Pace concluded that Con Edison "has not

Pace, together with NRDC, pursued a similar strategy in another rate proceeding before the New York PSC, related to the requested rate increase of Niagara Mohawk Power Corporation (Niagara Mohawk), a subsidiary of National Grid.[277] In January 2010, Niagara Mohawk filed a case with the New York PSC seeking an increase of $392 million, or 12 percent, in its electric rates, over a three-year period.[278] According to the Pace/NRDC testimony in the proceeding, a major component driving Niagara Mohawk's request for rate relief was the utility's existing and planned expenditures on T&D infrastructure.[279] Pace/NRDC pointed out that Niagara Mohawk proposed to invest $541 million, $649 million and $629 million in electric transmission and distribution infrastructure in calendar years 2011, 2012 and 2013.[280] According to Pace/NRDC, the role of T&D infrastructure investment as a driver in Niagara Mohawk's need for rate relief warranted an examination of the extent to which Niagara Mohawk evaluates 'non-wires alternatives' as possible tools in avoiding or deferring investment in T&D infrastructure.[281] Pace/NRDC defined "non-wires alternatives" to include demand-side management, DG, and customer energy efficiency.[282] Pace/NRDC cited in particular a report summarizing a comprehensive management audit of Niagara Mohawk, which concluded that such non-wires alternatives, as well as Smart Grid initiatives, were "not regularly considered" in Niagara Mohawk's system planning process.[283] Based on their discovery during the proceeding, Pace/NRDC claimed that the utility's planning engineers lacked "well-developed tools" for evaluating measures on the customer side of the meter (including DSM and DG resources) as alternatives to traditional T&D infrastructure investments.[284] Pace/NRDC also stated that Niagara Mohawk had failed to

been motivated to consider DG and microgrids as solutions," and thus the PSC "must step in to protect ratepayers and require swifter action." *Id*.

[277] New York Pub Serv. Comm'n, Case 10-E-0050, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=10-e-0050&submit=Search+by+Case+Number.

[278] Letter from Peter G. Flynn, Deputy General Counsel, National Grid to Jaclyn Brilling, Secretary, New York PSC, January 29, 2010, available at https://www2.dps.ny.gov/ETS/jobs/display/download/2836571.pdf, at 2.

[279] New York Pub Serv. Comm'n, Case 10-E-0050, Niagara Mohawk Power Corporation, Testimony of James M. Van Nostrand, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=10-e-0050&submit=Search+by+Case+Number, at 10.

[280] *Id*. at 9, citing the testimony of Thomas B. King.

[281] *Id*. at 10.

[282] *Id*. In other words, traditional T&D infrastructure investment constituted the "wires," and any measure that reduced investment in the "wires" was a "non-wires alternative."

[283] *Id*. at 11.

[284] *Id*. at 12.

perform any analyses of the possible impact of either customer-owned or utility-owned DG as a means of deferring or avoiding a T&D expansion project.[285]

Pace/NRDC concluded that Niagara Mohawk's record on the issue of evaluation of non-wires alternatives to traditional T&D infrastructure investment was "disappointing," and that there was "no sense of urgency on the issue" as the utility "continue[d] on its 'business as usual' path of making substantial—and possibly imprudent—investments in its T&D infrastructure, to the tune of over $1.7 billion over the next three years."[286] As in the 2009 Con Edison rate case, Pace/NRDC sought similar relief and urged the PSC to require Niagara Mohawk in future proceedings, to show as part of its burden of proof for recovering T&D costs in rates, that it evaluated non-wires alternatives as a means of deferring or avoiding additional investment in T&D infrastructure.[287] In other words, Niagara Mohawk should be required to show "as an integral component of its T&D planning that it has explored non-wires alternatives and determined them not to be cost-effective as compared to traditional wires investments."[288] Pace/NRDC further recommended that Niagara Mohawk be required to develop a "pilot program" that would demonstrate the potential use of non-wires alternatives to avoid or delay T&D investment.[289] Such a program would involve identifying a capacity-constrained area and requiring development of an "action plan" that would combine a variety of non-wires solutions (utility- and customer-owned DG, energy efficiency, and demand response) to provide a "true test" of how non-wires alternatives can be integrated into the T&D planning process.[290]

Niagara Mohawk indicated that it would be "amenable" to implementing a program, at least on a pilot basis, that would obtain more information on the potential for non-wires alternatives.[291] But it opposed imposition of a requirement that it address non-wires alternatives in future rate case presentations for the recovery of T&D system investments, citing the progress already underway at the utility on this issue, the "nascent stage of development" of non-wires alternatives throughout the country, and the fact that analysis of non-wires solutions requires consideration of site-specific circumstances."[292] In their recommended decision

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[285] *Id*. at 17.
[286] *Id*. at 19.
[287] *Id*. at 20.
[288] *Id*.
[289] *Id*. at 20-21.
[290] *Id*. at 21-22.
[291] New York Pub Serv. Comm'n, Case 10-E-0050, Niagara Mohawk Power Corporation, Initial Brief of Niagara Mohawk Power Corporation, October 8, 2010, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=10-e-0050&submit=Search+by+Case+Number, at 161.
[292] *Id*. at 163.

issued November 17, 2010, Administrative Law Judges William Bouteiller and Rudy Stegemoeller concluded that "[i]t is clear that Pace/NRDC perceive [Niagara Mohawk] as having dragged its heels" and, at the same time, "National Grid is promising to move promptly and effectively to undertake a pilot program."[293] They directed that these parties make a proposal in their briefs on exception for a timeline of activities over the subsequent two to three years that would explore the use of non-wires alternatives in the utility's service area.[294]

In its brief on exceptions to the PSC, Niagara Mohawk set forth a proposed course of action, as agreed upon with Pace/NRDC.[295] The plan contemplated collaborative discussions between Pace/NRDC and Niagara Mohawk, designed to develop a framework under which customer-sited options (energy efficiency investments and DG resources) would be considered as alternatives to traditional infrastructure investments, followed by identification of a range of possible pilot proposals demonstrating deployment of these non-wires alternatives.[296] These proposals would then be presented to the Department of Public Service Staff for its input and consideration, followed by comment from a larger group of interested parties.[297] In its order on January 24, 2011, the PSC adopted the proposal for evaluation of non-wires alternatives, finding that "a cooperative effort between [Niagara Mohawk] and Pace/NRDC, followed by input from Staff and other parties, is an efficient use of resources toward this important goal."[298]

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[293] New York Pub Serv. Comm'n, Case 10-E-0050, Niagara Mohawk Power Corporation, Recommended Decision, November 17, 2010, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=10-e-0050&submit=Search+by+Case+Number, at 116.

[294] *Id*. at 116-117. The parties were directed to set forth a "preferred course of action for the next 24 to 36 months for the approach that should be taken (including a timetable for action and a list of critical path milestones) to address the use of non-wires alternatives in the Niagara Mohawk service area."

[295] New York Pub Serv. Comm'n, Case 10-E-0050, Niagara Mohawk Power Corporation, Brief on Exceptions of Niagara Mohawk Power Corporation d/b/a National Grid, December 8, 2010, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=10-e-0050&submit=Search+by+Case+Number, at 46.

[296] *Id*.

[297] *Id*.

[298] New York Pub Serv. Comm'n, Case 10-E-0050, Niagara Mohawk Power Corporation, Order Establishing Rates of Electric Service, January 24, 2011, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=10-e-0050&submit=Search+by+Case+Number, at 67.

In its subsequent rate filing on April 2012, Niagara Mohawk reported its progress on the collaborative process.[299]According to the utility, it has been working collaboratively with Pace and NRDC to explore the potential for a pilot program for non-wires alternatives.[300] The work includes development of a "principles document" to be agreed upon by Niagara Mohawk, Pace and NRDC to guide the non-wires alternative implementation strategy.[301] Niagara Mohawk reported that a desired outcome of the collaborative process would be the identification of suitable pilot projects that it would present to the Commission for consideration.[302] In May 2012, Pace/NRDC and Niagara Mohawk executed a "Non-Wires Alternatives Principles" document which, among other things, commits National Grid to investigate the feasibility of using "non-wires alternatives" as a means of improving the efficiency of investments in its T&D system.[303] "Non-wires alternatives" were defined broadly to include measures on the customer's side of the meter such as energy efficiency, demand response, and deployment of DG resources.[304] The document acknowledges that the full integration of these resources "requires analysis of the specific costs and benefits of the various components of [non-wires alternatives] and their compatibility with wires based solutions," and reports that "new screening tools are being developed and incorporated into [National Grid's] planning processes."[305]

D. *The "Used and Useful" Doctrine, and the Role of DG Resources in Avoiding Excess Capacity*

Under the "used and useful" standard, a utility is allowed to include in its rate base (upon which it earns a return, or profit) only those assets that are "used and useful" in rendering utility service to its customers.[306] Generating electricity that is in excess of the utility's current needs to meet the demands of its customers

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[299] New York Pub Serv. Comm'n, Case 12-E-0201, Niagara Mohawk Power Corporation, Testimony of Infrastructure and Operations Panel, April 2012, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=12-e-0201&submit=Search+by+Case+Number, at 109.
[300] *Id*.
[301] *Id*. Niagara Mohawk, Pace and NRDC subsequently agreed upon this "principles document." Email from Thomas R. Bourgeois, Deputy Director, Pace Energy & Climate Center to James M. Van Nostrand, February 13, 2014.
[302] New York Pub Serv. Comm'n, Case 12-E-0201, Niagara Mohawk Power Corporation, Testimony of Infrastructure and Operations Panel, April 2012, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=12-e-0201&submit=Search+by+Case+Number, at 109.
[303] *Non-Wires Alternatives Principles*, email from Thomas Bourgeois, Deputy Director, Pace Energy & Climate Center, to author (Feb. 23, 2014) (on file with the author).
[304] *Id*. at 1.
[305] *Id*.
[306] *Denver Union Stock Yard Co. v. U.S.*, 304 U.S. 470, 475 (1938).

is subject to disallowance by regulators on the grounds that the assets used to generate the electricity are not "used and useful."[307] Because the optimal size for additions of nuclear, coal and natural gas-fired generating stations under the traditional, utility-scale central generating station model is fairly large, investments by utilities in new generating capacity are said to be "lumpy" or, in other words, available only on a substantial scale.[308] This large scale contrasts sharply with the more steady and smooth growth in demand typically experienced by retail electric utilities.[309] As a result, the resource additions under the traditional, utility scale model often result in a short-term mismatch between loads and resources, thereby potentially exposing utilities to disallowances as excess capacity under the "used and useful" principle.[310] This principle can come into play as a legal tool for promoting DG resources by demonstrating that these resources are a means of avoiding the "lumpiness" associated with the central generation model. Simply stated, DG resources allow the addition of smaller increments of new resources to match more precisely the utility's loads.

A 2002 article by William Baumol and Gregory Sidak used the analogy of a pig and a python to illustrate the concept of generation capacity as being a "lumpy" investment.[311] In an ideal situation, a "business entity can add productive capacity in infinitesimally small increments," thereby achieving a marginal cost curve that is "smooth over a range of output."[312] Where an investment is "lumpy," however, the curve has a "jerky, stair-step appearance." According to the *Baumol & Sidak* analogy, "[g]eneration capacity is our pig, and the electric utility our python":[313]

> When capacity constrains the utility's output, the utility must add capacity in discrete amount having some minimum efficient size. A utility, for example, cannot add one kilowatt of generation capacity at a time, but rather must add all of the capacity inherent in a single generator or a single

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[307] William Baumol & Gregory Sidak, *The Pig In The Python: Is Lumpy Capacity Investment Used and Useful?*, 23 Energy L.J. 383 (2002) [hereinafter BAUMOL & SIDAK].
[308] Id. at 385.
[309] The U.S. Energy Information Administration projects growth in total electricity demand of about 0.9% per year from 2012 to 2040. ANNUAL ENERGY OUTLOOK 2014, *Market Trends: Electricity Demand*, available at
http://www.eia.gov/forecasts/aeo/MT_electric.cfm#cap_natgas?src=Electricity-b1.
[310] Richard J. Pierce, *The Regulatory Treatment of Mistakes in Retrospect: Canceled Plants and Excess Capacity*, 132 U. PA. L. REV. 497 (1984).
[311] BAUMOL & SIDAK, *supra* note 307 at 385.
[312] *Id*.
[313] *Id*.

> power plant. This inability to add capacity in tiny, tailor-made increments means that new capacity will often give the utility more capacity than it needs for immediate purposes.[314]

As stated by *Baumol & Sidak*, "the technology of pigs and pythons imposes certain physical constraints: if there is to be any python meal at all, it must consist of at least a minimum-sized pig."[315] While the pig provides "current sustenance" for the python, "the pig is also the python's lumpy investment in future nourishment."[316]

Several cases illustrate the risk of a regulatory disallowance associated with the addition of "lumpy" generating additions that result in excess capacity that fails the "used and useful" test. In *Kansas Gas and Electric Company, et al v. State Corporation Commission*, the Supreme Court of Kansas upheld the Kansas State Corporation Commission's determination to exclude over $900 million in investment in the Wolf Creek Generating Station from the utilities' rate base; the disallowed portion reflected the investment associated with 641 MW which represented "excess physical capacity," because that portion of the plant was not "used or required to be used" to provide utility services to current customers.[317] In

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[314] *Id.*

[315] *Id.*

[316] *Id.*

[317] *Kansas Gas and Electric Company, Kansas City Power & Light Company, Kansas Electric Power Cooperative, Inc. v. State Corporation Commission*, 720 P.2d 1063 (Kansas, 1986). The Wolf Creek Nuclear Generating Station is approximately 1200 MW. Wolf Creek Nuclear Operating Corporation, About Wolf Creek, available at http://www.wcnoc.com/aboutwolfcreek.htm. It should be noted that the effect of the Kansas SCC's decision to exclude the investment from rate base was to deny a return or profit on this investment; the utilities were allowed to recover the investment itself through depreciation. 720 P.2d at 1083. *See also, Re Public Service Company of New Mexico*, where the New Mexico Public Service Commission applied a financial health test and the "used and useful" test to balance investor and ratepayer interests in its denial of 365 MW of excess capacity in base load generation investments from the utility's rate base. *Re Public Service Company of New Mexico*, New Mexico Pub. Serv. Comm'n, 101 P.U.R. 4th 126 (1989). *See also*, *Re Otter Tail Power Company*, North Dakota Pub. Serv. Comm'n, 44 P.U.R. 4th 219 (1981), where the North Dakota PSC addressed the issue of 66 MW of excess capacity associated with the Coyote lignite generating facility by disallowing the allocable common equity return associated with the investment representing the capacity found to be in excess of the utility's needs. 44 P.U.R. 4th at 228. Under this treatment, said the PSC, "the company's shareholders and ratepayers share the burden of excess capacity costs." *Id*. *See also, In Re Electric Power Co-Op, Inc*., Louisiana Pub. Serv. Comm'n, 1994 WL 794132 (1994), which involved a finding that Cajun Electric Power Cooperative's investment in the River Bend Nuclear Plant "failed the 'used and useful' standard set forth by the Louisiana Supreme Court in *Central Louisiana Electric Co. v. Louisiana Pub. Serv. Comm'n*, 508 So. 2d 1361 (La. 1987). As a result, Cajun's rates were reduced by $30.23 million to implement the

Iowa-Illinois Gas & Elec. Co. v. Iowa State Commerce Comm'n, the Iowa Supreme Court upheld a decision by the Iowa Commerce Commission to reduce the utility's return on investment in capacity that was found to be excessive.[318] The Iowa SCC determined that the utility had 199 MW of excess generating capacity, due largely to the addition of 125 MW from the utility's share of a new generating unit, the Ottumwa Generating Station.[319] The Court upheld the SCC's use of a complicated formula that effectively reduced the rate of return, on a graduated scale, on that portion of the plant found to be excess to the utility's need."[320] The Court ruled that a utility was not constitutionally entitled to earn a fair rate of return on that part of an investment that turned out to be unnecessary, irrespective of whether the utility's initial decision to undertake the investment was prudent.[321]

In *Philadelphia Elec. Co. v. Pennsylvania Pub. Util. Comm'n*, the Pennsylvania PUC excluded the least economical generating units from electric company's rate base in order to account for 775 MW of generating capacity found to be more than what was determined to be necessary in order to meet peak demand and a reserve margin.[322] The basis for the order, according to the Court, was the finding that excess generating capacity is not "used and useful" in rendering service to utility customers.[323] In upholding the decision of the Pennsylvania PUC, the Court stated that the "touchstone" for including a prudently constructed generating asset in a utility's rate base is whether or not the unit will be "used and useful" in rendering service to the public during the test

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determination that "River Bend is excess to Cajun's demand requirements, excess to Cajun's base load needs, and uneconomic." 1994 WL 794132 at 2.

318 *Iowa-Illinois Gas & Elec. Co. v. Iowa State Commerce Comm'n*, 347 N.W.2d 423, 428 (Iowa 1984).

319 347 N.W.2d at 428. The SCC defined "excess" to be the utility's electric generating capacity exceeding 125 percent of its actual annual peak load during 1980. *Id*.

320 *Id*.

321 *Id*. at 429. In *Iowa Public Service Co*., 46 P.U.R. 4th 339 (1982), the Iowa SCC established a formula for reducing a utility's rate of return by an amount proportionate to the amount of excess capacity on the utility's system. Professor Pierce referred to this solution as "the most promising approach to the difficult problem of regulatory treatment of excess capacity." Richard J. Pierce, Jr., *The Regulatory Treatment of Mistakes in Retrospect: Canceled Plants and Excess Capacity*, 132 U. PA. L. REV. 497, 540-41 (1984). According to Professor Pierce, this approach "has the advantage of permitting the Commission to impose a financial penalty that is meaningful but less extreme than the penalty of totally disallowing excess capacity in rate base." *Id*. at 541. It also allows the size of the financial penalty to be correlated with the magnitude of the forecasting error. *Id*.

322 *Philadelphia Elec. Co. v. Pennsylvania Pub. Util. Comm'n*, 433 A.2d 620, 622 (Pa. 1981).

323 *Id*. at 623.

year of the rate case.[324] The Texas Court of Appeals in *El Paso Elec. Co. v. Pub. Util. Comm'n of Texas* affirmed a decision of the Texas Commission to exclude from a utility's rate base a portion of its investment in a nuclear power plant to protect "Texas ratepayers from the massive cost burden of unneeded capacity."[325] The treatment afforded by the PUC excluded a portion of the capital costs associated with the utility's investment in the Palo Verde Nuclear Generating Station until such time as the excess capacity "is transformed into capacity 'used and useful to' [El Paso] in providing service to local ratepayers."[326]

As noted above, a premise of the *Baumol & Sidak* analysis is that capacity increments are available only on a substantial scale.[327] Rather than a "continuous function of output," lumpy capacity involves incremental generating capacity in quantities that are "of considerable size relative to total current demand,"[328] thereby creating a large share of excess capacity at the date of the introduction of the lumpy investment.[329] Although that excess capacity gradually shrinks as demand grows over time, *Baumol & Sidak* point out that "[a]t the moment it disappears altogether . . . yet another such lumpy facility may be brought on line—and the excess capacity appears all over again."[330] Thus these authors conclude that "the typical history of lumpy investment is one in which so-called *excess capacity is almost never absent*."[331] Professor Richard Pierce, for his part, acknowledges that it may be desirable in some circumstances to have excess capacity "because of indivisibilities in generating increments and large economies of scale in generation."[332]

Recent data from the U.S. Energy Information Administration (EIA) confirm these indivisibilities and the "lumpiness" associated with the traditional central generation model. In its Annual Energy Outlook 2014 Early Release, the EIA lists the "cost and performance characteristics of new central station electricity generating technologies."[333] The representative size listed for the

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[324] *Id*. The Court affirmed the PUC's decision to exclude $25 million from rate base attributable to excess capacity. *Id*. at 624.

[325] *El Paso Elec. Co. v. Pub. Util. Comm'n of Texas*, 917 S.W.2d 846, 857 (Tex. App. 1995).

[326] *Id*. at 858.

[327] BAUMOL & SIDAK, *supra* note 307 at 385 ("A lumpy investment is one that is only available on a substantial scale; when acquired, the investment significantly expands the firm's total capacity.)

[328] *Id*.

[329] *Id*. at 390.

[330] *Id*.

[331] Id. (emphasis in original).

[332] Richard J. Pierce, Jr., *The Regulatory Treatment of Mistakes in Retrospect: Canceled Plants and Excess Capacity*, 132 U. PA. L. REV. 497, 539 (1984).

[333] U.S. ENERGY INFORMATION ADMINISTRATION, *AEO2014 Early Release*, Table 8.2 *Cost and Performance Characteristics of New Central Station Electricity Generating Technologies*,

traditional central generation technologies—nuclear, pulverized coal, natural gas-fired combined cycle combustion turbines, integrated coal gasification combined cycle (IGCC)—are all in excess of 400 MW, with nuclear at 2236 MW, "scrubbed coal" at 1300 MW, IGCC at 1200 MW, and pulverized coal with carbon sequestration at 650 MW.[334] Natural gas-fired combined cycle generating units are listed at 620 MW and 400 MW, respectively.[335] In contrast, the technologies commonly used for DG resources, identified as "Distributed Generation—Base" and "Distributed Generation—Peak," in the EIA data, are listed at 2 MW and 1 MW respectively, while another commonly used DG technology—fuel cells—is listed at 10 MW.[336] A CHP unit, for its part, can be deployed in a variety of sizes, depending upon the desired thermal load; for illustrative purposes, the *ICF Study* cited above uses 1.5 MW as the generator capacity for CHP.[337]

With the availability of DG resources, the "lumpy" investment problem is dramatically reduced. It can no longer be said that the capacity increment for electric generating resources is available only on a substantial scale, as observed in *Baumol & Sidak*.[338] The "inability to add capacity in tiny, tailor-made increments," a valid observation when made by *Baumol & Sidak* twelve years ago, is no longer true today.[339] The "indivisibilities in generating increments" to which Professor Pierce referred are no longer indivisible.[340] Rather, DG resources enable utilities to add generation in smaller increments that more precisely match the gradual increase in utility loads, thereby avoiding the "jerky, stair-step appearance" of the supply curve cited in *Baumol & Sidak*. Nor is the reserve margin observed by Professor Pierce[341] as necessary now; the more nimble DG resources can address those situations where a reserve margin was considered desirable.

Not only are DG resources increasingly available and flexible, they are also becoming cost competitive with central generating units in many

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available at http://www.eia.gov/forecasts/aeo/assumptions/pdf/table8_2_2014er.pdf [hereinafter EIA 2014 AEO].

[334] *Id*.

[335] *Id*. The 620 MW figure refers to conventional combined cycle units, and while the 400 MW figure is for advanced combined cycle units. Simple cycle natural gas-fired units are listed at 210 MW for advanced and 85 MW for conventional. *Id*.

[336] *Id*.

[337] ICF Study, *supra* note 12 at Table A-2, *CHP Value Comparison With and Without Backup Power Capability*, at 41.

[338] BAUMOL & SIDAK, *supra* note 307 at 385.

[339] *Id*.

[340] Pierce, *supra* note 332 at 539.

[341] *Id*.

circumstances. For example, EIA's 2014 Annual Energy Outlook Early Release lists the "overnight capital cost" associated with DG resources at $1465/kW and $1759/kW, respectively,[342] while the same figure for nuclear is $5429/kW, for "scrubbed coal new" is $2883/kW, for IGCC is $3718/kW, and for pulverized coal with carbon sequestration is $5138/kW.[343] Natural gas-fired combined cycle generating units are listed at $1006/kW and $901/kW, respectively.[344] In the case of CHP, the *ICF Study* cited above uses $1800/kW as the installed cost for a 1.5 MW CHP unit.[345] Thus, the "large economies of scale in generation" cited by Professor Pierce in his 1984 article no longer clearly favor large central generating units.[346] DG resources are cost-competitive in many settings. As discussed in Section III.E. below, it is important that the pricing policies for integrating DG resources reflect the true costs and benefits associated with DG resources in order for this option to be evaluated properly alongside the traditional central generation resources.

E. The Role of Cost-Based Ratemaking

The utility ratemaking principle that rates should reflect costs provides another tool available in utility regulatory proceedings to push utilities towards a new paradigm featuring DG resources. Ratemaking statutes uniformly require utility rates to be "just and reasonable,"[347] or "fair, just, reasonable and sufficient."[348] The requirement of "just and reasonable" rates has commonly been interpreted to require rates that are cost-supported or, stated differently, that rates be set in accordance with the "cost-causation" principle.[349] As stated in a leading case interpreting the statutory standard under Section 4 of the Natural Gas Act, a number of decisions from the Federal Energy Regulatory Commission (FERC) and associated judicial opinions have interpreted the "just and reasonable" language as establishing a requirement that rates approved by utility regulators must "reflect to some degree the costs actually caused by the customer who must

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[342] EIA 2014 AEO, *supra* note 333 at Table 8.2. The "Total Overnight Capital Cost for Distributed Generation—Base" is $1465/kW, and $1750/kW for "Distributed Generation—Peak." *Id*.
[343] *Id*.
[344] The $901/kW figure refers to conventional combined cycle units, while the $1006/kW figure is for advanced combined cycle units. Simple cycle natural gas-fired units are listed at $956/kW for advanced and $664/kW for conventional. *Id*.
[345] ICF Study, *supra* note 12 at Table A-2, *CHP Value Comparison With and Without Backup Power Capability*, at 41.
[346] Pierce, *supra* note 332 at 539.
[347] Section 205 of the Federal Power Act, for example, requires rates, terms and conditions to be "just and reasonable" and must be "not unduly discriminatory or preferential." 16 U.S.C. § 824d.
[348] RCW 81.108.030 (Wash., 1991) ("In establishing the rates, the commission shall assure that they are fair, just, reasonable, and sufficient.")
[349] *K N Energy, Inc. v. F.E.R.C.*, 968 F.2d 1295, 1300 (D.C. Cir. 1992)

pay them."[350] FERC determines whether utilities have complied with this "cost causation principle" "by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party."[351]

The principle of cost-based utility ratemaking comes into play as a regulatory tool by directing regulators, in setting "cost-based" rates, to reflect in those rates all the benefits of DG resources. In other words, the costs assessed against a customer—in the form of rates paid by that customer—should reflect "costs actually caused by the customer."[352] As noted above, the Energy Policy Act of 2005 (EPAct) required the Department of Energy (DOE), in consultation with FERC, to conduct a study of the benefits of DG and the rate-related issues that impede their expansion;[353] the *DOE Study* identified many of the benefits that should be taken into account in setting "cost-based" rates.[354] The benefits required to be considered in the *DOE Study* include increased system reliability,[355] improved power quality,[356] the provision of ancillary services,[357] reduction of peak power requirements through onsite generation,[358] and the ability of DG resources to provide reactive power or volt-ampere reactives[359] and an emergency supply of power.[360] Other possible benefits of DG resources noted in EPAct include avoiding investments in generation, transmission, or distribution facilities,[361] reducing land use effects and the costs of right-of-way acquisition,[362] and reducing the vulnerability of the electric system to terrorism.[363] EPAct also

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[350] *Id*. *See also*, *Alabama Elec. Co-op., Inc. v. F.E.R.C.*, 684 F.2d 20, 27 (D.C. Cir. 1982)("Properly designed rates should produce revenues from each class of customers which match, as closely as practicable, the costs to serve each class or individual customer.")

[351] *Midwest ISO Transmission Owners v. F.E.R.C.*, 373 F.3d 1361, 1368 (D.C. Cir. 2004) citing *K N Energy, Inc*., *supra* note 349, 968 F.2d at 1300.

[352] *Id*.

[353] Energy Policy Act of 2005, Section 1817, required the Secretary of Energy to conduct a study of the potential benefits of cogeneration and small power production, otherwise known as distributed generation, or DG. In accordance with Section 1817 the study includes those benefits received "either directly or indirectly by an electricity distribution or transmission service provider, other customers served by an electricity distribution or transmission service provider and/or the general public in the area served by the public utility in which the cogenerator or small power producer is located." Subsection (a)(1)(B).

[354] DOE STUDY, *supra* note 10 at i-iii.

[355] Section 1817 (a)(2)(A)(i).

[356] Section 1817 (a)(2)(A)(ii).

[357] Section 1817 (a)(2)(A)(iii).

[358] Section 1817 (a)(2)(A)(iv).

[359] S Section 1817 (a)(2)(A)(v).

[360] Section 1817 (a)(2)(A)(vi).

[361] Section 1817 (a)(2)(A)(vii).

[362] Section 1817 (a)(2)(A)(viii).

[363] Section 1817 (a)(2)(A)(ix).

required DOE to identify regulatory barriers (in the form of rates, rules or other requirements) that may interfere with deployment of DG resources.[364]

In its major findings, the *DOE Study* concluded that DG resources offer potential benefits to electric system planning and operations by, among other things, using DG to reduce peak loads, to provide ancillary services such as reactive power and voltage support, and to improve power quality.[365] According to the *DOE Study*, all of these uses to meet local system needs may lead to increased reliability of the electric system.[366] Being able to quantify reliability benefits, however, has proven challenging; one energy analyst observed that there are no widely accepted financial metrics to quantify the benefits associated with energy security and reliability.[367] A group of researchers at Oak Ridge National Laboratory attempted a quantitative assessment of the benefits of DG resources in 2003, and concluded that many benefits are difficult to quantify given that the value depends on site-specific characteristics about the particular DG resource and the location on the grid where it is interconnected.[368] The *DOE Study* reached a similar conclusion,[369] and also noted the absence of "standard data, models, or analysis tools" for quantifying the value of DG resources.[370]

Notwithstanding these challenges, there are a few examples where regulators have successfully quantified the benefits of DG resources and reflected these benefits in the ratemaking process. In California, for example, utility regulators attempted to quantify some of the benefits of DG resources in order to calculate utility buyback rates that would achieve the objective promoting the

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364 Section 1817(a)(2)(B). DOE was directed to include an analysis of "any rate-related issue that may impede or otherwise discourage the expansion of cogeneration and small power production facilities, including a review of whether rates, rules, or other requirements imposed on the facilities are comparable to rates imposed on customers of the same class that do not have cogeneration or small power production." *Id*.
365 DOE STUDY, *supra* note 10 at iii.
366 *Id*.
367 Peter Asmus, Building the Business Case for Commercial Microgrids, Navigant Research Blog, January 2014, available at http://www.navigantresearch.com/blog/building-the-business-case-for-commercial-microgrids.
368 S.W. Hadley, J.W. Van Dyke, W.P. Poore, T.K. Stovall, *Quantitative Assessment of Distributed Energy Resource Benefits*, OAK RIDGE NATIONAL LABORATORY (May 2003), ORNL/TM-2003/20, available at http://www.tnmp.ornl.gov/sci/ees/etsd/pes/pubs/116227.pdf.
369 DOE STUDY, *supra* note 10 at iv ("calculating DG benefits requires a complete dataset of the operational characteristics for a specific site, rendering the possibility of a single, comprehensive analysis tool, model, or methodology to estimate national or regional benefits highly improbable.")
370 *Id*. at iii.

development of efficient CHP generation.[371] The California "Waste Heat and Carbon Emissions Reduction Act" amended the California Public Utilities Code to require utilities to offer to purchase, at a price set by the California PUC, electricity that is generated by certain CHP generators and delivered to the grid.[372] The California PUC sought clarification from FERC that in setting the "avoided cost" rate for utility purchases of electrical output from CHP units, the PUC would have flexibility in the avoided cost calculation in order to promote development of more efficient CHP facilities.[373] In particular, the California PUC sought to reflect the benefits to the utility of avoiding investment in T&D infrastructure by including a 10 percent price "adder" (or location "bonus") for CHP systems located in transmission-constrained areas.[374] Such an "adder" would reflect the avoided costs of the construction of T&D facilities that would otherwise be needed, but would be avoided by the utility purchasing the output of the CHP unit instead.[375] FERC clarified that so long as the costs "are real costs that would be incurred by utilities," then they "may be accounted for in determination of avoided cost rates."[376] Although FERC declined to address whether the specific amount of 10 percent is justified by avoided costs, it authorized the California PUC to include such an "adder" or "bonus" to the extent it is based on "an actual determination of the expected costs of upgrades to the distribution or transmission system that [purchasing from the qualifying facility] will permit the purchasing utility to avoid."[377]

Minnesota passed legislation in 2013 requiring a determination of the value of distributed solar photovoltaic (PV) installations.[378] Researchers produced an extensive analysis quantifying the benefits produced by interconnecting

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[371] *Re California Pub. Util. Comm'n*, Order Granting Clarification and Dismissing Rehearing, 133 FERC ¶ 61,059, 2010 WL 4144227 (2010).
[372] CAL. PUB. UTIL. CODE § 2841(b)(2).
[373] 133 FERC at ¶ 61,265. Under the Public Utility Regulatory Policies Act of 1978 (PURPA), a utility is required to purchase the output from "qualifying facilities" at the utility's "avoided costs," which reflects the costs that the utility avoids by purchasing the output from the qualifying facility rather than the purchase it would otherwise make. 16 U.S.C. § 824a-3 (2006); *see generally* 16 U.S.C. § 2601 *et seq*. (2006). "Avoided costs" is defined as "the incremental cost to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility . . ., such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6) (2010).
[374] 133 FERC at ¶ 61,267.
[375] *Id*.
[376] *Id*. at ¶ 61,268.
[377] *Id*.
[378] The legislation passed by Minnesota in 2013 allows investor-owned utilities in the state to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to the net metering provisions that would otherwise apply to purchases from the output of solar installations. MN Laws 2013, Chap. 85 HF 729, Art. 9, Sec. 10.

distributed solar PV facilities to the utility grid.[379] The 2013 legislation required quantification of a number of benefits from distributed PV, including the value of fuel costs, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value.[380] The legislature's goal was production of a tariff for buyback rates that the utility would pay for solar-generated power, with tariff rates that would capture the value of electricity generated by distributed PV sources.[381] Setting the rates correctly would make the utility and its ratepayers "indifferent" as between electricity supplied from customer-owned PV resources or from comparable conventional utility resources.[382] Under the methodology filed with the Minnesota PUC in January 2014, a value was placed on the fuels cost avoided by the utility, based on the PV output displacing natural gas-fired units during PV operating hours.[383] Similarly, the PV unit would allow the utility to avoid generation capacity cost—the capital cost of generation the utility would build to meet peak load—as well as avoided transmission capacity and distribution capacity costs—the capital cost of transmission and distribution facilities that will not have to be built.[384] The methodology also allows for "adders" for location-specific avoided costs, to allow higher rates to be paid in areas where capacity is most needed.[385]

In what has been described as a "groundbreaking methodology," Minnesota added a "climate factor" to utility rates that attempts to reflect the potential dollar damage to society associated with future storms and flooding caused by climate change.[386] The "avoided environmental cost" is calculated based on the federal social costs of carbon dioxide (CO_2) emissions and on the Minnesota PUC-established externality costs for non-CO_2 emissions (including particulate matter (PM_{10}), carbon monoxide (CO), lead (Pb), and nitrogen oxide (NO_X)).[387] In the sample calculation of the "Value of Solar" tariff, 13.5 cents per KWh would be paid for the output of a solar PV installation.[388] Nearly half of that

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379 CLEAN POWER RESEARCH, *Minnesota Value of Solar: Methodology*, January 31, 2014, available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7bEE336D18-74C3-4534-AC9F-0BA56F788EC4%7d&documentTitle=20141-96033-02 [hereinafter MN VALUE OF SOLAR], at ii.
380 *Id*.
381 *Id*. at 1.
382 *Id*.
383 *Id*. at 4, 5.
384 *Id*. at 4.
385 *Id*. at 33.
386 Peter Behr, *Minn. Tries to Put a Climate Value on Rooftop Solar*, E&E NEWS, Jan. 2m 2014, available at http://www.eenews.net/stories/1059992297.
387 MN VALUE OF SOLAR, supra note 379 at 39.
388 *Id*. at 42.

amount, or 6.6 cents/KWh, represents the avoided fuel cost, while 3.1 cents/KWh represents the avoided environmental cost.[389]

As noted above, the Energy Policy Act of 2005 also required the DOE to identify the obstacles to integration of DG resources in the form of "any rate-related issue that may impede or otherwise discourage the expansion of cogeneration and small power production facilities."[390] The *DOE Study* found a number of current impediments arising from regulations and ratemaking policies, including practices relating to standby rates and the failure to account for the impact of lost revenue on utilities.[391] Moreover, the *DOE Study* noted that there has been a failure to develop a standard business model for electric utilities that would encourage utilities to invest in DG resources.[392] A great deal of attention has recently been focused on the incompatibility of the utility business model with the widespread deployment of DG resources.

In January 2013, the Edison Electric Institute, the association that represents all U.S. investor-owned electric companies,[393] published a report, *Disruptive Challenges*, that highlighted the challenges to the electric utility industry posed by widespread deployment of DG resources.[394] The report identified a convergence of factors—including the declining costs of DG resources—that potentially could "challenge and transform" the electric utility industry."[395]The *Disruptive Challenges* report identified a number of emerging DG technologies that could provide competition for utility-provided services, including solar PV, battery storage, fuel cells, geothermal systems, wind micro turbines, and enhanced storage from electric vehicles.[396] According to the report, the traditional utility model of centralized generation could be threatened as these DG technologies become more cost-competitive.[397] The report concluded that as DG resources achieve increased penetration in the future, the industry and its

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389 *Id*.
390 Energy Policy Act of 2005, Section 1817(a)(2)(B).
391 DOE STUDY, *supra* note 10 at 8-1.
392 *Id*. at iii.
393 EDISON ELECTRIC INSTITUTE, *Mission & Vision*, available at http://www.eei.org/about/mission/Pages/default.aspx.
394 Peter Kind, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*, EDISON ELECTRIC INSTITUTE, Jan. 2013, available at http://www.eei.org/ourissues/finance/Documents/disruptivechallenges.pdf [hereinafter DISRUPTIVE CHALLENGES], at 1.
395 *Id*.
396 *Id*. at 3.
397 *Id*.

stakeholders will need to take action to respond to these challenges to minimize the impact of the "disruptive forces," particularly distributed resources.[398]

The Pace witness in the Con Edison proceeding cited the *Disruptive Challenges* report as a possible explanation for Con Edison's apparent strategy to discourage rather than encourage the development of DG resources in its service territory.[399] He described it as "alarming" that while the recommendations in the *NYS 2100 Commission Report* would encourage utilities to promote energy efficiency and renewable energy, the leading electric industry trade organization was characterizing these same measures as "threats." [400] Other industry observers have noted the threat posed to the utility business model by DG resources; Rhone Resch, President and CEO of the Solar Energy Industries Association, stated in January 2014 that utilities needed to "embrace" DG resources as part of their business model or risk being "overrun" in a manner similar to the experience of incumbent telephone companies in the telecommunications industry over the past 20 to 30 years.[401]

IV. CONCLUSION

The electric power system of the future is likely to be fundamentally different—both structurally and operationally—from the power systems of yesterday. The rapid pace of technological development, coupled with growing consumer demand for clean, reliable, resilient, and flexible power supplies, is already shaping the transformation occurring in the U.S. electric power sector. The inability of the centralized energy production and delivery model to respond to system stresses was exposed by Superstorm Sandy, which hit the U.S. Northeast coast in October 2012 and left millions of electric utility customers without power. Although extended power outages affected the region for days, new DG technologies allowed many commercial and industrial facilities and educational institutions to maintain their essential functions. The experience with Superstorm Sandy demonstrated the urgent need to adopt a different set of long-term planning strategies to improve the electric system's resilience and ability to cope with the anticipated extreme weather events of the future. An expanded role for DG resources will play a critical part in achieving a more resilient utility system.

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[398] *Id*. at 17.
[399] MORRIS TESTIMONY, *supra* note 53 at 14.
[400] *Id*.
[401] E&E TV, *Experts Weigh Impact of Distributed Generation on Utility Business Model*, Jan. 28, 2014, available at http://www.eenews.net/tv/videos/1771.

The traditional utility business model, however, poses a major barrier to greater penetration of clean technology resources and achieving a DG-based model. The Edison Electric Institute's *Disruptive Challenges* report highlights the tensions between actions that utilities should be taking to promote a more resilient utility system—integrating DG resources seamlessly and facilitating microgrid installations—and the actions necessary to preserve the revenue streams upon which the utility business model is based. A comprehensive legal and regulatory strategy will be necessary to encourage electric utilities to move in the direction of a resilient, DG-based model.

The recently concluded Con Edison case before the New York PSC provides a good example of using a general rate proceeding as a forum to challenge the "business as usual" approach typically followed by utilities. In that case, utility regulators had an opportunity to consider the "traditional" approach proposed by Con Edison—which featured $1 billion of "storm hardening" T&D infrastructure investments over four years—alongside a competing view featuring the latest thinking about available technology and measures to improve the long-term resiliency of the utility system. The result of that proceeding was a landmark decision by the New York PSC to require utilities to integrate climate change adaptation and system resiliency into their long-term planning processes, as well as to take specific steps to accommodate DG integration and creation of microgrids. The *PSC Order* provides a template for other state regulatory commissions to reject rate relief based on a "business as usual" model relying on traditional T&D infrastructure and "storm hardening" investments in favor of forward-looking strategies that better prepare utility systems for the extreme weather events of the future.

Another such tool is the inherent authority of regulatory agencies to direct utilities to take climate change adaptation into account in long-term system planning, as invoked by the petition filed with the New York PSC in December 2012. Whether an administrative rule or order can be used to encourage utilities to consider the climate change adaptation and mitigation benefits of DG resources through long-term hazard mitigation planning depends upon the statutory authority of the applicable regulatory agency. In New York, the Public Service Law likely provides the PSC with the broad statutory authority necessary to impose such a requirement on its jurisdictional utilities. As described above, the issue was largely subsumed within the Con Edison rate proceeding, and thus the specific relief granted by the PSC on this issue was, on its face, limited to Con Edison. At the same time, it is clear from the *PSC Order* that all utilities under its jurisdiction will be expected to evaluate anticipated climate change impacts within their service territories, and to integrate consideration of these issues in their long-term system planning and infrastructure investments.

Fundamental principles in utility ratemaking, such as the prudence and "used and useful" standards, can also be used in utility regulatory proceedings to push utilities toward a new utility paradigm that takes advantage of the resiliency benefits of DG resources. Under the prudence standard, utility expenditures on traditional T&D infrastructure can be challenged on the grounds that a DG-based approach may represent a more cost-effective solution. The experience in two New York PSC proceedings—Con Edison's 2009 electric rate case and National Grid's 2010 electric rate case—demonstrates the availability of this strategy to force utilities to integrate DG-based solutions into their long-term system planning. Both resulted in collaborative processes that allowed a deeper analysis of the opportunities of integrating DG-based solutions into utilities' system planning. The "used and useful" standard, which historically has come into play to preclude a utility from earning a return on large generating assets under the central generation model that may be "excess" to public demand, also may be used to promote DG resources, given DG resources' ability to achieve a better match with the gradual growth in customers' electricity demand. With the increasing cost-competitiveness of DG resources as compared to large, centralized generating stations, regulators have a viable alternative to accepting the excess capacity associated with the "lumpiness" of new generating additions. With cost-effective and appropriately-sized DG resources as an alternative, regulators may have a basis for disallowing the excess generation that often results from reliance on the traditional model of large, centralized generating facilities.

Finally, the required use of cost-causation principles in setting "just and reasonable" rates provides another tool for pursuing a DG-based strategy that promotes system resilience. If regulators set rates that reflect all the benefits of DG resources—particularly the reliability and resilience benefits—a DG-based model may be able to compete effectively on a cost basis with the traditional centralized generating resources. The *DOE Study* of the benefits of DG resources, required by the Energy Policy Act of 2005, itemizes the various categories of benefits associated with DG resources, as well as the rate-related issues that impede their expansion. That the *Disruptive Challenges* report identified the "falling costs of distributed generation and other distributed energy resources" as one of the converging factors that is "expected to challenge and transform the electric utility industry" confirms the threat posed by DG resources to the utility business model.[402] Utilities and their regulators can diminish this threat, of course, by imposing "rate-related impediments that discourage DG," and the *DOE Study* suggests that these practices have been occurring.[403] In exercising their wide discretion in setting "cost-based" rates, states should be encouraged to exercise

[402] DISRUPTIVE CHALLENGES, *supra* note 394 at 3.
[403] DOE STUDY, *supra* note 10 at 8-1.

this authority in favor of DG solutions rather than against them, as exemplified by Minnesota's efforts to establish a "Value of Solar" tariff and the California PUC's decision to recognize avoided T&D costs in setting DG buyback rates, which demonstrate the feasibility of capturing the benefits of DG resources in rates.

Jones Draft

PROMOTING CLEAN RELIABLE ENERGY THROUGH SMART TECHNOLOGIES AND POLICIES: LESSONS FROM THREE DISTRIBUTED ENERGY CASE STUDIES

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Abstract

Following the blackout of the electric grid in the 1965 it was hypothesized that large central generation would lead to continued reliability problems. More recently following Hurricanes' Irene and Sandy there have been additional criticisms of the risks that large centralized electric systems face in terms of system restoration following catastrophic storms. Together these concerns have led some in the electric industry to conclude that bigger is not always better. In 2007 with the passage of the Energy Independence and Security Act, Congress initiated policy support for a smarter more distributed grid. Since then utilities have begun to experiment with more distributed, micro-scale projects that allow sections of the grid to "island" and serve customers locally during catastrophic power outages. This paper examines three very different approaches to explore the benefits of distributed energy technologies as well as the public policies necessary to promote their vibrant future.

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INTRODUCTION

The Rocky Mountain Institute's study, Brittle Power: Energy Strategy for National Security, back in 1982 observed that, "[t]he United States has for decades been undermining the foundations of its own strength. It has gradually built up an energy system prone to sudden, massive failures with catastrophic consequences." [1] In this classic report Amory and Hunter Lovins explained how the grid's centralized system architecture makes it inherently prone to the instability we have witnessed throughout the decades.[2] A notable example occurred on November 9th 1965, when a relatively minor system disturbance triggered the failure of a power system protection component that was not properly configured. The interconnection was operating near peak capacity due to extreme cold weather and high heating demand. The small initial outage cascaded throughout the Northeast, affecting over 30 million people in an 80,000 square mile area without electricity for up to 12 hours.[3]

This disturbance lead to the development of the North American Electric Reliability Council (NERC) on June 1st 1968 by the electric utility industry to promote the reliability and adequacy of bulk power transmission in the electric utility system of North America. Even with the best efforts of NERC, on August 14th 2003, 50 million Americans lost power in what marked the worst blackout in United States and Canadian history. The cascading power outage first hit Toronto, then Rochester, and finally, New York. In less than 13 minutes, the blackout spread throughout the 80,000 square mile Canada-United States Eastern Interconnection power grid.[4] Power was not restored for four days in some parts of the United States. Estimates of total costs associated with this blackout are between $7-10 billion dollars.[5]

Nevertheless, our nation has continued to rely on overhead transmission systems and precise electronic signals to keep huge machines rotating synchronously half way across the

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[1] Amory and Hunter Lovins, *Brittle Power: Energy Strategy for National Security*. (Andover: Brick House Publishing Co., 1982), 1.
[2]Ibid. 1-4.
[3] Graab, Alison C. "The Smart Grid: A Solution to a Complicated Problem." *William and Mary Law Review* (2011) *WestLaw*. Web.
[4] Bluvas, Kristin. "Distributed Generation: A Step Forward in United States Policy." *Albany Law Review* (2007) *WestLaw*. Web.
[5] *Ibid*.

continent. Grid congestion and unusual power flows have also increased. Today, a major outage occurs about every decade and costs in excess of 2 billion dollars. Additionally, on any given day, an estimated 500,000 customers are without power for two hours or more in the United States. In turn, these power outages and disturbances cost the U.S. between $75 billion and $180 billion annually. Although the centralized transmission grid is the backbone of the electric system, the drawbacks are apparent and increasing. All users feel the effects of grid disturbances, outages, voltage fluctuations, blackouts and brownouts.

In addition to the traditional challenges of an increasingly centralized grid that often relies on technology that could be described as "antique," today's grid is facing new and additional challenges from extreme weather events such as Hurricanes Irene and Sandy. A recent report from the U.S. Department of Energy titled "U.S. Energy Sector Vulnerabilities to Climate Change and Extreme Weather," explores the impacts that increasing temperatures, decreasing water availability and increasing storms, flooding and sea level rise pose for the energy sector. The report notes that the electric grid faces a variety of vulnerabilities from increasing storms including, increasing sea level rise and storm surges pose risks to coastal thermoelectric facilities, increasing intensity and frequency of flooding pose risks to inland thermoelectric facilities, and increasing intensity of storm events increases the risks to electric transmission and distribution lines. The report notes that according to analysis from the Congressional Research Service, storm related power outages cost the U.S. economy $20-$55 billion annually.[6]

A different but equally important concern with the traditional grid is that the electric power sector is the largest—and one of the fastest growing—source(s) of CO2 emissions in the United States. This is primarily because of our heavy dependence on fossil fuels, which account for about 70% of net electricity generation in the United States. As a result, CO2 emissions from the electric power sector make up a third of the American economy's total greenhouse gas (GHG) emissions and about 8% of global CO2 emissions. Moreover, the electric power sector is also a significant source of other harmful air pollutants that pose a risk to human health and the environment, independent of climate change.

[6] "U.S. Energy Sector Vulnerabilities to Climate Change and Extreme Weather," U.S. Department of Energy, July 2013, 33-35. http://energy.gov/sites/prod/files/2013/07/f2/20130716-Energy%20Sector%20Vulnerabilities%20Report.pdf

In addition to greenhouse gas emissions, the electric power sector also produces several other harmful air pollutants, such as sulfur dioxide (SO2), nitrous oxides (NOx), and particulate matter, which pose risks to human health and the environment. Coal and natural gas power plants, for example, are a significant source of NOX and SO2. When released into the atmosphere, these pollutants transform into sulfuric acid (H2SO4) and nitric acid (HNO3), which fall as acid rain and snow. NOX and SO2 are also precursors to ozone (O3) and particulate matter (PM), both of which can cause and/or aggravate respiratory and cardiovascular diseases such as asthma, bronchitis, and non-fatal heart attacks. Ozone also reduces photosynthetic activity in plant life, which negatively affects crop yields in the agricultural sector. Finally, coal plants are a significant source of mercury, a hazardous air pollutant that can deposit onto land and water bodies and become "methylmercury . . . a highly toxic, more bioavailable form that magnifies in the aquatic food chain," creating dangers for humans and other animals alike.

The traditional centralized grid thus raises concerns about both the reliability of today's electric system as well its increasing environmental footprint. In 2001, NERC advised Congress that our grid was not designed for the way in which it is being used. Originally intended to transfer power over short distances, the grid now carries thousands of watts over long distances. As one response to concerns about the reliability and security of the grid, Congress supported the development of the 'Smart Grid' in the Energy Independence and Security Act of 2007. One of the motives behind Congress promoting the concept of the Smart Grid was to provide a solution to the nation's growing reliability concerns. According to the Act, 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.

THE ORIGIN OF FEDERAL SMART GRID POLICY -- THE ENERGY INDEPENDENCE AND SECURITY ACT OF 2007

With the passage of the Energy Independence and Security Act (EISA) of 2007, Congress made it "the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system"[7] and then defined a series of goals for grid modernization

[7] Energy Independence and Security Act of 2007, Sec. 1301

that the act characterized as the Smart Grid. Congress defined the goals of a Smart Grid to include:

- Increased use of digital information and controls technology;
- Dynamic optimization of grid operations and resources with full cyber security;
- Deployment and integration of distributed resources and generation, including renewable resources;
- Development and incorporation of demand side resources and energy efficiency;
- Deployment of “smart” technologies for metering, communications concerning grid operation and status, and distribution automation;
- Integration of “smart appliances” and consumer devices;
- Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning;
- Provision to consumers of timely information and control options;
- Development of standards for communication and interoperability of appliances and equipment connected to the grid; and
- Identification and lowering of unnecessary barriers to the smart grid.

While Congress included a comprehensive list of policies for grid modernization that were to be included as the Smart Grid nowhere was there mention of general expansion of the nations bulk power system. While this omission does not suggest that federal policy for grid modernization does not include expansion of the bulk power system, it does suggest that it is a separate and distinct policy from those characterized as a Smart Grid under this act.

In addition to defining the goals of the Smart Grid, Title III of the EISA of 2007 defined some federal policies intended to meet these goals. The act required the Secretary of Energy to report regularly to Congress on the status of smart grid deployments and any regulatory or government barriers to continued deployment. Congress also established a federal Smart Grid Advisory Committee and Smart Grid Task Force. The Smart Grid Advisory Committee was to be established by the Secretary of Energy and include eight or more members who have sufficient experience and expertise to represent the full range of smart grid technologies and services. The mission of this advisory committee was to advise relevant federal officials concerning the development of smart grid technologies, the progress on transition to these smart grid technologies and services and the evolution of standards and protocols for interoperability of smart grid devices. The Smart Grid Task Force was to be established by the Assistant Secretary of the Office of Electricity Delivery and Energy Reliability and was intended to be largely an internal Department of Energy coordination team from various divisions who have responsibilities related to smart grid technologies and practices with members also designated by the Chair of the Federal Energy Regulatory Committee and the Director of the National Institute of Standards and Technology. According to the act the mission of the Smart Grid Task Force was to ensure awareness, coordination, and integration within the federal government on smart grid technologies and practices. The Smart Grid Task Force was also given responsibility for the coordination function between smart grid technologies and practices to "infrastructure development, system reliability and security, and the relationship of smart grid technologies and practices to other facets of electricity supply, demand, transmission, distribution, and policy"[8] and thus the task force was established as a linkage between federal smart grid policy and related policies such as expansion of the transmission system.

Another key provision of the EISA of 2007 was the delegation of authority to the Director of the National Institute of Standards and Technology (NIST) to coordinate the development of a smart grid interoperability framework that includes protocols and model standards to achieve interoperability of smart grid devices and systems. The Director was directed to seek input from FERC, DOE (including its Smart Grid Task Force and Advisory Committee) and other state, federal and private entities. NIST was to issue an initial report on progress toward recommended standards within one year. FERC was then directed to conduct rulemaking proceedings as appropriate to adopt such standards necessary to insure smart grid functionality and interoperability in interstate transmission of power and in regional power markets.

The Act also included provisions guiding state consideration of smart grid investments through amendments to the 1978 Public Utilities Regulatory Policies Act that sought consideration of smart grid investments by utilities as well as consideration of means for rate recovery by the state. DOE was directed to report on the security attributes of smart grid systems. Finally, various smart grid demonstration programs were authorized as well as federal matching funds for smart grid investments. The American Recovery and Reinvestment Act of

[8] EISA of 2007, Sec, 1303

2009 (the federal stimulus program) added significant additional grand funds for utility smart grid investments.

FERC SMART GRID POLICY STATEMENT

While the Commission's jurisdiction over the transmission system is largely derived from the Federal Power Act in regards to both transmission of electric energy in interstate commerce and the reliable operation of the bulk power system, the Energy Independence and Security Act of 2007 added additional provisions regarding the process for adopting standards and protocols for the Smart Grid. As a result of these additional provisions of the EISA, on July 16, 2009 the Federal Energy Regulatory Commission issued its final Smart Grid Policy Statement which followed its March 19, 2009 Proposed Policy Statement and Action Plan.

As previously discussed, the EISA directs the National Institute of Standards and Technology to coordinate the development of a smart grid interoperability framework and for FERC, through a rulemaking proceeding, adopt such standards and protocols as necessary. In order to prioritize the development of key interoperability standards in its final Policy Statement the Commission reaffirmed the key priorities it had identified as necessary to address important challenges to the operation of the bulk power system. According to the Commission those challenges are[9]:

- Existing cybersecurity issues;
- Large-scale changes in generation mix and capabilities, and
- Large potential new load from electric vehicles.

The key priorities that the Commission identified as necessary to address these existing and emerging challenges include the two cross-cutting issues of system security and inter-system communications of which the four key grid functionalities are:

1. Wide-are situational awareness;
2. Demand response;
3. Electric storage; and
4. Electric transportation.

[9] FERC Docket No. PL09-4-000, Smart Grid Policy, Issued July 16, 2009 p. 18-19

THE ADVANTAGE OF SMART DISTRIBUTED TECHNOLOGIES

Smart grid technologies and smart energy policies can help correct many of traditional grid's inefficiencies and, in so doing, mitigate many of the electric power sector's negative environmental externalities. Indeed, although America's electricity infrastructure has drastically raised standards of living and improved economic productivity over the last century, these gains have come at a significant cost to the environment. The obvious question is: "What can the smart grid do to solve these problems?" First, the smart grid will make the existing electric power system both more reliable and efficient, such that generators will be able to burn fewer fossil fuels while still providing improved quality of service to customers. Of course, every unit of avoided fossil fuel combustion "carries an associated reduction in air emissions, including nitrogen oxides, sodium dioxide, volatile organic compounds (VOCs), other criteria air pollutants, and most significantly, greenhouse gases." The smart grid will also help integrate new distributed and cleaner technologies into the American energy portfolio, which will displace fossil fuel combustion as a source of electricity. In particular, smart grid technologies can help integrate more distributed solar PV. These and other renewables will help reduce GHG and criteria air pollutant emissions. One of the main benefits to implementing smart grid technologies is decreased carbon dioxide (CO2) emissions.

The smart grid is therefore critical not only to updating the nation's aging electricity infrastructure, but also to reducing emissions of both CO2 and other harmful pollutants. The Pacific Northwest National Laboratory (PNNL) estimates that, if smart grid technologies are fully deployed across the country in the next two decades, the electric power sector could reduce both energy use and carbon emissions by 12% of what they are projected to be in 2030. If the indirect benefits from the PNNL study are taken into account, then expected energy usage and carbon emissions decrease by an additional 6% for a combined reduction of 18% in direct and indirect savings. However, the reality is that no one knows exactly what the smart grid will ultimately look like. The 'smart grid' represents a major shift in our electrical energy infrastructure, which will likely take billions of dollars in new investment and multiple years, if not decades, to implement. Modernizing the grid is a capital-intensive undertaking. The Electric Power Research Institute (EPRI) estimates that it will cost $338 to $476 billion (or $17 to $24 billion per year over the next 20 years) to fully deploy smart grid technologies across the country.[10]

The first step that many utilities are undertaking is the installation of smart meters and associated Automated Meter Infrastructure (AMI). A significant part of AMI is adding two way communication technology to the electric distribution system so that the smart meters installed at individual homes and businesses can both receive and send data on the status of the grid as well as other relevant information. While we have made some progress in this area to date as John D. McDonald, with GE Digital Energy, notes, "we need to acknowledge that full-blown grid modernization is nascent at this state, with end-of-line sensors, a.k.a smart meters, being installed and distribution automation getting underway. There's much work ahead to derive full value…."[11]

As a result of the challenges facing the traditional grid, distributed generation has gained increasing public policy support given the opportunities for it to benefit both the reliability of the grid as well as reduce its environmental footprint. For purposes of this paper, distributed generation is defined as generation interconnected to the distribution system or on the customer side of the meter.[12] Distributed generation is an attractive energy resource option that in addition to providing energy to meet demand also can reduce electrical losses, increase voltage on the distribution system, and help forgo upgrades to the transmission and distribution system.

The fastest growing distributed generation recently has been Solar PV. Solar PV is on the rise and if the installed costs continue to decline it could become a disruptive technology in the future. FERC Chairman, Jon Wellinghoff recently stated, "solar is growing so fast it is going to overtake everything." According to the report, U.S. Solar Market Insight, it is expected that cumulative installed solar PV will surpass 10 GW in 2013 with 4.4 GW of PV installed in 2013, up 30% from the previous year with residential PV system prices falling to $4.81/W and $2.10/W for utility scale installations. According to the U.S. DOE, once solar installation costs reach $1.0/W they will be competitive with the wholesale rate for electricity without further

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[10] [10] Electric Power Research Institute, *Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid, 2011 Technical Report* (Palo Alto, CA: EPRI, 2011), 1-4.
http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001022519&Mode=download

[11] John D. McDonald, "Sandy and the Smart Grid," *Public Utilities Fortnightly*, April 2013, p. 48.

[12] Ackermann, Thomas, et al. "Distributed Generation: A Definition." *ElSevier* (2000) Web.

subsidy. GTM Research has predicted that "in the next 2 ½ years the U.S. will double its entire cumulative capacity of distributed solar – repeating in the span of a few short years what it originally took four decades to deploy. According to the Edison Electric Institute, the trade association for the nations investor owned electric utilities, "a variety of technologies are emerging that may compete with the utility provided services" including solar PV and battery storage. As the cost curve for these technologies improves, they could directly threaten the centralized utility model."[13]

The smart grid will also help facilitate new coordination among clean distributed technologies and help for microgrids which will help improve reliability and reduce the environmental foot print. Microgrids are "small-scale electricity systems for one or more large users, which combine efficient generation of power with its carefully monitored use, with demand response (DR) and energy efficient technologies, in a single geographic location."[14] There are a number of reasons that customers would want to deploy a microgrid including "improving the resilience and reliability, to improving the cost or environmental characteristics of their energy supply."[15]

DISTRIBUTED ENERGY CASE STUDIES

Some of the most progressive utilities and other organizations are already embracing the shift away from business as usual, and experimenting with ways to promote distributed technologies in order to improve reliability and reduce their environmental footprint. This paper will specifically focus on three examples of on-the- ground distributed generation – the Sacramento Municipal Utility District (SMUD) Photovoltaic (PV) & Smart Grid Pilot project in Anatolia, California; the San Diego Gas & Electric Borrego Springs Micro grid Demonstration Project; and the Pecan Street Project's Mueller Community Project.

This paper will be broken into two sections. The first section will delve into the organizational structure of each entity, project specifications and the unique aspects each project

[13] Peter Kind, "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business," Edison Electric Institute, January 2013, 3. http://www.eei.org/ourissues/finance/Documents/disruptivechallenges.pdf

[14] Edward N. Krapels and Clarke Buno, "Smaller, Cheaper, and More Resilient: The Rationale for Microgrds," *Public Utilities Fortnightly*, April 2013, 12.

[15] Ibid., 13.

offers to the surrounding communities. The second half of the paper will be tailored specifically to the commonalities and differences between all three projects, as well as share policy recommendations that can serve as a roadmap for current and future distributed generation projects to sustain themselves in the future.

The current regulatory framework encourages distributed generation through subsidies, incentives, and recognition of distributed generation in procurement and planning processes. Certain rules and regulations have been developed to encourage specific forms of distributed generation. However, there is a lack of research to support longer-term policy decisions, which will allow for easier implementation.

SACRAMENTO MUNICIPAL UTILITY DISTRICT

SMUD is a community-owned, not-for-profit electric utility that has provided public power throughout Sacramento since 1946.[16] Operating under an elected Board of Directors, owned by its customers, the board has exclusive legal authority to establish the rates and rules for electricity customers within its service territory.[17] It is the sixth largest community owned electric utility in the United States (U.S.) and the second largest in the state of California. It currently serves 529,695 residential customers and 68,510 business customers in a service area with a total population of about 1.4 million. All of the customers are serviced within a 900-square mile territory, including Sacramento, Placer and Yolo Counties.

To promote renewable energy and energy efficiency, SMUD has spearheaded programs that are nationally recognized for their leadership and innovation. In 2008, SMUD adopted a goal to obtain 33% renewable power by 2020 before it was mandatory for all electric utilities.[18] SMUD was also the only large utility that met the previous 20% renewable goal by 2010 using eligible resources under the current California Energy Commission Renewable Energy Portfolio

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[16] Sacramento County residents originally voted to establish SMUD in 1923 as a customer-owned utility, but due to legal issues with Pacific Gas & Electric Company of San Francisco, it did not start providing power for two decades. Additionally, it needed to build an organization of engineers, electricians, managers and office workers to take over Sacramento's old electric system before supply electricity to Sacramento customers. www.smud.org/en/about/pages/history-1940s.aspx,.

[17] http://www.smud.org/en/about/documents/reports-pdfs/draft-based-electricity-and-smart-grid.pdf

[18] SMUD comments on "Renewable Power in California: Status and Issues," October 5th, 2011, http://energy.ca.gov/2011_energypolicy/documents/2011-09-14_workshop/comments/SMUD_Comments_on_Draft_Renewable_Power_in_California_TN-62550.pdf, last visited July 13, 2013.

Standards Eligibility Guidebook. It currently has 102 MW of wind-powered facilities and 35 MW of photovoltaic generating facilities. These sources generate about 3% (2010) of SMUD's energy output with the remaining renewable energy supplied by Power Purchase Agreements. In 2010, SMUD's total energy from renewable sources was approximately 24%.[19]

As an organization, SMUD's overall policies focus on serving the community first. Its vision is to "empower its customers with solutions and options that increase energy efficiency, protect the environment, reduce global warming and lower the cost to serve its region."[20]

Enabling SMUD to uphold their overall vision, SMUD grants promoting the Smart Grid through the ARRA, including "Smart Grid Demonstrations – Storage for Grid Support." This initiative awards a sub-grant to Premium Power for two battery systems to demonstrate the integration of photovoltaics (PV) and energy storage into Smart Grid applications.[21] SMUD also plans to develop infrastructure standards for plug in hybrid electric vehicles (PHEVs) that charge off peak and feed electricity back to the grid during peak periods.[22]

Overall The Smart Grid research and development (R&D) budget is $42.9 million, bringing the total Smart Grid budget to over $350 million. A portion of this budget is allocated to include residential information and control pilots, smart controls in multifamily projects and a micro-grid demonstration. The purpose of these demonstrations will test the surrounding variables and benefits of emerging technologies for the future of Smart Grid development.

PV & Smart Grid Pilot at Anatolia

The Smart Grid Pilot at Anatolia addresses three key technical issues associated with deploying photovoltaics in high penetrations. Specifically, the lack of utility based PV power control, the lack of PV power production data in high penetration scenarios and the lack of data on storing PV. The project began as a joint effort between the National Renewable Energy

[19] *Ibid.*
[20] http://www.smartgridnews.com/artman/publish/Video-Education-and-Information/Smart-grid-implementation-at-SMUD-3304.html
[21] Jim Parks' Presentation to the CPUC Smart Grid Workshop; March 18th 2010; Smart Grid Implementation at the Sacramento Municipal Utility District; http://www.cpuc.ca.gov/NR/rdonlyres/D25C3103-D534-4F19-B267-823FD40C9C20/0/CPUCWorkshop31810SMUDParks2.pdf
[22] Allie Silverman and Kevin B. Jones, "SMUD's Smart Sacramento: A Clean Technology Pioneer," Institute for Energy and the Environment, Vermont Law School, June 2012, 21.

Laboratory (NREL) and SMUD. The objective of this project is to analyze distribution impacts of high penetration, grid-integrated PV equipped SolarSmart homes. Of the 795 homes located in this community, 600 will be implemented under SMUD's SolarSmart project – eventually amounting to 1.2 MW of potential generation. SMUD aims to examine how the integration of energy storage can be used to enhance the value of distributed PV resources. Additionally, the project will monitor the potential for energy storage of each PV system. From these objectives, SMUD hopes to create a better picture of the value of distributed energy resources from the utility's point of view.

The Anatolia Solar Smart Community is a neighborhood southeast of Sacramento, California called Ranchero Cordova. It is an area in which each house is built with highly energy efficient homes features and an average of 2.5 kW of PV on each home.[23] The Anatolia SolarSmart Homes typically include radiant barriers to reflect summer heat, high efficiency furnaces and HVAC systems, compact fluorescent lighting, ENERGY STAR qualified windows, a 2.0 kW alternative current PV system, and independent third party verification to confirm all energy efficiency measures are installed and operating correctly; Each of these homes will be served by a SMUD substation in the surrounding area.

Additionally, SMUD plans to study energy storage in two ways. Currently, Anatolia is served by the Anatolia-Chrysanthy Substation. As part of the SMUD smart grid pilot, 15 residential energy storage systems with 5 kw/8.8 kwh of battery storage have been installed along with 3 community energy storage systems, which are linked to 5 to 10 homes, providing 30 kw/34 kwh of battery storage capacity. The residential energy storage units are essentially a refrigerator-sized battery that can be located in the garage. CES systems are connected to pad mounted transformers on distribution feeders. They will be sized to work with the group of homes fed by each transformer.The homes with solar PV systems with battery storage are being studied to see if renewables firmed with storage, those with a smoother production curve, would reduce peak load, regulate voltage and improve reliability. The ultimate goal is to gain experimental data on how storage can help overcome the variable output of PV systems. A control group without energy storage will also be included in the project. A key point of this

[23] *Ibid., 29.*

project is to see how well these systems can support SMUD's "super peak" from 4 pm to 7 pm, particularly during the period from 5-7 pm when the output of PV systems tends to drop off.[24]

This project expects to add energy storage as an RES or CES, use the installed technology so that energy storage can be monitored and controlled by SMUD, as well as, coordinate the resources of the system at a more granular level. The total cost of this project is $5.15 million.

San Diego Gas & Electric

Today, San Diego Gas & Electric (SDG&E) is a regulated public utility that serves about 3.5 million customers. Its service area covers 4,100 square miles in San Diego and southern Orange counties throughout the state of California. It is a subsidiary of Sempra Energy – a San Diego based Fortune 500 Company.[25]

As SDG&E is located in one of the most renewable resource rich areas of the nation, Southern California, this utility has been an active player in developing distributed generation through both its utility business and procuring renewable energy from other Energy Services companies. To promote the smart grid, SDG&E is beginning to pair distributed generation alongside smart grid efforts. This occurred for several of reasons, including the strong renewable portfolio standard (RPS), being in a resource rich area, and the California Public Utility Commission has laid out a series of goals to be achieved through smart grid rollout projects, such as, enabling the support of distributed generation.

SDG&E estimates that the smart grid can lead to $391 million to $1.324 billion in benefits from its ability to help integrate distributed generation, large scale centralized renewable energy generation and plug-in electric vehicles (PEVs). SDG&E has great support from its customer base in the way of distributed rooftop solar. In fact, SDG&E customers "have already

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[24] DOE Energy Storage Database, SMUD PV & Smart Grid Pilot at Anatolia: RES, Sandia National Laboratories

[25] "San Diego Gas & Electric – About Us." San Diego Gas & Electric. Web. 15 Jul 2013. http://www.sdge.com/aboutus

installed more megawatts of rooftop solar in San Diego than utility customers in any other U.S. city.[26]

SDG&E has also said that the smart grid technology's ability to increase the automation of service and information flow will allow it to mitigate the problems caused by the intermittency of distributed renewable resources like wind and solar.[27] To this end, SDG&E is building out a network designed to acquire information about electricity generation from distributed generators and other intermittent generator. SDG&E plans to install enough smart transformers, inverters, and capacitors to control voltage fluctuations by 202 to better integrate all of the distributed resources on its system. SDG&E expects to have installed enough of this technology to ensure reliability in the smart grid by 2020.

Borrego Springs Micro-grid Demonstration Project

The San Diego County California community of Borrego Springs is home to an experimental micro-grid funded in part by a grant from the U.S. Department of Energy. The goal is to showcase and test various aspects of micro-grid technology, including smart meters, distributed renewable energy generation, and energy storage. While not completely cut-off from the main grid, the Borrego Springs micro-grid acts, as a self-contained grid that can maintain power on its own, should the main grid experience a power shortage. Borrego Springs is a small community with residents wo have avidly adopted rooftop solar, with 600 to 700 kilowatts (kW) of distributed generation that is already deployed. It was chosen to enhance overall reliability and capitalize on the opportunity to balance supply and demand to be more self sufficient as a locality. Aside from the installation of solar, energy storage is a key technology in the Borrego Spring demonstration project. SDG&E plans to install a 500 kW battery at the substation and two 25kW batteries for community energy storage. Some residence will also receive utility-supplied batteries that are capable of delivering 8 kW of electricity.[28]

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[26] Katie Thomas and Kevin B. Jones, " San Diego Gas & Electric," The Smart Grid's Leading Edge," Institute for Energy and the Environment, Vermont Law School, April 2013, 19

[27] *Ibid., 19.*

[28] Ibid., 21.

There are two important micro-grid applications for batteries. They can be used for islanding, delivering electricity when generation sources are offline. Batteries can also be used to firm steady and intermittent sources of power from voltage disruptions – drops and surges – in the distribution grid. SDG&E will test both applications once the energy storage technologies are installed. The objective of the project is to conduct a pilot scale "proof of concept" demonstration of how advanced information based technologies and distributed energy resources may increase utilization and reliability of the grid. In order to execute this project, SDG&E has developed specific project strategies to design and demonstrate a smart electrical grid that incorporates sophisticated sensors, communications, and controls. Specifically, SDG&E is incorporating solar power generators on homes and businesses into the electrical delivery system, enabling coordinated demand response programs, and integrating reliable electrical storage devices to operate the micro-grid in a more cost effective manner.

THE PECAN STREET PROJECT INC.

The Pecan Street Project is highly unique due to its public-private partnership, which demonstrates how the public and private electricity sectors can work together to achieve smart grid innovation. The structure has allowed greater efficiency in working with regulatory organizations and resolving customer issues in order to develop an advanced smart grid test project.[29] The Pecan Street Inc. is a 501(c)3 non-profit research organization headquartered at the University of Texas. The organization was formed in 2009 by representatives of the City of Austin, Austin Energy, The University of Texas, the Austin Technology Incubator, the Greater Austin Chamber of Commerce, and the Environmental Defense Fund.

The Pecan Street Project was created for several reasons. As the City of Austin relies on Austin Energy, the municipal utility provider, to supply a portion of its operating budget. Austin Energy functions as a department of the City of Austin, with dividends returning to the community each year. Therefore, the city budget is closely tied to a utility whose revenue is a direct result of how much energy it sells. Austin Energy is the nation's 9th largest community-

[29] Rebecca Wigg, Christine Breen, and Kevin B. Jones, "The Customers" Smart Grid: Pecan Street, Inc.'s Emergy Internet Demonstration Project," Institute for Energy and the Environment, Vermont Law School, January 2013, 3.

owned electric utility, serving more than 400,000 customers within the City of Austin, Travis County, and Wiliamson County. With this in mind, Austin Energy (AE) has made big commitments to promote energy efficiency and encourage distributed generation. For instance, AE operates a solar rebate program for its commercial and residential customers. The program supports more than 1,200 customer-owned solar energy systems, 100 commercial projects, 37 municipal projects, 32 school installations, and 6 libraries. Together, these entities produce more than 4.7 megawatts of generation capacity.[30]

Additionally, Austin Energy operates the nation's longest running and most subscribed green power program in the country.[31] The GreenChoice program offers Austin Energy customers the option of subscribing to a batch of clean electricity resources. GreenChoice subscribers pay a fuel charge of 5.7 cents per kWh instead of the standard fuel charge of 3.105 cents per kWh. To date, customers purchase 875 million kilowatt-hours of renewable energy annually.[32] The program is currently supplied by renewable resources such as wind and methane gas from surrounding landfills.

The City of Austin also operates the country's oldest and largest green building program, which continues to lead the industry on sustainable building practices. The Austin Energy Green Building (AEGB) program was created in 1990 and is leading the transformation of the building industry.

As a result of Austin Energy's early smart grid efforts, the Pecan Street Project is perfectly situated to highlight the potential of a fully integrated smart utility grid. With a focus on the consumer experience and benefits of smart grid applications, rather than the benefits for the utility, the Pecan Street Project used $10.4 million dollars in federal stimulus funds to develop an advanced smart grid demonstration in the Mueller community of Austin, Texas.

[30] Ibid., 7.
[31] Ibid.
[32]"AustinEnergy"http://www.austinenergy.com/energy%20efficiency/programs/green%choice/index.htm

The Mueller Community Development Project

The Mueller Community is located about three miles from downtown Austin and is less than two miles from the University of Texas campus. The Mueller Community is a 711-acre mixed use development in which every new building is either LEED certified or recognized by Austin's Green Building program. All commercial buildings over 25,000 sq. ft are LEED or the AEGB program two-star rating, while all single family homes must meet the AEGB three-star rating. Water is also a concern to the Mueller Community. Therefore, native or water-wise plants must account for at least 90% of the landscaping in all public open spaces, commercial and residential lots. The Mueller Community also utilizes reclaimed water and a water efficient irrigation system to irrigate public landscapes.

Located on the former Robert Mueller Municipal Airport, the Mueller community will provide an advanced platform for testing the impacts of a concentrated smart grid system. When fully developed, Mueller will have approximately three million square feet commercial and institutional space, and 4,900 single-family and multi-family dwelling units housing more than 10,000 residents. The Mueller Community is already home to Austin Energy's Mueller Energy Center, the Dell Children's Hospital, the University of Texas Academic Energy Research Center, as well as more than 2,000 people who live or work in the community.[33]

The goal of the demonstration project will be to transform how energy services are generated, delivered, and managed so that customers are able to have a zero net carbon impact – in a way that creates green collar jobs, effectively expands the use of clean energy, and provides greater control over specifics within their electricity bills.

To achieve these specific results, the project will collect data and analyze these results against the distribution feeder systems in other locations in the City of Austin to quantify how the integration of these technologies impact customers electric bills and usage, utility finances, environmental outcomes and electric system performance.

In particular, Austin Energy is installing a new automated substation at the specific distribution feeder for the Mueller development and has already begun upgrading its customer

[33] Ibid., 10.

billing system to allow integration of innovative rate and incentive structures, both of which will support many of future research projects.

Because the goal of this project is to show the capability of smart grid technologies in a modern community, the experimental technologies in the home and business will create value for the customers. In particular, the project metrics will analyze how the deployed smart grid technologies:

- Influence the customer's environmental impact
- Affect the customer's electric bill
- Provide financial incentive the customers, utilities, and the private sector to invest in energy efficiency,
- Impact load curve of customers; and
- Impact utility revenues.[34]

Additionally, the Pecan Street Project is developing and implementing an Energy Internet at the 711-acre mixed-use development to integrate with a micro-grid that links 1,000 residential meters, 75 commercial meters, and plug-in electric vehicles. Throughout this project, different storage technologies will be tested, such as, thermal storage, battery technologies, and fuel cell systems.

Through the two-way energy flow system set in place, customers can set electricity and water budgets, have software managed of their individual appliances, sell energy back to the grid, and help the utilities better manage and deliver electricity when need be.[35]

CASE STUDY ANALYSIS AND CONCLUSIONS

Rapid change is taking place throughout the electric industry. Each of the projects above highlights many of the different advantages distributed generation provides to both customers and utilities. Additionally, all three case studies provide a platform for other states seeking to implement distributed generation in similar ways. Before discussing what is necessary for states

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[34] *Ibid., 14.*

[35] SmartGrid.gov, U.S. Department of Energy, last accessed 10/1/2013, http://www.smartgrid.gov/project/pecan_street_project_inc_energy_internet_demonstration

to replicate projects such as the ones presented, it is important to note the similarities and differences between each of these models.

Beginning with the obvious similarities, the Mueller Community project and SMUD Anatolia project are both take a customer oriented approach. Each project aims to place the power of choice in the homeowner's hands. Both offer incentives that lead community members to take action and mold their community in the most energy resourceful ways possible.

For instance, SMUD has developed the Anatolia community, as well as others, via additional programs that have previously existed, such as the SolarSmart homes initiative. Like the Mueller community, there is a heavy emphasis to let the customer make their own personal choices regarding efficiency specifications and renewable power. Working with 18 local, regional and national homebuilders to construct 1041 homes that combine solar energy and advanced energy efficiency design, SMUD provides incentives to builders to buy down the cost of solar PV systems and provides rebates for energy efficiency upgrades. These rebates and incentives, along with attractive tax credits, make these homes an affordable option for more homebuyers. Residents save as much as 60% on energy bills.[36] More recently, SMUD now provides customers with the opportunity to buy a SolarSmart Home or build a new SolarSmart Home within additional SolarSmart Home communities. Today, SMUD has 15 SolarSmart Home communities that new homeowners can choose from. The incentive provided include a range of options such as:

- $1,250 for a baseline of 25 percent of household efficiencies
- An additional $250 for 30%
- An additional $250 for 35%
- An additional $500 for 40%;
- And $0.65 provided for a solar electric installation

Furthermore, a Zero Peak Home incentive of $2,000 will be provided for each home built to use no electricity during SMUD's peak period of 4 pm to 7 pm.[37]

[36] SMUD SolarSmart Homes, Accessed, October 1, 2013, https://www.smud.org/en/residential/environment/solarsmart-homes/buying.htm
[37] Ibid.

The Mueller Community Development project essentially offers the same choices through a more hands on approach. The Pecan Street Project now offers residents of the Mueller Community user-friendly ways to manage individual appliance, electric vehicle charging and rooftop PV systems. Additionally, two participants in this demonstration project serve on the executive committee, offering a valuable customer perspective.[38]

At the core of the "open platform Energy Internet" is the hope that it will become a customer self-service channel designed to increase customer satisfaction, reduce call center operating expenses, and empower customers to effectively manage their energy usage.[39]

The objective behind the Borrego Springs Micro-grid demonstration project is a bit different. Since there is little resistance from their customers to adopt renewables, the focus behind this demonstration project is to integrate all elements to create a more robust, self-sustaining grid that will incorporate solar power, battery energy storage, automated switching, and active customer participation. Although the elements incorporated throughout Borrego Springs follow the same trends as the other two projects, there is a heavier emphasis placed on the utility-side application. Although there is a customer-side component to this project, there is much more of an emphasis placed on where the utility can gain insight about battery storage, and how a utility of their scale can cope with challenges created from emerging smart grid software and technologies.

As all three projects have shown, implementation of distributed technologies will be compromised if legal and policy issues are not addressed. Specifically looking at the Borrego Springs project in California, the driving force behind this demonstration is state legislation requiring utilities to buy 20 percent of their power from renewable sources like solar and wind. However, that percentage increases to 30 percent by 2020. This is a hurdle for SDG&E and is also one of the main reasons why Borrego Springs was created. To cope with these challenges, SDG&E is not only focusing heavily on how to ensure reliability, but also how to empower customers to participate in smart metering programs.

[38] http://www.smartgridlegalnews.com/smart-meter/pecan-street-project-smart-grid-community-smart-customer-engagement/

[39] http://www.intelligentutility.com/article/10/05/utilities-are-innovative-empowering-their-customers

Rule Power Point

Solar Energy, Utilities, and Fairness

PROFESSOR TROY A. RULE
SANDRA DAY O'CONNOR COLLEGE OF LAW
SAN DIEGO CLIMATE & ENERGY LAW SYMPOSIUM
NOVEMBER 7, 2014

Net Metering:
A Primary Driver of Growth in Rooftop PV

Net metering programs:

- exist in more than 40 U.S. states
- allow ratepayers to sell excess generated energy back to the grid
- give ratepayers credits to offset their purchase of grid-delivered energy when the sun isn't shining
- account for 99% of all PV systems installed in 2012

The Current Push for Rooftop Solar Policy Reform

Recent Proposals Affecting Distributed Solar Energy:

- New monthly fees on solar users
- Increases in ratepayers' fixed/standby charges
- More restrictive caps on net metering programs
- Limits on the rollover of excess generation credits
- Limits on the size of net metering-eligible energy systems
- Prohibitive charges for the interconnection of PV systems

Utilities' Emphasis on Fairness

"Some have tried to paint those seeking net-metering reform as being anti-renewable or anti-self-generation. Quite the contrary, reform is just about ensuring those who benefit from net-metering pay ***fair*** prices."

-Tom Tanton, President of T2 and Associates (advocating Rocky Mountain Power's proposed net metering reforms in Utah)

Utilities' Emphasis on Fairness

"We're not anti-solar or anti-wind or trying to slow this down, we're just trying to keep it ***fair***."

- *Kathleen O'Shea, Oklahoma Gas and Electric Co. spokesperson*

"This is about ***fairness***."

--Jim McDonald, Arizona Public Service Co. spokesperson (describing a proposal for special fees on solar energy users)

Shavell and Kaplow on Fairness

"…[W]hen a particular result seems fair or unfair to us, we should explore the problem, both analytically and empirically…

In some instances, we will thereby identify important considerations that we might otherwise have omitted from our analysis. At other times, we will…find our notion of fairness to be misleading…

[A] common phenomenon is that the notion of fairness reflects one important factor in a situation but ignores others."

114 HARV. L. REV. 1315-16 (2001)

Unfairness toward non-solar customers: The "free rider" argument

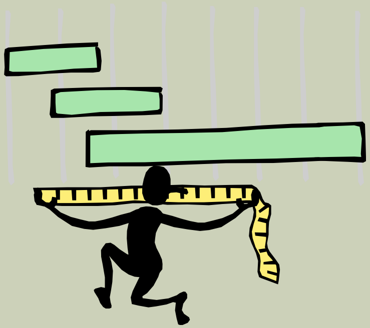
- Customers with rooftop PV use less grid-delivered power
- Because electricity service charges are based primarily on total kWh, these customers pay lower electricity bills.
- Net metering lowers their electricity bills even further.
- For these reasons, customers with PV systems arguably don't pay their ***fair share*** of grid maintenance costs.
- Those without PV systems pay <u>more</u> than their fair share.

https://www.youtube.com/watch?v=zJ8tToIeQ_U

How much cross-subsidization is too much?

Justice Breyer:

"It is clear that setting a rate of return cannot, even in principle, be reduced to an exact science…and suggestions of a proper rate—carried out to several decimal places—give an air of precision that must be false."



IS there significant free riding?

- Solar power tends to be “peak” (highly-valuable) power
- Very little distributed power is lost over wires because it’s located so close to end users
- Renewable power offers numerous environmental benefits and helps utilities to meet clean energy goals/requirements
- Minnesota’s “Value-of-Solar-Tariff” valuation of distributed solar power actually EXCEEDED near-term retail rates!

Unfairness toward low-income citizens: the “robbing the poor” argument

- Wealthy citizens are more likely to have PV systems and participate in net metering.
- Arguably, low-income citizens are less likely to have PV systems and thus ***unfairly*** fund a disproportionate amount of the subsidies that wealthy net metering customers enjoy.

https://www.youtube.com/watch?v=kpgXhQXgKGE

Are net metering policies generating unfair wealth transfers to the rich?

- Even if a southwestern U.S. utility met 10% of its customer demand using net-metered PV systems, its electricity rates would increase by just **2.5%**
- Under the existing APS Rate Discount Program, a family of five making nearly $42k/yr. can qualify for electricity rate discounts of between **26%** and **65%**.
- Low-income families are also more likely to live near coal-fired plants and thus may benefit from more clean energy.

Should energy policymakers even consider wealth distribution effects at all?

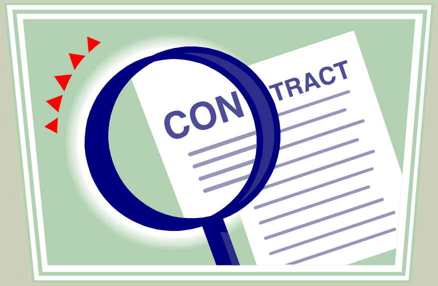
<u>Shavell and Kaplow on weighing distributive impacts</u>:

"[W]hen legal rules do have distributive effects, the effects usually should not be counted as favoring or disfavoring the rules because distributional objectives can often be best accomplished directly, using the income tax and transfer (welfare) programs. One reason economists have tended to favor these direct means of redistribution is that they reach all individuals and are based explicitly on income."

114 HARV. L. REV. 993-94 (2001)

Unfairness toward utilities: The "breach of implied contract" argument

- When utilities build grid infrastructure, they rely on an implied promise of regulatory protection against market forces.
- Arguably, net metering and related policies ***unfairly*** aid or favor competing energy producers, causing utilities to suffer financial losses.



Are net metering policies “unfair” to utilities?

- Governments have never given utilities a guarantee of perpetual financial protection against disruptive innovation and the sort of competition that results from it.
- Investors in utility companies have historically earned higher returns than are available with less-risky investments (such as treasury bills) to compensate for utilities’ inherent risk.

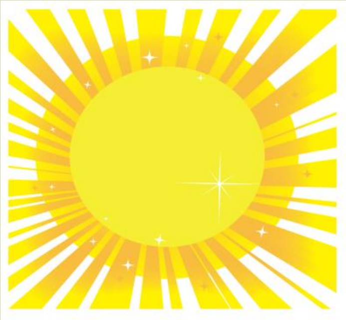
Fairness arguments can cut both ways

- Is it ***fair*** for utilities that enjoy regulated monopoly protection to compete directly against the private solar energy sector?
- Is it ***fair*** for a regulated utility to spend millions of dollars on campaigns aimed at preserving its monopoly status in the face of disruptive innovators?
  - APS allegedly spent $9 million on its recent anti-net-metering campaign

Replacing the Fairness Discussion

Stakeholders should:

- Avoid debating distributed solar energy and net metering as fairness issues and
- Focus more intently on the actual challenges at hand facilitating more seamless and efficient integration of more distributed energy generation into the electric system.



Winmill Paper

STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

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

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

August 22, 2014

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APPENDICES

STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

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

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

I. CONTEXT AND OVERVIEW

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

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

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

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

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

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

A. Summary of Track One Process

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

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

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

B. Summary of Findings and Recommendations

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

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

1. Critical Path Objectives

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

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

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

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

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

2. Findings

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

3. Policy Recommendations

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

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

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

C. Context for a Track One Policy Decision

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

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

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

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

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

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

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

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

1. Business as Usual

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

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

2. Drivers of Change

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

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5 NYISO Power Trends 2013 vs. 2014 at 15.

6 NYISO Power Trends 2014, p. 34.

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

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

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

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

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

3. Benefits of REV

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

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

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

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

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

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

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

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

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

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

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

4. REV/DSP Achievability

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

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

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

E. About This Straw Proposal

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

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

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

II. ESTABLISHING REV: DSP MARKET VISION

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

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

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

A. Distribution System Functions Required Under REV

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

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

1. Regulated Monopoly Functions

i. Market Operations

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

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

ii. Grid Operations

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

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

iii. Integrated System Planning

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

2. Competitive Offerings

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

B. DSP Market Structure

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

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

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

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

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

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

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

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

Staff proposes the following principles for market design:

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

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

C. Overview of Market Participants' Roles and Interactions

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

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

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

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

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

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

III. ENABLING NEW ROLES FOR KEY PARTICIPANTS

A. Identity of the DSP Provider

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

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

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

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

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

Table 1

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

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

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

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

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

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

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

B. Customer Engagement

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

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

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[16] Also known as Customer Engagement Working Group.

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

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

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

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

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

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

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

1. Data Access and Privacy[21]

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

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

i. Data Exchange

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2. Customer Acceptance

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

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

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

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

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

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

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

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

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

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

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

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

3. Affordability

i. Commitment to Affordable Service

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

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

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

ii. Low-Income Customer Engagement

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

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

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

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

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

iii. High-Usage Customers

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

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

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

C. DER Providers and ESCOs

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

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

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

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

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

D. Wholesale Market Interactions

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

1. Wholesale Benefits Resulting From Expanded Use of DER

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

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

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

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

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

2. Coordination Between DSPs and the NYISO

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

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

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

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

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

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

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

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

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

3. Coordination Impacts Resulting From FERC Order 745 Being Vacated

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

IV. GAUGING FEASIBILITY

A. Platform Technology

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

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

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

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

1. DSP Functional Requirements

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

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

Table 2

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

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

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

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

2. Existing Utility Distribution Systems and Capabilities

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

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

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

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

3. Technology Evaluation

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

i. Distribution System Operations

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

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

ii. Customer Facing Technologies

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

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

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

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

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

iii. Technology Platform Policy Mapping

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

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

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

iv. Technology Standardization

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

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

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

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

B. Benefit Cost Analysis Framework

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

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

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

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

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

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

1. Principles to Guide BCA Framework Development

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

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

2. Guidance on Key Parameters

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

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

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

Table 3

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

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

Table 4

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

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

Table 5

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

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

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

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

Table 6

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

3. Proposed Process for Developing the BCA Framework

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

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

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

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

4. BCA for Tariff Pricing and Resource Procurement Provisions

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

V. BUILDING THE DSP MARKET

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

A. Clean Energy

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

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

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

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

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

32 Id. at 29.

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

1. Transition

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

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

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

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

2. Supply-Side Renewable Resources

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

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

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

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

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

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

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

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

3. Energy Efficiency With Load Management Controls

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

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

i. Scope and Scale

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

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

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

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

ii. Quantification and Verification of Achievements

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

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

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

iii. Reporting and Data Management

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

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

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

B. Demonstration Projects

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

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

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

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

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

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

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

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

C. Interconnection Procedures

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

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

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

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

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

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

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

D. Microgrids

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

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

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

1. Benefits of Microgrids

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

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

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

2. Barriers to Microgrid Development

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

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

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

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

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

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

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

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

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

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

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

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

E. Demand Response Tariffs

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

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

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

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

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

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

F. Planning REV Implementation

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

1. Transition and Implementation Planning

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

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

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

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

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

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

2. DSP Platform and Market Vision Planning

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

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

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

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

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

VI. MITIGATING MARKET POWER

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

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

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

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

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

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

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

1. The Advantages and Disadvantages of Utility Engagement in DER

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

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

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

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

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

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

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

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

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

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

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

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

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

2. Factors to Consider in Mitigating Market Power

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

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

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

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

3. Discussion and Recommendations

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

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

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

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

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

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

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

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

Staff recommends the following approach to utility engagement in DER:

For direct activities of regulated utilities:

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

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

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

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

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

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

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

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

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

B. Interconnection

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

C. Dispatch

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

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

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

D. System Data

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

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

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

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

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

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

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

VII. IMPLEMENTING REV: FINDINGS AND RECOMMENDATIONS

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

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

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

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

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

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

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

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

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

A. Transition Phases and Critical Path Objectives

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

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

Table 6

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

B. Near-Term "No Regrets" Actions

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

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

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

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

C. Transitional Steps

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

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

D. Plans for Mature Platform and Markets

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

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

E. Considerations for Next Steps

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

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

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

APPENDICES

I. Existing Utility Distribution Systems and Capabilities

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

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

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

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

Utility Advancement towards a Smart Grid

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

II. Platform Functionality

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

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

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

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

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

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

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

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

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

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

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

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

III. Standards, Protocols, and Architecture

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

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

The benefits of architecture development include:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

IV. Platform Technology

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

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

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

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

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

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

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

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

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

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

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

V. Conclusion

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

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

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

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

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

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

Appendix B: Glossary and Acronyms

Glossary

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

Distributed system platform (DSP)

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

Market Actors

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

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

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

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

Other relevant terms

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

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

Acronyms

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

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

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BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS 2014 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN FOR RESET OF RENEWABLE ENERGY ADJUSTOR	DOCKET NO. E-01345A-13-0140 **SUPPLEMENTAL APPLICATION (UTILITY-OWNED DG)**

Responding to clear customer interest, APS proposes AZ Sun DG: a 20 MW utility-owned residential DG program that will help APS meet the 2015 renewable energy requirement established by Decision No. 71448. Under this program, APS would strategically deploy DG to maximize system benefits. APS would also support the local solar community by competitively selecting third-party local solar vendors to install these DG systems across APS's service territory. To benefit all customers, APS would install the DG on customer rooftops and on the utility side of the meter. APS would "rent" these rooftops in exchange for a $30 per month bill credit. This simple bill credit structure will provide all customers—including those who cannot currently afford it—an opportunity to "go solar."

AZ Sun DG is an alternative to the 20 MW large-scale Redhawk solar facility previously proposed in this docket on April 15, 2014. Because AZ Sun DG would help APS achieve compliance with APS's 2015 renewable energy requirement, APS requests that the Commission consider this proposal on an expedited basis, with an order by September 2014, if possible.

I. Under the AZ Sun DG Program, Participating Customers Would Receive a $30 Monthly Bill Credit for Making Their Rooftop Available to APS.

To install 20 MW of residential DG, APS would deploy systems on approximately 3,000 customer rooftops. On these rooftops, APS would install 4-8 kW photovoltaic systems, depending on the roofs' configurations. Just as APS might lease land to locate a large-scale solar facility, APS will "rent" these 3,000 customer rooftops for 20 years.

In exchange for use of a customer's roof for 20 years, APS would provide a $30 monthly bill credit. With the DG systems installed on APS's side of the meter, participating customers can help APS power their neighborhoods. While doing so, those participating customers can continue taking service under any rate for which they would otherwise be eligible.[1]

II. APS Would Competitively Select Local Solar Installers to Build AZ Sun DG in Strategically Targeted Locations on APS's System.

If the Commission authorized AZ Sun DG, APS would conduct a competitive RFP process with local solar installers. APS would then work with the selected installers to deploy AZ Sun DG systems. APS intends to strategically deploy a portion of the 3,000 systems to pursue specific purposes, such as serving low income or low credit score customers and providing system benefits.

The opportunity to achieve these benefits is unique to utility-owned installations. For example, APS will be able to orient AZ Sun DG systems towards the southwest and west. These orientations will maximize the amount of solar production during system peak periods. And by owning the DG systems, APS would be able to install and operate

[1] AZ Sun DG customers would not take net metering service.

advanced inverters. These inverters will provide flexibility to manage power quality and lay the foundation for better integrating rooftop solar with the distribution system.

III. To Reach Compliance, Benefit the System and Offer DG to Underserved Customers, APS Requests Authorization to Proceed with AZ Sun DG.

APS estimates that the capital cost to deploy the 20 MW AZ Sun DG program will be approximately $57-70 million. APS can only provide a program cost range because it can only estimate the bids that it will receive from third party solar installers. Although this capital cost is similar to the AZ Sun Redhawk project previously proposed in this docket, the AZ Sun DG program will produce less overall energy. Despite similar costs for less energy, APS still believes that the Commission should authorize AZ Sun DG.

AZ Sun DG offers several benefits beyond helping APS achieve compliance with its renewable energy requirements. Many customers are interested in rooftop solar, but either cannot afford to buy a system outright, or have insufficient credit to lease a system. AZ Sun DG provides a means for at least some of these customers to "go solar." Moreover, deploying utility-owned residential DG provides an exciting chance to explore the operational advantages of installing rooftop solar with advanced inverters. And AZ Sun DG represents a genuine opportunity to demonstrate how strategically deploying DG can maximize systems benefits. Combined with the opportunity to provide an underserved segment of customers with rooftop solar, and support local solar installers, APS believes that the Commission should authorize AZ Sun DG.

IV. Due to Tight Deployment Schedules, APS Requests that the Commission Grant Authorization to Proceed on an Expedited Basis.

The window of time during which the 20 MW of AZ Sun DG could be installed and help APS achieve compliance with its end-of-2015 renewable energy target is rapidly closing. An aggressive RFP, customer solicitation and construction schedule is 15 months. And a 15 month schedule would necessitate authorization to proceed with AZ Sun DG by September 2014. Accordingly, APS requests that the Commission authorize AZ Sun DG on an expedited basis, with an order by September 2014 if possible.

V. Conclusion

With AZ Sun DG, APS seeks to

- ensure compliance with its 2015 renewable energy target;
- offer another means for customers to put solar on their rooftops, even if they can't afford to buy or lease solar;
- strategically deploy DG to enhance potential system benefits; and,
- support local solar installers and Arizona's economy.

As an alternative to the previously-proposed Redhawk solar facility, APS requests that the Commission authorize AZ Sun DG, on an expedited basis, as the final 20 MW of APS's AZ Sun Program.

RESPECTFULLY SUBMITTED this 28th day of July, 2014.

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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS 2014 RENEWABLE ENERGY STANDARD IMPLEMENTAITION PLAN FOR RESET OF RENEWABLE ENERGY ADJUSTOR.	**DOCKET NO. E-01345A-13-0140** **MOTION TO DISMISS APS UTILTY DG PROPOSAL**

THE ALLIANCE FOR SOLAR CHOICE

MOTION TO DISMISS ARIZONA PUBLIC SERVICE COMPANY

APRIL 15, 2014 AND JULY 28, 2014 APPLICATIONS

Pursuant to A.A.C. §§ R14-3-106(K) and R14-3-109(C), The Alliance for Solar Choice ("TASC"), through its undersigned counsel, moves the Arizona Corporation Commission ("Commission") to dismiss two applications that Arizona Public Service Company ("APS") filed in the above-captioned docket on April 15, 2014 and July 28, 2014. These applications request approval for utility-owned solar generation that the Commission rejected in its final order in this proceeding over 7 months ago. The APS applications are contrary to that final order and should be dismissed with prejudice.

TASC was founded by the nation's largest rooftop companies and represents the vast majority of the nation's rooftop solar market. Its members include: Demeter Power, SolarCity, Solar Universe, Sungevity, Sunrun, and Verengo. These companies are responsible for many thousands of solar installations serving businesses, residents, schools, churches and government facilities in Arizona. TASC's member companies have brought hundreds of jobs and many tens of millions of dollars of investment to Arizona's cities and towns.

The Commission's final order in this proceeding rejects the need for *any* additional utility-owned capacity at this time, including the capacity APS proposes in its April 15, 2014 and July 28, 2014 applications. The final order states the Commission will address whether APS has a need for *any* additional capacity in the APS 2015 REST Plan, after the Commission has collected additional information on whether additional capacity is even necessary. Recent filings that APS submitted subsequent to the final order suggest that in fact additional utility-owned capacity is *not* necessary. Accordingly, the Commission should dismiss APS's applications, which are contrary to the final order. Consistent with the final order, the Commission should consider whether there is a need for *any* additional utility-owned generation when it reviews the APS 2015 REST Plan.

I. The Commission Should Enforce The Final Order In This Proceeding, Dismiss APS's Applications For New Capacity, And Determine Whether There Is A Need For *Any* Additional Utility-Owned Capacity In The 2015 REST Plan.

The Commission issued a final order on the APS 2014 REST Plan over 7 months ago, on January 7, 2014 ("Final Order").[1] APS requested authorization to complete a 50 MW phase of its AZ Sun program, including 30 MW of utility-owned solar adjacent to APS's Redhawk Power Station.[2] APS claimed this capacity is necessary to meet its REST requirements and a 2009 Settlement that requires APS to acquire "new renewable energy resources with annual generation or savings of at least 1.7 million Megawatt hours to be in service by 2015...."[3]

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[1] Decision No. 74237.
[2] Id. page 2, lines 9-12.
[3] Id. page 2, lines 12-13; Decision No. 71488 (December 30, 2009).

Staff opposed the APS 30 MW Redhawk facility, claiming it may not be needed. According to Staff:

> "we do not believe that approval of the final 30 MW of the AZ Sun Program (currently proposed to be located at the Redhawk facility) is warranted at this time. We believe that APS will be able to meet its obligations, under the 2009 Settlement Agreement, to achieve 1.7 million MWhs by December 31, 2015. According to information submitted by APS in its 2014 RES Application, (Exhibit 2B), there could be enough distributed generation to enable APS to meet its required target without the 30 MW at Redhawk."[4]

The Final Order accepts Staff's reasoning. It authorizes APS to build 20 MW of new utility-owned solar capacity at Luke Air Force Base and at the City of Phoenix. However, the Final Order rejects APS's proposal to build 30 MW of utility-owned solar at APS's Redhawk Power Station.[5] Instead, the Final Order directs APS and interested parties to submit information to the docket by April 15, 2014, addressing whether APS has a need for *any* additional capacity to meet the requirements of the 2009 Settlement.[6] The Final Order also requests information on the cost effectiveness of purchased power agreements over utility owned generation.[7] The Final Order directs Staff to take this information into account in issuing a Staff report *on the APS 2015 REST plan*. Specifically, the Final Order states:

> "IT IS FURTHER ORDERED that when Staff files its recommendations regarding Arizona Public Service Company's *2015 REST Implementation Plan*, it shall include a discussion of whether or not Arizona Public Service Company needs to install *any portion of the final 30 MW* phase of AZ Sun in order to comply with the REST Rules and/or the 2009 Settlement Agreement. These recommendations shall consider the information filed by Arizona Public Service Company and any interested parties regarding the cost effectiveness of utility owned generation and third party wholesale

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[4] Id. page 11, lines 1-6.

[5] Id. page 15, lines 8-10: "IT IS FURTHER ORDERED that Arizona Public Service Company's plan to move ahead with 10 MW at Luke Air Force Base and 10 MW at the City of Phoenix, as described herein, is approved. *However, the plan for 30 MW at Redhawk is not approved, at this time.*" (italics and underlining added)

[6] Id. page 15, lines 11-16.

[7] Id.

purchased power agreements in contemplating this final 30 MW phase of AZ Sun."[8] (italics and underlining added)

APS ignores the Final Order and instead submits two applications in this proceeding requesting authorization to build 20 MW of AZ Sun utility-owned generation that the Final Order rejects. On April 15, 2014, APS proposed a scaled down 20 MW utility-owned development at its Redhawk Power Station.[9] Then, on July 28, 2014, APS proposed a radically different alternative in which APS would locate 20 MW of utility-owned solar capacity on the rooftops of 3,000 residential customers in APS's service territory.[10] Despite the significant legal and policy questions such a proposal raises, APS's July 28, 2014 application spans barely three double-spaced pages and fails to provide the most basic information on proposed costs. Yet, APS asks the Commission to expedite approval with no evidentiary hearing in a ridiculously short 2-month timeframe.

The Commission should dismiss APS's April 15, 2014 and July 28, 2014 applications from this proceeding with prejudice. The Final Order in this proceeding approves no capacity for these applications. To the contrary, the Final Order rejects this capacity, questions whether it is needed, and states the Commission will consider ***any*** additional capacity in APS's 2015 REST Plan. Approval of either of APS's applications would require significant modification to the Final Order, which neither of APS's applications request. As such, APS has submitted applications that plainly contradict a Commission decision. Moreover, APS's recent filings in this docket, and in the 2015 REST Plan Implementation docket, clearly indicate that APS has ***no need*** for additional utility-owned capacity, regardless of its location.[11]

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8 Id. page 15, line 17-23.

9 APS, *Application and Response to Commission Inquiry in Decision 74237*, Docket No. E-01345A-13-0140, (Apr. 15, 2014).

10 APS, *Supplemental Application (Utility-Owned DG)*, Docket No. E-01345A-13-0140, (Jul. 28, 2014).

11 APS's April 15, 2014 application acknowledges that if the pace of residential DG applications received in the first quarter of 2014 continues until the end of 2015, which it has thus far, "APS anticipates that it would be very close to meeting its 2009 Settlement obligations." Page 3, lines 5-7.

II. The APS Applications Propose Capacity And Costs That Are Inconsistent With The Final Order In This Proceeding, Which APS Has Not Proposed to Modify. As Such, The Applications Should Be Dismissed As A Collateral Attack On A Commission Decision.

The April 15, 2014 and July 28, 2014 APS applications do not comply with the Commission's 2014 REST Plan Final Order. The Final Order requests additional information so the Commission can determine whether *any* additional capacity is needed *in the 2015 REST Plan*. The Final Order did not invite proposals for scaled down capacity or alternate locations for rejected capacity, which is what APS has proposed. The Final Order rejected the proposed capacity and approves no budget or funding for it. APS did not request a rehearing of the Final Order, and neither of APS's applications request that the Commission amend the Final Order to increase the 2014 REST Plan budget or provide funding to accommodate 20 MW of additional utility-owned generation. APS's applications are simply inconsistent with the Final Order and should be dismissed. In all collateral actions or proceedings, the orders and decisions of the commission that have become final shall be conclusive.[12] The Commission's Final Order in this proceeding is conclusive. The APS applications are contrary to it and should be dismissed with prejudice. The Final Order is clear this issue will be addressed in the APS 2015 REST Plan, which in fact has already been filed.

Even if APS had requested a modification of the Final Order, which it has not, APS has failed to provide sufficient information in either of its applications to determine what modifications to the 2014 Plan Final Order would be necessary, including modifications to the budget and funding levels. The Commission's REST Rules require a utility to provide the following information for every proposed Eligible Renewable Energy Resource:[13]

- A description of the kW and kWh to be obtained for the next 5 years;
- Estimated cost, including cost per kWh and total cost per year;
- An evaluation or whether existing rates allow for the ongoing recovery of proposed resources, including a Tariff application that meets the requirements of

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[12] A.R.S. § 40-252.
[13] A.C.C. § 14-2-1813(B)(1),(2),(4), (5).

R14-2-1808 if additional recovery is necessary; and

- A line item budget that allocates funding for each proposed resource.

Neither of APS's applications attempt to comply with the Commission's REST Rules. A single footnote in the April 15, 2014 application states APS "will provide updated revenue requirement numbers in its 2015 RES Implementation Plan that will be filed July 1, 2014."[14] The July 28, 2014 application provides nothing more than an apparent capital cost estimate that ranges wildly from $57-70 million. These applications fail to provide the minimal information required by the Commission's REST Rules. As such, the Commission lacks sufficient information to review these applications and they should be dismissed from this proceeding.

III. The Commission Should Enforce Its Final Order And Consider Whether APS Has A Need For *__Any__* Additional Capacity In The 2015 REST Plan.

APS filed its 2015 REST Plan on July 1, 2014. The 2015 REST Plan appears to confirm that in fact *__no__* additional AZ Sun capacity is needed to satisfy the REST or the 2009 Settlement. APS states: "By the end of 2015 and consistent with its intent to make best efforts to fulfill the RES and its 2009 Settlement obligations, APS projects it will have a total of approximately 1250 MW of installed renewable capacity within its service territory, including approximately 930 MW of solar capacity."[15] Likewise: "APS expects to achieve compliance with its 2015 RES requirements and maintain its renewable energy obligations in 2015 in accordance with APS's Settlement Agreement (2009 Settlement)."[16] These statements do not appear to be contingent on the approval of any additional utility-owned capacity.

Despite acknowledging that additional capacity is not needed, APS nevertheless includes a request to build a 20 MW utility-owned solar facility at the APS Redhawk Power Station.[17] According to APS:

> "APS is proposing in this plan that the Company be authorized to proceed with the construction of a 20 MW utility-owned solar project to the located at APS's Redhawk

[14] Page 4, lines 27-28.
[15] 2015 REST Plan Application, page 2, lines 8-11.
[16] 2015 REST Plan, page 1.
[17] 2015 REST Plan Application, page 3, lines 6-8.

Power Station, which is a previously identified site where the Company has already initiated pre-development activities. If approved, the Company expects it will be able to conduct the final RFP, sign a contract, and begin construction in 2014."[18]

APS proposes a budget of $153.8 million for the 2015 REST Plan, which apparently includes the cost of the proposed 20 MW project at Redhawk. APS proposes no alternate location or budget for the proposed capacity. APS claims it has undertaken "pre-development activities" at Redhawk and APS has provided no information for the Commission to consider alternate locations.

The Commission should enforce its Final Order and consider whether a 20 MW facility at Redhawk is necessary within the context of the APS 2015 REST Plan. APS's residential rooftop solar proposal is entirely inconsistent with the proposal APS has put forward in the 2015 Plan, and APS has not met the minimal information requirements of the REST Rules for a rooftop solar proposal to be considered. APS has provided no estimate of its total cost to lease residential rooftop space necessary to accommodate 20 MW, no estimate of installation costs, no estimate of interconnection costs, no estimate of permitting costs, and no estimate of operation and maintenance costs over a 20-25 year term. Without this information, the Commission has no basis to compare the cost of locating capacity on rooftops versus locating capacity where APS has already undertaken "pre-development activities". Accordingly, the Commission has no basis on which to consider any alternative to the proposal APS included in its proposed 2015 REST Plan. Moreover, the Commission should also not lose sight of the fact that it has questioned whether *any* additional capacity is necessary, regardless of location. Based on APS's recent filings, it appears the answer is no.

IV. APS's Proposal To Locate 20 MW Of Solar Capacity On The Rooftops Of 3,000 Residential Customers Raises Significant Public Policy And Legal Questions That Cannot Possibly Be Addressed In The 2 Month Timeframe APS Proposes.

[18] 2015 REST Plan, page 3.

APS's rationale for 20 MW of residential solar stands in stark contrast to the positions taken by APS in recent Commission proceedings. By substituting a distributed solar program (i.e. AZ Sun DG) for a utility-scale solar installation (i.e. the 20 MW Redhawk project), APS signals that it no longer believes its statement from a year ago, that rooftop solar is more expensive and less efficient than other types of renewable generation, including utility-scale solar; and, its claim that without incentives, rooftop solar is not economical for customers.[19] The structure of APS's program suggests that it has abandoned the position it took on November 7, 2013 where it attacked net metering because it supposedly relies on a fixed incentive, rather than on "compensation that can be adjusted."[20] Here APS proposes a fixed incentive applicable over a 20-year period.

The APS AZ Sun rooftop solar proposal raises a number of significant legal and public policy questions that the three-page, July 28, 2014 application makes no attempt to address. For example, there are several ways in which the APS program could raise costs to non-participating ratepayers. APS will add the program costs to rate base and recover a return on equity (over a 20-25 year life of the solar energy equipment) on $57-70 million of program costs. It is likely that this stream of costs will be higher than if the company looked to procure desired benefits from the full range of market actors. For example, customers who purchase or lease their systems and participate in net metering pay the full capital costs of PV equipment, and generate a surplus of system benefits. Any additional cost of incentivizing these customers to modify their systems to meet electric system needs is likely much smaller than the cost to APS and its ratepayers for paying for the full cost of systems installed on leased roofs. Similarly, third-partly lease systems involve no expenditure from the utility, and parties to these transactions can also be incentivized to adopt optimal orientation or inverter configuration.

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[19] Page 3 of the *Application* filed July 12, 2013 in Docket No. E-01345A-13-0140, *In The Matter Of The Application Of Arizona Public Service Company For Approval Of Its 2014 Renewable Energy Standard Implementation Plan For Reset Of Renewable Energy Adjustor*. See: http://images.edocket.azcc.gov/docketpdf/0000146805.pdf

[20] Proposed Amendment #6: Solar Adjuster Pilot Program, Page 11, filed November 7, 2013 in Docket No. E-01345A-13-0248, *Arizona Public Service Company Net Metering Cost Shift Solution*. See: http://images.edocket.azcc.gov/docketpdf/0000149819.pdf.

One reason these private transactions are less expensive to ratepayers is that the homeowner, his/her contractors, and the third party owner/lessor bear all the risks. Under APS's proposal, a whole host of risks are shifted onto the ratepayer. If program costs are higher than expected, ratepayers pay those costs. If PV panels or balance of system fails, ratepayers will pay the cost of replacing the systems (to the extent not covered by warranties or insurance) and will suffer lost system benefits until replacement occurs. If the utility needs to spend money on billing system changes to accommodate the $30/month credit – ratepayers pay those costs. If the utility's marketing costs are higher than those incurred by competitive suppliers, ratepayers pick up the difference. At a minimum, the Commission should carefully evaluate the costs APS has passed on to ratepayers in connection with its Flagstaff customer-sited DG pilot program to better understand the risk ratepayers face for cost overruns from utility-owned projects located on customers' premises.

Recent experience in California suggests that utility-owned distributed generation is more expensive than distributed generation procured through competitive bidding. Southern California Edison ("SCE") initially administered a system in which it procured distributed generation through a combination of utility-owned and competitively bid contracts. That utility found that the utility-owned option tended to be more expensive and repeatedly petitioned the California Public Utility Commission to reduce and ultimately eliminate the utility-owned portion of the procurement program.[21] Another utility, Duke Energy, suspended its rooftop program after a fire occurred at one of its locations.[22] These examples highlight the spotty record utilities have had attempting to locate utility-owned generation on the property of their customers.

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[21] In Application 08-03-015, SCE proposed a 250 MW utility-owned Solar PV Program. See: SCE, *Petition For Modification Of Decision No. 12-02-035,* July 27, 2012, page 11 at: http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=63977.
"Reducing the UOG portion of the SPVP program to 91 MW, as requested in this Petition, would continue to save customers money from having to bear the costs associated with SCE building relatively higher-cost rooftop SPV projects when SCE could buy these same renewable energy generated from SPV facilities through competitive, CPUC authorized procurement programs."
See also, *Southern California Edison Company's (U 338-E) Petition For Modification Of Decision 09-06-049,* February 11, 2011 at: http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=38778

[22] *See* Charlotte Business Journal, "Duke Energy Suspends 'Rooftop Solar' Effort After Fire, Apr. 25, 2011. Available: http://www.bizjournals.com/charlotte/blog/power_city/2011/04/duke-energy-suspends-rooftop-solar.html?page=all

The APS program also could increase the cost of solar energy systems to customers who prefer private solar energy services. When utility programs compete with non-utility-owned services, the advantages enjoyed by the incumbent utility threaten to drive competitive services out. The anti-competitive factors include:

- Access to customer data. The utility has detailed historical customer usage information that can greatly facilitate customer acquisition. This would create an unfair playing field for private solar vendors trying to compete with utilities for customers.

- Interconnection. Utilities can make it hard or easy to interconnect solar systems. Even short delays affect sales for competitive solar equipment vendors and utility sponsored projects that face no such delays would have an unfair advantage.

- System Capacity. The utility has advanced knowledge of where interconnection opportunities exist through its understanding of locations on the distribution system where there is spare capacity.

- Discretion in program implementation. The Utility can target its program in ways to disrupt marketing by private solar energy companies.

- Selection of Contractors. APS will be in charge of choosing which companies install systems under this program. It could discriminate among private solar companies, or condition contracts on terms that prevent vendors from installing net metered systems or engage in third-party ownership models.

Individually and in combination these factors would make competition unfair, with the result that customer choices would be restricted.[23] This is particularly true if the utility succeeds in driving-out or weakening private solar equipment vendors and then closes its own program. The proposed APS program is of limited duration and size, but in that period it could sufficiently damage competitive markets, such that when it is over customers are left without options.

APS has the motive and the opportunity to favor its own program and investments. The result is likely to be that building owners may have diminished access to competitive suppliers of rooftop PV systems and may experience higher costs due to a constrained marketplace. This outcome is antithetical to the general principle of open access to electric grids that has been central to energy policy-making for decades.

Competitive solar companies do not have the luxury of a rate base over which to spread costs. Granting APS the right to own customer-sited PV systems could result in systemic competitive advantages and unfair market power for APS, which could distort market clearing prices for certain products and services provided by the competitive market place. Unlike non-utility solar energy suppliers who are subject to competitive pressures of the private market place (which helps to control prices and ensure quality installations and service), APS has no reason to keep program costs low. In fact, it appears APS has proposed 20 MW of new utility owned solar capacity despite the fact that it does not need the capacity to meet its REST or 2009 Settlement requirements. And if costs escalate, APS is rewarded with a larger return on invested capital.

Finally, APS provides no information about how its cost estimates were calculated, or how it determined \$30/month is a reasonable cost for leasing residential customer roof space. The entire proposal is described in less than three pages (double-spaced). The Commission is left with only a vague idea regarding how much this will cost ratepayers. For example, does APS's estimate include costs of billing system changes to accommodate the \$30/month bill credit for participating customers? Does the cost estimate include expenses associated with establishing, marketing and administering the program? If these program costs are to be rate-based, how do overall ratepayer liabilities escalate to reflect the utility's return on equity

[23] Whether or not APS takes advantage of asymmetric information or market power, just the perception of an uneven playing field would likely constrain investment and participation by investors, third-parties and customers, which would hinder the development of distributed solar market services.

earnings? What interconnection costs and permitting costs will APS incur, and are these costs included in APS's cost estimate?

Morevoer, APS has not provided the lease that would govern the relationship with a participating customer. Without the lease, it is not clear how APS proposes to deal with a change in the identity of the real property owner that hosts an APS-owned solar system? What rights does APS propose for entering onto a residential customer's roof to perform maintenance and repairs or respond to any emergencies over a 20-year term? What recourse will APS seek if a new homeowner refuses to assume the lease that APS entered with the prior homeowner? Who is liable for any damage done to the customer's property? How will a system be removed at the end of the lease term? Who will be responsible for repairing any damage to the customer's property during the removal process? Who is liable if the solar system is damaged? Who will be responsible for resolving disputes between APS and customers hosting solar systems?

These considerations raise significant implications for would be participants in a utility-owned, residential rooftop solar program. For example, Arizona's utility statutes give utilities a broad right to pursue a civil action with treble damages and a right to pursue attorneys fees against any customer that "[t]ampers with property owned or used by the utility."[24] It is unlikely that the Arizona Legislature contemplated that these provisions might apply to a utility program that locates expensive generating equipment on the premises of residential customers. Nevertheless, these statues are broad enough to apply in this context, and the Commission should carefully consider the potential liability to which approval of a utility-owned rooftop solar program may expose residential customers.[25]

The primary justification APS offers for its rooftop solar proposal is that it responds to "clear customer interest."[26] However there is no support for this claim in the three-page APS

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[24] A.R.S. §§ 40-292, 40-493.

[25] The Commission's rules contemplate the utility's right of ingress and egress over a customer's premises extending only to the point of power delivery, which is the utility billing meter. *See, generally*, Rules R14-2-206(B),(C), R14-2-208(A),(B), and R14-2-209(D). The APS proposal would dramatically expand APS's need for ingress and egress over a customer's premises and would likely require a reevaluation of the Commission's rules providing for such access.

[26] July 28, 2014 Application, page 1, line 19.

application, and TASC questions whether residential customers would truly be interested in APS's proposal. APS proposes to provide a $30/month lease payment, but APS has not explained how it determined this proposed payment, or whether it has conducted any research to determine whether it is sufficient to motivate a residential customer to want to host utility-owned generation that provides no tax benefits to the customer or utility bill savings. In fact, any benefit of participation may be reduced by taxation of the lease payment and overwhelmed by increased liability and potential burdens associated with transferring property. Finally, although the application signals that this program would open solar opportunities to lower income customers and target high value locations, APS has more recently stated in discussing the proposed program that the program will be first-come/first-served and proposed system sizes of 4-8 kW suggest the smallest homes with little roof space will not qualify.

These questions cannot possibly be addressed within the 2-month timeframe APS has proposed for Commission action on the July 28, 2014 application. Considerable deliberation would be required to address these important public policy and legal matters. However, the Commission should first determine whether *__any__* proposed capacity is even necessary. Discussing alternate locations for capacity that has thus far been rejected, is likely not needed, and is not currently included in the APS 2015 REST Plan is a waste of Commission resources.

V. For The Reasons Discussed Herein, The Commission Should Dismiss APS's April 15, 2014 and July 28, 2014 Applications From This Proceeding And Address The Need For New Capacity In The 2015 REST Plan Proceeding.

WHEREFORE, The Alliance for Solar Choice requests that the Commission dismiss the APS April 15, 2014 and July 28, 2014 applications from the 2014 REST Plan proceeding. Consistent with the Commission's Final Order in the 2014 REST Plan proceeding, the Commission should address the need for *__any__* additional capacity, and the benefits of procuring capacity through purchased power agreements, in the context of the 2015 REST Plan that APS filed on July 1, 2014. The APS applications in the 2014 Plan proceeding propose capacity and costs that are inconsistent with the Final Order in the proceeding. APS's proposal to locate 20

MW of solar capacity on the rooftops of 3,000 residential customers raises significant public policy and legal questions that cannot be addressed in this docket and certainly cannot be addressed in the 2-month timeframe APS proposes. The Commission should enforce its Final Order, dismiss the APS April 15, 2014 and July 28, 2014 applications from the proceeding, and address the need for new capacity in the 2015 REST Plan proceeding.

Respectfully submitted this 15th day of August, 2014.

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Disruptive Challenges:

Financial Implications and Strategic Responses to a Changing Retail Electric Business

Prepared by: Peter Kind
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Prepared for: Edison Electric Institute

January 2013

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Executive Summary

Recent technological and economic changes are expected to challenge and transform the electric utility industry. These changes (or "disruptive challenges") arise due to a convergence of factors, including: falling costs of distributed generation and other distributed energy resources (DER); an enhanced focus on development of new DER technologies; increasing customer, regulatory, and political interest in demand-side management technologies (DSM); government programs to incentivize selected technologies; the declining price of natural gas; slowing economic growth trends; and rising electricity prices in certain areas of the country. Taken together, these factors are potential "game changers" to the U.S. electric utility industry, and are likely to dramatically impact customers, employees, investors, and the availability of capital to fund future investment. The timing of such transformative changes is unclear, but with the potential for technological innovation (e.g., solar photovoltaic or PV) becoming economically viable due to this confluence of forces, the industry and its stakeholders must proactively assess the impacts and alternatives available to address disruptive challenges in a timely manner.

This paper considers the financial risks and investor implications related to disruptive challenges, the potential strategic responses to these challenges, and the likely investor expectations to utility plans going forward. There are valuable lessons to be learned from other industries, as well as prior utility sector paradigm shifts, that can assist us in exploring risks and potential strategic responses.

The financial risks created by disruptive challenges include declining utility revenues, increasing costs, and lower profitability potential, particularly over the long-term. As DER and DSM programs continue to capture "market share," for example, utility revenues will be reduced. Adding the higher costs to integrate DER, increasing subsidies for DSM and direct metering of DER will result in the potential for a squeeze on profitability and, thus, credit metrics. While the regulatory process is expected to allow for recovery of lost revenues in future rate cases, tariff structures in most states call for non-DER customers to pay for (or absorb) lost revenues. As DER penetration increases, this is a cost-recovery structure that will lead to political pressure to undo these cross subsidies and may result in utility stranded cost exposure.

While the various disruptive challenges facing the electric utility industry may have different implications, they all create adverse impacts on revenues, as well as on investor returns, and require individual solutions as part of a comprehensive program to address these disruptive trends. Left unaddressed, these financial pressures could have a major impact on realized equity returns, required investor returns, and credit quality. As a result, the future cost and availability of capital for the electric utility industry would be adversely impacted. This would lead to increasing customer rate pressures.

The regulatory paradigm that has supported recovery of utility investment has been in place since the electric utility industry reached a mature state in the first half of the 20th century. Until there is a significant, clear, and present threat to this recovery paradigm, it is likely that the financial markets will not focus on these disruptive challenges, despite the fact that electric utility capital investment is recovered over a period of 30 or more years (i.e., which exposes the industry to stranded cost risks). However, with the current level of lost load nationwide from DER being less than 1 percent, investors are not taking notice of this phenomenon, despite the fact that the pace of change is increasing and will likely increase further as costs of disruptive technologies benefit further from scale efficiencies.

Investors, particularly equity investors, have developed confidence throughout time in a durable industry financial recovery model and, thus, tend to focus on earnings growth potential over a 12- to 24-month period.

So, despite the risks that a rapidly growing level of DER penetration and other disruptive challenges may impose, they are ***not*** currently being discussed by the investment community and factored into the valuation calculus reflected in the capital markets. In fact, electric utility valuations and access to capital today are as strong as we have seen in decades, reflecting the relative safety of utilities in this uncertain economic environment.

In the late 1970s, deregulation started to take hold in two industries that share similar characteristics with the electric utility industry—the airline industry and the telecommunications industry (or "the telephone utility business"). Both industries were price- and franchise-regulated, with large barriers to entry due to regulation and the capital-intensive nature of these businesses. Airline industry changes were driven by regulatory actions (a move to competition), and the telecommunications industry experienced technology changes that encouraged regulators to allow competition. Both industries have experienced significant shifts in the landscape of industry players as a result.

In the airline sector, each of the major U.S. carriers that were in existence prior to deregulation in 1978 faced bankruptcy. The telecommunication businesses of 1978, meanwhile, are not recognizable today, nor are the names of many of the players and the service they once provided ("the plain old telephone service"). Both industries experienced poor financial market results by many of the former incumbent players for their investors (equity and fixed-income) and have sought mergers of necessity to achieve scale economies to respond to competitive dynamics.

The combination of new technologies, increasing costs, and changing customer-usage trends allow us to consider alternative scenarios for how the future of the electric sector may develop. Without fundamental changes to regulatory rules and recovery paradigms, one can speculate as to the adverse impact of disruptive challenges on electric utilities, investors, and access to capital, as well as the resulting impact on customers from a price and service perspective. We have the benefit of lessons learned from other industries to shift the story and move the industry in a direction that will allow for customers, investors, and the U.S. economy to benefit and prosper.

Revising utility tariff structures, particularly in states with potential for high DER adoption, to mitigate (or eliminate) cross subsidies and provide proper customer price signals will support economic implementation of DER while limiting stress on non-DER participants and utility finances. This is a near-term, must-consider action by all policy setting industry stakeholders.

The electric utility sector will benefit from proactive assessment and planning to address disruptive challenges. Thirty year investments need to be made on the basis that they will be recoverable in the future in a timely manner. To the extent that increased risk is incurred, capital deployment and recovery mechanisms need to be adapted accordingly. The paper addresses possible strategic responses to competitive threats in order to protect investors and capital availability. While the paper does not propose new business models for the industry to pursue to address disruptive challenges in order to protect investors and retain access to capital, it does highlight several of the expectations and objectives of investors, which may lead to business model transformation alternatives.

Background

As a result of a confluence of factors (i.e., technological innovation, public policy support for sustainability and efficiency, declining trends in electricity demand growth, rising price pressures to maintain and upgrade the U.S. distribution grid, and enhancement of the generation fleet), the threat of disruptive forces (i.e., new products/markets that replace existing products/markets) impacting the utility industry is increasing and is adding to the effects of other types of disruptive forces like declining sales and end-use efficiency. While we cannot lay out an exact roadmap or timeline for the impact of potential disruptive forces, given the current shift in competitive dynamics, the utility industry and its stakeholders must be prepared to address these challenges in a way that will benefit customers, long-term economic growth, and investors. Recent business history has provided many examples of companies and whole industries that either failed or were slow to respond to disruptive forces and suffered as a result.

Today, a variety of disruptive technologies are emerging that may compete with utility-provided services. Such technologies include solar photovoltaics (PV), battery storage, fuel cells, geothermal energy systems, wind, micro turbines, and electric vehicle (EV) enhanced storage. As the cost curve for these technologies improves, they could directly threaten the centralized utility model. To promote the growth of these technologies in the near-term, policymakers have sought to encourage disruptive competing energy sources through various subsidy programs, such as tax incentives, renewable portfolio standards, and net metering where the pricing structure of utility services allows customers to engage in the use of new technologies, while shifting costs/lost revenues to remaining non-participating customers.

In addition, energy efficiency and DSM programs also promote reduced utility revenues while causing the utility to incur implementation costs. While decoupling recovery mechanisms, for example, may support recovery of lost revenues and costs, under/over recovery charges are typically imposed based on energy usage and, therefore, adversely impact non-participants of these programs. While the financial community is generally quite supportive of decoupling to capture lost revenues, investors have not delved into the long-term business and financial impact of cross subsidization on future customer rates inherent in most decoupling models and the effective recovery thereof. In other words, will non–DER participants continue to subsidize participants or will there be political pressure to not allow cost pass thru over time?

The threat to the centralized utility service model is likely to come from new technologies or customer behavioral changes that reduce load. Any recovery paradigms that force cost of service to be spread over fewer units of sales (i.e., kilowatt-hours or kWh) enhance the ongoing competitive threat of disruptive alternatives. While the cost--recovery challenges of lost load can be partially addressed by revising tariff structures (such as a fixed charge or demand charge service component), there is often significant opposition to these recovery structures in order to encourage the utilization of new technologies and to promote customer behavior change.

But, even if cross-subsidies are removed from rate structures, customers are not precluded from leaving the system entirely if a more cost-competitive alternative is available (e.g., a scenario where efficient energy storage combined with distributed generation could create the ultimate risk to grid viability). While tariff restructuring can be used to mitigate lost revenues, the longer-term threat of fully exiting from the grid (or customers solely using the electric grid for backup purposes) raises the potential for irreparable damages to revenues and growth prospects. This suggests that an old-line industry with 30-year cost recovery of investment is vulnerable to cost-recovery threats from disruptive forces.

Generators in organized, competitive markets are more directly exposed to threats from new technologies and enhanced efficiency programs, both of which reduce electricity use and demand. Reduced energy use and demand translate into lower prices for wholesale power and reduced profitability. With reduced profitability comes less cash flow to invest and to support the needs of generation customers. While every market-driven business is subject to competitive forces, public policy programs that provide for subsidized growth of competing technologies and/or participant economic incentives do not provide a level playing field upon which generators can compete fairly against new entrants. As an example, subsidized demand response programs or state contracted generation additions create threats to the generation owner (who competes based upon free market supply and demand forces).

According to the Solar Electric Power Association (SEPA), there were 200,000 distributed solar customers (aggregating 2,400 megawatts or MW) in the United States as of 2011. Thus, the largest near-term threat to the utility model represents less than 1 percent of the U.S. retail electricity market. Therefore, the current level of activity can be “covered over” without noticeable impact on utilities or their customers. However, at the present time, 70 percent of the distributed activity is concentrated within 10 utilities, which obviously speaks to the increased risk allocated to a small set of companies. As previously stated, due to a confluence of recent factors, the threat to the utility model from disruptive forces is now increasingly viable. One prominent example is in the area of distributed solar PV, where the threats to the centralized utility business model have accelerated due to:

- The decline in the price of PV panels from $3.80/watt in 2008 to $0.86/watt in mid-2012[1]. While some will question the sustainability of cost-curve trends experienced, it is expected that PV panel costs will not increase (or not increase meaningfully) even as the current supply glut is resolved. As a result, the all-in cost of PV solar installation approximates $5/watt, with expectations of the cost declining further as scale is realized;
- An increase in utility rates such that the competitive price opportunity for PV solar is now “in the market” for approximately 16 percent of the U.S. retail electricity market where rates are at or above $0.15/kWh[2]. In addition, projections by PV industry participants suggest that the “in the money” market size will double the share of contestable revenue by 2017 (to 33 percent, or $170 billion of annual utility revenue);
- Tax incentives that promote specific renewable resources, including the 30-percent Investment Tax Credit (ITC) that is effective through 2016 and five-year accelerated depreciation recovery of net asset costs;
- Public policies to encourage renewable resource development through Renewable Portfolio Standards (RPS), which are in place in 29 states and the District of Columbia and which call for renewable generation goals within a state’s energy mix;
- Public policies to encourage net metering, which are in effect in 43 states and the District of Columbia (3 additional states have utilities with voluntary net metering programs) and which typically allow customers to sell excess energy generated back to the utility at a price greater than the avoided variable cost[3];
- Time-of-use rates, structured for higher electric rates during daylight hours, that create incentives for installing distributed solar PV, thereby taking advantage of solar benefit (vs. time-of-use peak rates) and net metering subsidies; and

[1] Source: Bloomberg New Energy Finance, *Solar Module Price Index*
[2] Source: Energy Information Agency, *Electricity Data Overview*
[3] Source: Database for State Incentives for Renewables and Efficiency, www.dsireusa.org

- The evolution of capital markets' access to businesses that leverage the dynamics outlined above to support a for-profit business model. Examples include tax equity financing, project finance lending, residential PV leasing models (i.e., "no money down" for customers), and public equity markets for pure play renewable resource providers and owners. As an illustration, U.S. tax equity investment is running at $7.5 billion annualized for 2012.[4] Add other sources of capital, including traditional equity, and this suggests the potential to fund a large and growing industry.

Bloomberg New Energy Finance (BNEF) projects that distributed solar capacity will grow rapidly as a result of the competitive dynamics highlighted. BNEF projects 22-percent compound annual growth in PV installations through 2020, resulting in 30 gigawatts (GW) of capacity overall (and approximately 4.5 GW coming from distributed PV). This would account for 10 percent of capacity in key markets coming from distributed resources and even a larger share of year-round energy generated.

Assuming a decline in load, and possibly customers served, of 10 percent due to DER with full subsidization of DER participants, the average impact on base electricity prices for non-DER participants will be a 20 percent or more increase in rates, and the ongoing rate of growth in electricity prices will double for non-DER participants (before accounting for the impact of the increased cost of serving distributed resources). The fundamental drivers previously highlighted could suggest even further erosion of utility market share if public policy is not addressed to normalize this competitive threat.

While the immediate threat from solar PV is location dependent, if the cost curve of PV continues to bend and electricity rates continue to increase, it will open up the opportunity for PV to viably expand into more regions of the country. According to ThinkEquity, a boutique investment bank, as the installed cost of PV declines from $5/watt to $3.5/watt (a 30-percent decline), the targeted addressable market increases by 500 percent, including 18 states and 20 million homes, and customer demand for PV increases by 14 times. If PV system costs decline even further, the market opportunity grows exponentially. In addition, other DER technologies being developed may also pose additional viable alternatives to the centralized utility model.

Due to the variable nature of renewable DER, there is a perception that customers will always need to remain on the grid. While we would expect customers to remain on the grid until a fully viable and economic distributed non-variable resource is available, one can imagine a day when battery storage technology or micro turbines could allow customers to be electric grid independent. To put this into perspective, who would have believed 10 years ago that traditional wire line telephone customers could economically "cut the cord?"

The cost of providing interconnection and back-up supply for variable resources will add to the utility cost burden. If not properly addressed in the tariff structure, the provision of these services will create additional lost revenues and will further challenge non-DER participants in terms of being allocated costs incurred to serve others.

Another outcome of the trend of rising electricity prices is the potential growth in the market for energy efficiency solutions. Combining electricity price trends, customer sustainability objectives, and ratemaking incentives via cross-subsidies, it is estimated that spending on energy efficiency programs will increase by as much as 300 percent from 2010 to 2025, within a projected range of $6 to $16 billion per year[5]. This level of

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[4] Source: Bloomberg New Energy Finance, *Renewable Energy-Research Note*, July 18, 2012

[5] Source: Lawrence Berkeley National Laboratory, *The Future of Utility Funded Energy Efficiency Programs in the United States: Projected Spending and Savings 2010 to 2025*, January 2013

spending on energy efficiency services will have a meaningful impact on utility load and, thus, will create significant additional lost revenue exposure.

The financial implications of these threats are fairly evident. Start with the increased cost of supporting a network capable of managing and integrating distributed generation sources. Next, under most rate structures, add the decline in revenues attributed to revenues lost from sales foregone. These forces lead to increased revenues required from remaining customers (unless fixed costs are recovered through a service charge tariff structure) and sought through rate increases. The result of higher electricity prices and competitive threats will encourage a higher rate of DER additions, or will promote greater use of efficiency or demand-side solutions.

Increased uncertainty and risk will not be welcomed by investors, who will seek a higher return on investment and force defensive-minded investors to reduce exposure to the sector. These competitive and financial risks would likely erode credit quality. The decline in credit quality will lead to a higher cost of capital, putting further pressure on customer rates. Ultimately, capital availability will be reduced, and this will affect future investment plans. The cycle of decline has been previously witnessed in technology-disrupted sectors (such as telecommunications) and other deregulated industries (airlines).

Disruptive Threats—Strategic Considerations

A disruptive innovation is defined as "an innovation that helps create a new market and value network, and eventually goes on to disrupt an existing market and value network (over a few years or decades), displacing an earlier technology. The term is used in business and technology literature to describe innovations that improve a product or service in ways that the market does not expect, typically first by designing for a different set of consumers in the new market and later by lowering prices in the existing market."

Disruptive forces, if not actively addressed, threaten the viability of old-line exposed industries. Examples of once-dominant, blue chip companies/entities being threatened or succumbing to new entrants due to innovation include Kodak and the U.S. Postal Service (USPS). For years, Kodak owned the film and related supplies market. The company watched as the photo business was transformed by digital technology and finally filed for bankruptcy in 2012.

Meanwhile, the USPS is a monopoly, government-run agency with a mission of delivering mail and providing an essential service to keep the economy moving. The USPS has been threatened for decades by private package delivery services (e.g., UPS and FedEx) that compete to offer more efficient and flexible service. Today, the primary threat to USPS' viability is the delivery of information by email, including commercial correspondence such as bills and bill payments, bank and brokerage statements, etc. Many experts believe that the USPS must dramatically restructure its operations and costs to have a chance to protect its viability as an independent agency.

Participants in all industries must prepare for and develop plans to address disruptive threats, including plans to replace their own technology with more innovative, more valuable customer services offered at competitive prices. The traditional wire line telephone players, including AT&T and Verizon, for example, became leaders in U.S. wireless telephone services, which over time could make the old line telephone product extinct. But these innovative, former old-line telephone providers had the vision to get in front of the trend to wireless and lead the development of non-regulated infrastructure networks and consumer marketing skills. As a result, they now hold large domestic market shares. In fact, they have now further leveraged technology innovation to create new products that expand their customer offerings.

The electric utility sector has not previously experienced a viable disruptive threat to its service offering due customer reliance and the solid economic value of its product. However, a combination of technological innovation, public/regulatory policy, and changes in consumer objectives and preferences has resulted in distributed generation and other DER being on a path to becoming a viable alternative to the electric utility model. While investors are eager to support innovation and economic progress, they do not support the use of subsidies to attack the financial viability of their invested capital. Utility investors may not be opposed to DER technologies, but, in order for utilities to maintain their access to capital, it is essential that the financial implications of DER technologies be addressed so that non-DER participants and investors are not left to pay for revenues lost (and costs unrecovered) from DER participants.

Finance 101 - Introduction to Corporate Finance

Investors allocate investment capital to achieve their financial objectives consistent with their tolerance for risk and time horizon. Fixed-income (i.e., bond) investors seek certainty as to (investment) returns through a guarantee by the debt issuer of timely payment of principal and interest. Equity investors seek a higher expected return than debt investors and, accordingly, must accept increased risk. “Expected” return refers to the distinction that equity investor returns are not guaranteed; therefore, equity investors bear a higher level of risk than bondholders. The expected return on equity investment is realized through a combination of dividends received and expected growth in value per share (which is achieved through a combination of growth in earnings and dividends and/or a rerating of return expectations as a result of investment market forces).

Corporate financial objectives focus on enhancing shareholder value through achieving long-term growth consistent with the preservation of the corporate entity. Corporations develop financial policies to support the access to capital to achieve their business plans. For utilities, these financial policies are consistent with investment-grade credit ratings. Since practically all utilities have an ongoing need for capital to fund their capital expenditure programs, the industry has developed financial policies intended to support the access to relatively low-cost capital in (practically) all market environments. Under traditional cost-of-service ratemaking, customers benefit through lower cost of service and, therefore, lower rates.

In order to retain the financial flexibility required to maintain investment-grade credit ratings, the rating agencies prefer policies that promote the retention of corporate cash flow and provide a liquidity cushion to support fixed obligations. Prudent corporate financial management disdains significant fixed commitments to investors—since such commitments limit management flexibility and increase capital-access dependency and risk. While paying dividends to equity investors is not a legal obligation, the rating agencies and investors view dividends as a moral (or intended) obligation that management will not reduce unless it has no viable alternative to preserve long-term corporate value. The corporate financial objective of retaining cash from operations to support credit quality limits the potential to pay dividends to investors. Thus, growth of investment value is required by equity investors (as discussed above) to achieve return expectations warranted by the increased risk taken and investment return expectations relative to fixed income investors.

It is important to highlight that the rating agencies’ rating criteria and associated target corporate credit metrics reflect the credit risk of the industry environment of the corporation being rated. Thus, due to the benefits of a stable regulatory environment, utilities are able to maintain (for a given rating category) significantly more debt relative to cash flow than competitive industries. However, if business risks were to increase for utilities in the future, as we will discuss in the next sections, it would be likely that utility debt leverage (i.e., debt relative to cash flow) would need to be reduced in order to retain credit ratings.

Stable, mature industries—those that have a proven product, stable product demand, and low volatility related to their revenues and cash flow (the "defensive industries")—are attractive to investors as they offer more certainty and fewer business and financial risks. As a result, investors in these stable, defensive industries (such as utilities) will require a lower expected return compared to investors in less mature and more volatile industries. We describe this lower expected return requirement as a lower cost of capital. This lower cost of capital associated with defensive industries is manifested in lower borrowing costs and higher relative share values. In addition, in difficult financial market environments (such as we experienced in October 2008 through March 2009), these stable businesses typically experience less adverse stock price impact due to investors fleeing in order to reduce risk. Thus, in difficult markets, mature companies have demonstrated ongoing financial market access (investor demand) when those in other industries have not. This is the benefit (or the "insurance policy") of an investment-grade credit rating—lower capital costs and more stable access to capital despite market conditions.

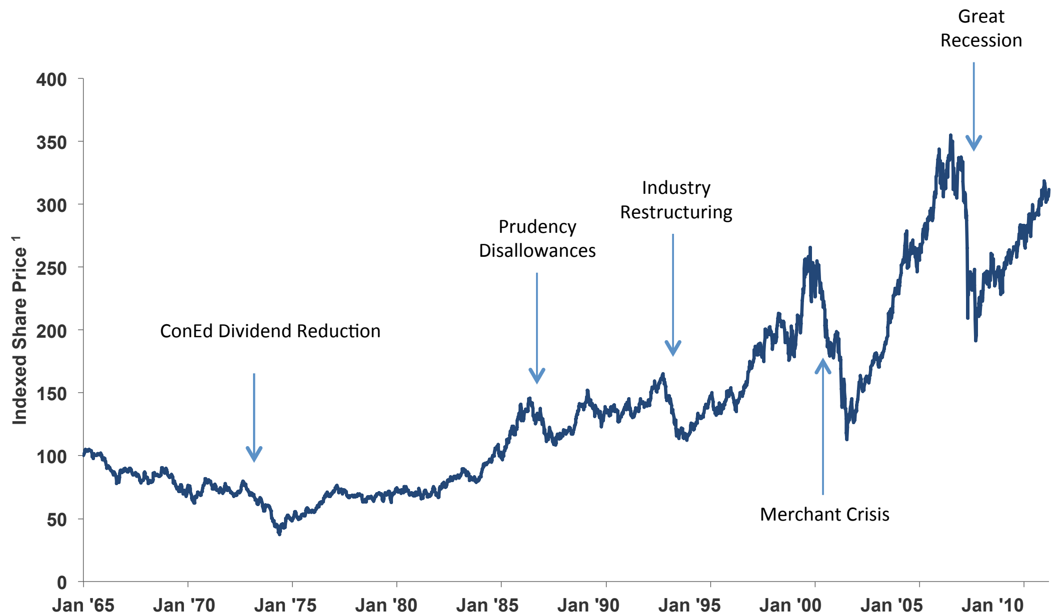
The benefit to customers of cost-of-service rate-regulated utilities is that a lower cost of capital contributes to lower utility rates. Also of importance, but often taken for granted, is the comfort that comes with knowing that utilities will have capital access to support the reliability and growth needs of their service territories and, thus, will not adversely expose customer service needs, including customer growth plans.

Finance 201 - Financial Market Realities

With the exception of a very few periods over the past century, utilities have experienced unfettered access to relatively low-cost capital. Even during challenging financial market environments when many industries have been effectively frozen from capital access, utilities have been able to raise capital to support their business plans. The primary reason for the markets' willingness to provide capital to the utility sector is the confidence that investors place in the regulatory model, particularly the premise that utilities will be awarded the opportunity to earn a fair return on investor capital investment.

However, at times of regulatory model uncertainty, we have seen the financial markets punish utility securities. Examples of periods of investor uncertainty would include the timeframe post the 1973 oil embargo, which was prior to the enactment of fuel adjustment clauses for purchased power; the nuclear power plant abandonments and cost disallowances of the 1980s that led to multiple bankruptcies and financial distress for quite a few utilities; the PURPA cost fallout of the 1990s; and the post-Enron bankruptcy collapse of the merchant power sector in the early 2000s, which challenged merchant energy providers and heavily exposed utility counterparties. These events led to bankruptcies, longstanding financial distress for impacted utilities, and ongoing erosion in credit quality and investor confidence. These examples highlight that regulated businesses are vulnerable to risks related to business model changes, economic trends and regulatory policy changes. When investors focus on these issues as being material risks, the impact on investors and capital formation can be significant.

Exhibit 1
Dow Jones Utility Index: 1965-2012



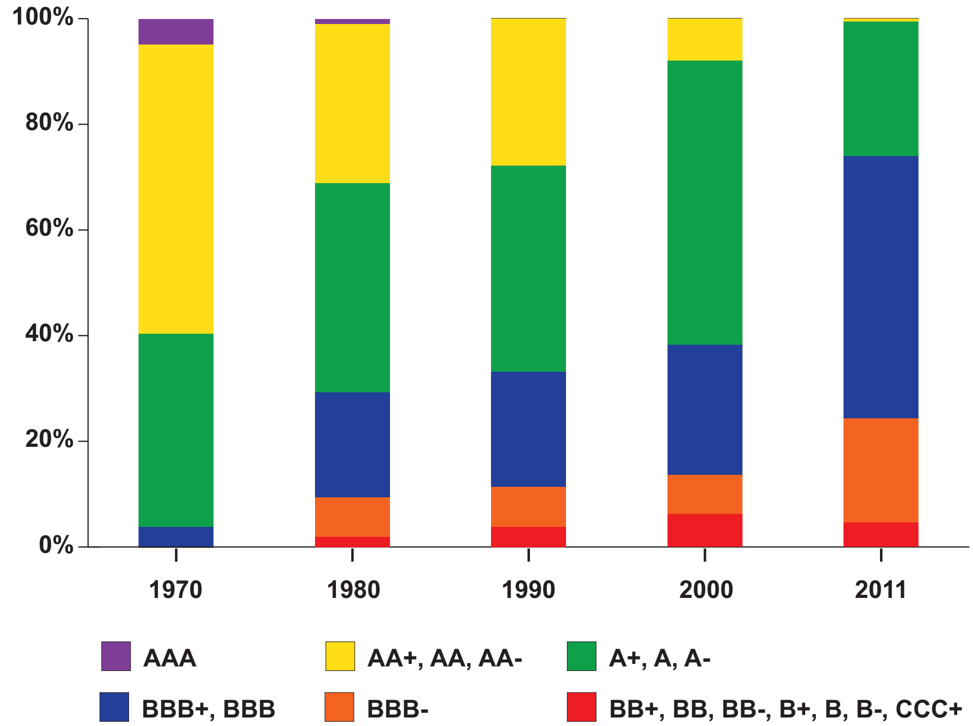
(1) Indexed to 1/2/1970 price

Source: Bloomberg

Prior to the 1980s, the utility sector was dominated by "AA" credit ratings. Power supply-side cost pressures, declining economic and customer growth trends, inflation in cost-of-service provision, and an evolving industry and regulatory model have resulted in steady erosion in credit quality over each of the last five decades. (See Exhibit 2 for a credit-rating history of the electric utility sector.) Investors responded to these periods of significant industry challenge with a rethink of their "blind" faith in the regulatory model and became more focused on company selection as they approached investment strategy. But, for the most part, as utilities and regulation adjusted to political, regulatory, and economic challenges, investor faith in the regulatory model has been restored.

After five decades of decline in industry credit quality, a potential significant concern now is that new competitive forces, which have not been a concern of investors to date, will lead to further credit erosion. The industry cannot afford to endure significant credit quality erosion from current ratings levels without threatening the BBB ratings that are held by the majority of the industry today. Non-investment grade ratings would lead to a significant rerating of capital costs, credit availability, and investor receptivity to the sector. The impact on customers would be dramatic in terms of increased revenue requirements (i.e., the level of revenues required for a utility to cover its operating costs and earn its allowed cost of capital), customer rates, and reduction in the availability of low-cost capital to enhance the system.

Exhibit 2
Electric utility industry credit ratings distribution evolution
(S&P Credit Ratings Distribution, U.S. Shareholder-Owned Electric Utilities)



Source: Standard & Poor's, Macquarie Capital

As we look at the electric utility sector today, investors, for the most part, remain confident that the regulatory model will be applied fairly to provide them with the opportunity to earn a reasonable and fair return on their investment. Those states that have experienced prior upheavals in their regulatory model (e.g., California) have had to tighten their approach to regulatory cost recovery to convince investors that past problems have been addressed. If a state has not been as receptive to addressing its approach to past problems, then investors will be highly reticent to deploy capital in those jurisdictions.

In reviewing recent sector research reports, the majority of security analysts continue to project future earnings levels based on assumed capital-investment levels and projected costs of capital (a bottoms-up approach). While analysts acknowledge that each rate case carries some degree of uncertainty, there appears to be limited focus in their analysis on service area quality, competitiveness of customer pricing, and the drivers for future service territory growth. No other significant industry is analyzed by Wall Street on a bottoms-up basis; the basis for analysis of non-utility industries is competitive position, sales prospects, and sales margins. In addition, the threat of disruptive forces is given no (or almost no) printed lines in utility sector research. This approach to investment analysis is based upon confidence in utilities' ability to earn a fair return on prudent investment. But, it may expose investors to the future economic risks posed by rapid growth in DER. What will happen as technological advancement in the utility sector provides customers with viable competitive alternatives?

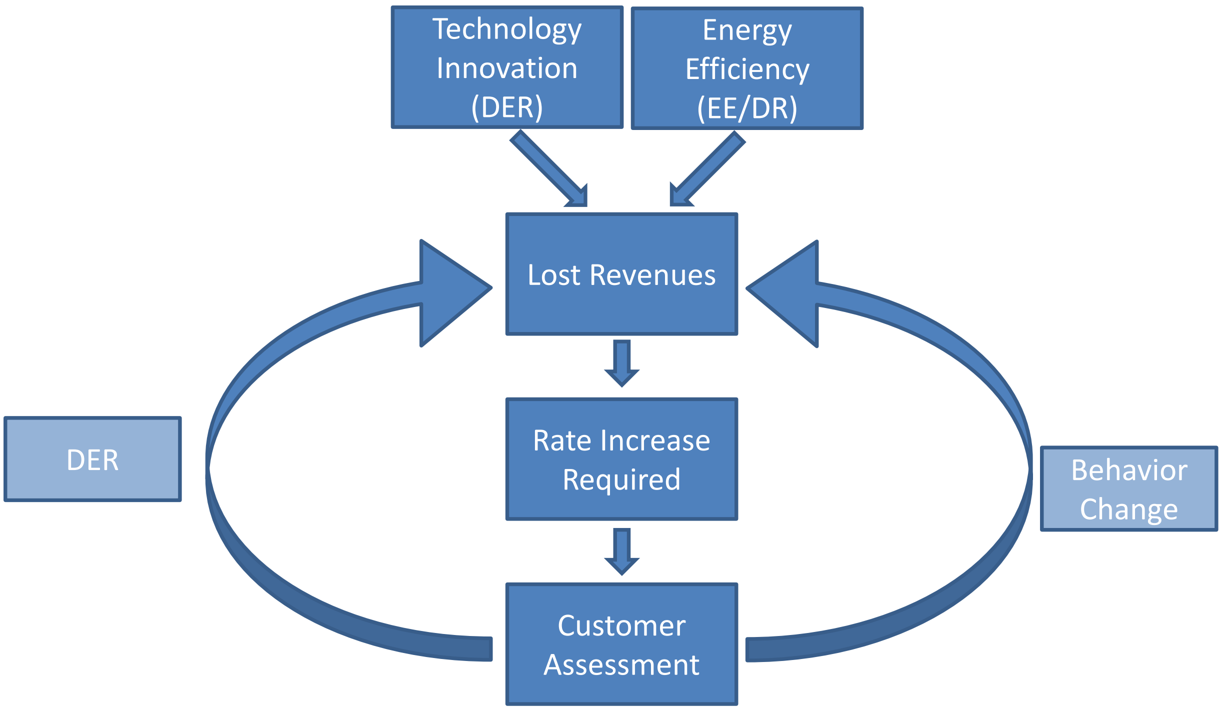
Finance 501 - Financial Implications of Disruptive Forces

As discussed previously, equity investors expect and will value an equity security based upon growth attributes as a major component of the expected total return investors require. Growth in utility earnings has historically been realized by a combination of increased electricity sales (volume), increased price per unit of sales (higher rates), and/or expanded profit margins on incremental revenues achieved between rate cases reflecting the realization of operational/overhead efficiencies. Earnings levels and growth are also impacted by changing costs of capital due to market forces—this is currently a depressant on utility earnings per share (EPS) levels due to the sector-wide decline in authorized returns on equity (ROE) realized over the last several years.

First, let's review the current climate for the utility sector. While valuations are near all-time highs, the headwinds facing the sector are significant. Concerns start with the anemic electricity demand, which has been primarily impacted by the overall economic climate but also impacted by demand-side efficiency programs and the emergence of DER. Next, there is the need to deploy capital investment at almost twice the rate of depreciation to enhance the grid and address various regulatory mandates. Soft electricity demand plus increasing capital investment lead to rate increase needs and the investment uncertainty created by a future active rate case calendar. While sell side analysts are expecting EPS growth of 4 percent to7 percent overall for the regulated sector, this is likely to be quite challenging. If investor expectations are not realized, a wholesale reevaluation of the sector is likely to occur.

So, what will happen when electricity sales growth declines and that decline is not cyclical but driven by disruptive forces, including new technology and/or the further implementation of public policy focused on DSM and DER initiatives? In a cost-of-service rate-regulated model, revenues are not directly correlated to customer levels or sales but to the cost of providing service. However, in most jurisdictions, customer rates are a function of usage/unit sales. In such a model, customer rate levels must increase via rate increase requests when usage declines, which from a financial perspective is intended to keep the company whole (i.e., earn its cost of capital). However, this may lead to a challenging cycle since an increase in customer rates over time to support investment spending in a declining sales environment (due to disruptive forces) will further enhance the competitive dynamics of competing technologies and supply/demand efficiency programs. This set of dynamics can become a vicious cycle (See Exhibit 3) that, in the worst-case scenario, would leave few(er) customers remaining to support the costs of a large embedded infrastructure system, some of which may be stranded investment but most of the costs will continue to be incurred in order to manage the flows between supply and customers.

Exhibit 3
Vicious Cycle from Disruptive Forces



When investors realize that a business model has been stung by systemic disruptive forces, they likely will retreat. When is the typical tipping point when investors realize that the merits of the investment they are evaluating or monitoring has been forever changed? Despite all the talk about investors assessing the future in their investment evaluations, it is often not until revenue declines are reported that investors realize that the viability of the business is in question.

An interesting example is the story of RIM, the manufacturer of the Blackberry handheld information management tool. From its public start in the 1990s thru 2008, RIM was a Wall Street darling. Its share price was less than \$3 in 1999 and peaked at \$150 in 2008. The company started to show a stall in sales in 2011, and, now, despite a large cash position and 90 million subscribers, the market is questioning RIM's ability to survive and RIM's stock has plummeted from its high.

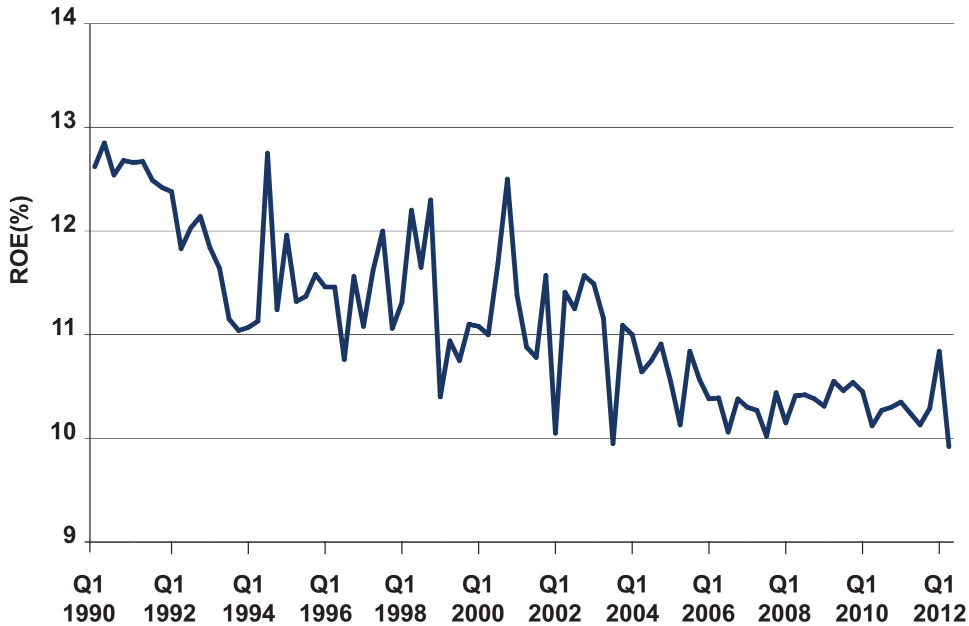
What happened to this powerful growth company that had dominant market shares in a growth market? The answer is the evolution of the iPhone, which transformed the handheld from an email machine to a dynamic Internet tool with seemingly unlimited applications/functionality. When the iPhone was first released in 2007, it was viewed as a threat to RIM, but RIM continued to grow its position until the introduction of the iPhone 4 in June 2010. The iPhone 4, which offered significant improvements from prior versions, led to a retreat in RIM's business and caused a significant drop in its stock price.

It seems that investors have proven to be reasonably optimistic on selected industries even though the competitive threat is staring them head-on. However, if we can identify actionable disruptive forces to a business or industry, then history tells us that management and investors need to take these threats seriously and not wait until the decline in sales and revenues has commenced to develop a new strategy or, in the case of investors, realize their loss.

As discussed above, investors in the utility sector seek increased certainty (or less risk) than in other industries and have confidence in the consistent application of ratemaking recovery models to provide a lower degree of investment risk. As a result of this confidence, when instances have occurred in the past that have not provided consistent application of expected cost recovery models, investors have responded and have caused significant adverse impact on entities' ability to raise incremental capital. But, with the exception of the California energy crisis in the early 2000s, these events reflected embedded cost issues that had defined exposures and time frames. Disruptive changes are a new type of threat to the electric utility industry. Disruptive changes lead to declining customer and usage per customer levels that cannot be easily quantified as to the potential threat posed to corporate profitability. This type of problem has not been faced before by the electric industry and, thus, must be understood as to the strategic issues and alternatives that are raised.

The new potential risk to utility investors from disruptive forces is the impact on future earnings growth expectations. Lost revenues within a net metering paradigm, for instance, are able to be recovered in future rate cases. However, without a shift in tariff structures, there is only so much of an increase that can be placed on remaining non-DER customers before political pressure is brought to bear on recovery mechanisms. Once the sustainability of the utility earnings model is questioned, investors will look at the industry through a new lens, and the view from this lens will be adverse to all stakeholders, including investors and customers. While we do not know the degree to which customer participation in DER and behavior change will impact utility earnings growth, the potential impact, based upon DER trends, is considerable (as stated earlier, industry projections propose that 33 percent of the market will be in the money for DER by 2017, assuming current tax and regulatory policies). Today, regulated utilities have seen allowed returns on equity decline to around 10 percent, a multi-decade low point, as a result of declining interest rates (See Exhibit 4). The cost of equity has also been growing. However, the risks in the business have never been higher, due to increasing customer rate pressures from capital expenditures required to upgrade the grid and address environmental mandates, inflation, low/negative demand growth from active customers, and the threat of load lost due to the rapid development of DER and disruptive forces. The impact of declining allowed returns and increasing business risk will place pressure on the quality and value of utility investments. How large of an impact on investment value will be a function of the impact of disruptive forces described herein. But, lower stock prices will likely translate into lower levels of capital spend, lower domestic economic growth, and fewer grid enhancements.

Exhibit 4
History of Allowed ROE's (U.S. Shareholder-Owned Electric Utilities)
(Based on regulatory cases **settled** each quarter)



Source: SNL Financial/Regulatory Research Associates (RRA), EEI Rate Department

Telephone Industry Parallels

There are other examples in other industries that can provide lessons as to the risks of disruptive change confronting the U.S. electric utility industry. The once fully regulated, monopoly telephone industry provides one clear example. The telephone industry experienced significant technological changes that led to deregulation—initially in the long-distance sector and then followed by the local exchange market.

Beginning in the 1970s, the impact of an array of new technologies (e.g., satellite, microwave, and fiber optic technologies) led to increased telephone system capacity and a reduction in the cost of providing telephone service. These technological changes provided the opportunity for competition by new entrants using newer technologies, while the monopoly service provided by AT&T used older analog technology. In 1974, MCI, a new entrant, filed an anti-trust case challenging AT&T's monopoly powers in long-distance telephone service. The U.S. government ruled against AT&T in 1982, which led to a negotiated plan to break up the Bell system, which was completed in 1984. As a result, long-distance telephone service and the Bell Labs' research arms were housed in AT&T. The local provision of phone service (i.e., intrastate regional calls) was to remain regulated and was to be provided by seven Bell Operating Companies ("the Baby Bells"). By 1996, the Telecommunications Act opened the local telephone market to competition and allowed for Internet providers to acquire spectrum services.

Dramatic technological change has evolved over the past 35 years, which has led to the development of a new infrastructure system; new services that are providing abundant transfer of information; and the convergence of voice, data, and entertainment into one combined service from what had previously been viewed as separate and distinct services and industries. Today, the number of customers who utilize the previously exclusive "copper wire "telephone system represents a rapidly declining percentage of the market for telephone services. (Verizon Communications, for example, has lost approximately 45 percent of its wire line customers over the past five years.) Today, many customers access voice services exclusively through mobile cellular (wireless) phones, a technology that became commercially viable in the mid- to late-1980s. In addition, the advent of cable-based phone service has sped the decline in copper-based services.

This transformation in the telephone sector of pre-1982 to today has not been smooth or easy. Significant capital investment has been made to develop new technologies and related infrastructure—it is estimated of that more than $300 billion has been deployed to build out new telephone infrastructure. New entrants have experienced booms and busts as the supply of capacity outstripped demand, leading to bankruptcies and mergers. The original AT&T, the seven Baby Bells, and several large independent monopolies (e.g., GTE, Citizens, United Telephone and Alltel) have merged into four independent companies. The sector today is dominated by wireless and cable-based technologies.

Exhibit 5
Verizon Stock Price vs. S&P500 from 2000 to 2012

Source: FactSet

There are important lessons to be learned from the history of the telephone industry. First, at the onset of the restructuring of the Bell System, there was no vision that the changes to come would be so radical in terms of the services to be provided and the technologies to be deployed. Second, the telephone players acted boldly to consolidate to gain scale and then take action to utilize their market position to expand into new services on a national scale. Finally, and most important, if telephone providers had not pursued new technologies and the transformation of their business model, they would not have been able to survive as viable businesses today. So, while the sector has underperformed the overall market since 2000, and as shown in Exhibit 5, even a leading industry participant like Verizon Communications has not been able to perform in-line with the overall market despite its growth, market share and solid profitability outlook due to the competitive uncertainties inherent in the business. However, those telecom providers that have embraced new technologies and addressed the competitive threats they faced have managed to survive and to protect investors from a "Kodak moment."

Exhibit 6
Credit Capacity of Regulated vs. Competitive Industries

Sector/Segment	Enterprise Value ($bn)	Credit Ratings		Credit Quality Metrics	
		Moody's	S&P	FFO/Debt	Debt/EBITDA
Regulated Utilities					
Southern Company	$63	Baa1	A	25%	3.5x
ConEd	27	Baa1	A-	25%	3.3x
Xcel Energy	24	Baa1	A-	23%	3.8x
Hybrid Utilities					
Exelon Corp	48	Baa2	BBB	55%	3.1x
PSEG Resources	23	Baa2	BBB	38%	2.3x
Telephone					
AT&T	266	A2	A-	54%	2.1x
Verizon Communications	222	A3	A-	63%	1.9x

	DDM COE [1]	Debt / EBITDA	Implied Debt / Capital	Pre-Tax WACC
Regulated Entity	10%	3.5	50%	10.20%
Competitive Telco	12%	2	34%	13.80%
Competitive Sector Cost Premium				3.60%
% Change in WACC				35.00%

(1) "DDM COE" is dividend discount model cost of equity

From being led by a "AAA" rated company with monopoly powers (AT&T), the telecommunications industry looks very different today. Services today are often comprised of a bundle of telephone, Internet, and entertainment options provided on an unlimited basis by a monthly fee (relative to usage-based pricing prior to 1982). The market has seen significant new entrants, capital investment, and boom and bust periods leading to bankruptcies and/or mergers to enhance scale. Due to the increased competitive business risk, the credit-rating agencies have downgraded the credit rating of AT&T from "AAA" in 1981 to "A "today. In addition, due to competitive business dynamics, the credit rating agencies expect to see significantly lower debt leverage (thereby, raising the overall cost of capital) in order to support the credit ratings assigned. To compare with the electric sector, a comparable rating in telecom would bear approximately 50 percent of the leverage level of a regulated electric utility—resulting in an approximately 35 percent higher pre-tax weighted cost of capital for the telephone sector based on credit-ratings metrics (See Exhibit 6).

While customers have benefitted from a proliferation of new services provided at a lower cost, investors have not done as well in financing a transition to a competitive industry. These lessons should be fully considered as stakeholders shape the approach electric utilities pursue in participating in an environment where disruptive technologies may transform the provision of services and the providers of these new services.

One significant difference between the electric sector and the telecom restructuring example is the value of the respective infrastructure following the disruptive threat. In the telecom situation, the original copper wire phone network is of no/low value in a wireless, Internet protocol, landline world. However, the value of the electric grid to the customer is retained in a distributed generation environment as the grid provides the highway to sell power generated by the DER and the back-up resource infrastructure to deliver power required when the DER is not meeting the load obligation of its provider. In essence, while a wireless user does not need a landline, an electric consumer-generator will not be able to and will not necessarily want to achieve full independence from the “wired” utility grid. So, while the telecom example is a tale of responding to the threat of obsolescence, the near-term challenge to the electric sector is providing the proper tariff design to allow for equitable recovery of revenue requirements to address the pace of non-economic sector disruption.

Strategic Implications of Distribution 2020 Disruptive Forces

The threats posed to the electric utility industry from disruptive forces, particularly distributed resources, have serious long-term implications for the traditional electric utility business model and investor opportunities. While the potential for significant immediate business impact is currently low (due to low DER participation to date), the industry and its stakeholders must begin to seriously address these challenges in order to mitigate the potential impact of disruptive forces, given the prospects for significant DER participation in the future.

One example of a significant potential adverse impact to utility investors stems from net metering. Utilities have witnessed the implementation of net metering rules in all but a handful of states. Lost revenues from DER are being recovered from non-DER customers in order to encourage distributed generation implementation. This type of lost revenue recovery drives up the prices of those non-participating customers and creates the environment for ongoing loss of additional customers as the system cost is transferred to a smaller and smaller base of remaining customers.

Utility investors are not being compensated for the risks associated with customer losses resulting from increasing DER. It is difficult to identify a rate case in which the cost-of-capital implications of net metering were considered. At the point when utility investors become focused on these new risks and start to witness significant customer and earnings erosion trends, they will respond to these challenges. But, by then, it may be too late to repair the utility business model.

DER is not the only disruptive risk the industry faces. Energy efficiency and DSM programs that promote lower electricity sales pressure earnings required to support capital investment. Without a tariff structure that properly allocates fixed vs. variable costs, any structure for lost revenues would come at a cost to non-participating customers, who will then be more motivated to find alternatives to reduce their consumption. While it is not the objective of this paper to outline new business model alternatives to address disruptive challenges, there are a number of actions that utilities and stakeholders should consider on a timely basis to align the interests of all stakeholders, while avoiding additional subsidies for non-participating customers.

These actions include:

Immediate Actions:

- Institute a monthly customer service charge to all tariffs in all states in order to recover fixed costs and eliminate the cross-subsidy biases that are created by distributed resources and net metering, energy efficiency, and demand-side resources;
- Develop a tariff structure to reflect the cost of service and value provided to DER customers, being off-peak service, back-up interruptible service, and the pathway to sell DER resources to the utility or other energy supply providers; and
- Analyze revision of net metering programs in all states so that self-generated DER sales to utilities are treated as supply-side purchases at a market-derived price. From a load provider's perspective, this would support the adoption of distributed resources on economically driven bases, as opposed to being incentivized by cross subsidies.

Longer-term Actions:

- Assess appropriateness of depreciation recovery lives based on the economic useful life of the investment, factoring the potential for disruptive loss of customers;
- Consider a stranded cost charge in all states to be paid by DER and fully departing customers to recognize the portion of investment deemed stranded as customers depart;
- Consider a customer advance in aid of construction in all states to recover upfront the cost of adding new customers and, thus, mitigate future stranded cost risk;
- Apply more stringent capital expenditure evaluation tools to factor-in potential investment that may be subject to stranded cost risk, including the potential to recover such investment through a customer hook-up charge or over a shorter depreciable life;
- Identify new business models and services that can be provided by electric utilities in all states to customers in order to recover lost margin while providing a valuable customer service—this was a key factor in the survival of the incumbent telephone players post deregulation; and
- Factor the threat of disruptive forces in the requested cost of capital being sought.

Investors have no desire to sit by and watch as disruptive forces slice away at the value and financial prospects of their investment. While the utility sector provides an important public good for customers, utilities and financial managers of investments have a fiduciary responsibility to protect the value of invested capital. Prompt action to mitigate lost revenue, while protecting customers from cross-subsidization better aligns the interests of customers and investors.

As growth in earnings and value is a major component of equity investment returns, what will investors expect to see as a strategic response from the industry to disruptive forces? The way to realize growth in earnings is to develop profit streams to counterbalance the impact of disruptive forces. Examples of new profit sources would include ownership of distributed resources with the receipt of an ongoing service fee or rate basing the investment and financial incentives for utilities to encourage demand side/energy efficiency benefits for customers. From an investor perspective, this may be easier said than done because the history of the electric utility industry in achieving non-regulated profits/value creation streams has not been a pleasant experience. So, investors will want to see very clear cut programs to capture value that are consistent with the core strengths of utilities: ability to execute construction projects, to provide dependable service with high reliability, and to access relatively low-cost capital.

Summary

While the threat of disruptive forces on the utility industry has been limited to date, economic fundamentals and public policies in place are likely to encourage significant future disruption to the utility business model. Technology innovation and rate structures that encourage cross subsidization of DER and/or behavioral modification by customers must be addressed quickly to mitigate further damage to the utility franchise and to better align interests of all stakeholders.

Utility investors seek a return on investment that depends on the increase in the value of their investment through growth in earnings and dividends. When customers have the opportunity to reduce their use of a product or find another provider of such service, utility earnings growth is threatened. As this threat to growth becomes more evident, investors will become less attracted to investments in the utility sector. This will be manifested via a higher cost of capital and less capital available to be allocated to the sector. Investors today appear confident in the utility regulatory model since the threat of disruptive forces has been modest to date. However, the competitive economics of distributed energy resources, such as PV solar, have improved significantly based on technology innovation and government incentives and subsidies, including tax and tariff-shifting incentives. But with policies in place that encourage cross subsidization of proactive customers, those not able or willing to respond to change will not be able to bear the responsibility left behind by proactive DER participating customers. It should not be left to the utility investor to bear the cost of these subsidies and the threat to their investment value.

This paper encourages an immediate focus on revising state and federal policies that do not align the interests of customers and investors, particularly revising utility tariff structures in order to eliminate cross subsidies (by non-DER participants) and utility investor cost-recovery uncertainties. In addition, utilities and stakeholders must develop policies and strategies to reduce the risk of ongoing customer disruption, including assessing business models where utilities can add value to customers and investors by providing new services.

While the pace of disruption cannot be predicted, the mere fact that we are seeing the beginning of customer disruption and that there is a large universe of companies pursuing this opportunity highlight the importance of proactive and timely planning to address these challenges early on so that uneconomic disruption does not proceed further. Ultimately, all stakeholders must embrace change in technology and business models in order to maintain a viable utility industry.

The **Edison Electric Institute (EEI)** is the association of U.S. shareholder-owned electric companies. Our members serve 95% of the ultimate customers in the shareholder-owned segment of the industry, and represent approximately 70% of the U.S. electric power industry. We also have as Affiliate members more than 80 International electric companies, and as Associate members more than 200 industry suppliers and related organizations.

Organized in 1933, EEI works closely with all of its members, representing their interests and advocating equitable policies in legislative and regulatory arenas.

EEI provides public policy leadership, critical industry data, strategic business intelligence, one-of-a-kind conferences and forums, and top-notch products and services.

For more information on EEI programs and activities, products and services, or membership, visit our Web site at www.eei.org.

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California's Electricity Policy Future — Beyond 2020

6th Annual Climate and Energy Law Symposium

November 7, 2014

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HOOVER INSTITUTION
SHULTZ-STEPHENSON TASK FORCE ON
Energy Policy

Overview

- The Challenges We Face
- A Strategy to Maintain Forward Progress
  - 4 Proposals
- Conclusion

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SHULTZ-STEPHENSON TASK FORCE ON
Energy Policy

The Challenges We Face

- Our 2012 "Renewable and Distributed Power in California" essay identified a a number of key stresses and institutional concerns:
  - The regulatory policy maze
  - Rising utility costs and rates
  - Outdated rate design and uneven cost allocation burdens among customers
  - Cumbersome regulatory framework
  - Inadequately incentivized utility business model

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Energy Policy

A Strategy to Maintain Forward Progress

- **Proposal 1: Move from Ad Hoc Collaboration to a Robust Interagency Coordinating Structure**

  – "[I]t is imperative that the state have a robust process for coordinating implementation. Increased collaboration, joint planning, and integration across agencies and goals will be required."

    Office of Planning and Research, "California @ 50 Million—Governor's Environmental Goals and Policy Report," discussion draft, September 2013.

  – "No single party or agency has complete responsibility for the energy sector . . . a reworked and comprehensive State program will be required that addresses all affected energy entities and is specifically designed to ensure that the proposed emissions are achieved."

    California Air Resources Board, "Proposed First Update to the Climate Change Scoping Plan: Building on the Framework," February 2014.

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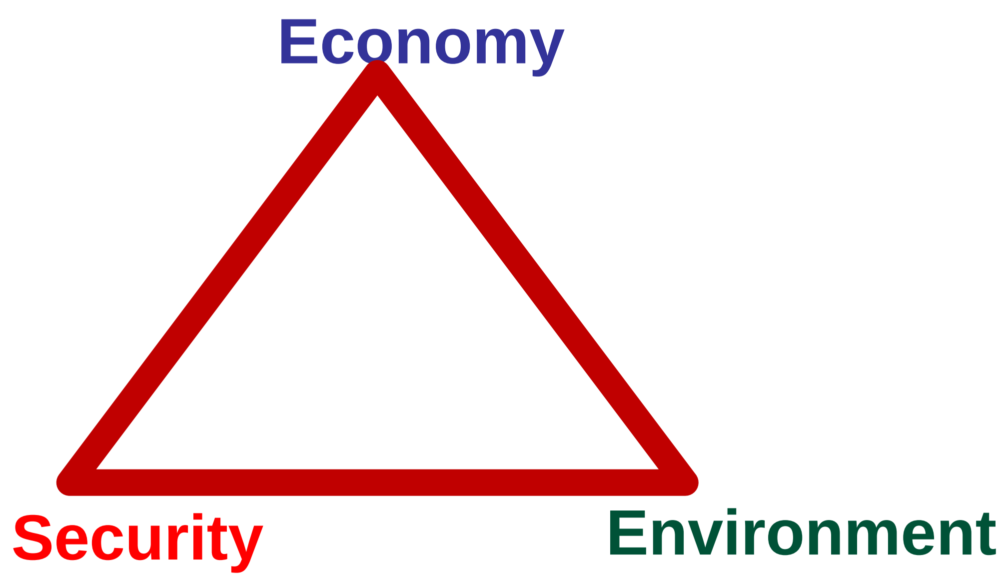
Energy Policy

A Strategy to Maintain Forward Progress (contd.)

- **Proposal 2: Develop California's Electricity Future within an Integrated Framework Focused on Thee Elements**
  - Reliability
  - Affordability
  - Sustainability



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A Strategy to Maintain Forward Progress (contd.)

- **Proposal 3: Investigate the Need for New California Electricity Analytical Capabilities through a Statewide Modeling Forum**
  - More rigorous analysis to assess costs and benefits of distributed resources
  - Understanding of potential changes due to alterations in rate structures
  - Modeling of GHG emissions in systems that include increasing levels of renewables while complying with reliability standards

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A Strategy to Maintain Forward Progress (contd.)

- **Proposal 4: Develop a 2030 Electricity Plan Integrated with 2030 Climate, Water, Air, and Transportation Goals**
  - Focus on 2030
  - Present a plan for the state's electricity transition using a framework optimizing reliability, affordability, and sustainability
  - Include specific links integrating the state's electricity future with climate, water, air quality, and transportation goals

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Conclusion

- We do not know for sure the specific challenges that may come up between now and 2050 or even 2030. But we do know that the issues and solutions will be complex and unprecedented. If we are to successfully transform California's electricity sector, we must:
  - Develop a consistent planning framework optimizing reliability, affordability, and sustainability;
  - Update and streamline regulatory governance, expand our planning capabilities; and
  - Identify our 2030 goals and develop a viable roadmap to achieve those goals.

Questions?

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Regulating Smart Grid Investments: The Illinois Path to a Modern Grid

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Regulatory Challenges of Modern Grid

- What is our conception of the grid
- POES vs Enabling
- Investment cost benefit stream
- Risk of investment differ
- Risk of cost recovery differ
- Business Model issues
- Changing Regulatory Objectives

What is the goal of grid modernization

- Reduce long term cost
- Provide reliability benefits
- Enabling consumer control

Illinois History of Policy Evolution

- 1980s Traditional Regulation
  - Intervenors come of age
  - Commission Engagement
- 1990s Deregulation
  - Utility Drives Stranded Cost Debate
  - Commissions Neutralized
- 2000's Post Transition Period
  - Return of Rate Case (procurement)
  - Public Policy Reengaged

Illinois Response to Regulatory Challenges

- Nuclear Issues- Administrative
  - Least cost planning
  - Audits
  - Benefits: DSM-load control vs EE- Usage
- High Costs of Service-Markets
  - Competition/Retail Access
  - Benefits: Giving Customers Choice
- Operationalize Choice
  - Incentives for infrastructure investment
  - AMI and grid modernization—enabling consumers

Summary- Evolution in policy response

  - Protect customer, Engage Customer, Empower Customers

Challenges Confronting Any Long term Grid Investment

- Utility Concerns-Large Capital Investments
  - Disallowances
  - Used and Useful
  - Lag in cost recovery
- Regulator Concerns/Risks
  - Cost minimization
  - Benefit maximization

Grid Investments – Regulatory Challenges

- Constraints of Cost of Service model
  - Commission Decisions to reject cost recovery
    - Rejection of Rider SMP
    - Post Test Year Adjustment
- Utility Search for Viability Cost Recovery
  - Pro Forma adjustments
  - Cost-tracking riders

Illinois Adjustment-EIMA Model

- Targeted, incremental capital improvements
- Annual formula rate update and reconciliation
- Reliability and AMI-related metrics
- Utility funding for customer education on smart meters and bill assistance programs
- A cost-beneficial plan to deploy AMI meters
- A “Smart-Grid test bed” and Technology Fund
- Opt-in market-based peak time rebate program

EIMA Model – Balancing Interests

- Floor and ceiling on incremental investments
- Projected long-term costs and benefits of AMI
- Annual reports on AMI and Investment Plans
- Financial penalties for not meeting annual metrics
- Specific protocols in the formula rate template
- Prudence and reasonableness review of delivery costs
- Annual reconciliation charge or credit
- “Collar” on earned rate of return
- Cap on average annual increase in average amount paid per kWh (supply, transmission, and distribution)
- Sunset provision (December 31, 2017)

Conclusions

- EIMA Interpretation- SB9
- ComEd Smart Grid Deployment
- Acceleration AMI plan
- Metrics Report
- ICC Imposed Additional Tracking Metrics
- Utility 2.0

Energy Consumption Data: The Key to Improved Energy Efficiency

Alexandra B. Klass*
Elizabeth J. Wilson**

INTRODUCTION

One of the overarching goals of the future energy system is to use less energy and to use it more efficiently. In order to use less energy more efficiency, the United States must use less electricity more efficiently. This is because electricity makes up 40% of total U.S. energy consumption.[1] Moreover, buildings account for 39% of total U.S. energy use and 68% of electricity use. As a result, increasing the efficiency of electricity use in buildings has the potential to reduce overall U.S. energy use, leading to decreased energy costs, reducing the need to build more power plants, greater energy security, greenhouse gas reductions and significant environmental protection benefits.

Energy efficiency, distributed generation such as rooftop solar, and demand-side management[2] all have the opportunity to link with electricity markets and drive future electricity system planning and market operations to meet many of these energy system goals. But deploying energy management technologies over multiple industrial sectors in 100 million buildings and billions of end use devices requires tremendous scale up in both project size and investments. Certainly, all levels of government as well as the private sector are attempting to meet the challenge. By 2015, a wide range of federal, state, and local funding mechanisms such as tax exemptions, tax deductions, tax rebates, grants, and loans for "green" construction efforts will total $122 billion.[3] Additionally, over 1000 municipalities have adopted greenhouse gas reduction targets, often focusing on energy efficiency measures. And experts conclude that even more investment in building energy efficiency would pay significant dividends. For instance, McKinsey estimates that $520 billion invested in non-transportation energy efficiency by 2020 could generate energy savings worth over $1.2 trillion, reduce end use energy demand by 23% of current projections, and as a co-benefit provide over 1.1 billion tons of greenhouse gas reductions.[4]

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[1] *See* U.S. EPA, Clean Energy, at http://www.epa.gov/cleanenergy/energy-and-you/.

[2] "Demand-side management" or "DSM" involves reducing electricity use through activities or programs that promote electric energy efficiency or conservation, or more efficient management of electric energy loads. These efforts can include greater energy efficiency in buildings, using more energy efficiency products, encouraging customers to shift their use of electricity from high demand to low demand periods, and giving utilities limited control over customer equipment such as air conditioners to shift or reduce electricity use. *See, e.g.*, PacificCorp., Demand Side Management, at http://www.pacificorp.com/env/dsm.html; BRANDON DAVITO, HUMAYUN TAI, & ROBERT UHLANER, THE SMART GRID AND THE PROMISE OF DEMAND SIDE MANAGEMENT, MCKINSEY ON SMART GRID 38-42 (Summer 2010), at https://www.smartgrid.gov/sites/default/files/doc/files/The_Smart_Grid_Promise_DemandSide_Management_201003.pdf (describing the load shifting programs and energy efficiency and conservation programs that make up DSM).

[3] Thomas Frank, *"Green" Growth Fuels an Entire Industry*, USA TODAY, Nov. 14, 2012, at http://www.usatoday.com/story/news/nation/2012/10/25/green-building-big-business-leed-certification/1655367/.

[4] MCKINSEY & CO., UNLOCKING ENERGY EFFICIENCY IN THE U.S. ECONOMY iii (July 2009).

But in spite of over thirty years of local, state and federal programs offering energy efficiency incentives and educating residential, commercial, and industrial customers about cost-effective energy saving opportunities, the impacts of these programs consistently fall short. One of the critical barriers standing in the way is adequate data on energy consumption. While emissions and electricity generation data is available at the boiler or plant level on an hourly basis through numerous government agencies such as the Energy Information Administration (EIA), the U.S. Environmental Protection Agency (EPA), and the Federal Energy Regulatory Commission (FERC), energy consumption data is available only as estimates through quadrennial surveys. But even these do not always happen as regularly scheduled. Additionally, the surveys only sample thousands of buildings nationwide, making evaluation or comparison of specific programs impossible due the lack of a representative sample. Given today's electricity system, where extensive interconnected transmission grids embedded with information communication technologies communicate real-time synchronized data and large regional electricity markets clear in the day ahead and real time (5 to 15 minute) markets, the lack of granularity of data for energy management is striking.

This lack of data creates important information asymmetries and high transaction costs and represents a serious market failure. This market failure causes several problems:

- *Evaluation of existing programs*: Lack of energy consumption data makes it impossible to comprehensively evaluate and compare the success of current efforts across jurisdictions. In 2012 utilities spent over $7 billion on energy efficiency programs (nearly $6 billion on programs for electricity efficiency and an additional $1.3 billion for natural gas efficiency programs), saving an estimated 23 million MWh in 2011, the most recent year for which data is available.[5] These investments are projected to increase to $15-17 billion per year by 2025.[6] But assessing, evaluating, and comparing programs effectiveness is often stymied by lack of energy use data and different evaluation, monitoring, and verification programs.[7]

- *Targeting Future Energy Management Opportunities*: Lack of energy consumption data makes energy management program targeting, design, planning, implementation, and evaluation much more difficult. Federal, state, and local governments encourage energy efficiency through a wide variety of different policies: tax incentives, building standards, and appliance efficiency standards. However, evaluating the efficiency of these investments and the effectiveness of the programs often focuses on larger industrial projects, while smaller residential projects rely on modeled data, making evaluation of smaller efforts or program comparison difficult.

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[5] AMERICAN COUNCIL FOR AN ENERGY EFFICIENT ENVIRONMENT (ACEEE), THE 2013 STATE ENERGY EFFICIENCY SCORECARD vi (Nov. 2013), at http://www.aceee.org/sites/default/files/publications/researchreports/e13k.pdf.
[6] ACEEE, *supra* note __, at 17.
[7] Energy.gov, About the Uniform Methods Project, Office of Energy Efficiency and Renewable Energy, at http://energy.gov/eere/about-us/uniform-methods-project-determining-energy-efficiency-program-savings/about-uniform-methods; SEE Action, Evaluation, Measurement and Verification, at https://www4.eere.energy.gov/seeaction/topic-category/evaluation-measurement-and-verification.

- *Scalability of Energy Management*: Lack of energy consumption data makes targeting new opportunities and scaling up energy efficient projects challenging and unable to benefit from large-scale investments. This lack of publicly available energy consumption data in the industrial, commercial, residential, municipal, university, school, and hospital sectors creates high project specific transaction costs and hinders future investment and scalability of energy management programs. Most banks or private investors only invest in projects of a certain scale, making individual small-scale energy management projects hard to finance.

Developing energy management to its potential requires both new analytics to evaluate and target opportunities and new mechanisms to scale and leverage financing. These analytics rest on a foundation of energy consumption data (also referred to as customer energy usage data) that is currently not available in any meaningful way to consumers, energy service companies, and government funders or researchers. The benefits associated with collecting energy consumption data are numerous, and include: (1) giving consumers the data they need to manage energy use based on real time price signals; (2) allowing distributed generation (DG) developers such as solar companies to size systems based on the energy use in buildings; (3) helping state regulators determine whether utilities are meeting their state-mandated energy efficiency targets; (4) allowing cities to determine their actual emissions in greenhouse gas emissions and whether they are reaching self-imposed reduction goals; and (5) allowing more large industrial electricity customers to play a more active role in energy markets and participate in aggregated demand side management programs and invest in DG.

This article explores recent efforts federal, state, and local governments have taken to create regulatory frameworks to collect energy consumption data and make it available to consumers and, in some cases, to the public. Part I explains in more detail the nature of energy consumption data, the problems with not having such data readily available to consumers and policymakers, and the benefits associated with making it available to a wider range of potential users. Part II explores developing federal, state, and local policies governing energy consumption data, including how policymakers have attempted to address the some of the privacy and other concerns associated with such data. Last, Part III evaluates these efforts and attempts to provide guidance to policymakers on how to develop more robust regulatory frameworks to help capitalize on the potential energy efficiency benefits associated with increased, collection, evaluation, and disclosure of ECD.

I. THE PROMISE OF ENERGY CONSUMPTION DATA AND CURRENT BARRIERS TO USE

Today, most detailed energy consumption data is privately held by utilities. The federal government also surveys energy consumption, but these surveys are scheduled only once every four years and cover a small subset of buildings. This section covers past and current practices in energy use data and discusses how these data could transform the management of the electric system.

A. Energy Consumption Data Today

While high-profile regional blackouts affecting the high-voltage transmission system have led to massive investments in technology and management to ensure system reliability, advancements and investments in the low-voltage distribution network that connects utility substations to customers have not always kept up.[8] This is starting to change as advances in information and communication technology (ICT) have enhanced the capabilities of electric "smart" meters, sensors and are potentially changing how electricity will be managed and consumed.

Historically, all utilities used meter readers to collect energy use data from every household and business each month. The utility then calculated the amount of electricity used, multiplied it by the rate (cents per kilowatt hour) and billed the customer. Non-payment of the bill meant the meter reader was sent to the premises to shut off the electricity. While some utilities still use this approach, many have upgraded their metering infrastructure to reduce system costs and eliminate the meter reading job. In the 1990s utilities began to widely install the first generation of automatic meter reading (AMR) meters, which often required the utility personnel to drive a truck through the neighborhood or walk by the residence to automatically collect the data. Information flowed from the meter to the collector and energy consumption data was still collected monthly and the customer billed only after the energy had been used.[9]

In the mid-2000s utilities began to invest advanced meter infrastructure (AMI), which allows for two-way communication between the utility and the consumer through wireless or fiber networks. These advances in ICT meters allow for automatic sub-hourly data collection and the two-way communication could also allow consumers to have real time information on their energy consumption and its cost. AMI can also allow utilities—and customers—to remotely monitor real time energy use, power quality, and automatically identify any system failure. One of the great promises of the smart meter, as AMI is called, is that it can help to bridge the information asymmetry between how much energy a customer uses and what they pay. Real-time energy use consumer interfaces promise a better alignment of consumer energy use and electricity market signals. Energy demand varies with the time of day, and the marginal cost of providing electricity also changes throughout the day, depending on which generators are producing electricity. However, most electric consumer still pay a flat price per kilowatt hour, even though the actual market price can vary by two orders of magnitude and shifts over time and space. Advocates imagine a world where consumers are sent price signals that reflect actual market prices and can adjust their behavior accordingly. This could be through the consumer actively shutting off of electric devices when prices are high or relying on pre-programed "set and forget" commands. For example, a subset of consumer appliances like air conditioners, water heaters or refrigerators could be programed to automatically cycle in response to system signals or pre-set price points. Ideally, this would not affect appliance performance, but it would allow

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[8] *See* Poyan Pourbeik, et al., *The Anatomy of a Power Grid Blackout*, 4 IEE POWER & ENERGY MAGAZINE 22 (Sept.-Oct. 2006).

[9] *See* Jim Roche, *AMR vs AMI*, ELECTRIC LIGHT & POWER, October 1, 2008, at http://www.elp.com/articles/powergrid_international/print/volume-13/issue-10/features/amr-vs-ami.html.

the system to more efficiently and economically manage resources. In an energy system with high levels of variable renewable resources, it could also allow for more active use of demand management.

In 2013, the most recent year for which data is available, U.S. utilities had installed over 50 million smart meters (89 percent for residential customers),[10] though the penetration levels vary significantly by state. Some states like Texas and Arizona have smart meter penetrations of over 50 percent, while others like Minnesota and Iowa have penetrations below 10 percent of customer meters.[11] AMI installation varies by utility too, as of 2012 Pacific Gas & Electric (CA), Florida Power & Light, Southern California Edison (CA), Oncor Electric (TX), Georgia Power (GA), Center Point (TX), PPL Electric (PA) and San Diego Gas and Electric (CA) each had over 1.3 million smart meters installed. Another 39 utilities in 20 additional states had over 100,000 customers with smart meters, yet over 1000 utilities had fewer than 100 AMI installed. The EIA tracks smart meter installations in Form EIA-861.[12] While consumers have opposed some smart meter programs and installations because of concerns associated with health, privacy, and safety, most smart meter rollouts have proceeded relatively smoothly.[13]

Smart meters can collect and store data in different ways and is not currently standardized (see discussion on the Green Button Program in Section II). Utilities can collect sub-hourly data (e.g. 15 minute intervals), hourly data, daily information, or monthly information. They can choose whether or not to share these data with customers, how to share it, and what format it will be available. While real-time energy use data may allow customers to manage their immediate energy use, historical data could help to inform decisions in energy efficient upgrades. While real time plug level data can reveal occupancy patterns, legacy hourly or monthly may not have the same privacy concerns. Who owns the data collected from smart meters is discussed in Section II, but today the utilities are the primary parties that collect, analyze, and have access to energy use data.

While smart meters can collect copious quantities of energy use data, linking it to better management of the system, or helping consumers save money has not been consistent. Utilities decide what kind or if a consumer interface will be included and many of the promises of a smart meter have been slow to be realized. Not all of the installed smart meter projects come with consumer interface devices or allow consumers to manage their electricity use in real time. Most

[10] *See* Energy Information Administration, Frequently Asked Questions, *How Many Smart Meters Are Installed in the U.S. and Who Has Them?*, (May 16, 2014), at http://www.eia.gov/tools/faqs/faq.cfm?id=108&t=3; Institute for Electric Innovation, *Utility-Scale Smart Meter Deployments*, (The Edison Foundation, Sept. 2014), at http://www.edisonfoundation.net/iei/Documents/IEI_SmartMeterUpdate_0914.pdf.

[11] *See* Energy Information Administration, *Smart Meter Deployments Continue to Rise*, http://www.eia.gov/todayinenergy/detail.cfm?id=8590; Form EIA-861 detailed data files, http://www.eia.gov/electricity/data/eia861/index.html.

[12] *See* Energy Information Administration, Electric Power Sales, Revenue, and Energy Efficiency, Form EIA-861 detailed data files, http://www.eia.gov/electricity/data/eia861/index.html.

[13] *See* Stop Smart Meters! http://stopsmartmeters.org/ and Felicity Barringer, *New Electricity Meter Stirs Fears*, N.Y. TIMES, Jan. 30, 2011, ***at*** http://www.nytimes.com/2011/01/31/science/earth/31meters.html?pagewanted=all

U.S. consumers still pay a flat per kilowatt charge and state public utility commissions have often been slow to approve time of time based rate-tariffs like time of use pricing, real time pricing, variable peak pricing or critical peak pricing.[14] Currently, about 5.3 million U.S. residential utility customers have access to price-responsive programs and 3.3 million to time responsive programs.[15] Additionally, demand devices to link consumer energy use with the smart grid have been slow to sell. While consultants estimate that worldwide smart appliance sales will top $35 billion by 2020, appliance manufacturers have been making "smart appliances" these are still sold at a price premium and market penetration has been low.[16] Evaluating the benefits of these technologies and programs also requires uniform evaluation methods, which, at the current time, are often not used or available.

B. The Promise of Energy Consumption Data

Energy consumption data could help consumers by giving them better information on how they use energy, both for real time management and for long-term planning. Hourly or intra-hourly information could allow consumers to manage energy use based on real time price signals. These data could also assist in planning and let people model and evaluate the financial impacts of different rate structure programs like dynamic pricing, time of use pricing, or a flat rate structure. One reason customers have often been reluctant to switch to dynamic pricing programs—and PUCs reluctant to approve them—is that they do not know what the costs would be beforehand. These data to evaluate the costs to individual consumers could close this information gap and reduce the political uncertainty. Hourly data could also allow consumers to size solar PV modules to their business or residence, target energy efficiency retrofits and investments, and better understand and manage how energy is used in their building. These data could also help commercial tenants, real estate investors and lending institutions understand the energy costs of a site when investing in or financing a property.

Distributed generation (DG) developers could use energy consumption data to both target new opportunities and size systems based on the energy use in buildings. New GIS software allows for hourly estimation of solar energy production at specific location; matching this to energy consumption would reduce the transaction costs of DG development.[17] While hourly data would be fine for fixed solar PV installations, DG technologies like micro-turbines and solar with tracking could also use sub-hourly data and potentially provide back-up reserves to the grid. These data would allow developers to tailor system size and technologies to match consumer

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[14] *See* SmartGrid.gov, Time Based Rate Programs, https://www.smartgrid.gov/recovery_act/deployment_status/time_based_rate_programs.

[15] *See* Energy Information Administration, *Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files, Demand Side Managemen*t at http://www.eia.gov/electricity/data/eia861/index.html.

[16] *See* Navigant Research, *Smart Appliances: Intelligent Control, Power Management, and Networking Technologies for Household Appliances on the Smart Grid: Global Market Analysis and Forecasts* at http://www.navigantresearch.com/research/smart-appliances.

[17] Dan Theide, *Solar Dream Team Wins National Award for MN Solar Suitability App*, (Univ. of Minnesota, July 2014), at https://uspatial.umn.edu/solar.

load and potentially play an important role in the future electricity system. Likewise, energy consumption data would allow energy service companies to target opportunities within a geographic area and lower the transaction costs associated with their services.

Energy consumption data could play an important role in compliance too. While there are many energy efficiency program models, many states have energy efficiency targets for utilities. For example, in Minnesota, utilities are required to reduce their electricity by 1.5% of average retail sales.[18] State regulators at the Department of Commerce are tasked with approving the energy efficiency programs utilities propose and then evaluating their results. In practice, they rely on third-party analysis using sub-metered data for large industrial projects, which claim savings over 1 million kWh. For smaller residential programs, regulators currently use modeled data with embedded assumptions on technology adoption and use.[19] Minnesota has also adopted the methods for evaluating energy efficiency proposed by the Uniform Methods Project, discussed in more detail in Part II.[20] While actual energy consumption data could allow the evaluation to be more accurate, it would also require new methods and analytics and staff to manage, assess, and interpret the data. They could also better compare programs across utilities and evaluate programmatic effectiveness within their state and compare their results with other states. Many states also give tax rebates to encourage green building programs. These programs model their energy use before they are built, but very few conduct post-occupant surveys to evaluate actual energy use. Additionally, many states also have efficient building construction standards, but they are not always able to assess if buildings meet the standards. Energy consumption data could help to close this gap. Likewise, over one thousand mayors have joined the U.S. Conference of Mayor's Climate Protection Agreement and have vowed to reduce greenhouse gas emissions from their municipalities.[21] However, unless the city also has a municipal utility, it may have a hard time measuring any change in energy use.[22]

With energy consumption data, energy consumers could play a more active role in energy markets. While many large industrial customers are on interruptible contracts and their power curtailed during emergency situations, and some residential customers are on programs that cycle their air conditioning when demand gets too high, energy consumption data could open up new possibilities to create responsive load. Energy consumption data plus investments in smart grid technologies could allow a greater segment of aggregated demand to participate both in energy

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[18] DSIRE, Database of State Incentives for Renewable Energy and Efficiency, Minnesota, Energy Efficiency Resource Standard, at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MN18R&re=1&ee=1.

[19] Jessica Burdette, Minnesota Department of Commerce, Presentation to Wilson Research Group, October 7, 2014.

[20] NREL, The Uniform Methods Project: Methods for Determining Energy Efficiency Savings, April 2013, http://energy.gov/sites/prod/files/2013/07/f2/53827_complete.pdf.

[21] The United States Conference of Mayors Climate Protection Center, at http://www.usmayors.org/climateprotection/revised/.

[22] Cities can use CEUD to target carbon reduction programs. For example, a city could analyze which customers used higher than average natural gas. They could then cross-reference this with a list of buildings that had not pulled a permit for a furnace in the last 20 years and then target this subset for furnace upgrades.

markets and potentially provide some ancillary services to enhance distribution network reliability.

Finally, energy consumption data could also be used to create new products. For example, the Tennessee Valley Authority has worked with large industrial customers to help them manage their Scope II carbon emissions. By providing the estimated carbon intensity of the electricity they use for all 8,760 hours of the year, the plants are able to more accurately report emissions associated with their electricity use.[23]

Thus, across all of these areas, energy consumption data could help benchmark energy use, energy management, and create a comparable context for best practice energy management. But there is presently no means for consumers, energy service companies, DG developers, or local or state governments to obtain meaningful and comparable energy consumption data. When efforts have been made to require utilities and other power providers to make energy consumption data publicly available, utilities and some consumer groups have raised privacy and other concerns.

II. Existing Law Governing Energy Consumption Data

Despite the clear benefits associated with increased access to energy consumption data, it is often difficult for consumers, third parties such as energy efficiency program administrators, energy efficiency service providers, and researchers to access to energy consumption data. The majority of states have no policies in place governing the disclosure of energy consumption data to customers or third parties.[24] In those states, customers and third parties must negotiate with individual electric utilities to obtain whatever information the utility makes available either on an ad hoc basis or under a public utility's individual privacy policy. The state and local government policies that do exist vary significantly.

Before discussing the existing policies, it is important to provide some additional detail on the different needs of different parties that seek access to energy consumption data.

First, there are consumers themselves who may wish to obtain data in a usable form from their utility to track their own energy consumption trends or provide that information to energy efficiency service providers or other third parties such as solar providers or researchers or use their own energy data in management applications. The data privacy issues associated with providing energy consumption data to consumers are limited and consist primarily of ensuring the means of providing the information to the consumer is secure and that the data is provided in

[23] Tennessee Valley Authority, *Pollution Prevention and Reduction: Carbon Dioxide*, at http://www.tva.com/environment/air/co2.htm; Greenhouse Gas Protocol, *Scope 2 Accounting: Clarifying the Treatment of Green Power Instruments*, at http://www.ghgprotocol.org/feature/ghg-protocol-power-accounting-guidelines.
[24] SEE Action, A Regulator's Privacy Guide to Third-Party Data Access for Energy Efficiency 7-8 (Dec. 2012).

a format that is useful to the consumer or third parties with whom the consumer chooses to share the data.

Second, there are third party energy efficiency program administrators that may obtain energy consumption data either with or without the consent of the customer. In some states, regulatory agencies such as public utility commissions or state energy offices manage energy efficiency programs or contract with private energy efficiency program administrators to meet state energy efficiency policy goals.[25] In order to track the success of such programs, these entities need access to energy consumption data. Because these entities, whether public or private, have delegated authority from the state to assist the state with energy efficiency policies, they should be entitled to any data the government itself has a right to obtain without customer consent in order to meet state policy goals so long as sufficient security measures are in place to avoid data breaches.

Third, there are energy efficiency service providers (EESPs) that are not affiliated with a state or local agency but are private companies that offer energy efficiency services or products such as energy audits; energy efficiency consulting services; installation of energy efficient heating, air conditioning, and lighting systems; and energy consumption tracking systems.[26] EESPs may be able to obtain energy consumption data for existing clients if the utility makes such information available to the customer and the customer consents to the release of the data to the EESP. But in many states, nothing requires the utility to make the data available to the customer or to make it available in a form useful to the customer or the EESP. Moreover, in most states the EESP cannot obtain customer data in any form for prospective clients because it is not in a position to obtain consent from parties who are not yet clients. According to EESPs, such data would allow the EESP to more effectively offer energy efficiency services to new customers by showing them, based on individualized or aggregated energy consumption data, how they could increase the efficiency of lighting, heating, cooling, and other energy systems in their homes, businesses, commercial buildings, or industrial facilities.[27]

Last, researchers at universities and non-profit entities seek access to energy consumption data in connection with scholarly work and to support policy development in the area of energy efficiency. Researchers could use energy consumption data to model and develop new technologies, evaluate different interventions and market products, and provide more nuanced research on the linkages between energy use and energy production.

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[25] According to the State and Local Energy Efficiency Action Network (SEE Action), utilities administer energy efficiency programs in approximately 40 states while state agencies or profit or nonprofit companies manage programs in eight states. *See* SEE ACTION, A REGULATOR'S PRIVACY GUIDE TO THIRD-PARTY DATA ACCESS FOR ENERGY EFFICIENCY 4 (Dec. 2012).

[26] *See* SEE Action, *supra* note __, at 4-5; Nat'l Ass'n of Energy Services Companies, *What is an ESCO?*, at http://www.naesco.org/what-is-an-esco.

[27] SEE Action, *supra* note __, at 5.

The remainder of this Part discusses federal, state, local, and utility policies currently in place governing energy consumption data. These include (1) federal policies to support consumer access to energy consumption data and potential federal privacy limitations on disclosure of such data, (2) state policies governing privacy of energy consumption data and aggregation of such data, and (3) local government efforts to create "benchmarking" for commercial building efficiency.

A. Federal Policies and Initiatives on Energy Consumption Data and Privacy

Under the Federal Power Act, the federal government, through FERC, regulates the wholesale sale of electricity in interstate commerce and the transmission of electricity in interstate commerce.[28] By contrast, state legislatures and state public utility commissions (PUCs) regulate retail sales of electricity.[29] As a result, the collection and disclosure of energy consumption data for energy efficiency and other purposes is primarily an issue of state law.[30] Nevertheless, there are several federal initiatives designed to promote better access to and use of energy consumption data. For instance, the American Recovery and Reinvestment Act of 2009 provided over $4.5 billion in new funding for smart grid and electric grid investments, including money designed to facilitate the installation of nearly 20 million new smart meters.[31] Such smart meters have the potential to dramatically increase the flow and granularity of data on energy consumption from the consumer to the utility, from the utility to the consumer and, ultimately, to EESPs and energy efficiency research centers. This Section discusses federal actions to date related to energy consumption data.

1. Federal Energy Use Surveys

[28] 16 U.S.C. § 813 (describing the power of the federal government to enter into interstate commerce and to regulate rates and charges); 16 U.S.C. § 824(s) ("Not later than 1 year after August 8, 2005, the Commission shall establish, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power."); 16 U.S.C. § 824e ("[T]he Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.").

[29] 16 U.S.C. § 824 ("Federal regulation [is]. . . to extend only to those matters which are not subject to regulation by the States."); SEE Action, *supra* note_, at 1 ("State legislatures and public utilities commissions (PUCs) are uniquely positioned to support energy efficiency and protect customer data because of their jurisdiction over retail electric utilities.").

[30] Adam Schira, *Protecting Progress and Privacy: The Challengers of Smart Grid Implementation*, 6 ISJLP 629, 642 (2011) (evaluating multiple federal legal doctrines that may be relevant to energy consumption data but are not used compared to state regulations); (SEE Action, *supra* note _, at 13 (describing how the federal government has not restricted access to energy consumption data, leading to state regulation of access).

[31] *See* THE WHITE HOUSE, TRANSFORMING THE AMERICAN ECONOMY THROUGH INNOVATION: EXECUTIVE SUMMARY, www.whitehouse.gov/recovery/innovations/executive-summary (providing an overview of Recovery Act programs, including smart meter and electric grid improvements); Energy.Gov, *Recovery Act: Smart Grid Investment Grants*, at http://energy.gov/oe/technology-development/smart-grid/recovery-act-smart-grid-investment-grants; Energy.Gov, *Recovery Act, Cumulative Federal Payments to OE Recovery Act Recipients Through June 30, 2014*, at http://energy.gov/oe/information-center/recovery-act.

In addition to the electricity sales data collected by utilities, the U.S. Department of Energy's Energy Information Administration (EIA) collects energy consumption data as part of several energy consumption surveys. Residential and commercial energy use surveys are supposed to take place at least every four years and are authorized under the Federal Energy Information Act of 1974,[32] with the first surveys beginning in the late 1970s. The Commercial Buildings Energy Consumption Survey (CBECS) collects energy use data from a sample of buildings and commercial energy users (first run in 1979), the Residential Energy Consumption Survey (RECS) samples residential housing energy use and expenditures (1978), the Manufacturing Energy Consumption (MECS)[33] surveys energy consumption in manufacturing (1985), and transportation, though this latter program was discontinued.[34] These quadrennial surveys are supposed help track changes in energy use across the country and to project future growth.

The RECS survey is voluntary for households and mandatory for energy suppliers and targets 15,400 respondents.[35] It has been run in 1980, 1981, 1982, 1984, 1987, 1990, 1993, 1997, 2001, and 2005 and 2009. For example, the 2009 RECS collected data from 12,083 households, which were chosen to represent the 113.6 million primary residence housing units in the United States.[36] The survey was 96 pages long and included information on resident demographics, housing unit characteristics; kitchen and home appliances; electronics; space and water heating; air conditioning; and miscellaneous information like how many windows the residence has, if the residence has high ceilings, pools or hot tubs, outdoor and indoor lighting habits, and if the resident had received any aid for weatherization or other services. The survey asks about any direct use and payment for fuels like electricity, natural gas, propane, wood as well as distributed generation like small-scale solar or wind. The survey also includes a few questions on residential transportation.[37]

The CBECS survey targeted 9,700 commercial building owners and occupants to provide information on building characteristics, building energy consumption and expenditures for the nation's commercial buildings.[38] The 241-page 2012 CBECS asked about the building age and size, how it was used, occupied, and operated, its energy use and equipment, electricity and

[32] 15 U.S.C. § 790a(a), Public Law 93-275 (Federal Energy Administration Act of 1974), Sec. 13(b), 5(a), 5(b), 52.
[33] MECS Surveys are authorized under 42 U.S.C. § 7135.
[34] *See* EIA, Commercial Buildings Energy Consumption Survey, http://www.eia.gov/consumption/commercial/about.cfm; EIA Residential Energy Consumption Survey, http://www.eia.gov/consumption/residential/; EIA, Manufacturing Energy Consumption Survey, http://www.eia.gov/consumption/manufacturing/; EIA, Transportation Energy Consumption Surveys, http://www.eia.gov/consumption/archive/rtecs/contents.html.
[35] EIA, RECS, http://www.eia.gov/survey/#eia-457.
[36] EIA, About the RECS, http://www.eia.gov/consumption/residential/about.cfm.
[37] EIA, RECS, http://www.eia.gov/survey/form/eia_457/form.pdf.
[38] Authorized by Public Law 93-275 (Federal Energy Administration Act of 1974), Sec. 13(b), 5(a), 5(b), 52

natural gas use, other fuel use (e.g. oil, diesel, kerosene), district steam, hot, and chilled water use, total water use, and for copies of energy bills.[39]

While these surveys allow for national and regional comparisons of energy use, they are not detailed enough to allow for evaluation or comparison of different utility or state energy efficiency initiatives or compare programmatic effectiveness across jurisdictions. Additionally, recent analyses suggest that when compared to actual energy use, the estimates derived from the surveys might not accurately estimate energy use.[40]

2. ENERGY STAR Portfolio Manager, Green Button and the Uniform Methods Project

Beyond government surveys, the federal government, sometimes in cooperation with private parties, has begun to develop uniform data collection protocols to make energy consumption data more accessible. First, the U.S. EPA has created a program called the ENERGY STAR Portfolio Manager.[41] The program is a survey that analyzes a building's attributes, such as building type, space attribute data, and energy consumption by fuel type. Based in part on the Commercial Buildings Energy Consumption Survey, Portfolio Manager scores buildings on a scale between 1 and 100, with fifty being an average score. After entering a building's data into the program, the building owner can compare its rating with national medians or similar buildings. The building owner can also obtain an ENERGY STAR performance document that summarizes the building's energy consumption data. Thus, the goal of Portfolio Manager is to increase consumer access to energy consumption data to spur improvements in building energy use.[42]

Second, the energy industry has developed the "Green Button" initiative in response to a challenge by the White House in 2011 for electricity providers to give customers easier access to uniform and more usable energy consumption data.[43] Using Green Button, customers can securely download their own energy usage by clicking a "Green Button" on their electric utilities' websites. The Green Button Program launched officially in 2012 and more than 35 utilities and electricity suppliers have adopted it. Green Button is based on the Energy Service

[39] EIA, 2012 CBECS Building Questionnaire Form EIA-871A, http://www.eia.gov/survey/form/eia_871/2012/cbecs-buildings-871a.pdf.

[40] *See* Brock Glasgo, Inês Lima Azevedo, & Chris Hendrickson, *Drivers of Home Energy Consumption from the Bottom Up and How Much Electricity Can We Save by Using Direct Current Circuits in Homes?*, Working Paper, Engineering and Public Policy Program, Carnegie Mellon University, at http://www.pecanstreet.org/wordpress/wp-content/uploads/2014/06/Pike-Powers-Glasgo.pdf; Brinda A. Thomas, Ines L. Azevedo, & Granger Morgan, *Edison Revisited: Should We Use DC Circuits for Lighting in Commercial Buildings?*, 45 ENERGY POLICY 399-411 (2012).

[41] *See* ENERGY STAR, *About ENERGY STAR*, at http://www.energystar.gov/about/.

[42] *See* ENERGY STAR, Federal, State, and Local Governments Leveraging ENERGY STAR (Jan. 30, 2103), at http://www.energystar.gov/ia/business/government/State_Local_Govts_Leveraging_ES.pdf.

[43] *See* Energy.Gov, Green Button, at www.energy.gov/datda/greenbutton; Pacific Gas & Elec., Green Button, at http://www.pge.com/myhome/addservices/moreservices/greenbutton/. *See also* The White House, Office of Science and Technology Policy, *Expanded "Green Button" Will Reach Federal Agencies and More American Energy Consumers*, Dec. 5, 2013, at http://www.whitehouse.gov/blog/2013/12/05/expanded-green-button-will-reach-federal-agencies-and-more-american-energy-consumers (explaining Green Button Program, listing participating utilities, and describing new expansion of the program).

Provider Interface data standard released by the North American Energy Standards Board. The standard consists of a common XML format for energy usage information and a data exchange protocol which allows the automatic transfer of data from a utility to a third party based on customer authorization. The standard means that utilities can follow a uniform approach to data collection and presentation, allowing EESPs to more easily develop software to analyze the data and recommend efficiency improvements to consumers, rather than develop software specific to each utility's data set.[44] Green Button data can been provided in 15-minute, hourly, daily, or monthly intervals depending on what the utility decides to make available and the level of detail it is able to provide.[45]

Utilities can make available the Green Button *Download My Data* feature, which allows the utility customer to download their energy consumption data to their own computer and then, if they choose, upload that data to a third party application.[46] Utilities can also offer Green Button *Connect My Data*, which allows utility customers to request the secure transfer of their energy consumption data directly to a third party, after express authorization and consent by the customer.[47] While many utilities have adopted the Green Button Program, not all utilities provide the service and currently there is no federal law that requires utilities to implement Green Button or any other energy consumption data program.

Finally, uniform standards for energy efficiency evaluation, monitoring, and verification (EMV) are helpful to calculate savings, ensure program transparency and comparability, and credibility. With energy efficiency mandates in 26 jurisdictions, the State and Local Energy Efficiency Action Network (SEE Action) sought to develop a standardized set of protocols to calculate savings from energy efficiency projects.[48] While other protocols exist, they had often been developed for other purposes.[49] See Action developed the Uniform Methods Project (UMP), to expand upon the International Performance Measurement and Verification Protocol (IPMVP), and provide additional procedural steps for implementation. The DOE Offices of Electricity Delivery and Energy Reliability and Energy and Renewable Energy managed the UMP by contracting with the Cadmus Group to develop a set of standardized protocols for consistent evaluation, monitoring, and verification of energy efficiency programs. Focused on commercial and residential programs, the first phase of the protocols covers residential and commercial lighting and controls, refrigerator recycling, residential air conditioning units, furnaces and boilers, and building retrofits.[50] The second set will cover a larger set of technologies, which will allow for more complete measurement, monitoring, and evaluation of energy efficiency programs.

[44] SEE Action, *supra* note __, at 4.
[45] Green Button, *supra* note __.
[46] Green Button, *supra* note __.
[47] Green Button, *supra* note __.
[48] NREL*supra* note __, at 1-3.
[49] *Id*. at 1-6.
[50] *Id*. at 1-5.

3. Privacy and the Fourth Amendment

Notably, neither Congress nor any other federal agency has created specific privacy policies governing energy consumption data. The U.S. Supreme Court has not addressed whether energy consumption data is protected by the Fourth Amendment, which protects "[t]he right of the people to be secure in their persons, houses, papers, and effects, against unreasonable searches and seizures."[51] It has, however, decided cases involving efforts by law enforcement officials to obtain access to cellular telephone data, GPS device data, and other modern technological information that contains personal information regarding the user.[52] At least one lower court has held that electricity customers cannot object to installation of smart meters on Fourth Amendment grounds under the "third-party doctrine," which denies protection to information a customer gives to a business as part of their commercial relationship.[53] But recent Supreme Court case law in the context of GPS monitoring has raised the question of whether the third party doctrine should continue to apply to the vast array of new digital communications that contains significant personal information.[54] Thus, the question of Fourth Amendment protection for smart meter data will continue to develop as such data becomes more pervasive and has the potential to be of use to law enforcement personnel, potential criminals who can more easily monitor household activities, and potential marketers who can monitor appliances for purposes of direct marketing.[55]

[51] *See* U.S. CONST. amend. IV.

[52] *See, e.g.*, Smith v. Maryland, 442 U.S. 735 (1979) (telephone numbers a person dials are not subject to Fourth Amendment protection and do not require a warrant because the caller voluntarily conveys the dialing information to the telephone company and thus obtaining the numbers is not a "search"); Riley v. California, 2014 WL 2864483 (U.S., June 25, 2014) (Fourth Amendment protects cellphone information and thus law enforcement officers need a warrant to search the cellphones of people they arrest and cannot obtain such information without a warrant under exception for searches incident to arrest because concern for officer safety is not present in such a situation and modern cellphone contains significant personal information).

[53] Naperville Smart Meter Awareness Program v. City of Naperville, 2013 WL 1196580 (N.D. Ill., Mar. 22, 2013) (citing Smith v. Maryland, 432 U.S. 735 (1979); BRANDON J. MURRILL, ET AL., CONGRESSIONAL RESEARCH SERVICE, SMART METER DATA: PRIVACY AND CYBERSECURITY (Feb. 3, 2012) (discussing third party doctrine).

[54] *See* United States v Jones, 132 S. Ct. 945 (2012) (holding that attaching a GPS tracking device to a vehicle was a "search" within the scope of the Fourth Amendment and required a warrant); *id.* at 957 (Sotomayor, J., concurring) (stating that "it may be necessary to reconsider the premise that an individual has no reasonable expectation of privacy in information voluntarily disclosed to third parties. . . This approach is ill suited to the digital age, in which people reveal a great deal of information about themselves to third parties in the course of carrying out mundane tasks. People disclose the phone numbers that they dial or text to their cellular providers; the URLs that they visit and the e-mail addresses with which they correspond to their Internet service providers; and the books, groceries, and medications they purchase to online retailers."); OFFICE OF THE PRESIDENT, BIG DATA: SEIZING OPPORTUNITIES, PRESERVING VALUES 32-34 (2014) (discussing continued application of the third party doctrine).

[55] *See, e.g.*, Katrina Fischer Kuh, *Personal Environmental Information: The Promise and Perils of the Emerging Capacity to Identify Individual Environmental Harms*, 65 VAND. L. REV. 1565, 1624-28 (2012) (potential law enforcement and other government uses of smart meter data); United States v. Kyllo, 190 F.3d 1041, 1043 (9th Cir. 1999), *rev'd on other grounds*, 533 U.S. 27 (2001) (federal agent subpoenaed monthly electricity records usage records, compared it to average electrical use, and concluded that the suspect's electrical usage was abnormally high and indicated a possible indoor marijuana grow operation); Armand La Barge, *Indoor Marijuana Grow Operations*, 72 POLICE CHIEF MAGAZINE (March 2005); Mikhail A. Lisovich, et al., *Inferring Personal Information from Demand-Response Systems*, IEEE SECURITY AND PRIVACY 11 (Jan./Feb. 2010), at

But even if smart meter data is not subject to Fourth Amendment protection, energy consumption data may still be protected from unauthorized disclosure or access under the Stored Communications Act (SCA), the Computer Fraud and Abuse Act (CFAA), and the Electronic Communications Privacy Act (ECPA).[56] These statutes appear to allow law enforcement to access smart meter data for investigative purposes under procedures provided in the SCA, ECPA, and the Foreign Intelligence Surveillance Act (FISA), subject to certain conditions.[57]

Outside the law enforcement context, how utilities use and distribute energy consumption data may be subject to Section 5 of the Federal Trade Commission Act (FTC Act).[58] In March 2012, the FTC issued a report that outlines "best practices" for businesses that collect, maintain, and use consumer data. The FTC limited the standard's applicability to data that that can be "reasonably linked to a specific consumer, computer, or other device" by stating that companies do not need to obtain consumer consent before collecting and using consumer data for practices that are consistent with the company's relationship with the consumer or that are specifically authorized by law. The FTC did recommend that companies obtain affirmative express consent before using customer data "in a materially different manner than claimed when the data was collected" or when collecting "sensitive data." Thus, although the FTC report does not prohibit the collection and use of energy consumption data for efficiency purposes, utilities may be concerned about FTC enforcement for violation of federal privacy policies if they make such data available to third parties or do not fully disclose to customers how the data will be used and with whom it may be shared.[59]

In sum, there are federal policies that encourage utilities, consumers, and third parties to better collect and utilize energy consumption data for energy efficiency purposes, but also more general federal privacy laws that may cause utilities to oppose greater third-party access to such data. Federal law in this area will undoubtedly continue to develop as smart meters become more common and consumers look for new ways to reduce energy use and save money. In the meantime, however, some states, local governments, and utilities have created more specific policies that govern the use, aggregation, and sharing of energy consumption data. The next sections explore these policies. But at both the federal and state level, as both smart meters and other modern technologies develop for the collection, use, and disclosure of energy consumption data, privacy concerns will continue to shape the applicable regulatory frameworks.[60]

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http://wisl.ece.cornell.edu/wicker/SWicker_lisovich (describing potential use of new residential smart meter data for law enforcement, criminal, and marketing purposes).

[56] *See* BRANDON J. MURRILL, ET AL., CONGRESSIONAL RESEARCH SERVICE, SMART METER DATA: PRIVACY AND CYBERSECURITY 22-28 (Feb. 3, 2012).

[57] MURRILL, ET AL., *supra* note __, at 22-28.

[58] MURRILL, ET AL., *supra* note __, at 29-40.

[59] *See, e.g.,* Dana B. Rosenfeld & Sharon Kim Schiavetti, *Third-Party Smart Meter Data Analytics: The FTC's Next Enforcement Target?*, THE ANTITRUST SOURCE (Oct. 2012).

[60] Katrina Fischer Kuh, *Personal Environmental Information: The Promise and Perils of the Emerging Capacity to Identify Individual Environmental Harms*, 65 VAND. L. REV. 1565, 1613-28 (2012) (discussing developing privacy protections for government and third party access to smart meter data).

B. State Policies on Energy Consumption Data

Several states have enacted a variety of policies to make energy consumption data available to customers and third parties to promote energy efficiency. Some of these policies relate to customer access to their own data and others apply to third party access to data. In all the proceedings establishing these policies, particularly those involving third-party or public access, concerns have been raised regarding the risks associated with the disclosure of energy consumption data. Some fear that third parties, including potential criminals, could determine from such data whether a residence is occupied at certain times, how many occupants there are, and their daily schedules and activities.[61] In response to such concerns, Texas has created a right to "privacy of customer consumption" information for all retail utility customers,[62] and Washington courts have held that the state constitution creates a right of privacy in residential electricity consumption information and requires "authority of law" to disclose it."[63] More states will undoubtedly take up this issue as smart meters allow ever more detailed information on consumer energy use. This may make it more difficult for third parties to access such data for purposes of research and energy efficiency analysis even if the states have created programs for customers to access their own data. The remainder of this section discusses existing state policies on both customer and third-party access to energy consumption data.

1. Customer and building owner access to energy consumption data

With regard to customer access to their own data, the states that have enacted statutes or rules on the subject have generally provided that customers should have access to their own data. These states include California, Colorado, Illinois, New York, Oklahoma, Pennsylvania, Texas, and Washington.[64]

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[61] *See* BRANDON J. MURRILL, ET AL., CONGRESSIONAL RESEARCH SERVICE, SMART METER DATA: PRIVACY AND CYBERSECURITY 5-6 (Feb. 3, 2012); Mikhail A. Lisovich, et al., *Inferring Personal Information from Demand-Response Systems*, IEEE SECURITY & PRIVACY 11 (Jan./Feb. 2010), at http://wisl.ece.cornell.edu/wicker/SWicker_lisovich (describing potential use of new residential smart meter data for law enforcement, criminal, and marketing purposes).

[62] TEX. UTIL. CODE ANN. § 17.004(a) (describing various protections that buyers of retail electric services are entitled to, including privacy of customer consumption information); Sara Mattern, Note, *Municipal Energy Benchmarking Legislation for Commercial Buildings: You Can't Manage What You Don't Measure*, 40 B.C. ENVTL. AFF. L. REV. 487, 496, 505 (2013).

[63] In re Maxfield, 945 P.2d 196 (Wash. 1997); Mattern, *supra* note __, at 507-08.

[64] 4 COLO. CODE REGS. 723-3 Pt. 3 §3026(d) ("[A] utility shall provide to a customer the customer's standard customer data, access to the customer's standard customer data in electronic machine-readable form."); Okla. Stat. tit. 17 §710.4(A) ("An electric utility shall provide customers with reasonable access to and shall maintain the confidentiality of customer information."); CAL. PUB. UTIL. CODE § 8380(a)(4) ("An electrical or gas corporation that utilizes an advanced metering infrastructure that allows a customer to access the customer's electrical and gas consumption data shall ensure that the customer has an option to access that data."); ILL. ADMIN. CODE. tit. 83 § 410.210 (discussing how the customer's utility bill should disclose how much energy the customer used during the billing period, how a utility must provide a statement of energy consumption up to the preceding twelve months at the customer's request, and how this information must be clear and concise); 66 PA. CONS. STAT. § 2807(d)(2) ("The commission shall establish regulations to require each electric distribution company, electricity supplier, marketer, aggregator and broker to provide adequate and accurate customer information to enable customers to make informed

For instance, starting in 2010, the New York PUC established a process for providing building owners served by Consolidated Edison (Con Edison) access to energy consumption data.[65] Under that policy, within 15 days of receiving a written request from a multifamily or commercial building owner or manager, Con Edison must provide aggregate building energy usage (in kWhs) and demand (in kW) for up to 24 months prior to the request.[66] If such a request requires a manual review of billing information, Con Edison will be allowed to recover the costs from the requesting party.[67] The data must be provided in aggregate form without revealing identifying customer information.[68] As discussed in the next section, several municipalities also have specific energy consumption data disclosure and reporting requirements for commercial buildings so the New York PUC policy facilitates the ability of building owners in New York City to obtain the data necessary to comply with local government building efficiency and benchmarking laws.

Likewise, Washington state law requires utilities to maintain energy consumption data for nonresidential customers for at least 12 months in a format compatible with ENERGY STAR Portfolio Manager and also requires utilities to upload that data into Portfolio Manager at the building owner's request.[69] Requiring a uniform format is significant as a common complaint about energy consumption data is that even when a utility does make such data available to a

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choices."); 2 TEX. UTIL. CODE § 39.107(b) ("All meter data, including all data generated, provided, or otherwise made available, by advanced meters and meter information networks, shall belong to a customer."); TEX. PUC REGS. § 130(j)(1) ("[A] utility shall provide to a customer the customer's standard customer data, access to the customer's standard customer data in electronic machine-readable form, in conformity with nationally recognized open standards and best practices, in a manner that ensures adequate protections for the utility's system security and the continued privacy of the customer data during transmission."); WASH. ADMIN. CODE § 480-100-153(1) ("An electric utility may not disclose or sell private consumer information with or to its affiliates, subsidiaries, or any other third party . . . unless the utility has first obtained the customer's written or electronic permission to do so."); SEE ACTION, *supra* note __, at 24.

[65] Case 09-E-0428, et al., Con Edison - Electric Rates, Order Establishing Three-Year Electric Rate Plan 2010 WL 1255789 (N.Y.P.S.C.) (issued March 26, 2010) ("[W]ithin 15 days of receipt of a written request of a multi-family or commercial building owner or manager, Con Edison will provide aggregate building energy usage (in kWhs) and demand (in kW) for up to 24 months prior to the request. This information will be provided in aggregate form without revealing particular or identifiable customer information."); RAP, *supra* note __, at 8.

[66] *Id.*

[67] *Id.* ("[W]here the Company's compliance with a building owner's or manager's request requires it to perform a manual review of historical usage or billing information, Con Edison will be allowed to impose a charge to the requesting party to recover the costs associated with such effort.).

[68] *Id*. ("This information will be provided in aggregate form without revealing particular or identifiable customer information.").

[69] WASH. REV. CODE § 19.27A.170(1) ("[Q]ualifying utilities shall maintain records of the energy consumption data of all nonresidential and qualifying public agency buildings to which they provide service. This data must be maintained for at least the most recent twelve months in a format compatible for uploading to the United States environmental protection agency's energy star portfolio manager."); § 19.27A.170(2) ("[A] qualifying utility shall upload the energy consumption data for the accounts specified by the owner or operator for a building to the United States environmental protection agency's energy star portfolio manager."); Mattern, *supra* note __, at 507.

customer or third party, such data is "often out of scope, aggregated beyond what is necessary to protect customer privacy and not useful to the requesters, and outdated."[70]

In sum, at least some states have provided expressly that customers and building owners should have access to energy consumption data and some, like Washington have created policies that require utilities to make such data available in a uniform format that can be more easily analyzed for energy efficiency purposes. However, as noted earlier some states like Texas and Washington have also created additional privacy protections beyond federal law, which may have the purpose of making it more difficult for third parties to access energy consumption data for energy efficiency or research purposes.

2. Third party access to energy consumption data

At least two states, Vermont and Wisconsin, have created formal third-party energy efficiency program administrators and formal agreements with program implementation contractors. Under these circumstances, since the contractors are working directly for the state, the contracts allow for access to customer data to perform the services required.[71] Such services include providing efficient home designs, financial assistance for building upgrades, and smart meter installation and maintenance, all through programs such as Vermont's "Efficiency Vermont" and Wisconsin's "Focus on Energy."[72] In Vermont, the Public Service Board created the nation's first "Energy Efficiency Utility" (EEU) known as "Efficiency Vermont."[73] Efficiency Vermont is administered by Vermont Energy Investment Corporation (VEIC), an independent nonprofit energy services organization under an appointment by the Vermont Public Service Board.[74] Vermont utilities or customers themselves share customer data with Efficiency Vermont, which can share it with other third parties for energy efficiency purposes after the information is

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[70] AUDREY LEE & MARZIA ZAFAR, CALIFORNIA PUBLIC UTILITIES COMMISSION, BRIEFING PAPER, ENERGY DATA CENTER BRIEFING PAPER 2 (Sept. 2012).

[71] SEE ACTION, *supra* note __, at 9, 22. For information on Vermont's third-party contractor access to customer data, *see* Vermont Public Service Board, *Investigation into Dispute Regarding the Provision of Customer Information to Efficiency Vermont by the Village of Hyde Park Electric Department*, Docket No. 6379 (2000) (discussing how the EEU Efficiency Vermont has access to customer data but must follow state confidentiality guidelines); Vermont Public Service Board, *Investigation into the Department of Public Service's proposed Energy Efficiency Plan Re: Phase II*, Docket No. 5980 (1999) (ordering the creation of a Vermont EEU to implement efficiency programs). For information on Wisconsin's third-party contractor access, *see* Wisconsin Public Service Commission, *Provision of Energy Utility Customer Information to Focus on Energy*, Docket No. 9501-GF-101 (2009) (detailing Wisconsin EEU Focus On Energy's confidentiality requirements for access to customer data).

[72] For information regarding Efficiency Vermont and its services, *see General Energy Efficiency Utility Information*, VT PUB. SERVICE BOARD, http://psb.vermont.gov/utilityindustries/eeu/generalinfo (last visited July 9, 2014) (providing general information on Efficiency Vermont's program, services, and accomplishments). For examples of services provided by Focus on Energy, *see Residential*, FOCUS ON ENERGY, https://focusonenergy.com/residential (listing various services offered by Focus on Energy to residencies); *see also Business*, FOCUS ON ENERGY, https://focusonenergy.com/business (providing examples of various energy services Focus on Energy provides to businesses and their buildings).

[73] Efficiency Vermont, FAQs, at https://www.efficiencyvermont.com/About-Us/Oversight-Reports-Plans/FAQs.

[74] Efficiency Vermont, FAQs, at https://www.efficiencyvermont.com/About-Us/Oversight-Reports-Plans/FAQs.

aggregated or the third party signs Efficiency Vermont's Privacy Policy.[75] However, such data must be aggregated at a level no smaller than the "town" level.[76] In Wisconsin, the administrator enters into individual agreements with utilities on how the data will be handled and used, including specifying that the administrator will protect the confidentiality of the customer data, how long the data will be retained, that the administration will destroy the information at a particular time, and that it will pay a penalty for unauthorized release of the data.[77]

Other states that have not created such formal energy efficiency programs have nevertheless enacted laws governing the ability of private EESPs to obtain access to customer data. In Colorado, Texas, and Washington, EESPs and other third parties cannot obtain individual customer data without express customer consent.[78] Some of these states, however, have allowed EESPs to obtain aggregated data without customer consent since such aggregated data does not pose the same privacy concerns as individualized data.[79] Moreover, aggregated data can provide valuable information on commercial and industrial building benchmarking and target energy efficiency opportunities in particular neighborhoods, counties, or geographic regions of the country.[80] But the ability to obtain even aggregate data without customer consent is uncertain in most states and, even where a state policy exists, it is often subject to numerous requirements making the aggregate data difficult to obtain and analyze.[81]

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[75] Efficiency Vermont, Efficiency Vermont Privacy Policy, at https://www.efficiencyvermont.com/About-Us/Privacy-Policy.

[76] SEE ACTION, *supra* note __, at 22. Vermont Public Service Board, *VEIC Order of Appointment Process & Administrative Document*, Docket No. 7466, 2010 WL 125775 (Vt.Pub. Serv. Bd. 2010) (directing how Vermont utilities may share customer data).

[77] SEE ACTION, *supra* note __, at 9, 22; AUDREY LEE & MARZIA ZAFAR, CALIFORNIA PUBLIC UTILITIES COMMISSION, BRIEFING PAPER, ENERGY DATA CENTER BRIEFING PAPER 9 (Sept. 2012) (describing Vermont and Wisconsin programs).

[78] 4 COLO. CODE REGS. § 723-3:3030(a) ("Except as outlined in paragraphs 3026(b) and 3029(a), a utility shall not disclose customer data to any third-party unless the customer or a third–party acting on behalf of a customer submits a paper or electronic signed consent."); 2 TEX. UTIL. CODE § 39.107(b) ("All meter data . . . shall belong to a customer, including data used to calculate charges for service, historical load data, and any other proprietary customer information. A customer may authorize its data to be provided to one or more retail electric providers under rules and charges established by the commission."); WASH. ADMIN. CODE § 480-100-153 ("An electric utility may not disclose or sell private consumer information with or to its affiliates, subsidiaries, or any other third party . . . unless the utility has first obtained the customer's written or electronic permission to do so.").

[79] 4 Colo. Code Regs. § 723-3:3031 (describing acceptable aggregated data in Colorado); Wash. Admin. Code § 480-100-153(7) ("The utility may collect and release customer information in aggregate form if the aggregated information does not allow any specific customer to be identified.").

[80] SEE Action, *supra* note _, at viii ("Aggregated data . . . allows program administrators, PICs, or EESPs to determine trends and evaluate results so that they, for example, can identify specific geographic areas or demographic groups that may have a higher ability to benefit from energy efficiency programs or services.").

[81] *See, e.g.*, 4 COLO. CODE REGS. § 723-3:3031(a)–(f) (outlining Colorado's 15/15 Rule, a state regulation of the release of aggregated data).

For instance, the Colorado PUC has adopted a "15/15" rule that governs the release of aggregated customer data upon the request of EESPs, building owners, or other third parties.[82] This rule provides that at a minimum an aggregated data report must contains at least 15 customers or premises and that within any customer class, no single customer's data or premise may comprise 15 percent or more of the data aggregated in the report.[83] If a third party or building owner requests a report that does not ensure customer privacy, the utilities must revise the report by including additional customers, expanding the geographic area, or taking other measures to ensure the report meets the rule.[84] Although Colorado has at least taken steps to create a program for third party access to energy consumption data, critics complain that the transfer of aggregate data from utilities to local governments and others is slow and often inadequate.[85] This problem has, for instance, resulted in Boulder, Colorado being unable to evaluate its greenhouse gas emissions since 2010.[86]

Likewise, in its May 2014 "Decision Adopting Rules to Provide Access to Energy Usage and Usage-Related Data While Protecting Privacy of Personal Data," the California PUC adopted rules providing for access to energy consumption data by local governments, researchers, and government agencies.[87] The decision created different categories of protection based on what entity was seeking the data and based on the character of the data sought. Thus, the decision created different rules for energy consumption data sought by local governments, building owners seeking building energy usage data, researchers, and other third parties such as solar PV installers. The decision also established separate aggregation levels for public release of data without consent for residential customers, commercial and agricultural customers, and for industrial customers.

For any regular building owner requesting data, the "request must have 15 or more customers, with no single account accounting for more than 20% of the total consumption in any interval requested."[88] Yet, for third parties requesting energy consumption data, "this decision requires the consent of the person to whom the usage or usage-related data pertains before the release of that data to a third party," but permits the disclosure of aggregated data with no personally identifiable information without customer consent.[89] For residential customers, data stripped of

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[82] 4 COLO. CODE REGS. § 723-3:3031(a)–(f) (providing the rules for aggregated data disclosure from Colorado utilities, including what customer and energy usage information can and cannot be provided in utility reports); REGULATORY ASSISTANCE PROJECT (hereinafter "RAP"), DRIVING BUILDING EFFICIENCY WITH AGGREGATED CUSTOMER DATA 9 (July 2013).
[83] *Id.*
[84] *Id.*
[85] Colo. P.U.C., *Possible Revisions and Additions to Electric and Gas Rules*, Docket no. 13M-1052EG, 4 (2014) ("While the current 15/15 rule is an opt-in process, it is administratively burdensome, and has resulted in a slow and sometimes insufficient transfer of aggregated data from utilities to local governments in the state.").
[86] *Id.* at 12.
[87] Decision Adopting Rules to Provide Access to Energy Usage-Related Data While Protecting Privacy of Personal Data, 2014 WL 1931946 (Cal. P.U.C., May 1, 2014), *1 (summarizing the purpose of the decision).
[88] *Id.* at *20.
[89] *See id.* at *11 (describing how access to data depends on the characteristics of the data sought); Cal. P.U.C., Decision Adopting Rules to Protect the Privacy & Security of the Elec. Usage Data of the Customers of Pacific Gas and Elec. Company, Southern California Edison Company, & San Diego Gas & Electric Company, Decision 11-07-056, at 87 (2011) (allowing the third party use of "aggregated data that is removed of all personally-identifiable information to be used for analysis, reporting or program management provided that the release of that data does not

personal identifying information, aggregated to a monthly time period and aggregated to the zip code level can be made publically available unless the zip code lacks 100 residential customers, in which case the zip code data must be combined with neighboring zip code data to equal 100 customers. For commercial and agricultural customers, as well as for industrial customers, the decision imposed a 15/15 rule, similar to Colorado, for public disclosure. The California PUC also established different aggregation levels for residential data than it did for commercial, industrial, and agricultural data.[90] According to the PUC using these aggregation rules allows parties to bypass traditional information gathering practices of contracts between utilities and third parties, awaiting an order from the PUC, or gaining the direct consent of the customer.[91] The PUC also set a timetable and data production formats for utilities to make such data available.

The PUC allowed more granular data to be released to local governments, allowing residential, commercial, and agricultural data to be aggregated to the census block level rather than by zip code or under a 15/15 rule,[92] and imposing a 5/25 rule for industrial customers.[93] Researchers can obtain even more granular data but must adhere to requirements regarding the scope of research, data handling, and privacy assurances.[94]

For any issues that arise between a requesting party and the utility, the PUC created the Energy Data Access Committee "to advise the utilities on process improvements and best practices

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disclose or reveal specific customer information."); *see also* PUB. UTIL. CODE § 8380(e)(1) (allowing aggregated consumption data to be disclosed if all personal identification is removed); RAP, supra note __, at 9 & n.31; Nadav Malin, *Energy Reporting: It's the Law*, BUILDINGGREEN (July 30, 2012), http://www2.buildinggreen.com/article/energy-reporting-its-law ("The problem became more manageable after the California Public Utilities Commission ruled in July 2011 on data privacy issues related to smart meters. That ruling clarified when and how this kind of data can be used, and who can have access to it.").

[90] Decision Adopting Rules to Provide Access to Energy Usage-Related Data While Protecting Privacy of Personal Data, 2014 WL 1931946 at *20 (Cal. P.U.C., May 1, 2014) (The level for residential, commercial, and agricultural customers is 15 or more customers with no one customer accounting for more than 20% of total consumption in the interval. For industrial customers, the level is five or more industrial customers with no single customer accounting for more than 25% of total consumption for any interval requested. For all levels, the requested data must not contain identifying information for any account); Malin, *supra* note __ ("The California disclosure requirement takes effect in stages, beginning on January 1, 2013, with transactions involving commercial buildings over 50,000 ft.").

[91] *See* CAL. PUB. UTIL. CODE § 8380(e)(2) ("provided that, for contracts entered into after January 1, 2011, the utility has required by contract that the third party implement and maintain reasonable security procedures and practices appropriate to the nature of the information."); CAL. PUB. UTIL. CODE § 8380(e)(3) ("This section shall not preclude an electrical corporation or gas corporation from disclosing electrical or gas consumption data as required or permitted under state or federal law or by an order of the commission."); *id.* § 8380(b)(1) ("An electrical corporation or gas corporation shall not share, disclose, or otherwise make accessible to any third party a customer's electrical or gas consumption data, except as provided in subdivision (e) or upon the consent of the customer").

[92] Decision Adopting Rules to Provide Access to Energy Usage-Related Data While Protecting Privacy of Personal Data, 2014 WL 1931946 (Cal. P.U.C., May 1, 2014), *15 ("15 commercial or agricultural customers, with no single account constituting more than 15% of the total consumption in any month for the combined zip codes.").

[93] *Id.* at *84 ("When requested by local government entities, industrial energy consumption data, anonymized over a group consisting of five customers in a single customer class and stripped of all personal identifying information, cannot be re-identified when the group contains five or more customers and no single customer accounts for more than 25%.").

[94] *Id.* at *19 (discussing access to granular data and various limitations).

related to data access and help mediate disagreements."[95] In addition to this measure, the 2014 decision discusses the potential for creating an "Energy Data Center" that would collect and retain some level of aggregated energy consumption data for public and third party access.[96] In a 2012 briefing paper, the CPUC explored current challenges to accessing aggregated data and found that "[c]onsolidating that information in one location, such as a data center, should help improve state energy policies and create new market opportunities to save energy."[97] Such a data center could help address concerns surrounding "over-aggregated" data devoid of any helpful customer consumption data, as well as differing interpretations of the Commission's data rules by different utilities. The 2012 CPUC briefing paper concluded that creation of an Energy Data Center would aggregate data to a point where it would protect personal information while allowing for viable use by the public and facilitating the transfer of information from utilities to third parties such as governmental entities.[98] In its 2014 decision, the CPUC declined to create an Energy Data Center at that time but agreed to study the issue in subsequent agency proceedings.[99]

Under Oklahoma law, utilities may disclose "aggregate usage data" to third parties and the public without customer consent for energy assistance and conservation purposes.[100] "Aggregate usage data" is defined as "data from which all identifying information has been removed such that the individual usage data of a customer cannot without extraordinary effort and expertise be associated with the identifying information of that customer."[101] The law also provides that aggregate usage data "shall contain a sufficient number of similarly situated customers within a particular geographic area so that the daily usage routines or habits of an individual customer could not be reasonably deduced from the data."[102]

In order to further ensure that customer privacy is protected even after customer consent to third-party access, certain states have established post-consent safeguards for customer data. For instance, Colorado requires third parties to destroy customer data after the intended purpose is accomplished while California and Vermont require third parties to maintain specific security

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[95] *Id.* at *1.
[96] *Id.* at *3 ("Finally, the workshops, which also explored issues relating to an Energy Data Center, anticipated that these steps might ameliorate the immediate need for a data center.").
[97] AUDREY LEE, ENERGY DATA CENTER 1 (C.P.U.C. Policy and Planning Division, 2012), *available at* http://www.cpuc.ca.gov/NR/rdonlyres/8B005D2C-9698-4F16-BB2B-D07E707DA676/0/EnergyDataCenterFinal.pdf.
[98] *Id.* at 2–3 (listing possible roles for an Energy Data Center and how those roles would correct issues within the current data accessibility framework).
[99] Order Instituting Rulemaking to Consider Smart Grid Technologies Pursuant to Federal Legislation and on the Commission's own Motion to Actively Guide Policy in California's Development of a Smart Grid System, 2014 WL 1931946 (Cal.P.U.C.), 16 ("[T]he Commission continues to see the importance of exploring the value of a dedicated energy data center in the future to increase access to data while developing reasonable protections on customer privacy.").
[100] OKLA. STAT. tit. 1, § 710.7 (describing how utilities may disclose aggregated information to third parties and the public, and the restrictions on how the information must be disclosed). For more information on Oklahoma laws protecting electricity usage data, *see generally id.* at §§ 710.1–710.8 (providing definitions and a framework for the use and disclosure of electricity usage information); RAP *supra* note __, at 8.
[101] *Id.* at § 710.3(1).
[102] *Id.* at § 710.7(B)(2).

measures regarding the data.[103] For California, although a utility may freely disclose customer usage information for such purposes as energy efficiency, demand management, or utility administration, for all disclosures the utility must "use reasonable security procedures and practices to protect a customer's unencrypted electrical or gas consumption data from unauthorized access, destruction, use, modification, or disclosure."[104] In Vermont, the EEU and any third party must adhere to the rules of the Confidential Information Management System (CIMS), a state program developed to identify what information is confidential and how best to prevent disclosures of that data to any unauthorized parties.[105]

The Texas Public Utilities Commission has also acted to provide additional protection of energy consumption data through a 2014 Order adopting new § 25.44 and § 25.500 of the Public Utility Regulatory Act. The new regulations prohibit utilities from selling or disclosing information from advanced metering systems.[106] Under § 25.44, "[a]n electric utility shall not sell, share, or disclose information generated, provided, or otherwise collected from an advanced metering system or meter information network," including energy consumption data, with an exception for third parties affiliated or contracted with the utility and using that information for customer approved services.[107] Similarly, under § 25.500 "[a] transmission and distribution utility shall not sell, share, or disclose information generated, provided, or otherwise collected from an advanced metering system or meter information network," unless allowed by a customer.[108] Therefore, under these new regulatory provisions, a utility may not release any energy consumption data to third parties without customer consent.

Both the Michigan PSC and the Minnesota PUC have proceedings underway to establish rules

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[103] 4 Colo. Code Regs. § 723-3:3029 ("A utility may disclose customer data to a contracted agent provided that the contract meets the following minimum requirements: . . . Destroy any customer data that is no longer necessary for the purpose for which it was transferred."); CAL. PUB. UTIL. CODE § 8389 (listing how electric utilities must safeguard consumption data); Vermont Public Service Board, *Investigation into Dispute Regarding the Provision of Customer Information to Efficiency Vermont by the Village of Hyde Park Electric Department*, Docket No. 6379 (2000) (introducing third party adherence to the privacy guidelines of the Confidential Information Management System).

[104] CAL. PUB. UTIL. CODE § 8380(d); *See also id.* at § 8380(e)(2) (describing how a utility may disclose information for its contract's primary purpose, as long as it protects personal information from unauthorized access, use, or disclosure).

[105] Vermont Public Service Board, *Investigation into Dispute Regarding the Provision of Customer Information to Efficiency Vermont by the Village of Hyde Park Electric Department*, Docket No. 6379 (2000); for more information on CIMS guidelines, *see* EFFICIENCY VERMONT, CONFIDENTIAL INFORMATION MANAGEMENT SYSTEM (2011) (listing the criteria for identifying confidential information, and the confidentiality procedures to protect that information).

[106] PUC Rulemaking Related to the Implementation of PURA, 2014 WL 1826803 (Tex. P.U.C., April 17, 2014), 1 ("The Public Utility Commission of Texas (commission) adopts new § 25.44, relating to Privacy of Advanced Metering System Information, and new § 25.500, relating to Privacy of Advanced Metering System Information, with changes to the proposed text as published in the January 3, 2014 issue of the Texas Register."). For information on the Public Utility Regulatory Act, *see* TEX. UTIL. CODE ANN. § 39.107 (West) (outlining metering and billing service requirements for Texas utilities).

[107] V.T.C.A., UTILITIES CODE § 25.44 (2013).

[108] V.T.C.A., UTILITIES CODE § 25.500 (2013).

governing disclosure of energy consumption data aggregation levels appropriate for disclosure to third parties for energy efficiency purposes without customer consent.[109] In the meantime, customer energy use data in those states is generally disclosed only pursuant to utility privacy policies and tariffs.

In the case of Michigan, in a 2013 Order on energy consumption data, the PSC ordered participating utilities to "file in this docket proposed customer data privacy tariffs for gas and electric service."[110] This order came after the PSC ordered utilities to comment on a PSC proposed customer privacy framework.[111] The proposed policy required customer consent for disclosure of energy consumption data, but also contained provisions for aggregated data with utility options for using a 15/15 standard of aggregation or a standard that is similarly protective of customer privacy.[112]

As for Minnesota, in a June 17, 2013 Order requesting further comments on proposed privacy policies of rate-regulated energy utilities, the Minnesota PUC proceeded with an investigation into the collection, storage, and dissemination of customer data to determine appropriate use of such data.[113] The PUC's stated purpose was to balance customer privacy and meet state energy efficiency goals.[114] To facilitate the identification of desired energy consumption data practices, the PUC created a working group to address the scope and definitions of energy consumption data and its collection and maintenance.[115] The working group issued a final report in September 2017, setting forth a framework to address the various privacy and data access goals of numerous parties; recommended components of any adopted state standard; a range of "use cases" including request for individual customer data, whole building data, geographic data, research requests, and government requests; and various options for aggregation levels.[116]

In 2014, the Illinois PUC began proceedings to create a new framework to guide utilities in

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[109] REGULATORY ASSISTANCE PROJECT, DRIVING BUILDING EFFICIENCY WITH AGGREGATED CUSTOMER DATA 11 (July 2013).

[110] Re Customer Information and Data Privacy, 2013 WL 3355856 (Mich. P.S.C., June 28, 2013) at *11 (directing certain energy utilities to adopt data privacy tariffs).

[111] *Id.* at *1 (describing the background of Michigan PSC's order).

[112] *Id.* at *12 ("Providers may opt to include "15/15 rule" here, or other method of data aggregation."). *See also id*. at Appendix A (defining aggregated data).

[113] In the Matter of a Commission Inquiry Into Privacy Policies of Rate-Regulated Utilities, 2013 WL 3009192 (Minn. P.U.C., June 17, 2013), at *5 ("The Commission will proceed in this docket to investigate the collection, storage, and dissemination of customer data, focusing the inquiry as informed by the responses to the Commission's initial questions.").

[114] *Id.* ("However the Commission seeks to identify and, to the extent appropriate, enact utility customer data practices that strike an appropriate balance between the interests of customer privacy and pursuit of state energy goals, while ensuring adequate and reliable services at reasonable rates.").

[115] *Id.* (describing the MPUC's delegation of authority to the Executive Secretary to further investigate energy consumption data-related issues and framework).

[116] MINN. PUC, CUSTOMER ENERGY USAGE DATA: BALANCING CUSTOMER PRIVACY AND MINNESOTA'S ENERGY GOALS, FINAL REPORT OF THE CEUD WORKGROUP, Sept. 15, 2014, at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=viewDocument&documentId={E73ECFE2-6CC9-4934-8364-6AE4F2EDE59D}&documentTitle=20149-103119-01&userType=public.

administering new data systems required under the state's smart grid law, called the Energy Infrastructure Modernization Act.[117] Under the Act, electricity providers must maintain records and report annually their total number of net metering users as well as promote the state's electric utility infrastructure through investments in economic and infrastructure development through use of such tools as smart meters.[118] In addition to the expansion of modern energy practices, the purpose of the Act is to secure the privacy of personal information and the right of customers to their usage information, and also outline the process of information disclosure between customers, utilities, and third parties.[119]As of 2014, the Illinois Commerce Commission (ICC) was accepting proposals from any interested parties to help promulgate specific rules to implement the law and inform utilities how to comply with it.[120] As the ICC notes, "there is no Commission order addressing issues such as how . . . customer usage should be provided, how often it should be provided, or how long authorization should be effective for."[121] Thus, the ICC specifically wants to answer the questions of who "owns" a household's energy use data, and how this information can be accessed by a third party.[122] This proceeding must be completed by April 2015, before the affected utilities' annual reviews.[123]

Answering the ICC's request for comments, the Citizens Utility Board and the Environmental Defense Fund, two non-profit organizations, filed a proposed Open Data Access Framework for handling customer energy data.[124] Under this framework a customer owns his or her electric consumption data and can disclose this information to a third party.[125] Customer access will be in fifteen-minute intervals, along with monthly aggregate consumption data for billing purposes.[126] Data may be delivered to the customer by the utility either directly from the meter or the Internet,

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[117] Energy Infrastructure Modernization Act, Pub. Act 097-0616, 220 ILCS 5/16-107.5(h) (2012) ("Within 120 days after the effective date of this amendatory Act of the 95th General Assembly, the Commission shall establish standards for net metering"); Kari Lydersen, *Illinois Grapples with Question of Who Owns Energy Data*, MIDWEST ENERGY NEWS (Aug. 28, 2013), http://www.midwestenergynews.com/2014/08/28/illinois-grapples-with-question-of-who-owns-energy-data/ (outlining Illinois's actions regarding the use and growth of new data systems).

[118] Energy Infrastructure Modernization Act, §§ 16-107(k), 16-108.5 (describing the process and purpose of improving energy infrastructure).

[119] *Id.* at §16-108.6(c)–(d) (providing the rules regarding data access).

[120] Lydersen, *supra* note __ ("These issues are being debated in Illinois before the Illinois Commerce Commission, which will in coming months adopt a framework.").

[121] Illinois Commerce Commission, Verified Petition of the Citizens Utility Board and Environmental Defense Fund to Initiate a Proceeding to Adopt the Illinois Open Data Access Framework, Docket No. 14-0507 (2014).

[122] Lydersen, *supra* note __ (listing several questions that the ICC plans to answer).

[123] *Id.* ("The proceeding must be completed before the utilities' annual review, including their smart grid deployment plans, in April 2015.").

[124] CITIZENS UTILITY BOARD & ENVIRONMENTAL DEFENSE FUND, OPEN DATA ACCESS FRAMEWORK, 1 (2014), *available at* (http://blogs.edf.org/energyexchange/files/2014/08/14-0507-CUB-EDF-Exhibit-1-1-Open-Data-Access-Framework-FINAL.pdf (providing guidance to the ICC for customer energy data access issues).

[125] CITIZENS UTILITY BOARD & ENVIRONMENTAL DEFENSE FUND, OPEN DATA ACCESS FRAMEWORK, 1 (2014), *available at* (http://blogs.edf.org/energyexchange/files/2014/08/14-0507-CUB-EDF-Exhibit-1-1-Open-Data-Access-Framework-FINAL.pdf ("Customer is principal owner of retail electric consumption data. The customer has the ability to affirmatively authorize third parties to access individual customer data, and the customer can revoke that access at the customer's discretion. The utility serves as the guardian of retail electric consumption data, and must allow access to third parties where the customer has authorized it.").

[126] *Id.* (describing customer access rights).

through a web portal, mobile applications, or bulk transfers.[127] When a third party seeks access to customer data without customer authorization, access is limited by the state's 15/15 rule permitting utilities to provide requesting parties twelve months of anonymized data containing information from at least fifteen customers within the same zip code such that no one customer's data constitutes more than fifteen percent of the entire group's data.[128] Currently, "there is no Commission order addressing issues such as how [that] customer usage should be provided, how often it should be provided, or how long authorization should be effective for."[129]

In addition to these state initiatives and programs, several other states are currently considering laws that would require energy rating and disclosure, and Massachusetts is considering a public website for energy consumption data.[130] Specifically, Massachusetts utilities would utilize a web portal to access energy consumption data in order to meet the state PUC requirements for its ten-year grid modernization plan.[131] Through a 2014 Order regarding the modernization of the electric grid, the PUC requires all electric distribution companies to submit a ten-year grid modernization plan to meet grid modernization goals, including reducing customer and system costs as well as improving asset management.[132] Utilities can meet these goals through monitoring customer energy usage with customer permission.[133] Also through this plan "the Department intends to address privacy, data access, and the use of aggregated interval data in more detail well before any wide-scale collection of interval data takes place."[134] Such measures include increased cyber-security measures, as well as the need for customer consent for energy consumption data.[135] According to one commentator, "[a]lthough tracking the information is a step in the right direction, if it never gets into the market, it could be a missed opportunity."[136]

C. Local Government Policies on Energy Consumption Data: Building Efficiency and Benchmarking

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[127] *Id.* at 3 (listing data delivery methods).
[128] *Id.* at 2 (outlining Illinois's 15/15 rule).
[129] Illinois Commerce Commission, Verified Petition of the Citizens Utility Board and Environmental Defense Fund to Initiate a Proceeding to Adopt the Illinois Open Data Access Framework, Docket No. 14-0507 (2014).
[130] Katherine Tweed, *Energy Benchmarking Picks Up Steam in the US*, GREENTECH MEDIA (May 24, 2011), http://www.greentechmedia.com/articles/read/energy-efficiency-benchmarking-pushes-retrofits-to-the-limelight (describing various benchmarking programs in U.S. states and cities).
[131] Modernization of the Electric Grid, 2014 WL 2883889 (Mass. D.P.U., June 12, 2014) at *14 (providing information on how utilities may fulfill their requirements for the grid modernization plan).
[132] *Id.* at *1 (describing the requirement for grid modernization plans and how these plans will be used).
[133] *Id.* at *5 ("Through mechanisms such as TVR and, with customers' permission, monitoring and control of customer appliances or equipment, a modernized grid will facilitate the reduction of peak demand by allowing retail customers to respond to price signals, as they currently do for airline tickets, hotel reservations, and other purchases.").
[134] *Id.* at *3.
[135] *Id.* at *16 ("[I]n their GMPs, electric distribution companies should address: (1) how customers will be provided access to consumption data that can be easily understood; (2) the procedures for allowing an authorized third party to access customer usage data with the customer's permission; and (3) procedures for making aggregate usage data available to third parties and ensuring that it cannot be linked to any individual customer.").
[136] Katherine Tweed, *supra* note __.

In addition to the federal and state policies discussed above, many local governments have created energy consumption data policies aimed at allowing building owners and potential building owners to better utilize energy consumption data to increase energy efficiency of buildings and to better inform potential purchasers of a building's current level of energy efficiency. Many of these policies are referred to as commercial building "benchmarking" programs. Benchmarking tracks and summarizes on an annual basis the energy used by an entire building, enabling building owners, potential building owners, municipalities, and others to track trends and comparisons of similar buildings under similar conditions on a local, state, or national level.[137]

The cities of Austin, Seattle, Minneapolis, and New York all impose some form of benchmarking requirements on commercial buildings and some information disclosure to local governments or prospective buyers to increase demand for energy efficient buildings.[138] Most building owners comply using ENERGY STAR Portfolio Manager, which allows owners and others to track building performance over time and compare similar buildings.[139] The municipal policies differ as to which buildings are covered, the timing of disclosure, and the role of utilities in assisting with benchmarking.[140] Benchmarking is particularly difficult in situations where tenants pay electricity bills directly to the utility, thus requiring a mechanism for building owners to obtain access to customer utility data.[141]

For instance, New York City's benchmarking program, Local Law 84, requires owners of single buildings 50,000 square feet and larger, two or more buildings on the same tax lot exceeding 100,000 square feet, and city buildings 10,000 square feet or more, to annually report their

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[137] *See, e.g.*, Lawrence Berkeley Nat'l Labs., Energy Benchmarking for Buildings and Industry, at http://energybenchmarking.lbl.gov/; Mattern, *supra* note __, at 488, 498.

[138] AUSTIN, TEX., CODE ch. 6–7, art. 1, §6-7-1(1) (2011) (Austin benchmarking program); SEATTLE MUNICIPAL CODE § 22.920.030 (2009) (amended by SEATTLE ORD. 123993 § 3 (2012) and SEATTLE ORD. 123226 § 1 (2010)) (Seattle benchmarking program); MINNEAPOLIS, MINN., REV. ORDINANCE ch. 47.190 (2013) (Minneapolis benchmarking program); N.Y. L.L. 84 § 28.309.3–309.4 (2009) (New York City benchmarking Program).

[139] SEATTLE MUNICIPAL CODE § 22.920.030 (2009) (amended by SEATTLE ORD. 123993 § 3 (2012) and SEATTLE ORD. 123226 § 1 (2010)) ("Building owners of each building subject to annual benchmarking requirements shall provide to the Director, using the Energy Star Portfolio Manager . . . an initial energy benchmarking report."); MINNEAPOLIS, MINN., REV. ORDINANCE ch. 47.190(a) (2013) ("*Energy Star Portfolio Manager* means the tool developed and maintained by the United States Environmental Protection Agency to track and assess the relative energy performance of buildings nationwide."). N.Y. L.L. 84 § 28-309.5 ("Information shall be directly uploaded to the benchmarking tool."). Austin Texas does not require the use of EnergyStar, and may exempt building owners from benchmarking requirements for previous use of EnergyStar to upload energy audit information. AUSTIN, TEX., CODE ch. 6–7, art. 1, §6-7-1(1) (2011) ("This article does not apply to a residential facility if one or more of the following apply: . . . the facility participated in the Austin Energy Home Performance with Energy Star program, or an equivalent Austin Electric Utility program, not more than ten years before the time of sale.").

[140] AUSTIN, TEX., CODE ch. 6–7, art. 1, §6-7 (2011) (providing requirements for covered buildings, when information must be submitted, and how the utility may facilitate reporting); SEATTLE MUNICIPAL CODE § 22.920 (2009) (amended by SEATTLE ORD. 123993 § 3 (2012) and SEATTLE ORD. 123226 § 1 (2010)) (same); MINNEAPOLIS, MINN., REV. ORDINANCE ch. 47.190 (2013) (same); N.Y. L.L. 84 § 28.309.2, 28.309.3, 28.309.5 (2009) (same).

[141] N.Y. L.L. 84 § 28.309.4.1 (describing the process for how a building owner must acquire tenant consumption data when the tenant is separately metered by the utility).

energy and water consumption data.[142] If the building owner does not have access to aggregated building information from its meters, this information can be requested from utilities such as ConEdison,[143] or from individual building tenants.[144] To increase access to aggregated information from utilities, the city encourages utilities to directly upload consumption information to the benchmarking tool, bypassing the need to get this information from building owners and tenants.[145] Beginning in late 2012, the New York City Mayor's Office presented improvements to the benchmarking program to increase the amount and accuracy of consumption reports, such as by having aggregated information solely generated by utilities instead of requiring building owners to gather this data from multiple tenants.[146] Such recommendations were meant to increase the effectiveness of the program by allowing for more direct uploading of energy consumption data from utilities and building meters, possibly decreasing the use of third-party consultants by city building owners to gather and submit this information.[147]

Once all building information is submitted through the benchmarking tool, consumption information is annually posted on the Internet for the public to view and building owners to compare consumption with other buildings.[148] Currently, "[o]f the five cities that have active legislation, only New York City, San Francisco and Washington, D.C. will require buildings to disclose the information on a public website."[149] Yet, due to the lobbying of various NYC building owners, Local Law 84 exempts buildings with ten percent or more of their floor space devoted to data centers, trading floors, or broadcast studios from receiving and posting

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[142] N.Y. L.L. 84 § 28.309.3–309.4 (listing the benchmarking requirements for city and privately-owned commercial buildings). SEATTLE MUNICIPAL CODE § 22.920.050 (2009) (amended by SEATTLE ORD. 123993 § 3 (2012) and SEATTLE ORD. 123226 § 1 (2010)) ("Each tenant located in a building subject to this chapter shall, within 30 days of a request by the building owner, provide in a form that does not disclose personally-identifying information, all information that cannot otherwise be acquired by the building owner and that is needed by the building owner to comply with the requirements of this chapter.").

[143] *Aggregated Consumption Frequently Asked Questions*, CONEDISON, http://www.coned.com/energyefficiency/PDF/FAQ-Aggregated-Consumption.pdf (last visited July 11, 2014) (discussing how a building owner may request consumption data from the utility).

[144] N.Y. L.L. § 28-309.4.1 ("Where a unit or other space in a covered building, other than a dwelling unit, is occupied by a tenant and such unit or space is separately metered by a utility company, the owner of such building shall request from such tenant information relating to such tenant's separately metered energy use.").

[145] N.Y. L.L. § 28-309.5.1 (describing the direct upload process of ECD by utilities within the NYC benchmarking program).

[146] PlaNYC, New York City Local Law 84 Benchmarking Report 22, 38 (2013), *available at* http://nytelecom.vo.llnwd.net/o15/agencies/planyc2030/pdf/ll84_year_two_report.pdf (since LL84 went into effect, both companies have made aggregated whole building data available. Consequently, sending the letter to tenants is now an unnecessary burden. The Mayor's Office will remove this requirement from the law."). Other recommendations include the creation of automatic upload systems for consumption information, more accurate gross floor area measurements for buildings, and improving benchmarking reporting through updates to the Portfolio Manager tool and creation of a National Energy Efficiency Data System. *Id.* at 39–40.

[147] Malin, *supra* note __ (describing the use of consultants by NYC building owners to submit their building benchmarking reports and comparing it with Seattle's direct upload program).

[148] *Id.* at §28-309.8 (providing the process for disclosure of benchmarking information to the public).

[149] Katherine Tweed, *supra* note __ (discussing energy benchmarking programs in various U.S. cities).

benchmarking ratings.[150] Such exemptions are meant to prevent inaccuracies within Portfolio Manager that may not account for these high intensity uses in its energy scoring.[151] However, such exemptions limit public knowledge of the energy intensive nature of such buildings and may limit new policies to improve energy efficiencies in such buildings.

Local Law 84 falls within NYC's Greener, Greater Buildings Plan, which is designed to make 15,000 properties 50,000 square feet and larger more energy efficient through access to energy consumption data and the use of cost-effective efficiency practices.[152] Created in 2009, this overall energy plan includes four regulations that include the benchmarking within Local Law 84, the NYC Energy Conservation Code within Local Law 85, energy audits and retro-commissioning through Local Law 87, and lighting upgrading and sub-metering through Local Law 88.[153] The plan's goal is to reduce greenhouse gases by five percent, save NYC buildings seven billion dollars, and create thousands of jobs.[154] Together, these four regulations constituted the first effort by an American city to create a mandatory program to reduce emissions from large buildings.[155] Since its inception, the program has seen multiple highlights such as the benchmarking of 2,730 buildings, 130 building energy retrofits stemming from data reporting, and a reduction of 10–15% of city energy usage.[156]

Seattle requires owners of all non-residential and multifamily buildings 20,000 square feet and larger to report energy benchmarking data to the city by April 1 of each year, while buildings smaller than 20,000 square feet may voluntarily report this data.[157] These reports are to be

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[150] N.Y. L.L. 84 § 28-309.8 ("Ratings generated by the benchmarking tool for a covered building that contains a data center, television studio, and/or trading floor that together exceed ten percent of the gross square footage of any such building shall not be disclosed until the office of long-term planning and sustainability determines that the benchmarking tool can make adequate adjustments for such facilities.").

[151] PlaNYC, *supra* note __, at 27 ("LL84 Section 28-309.9(v) includes a disclosure exemption for the scores for buildings in which high intensity uses like data centers, trading floors and television studios comprise more than 10% of the floor area, because of concern that Portfolio Manager does not accurately account for those uses.").

[152] *Greener, Greater Buildings Plan*, PLANYC, http://www.nyc.gov/html/gbee/html/plan/plan.shtml (last visited July 15, 2014) (providing background information on NYC's Greener, Greater Buildings Plan).

[153] *Id.* (listing the four regulations included in the Greener, Greater Buildings Plan). For a definition of "retro-commissioning, *see* N.Y. L.L. 87 § 28-308.1 ("A systematic process for optimizing the energy efficiency of existing base building systems through the identification and correction of deficiencies in such systems, including but not limited to repairs of defects, cleaning, adjustments of valves, sensors, controls or programmed settings, and/or changes in operational practices.").

[154] *Id.* ("These laws will reduce greenhouse gas emissions by almost five percent, have a net savings of $7 billion, and create roughly 17,800 construction-related jobs over 10 years.").

[155] Stu Loeser, Press Release, *Mayor Bloomberg Signs Landmark Package of Legislation to Create Greener, Greater Buildings in New York City* (Dec. 28, 2009) (on file with NYC.gov) ("The first four of twelve bills before me today are Introductory Numbers 476-A, 564-A, 967-A and 973-A, which together form a landmark package of legislation that will make New York the first American city with a comprehensive, mandatory effort to reduce emissions from existing large buildings.").

[156] Don Knapp, *New York City Leads on Benchmarking Building Energy Efficiency*, ICLEI USA, http://www.icleiusa.org/blog/new-york-city-leads-on-benchmarking-building-energy-efficiency (highlighting results from NYC's Greener, Greater Buildings Plan).

[157] SEATTLE MUNICIPAL CODE § 22.920.030 (2009) (amended by SEATTLE ORD. 123993 § 3 (2012) and SEATTLE ORD. 123226 § 1 (2010)) ("For buildings smaller than 50,000 square feet and larger than 20,000 square feet and

submitted using ENERGY STAR Portfolio Manager or a similar system.[158] The building owner may either collect energy usage data on its own, such as through collection from tenants, or may request this information directly from the utility. If a current tenant's energy usage information cannot be otherwise obtained by the building owner the tenant is required to submit such data to the owner without personally identifying information.[159] Utilities must also maintain energy consumption data for benchmarked buildings for the most recent twelve months, in a form compatible with the reporting system used, to allow for easy access to this information by a building owner for reporting or for the utility to directly upload to the city system at the request of the owner.[160]

Also, the building owner must provide an energy disclosure report to a current tenant, prospective tenant, or lender involved with a real estate transaction upon their request.[161] This requirement is to allow the real estate market to make energy and efficiency comparisons between buildings that can lead to disparate costs. To date, however, the information collected and submitted to the city is not made public but instead can only be disclosed for transaction purposes such as leasing or purchasing a building. [162] Thus, critics of the Seattle program claim that compared to the New York City benchmarking program, which discloses data to the public, the Seattle plan is less effective at instigating consumption changes due to a weak real estate market (allowing for fewer transactions and accompanying disclosures) and the fact that highly visible information is more likely to encourage building owners to increase energy efficiency.[163]

In Austin, Texas, the benchmarking program applies to commercial facilities with a gross floor area of 10,000 square feet or more by 2014.[164] Covered commercial facility owners must perform an annual energy use rating through an approved audit or rating system.[165] Any buildings with less than 10,000 square feet of gross floor area are not required to comply. Covered commercial building owners need only disclose their building's rating to any prospective buyers while also

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having an initial occupancy date before January 1, 2012, reports and ratings pertaining to benchmarking for the year 2012 shall be submitted by April 1, 2013, and thereafter, annual reports and ratings for each subsequent year shall be due each April 1st.").

158 *Id.* at § 22.920.040 (detailing how the building owner will submit energy information to the city).

159 *Id.* at § 22.920.050 ("Each tenant located in a building subject to this chapter shall, within 30 days of a request by the building owner, provide in a form that does not disclose personally-identifying information, all information that cannot otherwise be acquired by the building owner and that is needed by the building owner to comply with the requirements of this chapter.").

160 *Id.* at § 22.920.060 ("Utilities providing energy service to an annual or three-year-benchmark building shall maintain energy consumption data for each building for at least the most-recent twelve months in a format capable of being uploaded to the United States Environmental Protection Agency's Energy Star Portfolio Manager.").

161 *Id.* at § 22.920.080 (describing requests for benchmarking reports by tenants and lenders).

162 Malin, *supra* note __ ("Seattle won't make the data it collects public other than by releasing it to tenants and buyers.").

163 *Id.* (comparing the New York City benchmarking program and the Seattle program).

164 AUSTIN, TEX., CODE ch. 6–7, art. 1, §6-7-1(1) (2011) (describing the benchmarking requirements for each type of building).

165 *Id.* at art. 4, § 6-7-31(D) ("The owner of a commercial facility required to calculate an energy use rating for the facility under subsection (A), (B), or (C) must calculate an energy use rating for the facility by June 1 of each year following the First rating required for the facility using an audit or rating system approved by the director.").

submitting it to the city program director to be benchmarked.[166] With regard to data collection for the rating, the building owner is responsible for acquiring the entire building data on its own from either individual tenants or directly from the utility, as Austin Energy does not provide automatic uploads to Energy Star.[167] Yet, difficulties may arise with collecting this information, as data from Austin Energy must be aggregated from at least four separate utility meters with one meter unable to account for 80% or more of the collected information.[168]

Minneapolis and Philadelphia have adopted benchmarking programs where commercial building owners must submit energy consumption data to the city for buildings over a certain size.[169] Similar to New York City, building information in both Minneapolis and Philadelphia is available online for the general public to access.[170] Also, similar to Austin and Seattle, Philadelphia building owners are required to provide energy performance information to prospective buyers and tenants.[171]

[166] *Id.* at art. 4, § 6-7-32 ("The owner of a commercial facility must make a copy of the energy rating calculation required under this article available to a purchaser or prospective purchaser of the facility before the time of sale and must provide a copy to the director not later than 30 days after the audit is complete."); *see also* Malin, *supra* note _ ("In Austin, the information only has to be disclosed to buyers."); see also Katherine Tweed, *supra* note _ ("In Austin, the information only has to be disclosed to buyers.").

[167] *Frequently Asked Questions, ECAD for Commercial Buildings*, Austin Energy, http://www.austintexas.gov (select "Austin Energy" department; then select "ECD Ordinance" program; then select "FAQS" for Commercial Buildings) (last visited July 14, 2014) (providing answers for how commercial building owners should comply with Austin's benchmarking program).

[168] Amy Jewel, *Energy Benchmarking and Disclosure: Challenges for Building Owners and Managers*, DNVGL (May 14, 2013), http://www.dnvkemautilityfuture.com/energy-benchmarking-and-disclosure-challenges-for-building-owners-and-managers ("[W]hen data for an entire building is provided by Austin Energy (the utility serving the City of Austin), data from at least four separate meters must be aggregated together, and energy data from one single meter cannot account for 80 percent or more of the aggregated energy consumption.").

[169] For information on Minneapolis benchmarking, *see* MINNEAPOLIS, MINN., REV. ORDINANCE ch. 47.190 (2013) (explaining the Minneapolis commercial benchmarking requirements, exemptions, and enforcement); City of Minneapolis, Commercial Building Rating and Disclosure Policy, at http://www.minneapolismn.gov/environment/energy/WCMS1P-105433 (listing the Minneapolis benchmarking disclosure policy). For a background on Philadelphia's benchmarking program, *see* Philadelphia, Pa., Bill No. 120428-A § 9-3402 (outlining the benchmarking program requirements); ANDREA KRUKOWSKI & CLIFF MAJERSIK, UTILITIES' GUIDE TO DATA ACCESS FOR BUILDING BENCHMARKING 5 (Energy Efficient Buildings Hub and Institute for Market Transformation, 2013) (providing a summary of Philadelphia's benchmarking initiative); GUIDE TO STATE & LOCAL ENERGY PERFORMANCE REGULATIONS 12 (Institute for Market Transformation, 2013), at http://www.imt.org/uploads/resources/files/GuidetoStateandLocalEnergyRegulations_V2_2.pdf (listing exempted buildings under the Philadelphia Bill).

[170] Minneapolis' first benchmarking report covering public buildings is available at City of Minneapolis, 2012 Energy Benchmarking Report: Public Buildings (2013), at http://www.minneapolismn.gov/www/groups/public/@citycoordinator/documents/webcontent/wcms1p-117371.pdf. For Philadelphia's benchmarking results, *see* *http://www.phillybuildingbenchmarking.com/images/uploads/documents/2012-philly-benchmarking-resultsFINAL.pdf*.

[171] Philadelphia, Pa., Bill No. 120428-A § 9-3402 ("The Council calls on the Administration to implement a Citywide program to provide for the reporting of Citywide benchmarking data online and in a manner that permits owners and tenants of Covered Buildings, prospective purchasers and lessees, and the public to view and compare Energy and water usage among comparable buildings and uses."); GUIDE TO STATE & LOCAL ENERGY PERFORMANCE REGULATIONS 12 (Institute for Market Transformation, 2013), at

Multiple municipalities are starting to create programs to track residential buildings in addition to commercial buildings. For instance, Gainesville, Florida has established the "Gainesville Green" program, which allows residential property owners, prospective purchasers, and third parties to determine the electricity, water, and natural gas use of residential properties throughout the city. This program was created by EnergyIT.com, a technology group producing software to aid in the use of energy consumption data, along with various government and university groups.[172] The purpose of the Gainesville Green database is to provide comparisons between home energy use that can then be used by homeowners to understand their own energy use compared to their peers.[173] Unlike other benchmarking programs that require building owners to submit data to the city, Gainesville Green itself compiles data from three different energy databases made available by the Gainesville Regional Utility (a municipal utility), allowing for residential building owners to find their own data and compare it to others and for the public to access such data as well.[174]

Individual utilities, such as PECO in Philadelphia and PEPCO in Washington, D.C., have worked with municipalities to improve benchmarking programs and reporting. For instance, PECO, the Department of Energy Efficiency Building Hub, the Pennsylvania PUC, and Philadelphia adopted the Green Button standards and created the PECO Smart Energy Usage Data Tool to make it easier for customers to uphold energy consumption data.[175] Such initiatives allow building owners to directly upload data from PECO to ENERGY STAR Portfolio Manager.[176] In the District of Columbia, PEPCO created the Building Electricity Consumption Data Request Form to assist building owners in complying with the Green Building Act of 2006 and the Clean and Affordable Energy Act of 2008.[177] Upon completion of this form by the

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http://www.imt.org/uploads/resources/files/GuidetoStateandLocalEnergyRegulations_V2_2.pdf (listing benchmarking disclosure requirements).

172 Gainesville Green, *Frequently Asked Questions*, http://gainesville-green.com/faq (last visited July 15, 2014) (answering who created the Gainesville Green site).

173 Gainesville Green, *Overview*, http://gainesville-green.com/faq (last visited July 15, 2014) ("This site calculates relevant comparisons for home energy use and displays detailed information about household performance. Users are given various options to view, analyze, and understand how they use energy and compare with their peers.").

174 Gainseville Green, *Frequently Asked Questions*, *supra* note __ ("This represents the combination of three databases.").

175 KRUKOWSKI & MAJERSIK, *supra* note __ (describing PECO's work with state and federal organizations to improve electronic uploading of consumption data to benchmarking programs). For more background information on this program, *see* PECO, *Benchmarking for Buildings*, https://www.peco.com/Savings/ProgramsandRebates/Business/Pages/PECOSmartEnergyUsageDataTool.aspx (last visited July 16, 2014) (providing background information on PECO's new uploading program that is currently in development).

176 PECO, *supra* note __ ("This system also allows for easy data export into the ENERGY STAR® Portfolio Manager, enabling owners and operators to benchmark their buildings' energy performance to similar buildings throughout the country.").

177 PEPCO, *Energy Benchmarking*, http://www.pepco.com/my-business/energy-benchmarking/ (last visited July 16, 2014) (describing the creation of the Building Electricity Consumption Data Request Form); *See also* D.C. CODE § 6-1451.03 ("The owner or a designee of the owner shall annually benchmark the building using the Energy Star® Portfolio Manager benchmarking tool."); D.C. CODE § 34-1553("A building owner, operator, or manager shall maintain adequate records regarding energy submetering equipment or energy allocation equipment.").

owner, PEPCO provides aggregated consumption data by month and year for the accounts provided.[178] This process allows building owners to bypass obtaining consumption data separately from each account, instead providing the aggregated total for the entire building without the need for individual collection.[179]

III. Moving Forward: Shaping Future State and Local Energy Consumption Data Policies

A review of the growing number policies governing energy consumption data shows that there have been helpful developments at the federal, state, and local levels of government. Notably, each level of government has focused on different aspects of the issue.

At the federal level, the Green Button program and the Uniform Methods Project encourage utilities to collect and make available data in a uniform format. This allows multi-state utilities to create a uniform system of data collection and program evaluation for all their customers in multiple states, eases burdens on EESPs attempting to work with clients on energy efficiency efforts, and can also help state and local government efforts to collect, evaluate, and make public some forms of aggregated energy consumption data and allow individual app developers to create energy management products. The federal level is the ideal place for this type of standardization to take place, as it creates a nationwide, uniform, format that states, local governments, and utilities can then use in order to make certain portions of that data available to customers, EESPs, and the public depending on the level of granularity of data they deem appropriate to balance disclosure and privacy. Indeed the lack of a uniform format for energy consumption is what has caused utilities to complain about the costs associated with making such data available because the parties seeking such data all need it in a different format. Likewise, without uniformity in data format, customers often find the data not helpful in energy efficiency decision making, EESPs cannot use the data and standardized evaluation methods to assist their customers, and local governments cannot determine what efficiency measures are working or whether they are meeting their GHG reduction targets. Although Green Button is a good start, only a few utilities have embraced the program. In order for Green Button or the Uniform Methods Project to effectively provide the standardization necessary to make energy consumption data more widely available, comparable, and, importantly, more useful, the EPA, DOE, or FERC should consider using their regulatory authority to require rather than encourage utility adoption of Green Button, the UMP standardized protocols, or another similar framework. In the alternative, EPA, DOE, or FERC could provide a regulatory framework that states could adopt to impose such requirements on utilities through legislation or PUC order.

[178] PEPCO, *Energy Benchmarking*, *supra* note _ ("We will provide consumption data, in the aggregate, by month and year, for service points and/or account numbers that are provided and will work to respond to these requests within thirty (30) calendar days.").
[179] *Id.* (describing how the Form assists building owners in collecting building data for benchmarking).

By contrast, the federal government has focused very little on determining levels of aggregation for energy consumption data disclosure or privacy concerns. Certainly, there is concern among utilities and others that the 2012 FTC report addressing consumer data in general can impose potential liability for disclosure of certain types of energy consumption data. And it is likely that Fourth Amendment privacy concerns will arise as energy consumption data becomes more in demand for energy efficiency purposes. But at least at the present time, the federal government is not attempting to set specific standards regarding privacy and levels of aggregation for energy consumption data.

By contrast, at the state level, legislatures and PUCs are focusing much more directly on issues relating to energy consumption data privacy, aggregation, and disclosure. Those state legislatures that have addressed the issue have declared that customers should have access to their own data, which certainly helps the efforts of consumers to obtain such data for energy efficiency purposes. But many state legislatures have not addressed the issue at all. More importantly, no state has yet created a comprehensive framework to facilitate third party access to energy consumption data by third party researchers or EESPs for energy efficiency purposes with safeguards in place regarding levels of aggregation, other means of de-identifying the data, and records security. There is significant work to be done to develop appropriate models that address these issues. What levels of aggregation are sufficient to protect customer privacy? Is customer privacy even a real concern in the context of energy consumption data? To the extent consumers feel that disclosure of energy consumption data is an invasion of privacy at all, is the concern really the same as regards 15-minute interval data versus weekly or monthly data? These are questions state PUCs need to put on their dockets and address.

Another issue that states must consider is whether the same levels of aggregation are appropriate for commercial and industrial data as compared to residential data. To the extent privacy is a concern at all in regulating the disclosure of energy consumption data, it would appear to be less of concern with commercial and industrial electricity use than it would be for residential electricity use. Indeed, in its initial efforts on this issue, the California PUC has created different levels of required aggregation for commercial and industrial electricity users than it has for residential electricity consumers. This level of specificity regarding levels of aggregation, who can receive the data, and the security measures third parties must have in place to receive data will be critical to efforts by states to require utilities to disclosure greater levels of energy consumption data and assure customers that such data will be used to benefit them and will be secure.

To the extent state legislatures, energy offices, and PUCs can require utilities to adopt the Green Button program, standardized evaluation metrics, or other national standards for the collection, disclosure, and evaluation of energy consumption data that will go a long way toward creating the frameworks necessary for consumers, cities, and states to reduce energy costs as well as GHG emissions. As discussed in Part II, both New York and Washington have taken helpful steps in this area. The New York PUC established a process for building owners to obtain data for multi-family and commercial buildings from utilities to meet local building efficiency benchmarking laws and Washington law requires utilities to maintain energy consumption data for 12 months in a format compatible with Green Button Portfolio Manager and requires utilities to upload that data into Portfolio Manager at the building owner's requests. These state requirements regarding the collection and maintenance of data in a uniform format will be critical in efforts to improve energy efficiency through greater use of energy consumption data. Energy data centers and public websites will also be an important component of any statewide effort to make better use of energy consumption data. California has taken the first steps in considering an energy data center and Massachusetts is considering a public website. Such initiatives can create a centralized repository for valuable data and also may provide additional security and quality control for data because one entity—a state agency—can control access to the data.

Notably, not all of the policy developments at the state level have been helpful in terms allowing increased access to energy consumption data for energy efficiency purposes. For instance, The Texas PUC's 2014 order makes it difficult, if not impossible, for third parties not affiliated with a utility to obtain energy consumption data without customer consent. Likewise, other states creating privacy rights in energy consumption data without also creating corresponding frameworks for disclosing such data under circumstances that will address privacy concerns, such as data aggregation protocols, provides a disincentive for utilities to work with municipalities, EESPs, and researchers, to make any data available. It is critical for states to provide a forum, through PUC hearings and orders, along with state legislation to address these issues in sufficient detail to give direction to utilities, assurances to consumers, and make data available for third parties in an aggregated or de-identified format.

Then there are local governments. Local governments are in a unique position with regard to energy consumption data. One the one hand, local governments are just like other third parties seeking energy consumption data from utilities that is available only subject to state law and individual utility data policies. On the other hand, local governments are also regulators themselves imposing collection and disclosure requirements building owners through commercial building benchmarking programs. Perhaps as a result, local governments have in many ways been more focused and innovative with regard to energy consumption data as compared to state legislatures and state PUCs as well as the federal government. Cities have created benchmarking programs, public websites, and firm GHG reduction goals that far exceed efforts the state or federal levels. At the same time, however, local government initiatives are necessarily more limited in that they can apply only to a single city and are circumscribed by state law and sometimes individual utility policies on data collection and disclosure when the electricity provider is not a municipal utility. Even beyond these outside limits on municipal policies, most cities have mandated disclosure of energy consumption data in only limited circumstances. Most city policies cover only commercial and municipal buildings, only a handful make such data available to the public as opposed to potential buyers, and even New York City excludes some commercial buildings with significant electricity use such as data centers.

In sum, different levels of government have been addressing different issues with regard to energy consumption data and, at least for now, that seems appropriate. The federal government may be in the best position to encourage or require standardized data collection practices that utilities can implement across the country. This will allow states, cities, customers, researchers, and EESPs to all use a uniform data format, which will streamline the type of comparative analysis that is critical to determining the levels of success of various energy efficiency programs. States can experiment with varying levels of privacy, data aggregation, and collection of data into data centers, thus acting as "laboratories of democracy" in the best sense. States like New York, California, and Massachusetts have already started this process and other states will look to them as their PUCs open dockets on this issue to guide and direct utilities and consumers. Last, local governments, like New York City, can be even more nimble than states and engage in targeted efforts to significantly reduce electricity use in various commercial sectors. To do so, however, local governments need the support of states to force utilities to provide the data and the support of the federal government to help ensure that the data is in a usable format.

CONCLUSION

As this essay illustrates, all levels of government as well as private parties have placed significant focus in recent years on developing policies and programs to collect, manage, and make public energy consumption data and have attempted to put into place policies to address any privacy concerns associated with the data. A review of these developments shows each level of government is focused on different aspects of the problem, with the federal government focused on standardization issues, the state governments focused on privacy and access, and the local governments focused more directly on building efficiency and benchmarking. But all levels of government, in conjunction with private parties, must take steps to create more certainty regarding what type of data can be made available, how it should be made available, and ensuring that the right third parties have access to the data to improve energy efficiency outcomes.

Stanfield Paper

Integrated Distribution Planning Concept Paper

A Proactive Approach for Accommodating High Penetrations of Distributed Generation Resources

May 2013

IREC Interstate Renewable Energy Council

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A Proactive Approach for Accommodating High Penetrations of Distributed Generation Resources

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Sandia National Laboratories

May 2013

IREC enables greater use of clean energy in a sustainable way by (i) introducing regulatory policy innovations that empower consumers and support a transition to a sustainable energy future, (ii) removing technical constraints to distributed energy resource integration, and (iii) developing and coordinating national strategies and policy guidance to provide consistency on these policies centered on best practices and solid research. The scope of IREC's work includes updating interconnection processes to facilitate deployment of distributed energy resources under high deployment scenarios.

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PLANNING FOR HIGH PENETRATIONS

In many parts of the country, legislative and regulatory promotion of renewable generation at the distribution-level ("distributed generation" or "DG") has significantly expanded the installed capacity of DG interconnected to utility distribution systems. It has also greatly increased requests to interconnect DG. In areas with the most robust DG growth, applications to interconnect new generation, particularly solar photovoltaic (PV) generation, have overwhelmed utility interconnection processes and caused project delays and, in some cases, prohibitive cost increases. In areas where DG penetration (installed DG capacity relative to customer load) is already high, these delays and increased costs have slowed DG growth and resulted in public criticism of utilities' interconnection processes.

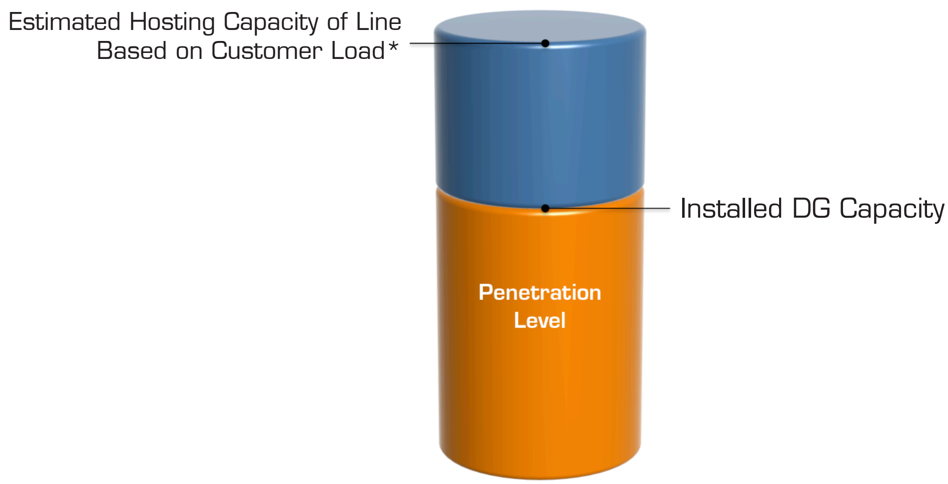
A well-designed interconnection process can contribute significantly to facilitating DG growth. Interconnection processes aim to satisfy the dual objectives of allowing utilities to maintain electric power system safety, reliability and power quality while also providing a transparent, efficient and cost-effective path to interconnect a generator on a predictable timeframe. To balance these objectives, interconnection processes often use penetration-based screening that increases the level of technical review as the DG penetration level on a circuit increases.

Penetration-based screening is broadly used in the United States to quickly review DG interconnection requests at lower penetrations, particularly penetrations below 15 percent of customer peak load on a distribution circuit. However, at higher penetrations there is a lack of consensus on how much review is necessary. One approach that has been recently adopted in California and Hawaii is to roughly divide generators on the basis of whether their capacity may exceed 100 percent of minimum customer load on a distribution feeder. A utility will have broad discretion in these states to assess potential impacts to safety, reliability and power quality both above and below this threshold, but below the threshold, it will have less time to assess potential impacts. The Federal Energy Regulatory Commission (FERC) recently issued a Notice of Proposed Rulemaking (NOPR) that would revise the federal Small Generator Interconnection Procedures (SGIP) to mirror the approach used in California and Hawaii.[1] One recently released study from the National Renewable Energy Laboratory (NREL), and another study from NREL, the U.S. Department of Energy (DOE), Sandia National Laboratories (Sandia) and the Electric Power Research Institute (EPRI) also support this approach.[2]

The California and Hawaii processes improve the timeliness, transparency, and cost-effectiveness of interconnecting a generator at higher penetrations, but the processes are still largely reactive, waiting for an application to interconnect a generator before potential impacts to safety, reliability and power quality may be assessed. The reactive nature of this approach means that the hosting capacity of a distribution circuit (the ability to accommodate new DG without upgrading the circuit) is determined after an interconnection request is received, if it is determined at all.

To better facilitate interconnection of high penetrations of DG, some utilities are beginning to consider approaches to proactively study distribution circuits in an effort to determine—in advance—their hosting capacities. These approaches generally use a two-step process. The first step utilizes modeling to determine the ability of distribution circuits to host DG. The second step leverages existing distribution system planning efforts to anticipate DG growth. Where anticipated growth exceeds a distribution circuit's hosting capacity, the utility can identify additional infrastructure that may be necessary to accommodate the anticipated growth. The results of a proactive study inform the processing of subsequent interconnection requests by estimating in advance the level of DG that can be accommodated without impacts. At higher penetration levels, a utility will have foreknowledge of the upgrades that may be required to ensure maintenance of safety, reliability and power quality standards.

Figure 1: DG Penetration Relative to Estimated Hosting Capacity



*The two most common estimates of hosting capacity based on customer load are 15% of peak load and 100% of minimum load.

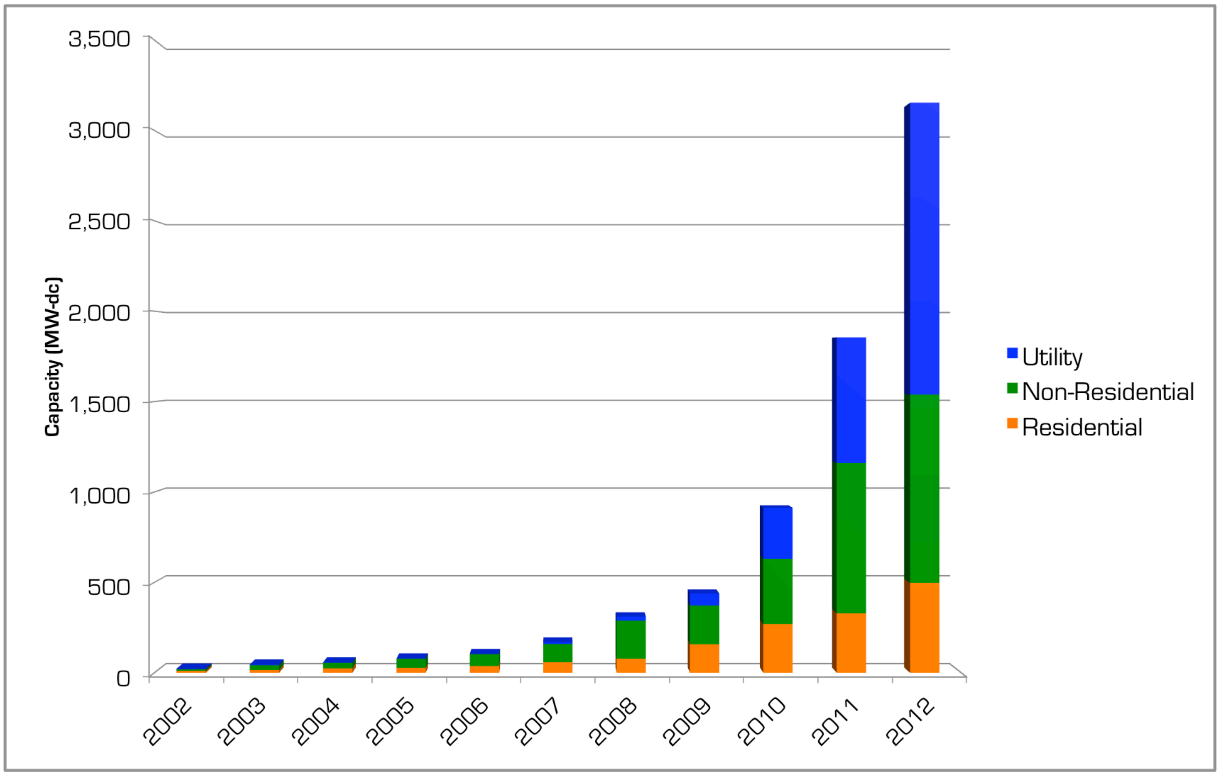
This paper discusses proactive planning efforts that are being contemplated or implemented by utilities across the United States. Drawing upon these efforts, this paper proposes an Integrated Distribution Planning (IDP) approach to proactive planning for DG growth. IDP leverages existing tools from distribution system planning to estimate the hosting capacity of distribution circuits in advance of a utility studying a particular interconnection request. IDP also analyzes a circuit's ability to accommodate anticipated DG growth and identifies any potential infrastructure upgrades needed to accommodate that growth.

In addition to introducing the concept of IDP, this paper discusses the ways in which IDP can increase the efficiency and cost-effectiveness of interconnecting DG at high penetrations while maintaining the safety, reliability and power quality of utility distribution systems. It also discusses potential implementation issues. One such issue is cost allocation; specifically, how to allocate the cost of distribution upgrades between generators and possibly even between generators and ratepayers. While we recongize this is an important consideration, cost allocation requires a more thorough examination than would be allowed in this introductory concept paper. Accordingly, we only provide some broad comments on the issue in this paper and hope to address it in further detail in a follow-up paper.

RISING PENETRATIONS STRAIN UTILITY RESOURCES

The success of policies promoting PV resources has caused a high volume of interconnection requests from both small and large PV projects for many utilities. In 2005, utilities and developers installed only 79 Megawatts (MW) of grid-connected PV capacity across the United States. Six years later, the grid-connected solar PV capacity installed in just one year totaled 1,856 MW, over 23 times the cumulative amount installed just six years earlier and more than double the capacity that had been installed the prior year.[3] Annual grid-connected PV capacity almost doubled again in 2012 to 3,153 MW (see figure 2 below), which brought the grid-connected PV capacity in the United States to 7,000 MW by the end of that year.[4] That is a 4000-percent increase in 7 years.

Figure 2: Annual Installed Grid-Connected PV Capacity



In 2011, the nation's most PV-active utilities integrated almost 1,500 MW-ac of new solar capacity, the equivalent of six natural gas power plants.[5] Solar Electric Power Association's (SEPA) 2011 Utility Solar Rankings Report describes the incredible undertaking that interconnecting all of these new generators can mean, particularly for utilities in states with the highest penetrations of solar:

> Utilities are adapting to solar as their fastest growing electricity source. In 2011, utilities interconnected over 62,500 PV systems, 89% of which were residential homes, and which was a 38% growth over 2010. Thirteen utilities interconnected more than 1,000 PV systems and 22 interconnected more than 500 systems. To put this in perspective, about 350 non-solar power plants (> 1 MW) were expected across the entire U.S. in 2011. This annual volume of smaller, distributed solar interconnections is unlike anything the utility industry has previously managed, and conservative forecasts indicate that this number will grow to more than 150,000 interconnections in 2015.[6]

This increase in interconnection requests has resulted in higher PV penetrations on many utility distribution systems.[7] Continued robust growth in PV markets will inevitably result in more areas with high penetrations of PV resources. Although most utilities do not publish information about penetration levels on their distribution feeders, several regions of the country are clearly experiencing high penetrations due to the sheer volume and concentration of DG that has interconnected or is requesting interconnection. In Hawaii, for example, 20 percent of the distribution circuits are already above 15 percent of peak load, a common benchmark for high penetration.[8]

It is also clear that these high-penetration solar regions have expanded beyond just California and Hawaii, and are now moving into Eastern states. In 2008, 93 percent of the nation's total annual solar capacity was installed in the Western region. By 2011, however, Western states held only 61 percent of the nation's annual installed solar capacity, and only two California utilities were among the top ten for Cumulative Solar Watts-per-Customer (see figure 3).[9] Pepco, Inc., (Pepco) the parent company of Atlantic City Electric, the utility for many parts of southern New Jersey, has closed five of its distribution circuits to new generation because the circuits have reached operating voltage limits on account of high penetration.[10]

Figure 3: Cumulative Solar Watts-per-Customer

2011	2010	Utility	Watts (AC)
1	Not Ranked	Vineland Municipal Electric (NJ)	991.2
2	5	Maui Electric Co. (HI)	209.3
3	66	Blue Ridge Mountain EMC (GA)	194.7
4	11	Atlantic City Electric (NJ)	185
5	2	Kauai Island Utility Co-op (HI)	179.1
6	18	Arizona Public Service - APS (AZ)	176.3
7	1	Southern California Edison (CA)	151.9
8	117	Fayetteville Public Utilities (TN)	150.1
9	9	Hawaiian Electric Co. (HI)	148.5
10	6	Pacific Gas & Electric (CA)	146.2

As penetration levels rise, the need to take a closer look at the impacts of these generators, in the form of detailed interconnection studies, also rises. A detailed study frequently requires an upfront fee, can take months to complete, and can result in high upgrade costs.[11] In addition, waiting for a study to be completed can cause delay for other applicants that may be seeking to interconnect to the same circuit but have to wait for the prior applicant to complete the process before they can move forward.

Members of the solar industry have identified the increased need for detailed studies as a market barrier to future development.[12] As penetration levels increase, the combination of study costs, uncertainty, delays and upgrade costs can undermine otherwise positive project economics, especially for small projects. In localized areas, the cost of a large upgrade, such as replacing the conductors on a distribution feeder, can prove so burdensome for a single project, or group of projects, that neither the project nor the upgrade is completed. The problem is accentuated in areas with serial interconnection queues, where a large upgrade not only deters the current project but also those projects behind it in the queue. The result is an interconnection upgrade bottleneck in high-penetration areas of the distribution system that eventually stymies DG development.

It is easy to understand the challenges that arise for the solar industry from the combination of increasing interconnection requests and more detailed studies. Less obvious are the difficulties that arise for utilities. Detailed studies can deplete utility resources as interconnection queues outpace the utility's ability to process requests. Even in places where group study processes allow for the concurrent interconnection of large numbers of projects, detailed studies can overwhelm utility resources and require the use of outside consultants, which can increase interconnection timelines due to the additional time for information exchange between the consultant and the utility.[13] Timelines for studies performed by external engineers are also dependent on those engineers' availability, and delays can result.[14]

Utilities have recently become the target of public criticism where interconnection processes have been unable to keep pace with customers' choices to install DG. A recent article in *Businessweek* calls a common penetration screen, the 15 percent of peak load screen, a market obstacle for solar energy in the United States.[15] Another example is a resolution passed by the County of Hawaii, the governing body of the island that shares the State's name.[16] The resolution encourages the Hawaii Public Utilities Commission to change Hawaii Electric Light Company's (HELCO's) existing interconnection process to allow higher levels of penetration before detailed study is required.[17] The Hawaii resolution and *Businessweek* article demonstrate how, in high penetration areas, the public has become critical of interconnection processes that appear to limit customers' ability to install DG.

PENETRATION SCREENS ARE NOT SUFFICIENT

Penetration screens can be helpful in achieving the dual objectives of an effective interconnection process: on the one hand maintaining the safety, reliability and power quality of electric power systems while on the other hand providing a transparent, efficient and cost-effective path to interconnection. From a technical standpoint, the risk of unintentional islanding, voltage deviations, protection miscoordination, and other negative impacts, increase as the capacity of installed DG on a circuit rises.[18] Penetration screens serve as a gatekeeper in the interconnection process, increasing the level of review that is needed as DG penetration rises.[19]

The federal SGIP and many state interconnection procedures allow interconnections to be expedited when penetration is less than 15 percent of peak load on a distribution feeder, so long as a number of additional technical screens that assess potential impacts are also passed.[20] If all of the "initial review" screens are passed, an interconnection can be approved in as little as 10 to 20 business days.

There is presently no consensus on what level of review is needed for penetrations above 15 percent of peak load. There is, however, a growing recognition that DG capacity relative to minimum load is a more relevant consideration at higher penetrations than DG capacity relative to peak load. For example, utilities in Hawaii and California recently agreed to incorporate a 100 percent of minimum load threshold into their supplemental review processes.[21] In California, if a generator fails the 15 percent of peak load screen during initial review, it will be required to undergo supplemental review.[22] If it is determined that the aggregate generating capacity is less than 100 percent of minimum load (daytime minimum load for PV systems), a generator may be allowed to interconnect without detailed study.[23] If the generating capacity exceeds 100 percent of minimum load, the generator will likely require detailed study.[24]

In Hawaii, a similar process has been proposed that would require detailed study only when aggregate generation reaches 100 percent of minimum load, 75 percent of minimum load, or 15 percent of peak load, depending on the data available for the circuit in question.[25] Similarly, FERC's recent NOPR would revise the federal SGIP to reflect the approaches used in California and Hawaii, making detailed study more likely only above 100% of minimum load.[26] As we noted earlier, two studies, one from NREL and the other from NREL, DOE, Sandia and EPRI, support the use of a daytime minimum load screen for PV at high penetration levels.[27]

Although penetration screens may be helpful in determining the level of review that is generally appropriate for interconnecting generators at different penetration levels, they do not provide much guidance regarding the ability of the local distribution system to accommodate a specific proposed generator at a specific point of interconnection. The ability of a distribution circuit to accommodate a generating facility without upgrades can vary significantly depending on the configuration of the local circuit and the generating facility type, size and location on the circuit. In locations that are experiencing high DG penetrations, many utilities are increasingly looking to determine the ability of existing circuits to host additional DG interconnections in an effort to expedite the review of interconnection applications.

INNOVATIVE RESPONSES TO HIGH PENETRATION

In recent years, a number of states and utilities have taken steps to streamline interconnection procedures to accommodate high DG deployment. The states of Massachusetts, California, Hawaii, and Pepco, the parent company of utilities in New Jersey, Delaware, and Maryland, are leading the way to a more comprehensive understanding of the characteristics of the distribution system and its ability to host DG prior to interconnection requests being submitted.

Massachusetts

Observing that legislative and regulatory changes in the Commonwealth had markedly increased the number of requests to interconnect to the Commonwealth's distribution systems,[28] the Massachusetts Department of Public Utilities (DPU) initiated two proceedings in the past few years to find ways to accommodate this growth. In March 2013, the DPU issued an order adopting certain recommendations from a collaborative stakeholder process to improve to Massachusetts' interconnection procedures.[29] The order adopts a number of revisions that reduce interconnection timelines, increase the transparency of the technical review screens the Massachusetts utilities apply, and improve the supplemental review process to allow more projects to qualify for expedited interconnection.[30]

The DPU also opened an inquiry to study the "modernization" of the Commonwealth's distribution system "over the short, medium and long term."[31] While focused on smart grid technologies, the order initiating the inquiry stresses the importance of studying and monitoring the impacts of DG on the distribution system. Stakeholders are considering how "the modern grid

… should be capable of fully integrating new distributed technologies."[32] Part of that task will include proposing regulatory changes to facilitate "grid modernization" that can integrate DG "in a strategic and cost-effective manner."[33]

California

A first step to streamlining interconnection in California was completed in September 2012 when the California Public Utilities Commission adopted a fourteen-party settlement agreement fundamentally redesigning Rule 21, California's distribution-level interconnection tariff.[34] The settlement, which includes as parties the State's three investor-owned utilities, revises substantial portions of Rule 21's expedited and supplemental review processes with the aim of improving efficiency, cost-effectiveness and transparency for developers.[35] The decision adopting the settlement concluded the first phase of a two-phase proceeding aimed at resolving the viscosity and opacity in the State's interconnection queues and procedures.[36]

The second phase of the Rule 21 proceeding builds on other California initiatives to take a more holistic view of DG in the context of distribution planning. State law already requires California utilities to incorporate DG into utility distribution system planning and operations.[37] In addition, a number of regulatory proceedings since 2003 have worked to integrate DG into California's distribution system planning proceedings with the aim of deferring investment in distribution system infrastructure; however, these programs have largely remained unimplemented.[38]

An innovative proposal in the second phase of the Rule 21 proceeding would use interconnection costs and timelines to incentivize DG siting in places that would defer distribution system investments. The proposal, one of a handful in the proceeding, relies on the principle that strategically located DG can "defer transformer and transmission line upgrades, extend equipment maintenance intervals, reduce electrical line, losses, and improve distribution system reliability, all with cost savings to utilities."[39] The proposal uses a series of metrics and distribution system characteristics to define low-cost areas to interconnect that are likely to have high value in terms of deferring investments in distribution infrastructure.[40] If a project's point of interconnection is in an area that meets the low-cost, high-value criteria, it will be able to interconnect to the distribution system for a fixed fee, regardless of any costs the project is assigned as part of an interconnection study.[41]

A recently published Southern California Edison Company (SCE) report also emphasizes the importance of implementing California's DG goals with strategic locational considerations.[42] The report analyzes the system-wide distribution and interconnection costs of DG installations in SCE's service territory and concludes that these costs decrease substantially if projects are sited in more urban areas where the distribution system is stiffer.[43] The report advocates "appropriate incentives for developers to interconnect in preferred areas."[44] It also calls for further study of the SCE distribution and transmission systems in order to more precisely determine DG installation costs and to create location information to guide developers towards areas with lower costs to interconnect.[45]

An on-going EPRI study, funded by the California Solar Initiative, is exploring methodologies to more quickly and accurately determine the hosting capacity for PV generation on individual distribution feeders.[46] The study is in response to the increased pressure on California's utilities to accommodate higher levels of DG and, at the same time, expedite the interconnection process.[47] It examines a wide range of PV deployment scenarios and penetration levels on California feeders in order to determine the level at which utility operations are impacted.[48] EPRI is building detailed distribution models to evaluate impacts of PV on the distribution system as part of the study.[49] Preliminary results show that establishing a minimum hosting capacity, below which no impacts are anticipated regardless of a project's size or location, and maximum hosting capacity, above which there are impacts regardless of a project's size or location, may be a better approach than using proxy screens, such as 15% of peak load.[50] EPRI hopes to use its study results to develop new interconnection screens that can reduce both interconnection study time and costs.[51]

Pepco and New Jersey, Delaware and Maryland

Pepco is in the early stages of implementing a program to completely model its distribution system in response to high DG penetration levels. The utility has over 7,200 interconnected DG resources, and numerous distribution feeders in its New Jersey service territory have experienced high penetrations of solar DG.[52] High penetration has even resulted in the company closing five of its feeders to further solar DG development.[53] Initially, the deluge of PV system applications in its service territories caused the utility problems in meeting the timeframes in its interconnection procedures.[54] Pepco recognized that with increased penetration it needed to find a better way to plan for DG resources and to invest in the development of an advance load flow program.[55]

Pepco will utilize the advanced load flow model to conduct detailed DG impact studies. The Pepco approach will develop a model that includes both active and pending interconnection requests in its queue.[56] It will then use time series models to show the impacts of those generators on the distribution system, identifying constraints based on voltage impacts, reverse flow, protection concerns and other criteria.[57] The time series models will be based on historical Supervisory Control and Data Acquisition (SCADA) information as well as time series models of solar and other generation sources.[58]

The program will provide stakeholders a faster response to the questions of what is the hosting capacity at a project's location and what upgrades are needed.[59] The program can also be used in high penetration studies.[60] Pepco anticipates interconnection assessments for DG will eventually be "semi-automated" such that developers and utility engineers will know the impact of a proposed facility within days of the facility submitting a complete and valid interconnection request rather than weeks or months.[61] Where design of major upgrades and engineering estimates are needed, response will still take longer than a few days.[62] Pepco's program will also allow the utility to consider mitigation strategies on both the customer and utility side of the point of interconnection.[63]

Hawaii

Customers in many parts of the Hawaiian Electric Company's (HECO's) service territory are already unable to interconnect DG due to high penetration levels, and the associated detailed study fees and upgrade costs.[64] In May 2012, the Hawaii Public Utilities Commission issued an order asking stakeholders to find ways to use PV system data to enhance the interconnection screening process and increase DG penetration.[65] In March 2013, a collaborative stakeholder effort, including members of the PV industry and HECO, culminated in a unanimously supported "Proactive Approach" proposal to plan for high penetrations of DG.[66]

The Proactive Approach utilizes what is essentially a four-step process to integrate HECO's interconnection and annual distribution planning functions in a forward-looking manner.[67] During its annual distribution planning effort, the HECO utilities will:

1. Determine likely DG growth on its distribution system over one year, using its existing interconnection queue, along with other data points, to establish a reasonable forecast of anticipated DG development;
2. Study the aggregate generation of existing facilities and the hosting capacity of existing equipment on the distribution system, to determine the precise available capacity for additional DG.
3. Assess whether the hosting capacity of existing equipment can accommodate the anticipated DG growth; and
4. Proactively plan distribution system upgrades in areas where DG growth outpaces the distribution equipment's hosting capacity.[68]

The aim of the approach is to identify opportunities where infrastructure upgrades can accommodate both DG and load such that a greater number of generators and customers can benefit from system upgrades.[69]

To achieve these ends, HECO will employ enhanced tools for modeling DG to inform distribution-level planning and operations.[70] Those models will leverage PV production data, which members of the PV industry have voluntarily made available to HECO. The models will also use a network of HECO PV field monitors.[71] When the utility identifies additional needs for monitoring data to populate its models, it will look to deploy additional utility field monitors or engage developers and customers to facilitate any necessary cooperation to gather owner- or customer-collected data.[72]

The Hawaii Public Utilities Commission has not yet formally adopted the proposal.[73] However, once approved, the HECO companies hope to implement the Proactive Approach in high-priority areas in 2013, with the aim to apply the approach to the entire distribution system by the end of 2015.[74]

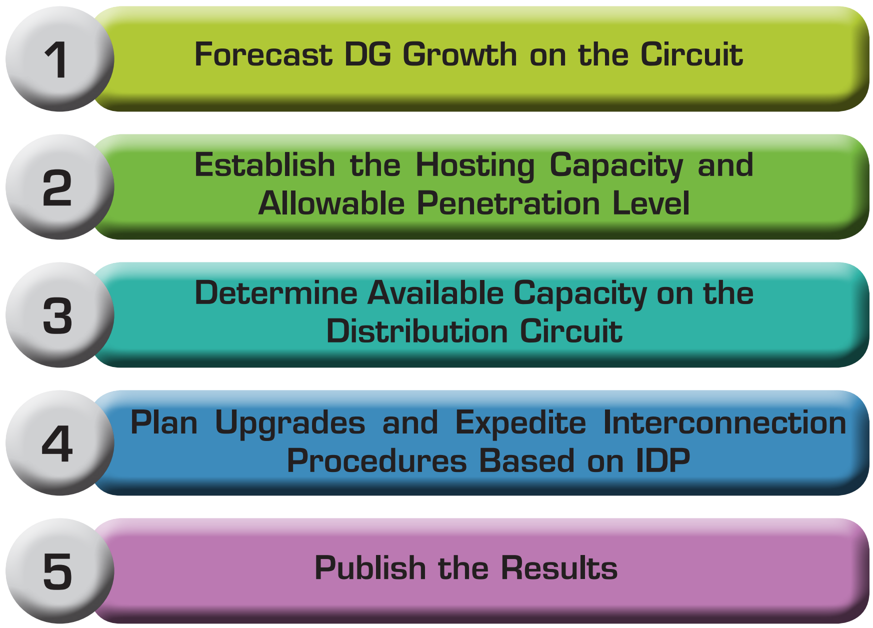
INTEGRATED DISTRIBUTION PLANNING

As the above examples illustrate, utilities in high penetration areas are increasingly looking to gain a better understanding of the amount of DG that can be accommodated without costly upgrades. These examples demonstrate the potential for more proactive interconnection and distribution planning to improve interconnection timelines, increase cost certainty and allow utilities to respond more efficiently to requests to interconnect DG.

Using these examples as a guide, this section looks to generalize and combine features of these efforts into a comprehensive approach, which we call Integrated Distribution Planning (IDP). IDP determines the hosting capacity of existing distribution circuits and identifies potential upgrades that may be needed to accommodate anticipated DG growth. IDP will allow utilities to process interconnection applications more efficiently without any reduction in the utility's ability to maintain safety, reliability and power quality.

IDP proceeds in the five steps shown in Figure 4.

Figure 4: The Five Steps of IDP



1. Forecasting DG Growth on the Circuit

Not all circuits are likely to experience the same level of DG growth; therefore not all circuits will benefit equally from proactive study. Some circuits may be in locations that are not well suited for development while others may be in locations where there is significant interest. IDP efforts should focus on circuits where significant additional DG deployment is likely. One potential trigger point for determining when IDP efforts may prove effective is when circuit penetration level passes 15% of peak load. Another possibility would be to proactively study a circuit if the forecasted growth for that circuit exceeds some pre-determined percentage of minimum load, which could be utility-specific.

Regardless of the approach taken for determining when to proactively study a circuit, it will be helpful to have a reasonable forecast of DG growth to determine the amount of DG that may need to be accommodated. One way to construct a forecast for DG growth is to take the utility's existing interconnection queue and add to it a reasonable prediction of DG capacity growth during the study period. There are numerous factors that can impact a forecast of incremental DG growth that may need to be accommodated, including data regarding utility DG procurement programs, the typical size of generating facilities that have sought interconnection, project success rates within those programs, PV pricing trends, and federal, state and local policy activity. Other elements normally modeled in a distribution planning study can also be included, such as anticipated changes in load profiles, demand response programs and energy efficiency installations.

2. Establishing the Hosting Capacity and Allowable Penetration Level

The hosting capacity of a distribution circuit is the maximum amount of generation the circuit can host without upgrades while maintaining safety, reliability and power quality. There are many factors that affect a circuit's hosting capacity, including circuit characteristics and the size and location of proposed facilities. Without these details, it is difficult to pinpoint exact hosting capacity. Nonetheless, a proactive circuit study can identify circuit characteristics that may need to be modified if forecasted levels of DG growth materialize. That will allow estimates of hosting capacity to be made on the distribution circuits, which builds confidence within the utility that system impacts are unlikely for generators of certain types and sizes.[75]

The estimate of hosting capacity should reveal the allowable penetration levels that may be accommodated without the need for distribution upgrades. With this approach, allowable penetration levels will be more closely related to the actual engineering limits of the infrastructure being studied, and therefore will establish a more precise alternative to using the simple rules of thumb that are incorporated into interconnection processes. The penetration levels will show the amount of generation allowable on a circuit up to the circuit's hosting capacity, and generators of certain types and sizes that are below the allowable penetration level should be able to interconnect simply and quickly without detailed study or even supplemental review.

3. Determining Available Capacity on the Distribution Circuit

Once the hosting capacity and allowable penetration levels are established, the utility can determine the remaining capacity available on a distribution circuit, that is, the known maximum MW value of DG that can be connected before an upgrade is required (see figure 5). This number may need to be differentiated by generator types, sizes and locations. This metric reveals a circuit's remaining ability to absorb new projects before upgrades will be needed, signaling to utilities and developers where these circuits exist.

Figure 5: Forecasted Generation is Less than Infrastructure's Hosting Capacity

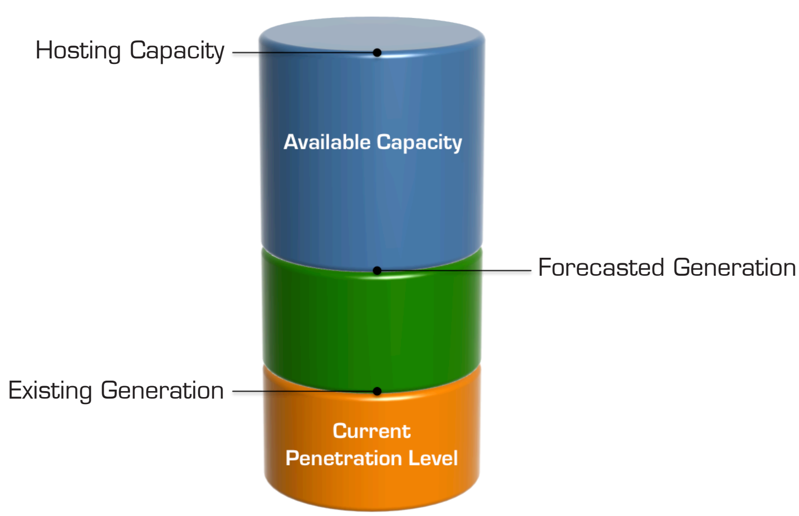
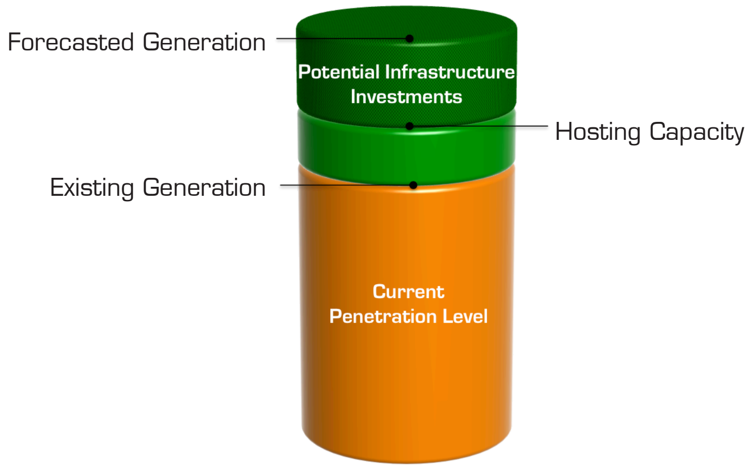


Figure 6: Forecasted Generation Exceeds Infrastructure's Hosting Capacity



4. *Planning Upgrades and Expediting Interconnection Procedures Based on IDP*

Forecasted DG development may push penetration levels past the hosting capacity, meaning anticipated DG growth will consume all available capacity. Through IDP, the utility can identify the technical factor limiting the hosting capacity of the circuit. That is, the utility may be able to determine whether interconnecting DG beyond the hosting capacity requires a major upgrade, such as replacing a transformer, or a relatively minor change, such as changing local settings on protection or control devices. This data can be used in two ways. First, it can be used on an aggregate level as an input to inform the remainder of the utility's distribution planning effort, giving the utility the opportunity to identify and prioritize the possible upgrades to distribution infrastructure that would be required to accommodate anticipated DG growth (see figure 6). Second, it can be used on a project-by-project basis to inform the interconnection screens and procedures that are applied to each facility individually.

5. *Publishing the Results*

Ideally, a utility will publish the available capacity and nature of the upgrades needed for the distribution infrastructure studied, and the location and timing of any planned upgrades that would affect hosting capacity. These results can be made public through a website, provided in response to requests from project developers, or included in utility locational value maps, depending on the confidentiality and critical infrastructure considerations that apply to the utility.

THE BENEFITS OF ADVANCED PLANNING FOR HIGH PENETRATIONS

IDP may provide a number of benefits to utilities and developers, including more efficient planning, improved interconnection timelines, and reduced interconnection costs. This section introduces these benefits.

Optimal Distribution System Planning

IDP allows utilities to proactively plan more efficient and cost-effective upgrades. For example, a utility can determine where a small fix in a strategic location can benefit a number of generators. It also allows the utility to consider upgrades that can be shared between interconnecting projects, across any number of distribution feeders or a network, or between load and generation. The result is upgrade costs can be spread more evenly among the parties that benefit. Moreover, the upgrades can be planned more efficiently, where electrically related projects and load can share the cost of an upgrade that benefits both. These cost allocation options are at the core of interconnection policy, and are discussed further below.

Improved Interconnection Timelines

IDP will allow a utility to measure penetration levels and hosting capacity in a particular area, and use this information to more efficiently evaluate interconnection requests during the initial or supplemental review study phases. Better knowledge of the existing penetration levels and available capacity allows utilities to replace proxy interconnection screens, such as the 15 percent of peak load penetration screen, with screens tailored to the distribution infrastructure itself. For example, certain projects will pass Hawaii's new proposed penetration screen in supplemental review if aggregate generation on a circuit falls below the hosting capacity determined through the Proactive Approach.[76] Better screens allow the utility to interconnect more projects using expedited interconnection procedures, such as fast track and supplemental review, and with more confidence than that derived from proxy screens. In turn, IDP will reduce the workload on utility engineers and make it easier for a utility to meet interconnection timelines.

Proactive planning will also allow a utility to determine potential upgrades for projects in a particular area before a utility studies those projects, meaning shorter timelines for projects that fail fast track and supplemental review. In California and Hawaii, IDP will complement new "Quick Review" features that are embedded in interconnection procedures. Rule 21 in California gives utilities discretion to avoid pushing projects into detailed study when a project fails a screen, allowing the utility to determine with a quick review of the failed screen a solution to address the issue.[77] Hawaii has proposed a similar process.[78] Through IDP, a utility will know many upgrade requirements in advance of applying the interconnection screens. Thus, when a generator fails a fast track or supplemental review screen in an area that has undergone IDP, the utility may already know the upgrade needed without having to conduct further study.

Finally, some utilities contract with independent consultants to conduct supplemental review and detailed interconnection studies. A utility's ability to meet interconnection timelines, therefore, depends on the availability of consultants with an intimate knowledge of the utility's distribution system. A reduction in the need for detailed studies may reduce the need for outside consultants and result in a better ability to meet timelines.

Cost Reductions for Both Developers and Utilities

The decreased need for detailed studies resulting from IDP may provide cost advantages for utilities. Without a means to accommodate increased distribution-level interconnection requests, a utility will see the need for detailed studies increase as DG penetrations increase. Detailed studies require utility engineers to intensively investigate the impact of interconnecting generators on existing facilities, load and distribution infrastructure. Streamlining interconnection through IDP will allow more projects to avoid detailed study, which will reduce the engineering resources utilities must expend or procure to study each applicant.

IDP also provides cost benefits for developers. High penetrations are indicative of a likelihood of needed upgrades, which are frequently funded by project developers. For wholesale projects, a database of feeder penetrations and available interconnection capacity can be valuable to developers looking for low-cost places to interconnect. For developers with little choice about where to interconnect, such as on-site generators, IDP can set expectations regarding the potential for upgrade costs and, therefore, reduce investment risk through increased cost certainty.

POTENTIAL IMPLEMENTATION ISSUES

A number of issues may arise in implementing an IDP framework. This section introduces some of those issues and discusses potential solutions.

Data

The implementation of IDP allows a utility to estimate the hosting capacity, existing DG penetration, and needed upgrades for a studied system. The tools to establish these metrics include access to distribution system modeling that can include DG, specifications on the physical limitations of utility infrastructure, methodologies and data to measure minimum load, access to DG output data, and a system to store and manage both minimum load and output data. While at first blush the development of these tools appears cost prohibitive, a number of solutions may already exist, or are in development, to allow IDP to go forward in a cost-effective manner.

Distribution system planning already requires utilities to model the physical limitations of equipment in relation to load patterns. There are numerous different types of models employed to determine the upgrades required to accommodate changes in load, some of which may be adapted to include DG. In Hawaii, HECO plans to continue to utilize its existing distribution system planning software to model DG and implement the Proactive Approach. On the other hand, Pepco invested in developing a new advanced load flow model with a DG impact assessment tool to model its entire distribution and transmission system. Both experiences suggest that a number of different tools are now, or will soon be, able to model DG for the purposes of IDP.

Currently, few utilities collect enough information to measure minimum load at the feeder level. However, it is not strictly necessary for a utility to install additional load monitoring equipment on all distribution circuits in order to implement IDP. Methodologies exist to estimate minimum loads with levels of accuracy sufficient for planning, including the use of standard load profiles for various customer classes, which many utilities maintain and update on an annual basis.[79]

Other modeling methods are also available for calculating or estimating minimum load that may be similar to methods used for determining peak load levels of circuits. If a reasonable method to estimate minimum load data is unavailable, utilities can target high penetration areas first for the installation of monitoring equipment and later expand to other areas of the distribution system.

Output data from DG facilities are also needed to populate utility power flow models. As more utilities install SCADA systems and roll out smart grid features there will be an increasing amount of historical data available. Pepco's time series models will be based on historical SCADA, solar and customer-use data.[80] EPRI's study validates its modeling using data obtained from EPRI-provided monitoring equipment at existing PV facilities and one-second PV production data from selected distribution circuits via field monitoring.[81] HECO's Proactive Approach will use a combination of historical SCADA data, data from utility field monitors and production data that has been voluntarily offered by members of the PV industry.[82]

The Hawaii solution is worth noting. Historical data can go a long way towards building a utility's understanding of DG's impacts on a circuit, validating its modeling of those impacts, and greatly improving the accuracy of measurements to establish penetration levels and hosting capacity. Normally, a suggestion to share data with utilities in real time causes developers to wince since it is frequently associated with SCADA, which is frequently, although erroneously, associated with allowing a utility to control the output of a solar facility. Further, the provision of real time or one-to-five second production data can be very costly due to the fiber optic or cellular equipment needed for near-instantaneous communication. However, the approach in Hawaii shows that useful data can be historical, does not need to be SCADA quality, can be communicated using existing Internet connections, and can be anywhere from 2-second to 15-minute data. Moreover, an informal IREC survey of inverter manufacturers, data monitoring companies and solar developers confirms that many companies across the country already record data for customers that would be useful to utilities and can be communicated for low cost.[83] The solution to a perceived lack of data, it seems, is simply cooperation between utilities and the PV industry.

Another related issue is the significant technical challenge surrounding the utility's ability to store and manage large amounts of data. However, the HECO and Pepco approaches suggest that this issue can also be addressed.

Building Upgrades and Allocating Costs to Projects

Two key issues that will need to be addressed when implementing IDP is how distribution upgrade costs will be allocated and whether utilities should install upgrades before an interconnecting generator that will need that upgrade is proposed. The necessary solutions will vary for different utilities and states, given each jurisdiction's existing policy for cost allocation of both interconnection upgrades and distribution system planning upgrades. However, it should be noted that utilities and regulators have long wrestled with the issue of allocating infrastructure upgrade costs between load and generation, and it is likely that established approaches on that issue could be applied to IDP.

Two such approaches may be especially useful in this context. The first approach allocates costs of service to the class of customers that benefits from the capital improvements. This approach could be applied to customers that install DG to serve onsite electrical needs, such as small net-metered systems (less than 10 kW), which are typically installed by the residential class of customers. Such projects will likely avoid upgrade costs because the upgrades necessary to accommodate them are also likely to benefit, and therefore be shared by, the full rate class. For example, when performing a distribution planning study, small-scale generators with widespread distribution look very similar to a highly effective energy efficiency program that decreases the load on the circuit. This reduction in load reduces the growth rates on distribution circuits and may allow for the postponement of capital upgrades, which is a net benefit. Similar arguments can be made for larger systems connected on commercial customer sites that are non-exporting.

The second approach allocates costs to the customers who caused those costs to be incurred. This principle could impact other classes of interconnecting DG, typically MW-scale, wholesale DG plants that are discrete systems seeking new services to interconnect and are not net-metered systems behind an existing service. Thus, cost causality could apply to this class of DG just as it would for a new load seeking to receive service from the utility. Under this second principle, the cost for the upgrades identified through the IDP process would be assigned to all DG in the "study group" based on each facility's contribution to the need for an upgrade.

With regard to completing upgrades in advance, the IDP process contains a level of uncertainty regarding the amount of DG growth that may ultimately seek interconnection. Thus, it is possible that upgrades could be planned and built for DG projects that do not come to fruition, potentially leaving utilities unable to recover the costs of those upgrades. However, general utility planning principles exist that can shed light on potential solutions. Utilities already contend with right-sizing issues when planning for load. Load anticipated during distribution planning may not appear for any number of reasons dealing with economic pressures and planned development. Mechanisms and planning methodologies that currently exist to prevent over-building a distribution system on account of a lack of anticipated load could be applied to similar risks related to IDP, at least with regard to small net-metered systems and larger non-exporting systems where costs are allocated to members of an appropriate rate class. Because most distribution planning processes are conducted annually, forecasts can be revised frequently. Such an approach would require a sufficient and clear indication from regulators to utilities that investments made on behalf of anticipated DG would qualify for cost recovery in the same manner as investments made on behalf of load.

While these existing approaches are helpful as a starting point, cost allocation requires a more thorough exploration. We expect to supplement the broad concepts discussed above with further detail in a follow-up paper.

CONCLUSION

The success of programs to encourage distribution-level resources is quickly overwhelming existing utility interconnection procedures. The proactive modeling and planning approaches within IDP leverage existing tools to allow utilities flexibility and foresight in accommodating high penetrations. As the amount of DG on distribution circuits increases, IDP allows utilities to continue to apply technically rigorous interconnection screens without sacrificing efficiency, transparency and economy.

Endnotes

1 Federal Energy Regulatory Commission, *Notice of Proposed Rulemaking re Small Generator Interconnection Agreements and Procedures*, 142 FERC ¶ 61,049, Docket No. RM13-2-000, (January 17, 2013) ("FERC NOPR").

2 Michael Coddington, Barry Mather, and Benjamin Kropski, National Renewable Energy Laboratory, Kevin Lynn and Alvin Razon, U.S. Department of Energy, Abraham Ellis and Roger Hill, Sandia National Laboratories, Tom Key, Kristen Nicole, and Jeff Smith, Electric Power Research Institute, *Updating Interconnection Screens for PV System Integration*, pp. 9-11 (January 2012) ("Interconnection Screens Report"); Kevin Fox, *et al.*, *Updating Small Generator Interconnection Procedures for New Market Conditions*, pp. 22-24 (Dec. 2012) ("Updating Small Generator Interconnection Procedures").

3 *Solar Energy Industries Association Petition for Rulemaking to Update Small Generator Interconnection Rules and Procedures for Solar Electric Generation*, FERC Docket No. RM12-10-000, p. 6 (February 16, 2012) ("SEIA Petition").

4 Larry Sherwood, Interstate Renewable Energy Council, *U.S. Solar Market Trends 2011*, p. 5 (July 2012) ("Solar Market Trends").

5 Becky Campbell & Mike Taylor, *2011 SEPA Utility Solar Rankings,* p. 7 ("Utility Solar Rankings") (May 2012).

6 *Id.* at p. 6.

7 *See, e.g., PJM Interconnection, L.L.C.*, FERC Docket No. ER12-1177-000, Transmittal Letter, p. 1 (February 29, 2012) ("[PJM] hereby submits modifications to its Open Access Transmission Tariff ("PJM Tariff") to implement interconnection queue process reforms that are intended to relieve bottlenecks in the interconnection queue and provide for greater certainty and transparency."); *Cal. Independent System Operator Corp.,* FERC Docket No. ER11-1830-000, Transmittal Letter, p. 2 (October 19, 2010) ("[S]ince 2008, the ISO has experienced a large and rapidly increasing volume of small generator interconnection requests, to a level which has made it impossible for the ISO to study these projects serially under the method within the timelines of the current [SGIP]"); *So. Cal. Edison Co.,* Docket No. ER11-2977-000, Transmittal Letter, p. 3 (March 1, 2011); *Pacific Gas & Electric Co.*, FERC Docket No. ER11-3004-000, Transmittal Letter, p. 4 (March 2, 2011) ("Like the CAISO, PG&E has similarly experienced a dramatic increase in the number of small generator interconnection requests to interconnect with PG&E's distribution system. These requests, which are processed through PG&E's WDT SGIP, have also arisen as a result of California's RPS requirements. Currently, PG&E has a backlog of over 170 interconnection requests for small generators."); Photon Magazine, *Uncharted Territory, Hawaii's solar industry struggles with its own success*, table on p. 25 (September 2012) ("Photon"); California Public Utilities Commission, *Order Instituting Rulemaking 11-09-011*, pp. 3-4 (Sept. 27, 2011) (addressing reforms to California's Rule 21 to accommodate increasingly large numbers of interconnection requests to the distribution grid from exporting and wholesale generators).

8 Photon at p. 25.

9 Utility Solar Rankings at pp. 14, 22. The value of the metrics in Figure 3 is to point out which utilities are seeing growth in renewables, not to identify utilities with congested distribution circuits.

10 Steve Steffel, Pepco Holdings, Inc., *Advanced Modeling and Analysis*, EUCI Presentation at Denver, CO (Nov.15, 2012) ("Pepco Presentation").

[11] *See, e.g.,* California Public Utilities Commission, Decision No. 12-09-018, Attachment A to Attachment A, Revised Rule 21 § E.2.c (Sep. 20, 2012) ("Revised Rule 21") (setting study deposits for facilities 5 MW or less at $10,000 for a System Impact Study and $15,000 for a Facilities Study and for facilities above 5 MW at $50,000 plus $1,000 per MW, up to a maximum of $250,000); Hawaiian Electric Company Tariff Rule 14H, Appendix III § 4(e) (Dec. 20, 2011) (setting a 150-day timeframe for detailed study) ("Rule 14H").

[12] *See* SEIA Petition at p. 9.

[13] *See* Rule 14H, Appendix III § 4(d) (allowing the Hawaiian Electric Company to contract with outside consultants in order to conduct an Interconnection Requirements Study); Pepco Presentation.

[14] Pepco Presentation.

[15] Ken Wells, *Solar Energy is Ready. The US Isn't*, Businessweek (Oct. 25, 2012).

[16] County of Hawaii, Resolution 277-12 (July 18, 2012).

[17] *Id.*

[18] Interconnection Screens Report at pp. 2-5; *see also* Southern California Edison Company, *The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System*, pp. 11-14 (May 2012) ("SCE DG Study").

[19] Interconnection Screens Report at p. 2; *see, e.g.,* Federal Energy Regulatory Commission, *Small Generator Interconnection Procedures* § 2.2.1.2 ("SGIP") (requiring further study once penetration reaches 15 percent of peak load), *app'd* in *Standardization of Small Generator Interconnection Agreements and Procedures,* Order No. 2006, FERC Stats. & Regs. ¶ 31,180, at p. 18 (¶45) (May 12, 2005), *order on reh'g.,* Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (Nov. 22, 2005), *order on reh'g*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (July 20, 2006) ("FERC Order No. 2006"); California Public Utilities Commission, Decision No. 12-09-018 ("CPUC D.12-09-018"), Attachment A to Attachment A, Revised Rule 21 § G.1.m (Sep. 20, 2012) ("Revised Rule 21") (hereinafter, the engineering screens in Section G of the Revised Rule 21 are referred to by the title of the screen, *e.g.*, "Rule 21 Screen M" for the Revised Rule 21 § G.1.m to which this note refers.); Massachusetts Standards for Interconnecting Distributed Generation, Appendix B, Figure 1 (applying as the penetration screen a threshold of 7.5 percent of circuit annual peak load.); New Jersey Interconnection Procedures, N.J.A.C. § 14:8-5.5(f) (Setting the aggregate generation capacity at "10 percent (or 15 percent for solar electric generation) of the total circuit annual peak load."). Rule 14H, Appendix III § 2, Screen 4 (hereinafter, the engineering screens in Section 2 of Rule 14H are referred to by the title of the screens, *e.g.*, "Rule 14H Screen 4" for the screen to which this note refers.).

[20] SGIP § 2.2.1.2; *see, e.g.,* Rule 21 Screen M and Rule 14H Screen 4.

[21] *Motion for Approval of Settlement Agreement Revising Distribution Level Interconnection Rules and Regulations*, California Public Utilities Commission, R.11-09-011, p. 5 (Mar. 16, 2012) ("Motion to Adopt Rule 21 Settlement"); *Reliability Standards Working Group Independent Facilitator's Submittal and Final Report*, Hawaii Public Utilities Commission, Docket 2011-0206, Attachment 4, PV-DG Subgroup Rule 14H Sections 2-3 Recommendation, Screen 12 (March 25, 2013) ("Rule 14H Recommendation").

[22] Rule 21 Screen M; Rule 14H Screen 4.

[23] Rule 21 Screen N; Supplemental Review Screens O and P ensure an interconnection does not raise potential power quality, voltage, safety or reliability concerns that require detailed study.

[24] Rule 21 Screen N. If a generator fails Screen N, a quick review of the failed screen may allow interconnection to occur without detailed study. *See* Rule 21 § G.2.

[25] Rule 14H Recommendation, Screen 12.

[26] FERC NOPR at pp. 23-27.

[27] *See* Interconnection Screens Report at pp. 9-11; Updating Small Generator Interconnection Procedures at pp. 22-24.

[28] *Order Opening Investigation by the Department of Public Utilities on its own Motion into Distributed Generation Interconnection*, Massachusetts Department of Public Utilities, Docket 11-75, p. 2 (September 28, 2011) ("Massachusetts Investigation Order").

[29] Massachusetts Department of Public Utilities, *Order on the Distributed Generation Working Group's Redlined Tariff and Non-Tariff Recommendations*, D.P.U. 11-75-E (Mar. 13, 2013) ("Massachusetts Interconnection Order").

[30] Massachusetts Interconnection Order at pp. 29-39; Massachusetts Distributed Generation Working Group, *Proposed Changes to the Uniform Standards for Interconnecting Distributed Generation in Massachusetts*, p. 8 (September 14, 2012).

[31] Massachusetts Investigation Order at p. 5.

[32] *Id.* at p. 7.

[33] *Id.* at pp. 5, 7

[34] CPUC D.12-09-018 at p. 3.

[35] Motion to Adopt Rule 21 Settlement at p. 5.

[36] *See* CPUC D.12-09-018 at pp. 11-12.

[37] *See* Cal. Pub. Util. Code § 353.5 ("Each electrical corporation, as part of its distribution planning process, shall consider nonutility owned distributed energy resources as a possible alternative to investments in its distribution system in order to ensure reliable electric service at the lowest possible cost.").

[38] *See* California Public Utilities Commission, *Orders Instituting Rulemakings* 99-10-025 and R.04-04-003 (Oct. 1999 and Apr. 2004); *Shaping A California Distributed Energy Resources Procurement*, Draft PIER Consultant Report for the California Energy Commission, Proceeding CEC-500-2005-062-D, p. 2-1 (April 2005). In 2003, the CPUC ordered California's utilities to incorporate into their distribution planning processes a DG procurement program to evaluate alternatives to distribution system upgrades, although there is little evidence of the utilities implementing the program. California Public Utilities Commission, Decision 03-02-068, Rulemaking 99-10-025, ordering paragraphs 1-3, p. 72 (Feb. 27, 2003). A Southern California Edison Company Request for Offers to place DG resources in areas that would defer distribution upgrades, issued nine years after the CPUC's Order, is currently stalled. *See* http://www.sce.com/b-db/distributed-generation-solutions.htm.

[39] T. Hoff, Pacific Energy Group & D.S. Shugar, Pacific Gas & Electric Company, *The Value of Grid-Support Photovoltaics in Reducing Distribution System Losses*, IEEE Transactions on Energy Conversions (Sep. 1995).

40 *Comments of the Interstate Renewable Energy Council, Inc., on Amended Scoping Memo and Ruling Requesting Comments*, Rulemaking 11-09-011, p. 4 (Oct. 25, 2012) ("IREC Comments"). According to the proposal, a low-cost, high-value area is one less than 2.5 miles from a substation, on a distribution system main circuit, where a system will not cause the circuit's thermal capacity to be exceeded, and where a system will not cause backfeed. IREC Comments at p. 4.

41 IREC Comments at p. 5. Under the proposal, any project that is under 2 MW will be interconnected for a fixed fee if it is sited in a low-cost, high-value area. IREC Comments at p. 4. If a facility is greater than 2 MW, it will qualify for fixed fee interconnection if it is interconnecting in a location with the same characteristics as those under 2 MW, and is also connecting to a main circuit that is greater than 600 amps. IREC Comments at p. 4. A balancing account will deal with instances where actual interconnections costs exceed or fall short of the fixed interconnection fee. IREC Comments at p. 5. The utilities will use an average cost approach derived from data from existing interconnections in low-cost areas to come up with the fixed fee. IREC Comments at p. 5. They will update that average as necessary. IREC Comments at p. 5.

42 SCE DG Study at p. 34.

43 *See id.* at pp. 18-19, 33-34.

44 *Id.* at p. 34.

45 *Id.* at p. 35.

46 *Resolution E-4470*, California Public Utilities Commission, p. 10 (Mar. 8, 2012) ("CSI Resolution"); Jeff Smith, Electric Power Research Institute, *Alternative Screening Methods PV Hosting Capacity in Distribution Systems*, U.S. Department of Energy High Penetration Solar Forum (Feb. 14, 2013) ("EPRI Presentation").

47 *Id.*

48 *Id.*

49 *Id.*

50 *Id.*

51 CSI Resolution at 10; EPRI Presentation.

52 Pepco Presentation.

53 *Id.*

54 *Id.*

55 *Id.*

56 *Id.*

57 *Id.*

58 *Id.*

59 *Id.*

60 *Id.*

61 *Id.*

62 *Id.*

63 *Id.*

[64] Photon at pp. 24-25.

[65] Hawaii Public Utilities Commission, *Order No. 30371 Relating to Various Matter in RSWG Process*, Docket 2011-0206, at p. 14 (May 4, 2012).

[66] Hawaii Public Utilities Commission, *Reliability Standards Working Group Independent Facilitator's Submittal and Final Report*, Docket 2011-0206, Attachment 4, PV-DG Subgroup Summary of Proposal for Proactive Review Approach, (March 25, 2013) ("Proactive Approach Summary").

[67] *Id.*

[68] *Id.*

[69] *Id.*

[70] *Reliability Standards Working Group Independent Facilitator's Submittal and Final Report*, Hawaii Public Utilities Commission, Docket 2011-0206, Attachment 4, Distributed Photovoltaic Monitoring, (March 25, 2013) ("Hawaii PV Monitoring Report").

[71] *Id.*

[72] *Id.*

[73] *See Reliability Standards Working Group Independent Facilitator's Submittal and Final Report*, Hawaii Public Utilities Commission, Docket 2011-0206 (March 25, 2013).

[74] Proactive Approach Summary.

[75] EPRI Presentation.

[76] Rule 14H Recommendation, Screen 12 ("If minimum load data is not available and must be calculated or estimated, Screen 12 defaults to the higher of either 75% of the estimated/calculated minimum load or a percentage of minimum load predetermined and posted by the utility for that feeder.").

[77] Rule 21 § G.2.

[78] Rule 14H, Appendix III §§ 2(d), 3(c).

[79] Interconnection Screens Report, p. 7.

[80] Pepco Presentation.

[81] EPRI Presentation.

[82] Hawaii PV Monitoring Report.

[83] IREC conducted informal telephone and e-mail surveys from June through August 2012 with the following companies and organizations: Itron, Inc., SMA, RevoluSun, Rising Sun Solar, and Solar City.