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Summary Report
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Minding the Gaps: Identifying Priority Areas for REV Demonstration Projects to Address

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Background

New York's "Reforming the Energy Vision" (REV) proceeding[1] aims to take advantage of advances in distributed energy resource (DER) technology to make the State's electricity system more efficient, resilient, and sustainable.[2] The change that New York seeks to achieve is nothing short of transformative and will take many years to fully realize. To ensure that utilities make appropriate progress toward the desired end-state in the near-term, the New York State Public Service Commission (Commission) has urged utilities to develop demonstration projects that can "beta-test" various DER services and financing mechanisms prior to wide-scale deployment.[3]

In December 2014, the Commission issued a *Memorandum and Resolution on Demonstration Projects*,[4] which articulated a set of guidelines – "principles," in the Commission's parlance – to inform the design of REV demonstration projects. In its February 2015 *Order Adopting Regulatory Policy Framework and Implementation Plan*, the Commission ordered utilities to propose projects that conform to these principles by July 1, 2015.[5] These proposals are expected to set a new gold standard in technological and financial innovation by leveraging private capital to deploy a diversity of DER solutions that advance REV objectives.

Although the July 1 submissions will be the first official REV demonstration projects, the Commission's December *Memorandum* described "various pilot or demonstration projects currently underway or proposed" that it expects "to provide valuable feedback and to inform the REV initiative."[6] To date, each of the six investor-owned utilities that operate in New York[7] has proposed a capital improvement or "non-wires alternatives"[8] project that beta-tests new technologies and services in lieu of business-as-usual solutions. For ease of reference, we refer to this group of initiatives as "existing pilot projects," as opposed to the REV demonstration projects that will be filed in short order. Importantly, the existing pilot projects have come about as part of rate cases or long-term planning proceedings, which constrains how innovative they can be –

[1] *See* Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (N.Y. Pub. Serv. Comm'n, Apr. 24, 2014).
[2] The six long-term REV policy objectives are: enhanced customer knowledge and tools that will support effective management of their total energy bill; market animation and leverage of ratepayer contributions; system-wide efficiency; fuel and resource diversity; system reliability and resiliency; and reduction of greenhouse gas emissions. *See* 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 at 1-2 (N.Y. Pub. Serv. Comm'n, Aug. 22, 2014).
[3] *See* Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan at 113 (N.Y. Pub. Serv. Comm'n, Feb. 26, 2015).
[4] *See* Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Memorandum and Resolution on Demonstration Projects (N.Y. Pub. Serv. Comm'n, Dec. 12, 2014).
[5] *See* Order Adopting Regulatory Policy Framework and Implementation Plan at 115 (N.Y. Pub. Serv. Comm'n, Feb. 26, 2015).
[6] *See* Memorandum and Resolution on Demonstration Projects at 2 (N.Y. Pub. Serv. Comm'n, Dec. 12, 2014).
[7] PSEG Long Island (PSEG-LI), which is a subsidiary of investor-owned New Jersey holding company Public Service Enterprise Group, operates the electric distribution system in Long Island and the Rockaway peninsula of Queens under an agreement with the State-owned Long Island Power Authority (LIPA). As such, PSEG-LI is not subject to the general jurisdiction of the New York State Public Service Commission, but is instead subject to Department of Public Service "review and recommend" authority under the LIPA Reform Act. PSEG-LI has made clear that it intends to "comply with the direction of the final determinations in the REV proceeding" and "meet [REV's] objectives." *See* Matter 14-01299 – In the Matter of PSEG-LI Utility 2.0 Long Range Plan, Utility 2.0 Long Range Plan Update Document at 10 (N.Y. Pub. Serv. Comm'n, October 6, 2014).
[8] Non-wires alternatives are strategies that can help defer or eliminate the need to construct or upgrade a distribution substation. *See* Richard Cowart, "Recommendations on Non-Wires Solutions," Memorandum to Patricia Hoffman, DOE Electricity Advisory Committee (Oct. 17, 2012). Retrieved from: http://energy.gov/sites/prod/files/EAC%20Paper%20-%20Recommendations%20on%20Non-Wires%20Solutions%20-%20%20Final%20-25-Oct-2012.pdf.

particularly in terms of alternative financing. Still, the existing pilots bear great promise to illustrate the potential for DER products and services to capably address system needs throughout New York State.

This report assesses the extent to which the existing pilot projects address the principles that the Commission has outlined for impending REV demonstration project proposals. Because the existing pilots are arguably the best indication of near-term progress toward achieving REV objectives, it is critical that the Commission and other stakeholders understand which principles these projects collectively address and where there remain gaps that REV demonstration projects need to target.

Demonstration Principles and Existing Pilot Projects

Demonstration Principles

Demonstration projects must be approved by the Commission in order for utilities to recover their share of project costs through rates.[9] To guide these determinations and establish guidelines for utilities to follow in developing REV demonstration proposals, the Commission set out a list of eight "Principles for REV Demonstrations" in its December 2014 *Memorandum*.[10] Unfortunately, the *Memorandum* describes the principles in vague terms and it is difficult to distinguish one principle from another.[11] In fact, there is reason to believe that utilities have struggled to fully grasp the Commission's intentions for demonstration projects.[12]

This report attempts to distill the eight principles into guidelines that can more readily be used to prospectively appraise REV demonstration projects and retrospectively evaluate existing pilots. Specifically, we have interpreted and reformulated the Commission's "Principles for REV Demonstrations" as follows:

1. **Partnerships** | Utilities should partner with third-party service providers to carry out demonstration projects and should seek to mobilize third-party capital.
2. **Market-Driven Solutions** | Demonstration projects should actively engage third parties in identifying creative solutions to problems.
3. **Distribution of Value** | Demonstration projects should allocate economic value between the utility, its customers, and third-parties. This hinges to a large extent on how involved parties allocate costs; projects should animate private capital to relieve the burden on ratepayers.
4. **Competition in Grid Services** | Projects should promote diverse ownership of DER and DER-enabling assets.[13]
5. **Developing Competitive Markets** | Demonstration projects should help lay the groundwork for markets to develop where they do not yet exist. Projects can address this principle by, *inter alia*, establishing operational standards, data agreements and terms of use (e.g., rules governing access to and

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[9] Notably, in order to reduce ratepayer costs, the Commission has encouraged utilities to utilize private capital to finance projects, at least in part, instead of relying exclusively on rate increases to recover costs. *See, e.g.,* Principle #3 below.
[10] *See* Memorandum and Resolution on Demonstration Projects at A-1 (N.Y. Pub. Serv. Comm'n, Dec. 12, 2014).
[11] For example, the phrases "The market for grid services should be competitive" and "utilities and service provider should propose rules […] that will help create subsequently competitive markets" appear in separate principles. *See* ibid.
[12] For example, Central Hudson explains how its proposals-in-development would address each of the Commission's principles, but mischaracterizes some of them. *See* Cases 14-E-0318 and 14-G-0319 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service, Central Hudson's Report Regarding the REV Collaborative and Developing Demonstration Projects (N.Y. Pub. Serv. Comm'n, May 1, 2015).
[13] This is consistent with the Commission's general prohibition of utility DER ownership *See* Order Adopting Regulatory Policy Framework and Implementation Plan at 70 (N.Y. Pub. Serv. Comm'n, Feb. 26, 2015).

use of data generated by advanced meters) to reduce transaction costs and/or provide greater certainty regarding future market opportunities.

6. **Innovative Pricing/Rate Design** | Demonstration projects should test pricing methods that are more responsive to dynamic market conditions than regulatory tariffs. Projects should introduce variable, market-based pricing techniques such as time-varying pricing.
7. **Advanced Distribution Technology** | To help utilities transition to their role as "distributed system platform" (DSP)[14] providers, demonstration projects should include advanced distribution technologies such as those that enable two-way communication and real-time load management.
8. **Customer Engagement** | Demonstration projects should engage diverse classes of customers (i.e., residential, commercial, institutional and industrial customers).

Critically, while the principles above represent our best interpretation of the Commission's stated criteria for evaluating REV Demonstration Projects, we do not believe that these criteria are entirely sufficient. For example, the "Market-Driven Solutions" principle is less ambitious than we believe it should be; rather than suggesting that utilities should only engage third parties in devising solutions to network problems, this principle should encourage utilities to engage third-parties in diagnosing network problems as well. We also feel that the Commission has omitted some important criteria. For instance, we believe that utilities should be explicitly encouraged to articulate metrics and targets that would help the Commission to measure their progress toward achieving the objectives their projects claim to advance.[15]

Existing Pilot Projects[16]

Working in parallel to the REV proceeding, investor-owned utilities have already proposed a number of capital improvement and non-wires alternatives projects that showcase the types of technologies and services that REV promotes. However, the robustness and specificity of these proposals has varied considerably.

At one end of the spectrum, Con Edison has submitted (and received approval for) a highly detailed and ambitious plan known as the Brooklyn/Queens Demand Management (BQDM) program, which aims to use DER solutions to defer a $1 billion substation upgrade.[17] Initially outlined in a Con Edison rate case that concluded in early 2014,[18] the BQDM program was formally proposed in a separate proceeding in July 2014.[19] While not as fully fleshed out as BQDM, Central Hudson Gas & Electric has received approval to pilot a fairly sophisticated system-wide communications and distribution automation upgrades that were

[14] The Commission characterizes the DSP as an "intelligent network platform" that valuates power system and societal attributes, engages customers and third parties, and integrates DERs. *See* DPS Staff Straw Proposal on Track One Issues at 12 (N.Y. Pub. Serv. Comm'n, Aug. 22, 2014).

[15] The Commission took tentative steps toward encouraging definition and measurement of project outputs in its August 2014 *Track One Straw Proposal*, but appears to have abandoned this notion in its final principles. *See* id at 56.

[16] Appendix A to this report contains overviews of the relevant existing pilot projects.

[17] *See* Case 14-E-0302 – Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program (N.Y. Pub. Serv. Comm'n, July 15, 2014).

[18] *See* Cases 13-E-0030 et al. – 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 at 4 (N.Y. Pub. Serv. Comm'n, February 21, 2014) Case 14-E-0302 – Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program, Order Establishing Brooklyn/Queens Demand Management Program at 2 (N.Y. Pub. Serv. Comm'n, December 12, 2014).

[19] *See* Case 14-E-0302 – Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program (N.Y. Pub. Serv. Comm'n, July 15, 2014).

proposed in its recently completed rate case.[20] PSEG-LI has also filed a number of detailed proposals for investments aimed at modernizing Long Island's distribution networks in its "Utility 2.0 Long Range Plan." This plan includes several targeted non-wires alternatives projects aimed at addressing system needs in priority load areas, such as the Far Rockaway area of Queens and the South Fork area of Eastern Long Island.[21]

New York State's other three investor-owned utilities – Iberdrola USA, National Grid USA, and Orange & Rockland Utilities – have provided relatively scarce information regarding the pilot projects they have announced to date. One factor that may explain the disparate level of detail in the various proposals is timing; whereas Con Edison, Central Hudson and PSEG-LI each presented initial proposals for their pilots in July of 2014, the other utilities initiated rate cases more recently. Without a similar "head start" prior to the Commission's December *Memorandum*,[22] these three utilities may have focused their efforts in the time since on readying REV demonstration submissions rather than further developing these pilots.

Appraising the Early Pilot Projects

Table 1 illustrates the extent to which existing pilot projects already address the principles for REV demonstrations that the Commission has set forth. Because the Commission devised the REV demonstration principles for proposals received on or after July 1, 2015, this exercise does not seek to imply that existing pilots are deficient if they do not address each principle. Instead, we intend for this inventory to inform a prospective needs assessment as the Commission reviews, and other stakeholders design, REV demonstration proposals going forward.

The existing pilots address several of the principles articulated by the Commission. The principles best addressed by existing pilots (denoted by green headers in Table 1) are "Partnerships" and "Customer Engagement." Nearly all pilots further these principles. In addition, more than half of the existing pilot projects address the "Market-Driven Solutions" and "Advanced Distribution Technology" principles, which together signal an increasingly prominent role for third-parties and modern network equipment. Furthermore, three projects address the "Competition in Grid Services" principle, which shows that utilities are beginning to facilitate network access for DER service providers.

However, there are several important dimensions (denoted by red headers in Table 1) that are not well addressed by the existing pilots. In particular, while nearly all pilots could *facilitate* cost allocation methodologies that address the "Distribution of Value" principle (denoted by gray boxes in Table 1), no pilot project has given concrete indications that it will relieve ratepayers of the financing burden. However, because the Commission has identified the development of new revenue streams and business models as a primary focus going forward,[23] this principle appears likely to be adequately addressed by REV demonstration projects. Similarly, no project clearly addresses the "Developing Competitive Markets" or "Innovative

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[20] *See* Cases 14-E-0318 and 14-G-0319 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service, Order Approving Rate Plan at 51 (N.Y. Pub. Serv. Comm'n, June 17, 2015).

[21] *See* Matter 14-01299 – In the Matter of PSEG-LI Utility 2.0 Long Range Plan, Utility 2.0 Long Range Plan Update Document (October 6, 2014).

[22] Orange & Rockland Utilities initiated a rate case effective November 14, 2014, less than a month before the Commission's December *Memorandum*. Both utilities owned by Iberdrola USA initiated rate cases effective May 20, 2015.

[23] *See* Order Adopting Regulatory Policy Framework and Implementation Plan at 115 (N.Y. Pub. Serv. Comm'n, Feb. 26, 2015).

Pricing/Rate Design" principles, and only a handful show signs that they may eventually seek to reduce transaction costs and introduce innovative pricing techniques in the future, respectively.

There are several possible explanations for why utilities have not yet addressed some of these important areas. The most straightforward explanation is that regulated electric utilities, which have considerable experience providing distribution-level services under regulated tariffs as natural monopolies, are unfamiliar with market principles. This is especially relevant for the "Distribution of Value" principle – it may simply be unrealistic to expect utilities to propose alternative financing mechanisms in the context of conventional rate-base proceedings. Another explanation is that utilities may not believe that laying a foundation for competitive network access – which may scale back the boundaries of what is defined to fit within natural monopoly functions – will further their economic interests. It is therefore imperative that REV reforms ensure that the regulatory process encourage, rather than impede, utilities' attempts to test bold new business models.

Conclusion

While utilities' existing pilot projects address most of the "Principles for REV Demonstrations," some important principles remain unaddressed. Specifically, the existing pilot projects do not lay out explicit plans for value distribution, introduce innovative means of pricing DER services, or establish rules to help competitive markets to take root. With the first official REV demonstration project proposals looming, the Commission should prioritize these three principles to ensure that the State's electricity projects collectively advance desired tenets of innovation and market design.

Still, the Commission's imprecise guidance threatens to undermine utilities' attempts to address all desired criteria. For instance, utilities may not fully appreciate the difference between providing rules for competitive markets and soliciting market solutions based on the vague descriptions of these concepts in the "Principles for REV Demonstrations." This ambiguous language may impede the construction of the critical market foundations that REV seeks to inspire. The Commission should therefore consider issuing a clarification and/or revision of its "Principles for REV Demonstrations" soon so that subsequent REV demonstration projects can fully measure up to expectations.

Table 1. *Existing pilot projects address most, but not all, design principles*

		Principles for REV Demonstrations							
Utility	Existing Pilot Project	Partnerships	Market-Driven Solutions	Distribution of Value	Competition in Grid Services	Developing Competitive Markets	Innovative Pricing/ Rate Design	Advanced Distribution Technology	Customer Engagement
Central Hudson	Network Strategy and Distribution Automation	Facilitates						Addresses	Facilitates
Con Edison	Brooklyn/Queens Demand Management	Addresses	Addresses	Facilitates	Addresses				Addresses
Iberdrola USA	Smart Energy Community	Addresses	Addresses	Facilitates	Addresses	Facilitates	Facilitates	Facilitates	Addresses
National Grid USA	Potsdam Underground Microgrid Design	Addresses		Facilitates	Facilitates			Addresses	Addresses
Orange & Rockland	Rockland County AMI			Facilitates				Addresses	Addresses
Orange & Rockland	Pomona DER	Addresses	Addresses	Facilitates	Facilitates		Facilitates		Addresses
PSEG-LI	Utility 2.0 Long Range Plan	Addresses	Addresses	Facilitates	Addresses	Facilitates	Facilitates	Addresses	Addresses

Addresses principle

Facilitates but does not definitively address principle

Appendix A

Descriptions of existing pilot projects proposed by investor-owned utilities in New York State

The six investor-owned utilities operating in New York State have begun to develop pilot projects outside of the REV proceeding that nevertheless beta-test "REV-like" technologies and services. The pilot projects that have been proposed to date are summarized below:

Central Hudson Gas & Electric

Central Hudson has received approval to pilot its *Network Strategy and Distribution Automation* program in its recently approved rate plan.[1] Central Hudson intends for this program to provide "foundational elements for system operational needs of the Distributed System Platform Provider."[2] This program was initially proposed as separate but interrelated components of Central Hudson's five-year capital program.

Through the Distribution Automation (DA) program, Central Hudson hopes to reduce network losses and customer energy usage while deferring the need for costly infrastructure reinforcements. Central Hudson proposes two components of the DA program: a distribution management system (DMS) and infrastructure upgrades. The DMS will provide real-time remote visibility of the operations of the distribution system, advanced system modeling, and near real-time loadflow and contingency analysis capabilities. Improvements to the distribution communications infrastructure will include the installation of intelligent/controllable devices and robust mainline feeders that can be used to restore power to customers more quickly after an outage, and to optimize and balance feeders during normal operations. Finally, system-wide volt/VAR optimization will reduce system losses and customer energy usage. Central Hudson requested $46.3 million for the DA program, for which it estimated total annual benefits of $11.3 million in avoided energy costs and deferred infrastructure costs.[3]

The Network Strategy plan is intended to establish robust systems that provide reliable and secure communications between Central Hudson's fixed assets. This will allow Central Hudson to strengthen its demand response and DER integration capabilities while supporting the communications needs of the DA program; the network established by the Network Strategy plan will act as a two-way communications system between the DMS and intelligent electronic devices in use on the network, including supervisory control and data acquisition (SCADA) systems, transmission line protection, security, and general network traffic applications. Central Hudson seeks to implement Network Strategy as a two-tiered communications network – Tier 1 for high-bandwidth fiber-optic applications and Tier 2 for medium-bandwidth radio applications. Central Hudson proposes to leverage third-party providers for the above communications needs. Central Hudson requested $18.5 million for Network Strategy, and estimated that its implementation would generate a 10-year net present value that was $400,000 lower than the business-as-usual projection.[4]

[1] *See* Cases 14-E-0318 and 14-G-0319, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric and Gas Service, Order Approving Rate Plan at 51 (N.Y. Pub. Serv. Comm'n, June 17, 2015).
[2] *See* Cases 14-E-0318 and 14-G-0319, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric and Gas Service, Direct Testimony of Paul E. Haering at 4 (N.Y. Pub. Serv. Comm'n, July 25, 2014).
[3] *See* id at 8-14.
[4] *See* id at 15-19.

The Commission received several comments that expressed concern over the potential for these projects either to oppose REV initiatives or impede network participation by customers and third parties over time. In light of the considerable investment that these projects represent, the comments further noted the potential for large stranded costs if the projects need to be abandoned.[5] Accordingly, the Commission has only approved funding for the first year of these projects as a combined initiative in Central Hudson's forthcoming rate plan. Consistent with Commission staff's recommendations, the project will be treated as an opportunity to demonstrate viability, with checkpoints to evaluate its functional capability and operation. Now that its rate plan has been approved, Central Hudson will work with the Commission to define the scope of this demonstration as well as the relevant checkpoints and milestones that can indicate whether the project shall be continued or modified thereafter.[6]

[5] *See* Cases 14-E-0318 and 14-G-0319, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric and Gas Service, Order Approving Rate Plan at 51-52 (N.Y. Pub. Serv. Comm'n, June 17, 2015).
[6] *See* id at 15-16.

Con Edison

Con Edison's *Brooklyn/Queens Demand Management* (BQDM) project is intended to reduce the potential for overload of subtransmission feeders serving the Brownsville load area in Brooklyn and Queens during peak summer hours. In so doing, the project should allow the company to defer $1 billion in infrastructure expense that would otherwise be needed.[7]

As part of the BQDM project, Con Edison will undertake 17 MW of traditional infrastructure investment, consisting of capacitor bank installations and load transfers to other networks.[8] But the distinguishing feature of the BQDM project is the 52 MW of capacity provided by nontraditional solutions – 41 MW will come from customer-sided solutions and 11 MW from utility-sided solutions. Con Edison issued an RFI to third-party providers for solutions,[9] which received 78 responses proposing projects that include energy efficiency, energy management and audit software, energy storage, customer engagement, and demand response. To ensure that the selection process is transparent and fair, the Commission has ordered Con Edison to retain an independent third party consultant to oversee the process and report to the Commission on the selections made.[10]

In addition to the utility-sided solutions proposed by third parties, Con Edison has proposed several utility-sided solutions, including utility-side battery storage and one or more microgrids at apartment complexes near Brownsville. It proposes to deploy company-owned generation on company-owned land that will be synchronized to the distribution grid. Moreover, the company will deploy voltage and reactive power (volt/VAR) optimization on the microgrid to reduce voltage by 2.25%, which will result in an effective demand reduction of 2 MW.[11] In response to concerns that Con Edison's proposal to own these DER assets violates the State's Vertical Market Power Policy, the Commission has limited Con Edison's ownership of DER assets to certain battery storage solutions and non-storage assets for which it can demonstrate that the market has failed to respond.[12]

The primary benefit of the BQDM project is that it defers construction of a new area substation that would cost $1 billion. On its own, the project delays the need for a new area substation from 2017 to 2019. When combined with three other measures (a proposed 80 MW load transfer to the Glendale substation, the addition of a fourth transformer at the Newtown substation, and the installation of a fifth transformer at the Glendale substation), the need for new infrastructure will be further delayed to 2026.[13]

Con Edison submitted a detailed benefit-cost analysis (BCA) to compare the net present value of the program with the net present value of constructing a new area substation. The BCA showed that the BQDM program would confer a net present value benefit of approximately $40 million. However, the Commission determined that the BCA as submitted was insufficient because it lacked the benefits and costs of the specific customer-

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[7] *See* Case 14-E-0302 – Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program (N.Y. Pub. Serv. Comm'n, July 15, 2014).
[8] *See* BQDM Petition at 7.
[9] *See* Consolidated Edison Company of New York, Inc., Request for Information: Innovative Solutions to Provide Demand Side Management to Provide Transmission and Distribution System Load Relief and Reduce Generation Capacity Requirements (N.Y. Pub. Serv. Comm'n, July 15, 2014).
[10] *See* Case 14-E-0302 – Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program, Order Establishing Brooklyn/Queens Demand Management Program (N.Y. Pub. Serv. Comm'n, December 12, 2014).
[11] *See* BQDM Petition at 12.
[12] *See* Order Establishing BQDM Project at 23.
[13] *See* id at 3-4.

side projects to be deployed. The Commission ordered Con Edison to submit a more detailed analysis once the request for information (RFI) selection process has been completed.[14]

To assure ratepayers of this net benefit, the Commission has capped the costs of the program at $200 million and has ordered Con Edison to amortize the costs over 10 years. $25 million will be funded through Con Edison's Targeted Demand Side Management (TDSM) program budget. The remaining $175 million will be eligible for recovery through the monthly adjustment clause (MAC) and NYPA surcharges. The Commission has ordered Con Edison to propose during its next rate proceeding to recover residual program costs through base rates rather than through these surcharges.[15]

[14] *See* id at 18.
[15] *See* id at 19-21.

Iberdrola USA[16]

Together with Cornell University and the broader Tompkins County community, New York State Electric & Gas (NYSEG, a subsidiary of Iberdrola USA) plans to implement the *Smart Energy Community* program in Ithaca, NY as a test-bed for DER technologies. This program is in the early planning stages, but seeks to engage the greater Ithaca area community (10,000-15,000 customers) to provide enhanced opportunities for distributed generation and access to tools to optimize demand.[17]

Specific initiatives that NYSEG hopes to pilot through its Smart Energy Community program include:

- new processes and tools for integrated distribution system planning;
- supporting customer and third-party engagement in market operations; and
- operating the grid efficiently and reliably.[18]

To this end, Iberdrola USA has issued an RFI with the intention of deploying various DER and DER-enabling technologies and practices.[19] NYSEG has cited numerous operational benefits, including reductions in technical losses, improved outage management, efficiencies in billing, and improved power quality and voltage management. NYSEG has also cited many customer benefits, including support for time-differentiated rates and demand response programs, tools and information to help customers understand and manage usage, improved reliability, and more accurate bills. Finally, anticipated market benefits include data collection for possible information sharing and third-party participation in the platform.[20]

NYSEG has estimated total project costs of $15.5 million from 2016-2019.[21] To finance this program, NYSEG hopes to secure funding from state, federal (e.g., NSF), and nonprofit sources, but believes that the program is likely to attract private sector resources as well.[22]

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[16] Iberdrola USA holds two investor-owned utilities – New York State Electric & Gas and Rochester Gas & Electric.
[17] *See* Tompkins County Climate Protection Initiative, Meeting Highlights: 2015, March 2015. http://www.tccpi.org/meeting-highlights--2015.html
[18] *See* Iberdrola USA, NYSEG and RG&E Capital Investment Plan 2015-2019 (April 1, 2015).
[19] *See* Memorandum and Resolution on Demonstration Projects at 3 (N.Y. Pub. Serv. Comm'n, Dec. 12, 2014).
[20] *See* supra note 18.
[21] *See* id.
[22] *See* supra note 17.

National Grid USA

A group consisting of National Grid USA, Clarkson University, GE Energy Consulting, Nova Energy Specialists, and the National Renewable Energy Laboratory has received funding to begin the *Potsdam Underground Microgrid Design* project. In light of frequent outages caused by severe winter weather and flooding in the Village of Potsdam in New York's North County, this partnership intends to harden energy infrastructure to maintain essential community services during emergencies caused by either weather events or bulk power faults. The proposed microgrid will operate in "grid-connected" mode under normal conditions, but will switch to "island" mode in an emergency to serve critical loads directly with local generation using an enhanced microgrid control system (eMCS). These facilities will include up to 3 MW of combined heat and power generators, 2 MW of solar photovoltaic power, 900 kW or more of hydroelectric generation, and may use up to 2 MW of energy storage to improve power quality. The microgrid's primary distribution network, which will connect the system's generating sources to loads, will be installed underground to ensure that it will not be vulnerable to extreme weather events. The project has received a $1.2 million grant from the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, $381,000 in competitive NYSERDA funding, and a $300,000 investment from GE.[23]

National Grid has also received NYSERDA funding to conduct a *Microgrid Feasibility Study* for the City of Buffalo, in partnership with EPRI, the University of Buffalo, and the Buffalo Niagara Medical Campus (BNMC).[24] The results of this study will determine whether National Grid will proceed with implementation of a microgrid for BNMC and can inform BNMC's efforts to integrate DER technologies. Because this effort only consists of a feasibility study rather than a concrete plan to pursue a demonstration project, it is omitted from Table 1.

[23] *See* National Grid U.S., "Clarkson University Receives Approval on Design of Resilient Underground Microgrid," News release (August 6, 2014). Available at: http://www.nationalgridus.com/aboutus/a3-1_news2.asp?document=8653 and GE Global Research, "GE, Utility, Government, and Academia Partner on Microgrid Project," News release (December 10, 2014). Available at: http://www.geglobalresearch.com/news/press-releases/ge-utility-government-academia-partner-underground-microgrid-project-improve-electricity-reliability-nys-north-country.

[24] *See* Memorandum and Resolution on Demonstration Projects at 3 (N.Y. Pub. Serv. Comm'n, Dec. 12, 2014).

Orange & Rockland Utilities
O&R REV initiatives consist of two components – deployment of advanced metering infrastructure (AMI) and the Pomona DER program.

The *Rockland County AMI* project will consist of an integrated system of smart meters, communications networks, and data management systems to allow for two-way communications between O&R and its customers. While O&R proposes to implement AMI across its entire system, the demonstration phase will be limited to Rockland County.[25]

For O&R's *Pomona DER* program, the utility plans on working with third party vendors to deploy a variety of DER solutions to achieve demand reductions in the Pomona load pocket. To this end, O&R published an RFI seeking proposals on the following types of solutions:

- targeted energy efficiency (EE);
- demand response (DR);
- clean distributed generation (DG);
- energy storage (ES);
- customer incentive mechanisms (e.g., rebates and turn-key DG);
- customer outreach and education; and
- creative marketing, sales, financing, transaction structures and pricing formulas.[26]

Consistent with the Commission's conditions regarding utility ownership of DER assets,[27] O&R's DER ownership in the Pomona project is essentially limited to utility-side energy storage. The Commission has approved O&R to recover $380,000 per year through base rates to finance the Pomona project, with total spending capped at $9.5 million.[28]

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[25] *See* Case 14-E-0493 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service (N.Y. Pub. Serv. Comm'n, November 14, 2014).
[26] *See* Orange and Rockland Utilities, Inc., Request for Information: Seeking Innovative Solutions to Provide Demand Management for the Purpose of Transmission and Distribution System Load Relief (October 20, 2014).
[27] *See* Order Adopting Regulatory Policy Framework and Implementation Plan at 70 (N.Y. Pub. Serv. Comm'n, Feb. 26, 2015).
[28] *See* Cases 14-E-0493 and 14-G-0494 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric and Gas Service, Joint Proposal at 38 (N.Y. Pub. Serv. Comm'n, June 5, 2015).

PSEG Long Island
PSEG Long Island (PSEG-LI), which is a subsidiary of investor-owned New Jersey holding company Public Service Enterprise Group, operates the electric distribution system in Long Island and the Rockaway peninsula of Queens under an agreement with the State-owned Long Island Power Authority. While PSEG-LI is not subject to the general jurisdiction of the Commission,[29] it has made clear that it intends to "comply with the direction of the final determinations in the REV proceeding."[30] Accordingly, PSEG-LI has initiated a formal Commission review of its *Utility 2.0 Long Range Plan*, which represents its "best attempt to meet [REV's] objectives."[31]

In its Utility 2.0 Long Range Plan, PSEG-LI proposes to deploy DERs and other solutions that provide capacity relief in areas that would otherwise require costly network upgrades. Specifically, the plan identifies the South Fork, Far Rockaway, and Glenwood areas as high-priority load pockets. PSEG-LI proposes to issue RFPs for third-party solutions that inject a mix of behind-the-meter and grid-connected solutions to defer transmission and distribution upgrades in these three areas. Subsequently, PSEG-LI plans to issue RFIs to identify nontraditional, distributed solutions for as many as five other targeted load areas.[32]

In addition to these targeted infrastructure deferment efforts, PSEG-LI will consider the following distributed solutions to expand access to DER as part of the Utility 2.0 Plan:

- direct load control modernization and expansion;
- residential home energy management;
- advanced metering infrastructure;
- solar PV expansion (both utility-scale and customer-sited);
- energy conservation for hospitals; and
- electric vehicle charging infrastructure.

Between 2015 and 2018, PSEG-LI projects that the above measures and infrastructure deferments will conserve just under 300 GWh annually at a total cost of $345 million.[33]

In its recommendations on the Utility 2.0 Long Range Plan, submitted to the LIPA Board of Trustees on April 15, 2015, the Commission stated that PSEG-LI should pursue the three capacity relief projects noted above and recommended that a Long Island-wide communications network be built to accommodate future REV deployments.[34]

[29] PSEG-LI is instead subject to Department of Public Service "review and recommend" authority under the LIPA Reform Act.
[30] *See* Matter 14-01299 – In the Matter of PSEG-LI Utility 2.0 Long Range Plan, Utility 2.0 Long Range Plan Update Document at 10 (N.Y. Pub. Serv. Comm'n, October 6, 2014).
[31] *See* ibid.
[32] *See* Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Response of PSEG LI to Order Adopting Regulatory Policy Framework and Implementation Plan (N.Y. Pub. Serv. Comm'n, May 1, 2015) at 2.
[33] *See* Utility 2.0 Long Range Plan Update Document at 4-5 (N.Y. Pub. Serv. Comm'n, October 6, 2014).
[34] *See* Matter 14-01299 – In the Matter of PSEG-LI Utility 2.0 Long Range Plan, DPS Recommendations of PSEG's First Annual Long Range Plan (N.Y. Pub. Serv. Comm'n, April 15, 2015).