Anna Chacko
Senior Associate General Counsel

October 26, 2015

Honorable Kathleen H. Burgess
Secretary
New York State Public Service Commission
Three Empire State Plaza
Albany, NY 12223-1350

Re: Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision – Staff's White Paper on Ratemaking and Utility Business Models

Dear Secretary Burgess:

Enclosed are the Comments of Consolidated Edison Company of New York, Inc., and Orange and Rockland Utilities, Inc. in the referenced matter.

Thank you.

Respectfully submitted,



Anna Chacko

Enclosure

Consolidated Edison Company of New York, Inc.
4 Irving Place New York NY 10003 212 460 2524 212 677 5850 fax chackoa@coned.com

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision	x x x x	**Case 14-M-0101**

Comments of Consolidated Edison Company of New York, Inc. and Orange & Rockland Utilities, Inc. on Staff's White Paper on Ratemaking and Utility Business Models

Consolidated Edison Company of New York, Inc. ("Con Edison") and Orange and Rockland Utilities, Inc. ("O&R") (collectively "the Companies") hereby submit their joint comments ("Comments") to Staff's White Paper on Ratemaking and Utility Business Models dated July 28, 2015 ("Track Two White Paper" or the "White Paper").[1]

These Comments supplement the Comments of the Joint Utilities ("Joint Utility Comments"),[2] which the Companies helped to develop and fully support. These Comments: (1) provide specific characteristics of the network system in the Con Edison service territory; (2) provide the Companies' assessment of Staff's proposed Peak Reduction Metric; and (3) explain that the Companies' advanced metering infrastructure ("AMI") proposals facilitate implementation of new rate designs for all customers.

As noted elsewhere in this proceeding, the Companies continue to support the Commission's Reforming the Energy Vision ("REV") initiatives and appreciate the opportunity

[1] Case 14-M-0101 –*Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, ("REV Proceeding"), White Paper on Ratemaking and Utility Business Models (issued July 28, 2015).

[2] Con Edison and O&R are also filing joint comments today with Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation (the "Joint Utilities") in a separate document. REV Proceeding, Initial Comments of the Joint Utilities on Staff's July 28, 2015 White Paper on Ratemaking and Utility Business Models, dated October 26, 2015 ("Joint Utilities' Comments"). These Comments reflect only the position of Con Edison and O&R.

to address critical issues related to the future structure of the energy industry and regulated utilities in New York State. The Companies continue to identify cost-effective opportunities to defer utility infrastructure investments with Distributed Energy Resources ("DER") consistent with REV concepts and goals. However, the mechanisms proposed in the Track Two White Paper raise concerns about the focus of such initiatives as they relate to deferring utility infrastructure investments. The Companies recommend that the Commission consider costs and benefits throughout the REV process, especially when developing REV-related requirements. Such an approach is key to aligning utility interests with customer benefits in the REV proceeding, which ultimately will be a cornerstone of REV's success.

Characteristics of Con Edison's Network System

REV presents additional challenges for Con Edison because of its size, its energy density and growth, and the complexity of serving its 3.4 million electric customers in New York City and Westchester County. These challenges include meeting the disparate needs of the financial capital of the world, a significant amount of low-income housing, and new complex urban developments, such as Hudson Yards, while maintaining service reliability at levels beyond those of virtually all other utilities. Further, Con Edison's customer mix includes a large number of critical financial, data, and information centers as well as hospitals, and transportation infrastructure, all of which require high levels of power quality and/or reliability.

In fact, Con Edison has already set in motion much of what REV calls for to address the needs of customers, including the energy efficiency ("EE") and demand response ("DR") programs that have been part of Con Edison's approach to managing energy needs for at least a decade. Con Edison's experiences translate well into new initiatives, such as its Brooklyn

Queens Demand Management ("BQDM") program,[3] aimed at addressing peak demand through non-traditional means, that has become a hallmark of REV. These experiences and initiatives reflect the fact that most of Con Edison's customers are served through a network system that has unique characteristics in terms of the scale, design, and performance that it delivers. The density of the load and the nature of the underground network create unique modeling complexity for planning and logistical complications for operation and maintenance of the grid that are different from a radial system.

The distribution network design consists of a robust and tightly intertwined electrical mesh, typically called the secondary network, which provides multiple routes to deliver electricity to the same customer premises. Electricity is fed into the network from a substation via medium voltage primary feeders and then transformed to 120/208 volt power that is delivered to the customers via the secondary network. Switches, called network protectors, are designed so that the multi-directional power on the secondary network does not back-feed and create a fault on the primary feeders. Also, the relay protection for the primary feeder is designed such that when a fault occurs on the primary feeder, after the substation breaker opens, all the network protectors on the feeder will sense the reverse power flow and open to isolate the feeder with the fault condition. Failure of the network protectors to open on the reverse power flow will result in the fault condition remaining energized. These network protectors must be coordinated with any type of DER that exports onto the secondary system and presents challenges that do not exist with radial systems.

[3] Case 14-E-0302, *Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program*, Order Establishing Brooklyn/Queens Demand Management Program (issued December 12, 2014), as modified by Order Granting Rehearing and Granting Clarification in Part (issued April 20, 2015).

Con Edison uses an "N-2" design criteria to minimize outages to high-rise buildings, transportation systems, and other critical loads (in contrast, radial systems are typically "N-1"). This N-2 (*i.e.*, second contingency) design criteria means that any two supply elements can be out-of-service and the remaining elements will be able to serve the peak load. This combination of network design and second contingency criteria provides Con Edison's network customers with one of the highest levels of reliability in the nation. This combination also produces some potentially unique performance characteristics relative to traditional radial systems that constitute most of the electrical grid outside New York City. For example, the higher fault currents inherent in a secondary mesh design can impact the cost to interconnect generating units to the distribution network.

The secondary network is designed to mitigate the potential for unwanted back-feed during fault conditions on a feeder or simple low-load conditions on a part of the network. In this case, the network protector switch is designed to open and isolate the low-voltage grid from the primary feeder. The density of the Con Edison load can mitigate potential back-feed because the output of a generator can often (but not always) be consumed locally.

Con Edison is committed to developing capabilities to accept more injections. However, synchronous generators, like combined heat and power ("CHP") that operate regularly, have more potential to cause back-feed issues. Consistent with reliability standards, Con Edison requires a detailed review of CHP units that plan to export power, and will require any resulting system modifications to be paid for by the customer installing the CHP unit. For smaller and more intermittent resources like rooftop solar energy, Con Edison can address many of the concerns through modifications to the relay settings on the network protectors. As REV enables

increased levels of renewable energy, Con Edison will continue to monitor what implications this may have, especially for projects that propose oversized net-metered generators.

From a REV perspective, the proximity to customer needs and the current-carrying capability of the network mean that any net injections or reduced customer demand from DER assets are likely to be delivered locally to nearby customers and will not have a material impact on power flows outside the local network area. This means that the benefit of DER in a network requiring reinforcement upgrades decreases as the distance from the system need grows. In addition, the second contingency design means the need for deploying DER resources will likely be based on thermal equipment loadings during primary feeder contingencies, which can occur any time of the year and may not be isolated to high-load days. More importantly, over 75 percent of Con Edison's networks peak at times that differ from the state-wide peak load, with some networks peaking midday and others peaking in the late evening. Further work will be needed to quantify the extent of opportunities where DER can benefit both the network and system peaks and develop strategies to take advantage of these opportunities.

The impacts and resulting needs in a second contingency design are inherently more complex and require non-linear solutions to calculate power flows and impacts from customer-sited solutions. As a result, the need for DER resources within the network portions of the Con Edison system will require different tools to evaluate and value the resources than is the case for the radial portions of the electrical grid. Con Edison expects to spend capital to build out its modeling and design capabilities as part of REV and ultimately implement a full locational information system to better track DER deployment and enable REV.

Con Edison has experienced load growth in specific areas of the distribution systems. While overall system peak growth has slowed, in part due to EE programs and new codes and

standards, there are local pockets of strong growth, such as various neighborhoods of Brooklyn, Manhattan, and Queens. Such local growth continues to be a hallmark of the local economy, with each neighborhood having electricity needs that are different from other areas, and certainly different in many cases from overall system needs.

For all of these reasons, the Commission should provide additional flexibility for REV initiatives. For example, Con Edison, along with interested customers and third-party service providers, are currently expending significant resources to develop the BQDM alternatives. BQDM provides a unique opportunity to learn from efforts to deploy significant amounts of DER systems and these results should be used to inform future REV endeavors. As a result, the Companies recommend using experiences from BQDM and demonstration projects to tailor REV to meet the specific requirements of each utility as well as their respective customers and third-party service providers. Such flexibility for implementing REV will ultimately be more effective than blanket requirements and should be considered a guiding principle of REV.

Peak Reduction EIM

In its Track Two White Paper, Staff proposes an EIM to reduce peak demand by 14 percent over a five-year period, incorporating a target to reduce statewide peak demand by 545 MW per year, incremental to existing DER programs. The Companies are concerned that this EIM does not take into account existing customer needs, consequences of proposed solutions, and the ability and cost of achieving it. Further, the proposal could have unintended consequences such as stunting economic growth in Con Edison's service territories.

In proposing such an aggressive target, the Track Two White Paper assumes peak load reductions will benefit customers, but fails to estimate the costs that would be incurred to reach its stated goal. In fact, these aggressive peak reduction targets are unrealistic and unlikely to be cost-effective. For example, as explained in the Joint Utilities' Comments, Con Edison's

Demand Management Program that focusses on system peak reductions costs approximately $5 million per MW.[4] Extrapolating to the total 4,846 MW of peak reduction proposed in the Track Two White Paper, customers could be paying $24 billion over a five-year period for these resources.

The Companies are concerned that the costs of such a program could be even higher and that there may be little in the way of offsetting benefits. Wholesale market benefits may be hard to realize because of the current capacity surpluses throughout the State, as well as the wholesale market design and dynamics. In addition, the lack of coincidence between the statewide system peak and the Companies' local network peaks means that system peak reduction programs will provide little benefit for the local distribution system and can potentially increase local area peak demand. Of Con Edison's 82 networks, only 18 peak during the same hour as statewide system peak, with 35 networks peaking earlier and 29 networks peaking later. Networks where demand growth is projected to require infrastructure investments that could potentially be deferred or avoided with DER are primarily evening peaking and are not coincident with the system peak demand.

Focusing reduction goals on the system peak may be the wrong measure because it has the potential to increase the distribution network peak demand in areas that experience their peak demand at times other than the statewide system peak. For example, commercial customers who participate in DR programs tend to "pre-cool" their buildings in the period before they reduce demand. If demand reductions begin at 2:00 pm, commercial customers in a noon-peaking network may pre-cool their buildings at noon, increasing the peak of the network in which they are located. Similarly, the system experiences an increase in load called "snap back" in the

[4] This includes customer costs, implementation and administrative costs, and incentives as would be used in a Total Resource Cost Test ("TRCT").

period after load reduction has occurred. Reducing system demand will not allow Con Edison to defer local infrastructure investments because networks must be built to meet their individual peak demand, and in fact doing so can accelerate when the investment is needed. As a result, system peak reduction programs have the potential to increase distribution system (network) needs and accelerate the need for distribution system upgrades.

The Companies recommend that the utilities should first take a programmatic approach to designing targeted distribution programs aimed at providing DER solutions that can defer distribution-level needs. The Companies would seek a mix of optimized resources that contribute to meeting both network and system peak needs to create the potential to defer distribution-level needs in a cost-effective manner. This is precisely the approach that the Joint Utilities proposed in comments on the *Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding*.[5] By using the Benefit-Cost Analysis process to determine an economically appropriate level of network peak reduction, the Companies can calculate an economically efficient level of system peak reduction and implement programs to meet that need.

Rate Design and Supporting Advanced Metering Infrastructure

Con Edison and O&R support the position in the Joint Utilities' Comments that a transition of recovery of fixed costs from volumetric charges to either customer or demand charges is consistent with REV policy to develop and efficient rate design fair to all customers. In the near term, rates should better reflect the fixed cost of service by increasing fixed customer charges for residential and small commercial customers.

[5] REV Proceeding, Comments of Joint Utilities on Staff White paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding, dated July 2, 2015.

The Companies are exploring alternative rate designs including a gradual shifting of residential and small commercial customer rates from volumetric rates to demand rates when AMI is implemented. Demand rates better reflect the cost of service and provide a price signal that should encourage customer behavior that will help defer or avoid capital investments in network expansions, thereby lowering customer costs.[6]

The Companies are well positioned to implement these alternative rate designs through the Companies' respective AMI proposals. As stated by both Con Edison and O&R, in addition to facilitating alternative rate designs, AMI will provide the foundational infrastructure to enable many of the other goals of REV. Specifically, smart meters associated with AMI will enable customers to install and deploy DERs to participate in DR and other "intelligent" grid opportunities without the current cost and lead-time required to upgrade meters. Furthermore, AMI will drive customer engagement, allowing all customers to evaluate their energy consumption and make informed energy decisions based on their actual interval metering. Finally, the Companies' AMI proposals will allow all customers to reduce their energy costs and help provide distribution benefit by reducing demand and/or on-peak usage.[7]

[6] *Designing and Unlocking Markets for Distributed Energy Resources.* Nexant, June 22, 2015 (Appendix A).
[7] Case 15-E-0050, Advanced Metering Infrastructure Business Plan, dated October 15, 2015; Case 14-E-0493, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities for Electric Service, et al.*, Order Adopting Terms of Joint Proposal and Establishing Electric Rate Plan (issued October 6, 2015) ("O&R Order").

Conclusion

The Companies request that the Commission consider these Comments and allow the flexibility sought above to implement REV initiatives in a manner that considers the specific capabilities and needs of each utility and their customers.

Dated: October 26, 2015

Respectfully submitted,

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. and ORANGE AND ROCKLAND UTILITIES, INC.
By Their Attorneys,



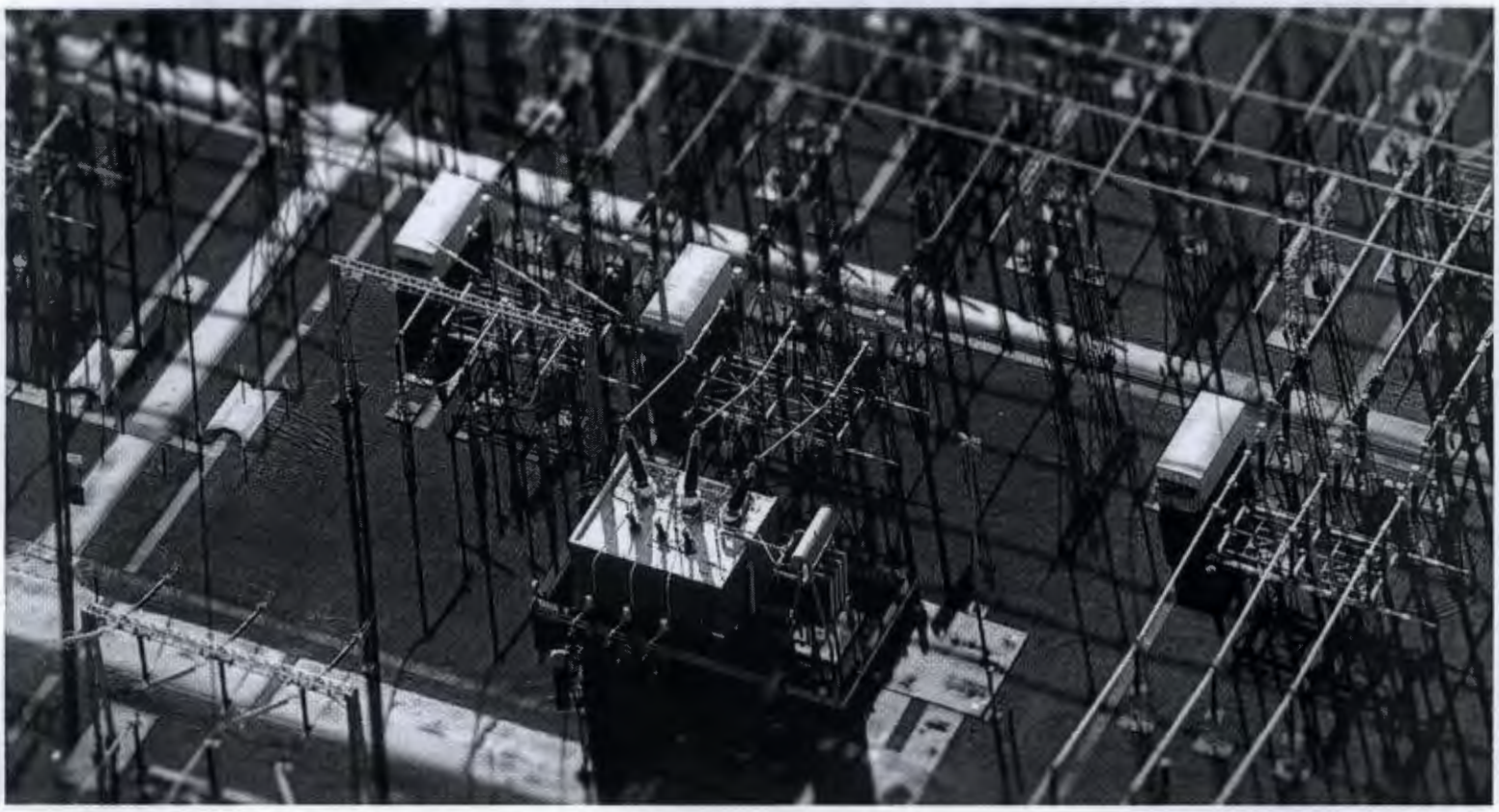
Anna Chacko
Susan Vercheak
Consolidated Edison Company
of New York, Inc.
4 Irving Place, Room 1815-S
New York, NY 10009
Tel: 212-460-2524
Fax: 212-677-5850
Email: chackoa@coned.com

Designing and Unlocking Markets for Distributed Energy Resources

June 22, 2015

Prepared for
Consolidated Edison Company of New York

Prepared by
Josh Bode, M.P.P., Principal Consultant
Stephen S. George, PhD., Sr. Vice President
Alana Lemarchand, Consultant
Nexant, Inc.



Reimagine tomorrow.

Reimagine tomorrow.



Every day we work with our customers to reimagine tomorrow.
Together, we are the driving force behind a more productive
and energy sustainable world.

Table of Contents

1 Introduction 2

2 What Value Do DERs Provide to the Bulk System and Distribution Grid? 4

3 How, When, and Where Do DER's Provide Locational Value? 6

3.1 Value of Distribution Capacity 6

3.2 Value of Emergency Relief 8

3.3 How Do Local Load Patterns and DER Characteristics Affect Value? 10

3.3.1 The Role of Local Peak Patterns 11

3.3.2 DER Operational Characteristics Affect Their Value 12

3.3.3 The Whole is More Important than the Parts 14

4 What Experience is There with DER Integration into Distribution Planning and Operations Through Markets and Otherwise? 15

5 How Should Markets Be Designed to Unlock Distribution Value Streams? 21

5.1 Do We Need a Distribution Level Forward Market, a Short-term Market, or Both? 21

5.2 Key Principles of a Forward Market for Distribution Capacity 22

5.3 Key Principles for a Short-term Distribution Level Energy Market 24

6 Next Steps and Recommendations 26

Appendix A Experience with Distribution Level Markets 28

Appendix B Competitive Market Structure Examples 31

1 Introduction

The New York Public Service Commission proceeding on Reforming the Energy Vision (REV) raises fundamental questions about market design, distribution planning, resource acquisition, and the role of utilities. An explicit goal of the REV is to establish or unlock markets for distributed energy resources. In the context of the proceeding, distributed energy resources are broadly defined to include rooftop solar, customer owned generation, battery storage, energy efficiency, and demand response—namely, an extensive array of relatively small, geographically dispersed resources that connect directly to the distribution system rather than to the bulk transmission system.

There are two distinct features of distributed energy resources: they include a wide range of technologies with diverse operating characteristics and they can provide a wider range of value streams than traditional bulk system resources or distribution investments.

Distributed energy resources vary in terms of flexibility, load shapes, and operating characteristics. Not all distributed energy resources are flexible, for example. Some are tied to specific load shapes or production patterns and are not available for all hours. Other resources have limits on how long they can sustain production (or load reductions), how often they can be used, and how fast they can be delivered. These characteristics fundamentally affect the value of each type of distributed energy resource in each distribution area and also affect how they should be integrated into distribution planning and markets.

One of the most unique attributes of DERs is that they can affect all aspects of the electric grid's infrastructure, including investments in the central, or bulk, electricity system, and in distribution grids. Centralized power plants, in contrast, do not reduce the need for distribution grid investments and distribution grid investments occur independently of generation investments.

Developing markets that allow distributed energy resources to compete, side-by-side with large-scale generators and traditional distribution grid equipment would, in theory, increase competition and improve efficiency. There are, however, several questions that must be addressed to determine how to cost-effectively integrate DERs into grid planning and operations, including:

One of the most unique attributes of DERs is that they can affect all aspects of the electric grid's infrastructure, including investments in the central, or bulk, electricity system, and in distribution grids.

- What value streams do DERs provide to the bulk and distribution grids?
- How, when, and where do DERs provide locational value? How do the characteristics of distributed energy resources and of local peaks affect distribution value?
- What experience is there with DER integration into distribution planning and operations? What has and has not been tested?
- How should markets be designed to unlock distribution value streams for DERs?
- What demonstrations need to take place to ensure distribution level markets will be cost-efficient and ensure reliability?

Introduction

This paper focuses mainly on integration of distributed energy resources into distribution planning and distribution level markets. How to integrate distributed energy resources into existing wholesale markets for energy, system peaking capacity, and ancillary services is an important question, but it is not our main focus.

The central question of this paper is how to create markets that allow distributed energy resources to compete in delivering cost-effective distribution load relief and how to structure markets to ensure competition, transparency, and grid reliability.

2 What Value Do DERs Provide to the Bulk System and Distribution Grid?

An important focus of REV is to monetize system values of distributed energy resources, via competitive mechanisms such as markets, and allow them to compete side-by-side with traditional generation and distribution investments. Fully integrating distributed energy resources requires clear delineation of the products and services required to operate the bulk and distribution systems.

Table 2-1 summarizes the main electric grid products and services in place today and the existing competitive mechanisms through which they often operate. Some elements are essential for grid operations and must be met or the electricity grid cannot function. For simplicity, we refer to these functions as *grid services* and distinguish them from power production. Grid services do not sell power production (kWh), but instead either provide different types of insurance designed to ensure grid reliability or are used to instantaneously balance the system. For example, for most ancillary services the defining characteristics are availability and the ability to inject or remove power or loads into the system quickly with a high degree of control.

One of the most unique attributes of DERs is that they affect all aspects of the electricity grid's infrastructure including the need for transmission, generation, and distribution capacity. While a significant amount of electricity costs are tied to fuel and energy production, a similarly significant amount is tied to power infrastructure. Many DERs produce energy, and all of them reduce the need to transmit power across long distances. Both generation and distribution infrastructure are sized to meet the aggregate peak demand of customers when it is forecasted to be at its highest. The key difference is that generation and transmission infrastructure is sized to cover broad geographic regions whereas distribution infrastructure is sized to cover a local area's coincident demand, which can be quite diverse. If DERs deliver when the system peaks, they can help avoid the need to build peaking generators that mostly sit idle throughout the year. If DERs deliver when local demand is nearing distribution capacity—often based on local, coincident peaks—they may help avoid or defer growth-related distribution investments.

System peaks and distribution peaks do not necessarily occur at the same time or on the same day. The implication is the benefits may not be additive for all DERs because a DER responding to a bulk system need may not be able to also respond to a distribution need. Further, some DERs are only able to deliver reductions or energy at certain times that may or may not align with the system or distribution peaks due to technology (e.g., solar) or customer characteristics (e.g., commercial office customers have limited loads in the evenings).

Many grid products and services provide value to the bulk system, where well established competitive mechanisms—wholesale markets—already exist, but are not necessarily designed for small, geographically dispersed DERs. At the distribution level, existing mechanisms exist that already incent many types of DERs to locate and deliver resources where they provide the most value. Current examples include Con Edison's demand response (DR) programs, which are structured and operated to provide distribution relief, and the recent Brooklyn-Queens Demand Management (BQDM) initiative. A key question is whether these existing mechanisms are sufficient or whether additional market mechanisms are needed.

Table 2-1: Grid Products and Services that Provide Value to the Electric Grid

Grid Product or Service		Key Function	Existing Competitive Mechanisms and Products	Unit being sold							
				kWh	kW[1]	kVar	kVarh	Balancing Services	Voltage Control	Speed	Insurance Value
1	Energy production	What mix of resources can produce electricity at lowest cost?	▪ Bilateral contracts ▪ NYISO Day-Ahead Auction ▪ NYISO Real-Time Auction	X							
2	Bulk Power Capacity	Is the system able to meet peak demand plus reserve margin levels?	▪ NYISO capacity market (UCAP/ICAP) ▪ Utility Tariffs		X						X
3	Distribution capacity relief	Is the distribution system able to accommodate local peak loads?	▪ Utility program tariffs ▪ RFI/RFP's		X						X
4	Bulk System Ancillary Services	Is the bulk system able to respond quickly enough to balance supply and demand? Does it have the ability to withstand system shocks (e.g., forced outages)?	▪ Regulation ▪ 10 Minute Spinning Reserve ▪ 10 Minute Non-Synchronous Reserve ▪ 30 Minute Operating Reserve	X	X	X	X	X		X	X
5	Distribution-level Ancillary Services	Are voltage levels stable and reliable? Can line losses be reduced?	▪ No market ▪ Some tariffs			X	X		X	X	X
6	Bulk System Flexibility	Is the resource mix flexible enough to meet forecasted and unforeseen ramps at different time scales?	▪ No market product for distributed energy resources or centralized generation	X	X	X	X	X		X	X

[1] System peaks and distribution peaks do not necessarily occur at the same time or on the same day. The kW needed for distribution and bulk system capacity is not one and the same.

3 How, When, and Where Do DER's Provide Locational Value?

The electricity distribution system is the last link in a vast infrastructure network that connects electricity end users with generation sources. Historically, distribution grids were engineered to accommodate a unidirectional flow of electricity from centralized generation to end users. Both generation and distribution infrastructure was sized to meet the aggregate demand of end users when it is forecasted to be at its highest—peak demand. Distribution infrastructure, however, is sized based on local peaks, which can be quite diverse, and often differ from system peaks that drive generation infrastructure.

One vital role of the electric utility is to ensure that electricity supply remains reliable by projecting future demand and reinforcing the local distribution network so that distribution capacity is available to meet local needs as they grow over time, thereby avoiding costly outages. When demand exceeds local distribution capacity, equipment is overloaded, degrades more quickly, and the risk of an adverse reliability event grows considerably.

The locational value of DERs is in mainly in supplying distribution capacity—the ability to provide load relief when needed to ensure reliability and avoid distribution equipment overloads—not in supplying energy.

The locational value of DERs is tied mainly to supplying distribution capacity—the ability to provide load relief when needed to ensure reliability and avoid distribution equipment overloads—not in supplying energy. Distribution capacity provided by DERs is not energy per se but a type of insurance. If DERs cannot be incorporated into distribution planning with enough lead time, the value they provide diminishes substantially.

3.1 Value of Distribution Capacity

Figures 3-1 and 3-2 illustrate the effect of reducing local, coincident peaks on the timing and magnitude of distribution investments. Distribution investments are characterized by smaller investments that occur annually and major investments that occur less frequently. As loads grow, excess distribution capacity—the head room that provides reliability—dwindles. With less excess capacity, grid management becomes more challenging and the likelihood of component failures and adverse reliability events in the area's distribution grid increases.

Not all distribution investments are driven by local, coincident peak loads. Some investments are tied to customer interconnection costs and are essentially fixed. Other investments must take place because of aging or failed equipment or because of the need to improve reliability and modernize the grid.

The main value of integrating distributed energy resources into distribution planning and operations is in managing local, coincident demands that are shared across many customers. If a customer helps reduce coincident demand, either by injecting power within the distribution grid (e.g., behind-the-meter generation) or by reducing demand, the unused capacity can accommodate another customer's load growth and thereby help avoid or defer investments required to meet load growth.

Figure 3-1: Illustration of Local Peak Demand and Distribution Capacity

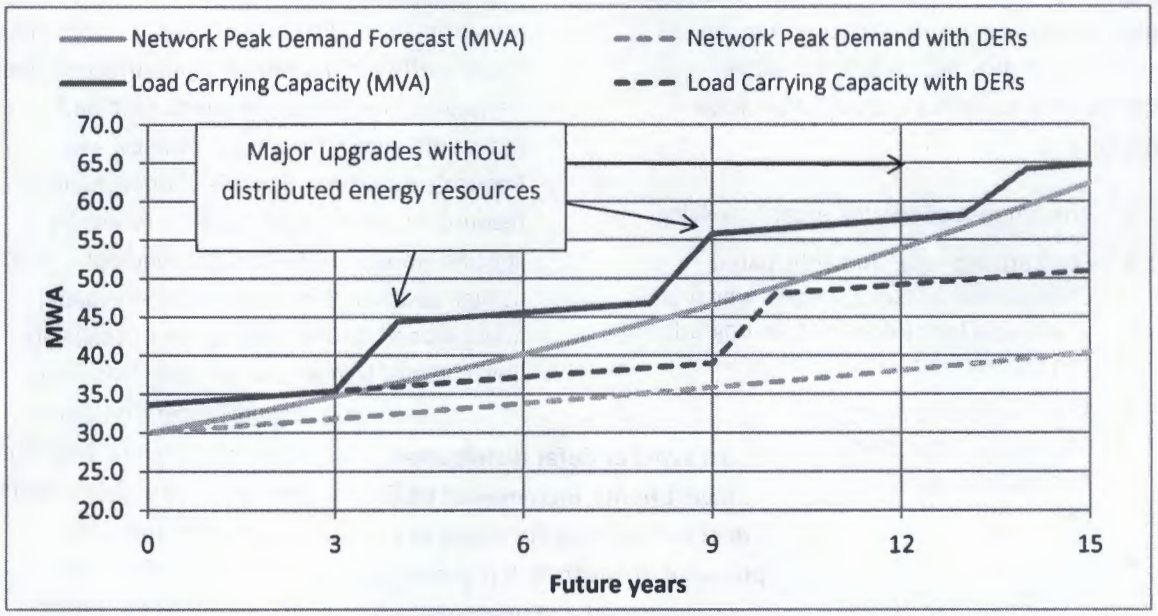
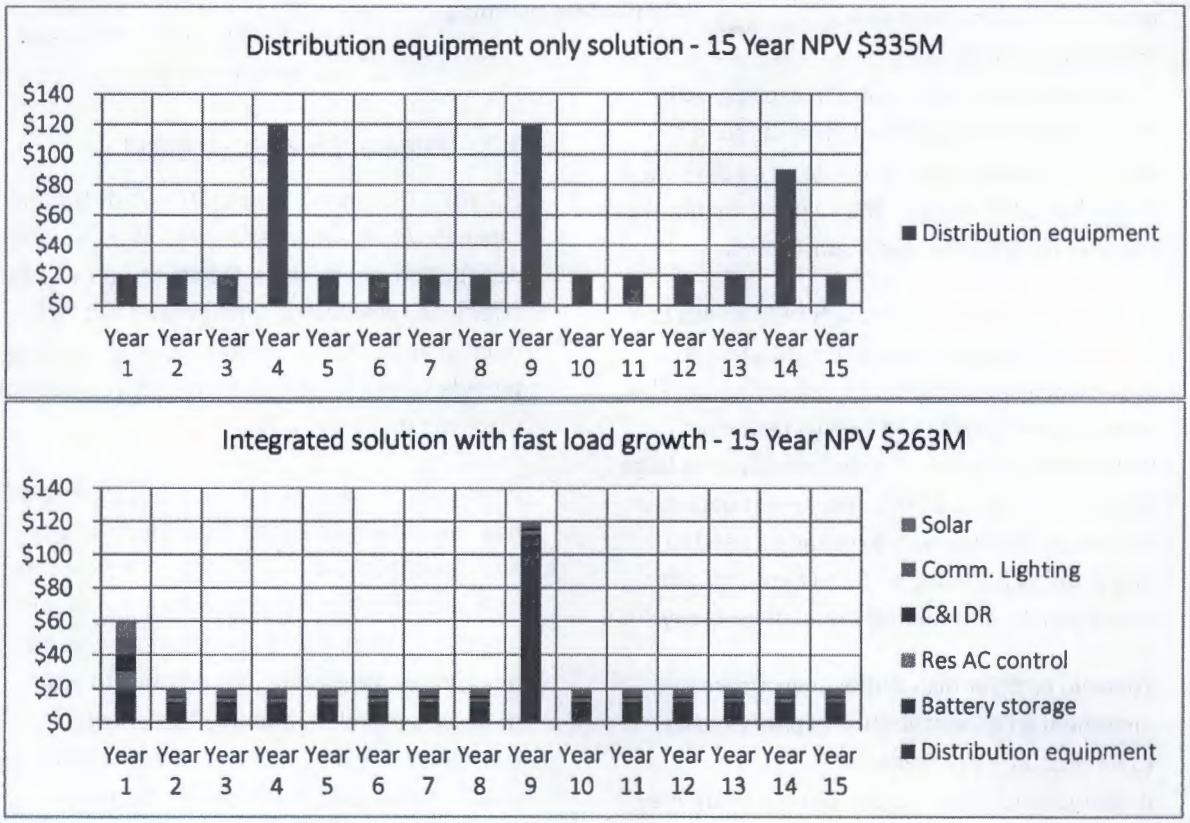


Figure 3-2: Hypothetical Illustration of the Effect of DERs on Expenditures



When distribution investments are avoided or deferred, it frees up capital for other alternate uses, improving the efficient use of resources. The value of distribution deferral varies significantly across local distribution areas because of:

- The amount of existing excess capacity;
- Load growth rates and anticipated changes in load curve shapes, which affect how long infrastructure upgrades can be deferred;
- The magnitude, timing, and cost of projected distribution upgrades; and
- The design of the distribution system.

In areas with excess distribution capacity and where local, coincident peaks are declining or growing slowly, the value of distribution capacity relief can be minimal. By contrast, in areas such as Brooklyn-Queens, where a large, growth related investment is imminent, the value of distribution capacity relief can be quite substantial.

Demand management through DERs needs to ramp up at the right time and right place to provide distribution relief or deferral value. The magnitude of distributed energy resources introduced, as a portfolio, also needs to be large enough to influence both investment decisions and reliability. Finally, the resources need to target the right hours, with the right amount of availability, and the right level of certainty.

To avoid or defer distribution investments, incremental DER distribution capacity needs to be procured in advance. If it shows up, unannounced and unaccounted for, there may not be enough lead time to incorporate it into distribution planning. Because of this, procurement of distribution capacity from DERs today is often in the form of option/reservation payments, investments in permanent load reductions through energy efficiency, and Requests for Proposals (RFPs). For example, resources commit to produce (or reduce) a specific amount under specific conditions—such as high peak loads in networks where loads could exceed distribution equipment capacity limits, loss of transmission or sub-transmission supply feeders, or loss of distribution feeders—and in exchange receive payments for the insurance they provide. Because they are delivering insurance, resources receive significant compensation regardless of whether they are in fact called upon to produce or reduce energy.

To avoid or defer distribution investments, incremental DER distribution capacity needs to be procured in advance. If it shows up, unannounced and unaccounted for, there may not be enough lead time to incorporate it into distribution planning.

3.2 Value of Emergency Relief

The main locational value of DERs is distribution capacity, which allows a utility to avoid or defer distribution investments. However, some DERs offer load relief during emergencies but lack multi-year contractual commitments—do they provide value? The short answer is: yes, but not the same degree of value.

Emergencies are by definition unexpected and require immediate action. Con Edison designs and operates most of its distribution networks so it can ensure reliable power supply even if one or two large distribution components are unavailable. While rare, it is possible to lose multiple transmission supply feeders or distribution feeders, reducing the available distribution capacity. When unexpected

emergencies occur, reductions in demand can help avoid overloading distribution equipment, thereby slowing degradation of existing equipment, or help ensure the system can operate reliably even if an additional component is lost.

The value of emergency relief is illustrated by two concrete examples in Figures 3-3 and 3-4. Figure 3-3 shows a scenario where two transmission supply feeders are unavailable, reducing the capacity to supply power to the network. Figure 3-4 shows a scenario with the loss of two distribution feeders. In both cases, the losses reduce the capacity available to power the system and increase the risk of an adverse reliability event.

On a cool day or during an off-peak hour, when electricity demand is lower, the remaining transmission capability is often sufficient to ensure power can be reliably delivered to all customers. On a hotter day, when demand is higher, the constraint may be material and affect the ability to deliver power to customers. Most of Con Edison's networks are built to sustain the loss of one or two of the largest components and still deliver uninterrupted power. This is the mesh or network grid.

The most critical risk is losing a third transmission supply feeder or a third distribution supply feeder during peak load conditions, in which case there may not be enough delivery capacity to power the network resulting in equipment overloads or failure unless some customers are involuntarily curtailed. Injecting incremental power or reducing demand through DERs increases the head room and reduces the risk of overloads and of outages should a third component fail.

DERs that provide load relief in emergencies may help alleviate the immediate shortfall, but even if they do, if unaccounted for in

Figure 3-3: Emergency Relief Example—Constraint at the Sub-transmission Level

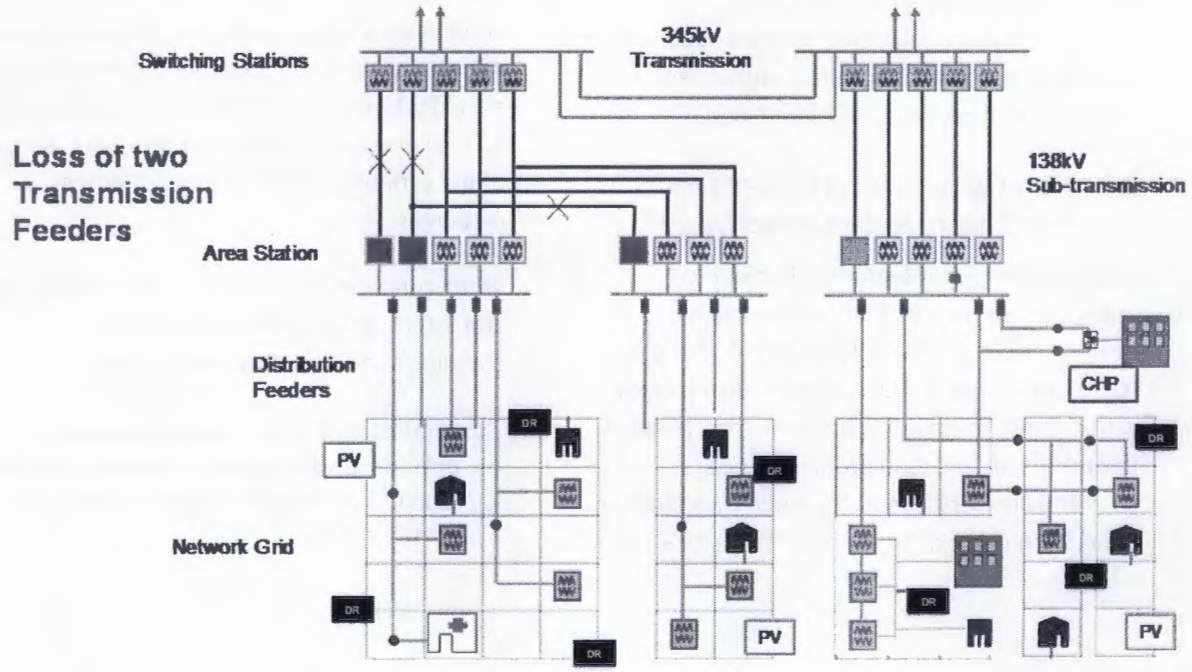
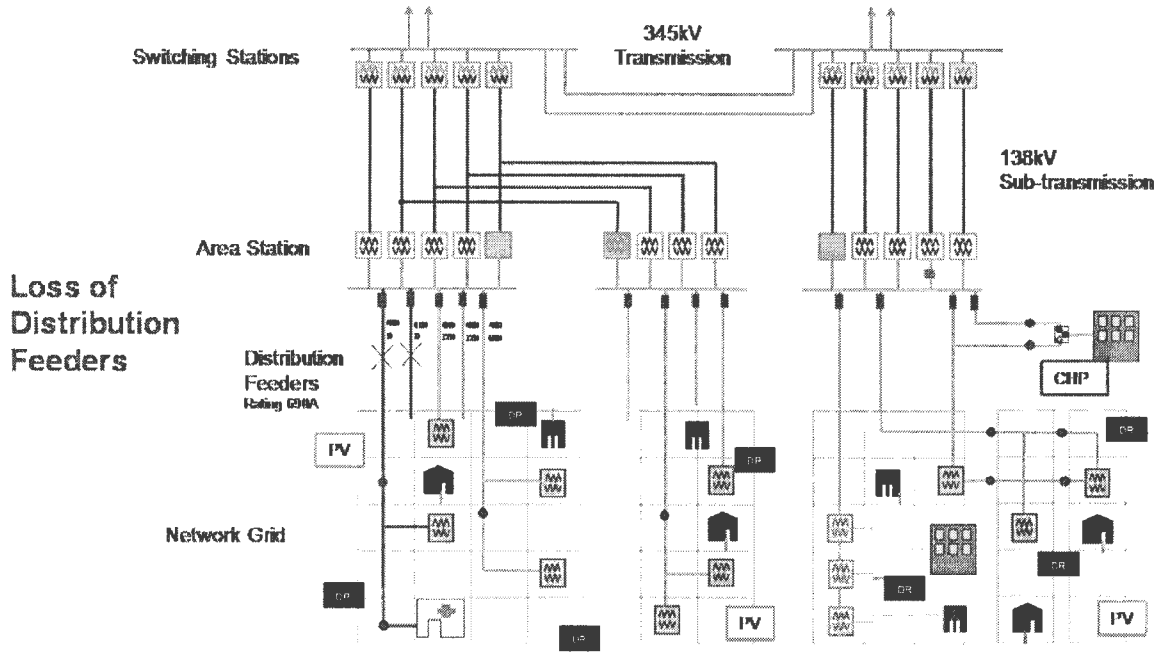


Figure 3-4: Emergency Relief Example—Constraint at the Distribution Circuit Level



distribution planning, they do not reduce the need by the distribution company to make investments in the grid. A distribution company has an obligation to provide reliable service—it cannot rely on voluntary DERs during emergencies; instead it must procure sufficient capacity in advance of potential unplanned shortages to meet reliability standards.

3.3 How Do Local Load Patterns and DER Characteristics Affect Value?

A key challenge of integrating distributed energy resources into distribution planning and operations is their diversity. Distributed energy resources include a wide range of technologies, with different operating characteristics, levels of flexibility, risk, and load profiles. They are inherently dispersed, and the value they provide depends in part on the specifics of the local distribution system and the characteristics of the specific distributed energy resource.

A key shortcoming of many valuation frameworks is that they have largely focused on enumerating benefits and recognizing locational value rather than on how the valuation process should take into account both the characteristics of local demand patterns and the characteristics of the various types of distributed energy resources.

Three concepts are fundamental in valuing DERs and for integrating them into distribution planning and competitive processes:

1. **Local coincident peak demand patterns** determine when, how, how much, and what type of distributed energy resources are most valuable;

2. **Each DER's operational characteristics influence their value at each location.** As a result, the ability of distributed energy resources to address distribution relief is highly varied across time, location, and technology;
3. **The whole is more important than the parts.** Many distributed energy resources deliver incomplete solutions for local distribution capacity relief when they are deployed individually, but have characteristics that can provide complementary value when combined with other DERs or distribution solutions. In the right combination, DERs can deliver more value as a whole solution or portfolio, rather than as stand-alone components, but the composition of that combination is critical.

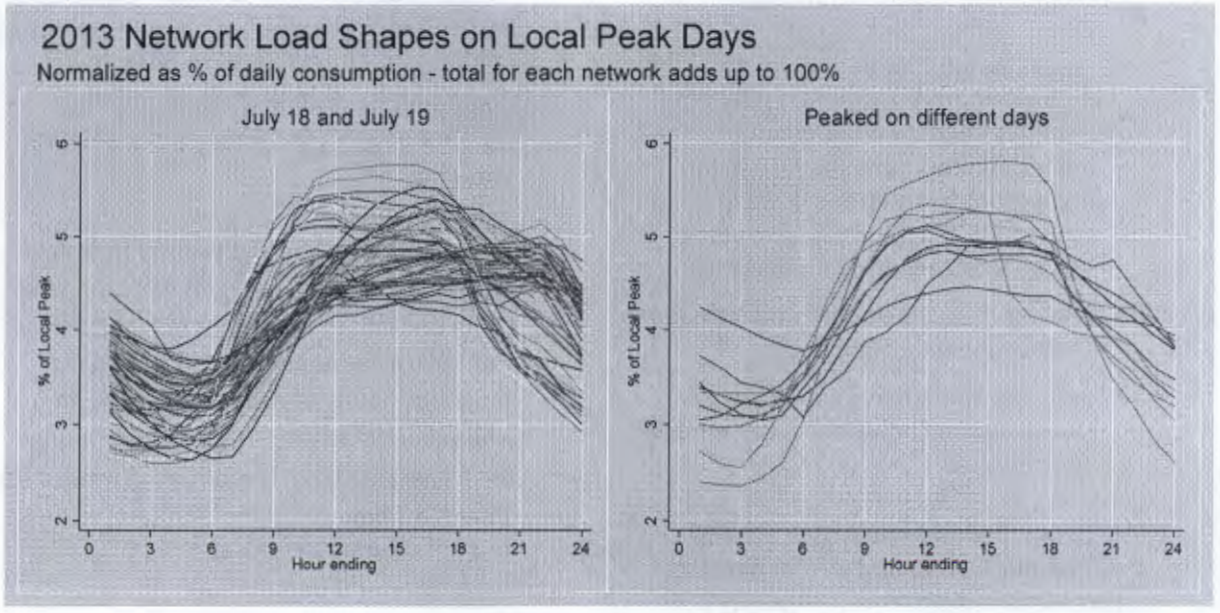
3.3.1 The Role of Local Peak Patterns

Figure 3-5 illustrates the role of local peak demand patterns. It shows the load shape for each of Con Edison's distribution networks on the day when each network peaked in 2013, one of the hottest years on record. Individual networks did not peak during the same hours, with the peak hour ranging from 9 am to 11 pm. In addition, not all networks peaked on the same day. Most networks peaked on July 18 or July 19 but 12 networks peaked on additional dates.

The diversity of local, coincident peaks has several implications:

- If DERs are to avoid growth-related distribution investments, they must be dispatched on different hours and days. DERs also must sustain production (or reduction) levels for different periods of time at different local networks.
- For some areas, there may be little or no avoidable distribution investments because of existing excess capacity, slow growth, or declining peaks.
- Local peak days and hours often do not always align with Con Edison or NYSIO territory-wide peak days, creating coordination issues with DERs focused on

Figure 3-5: Con Edison Normalized Network Load Shapes on 2013 Local Peak Days



bulk system values.

- To capture both bulk system and distribution level value, a distributed energy resource may need to sustain production (or reduction) for a prolonged period of time.
- The usefulness of DERs depends on whether load relief is needed and on how well distributed energy resource production (or reduction) capability aligns with local peak patterns.

The diversity in local, coincident peak patterns must be factored in when estimating distributed energy resource value and fundamentally affects how they are integrated into planning, and how competitive markets or processes must be designed.

3.3.2 DER Operational Characteristics Affect Their Value

A distinctive feature of distributed energy resources is that they include a wide range of technologies with diverse operating characteristics. From a distribution capacity standpoint, prices being equal, the ideal, stand-alone distributed energy resource is:

- Available at all hours;
- Reliable and predictable;
- Able to quickly ramp production (or reduction) levels up and down in a controlled and predictable manner or deliver permanent load reductions;
- Deliver the right amount of production (or reduction) at the right hour;
- Without limitations on when, for how long, and how often it can produce (or reduce).

Most types of DERs deviate from the ideal resource and, individually, are not direct substitutes for distribution equipment. Distribution equipment is always there and accommodates additional loads.

Figure 3-6 illustrates how important it is for DER characteristics to align with peaking risk. It shows various types of DERs that either follow a specific production pattern or are based on loads that vary by hour (note: the figure does not include DERs that are not time dependent). The load shapes are normalized (as the percent of the annual peak) so they can be directly compared and juxtaposed against the local peaking risk (the shaded area in the graph).

In the illustrated network, some resources—commercial and residential air conditioner loads—align well with the local peaking risk. Other resources—residential lighting, solar—do not align as well. The concentration of local peaking risk and the alignment with specific DERs will vary for local areas. Distribution operators must have the right mix of resources at the right location at the right time.

However, it is not only load shapes that influence how useful a DER is at reducing the need for additional distribution infrastructure investments. Operating constraints such as how long a resource can sustain production (or reductions), when it is available, and how many hours it can be utilized, can materially affect value.

Figure 3-7 shows how the inability to sustain production (or reductions) for more than four hours can limit the value of a DER or portfolio with such a constraint. The left hand panel shows the hourly peak patterns during days when capacity relief is needed most. During the highest load day, resources are needed from 11 am to 7 pm.

Figure 3-6: Distributed Energy Resource Load Shapes and Alignment with Peaking Risk

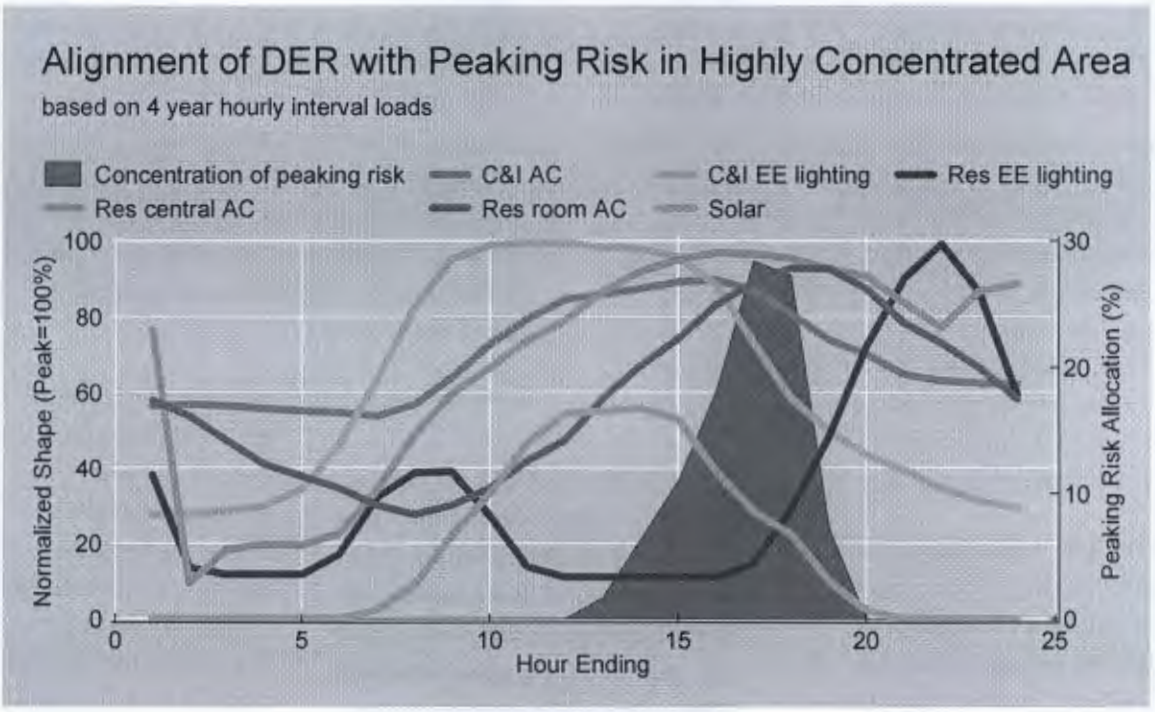
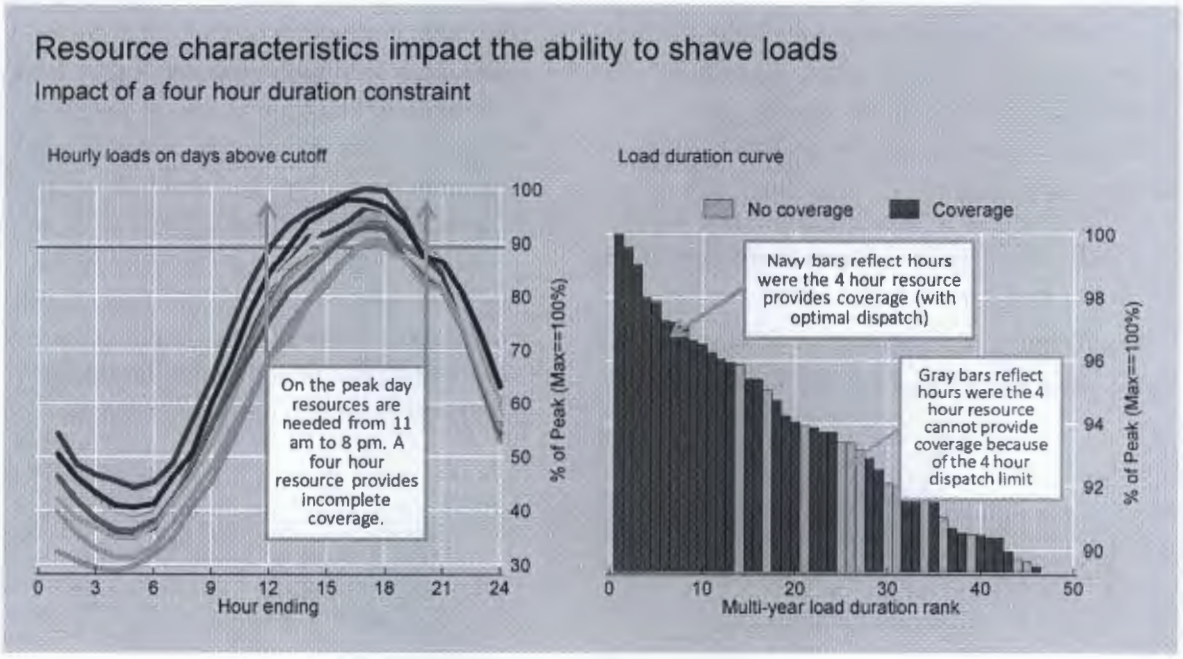


Figure 3-7: Illustration of the Effect of DER Constraints—4-Hour Limits on Dispatch Duration



A resource with a four-hour dispatch duration limit cannot, on its own, sustain loads below the target threshold during the highest load day. The right hand panel shows the loads above the target threshold in the form of a load duration curve. Each bar represents a specific hour when resources are needed to maintain loads below the target threshold. A resource or portfolio with a four-hour dispatch duration limit cannot deliver resources for all of the hours needed. The gray bars are specific hours when reductions are needed, but the specific DER or portfolio cannot deliver because the resource has already reached the four-hour constraints on a given day.

The specifics will vary across each network and across each individual DER resource. In some cases, constraints are material, in others they are inconsequential. The usefulness of DERs in helping reduce growth related distribution costs very much depends on how well operational characteristics of DERs, both individually and as part of a portfolio (as discussed below), align with local peak patterns and reduction needs.

The usefulness of DERs in helping reduce growth related distribution costs very much depends on how well operational characteristics of DERs, both individually and as part of a portfolio (as discussed below), align with local peak patterns and reduction needs.

3.3.3 The Whole is More Important than the Parts

Many DERs deliver incomplete solutions for local distribution capacity relief when deployed individually but have characteristics that can provide complementary value when deployed in combination with other DERs or traditional distribution solutions. In the right combination, DERs deliver more value as a whole solution than as stand-alone components. Distribution capacity relief using DERs is not a simple commodity, but is a complex problem that requires building and optimizing a portfolio based on cost, DER attributes, and local peaking patterns.

The diversity of DERs and local needs are the main challenges for integrating these resources. This same diversity is also a key strength. The overall value of each individual part depends on the other DERs available for bundling. To use an analogy, if one is building a single car, one needs the right type and quantity of parts that can be combined into a whole car. A car without wheels is not useful, nor is having two engines. Ideally, there are multiple sellers able to produce the different components and they compete with each other, transparently, in pricing the parts. In the same way, with DERs, there are multiple ways to bundle a solution. The best bundle is not always made up of the cheapest parts but rather the best overall bundle with which the electric distribution grid can be operated reliably.

4 What Experience is There with DER Integration into Distribution Planning and Operations Through Markets and Otherwise?

Significant attention has been given to the concept of "transactive energy" in REV discussions about market design. Transactive energy markets are based on four main pillars:

1. Markets at the distribution level;
2. Locational time-varying prices for customers and distributed energy resources;
3. Engaged customers; and
4. End-use technologies that allow consumers to automatically respond to price signals.

The amount of attention given to this theoretical concept is surprising given the extremely limited empirical evidence existing on the topic. What little evidence that does exist is comprised of two very small pilots involving a couple of hundred, highly self-selected customers and one slightly larger pilot in Denmark with questionable external validity for what might occur in New York.

What little evidence that does exist on transactive energy markets is comprised of two very small pilots involving a couple of hundred, highly self-selected customers and one slightly larger pilot in Denmark with questionable external validity for what might occur in New York.

On the other hand, there is more than 25 years of experience involving numerous pilots, programs, and demonstration projects involving the integration DERs into distribution planning and operations using more practical and less theoretical mechanisms. These projects and pilots represent a range of competitive frameworks and distributed energy resources.

Table 4-1 summarizes select examples of these distribution deferral case studies, including what they did and did not test. The studies are grouped into four types of competitive frameworks, each with distinct strengths and weaknesses: Utility energy efficiency and demand response programs, Utility standard offer tariffs, RFP / RFI, and distribution level energy markets.

Some of the earliest forays into T&D deferral were utility funded energy efficiency and demand response projects in the 1990s, including Con Edison's use of geographically targeted programs to cost-effectively defer investments in its distribution system. Table 4-1 includes two examples that specifically targeted deferral of distribution investments, but there are many more examples of projects that sought to defer T&D investments more broadly, often focusing on deferring construction or expansion of transmission lines.[2] These utility funded projects were generally designed with the purpose of deferring a specific transmission or distribution investment (substation, transmission line, etc.) by reducing peak demand through targeted deployment of energy efficiency retrofits (often with a heavy HVAC component), sometimes with a load control component (automated demand response).

[2] For a more comprehensive list of pilots implemented prior to 2012, including projects for transmission deferral, please see the Regulatory Assistance Project's report titled "US Experience with Efficiency As a Transmission and Distribution System Resource." Available at: http://www.raponline.org/document/download/id/4765

What Experience is There with DER Integration into Distribution Planning and Operations Through Markets and Otherwise?

Table 4-1: Distribution Deferral Examples

Competitive Framework	Utility EE Program Pilots		Utility Programs / Tariffs	RFI / RFP		Distribution Level Markets		
Background								
Project name	PG&E Delta Project	Portland General Electric Downtown Pilot	ConEd EE and DR programs	SCE LCR RFO	ConEd BQDM	GridWise Testbed	AEP Smart Choice	EcoGrid EU
Location	San Joaquin Delta	Downtown Portland	NYC	Los Angeles basin	Brooklyn-Queens	Olympic Peninsula, WA	Northeast Central Ohio	Bornholm Island, Denmark
Time period	1991-1993	1993	2003-present	2014-Present	2014-Present	2006-2007	2013	2013-present
Sample size	>2k	12	NA	NA	NA	112	217	2000
Participation rate	~10%	12%	NA	NA	NA	Un-known	Un-known	10%
Deferral of a specific T&D investment?	✓	✓	✓		✓			
DER integration								
Energy efficiency	✓	✓	✓	✓	✓			
Automate Demand Response	✓		✓	✓	✓	✓	✓	✓
Price responsive Demand Response						✓	✓	✓
Dispatchable distributed generation				✓	✓	✓		✓
Non-dispatchable distribution generation					✓			✓
Energy storage				✓	✓			✓
Prices incorporate distribution congestion?								
DER integrated as supply (versus demand)?				✓				
Peer-to-peer trading?								
Integrated into long term reliability planning?	✓	✓	✓	✓	✓			

What Experience is There with DER Integration into Distribution Planning and Operations Through Markets and Otherwise?

Utility funded programs have the advantage of making it easier to align projects with specific policy objectives, including jumpstarting or maximizing uptake of certain technologies. On the other hand, utility programs are non-market solutions that, in some instances, may not produce the most economically efficient outcome.

Beginning in the early 2000s, new distribution deferral programs began to emerge that addressed some of the issues with the utility energy efficiency and demand response programs. Among the more innovative approaches were the programs developed by Con Edison. Distribution investments in the Con Edison territory are particularly costly due to New York City street congestion and a predominantly underground distribution grid, making it highly disruptive and costly to implement "wires" investments. Like other programs, the Con Edison programs use targeted deployment of energy efficiency to defer these distribution investments.

Recently, utilities, including Con Edison, have used competitive RFP/RFI processes to procure distributed energy resources, including energy efficiency, demand response, distributed generation, and thermal and battery storage. The RFP/RFI process has been used both for distribution investment deferral—such as in Con Edison's Brooklyn-Queens Demand Management RFI and Central Hudson's Targeted Demand Management demonstration—and to replace retired local generation in transmission constrained areas—such as Southern California Edison's Local Capacity Requirement (LCR) Request for Offers(RFO). These examples are still in the implementation stage, but are relying on a competitive selection process to identify a cost-effective portfolio of vendor offers to address local area needs.

As with utility programs, RFPs also have strengths and weaknesses to consider. A broad, inclusive RFP encourages a large number of vendors to submit proposals. It also requires them to reveal their sell price and compete directly with each other and with traditional utility investments. The RFP also allows a utility to provide specific information about the distribution deferral requirements for a specific area, as well as to request specifics from vendors in their proposals on how well they will be able to meet distribution needs. The concept has very much the underpinning of a market. The buyer, the utility, specifies the product it needs and how much of it wants to buy. The sellers, DER vendors, compete against each other, describing their product and disclosing their "sell price," which allows the buyer to select a cost-effective bundle of resources that meets its needs. On the other hand, historically, the RFP process has been cumbersome, leading to high transaction costs for both the utility and for DER vendors. With few exceptions, RFP selection processes are typically not transparent. Both of these issues—high transaction costs and transparency—can be addressed by streamlining and standardizing the process and by publicly disclosing seller bids and technical scores.[3]

Finally, there are three small pilots that have explored elements of real time energy markets at the distribution level. These come in two varieties. The first is a one-way "prices to devices" configuration, where wholesale prices and forecasts of demand response and renewable generation are used to determine five-minute interval prices that are pushed out

[3] A few utilities, such as the Sacramento Municipal Utility District, publicly disclose seller bids and details about scoring.

to automatically responding loads (EcoGrid EU). The second is a quasi-five-minute forward market where a market clearing price is determined by aggregating price responsive demand capacity into a demand curve (GridWise Testbed and AEP Smart Choice, both in partnership with PNNL).

These three examples of distribution level energy markets, covered in more detail in Appendix A, are the closest experience to the concept of transactive energy markets. While these pilots are innovative and exploratory, they are also notable for their limitations:

- Sample sizes are small;
- Customers are highly self-selected and do not represent typical consumers;
- Automated technology to respond to prices is cost-free;
- The DERs tested were mainly price responsive demand from air conditioners and water heaters and large non-residential customers—not the full scope of DER technologies;
- None of these pilots incorporated distribution congestion into their pricing. The pilots mainly passed through wholesale market prices to customers and some "simulated" congestion events.
- None of the pilots tested the ability of short-term energy markets to ensure long-term reliability and spur additional distribution capacity of investments of the right kind, at the right locations, and at the right time;
- None of the pilots demonstrated that distribution level real time energy markets provided sufficient value to offset the costs (and did so at lower expense than other alternatives for passing prices to customers).

None of the transactive energy pilots have assessed the ability of short-term energy markets to ensure long-term reliability and spur additional distribution capacity investments of the right kind, at the right locations, and at the right time.

The two PNNL pilots each included fewer than 250 customers. In spite of the small number of highly self-selected, technophile participants, the enabling technology was very costly and customers experienced multiple installation visits to get technology systems functional. This casts doubt on whether larger scale programs with defaulted, or at least less technologically enthusiastic or savvy participants, would reach scale and be able to produce meaningful and cost-effective distribution deferrals.

The availability of enabling technology is very different from the use and cost-effectiveness of enabling technology. There have been numerous demand response and energy efficiency pilots and programs that make enabling technology available for free to automate consumer response to utility price signals or other information. A very common finding is that even when provided free of charge, many (in some cases most) customers are not engaged enough to set up the technology in the way it was intended in order to deliver the demand reductions or energy savings it is designed to produce.[4, 5] A critical

[4] Stephen S. George, Jennifer Potter, and Lupe Jimenez. Smart Pricing Options Final Evaluation. SMUD. September 5, 2014. Available at: https://www.smartgrid.gov/files/SMUD_SmartPricingOptionPilotEvaluationFinalCombo11_5_2014.pdf

[5] Electric Power Research Institute. 2011. The Effect on Electricity Consumption of the Commonwealth Edison Customer Applications Program: Phase 2 Final Analysis. Available at: https://www.smartgrid.gov/document/effect_electricity_c

concern about whether transactive markets will ever be realized is whether enough consumers will ever be engaged enough to make the markets functional and valuable. There is no empirical evidence supporting this assumption and there is significant evidence suggesting this may not be true.

Some of the issues exposed in the PNNL pilots were presaged in the implementation report for the largest pilot that is currently being implemented in Denmark, on the island of Bornholm. This pilot involves a total of 2,000 customers, 1,900 of which were residences. The European Union's EcoGrid report, based on actual experience with a transactive energy market, was cautious in its findings. It noted that implementation of a real-time market at the distribution level was no silver bullet. In their words, "It is important to clarify that the EcoGrid EU market concept only represents one possible suggestion for a cost-effective activation of flexible consumption at household customers and/or smaller production units." (EcoGrid, 2014). The report also concluded that the EcoGrid real-time concept must prove its economic value for society and stakeholders and must prove its ability to provide reliable and efficient balancing services.

Moving toward transactive energy markets without comparing them to the potentially more practical step of deploying AMI and implementing utility rate solutions is premature.

In all three of these pilots, rolling out the control and communication technology necessary to support the five-minute pricing and responses was prone to technical challenges and led to higher than expected costs. Further, even in cases where devices effectively communicated prices and led to a market clearing price, the underlying price signal was ultimately based on wholesale prices, not on distribution locational value, although some pilots included simulated distribution emergency events.

At the current time, there is not a sufficient penetration of intelligent devices and engaged consumers and producers to cede responsibility for managing the grid to a distributed "society" of devices and system entities. Indeed, a recent, objective assessment of transactive energy markets conducted by staff members at the California PUC raised important questions concerning whether it is even a feasible solution to grid problems or a surreal vision that might work on paper but is too complex to be realized.[6] The answer to these questions will not be known for a very long time and there are alternate, more practical solutions that unlock value streams, increase transparency, and more fully integrate distributed energy resources into electricity supply and grid operations.

The REV proceeding is correct to recognize the growing availability and influence of DERs and the importance of allowing side-by-side competition of DERs with other traditional resources. There are several ways to monetize the value of DERs and foster competition short of creating real time distribution markets. There is little evidence that localized, transactive energy markets provide value that exceeds the potentially high costs of creating them. Investing

onsumption_commonwealth_edison_customer_applications_program_phase_2_fi

[6] Nilgun Atamturk and Marzia Zafar. "Transactive Energy: A Surreal Vision or a Necessary and Feasible Solution to Grid Problems?" California Public Utilities Commission Policy & Planning Division. October 2014.

significant time, energy, and resources in attempting to develop transactive energy markets could be inappropriately premature when pragmatic and proven market mechanisms for encouraging DER integration and competition already exist.

One concept that has not been discussed much in the context of the REV is the wide-scale deployment of pricing and DER incentive structures enabled by deployment of advanced metering infrastructure (AMI). It may be possible to design utility rates and programs that monetize the value of DERs and encourage greater DER integration without creating the complexity associated with local, real-time energy markets. To do so, it would be necessary to modify utility rates to better reflect the fixed nature of utility delivery system costs and introduce programs with price signals that reflect both system and local capacity needs and, thus, encourage significant integration of DERs to meet those needs. Moving toward transactive energy markets without comparing them to the potentially more practical step of deploying AMI and implementing other less complicated solutions is premature.

5 How Should Markets Be Designed to Unlock Distribution Value Streams?

Perfectly competitive markets produce economically efficient allocations of resources. However, this is only definitely true if the conditions of a perfectly competitive market are met. These conditions require:

- A large number of buyers;
- A large number of sellers;
- Free entry and exit into the market, including the ability to choose whether or not to buy or sell;
- Perfect information, including full price transparency and full knowledge of product quality;
- Zero transaction costs;
- A commodity where products are perfect substitutes for each other (homogenous products); and
- The absence of externalities.

Perfectly competitive markets are very rare in practice. However, it is important to keep in mind the fundamentals of competitive markets in making market design decisions and to assess if these fundamentals are met or violated. Do departures from competitive market fundamentals materially affect the outcomes? How expensive are markets to create? Are real time markets or forward markets necessary to ensure long-term reliability? Are they even feasible? Are there less complex ways to introduce competition, improve transparency, and unlock distribution value to DERs?

5.1 Do We Need a Distribution Level Forward Market, a Short-term Market, or Both?

Distribution planning and operations are fundamentally tied to ensuring the reliability of the grid. The role of the planner is to identify, in advance, where distribution reinforcements are needed, identify alternative potential solutions, model the effect of different solutions on power flows, reliability, and resilience, and select a portfolio of cost-effective solutions that eliminate constraints before they are binding. In other words, their role is to avoid or reduce the likelihood that sections of the distribution grid will be unable to maintain reliability because of bad planning (i.e., insufficient equipment capacity or poor design).

Distribution operators have a narrower role and are concerned with the distribution grid in real time. Operators do not have the luxury of being able to upgrade the system and must work with the equipment that is in place. Operators are concerned with week-ahead, day-ahead, or same-day operations.

The same distinction between planning and real-time operations can be observed in electricity markets. Most electricity markets are concerned with operations: how do you operate the system efficiently given the resources—generators and wires—already in place? While the main concern of markets is balancing supply and demand in real time, they also must ensure that sufficient generation capacity is in place to reliably operate the electric grid so it can function. Most market operators, including NYISO, have distinct markets for energy and for capacity.

Capacity markets are forward markets, conducted several years in advance, and are designed to bring new generation capacity online. When the market operator pays for generation capacity, they are paying for a contractual commitment for a resource to supply into the market under a pre-specified set of conditions. The payments are for a type of

reliability insurance—in the form of installed capacity—and are not, per se, payments for energy production.

Forward markets or other similar mechanisms for procuring distribution capacity could ensure that the right amount of resources—whether distributed energy resources or distribution equipment—is built on time and at the right locations in order to avoid inadequate levels of reliability. The day-ahead and real-time markets, if designed well, may be a way to determine which resources to dispatch and when to do so, once those resources are in place. However, they are not the only way to establish transparent dispatch rules and they may not be the most cost-effective way to do so.

The fact that there is very limited experience with distribution level, real-time energy markets cannot be overemphasized. None of the referenced demonstration pilots have tested the ability to maintain long-term distribution reliability. Put differently, the ability of such markets to drive the right type of capacity additions, at the right locations and at the right time, remains completely unproven. While distribution level real time markets may be useful for providing relief during emergency conditions provided there is existing DER capacity, there is little reason to believe they will, in fact, avoid distribution capacity costs.

The pilots testing real time, distribution level energy markets also have not included direct competition between DERs and distribution equipment investments. Where and when do DER resources compete with distribution equipment options? How often should a DSP/utility allow distribution emergencies that lead to price spikes? When does a utility move forward with a distribution upgrade?

5.2 Key Principles of a Forward Market for Distribution Capacity

Managing local, coincident demands in order to avoid or defer capacity investments represents the largest, tangible value of distributed energy resources to the distribution system. A venue for distributed energy resource to access monetized distribution capacity value is by participating in utility programs that pay pre-specified reservation and performance payments. With this model, utilities set a price and aggregators recruit customers to produce or reduce energy when distribution capacity relief is needed. The price is not based on bids by distributed energy resource providers, but set via administrative calculations. While this approach monetizes distribution capacity value, it falls short of the vision of having distributed energy resources compete, side-by-side against traditional distribution grid equipment upgrades and against other DER resources.

There are several principles for designing a practical market for distribution capacity services:

1. **Distribution capacity must be traded in a forward market (1 to 5 years)** that monetizes the insurance value it provides. This is necessary so the resources can be incorporated into distribution planning while they can still influence distribution investment decisions. Resources that have not been accounted for in the planning process deliver far less value and do not avoid capacity investments.
2. **Markets for distribution capacity require granularity** by location, hour of day, season, and forecast year.
3. **Sellers must compete against each other and reveal prices of their products to the buyer.** They must specify their sales price, and the amount of megawatts they are

willing to sell at specific locations, for specific hours of the day, seasons, and forecast years. Many parties in the REV are asking for the reverse—namely, for the utility to post the price it is willing to pay for distribution capacity. This allows DER providers to avoid competition with other DER providers or with distribution equipment. More importantly, revealing the maximum price a utility is willing to pay will not result in the least cost solution.

4. **Information on seller prices and product specifications should be public**, as in most markets, in order to ensure price transparency and foster competition. This would include both DERs and distribution equipment providers.
5. **The product being traded is not energy** (kWh), but a specific amount and type of insurance characterized in the form of a contractual obligation to deliver resources when they are needed most. The seller must deliver verifiable production (or reductions) either when contingencies occur or when a distribution area's demand approaches the installed equipment rating.
6. **If sellers do not meet contractual obligations or under-deliver, they must face reduced payments or penalties.** Without reduced payments and penalties, there is potential for arbitrage.
7. **The operational characteristics of the distributed energy resources must be disclosed in a standardized manner** in order to enable bundling of a cost-effective portfolio of solutions.
8. **A cost-effective, integrated solution should be selected.** Many DERs deliver incomplete solutions for local distribution capacity relief when deployed individually but have characteristics that can provide complementary value when deployed as a combined solution. In the right combination, DERs deliver more value as a whole solution than as stand-alone components. A cost-effective distributed resource option bundle should be selected if it meets all reliability and performance criteria. The selection criteria must be publicly disclosed to ensure transparency.
9. **The buyer, the utility, must not have an obligation to purchase all DERs' capacity offered into the market.** In most markets, buyers decide if and how much they purchase depending on whether the products offered meet their need. If the DERs bid into the market are insufficient in magnitude, do not address reliability needs, or if distribution infrastructure can be built at a lower cost, the utility should have the option not to purchase the DERs' distribution capacity offered by sellers.
10. **Distributed energy resources must compete against each other and against traditional distribution investments.** If a DER solution is more expensive or otherwise inappropriate, as compared to distribution infrastructure investment, the distribution investment should be made.
11. **DER distribution capacity must be incremental.** The availability of incremental DER capacity can help defer and avoid distribution capacity investments. Payments to pre-existing resources, on the other hand, may lead to higher costs to ratepayers and be a form of windfall gains.
12. **Double-counting of resources that are yet to be built needs to be avoided.** To illustrate, if an aggregator projects they can recruit 5 MW of residential air conditioner load control in a local area and another aggregator also projects 5 MW, those values are not additive since both aggregators are basing their estimate on the same recruitment pool.

These market principles monetize the insurance value of distribution capacity services, ensure

transparency, and allow distributed energy resources to compete side-by-side with traditional distribution investments.

5.3 Key Principles for a Short-term Distribution Level Energy Market

We recommend against establishing distribution level energy markets for two main reasons. First, the locational value of DERs is primarily in supplying distribution capacity, not in supplying energy. While distribution level real time markets may be useful for providing relief during emergency conditions, there is little reason to believe they will, in fact, avoid distribution capacity costs. A distribution company has an obligation to provide reliable service and must procure sufficient capacity in advance of shortages – it cannot wait to see what does and does not show up during emergencies. Second, experience with distribution level energy markets is insufficient. While intriguing, the transactive energy concept has yet to demonstrate its value. As noted earlier, none of the pilots have demonstrated that such markets incent capacity additions on their own and none have demonstrated that the benefits of setting up a distribution level energy market outweigh the costs.

A distribution level energy market, if structured correctly, would provide two main functions:

- It would send a clear signal as to when and where distribution relief is needed most and an operational dispatch trigger, and
- It would potentially allow existing resources without contractual commitments for distribution capacity to participate during emergency conditions.

However, there are alternative ways to accomplish the above goals that may be less complex and less costly to rate payers.

Most of the fundamental principles that apply to distribution capacity markets also apply to energy markets. Should the New York Public Service Commission decide to move forward with distribution level energy markets, there are additional principles to consider:

1. **Distribution level energy prices should not be determined administratively, but through competition** among DER providers. DERs must reveal their "sell price" and specify DER characteristics so an adequate supply stack can be established. An administratively determined price is not based on market competition and is not truly a market.

2. **The demand cannot be fixed or inelastic,** otherwise it provides room for market manipulation. In practice, there is only one buyer for the operating head room provided by distribution emergency relief—the utility. However, that demand is not inelastic, as distribution networks can be operated with less head room, albeit with a higher risk of outages and overloads. Because the amount of transactions is unknown, we also recommend a price cap to prevent market manipulation.

3. **Distribution congestion pricing only occurs when available excess capacity dwindles** either due to distribution component outages or because of high loads.

4. **Prices must be tied to available excess supply.** The utility/DSO must be able to set the target amount of excess capacity, and to establish different levels of demand at different prices.

5. **Distribution congestion prices should not include the value of distribution capacity** since there is little reason to believe they

will, in fact, avoid distribution capacity costs. The benefits reflected must be restricted to decrease the risk of outages and in equipment degradation associated with potential overloads.

6. **Prior to establishing distribution energy only market at a utility scale, it is necessary to demonstrate that the benefits exceed the costs and that it is more effective than other methods.** In other words, distribution real time markets must compete with other mechanisms that monetize distribution value for DERs. The benefits and costs need to be based on actual empirical evidence, not on theoretical models or arguments.

The goal of unlocking and monetizing distribution value to DERs is a sound one. Allowing distributed energy resources to compete side-by-side with large scale generators and traditional distribution grid equipment should foster more competition and should lead to increased efficiencies. However, distribution level real time markets are neither ripe in terms of maturity nor are the only way to establish competition and monetize DER value. There are more practical and better tested options.

6 Next Steps and Recommendations

The central question of this paper is how to structure markets that:

- Monetize the distribution or locational value for DERs;
- Allow DERs to compete side-by-side with each other and with traditional distribution investments;
- Increase transparency; and
- Ensure both short and long term grid reliability.

The task of designing markets to integrate DERs into distribution planning and operations can be summed up in a single word: innovation.

When managed properly, innovation proceeds through an orderly process in stages—idea generation, concept development, concept testing, business case development, market testing, and full-scale implementation. Experimentation is a critical requirement in the process of innovation. It is the mechanism that innovators use to identify what works and what does not work. Often programs, products, and market designs go directly from concept testing to full-scale implementation, without the critical step of evaluating performance under conditions as similar as possible to those in real life. Nothing fails quite as spectacularly as a product brought to market before it is ready.

Certain basic principles should guide the development of new products, including:

- A project manager should be assigned responsibility for managing the project.
- Maximum utility should be obtained from information early on in the development process.
- Experiment frequently—experiments can be expensive, but late stage failures and rework are more expensive. It is better to experiment with small-scale models of designs early and often then to wait until the end of the design and development process to perform a big test on the whole system.
- Experiment rapidly—the purpose of experimentation is to obtain relatively immediate and useful feedback. Experiments that take too long to complete may impede progress toward a solution to the problem rather than enhance it.
- Fail early and often but avoid large scale mistakes—failures in experimentation are to be expected and provide valuable information about the way the world works. To experiment and innovate, one needs room to test concepts that may fail.

Taken together, the above principles define a highly controlled development environment in which mostly small-scale experiments with program elements are performed early on in the development process in order to minimize the risk of big program failures.

The current state of markets for DER integration is at the concept development stage. There has been some small scale concept testing of real time distribution level energy markets and forward procurement efforts in the form of RFPs. However, those tests have not addressed many core questions and have not demonstrated that real time energy markets at the distribution level deliver value, much less shown that it is the best way to structure competitive processes that integrate DERs. Based on review of the evidence to date and an

understanding of how distribution planning and operations work, the concept of forward markets for distribution capacity, in our assessment, better aligns with the REV proceeding objectives and does a better job of integrating DER resources into planning and operations. However, there is simply not enough evidence to identify the most effective approach, much less move to full-scale implementation, at this point in time.

We recommend **evidence based policy making on market structures** for DER integration. We believe that policy must rely on empirical evidence that assesses the performance of market concepts and products under real world conditions. To this end, we **recommend side-by-side testing of:**

- Real time energy markets with locational marginal pricing plus distribution value;
- Forward distribution capacity markets;
- Utility rates and programs, enabled by advanced metering infrastructure, that incent customers to reduce local, coincident peak demands; and
- The status quo (which might be defined to include the use of RFPs and standard offers to procure DERs for distribution capacity relief).

These tests, done properly, will need to be carefully designed to ensure valid, side-by-side comparisons of the various alternatives. The goal would be to determine which market structures provide the most value given the cost of implementing them. How much does it realistically cost to establish these market structures? Do they deliver changes that improve efficiency? Do they help incent additional DERs at the right locations? Are customers and DERs willing to participate?

The design of valid tests will take careful thought and sufficient time to determine how best to proceed. They will most likely need to be done on separate networks that are as similar as possible to each other. The tests themselves will likely require two years or more in order to provide sufficient evidence to support policy decisions. We recommend that this process begin as soon as possible.

Appendix A Experience with Distribution Level Markets

DER Market Integration: AEP Smart Choice

Basic Facts

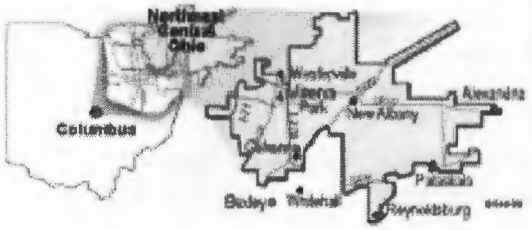
DER Participation (all as demand):
~217 homes (w/ ePCT controlled HVAC only)

Recruiting: Unknown recruitment rate
Utility targeted specific segments using multiple marketing channels. Most joined to save money.

Treatments:
Real Time Pricing (plus control group)

Duration:
4 months (load impacts for Jun-13 to Sep-13)

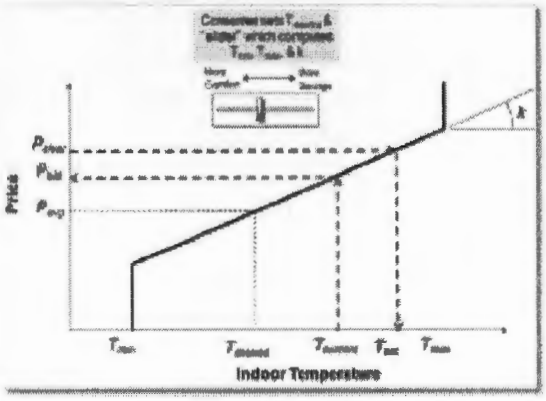
Financial:
Pilot costs unknown, average savings $22/mo



Northeast Central Ohio (AEP territory)
Pilot in partnership with PNNL

Pricing Structure

Home Energy Manager Bids: Comfort vs Savings

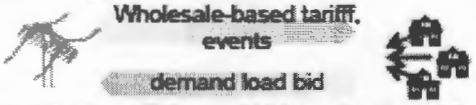


Market Good: Automated response to pricing aggregated at the circuit

Market Interval: 5 minute, with 10 minute lag

Market Pricing: Customers set consumption (load) levels for different prices; utility submits supply bids (function of 5-minute wholesale PJM price, RTP tariff, etc.). Price clears where aggregated supply meets aggregated demand.

Automated Communication: 2-way



User interface: Enhanced PCT and web-portal with slider control for comfort vs savings

Conclusions

- ✓ **Bidding algorithm** theories proven
- ✓ **Cost too high** for ePCT, HEM, cellular communication for individual premises
- ✓ Value was greater for **other consumer programs**
- ✓ **Cellular service most cost effective** and easiest to implement **but lack of access restricted access**; explore other technologies
- ✓ **Often multiple installation trips** required
- ✓ **Opted or 10-minute lag** due to data processing challenges

DER Market Scorecard

- ☒ Prices incorporate **distribution congestion?**
- ☒ **DER integrated as supply** (versus demand)?
- ☒ **Peer-to-peer trading?**
- ☒ Testing of implications for **long term reliability?**
- ☒ **Defaulting** of customers (versus self-selection)?

Public report: https://www.smartgrid.gov/document/aep_ohio_gridsmart_demonstration_project.html

DER Market Integration: EcoGrid EU

Basic Facts

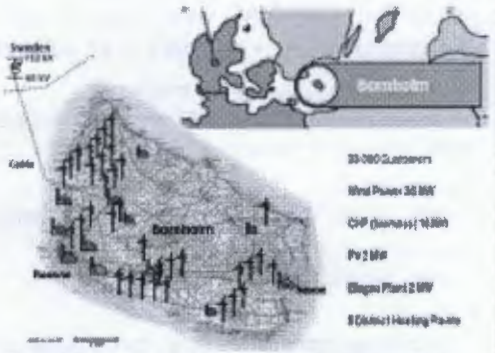
DER Participation (all as demand):
1,900 homes (all w/ electric heating or heat pump, some w/ PV, EV) + 100 C&I customers (including micro CHP, district heating)

Recruiting: 10% recruit rate of households.72% accepted load control. Effort to recruit non-enthusiasts

Treatments:
200 control group, 500 manual (no automation), 700 automated controls responding directly to price, 500 aggregator managed automated loads

Duration:
Ongoing (2013-present)

Financial:
€25M project budget

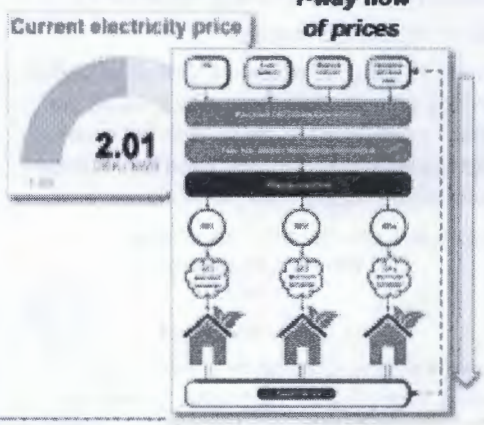


Bornholm: Danish island, high renewables penetration with load balancing needs

Pricing Structure

Pricing dashboard

1-way flow of prices

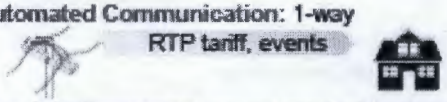


Market Good: Automated response to pricing (demand and dispatchable generation)

Market Interval: 5 minute

Market Pricing: Automated price response set by participants. Prices based on forecasted demand response of Bornholm test participants and power prices. Prices do NOT directly include participant demand.

Automated Communication: 1-way RTP tariff, events



User interface: users pre-set comfort limits using web-portal which also provides real-time, past, and forecast prices and load data

Conclusions

Goals / success factors for pilot:
- ✓ be **accepted / understood**
- ✓ prove **economic value** for society and stakeholders
- ✓ prove ability to provide **reliable, efficient** balancing services

Participant focus groups (N=50):
- ✓ **Failures** in system, equipment
- ✓ **Many web-portal bugs**, explore an app to improve access
- ✓ Good **customer service**, improved **participant comfort**

DER Market Scorecard

- ☒ Prices incorporate **distribution congestion?**
- ☒ **DER integrated as supply** (versus demand)?
- ☒ **Peer-to-peer trading?**
- ☒ Testing of implications for **long term reliability?**
- ☒ **Defaulting** of customers (versus self-selection)?

Public report: http://ecogridbornholm.dk/wp-content/uploads/2013/10/EcoGrid-Report-Octobre-2013.pdf

DER Market Integration: PNNL GridWise Testbed

Basic Facts

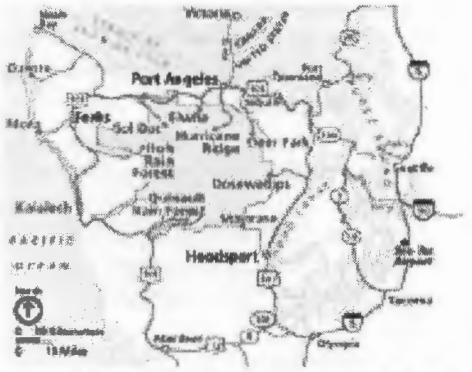
DER Participation (all as demand):
112 homes (w/ HVAC, water heater, dryer) +
4 reservoir pumps+ 2 generators (as demand)

Recruiting: Unknown recruitment rate
Screened out 88 of initial 200 recruits on lack of high speed internet or relevant loads.

Treatments:
Control, Fixed, TOU, RTP (preference assigned)

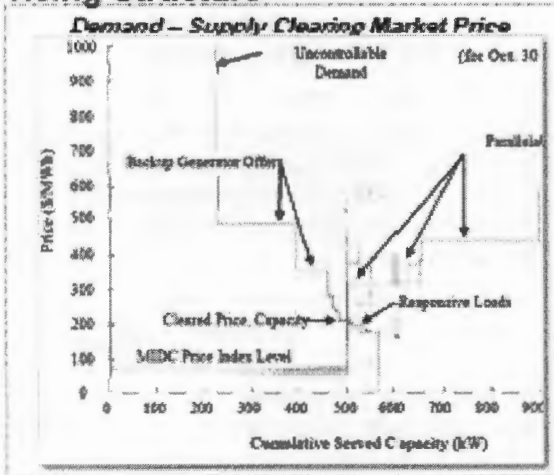
Duration:
1 year (2006-2007)

Financial:
Pilot costs unknown, incentives min. $150pp



Olympic Peninsula: capacity-constrained, radial transmission system

Pricing Structure

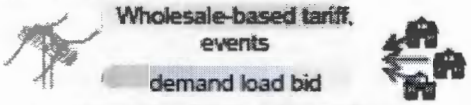


Market Good: Automated response to pricing (demand and dispatchable generation)

Market Interval: 5 minute

Market Pricing: Wholesale-based price signals sent from the shadow market. Customers set consumption (load) levels for different prices. Aggregated loads form a demand curve. Price clears where supply meets demand.

Automated Communication: 2-way



User interface: Comfort vs price preference setting, high price warning lights, web-portal

Conclusions

- ✓ **Market-based control** shifted loads in RTP homes & managed C&I HVAC loads
- ✓ **Efficient frontiers** useful for utility analysis
- ✓ **Internet-based control** works but poses implementation challenges
- ✓ **Automation** helpful for obtaining consistent responses
- ✓ **Thermal storage** (pre-cooling / heating) particularly leveraged by RTP participants

DER Market Scorecard

- ☒ **Prices incorporate distribution congestion?**
- ☒ **DER integrated as supply (versus demand)?**
- ☒ **Peer-to-peer trading?**
- ☒ **Testing of implications for long term reliability?**
- ☒ **Defaulting of customers (versus self-selection)?**

Public report: http://www.pnl.gov/main/publications/external/technical_reports/PNNL-17167.pdf

Appendix B Competitive Market Structure Examples

There are a variety of market mechanisms though which goods and services can be competitively offered and procured, as summarized in Table B-1. Some of these market competition processes (e.g., RFPs, tariffs, etc.) are already prevalent in the electricity industry.

The wholesale electricity markets that already exist in New York are mostly similar to the second basic framework described in Table B-1. The system operator specifies the product specifications and the quantity needed (based on load schedules) and subsequently holds an auction to determine prices. This process is remarkably similar to the essential structure of a request for offers—the buyer specifies what it needs and the quantity it needs, and asks sellers to submit their bids—but it is more structured and more transparent.

Notably, electricity markets hold blind auctions—that is, buyer and seller bids are not revealed—only the marginal bid or market clearing price is published. This differs from most competitive markets, where sellers publicly reveal the sales price for their product in order to attract buyers, leading to price transparency, and adjust their prices to compete with other sellers.

Table B-1: Summary of Competitive Frameworks and Examples

	Basic Framework	Examples
1	**Buyers post the price they are willing to pay and the specifications they require.** Sellers can see the offer and indicate if they meet the specifications, are willing to accept the price, and, if so, how much they are willing to sell. Buyers stop buying when their needs are satisfied.	▪ Utility programs ▪ Tariffs ▪ Priceline's Name Your Own Price™
2	**Buyers post the product specifications they are looking for and how much of the product they need.** Sellers reveal their price and how much of the product they are willing to sell at that price.	▪ Requests for proposals or requests for offers ▪ Wholesale energy markets ▪ Energy ▪ Capacity ▪ Ancillary services ▪ Travel/hotel online markets ▪ Craigslist want ads

Competitive Market Structure Examples

	Basic Framework	Examples
3	**Sellers post the product specifications and their sale price.** Buyers search and compare product offers from multiple sellers and buy from the most suitable seller.	▪ Craigslist for sale ads ▪ Gas stations ▪ Nearly all retail and grocery stores ▪ Amazon ▪ Ebay search ▪ Google shopping
4	**Organized market in which prices are posted and market participants decide whether to buy, sell, or hold** at the posted price. Participants can also submit standing instructions to buy or sell at different prices. However, participants do not have direct access to each other's information regarding buy or sell strike prices.	▪ Most stock markets ▪ Most commodity markets
5	**Buyers post the product specifications they seek, how much they want, and the price they are willing to pay. Sellers also post the products they have for sale.** A buyer can bid on any seller's offer and sellers can hold auctions (with time limits) to assess if any other buyers are willing to pay more.	▪ EBay auctions ▪ Online gaming markets such as FIFA transfer market