

The Role of Energy Efficiency in a Distributed Energy Future

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Contents

About the Authors.....	iii
Acknowledgments.....	iii
Executive Summary	iv
Introduction.....	1
Methodology	2
Grid Modernization	3
Resource Planning Primer	6
Integrated Resource Planning	7
Transmission Planning.....	9
Distribution System Planning	11
Load Forecasting	13
Distributed Resource Planning	14
Energy Efficiency in Distribution System and Distributed Resource Planning	16
Data Request Responses.....	17
Other State and Utility Examples	19
Valuing Energy Efficiency as a Distributed Resource: Time and Location.....	34
Improving Valuation of Energy Savings	35
State and Utility Examples.....	38
Discussion	41
Geotargeting.....	41
Distribution	42
Transmission.....	45
Evaluating Efficiency as a Distributed Resource	47
Conclusions and Recommendations.....	49

References 51

Appendix A. Definitions of Distributed Energy Resources 63

Appendix B. Utility Data Request Responses 65

Appendix C. Utility Distribution System Planning Data Request 67

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Executive Summary

The electric utility industry is currently undergoing a transformative period of fundamental change. The growth of technologies such as rooftop solar, battery storage, and advanced metering infrastructure is driving many of these changes. Many states are now undertaking broad regulatory investigations to discuss ways to modernize antiquated distribution systems while also addressing related issues, including electric rate design. Central to many of these new regulatory proceedings is system planning. Regulators are exploring changes in resource planning with a focus on how technological changes should be integrated into system planning.¹ The proceedings also allow states an opportunity to investigate the role of energy efficiency in these processes. In this paper, we examine the approaches in various states, with a focus on energy efficiency.

DEFINING DISTRIBUTED RESOURCE PLANNING AND DISTRIBUTED ENERGY RESOURCES

States do not share a common definition of distributed resource planning (DRP). However the term generally describes the processes undertaken by utilities and regulators to plan for and integrate distributed energy resources (DERs) into various utility systems. DRP is heavily focused on the distribution system but also includes other aspects of utility planning, such as resource and transmission planning. Because distributed resources may reduce the need for new transmission and distribution (T&D) infrastructure as well as new generation, these resources affect all levels of utility system planning. Distributed resources affect customer demand, driving resource planning decisions and altering outcomes.

As with distributed resource planning, DERs do not have a common definition among states. The National Association of Regulatory Utility Commissioners defines a DER as “a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid” (NARUC 2016). Our review of definitions shows that most, but not all, include energy efficiency as a DER.

RESEARCH QUESTIONS AND METHODOLOGY

Grid modernization proceedings are highlighting many challenges faced by electric utilities and are also driving discussion on many important questions related to how utilities and regulators will integrate DERs into distribution systems. Each DER poses its own challenges but provides unique benefits. Given that energy efficiency programs have traditionally been a low-cost resource for electric utilities, our research questions include:

- Which states and electric utilities are currently conducting distributed resource planning? Of these, which are including energy efficiency, and how are they approaching that task?

¹ We describe the differences between resource planning and system planning later in this document.

- What valuation methods are used to integrate energy efficiency into integrated resource planning and distributed resource planning?² What has been the experience thus far with these approaches?
- How is energy efficiency currently considered in distribution system planning?

We relied on a blend of data collection approaches to answer these research questions. We conducted a survey of electric utilities, ultimately receiving responses from 31. Sixteen of the responding utilities are among the largest 50 in the United States, averaging more than 1.9 million customers and more than 46 million MWh in annual sales. We also collected regulatory filings and other documents related to distribution system planning and energy efficiency. These documents formed the basis of our research, but we also conducted follow-up interviews with utility respondents and other industry experts.

ENERGY EFFICIENCY AND DISTRIBUTED RESOURCE PLANNING

All of the electric utilities we surveyed indicated that they conduct distribution system planning, but only half file these plans publicly with a regulatory body. The publicly available plans varied in structure and content. For example, three utilities cited integrated resource plans, and two publicly file transmission plans but not distribution plans. Of the distribution plans that were filed, those in the states of New York and Washington were the most detailed.

We also asked utilities if energy efficiency and other demand reductions were considered in distribution system planning. Eighteen of 30 responded affirmatively. Six of the 18 utilities consider energy efficiency and other demand reductions only indirectly, through reductions in load forecasts. Seven of the 18 stated they specifically consider energy efficiency as an active resource. Finally, we asked utilities about how distribution planning departments communicate with energy efficiency program planners or implementers. Fourteen of 30 utilities replied that they coordinate between the energy efficiency and distribution/transmission planning groups, with variation in the degree of coordination.

State Examples

States and utilities are at different levels of engagement in distributed resource planning. California is likely the most advanced in terms of developing a formal distributed resource planning process. The California approach is heavily focused on integration of several planning processes at various levels to optimize integration of DERs. The California Public Utilities Commission (CPUC) is leading the effort, developing uniform tools and approaches to distribution system planning and analysis with an emphasis on estimating hosting capacity, locational value, operations, and DER dispatch for reliability needs. This process was initiated in 2014, with utilities filing plans in 2015. The California approach is also

² An integrated resource plan (IRP) is a long-term plan conducted by utilities to determine the favored approach to meet forecast demand, relying on both supply- and demand-side resources.

reliant on a series of demonstration projects to test the tools and various approaches to using DERs in system planning to meet constraints.

The Southern California Edison (SCE) Preferred Resources Pilot (PRP) is a demonstration project seeking to use DERs to offset 300 MW of demand in a densely populated area of Orange County, California. The pilot focuses on using energy efficiency, demand response, renewable generation, and energy storage on the distribution system to offset demand. SCE used competitive procurement solicitations to secure contracts for 24.3 MW of energy efficiency, a large part of the SCE PRP. Additional pilots are underway within the DRP proceeding, as well as within the Integrated Distributed Energy Resources proceeding exploring utility incentive structure.

New York State, through the Reforming the Energy Vision (REV) process, is taking a different approach, focusing on market transformation, utility business model enhancements, and rate reform. In New York, the intention is to use distribution companies as platforms to facilitate transactions of energy and energy services to drive investments in DERs. Utilities are required to submit an annual Distributed System Implementation Plan (DSIP) (NY DPS 2015a). These plans are intended to create an integrated approach to system planning, with a specific emphasis on innovative ways of integrating DERs (including efficiency) to enable cost-effective deferral of traditional infrastructure. Another primary focus is the use of demonstration projects to test new regulatory approaches in real time. New York is additionally examining market transformation approaches in place of resource acquisition alone for energy efficiency savings, but it is too early in this process to gauge success.

Washington State is very early in its reform process but is actively engaged in discussions to increase penetration of DERs. The initial focus of discussion has been on valuation methods and recognizing the benefits of DERs at different times and locations. Tacoma Power, a municipal utility in Washington, has also demonstrated the use of conservation voltage reduction as an option for targeted energy efficiency. Other states, such as Oregon, Minnesota, Connecticut, and Massachusetts, are also exploring changes to planning processes to value energy efficiency and other demand reductions in distribution system investment considerations. For example, Pacific Power in Oregon is piloting a screening tool to compare solar, energy storage, and demand-side management as alternatives to transmission and distribution infrastructure investment.

VALUING EFFICIENCY AS A DISTRIBUTED RESOURCE

One component critical to the inclusion of energy efficiency in distributed resource and distribution system planning is improving valuation methods. Most approaches to valuing energy efficiency in the past have focused on annual system-level benefits, but enhanced planning approaches recognize that value varies by time of day, by season, and by location. Energy efficiency savings that occur during a utility coincident peak are likely more

valuable than energy savings in off-peak periods.³ Energy prices and the value of demand reductions for avoiding T&D and generation capacity will differ according to where those savings occur. A key issue in moving forward with DRP is understanding the value of distributed resources that can help to defer more traditional distribution system investments.

State Examples

In New York, as part of the REV process, the Department of Public Service released a societal valuation framework to build on the traditional cost-effectiveness tests used for energy efficiency portfolios and to accurately capture the full value of DERs through a more granular accounting of costs and benefits. The framework includes several benefits to capture time and locational value of energy and demand savings but directs utilities to file territory-specific estimates of these benefits.

In California, utilities are using an approach known as locational net benefit analysis to assess cost effectiveness of various DERs within planning processes. This methodology is based on a previously approved cost-effectiveness calculator but is modified to include location-specific values and additional avoided-cost components.

The Northwest Power and Conservation Council employs a method to determine peak capacity value of efficiency resources based on the time when the savings occur. This approach places a higher value on energy savings that reduce peak demand in the context of resource planning.

Regulators in Rhode Island have developed what is known as the Rhode Island Test. This method is used in distribution system planning and enhances the benefit-cost analysis with additional elements for system planners considering the use of alternatives to building new distribution infrastructure. In addition to benefits such as avoided capacity costs, avoided ancillary costs, and avoided environmental externality and compliance costs, the legislation states that other benefits may include “any site-specific, or option-specific benefits or costs directly attributable to the location of the project or the proposed alternatives” (Rhode Island PUC 2017b).

Our examples show that several states are working toward improving valuation of energy efficiency through consideration of time and locational value. The integration of various planning processes and the development of screening tools to model different scenarios of DER adoption are the primary commonalities among states pursuing this path.

³ Energy efficiency that provides greater total savings off-peak rather than at peak times may appear to lower system efficiency but in fact still provides very significant system and deferral benefits.

In all of the state examples we reviewed, distributed resource planning and integrated distribution system approaches are in early stages of development. While there are several ongoing pilot projects and successful examples of utilities relying on efficiency as a distributed resource, these processes are not mature and should continue to be monitored for emerging best practices. Not only are analytical approaches different among states, but regulatory approaches vary as well. For example, New York is seeking to develop a market-based distribution system platform, while California is continuing a central planning effort led by the CPUC and the California Energy Commission (CEC).⁴

GEOTARGETING

In addition to improved valuation and integration approaches for distributed resources, DRP also may include geotargeting, the process of using energy efficiency (or other resources) to reduce demand in specific areas facing distribution or transmission capacity constraints. This practice, which allows a utility to avoid or defer construction of new infrastructure needed to meet higher demand, is not a new one.

State Examples

Consolidated Edison (ConEd) in New York, National Grid New York, and National Grid Rhode Island have engaged in geotargeting for several years. Their experience provides valuable guidance to states and utilities seeking to implement demand reduction strategies in distribution system planning.

Utilities can use geotargeting as an approach to defer both transmission and distribution assets.⁵ One of the best-known distribution geotargeting efforts is ConEd's Brooklyn Queens Demand Management (BQDM) project. The effort aims to reduce peak load by 52 MW in the designated BQDM territory by the summer of 2018 to defer an approximately \$1 billion upgrade including a new substation. The project has achieved about 36 MW of peak load reduction, more than half of this (19 MW) through ConEd's implementation of energy efficiency measures in the residential, commercial, and public building sectors. The remaining demand reductions were achieved through voltage optimization (ConEd 2014, 2017b).

Utilities have also used energy efficiency and other demand-side solutions to avoid or defer transmission upgrades. In 2009, the Bonneville Power Administration (BPA) proposed the I-5 Corridor Reinforcement Project, a new 79-mile transmission project along the Interstate 5 corridor of Oregon and Washington with an estimated cost of \$722 million (Pesanti 2017). In

⁴ However, with Governor Andrew Cuomo's recent announcement requiring the New York Department of Public Service and the New York State Energy Research and Development Authority to develop energy efficiency savings targets to 2025, it is unclear how a market-based distribution system platform will drive energy efficiency savings.

⁵ Here we discuss transmission and distribution asset deferral jointly, but decisions regarding transmission and distribution infrastructure investments are determined through separate processes.

several assessments, BPA found that non-wires alternatives, including energy efficiency, would be able to defer the need for the project. In May 2017, the administrator and CEO of BPA signed a letter notifying the public of the decision to cancel the I-5 project (BPA 2017b). While the project was not scuttled solely due to energy efficiency and demand response, these resources were cited as factors slowing the load growth that had driven the original proposal.

RECOMMENDATIONS

As a result of the research presented in this report, we offer the following recommendations for regulators and utilities:

Continue to enhance and improve valuation methods to capture the full value of energy efficiency. This includes improvements to measuring the time and locational value of energy efficiency, as well as improving load and resource forecasting methods and approaches. These improvements will lead to more economically efficient outcomes in system planning. More-robust scenarios should be developed to consider the impacts of specific technologies, rate design, and demand-side resources, allowing energy efficiency to be considered as a resource.

Coordinate planning processes—including distribution, transmission, generation/resource, and energy efficiency—to improve outcomes. As the electric utility system continues to evolve, the work of these various departments will become more interdependent, requiring coordination during system planning. The inclusion of energy efficiency planning with other processes, such as regional transmission planning efforts, will also optimize cost-effective outcomes throughout the system.

Consider the National Standard Practice Manual (NSPM) as a tool for regulators and utilities to measure the cost effectiveness of energy efficiency investments. The NSPM provides an updated, more comprehensive, and more flexible approach for benefit-cost analysis than traditional approaches, one that can be better utilized for the assessment of energy efficiency as a distributed resource (Woolf et al. 2017). Essentially, the NSPM provides a framework and process for a state to develop its own tailored cost-effectiveness test for energy efficiency, which may also be applied to other DERs.

Use geotargeted energy efficiency as a complement to broad-scale or system-wide efficiency, not as a replacement. Research shows energy efficiency can be used to actively defer specific distribution and transmission assets, and improved valuation methods also document that the value of efficiency is higher during specific times and in particular locations. While this approach can be used to enhance planning efforts, it is important to bear in mind that efficiency still provides significant value as a reliable system-wide resource, capable of reducing demand across an entire service territory and during all time periods.

CONCLUSION

Our review of distribution planning processes and survey results shows that the majority of utilities are currently not using energy efficiency as a distribution system resource. States like California and New York are far ahead of most others in this area, with several additional states in the early stages of implementing regulatory structures and valuation

approaches for DERs within grid modernization proceedings. These proceedings are intended to adequately consider distributed resources as reliable alternatives to new infrastructure to meet growing demand. Several demonstration projects provide proof of concept that this can be done in a cost-effective way to avoid or defer construction of new distribution and transmission infrastructure.

Our review also documents advancements in estimating the value of energy efficiency at different times and in different locations. The improvements to valuation methods will allow system planners to use efficiency to cost effectively reduce demand in areas and times of the highest value, supplementing broad-based efficiency measures that deliver system-wide benefits. These valuation methods are also being used in combination with other enhanced planning tools to optimize planning processes. Finally, the early demonstration projects in New York and California document the high value of using energy efficiency as a distributed resource. The ConEd BQDM and SCE Preferred Resources Pilot projects have both relied heavily on energy efficiency as a highly cost-effective resource to meet their demand reduction targets.

Along with several other ongoing pilots, these projects offer evidence and guidance to other utilities and regulators early in the process of determining how to best utilize distributed resources in system planning. Our research shows that there is much more potential for these utility planning processes to include targeted energy efficiency, acting as a complement to broad-based efficiency. As these planning processes become more integrated, these enhancements and lessons learned will also be critical for improvements to integrated resource and transmission system planning.

Introduction

The electric utility industry is in a period of fundamental change. In many parts of the country, the industry is moving away from a centralized generation approach, dominated by vertically integrated utilities, to a decentralized approach. The decentralized paradigm is fueled by changes in technology and policy. In terms of technology, utilities are deploying communications and automation to improve efficiency and reliability of distribution systems. Cost reductions in battery storage and rooftop solar technologies are also contributing to decentralization.

In terms of policy, deregulated markets are allowing greater competition for generation resources. Greenhouse gas reduction goals and renewable portfolio standards are also changing the nature of generation on the grid. Additionally, many states have undertaken regulatory processes to discuss ways to modernize antiquated distribution systems while also addressing related issues, including electric rate design. A few states, like California, Minnesota, Illinois, and New York, have begun broader proceedings to consider more substantial changes to utility markets and systems in order to address decentralization and related issues. Central to many of these new regulatory proceedings is system planning. Regulators are exploring changes in resource planning with a focus on how technological changes should be integrated into system planning.⁶

These technological changes, including enhanced analytic approaches, are also allowing utilities to consider non-wires alternatives in transmission and distribution planning. Non-wires alternatives are the use of distributed generation technologies, battery storage, demand response, and/or energy efficiency to defer or avoid the need to upgrade transmission or distribution infrastructure to meet increasing demand. This concept is also known as geotargeting—the geographic targeting of specific demand reductions or resources to defer transmission and distribution (T&D) assets—which can be a lower-cost or more cost-effective alternative to traditional infrastructure upgrades.

This report considers how utilities and regulators are currently incorporating energy efficiency into these new approaches. We focus on the ways in which energy efficiency may be considered as a resource in a distributed context, in either distribution, transmission, or resource planning. While the majority of utilities are in the early stages of answering these questions, several states are taking a leading role, and their efforts may provide guidance and information to other states considering how to incorporate energy efficiency into the utility of the future.

First we describe our methodology; then we discuss active grid modernization proceedings driving changes in utility planning and models. This is followed by a general overview of utility system planning processes, including distribution, transmission, and integrated resource planning. We then examine specific state and utility efforts to consider energy

⁶ We describe the differences between resource planning and system planning later in this document.

efficiency in the context of distributed resource planning, relying on existing literature and information from more than 30 utilities in the United States. After a short discussion of energy efficiency in distributed resource planning, we conclude with recommendations for regulators engaging in this process.

Methodology

We relied on several methods to gather information for this report. First we conducted a preliminary literature review to understand existing research on energy efficiency and utility system planning, with particular attention to distributed resource planning. We then conducted interviews with more than a dozen experts to determine the states and utilities with the most advanced efforts in this area. Our primary focus was on planning approaches that value energy efficiency in a distributed planning context. While we did collect some information about the inclusion of energy efficiency in system-wide planning efforts, like integrated resource planning, our research centered on how energy efficiency is valued and planned for in specific locations at specific times.

Finally, to collect primary-source documentation on utility distribution system planning, we sent a data request to utilities. We asked for primary-source documentation related to four topics: utility distribution planning, consideration of energy efficiency and other demand reductions in those processes, geotargeting, and coordination between energy efficiency and distribution/transmission planning groups. The data request form is shown in Appendix C.

We sent data requests to 129 utilities in all 50 states and the District of Columbia in August 2017. To select the utilities, we began with the 52 largest utilities in terms of sales, then added utilities in states that did not have at least one in the top 52. The types of organizations included investor-owned utilities (IOUs) and municipal and other public power companies; we also contacted third-party statewide program administrators for a few states.⁷ We did not survey any cooperative utilities because of size. Utility contacts sent 29 complete responses covering 31 utilities.⁸ Utilities from 26 states responded, representing all regions of the United States. Of the 31 utilities, 26 are investor-owned, 3 are municipally owned, 1 is federally owned (Tennessee Valley Authority), and 1 is a nonprofit organization (Energy Trust of Oregon). Sixteen of the responding utilities are among the largest 50 in the United States, averaging more than 1.9 million customers and more than 46 million MWh in annual sales.

We then collected regulatory filings and other documents related to distribution system planning and energy efficiency. These documents formed the basis of our research, supplemented with follow-up interviews of utility respondents.

⁷ For simplicity, we use the term *utilities* for all these types of organizations.

⁸ Virginia Electric and Power Company serves customers in Virginia and North Carolina. Southwestern Public Service Company serves customers in Texas and New Mexico.

Grid Modernization

Grid modernization is a term used widely across the energy industry, but with no common definition. The term refers generally to regulatory processes that make the electricity system more responsive to the changing energy landscape of today and tomorrow in the face of decreasing costs for renewable energy, increasing penetration of distributed energy resources (DERs), more sophisticated system management software, and aging grid infrastructure (Proudlove et al. 2017a). The issues frequently included under the grid modernization umbrella have been driving utilities and regulators to review resource and infrastructure planning processes in recent years. States have chosen to focus on different aspects of grid modernization, but all areas present an opportunity to investigate the role of energy efficiency in a modern power system. In particular, aging infrastructure presents an opportunity to upgrade and replace physical equipment. Estimates show that necessary investments in electric utility infrastructure will reach \$1.5–2 trillion by 2030. T&D investments will likely account for around \$900 billion of this total (DOE 2015).

The US Department of Energy (DOE) is developing strategies to modernize the grid and resources to move states and localities toward their own goals. DOE envisions a modern grid as a system that has greater resilience to all hazards, improved reliability, enhanced security from evolving threats, affordability, the flexibility to respond to variability, and increased sustainability (Schwartz 2016).

Many states in the United States are currently undertaking some sort of grid modernization activities, with various end goals and with a wide range of programs being implemented (Proudlove et al. 2017a). Lawrence Berkeley National Laboratory identified the following stated goals of grid modernization activities across the United States (Homer et al. 2017):

- Increase grid reliability and resilience
- Develop and integrate renewable and distributed energy resources (as defined independently by various jurisdictions)
- Reduce costs and otherwise enhance societal benefits for customers, utilities, and grid operators
- Enhance customer service and choice
- Save energy, reduce peak demand, or optimize load/demand shapes
- Optimize existing generation and T&D systems
- Modernize/accommodate new technologies
- Animate new or existing markets through a grid platform
- Enhance safety and security
- Reduce emissions
- Support workforce and economic development
- Facilitate integrated planning

To achieve these goals, grid modernization activities include physical upgrades to aging transmission and distribution infrastructure, but they also include:

- Promoting alternatives to T&D infrastructure upgrades (such as through demand management)

- Implementing advanced metering systems (including communications and control technologies that help manage DERs)
- Using software or market mechanisms to balance energy supply and demand
- Rethinking utility business models to facilitate the integration of additional distributed energy resources and behind-the-meter technologies

Table 1 shows the major activities of grid modernization identified by the NC Clean Energy Technology Center, along with state examples from 2017 (Proudlove et al. 2017a, b). These activities were identified and categorized based on proposed and adopted policy changes related to grid modernization and DERs. They often encompass energy efficiency actions, although efficiency efforts are not identified in this report as a stand-alone major activity.

Table 1. Major grid modernization activities and state examples

Activity	Strategies included	State example (2017)
Smart grid and advanced metering infrastructure	Studying and implementing advanced metering infrastructure (AMI) communication and control technologies for managing DER	Ohio approved a project for a utility to deploy 894,000 advanced meters to customers.
Utility business model reform	Studying and implementing changes to utility earning mechanisms to better align incentives with grid modernization objectives	New York directed utilities to propose earning adjustment mechanisms (EAMs) for financial incentives for advancing state policy objectives as well as shared savings-based incentives for projects other than traditional transmission and distribution investments.
Regulatory reform	Studying and implementing changes in how regulatory practices incentivize utility efforts toward stated grid modernization goals	Rhode Island's governor directed the Public Utilities Commission to design a new regulatory framework for the electric utilities industry.
Utility rate reform	Investigating and implementing rates that work to achieve stated grid modernization goals	Pennsylvania is investigating the implementation of demand-side management performance incentives, multiyear rate plans, and other strategies.
Energy storage	Studying and optimally implementing energy storage technologies into markets and as a grid resource	Nevada opened a docket to explore energy storage technologies and convened stakeholders for discussions on the technologies.
Microgrids	Studying and deploying microgrid technologies	Maine introduced a bill that would allow municipalities to work with utilities to deploy microgrid projects.
Demand response	Investigating and using demand response as a grid resource to manage peak demand	Michigan released a potential study on demand response resources in the state and began regulatory proceedings to investigate its use.

The most common activities include deploying advanced metering infrastructure and DER communication and control technologies, as well as adopting time-varying customer rates (Proudlove et al. 2017a).

Figure 1 shows states that undertook one or more of the above grid modernization activities in the second quarter of 2017.

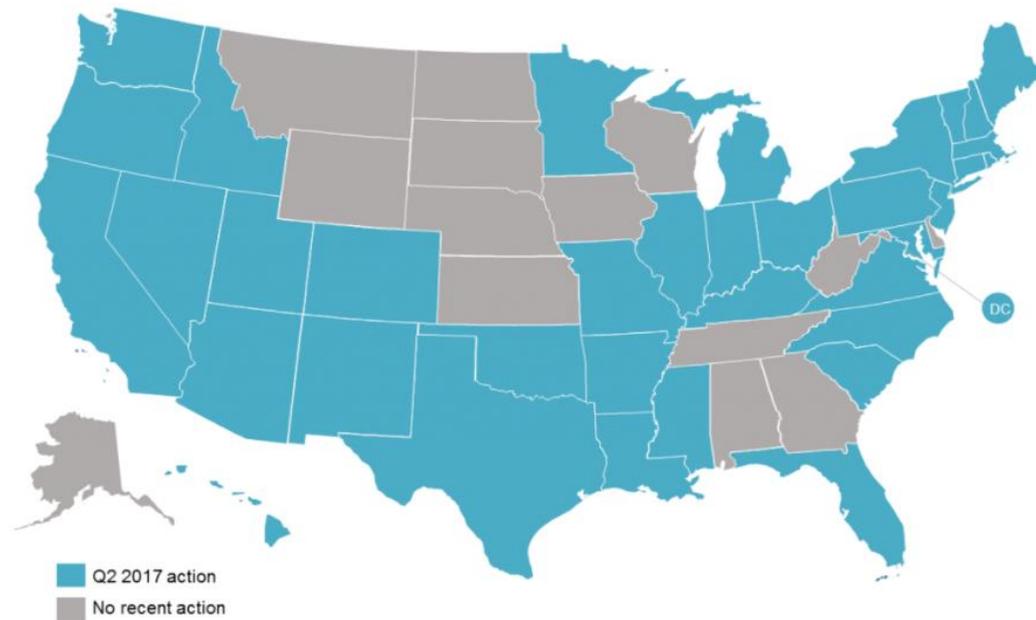


Figure 1. Legislative and regulatory action on grid modernization. Iowa also undertook grid modernization actions in Q1 of 2017.
Source: Proudlove et al. 2017b.

New York, California, and Hawaii are states at the forefront of large-scale transformation of the energy industry and utility business model, especially with regard to distribution system planning, discussed in greater detail in the following sections of this report. In addition, many other states (Minnesota, Massachusetts, Rhode Island, Vermont, Pennsylvania, Florida, Texas, Ohio, Illinois, Washington State and Washington, DC) are considering or implementing small-scale changes to facilitate greater integration of DERs. For example, Texas is working toward the aggregation and participation of DERs in wholesale markets, with a focus on supply-side resources such as combined heat and power (Proudlove et al. 2017b).

In the first quarter of 2017, six states considered changes to the utility integrated resource plan (IRP) process (Louisiana, Michigan, Minnesota, New Mexico, Nevada, and Washington), and three considered changes to the distribution system planning process

(New York, Rhode Island, and Washington). This included requiring consideration of energy storage technologies, requiring consideration of resources with environmental benefits, and other changes. Additionally, Maine considered changes to how non-wires alternatives (NWAs) are implemented and incentivized within its Smart Grid Policy Act framework (Proudlove et al. 2017b).⁹ The Maine approach requires that regulators consider whether NWAs can meet system needs in a more cost-effective manner when approving transmission projects (Neme and Grevatt 2015).

Whether or not grid modernization efforts explicitly include provisions for the consideration of energy efficiency varies by state and by the specific actions being taken, as we discuss later in this report.

Resource Planning Primer

The activities and policy questions under the umbrella of grid modernization have largely focused on changes in utility planning. Utilities, regulators, and regional transmission operators conduct planning processes for generation, transmission, and distribution. These processes vary in scope, ranging from the micro (e.g., circuit-level distribution planning) to the macro (e.g., regional-level generation resource planning). The duration of the planning process also varies, ranging from less than a month to more than 20 years. Here we provide a general overview of utility planning processes, including integrated resource, transmission, distribution, and distributed resource planning, to provide a foundation for later sections of this report.

Integrated resource planning generally includes planning for a specific utility system or region and is focused on matching supply and demand over a specific period, like 10 years. While some integrated resource plans include transmission and distribution, many do not. Transmission planning, often conducted by a regional planning entity or utility, focuses on ensuring transmission capacity and infrastructure needs. Distribution system planning focuses on constraints and capacity needs at the distribution level, often under 13 kV.

Figure 2 shows the basic structure of the electric system.

⁹ Non-wires alternatives include the use of distributed generation technologies, battery storage, demand response, or energy efficiency to defer or avoid the need to upgrade transmission or distribution infrastructure to meet increasing demand. This concept is also known as geotargeting—the geographic targeting of specific demand reductions or resources to defer transmission and distribution (T&D) assets—which can be a lower-cost alternative.

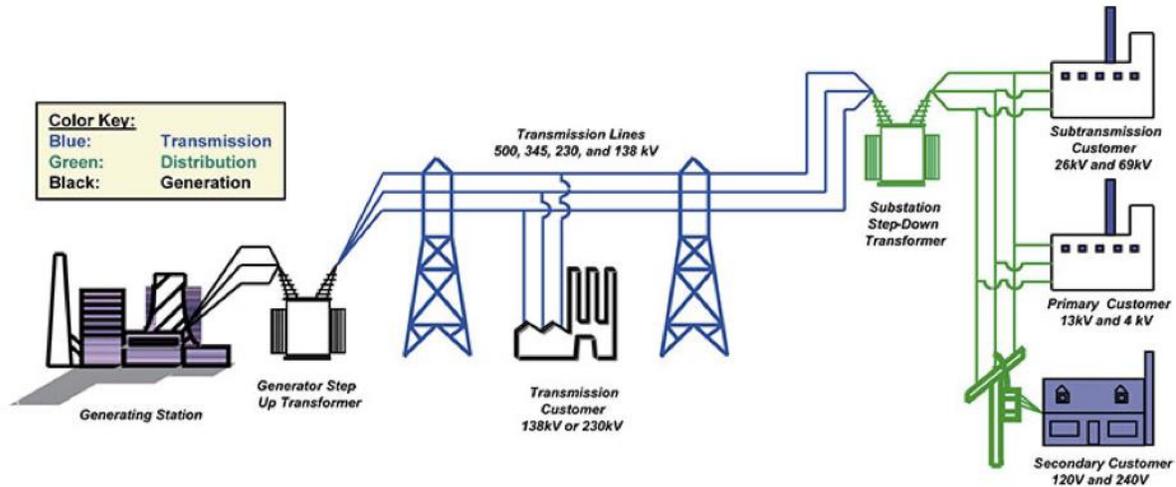


Figure 2. Structure of the electric system. *Source:* Hein et al. 2011.

INTEGRATED RESOURCE PLANNING

An IRP is a long-term plan conducted by utilities to determine the favored approach to meet forecast demand, relying on both supply- and demand-side resources. IRPs are typically conducted by regulated utilities owning generation assets or state planning agencies. While many IRPs focus on least-cost planning as the desired approach, other objectives also drive a preferred outcome. These objectives include construction cost risk, environmental concerns, economic impacts, and other factors. As of 2013, 26 states required utilities to file an IRP (Wilson and Biewald 2013). Ten additional states have filing requirements for a long-term plan similar to an integrated resource plan.

The completion of an integrated resource plan generally requires several key steps, including forecasting future demand, assessing costs and feasibility of specific supply- and demand-side resource options, consideration of current and future environmental regulations affecting resource planning, and assessing risks associated with each component of the IRP. Once data are collected for these specific components, an optimization analysis of some sort is completed to determine the least-cost approach to meeting future demand. The methods and approaches to this step vary considerably, especially in terms of complexity and rigor.

Energy efficiency is often considered within the context of an IRP, usually through an adjustment to the load forecast. This can include both utility-sector programs and naturally occurring energy efficiency (savings that would have occurred even in the absence of utility programs).¹⁰ This approach estimates the expected annual energy savings from efficiency programs and reduces the load forecast accordingly. The energy savings projections are often based on energy efficiency resource standards (EERSs) or market potential studies.

¹⁰ From a utility perspective, savings from nonutility programs, such as state and local government programs, are part of “naturally occurring” efficiency. We discuss load forecasting in greater detail later in this report.

The naturally occurring savings projections are often based on codes and standards but can include assumptions on efficient product saturation for specific technologies.

Other approaches include the development of an energy efficiency supply curve, based on the levelized cost of specific energy efficiency investments.¹¹ This approach is utilized in the Northwest Power and Conservation Council’s Seventh Power Plan (NWPPCC 2016) and PacifiCorp’s 2017 IRP (PacifiCorp 2017). The assumptions used for this approach, including the estimated energy and demand savings and potential costs of resource acquisition, do vary. However this approach allows system planning to understand the potential demand-side resources available at specific cost thresholds. Figure 3 shows this approach for the commercial sector by end use for the Seventh Power Plan.

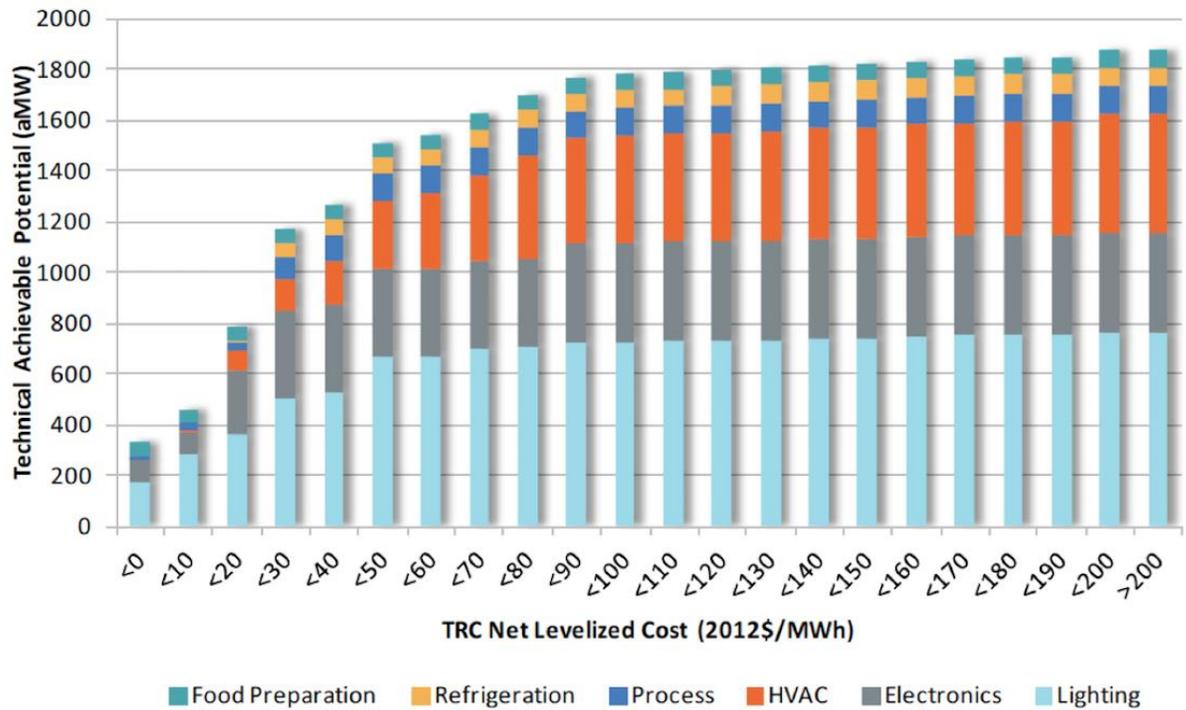


Figure 3. Commercial energy efficiency potential by 2035 by end use and levelized cost. *Source:* NWPPCC 2016.

Other utilities have used a similar approach, creating blocks of energy efficiency savings based on historical performance or market potential studies. These blocks are intended to act as potential power resources in an IRP modeling approach. The Tennessee Valley Authority’s most recent IRP used this approach (TVA 2015). This approach does not

¹¹ Levelized cost of energy represents the per kWh cost of building and operating a generating plant over an assumed financial life and plant dispatch cycle (EIA 2017b).

consider the time and locational value of energy efficiency but instead just considers the cost of the resource.

TRANSMISSION PLANNING

The US electric system is governed by multiple levels of organizations, from federal agencies to state regulatory commissions to private regulated utilities. The governance and regulatory structure in each region influences how transmission system planning is conducted. At the highest level, the Federal Energy Regulatory Commission (FERC) oversees interstate commerce, including interstate transmission rates and wholesale power markets. Additionally, the North American Electric Reliability Corporation (NERC) sets technical reliability standards for utility transmission planning (Woodall 2012).

Prior to the formation of regional transmission organizations, utilities often operated individually with regard to transmission planning. Transmission was viewed as a direct line between the generating plant and the distribution system (EISPC and NARUC 2014). It was largely assumed that utilities would be able to share the coordination of generation and transmission resources in times of emergency (EISPC and NARUC 2014). However, as demand for electricity grew, utilities began to coordinate further, realizing the benefits of economies of scale in the industry (EISPC and NARUC 2014).

FERC Order 1000 mandates participation in regional planning (FERC 2016). Currently there are seven regional transmission organizations (RTOs), also sometimes called independent system operators (ISOs), in the United States that operate under FERC jurisdiction to coordinate grid functions. Each ISO works to ensure system reliability and conducts transmission system planning, load forecasting, and facilitation of wholesale energy markets (EISPC and NARUC 2014). They also lay out rules and agreements for generators connecting to the transmission system. ISOs are required to help ensure that generation owners have open and fair access to the transmission system under FERC's open access transmission tariff (Woodall 2012, ISO-NE 2017).

In regions not covered by an ISO, transmission utilities conduct system planning within a balancing authority area.¹² Outside agencies, including regional reliability organizations like the Western Electricity Coordinating Council (WECC) or the Midwest Reliability Organization (MRO), are responsible for developing and enforcing transmission reliability standards and overseeing the planning process (Woodall 2012).

Transmission system planning is required to be transparent and collaborative. It is at the same time a very technical process and is also driven by stakeholder input. Transmission plans are forward-looking, covering 10–20 years, and are typically revised every year or two

¹² A balancing authority is defined as “the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority area, and supports Interconnection frequency in real time” (EIA 2017a).

to account for changes in assumptions. Transmission plans are most strongly driven by regional peak load forecasts (largely informed by the utility distribution system planning process). Plans also account for technical constraints on equipment, public policy (such as renewable portfolio standards), environmental impacts, and costs (Woodall 2012).

Technical transmission constraints that planners consider may include thermal constraints (regulating the heat of the lines to prevent faults), voltage constraints (to protect equipment within a specified range), parallel power flows (that may cause transfer limit infractions at substations), operating security (built-in equipment redundancy based on NERC standards in case of failures), and system and voltage stability (protection against large variations in voltage) (Molburg, Kavicky, and Picel 2007).

Once planners have identified areas of constraint on the system, they analyze options for meeting demand needs based on a variety of assumptions and scenarios, weighing financial and other costs (such as environmental concerns). Increasingly, scenarios are including the evaluation of non-wires solutions, including energy efficiency and other demand-side resources. Transmission plans may be subject to additional state regulatory approval (Woodall 2012). Alternatives to new transmission line construction that may be considered include permitting higher line operating temperatures, improvements in real-time transmission line monitoring (to improve operational efficiency), upgrading substation equipment to increase the maximum current flow, upgrading or replacing existing equipment (such as conductors, transformers, and capacitors), and non-wires alternatives (Molburg, Kavicky, and Picel 2007).

Transmission projects consist of towers, conductors, substations, and right-of-ways (land area acquired for a purpose such as a transmission line), all in consideration of the system's peak load requirements. The planning process typically includes surveys and mapping of proposed routes and right-of-ways, civil and geotechnical engineering assessments (foundation and subsurface analysis), environmental and construction permitting, and community involvement (Molburg, Kavicky, and Picel 2007).

ISO New England (ISO-NE) offers a good example of the transmission planning process, as the ISO acts as the foundational transmission planning entity for its namesake region. ISO-NE evaluates the impact of modifications such as interconnection of new or upgraded resources to the system for reliability. The ISO conducts regional load forecasting, which feeds into an annual regional system plan that reports on system reliability needs for the following 10 years. The ISO then reviews and approves project applications and conducts cost allocation analysis for regional cost support. The ISO works closely with utilities for data and has many working groups for different topics, such as demand resources and energy efficiency (ISO-NE 2018). The region's Forward Capacity Auction (FCA) plays a

large role in the regional demand forecast. The FCA includes energy efficiency resources, which creates value for efficiency providers and for the system overall.¹³

The transmission planning process continues to evolve with increasing levels of DER penetration, deployment of demand-side management (DSM) resources, and much more sophisticated modeling techniques. Stakeholders are increasingly recognizing the need to incorporate time and locational benefits of various resources in their cost analyses for transmission and distribution projects (PNDERP 2016). The process also continues to evolve from a passive deferral process (in which transmission upgrades are deferred from reduced demand from efficiency projects implemented for purposes other than infrastructure deferral) to active deferral (in which transmission system upgrades are the explicit purpose of efficiency projects) (Neme and Grevatt 2015).

However there remain challenges that make using energy efficiency as a transmission deferral strategy difficult and likely more challenging than at the distribution level. More parties are involved in the transmission planning process, making coordination and decision making more complex. In addition, reliability planning criteria are more stringent for the transmission system than for the distribution system. Both of these elements contribute to a longer planning horizon for the transmission system, making the planning process less adaptable to NWA opportunities that may arise. Additionally, costs for NWAs are currently fully borne by the state in which the project is undertaken, as opposed to allocated across all parties within the transmission system's jurisdiction. This complicates the incentives for implementing NWAs at this level (Neme and Grevatt 2015).

DISTRIBUTION SYSTEM PLANNING

Utilities conduct distribution system planning to maintain the safety and reliability of the distribution system at a reasonable cost to customers (Coddington, Schneider, and Homer 2017).¹⁴ Individual states are responsible for regulating the reliability of the distribution system and power quality, typically through state laws.¹⁵ State regulators expand on these laws, setting and enforcing standards for the regulated distribution utilities in the state (Hesmondhalgh et al. 2012). Utilities may use the IRP process to ensure resource reliability. Energy efficiency is sometimes included in IRPs as a reliable supply-side resource.

Many regulators use common standards developed by the Institute of Electrical and Electronics Engineers (IEEE) or the National Electrical Manufacturers Association (NEMA) to inform reliability standards. The distribution system planning process is used to account for and justify investments in distribution equipment, such as feeders, transformers, and

¹³ See Relf and Baatz (2017) for more information on efficiency in capacity auctions.

¹⁴ The distribution system is "the portion of the transmission and facilities of an electric system that is dedicated to delivering electric energy to an end-user" (EIA 2017a).

¹⁵ Power quality is "the absence of perturbations in the voltage and flow of electricity that could damage end-use equipment or reduce the quality of end-use services" (DOE 2017).

other infrastructure as necessary to meet new or changing loads and to replace aging equipment.¹⁶

Maintaining reliability includes reducing the frequency and duration of power outages and maintaining power quality (voltage and frequency). Distribution systems must step down the voltage of the electricity coming from the transmission system and maintain a stable voltage for delivery to the customer based on the tolerance of their equipment and the operational standards. Systems must also regulate power frequency to stabilize it within a defined range of acceptable limits (NERC 2014). Indexes used to gauge reliability include measures of system-wide, individual customer, and individual feeder-level interruption duration and frequency (Harikrishna et al. 2013).¹⁷

As part of distribution planning, utilities conduct long-range load forecasting (typically extending 10–20 years) at the distribution feeder or individual circuit level in order to determine system needs. Forecasting includes analysis of DER penetration, peak demand, and other technical analyses of power and load characteristics. For example, utilities may conduct hosting capacity analysis to determine the ability of individual circuits to support photovoltaic (PV) installations coming online. Load and other forecasts are used in conjunction with technical systems analyses to determine risks and areas of congestion such as overloaded feeders and risk of equipment failure at peak demand. Risks may also include equipment exposure and variable power quality (voltage) (Coddington, Schneider, and Homer 2017).

During the planning process, each feeder is analyzed for load growth and new loads. These data are aggregated to the substation level to determine potential need to upgrade substations, transformers, or transformer banks. Utilities then consider ways to alleviate issues and prioritize investments. Solutions may include investing in new distribution feeders, upgrading existing feeders, building new substations, expanding existing substations, and replacing or moving capacitors (which store an electric charge) and voltage regulators (Coddington, Schneider, and Homer 2017). Some state regulators require that utilities publicly file their distribution plans, while others conduct the process internally only. The planning process typically includes the utility’s distribution engineering group and the load forecasting group. Some states are updating distribution system planning processes to account for grid modernization, including increasing DER penetration. These changes are discussed with relation to energy efficiency in state examples below.¹⁸

¹⁶ A feeder is “an electrical line that extends radially from a distribution substation to supply electrical energy within an electric area or sub-area.” A transformer is “an electrical device for changing the voltage of alternating current” (EIA 2017a).

¹⁷ These indexes include the System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI), and the Momentary Average Interruption Frequency Index (MAIFI), among others (Harikrishna et al. 2013).

¹⁸ See Homer et al. (2017) for more information on how states are addressing these issues.

LOAD FORECASTING

Power system planning relies heavily on load forecasting to understand where and when need will arise for new utility infrastructure. Load forecasting occurs at the generation, transmission, and distribution levels. The spatial and temporal focus of load forecasting varies considerably, depending on the objectives of the forecast. For example, traditional integrated resource planning relies on forecasting demand 10–20 years into the future at a whole-system level. In contrast, at the distribution level, forecasting may be done at the circuit level with an hourly or daily focus.

Energy demand is typically overestimated in load forecasts. There are several primary reasons for this. First, energy intensity continues to decline in the United States. Economic variables are key drivers for demand forecasting. If economic growth and energy intensity are overstated, demand forecasts will also be overstated. Second, overestimates likely include a certain level of conservatism because it is less risky to overestimate demand than to underestimate. Under-forecasting of demand could result in blackouts and other serious consequences. Third, utilities have an incentive to overestimate demand because the current utility business model promotes higher earnings through increased infrastructure investments (Engel and Dyson 2017).

A review of seven integrated resource plans in western states from the mid-2000s to 2014 show energy consumption growth projections were overestimated in all but one IRP, ranging up to 20% (Carvallo et al. 2016). Over-forecasting may also occur at the RTO level in wholesale capacity and transmission planning. PJM recently updated its forecasting model to address a noticeable trend of overestimating future demand (PJM 2016). The update included changes to the treatment of weather, penetration of DER technologies (specifically solar), and new variables to account for equipment and appliance saturation and efficiency. Figure 4 shows PJM peak demand forecasts for 2006 through 2012.

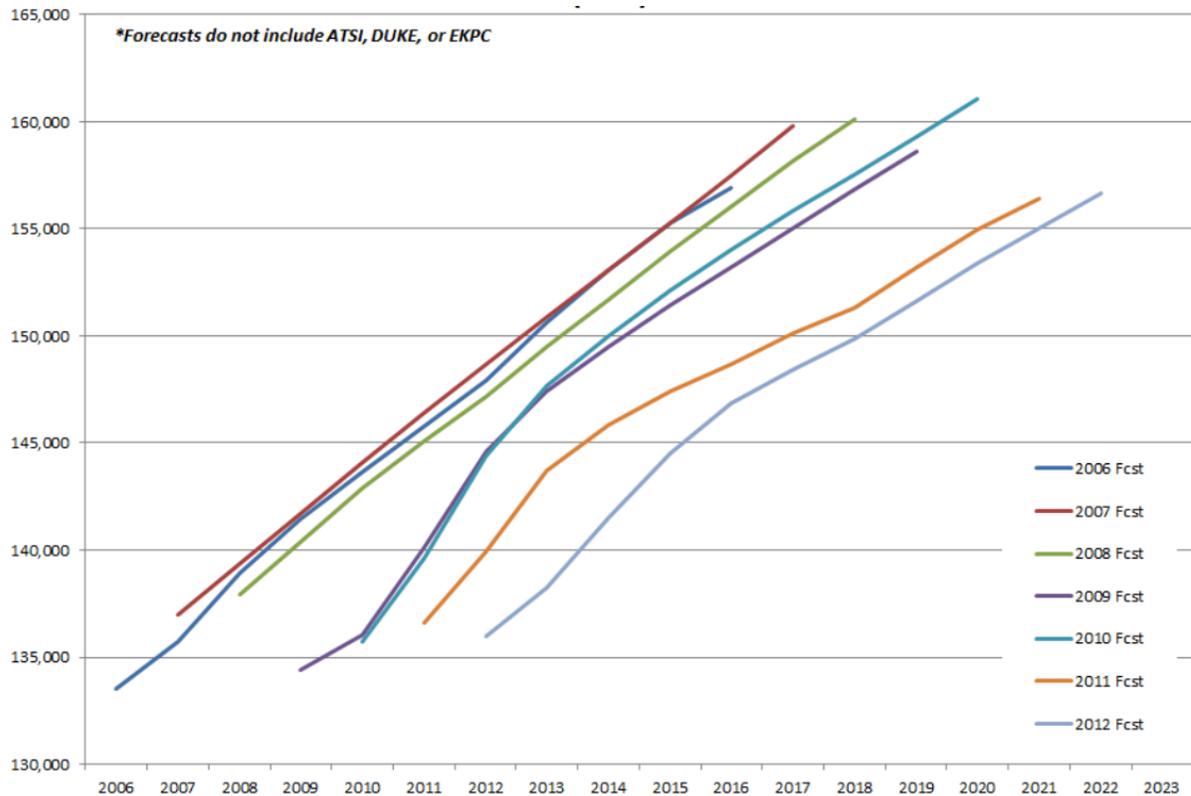


Figure 4. PJM RTO summer peak forecasts in MW, 2006–2012. *Source:* PJM 2016.

Overestimating future peak demand can produce costly outcomes for electricity customers by leading to investments in unnecessary infrastructure and over-procurement of energy and capacity resources. While weather and economic variables are key drivers of load forecasting, estimates of demand-side resource penetration, including energy efficiency and other DER technologies, are also important.

DISTRIBUTED RESOURCE PLANNING

Distributed energy resources (DERs) are resources sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (as with energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. Examples of technologies and services that are frequently included in definitions of DERs include distributed renewable energy generation (such as customer-sited solar), energy storage, microgrids, combined heat and power (CHP) systems, demand response, electric vehicles, and energy efficiency.

DERs typically include technologies on the customer side of the meter and may explicitly include certain technologies or services to meet specific policy objectives. They may also involve capacity limits to encompass smaller resources rather than large, centralized resources. For example, the Electric Reliability Council of Texas (ERCOT) limits DERs to technologies under 60 kW in capacity (NARUC 2016).

Distributed resource planning (DRP) describes the planning processes undertaken by utilities and regulators to integrate distributed energy resources into various utility systems. Because distributed resources may reduce the need for new T&D infrastructure while also reducing the need for new generation, these resources affect all levels of utility system planning. Some of these resources may also require additional investment. For example, investments in a communications network and associated technologies may be required to properly value DERs. Distributed resources affect customer demand, driving resource planning decisions and altering outcomes.

Utilities and regional/state planners are engaged in varying levels of distributed resource planning. California is currently developing a formal holistic approach driven by the California Public Utilities Commission (CPUC). One of the stated goals of this process is to increase penetration of distributed energy resources (defined as distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies) through regulated planning (CPUC 2017). The CPUC is also addressing specific issues regarding the planning process, valuation methods, and other factors through formal workshops and rulemakings.

In a different approach, New York, through the Reforming the Energy Vision (REV) process, is working to establish markets for distributed energy resources and other energy services. The intent of the REV process is to implement market structures and ratemaking approaches to optimize the level of DER based on market demand and willingness to pay (NY PSC 2015).

Several utilities estimate and forecast penetration of distributed generation within integrated resource planning. However this is often addressed through adjustments to load forecasts. Methods vary but are usually based on projecting growth in customer-sited renewable energy such as rooftop solar. Utilities are including these projections in integrated resource planning because such resource additions reduce overall demand and alter future resource planning decisions, but most utilities are not actively planning for utilization of these resources as a solution to need. The variability of some distributed resources also requires more flexible generation dispatch (EPRI 2014). While the focal point for distributed resource planning is in distribution system planning (because of where these resources are located), transmission and generation planning is also affected. Integration of DERs is optimized through integrated planning of distribution, generation, and transmission.

Distributed resource technologies also differ substantially, requiring varying approaches to integration and consideration in planning. Because distributed resources are located throughout the distribution system, distribution system planning will be a key focus. In fact, several states are addressing distributed resource planning through integrated distribution system planning, a process that integrates DER valuation with traditional transmission and generation planning processes to determine optimal distribution investment decisions. Figure 5 shows a theoretical example of integrated distribution system planning.

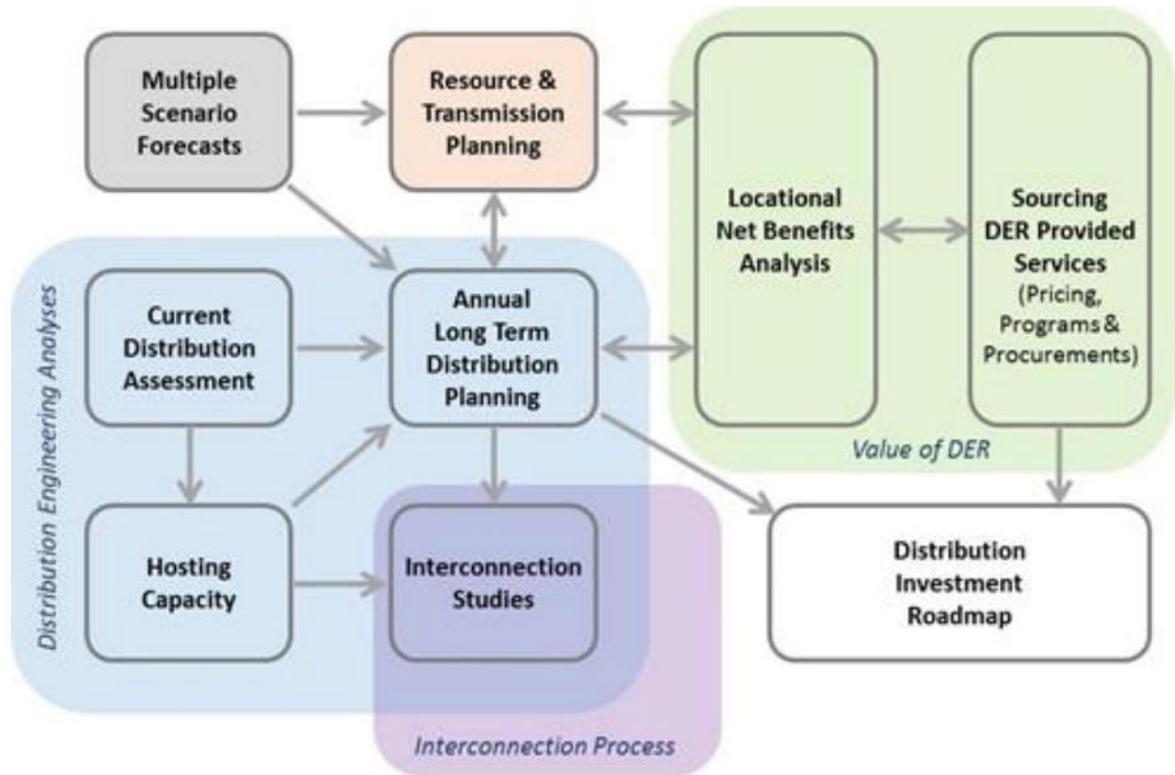


Figure 5. Integrated distribution system planning. *Source:* De Martini 2016.

The distribution engineering analysis is a focal point in traditional distribution system planning. The additional components include valuation of DERs specific to time and location, as well as scenario forecasts and generation/transmission planning processes. Figure 5 demonstrates at a basic level how these various planning processes are interdependent and should be integrated. Our review of current utility practice shows that no utilities are using this framework, but California is working on integrated several of these pieces.

Energy Efficiency in Distribution System and Distributed Resource Planning

Many DER definitions specifically include energy efficiency, while others have focused on generation resources. We use the term *energy efficiency* throughout this report to refer to traditional utility-sector investments in customer energy efficiency programs. These programs are intended to reduce end-use energy consumption for residential (including multifamily), commercial, and industrial customers. Residential programs often target building shell measures, heating and cooling, lighting, and appliance efficiency improvements. In addition to those types of measures, commercial and industrial programs often focus on process improvements, specific industrial technologies, lighting and HVAC

improvements, and the deployment and use of energy management systems. Other energy efficiency gains may be derived from conservation voltage reduction and combined heat and power.¹⁹ Electric vehicles clearly add load to the system but provide efficiency gains in the transportation sector. EVs, CVR, and CHP are also important in the context of distributed resource planning but are often outside the definition of energy efficiency in many of the sources we reviewed.

In this section, we review the current role of energy efficiency in distribution system and distributed resource planning. We present information provided by the 31 electric utilities that responded to our data request, and we review other examples to better understand how utilities currently consider energy efficiency in the context of distribution system planning. We focus on the inclusion of efficiency in distribution system planning through practice and process.

DATA REQUEST RESPONSES

All but one of the respondents to our data request stated that they conduct distribution and transmission system planning.²⁰ (We summarize the data request responses in a table in Appendix B.) Sixteen confirmed publicly filing the plans with a regulatory body. We asked utilities to provide access to the publicly available plan documents. The publicly available plans varied in structure and content. For example, three utilities reported filing integrated resource plans. Two utilities, NorthWestern Energy and TVA, publicly file transmission plans but not distribution plans. The other 11 utilities publicly filed distribution-level plans.

Among those, the New York utilities (National Grid NY and ConEd) file some of the most comprehensive plans. New York regulators require utilities to submit a distributed system implementation plan (DSIP) annually (and biennially beginning in 2018) and to include capital budgets for a forward five-year period (New York DPS 2015a). The DSIPs must include planning for infrastructure, operations, investments, and DERs including energy efficiency.²¹

Seattle City Light, a municipal utility regulated by the Seattle City Council, files its plan with the city council. The plan, titled the *Six-Year Horizon Plan: Transmission, Distribution, Substations, Protection and Communications*, covers physical distribution system investments and budgets but does not address energy efficiency or conservation programs (SCL 2012).

¹⁹ Conservation voltage reduction (CVR) is a reduction of energy consumption resulting from a reduction of feeder voltage. CVR can provide peak load reduction and annual energy reduction of approximately 0.5– 4%, depending on the specific feeder (Schneider et al. 2010).

²⁰ Energy Trust of Oregon is an independent program administrator and does not own or operate distribution. Utilities conduct distribution and transmission planning in Oregon.

²¹ New York's processes for distribution system planning and integration of energy efficiency are discussed in more detail in the section "Other State and Utility Examples," later in this report.

Northern Indiana Public Service Company (NIPSCO), in addition to an IRP, conducts transmission and distribution planning through its Transmission, Distribution, and Storage System Improvement Charge (TDSIC) and seven-year plan proceedings. NIPSCO considers both energy efficiency and demand response in its distribution and transmission planning. The approved NIPSCO 7-Year Electric TDSIC Plan calls for the replacement of approximately 42,000 NIPSCO-owned street lights with LED lights in 112 communities in its service territory (IURC 2017). While the LED lights are more efficient than the existing street lights, the summary testimony filed with the order states that the purpose of the plan and TDSIC was to replace outdated technology rather than to save energy.

Eighteen out of 30 utilities answered yes to the question “Regarding distribution and transmission planning, are energy efficiency programs or other customer-sited demand reductions considered in these planning processes?” Among these 18 utilities, 7 specifically examine energy efficiency as an active resource in planning. Six others stated that consideration of energy efficiency and other demand reductions is only indirect or passive in distribution and transmission planning. Rather than conducting analysis of how, where, and how much demand reduction to include in distribution system plans, these utilities consider energy efficiency impacts only insofar as existing policies and programs may reduce forecast loads.

For example, Ameren Missouri replied that since it bases distribution system planning on measured and forecast seasonal peak demand, the effects of energy efficiency programs and other demand reductions are indirectly included to the degree that they reduce measured peak demand values. Similarly, National Grid Massachusetts affirmed that it considers energy efficiency programs, but it does not propose specific projects as part of the plans it files with regulators, nor does the utility consider demand response in those plans. National Grid did undertake one pilot effort to include geotargeted energy efficiency, the Nantucket non-wires alternative project. If it had been implemented as filed, National Grid would have achieved 18 MW of load reduction over 17 years, and it may also have deferred investment in a third undersea cable (Mass Save 2015). National Grid later withdrew its petition, citing an error in calculating the benefits of deferring investments (National Grid 2016a).

In Wisconsin, state statutes require that energy efficiency be included as part of the assessment of transmission and substation projects submitted for regulatory approval. The requirement is only for larger projects, those exceeding specific cost thresholds.²² Also in Wisconsin, in the PSC Substation Application Filing Requirements, there is a request for “an

²² Wis. Admin. Code § PSC 112.05(3) describes the cost thresholds: For an electric public utility whose electric operating revenues in the prior year were less than \$5 million, the cost threshold is \$250,000. For a utility with revenues between \$5 million and \$250 million, the threshold is 4% of operating revenues. For revenues of \$250 million or more, the cost threshold is \$10 million.

analysis of the ability of energy conservation and efficiency and load response to reduce, alter, or eliminate the need for this project.”²³

We also asked utilities whether distribution planning departments communicate with energy efficiency program planners or implementers. Fourteen of 30 utilities replied in the affirmative. However the degree of coordination, structure, and particular collaborative processes employed vary by utility. For example, the Sacramento Municipal Utility District established a Distributed Energy Strategy department to be an interface with other departments on multiple aspects of distributed energy resources. Dominion Energy has frequent and direct interaction between the groups that perform modeling analysis for its IRP development and DSM program cost-effectiveness modeling.²⁴ A schedule of regular meetings is established before each DSM and IRP filing (M. Hubbard, manager of energy conservation, Dominion Energy Virginia, pers. comm., October 30, 2017). At the other extreme, the smallest utility in our data set, Alaska Electric Light & Power, described its internal coordination as follows: “We’re small, so we just talk to each other.”

OTHER STATE AND UTILITY EXAMPLES

As our data request responses demonstrate, wide variation exists among states and utilities regarding system planning processes. Here we discuss in greater detail different state and utility approaches to integrating energy efficiency into planning. Our primary focus is distribution planning; however many states are also considering changes to integrated resource planning, in conjunction with planning for increased DER integration.

California

California amended its Public Utilities Act in 2013 with several sweeping changes to the state’s practices related to renewable energy, net energy metering, electric rate design, and resource planning. The law required electric utilities to submit DRPs to the CPUC by July 1, 2015 (CA AB 327). It further required utilities to evaluate location benefits and costs of DER on the distribution system, propose or identify financial mechanisms (including tariffs or contracts) to deploy DER, identify spending requirements to meet goals outlined in the plan, and identify barriers to the deployment of DER. The law also required that the plans propose cost-effective methods to coordinate existing programs, incentives, and tariffs to maximize locational benefits while minimizing incremental costs of resource deployment

²³ The following energy efficiency information is requested in Section 2.0 Engineering of the PSC Substation Application Filing Requirements: “2.4. Provide an analysis of the ability of energy conservation and efficiency and load response to reduce, alter, or eliminate the need for this project. Analysis should include: 2.4.1 A description of the energy conservation and efficiency and load response programs and services available to customers in the project area. 2.4.2 An indication of the amount of additional energy efficiency and demand response, not already included in the forecast, needed to reduce, alter, or eliminate the need for this project. 2.4.3 A discussion of the feasibility of achieving the level of energy efficiency and demand response identified in Section 2.4.2.”

²⁴ Demand-side management (DSM) program cost-effectiveness modeling compares the benefits and costs of energy efficiency, demand response, or other programs on the customer side of the meter.

(CA AB 327). Finally, the bill required utilities to consider non-utility-owned DER as an alternative to distribution system investments as part of distribution system planning processes.

The DRPs filed by the California utilities in July 2015 raised several specific areas of consideration. In a January 2016 order, the CPUC divided these issues into three groups: methodological issues, demonstration and pilot projects, and policy issues. The policy issues were organized under three subgroups that outlined further areas of focus:

- DER adoption and distribution load forecasting
 - Coordination with other procurement-related proceedings within the Commission, including the Long-Term Procurement Plan proceeding and integrated resource planning
 - Coordination with the California Energy Commission's Integrated Energy Policy Report and demand forecast, as well as with the California ISO's (CAISO) transmission planning process
 - Appropriate growth scenarios
- Grid modernization investment guidance
 - Grid modernization investment frameworks
 - What grid modernization functions need to be deployed to support full DER integration
- Distribution investment deferral process
 - Whether and when to require periodic updates to utility DRPs
 - Relationship with general rate cases
 - Integration of DRPs into utility distribution infrastructure planning and investment (CPUC 2016)

Through a series of orders, the CPUC outlined specific areas of focus and established several working groups. The integration capacity analysis (ICA) working group was developed to coordinate utility methodologies and align approaches. This group also offered recommendations for iterative improvements to the methodology over time and suggestions for how the ICA should be used by utilities and other parties (Integration Capacity Analysis Working Group 2017). The ICA methodology provides guidance to establish hosting capacity and interconnection for DER. The working group suggested two primary-use cases for ICA: informing siting decisions and informing distribution system planning. The second use case was ultimately determined to be a long-term issue because of the lack of clarity in how the ICA might be used in various planning processes.

The California approach places a strong emphasis on integration of planning processes including statewide procurement planning (integrated resource and long-term procurement), the CAISO transmission planning process, and statewide demand forecasts. The initial 2015 DRP plan filings commented on potential coordination strategies. For instance, Pacific Gas and Electric's (PG&E) coordination efforts will focus on improved communication with state planning agencies on load forecasting and DER growth scenarios.

Further, the latest decision in the DRP proceeding directs the IOUs to make publicly available maps and downloadable data sets that reflect planned investments, potential

deferral projects, conventional cost estimations, and data that will result from efforts in ICA and locational net benefit analysis (LNBA).

Southern California Edison (SCE) focused on improvements to the accuracy and granularity of load forecasts and greater coordination among the California Energy Commission (CEC), CAISO, and CPUC to improve distribution system planning. SCE further proposed to integrate forecasting procedures for system-level procurement, distribution, and transmission with reconciliation procedures. For example, SCE said it may need to adjust its forecasting approach because of DRP, creating potential issues with the CEC forecasting approach. To ensure coordination, CEC may need to update its forecasting approach.²⁵ SCE also suggested improved communication between agencies and utilities related to load forecasting and the need for more input from other stakeholders such as local governments and third-party DER developers. Figure 6 shows the SCE proposal for changes in load forecasting.²⁶

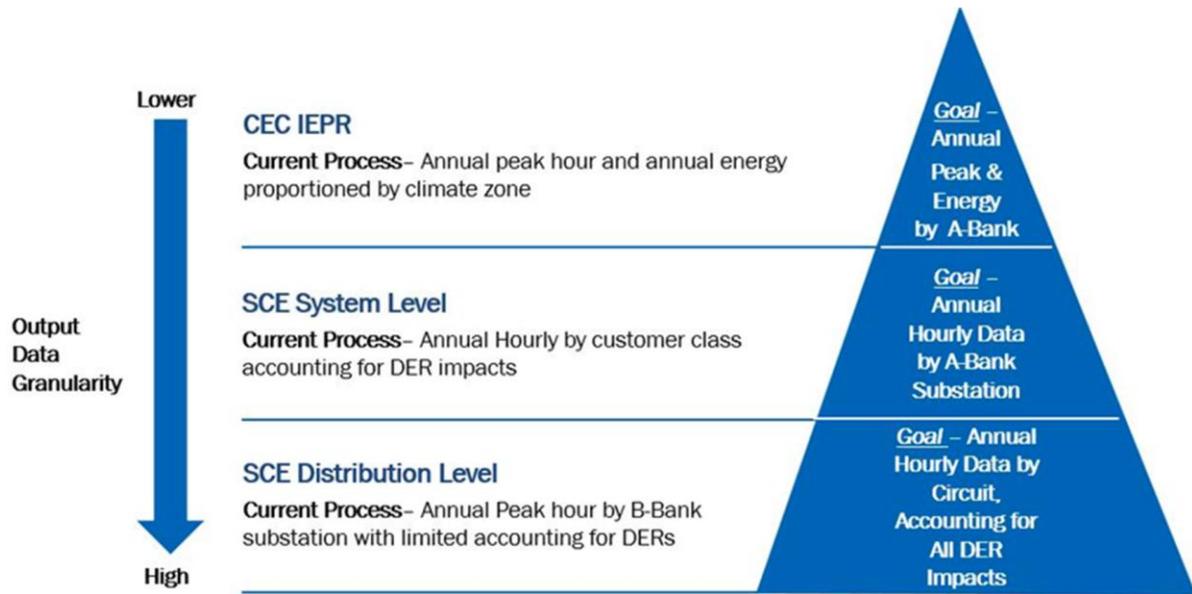


Figure 6. SCE load forecasting, 2020 End State Vision. *Source:* SCE 2015.

SCE's current distribution planning process does not consider energy efficiency (beyond system-level lighting standards) or CHP. These technologies have the ability to reduce demand at the system and substation levels. As SCE implements its DRP action plan, the

²⁵ For much more detail on the potential changes necessary to align the SCE and CEC forecasting approaches, see the Southern California Edison Distributed Resource Plan at cpuc.ca.gov/General.aspx?id=5071.

²⁶ A-Bank transformers are located in major substations, taking electricity at 220-kV transmission level and stepping it down to a sub-transmission voltage, either 115 kV or 66 kV (SCE 2013, 71).

forecasting and planning of DERs on the distribution system will be incorporated through planning tools and approaches that have yet to be determined.

A critical step in the DRP rulemaking process in California is the demonstration project phase. Utilities were required to propose demonstration and deployment projects to validate and test DRP methodologies. Table 2 shows the demonstration projects, descriptions, and current timing.

Table 2. California DRP demonstration projects

Project	Title	Objectives	Timing
A	Dynamic Integrated Capacity Analysis	Validate tools and methodologies used to determine the maximum amount of DERs that can be connected without adversely impacting the utility's distribution system functions. More specifically, demonstrate the ICA methodology and consider different scenarios for it. This demonstration is also expected to drive more consistency between utilities, explore multiple calculation techniques, and incorporate other requirements set by CPUC.	Complete as of December 2016
B	Optimal Location Benefit Analysis Methodology	Demonstrate Commission-approved optimal location benefit analysis (LNBA) methodology for one near-term (0–3 years) and one longer-term (3 years or greater) distribution infrastructure project that can be deferred due to the integration of DERs.	Complete as of December 2016
C	DER Locational Benefits	Implement a field demonstration project that can be used to validate the ability of DERs to achieve net benefits for at least three DER-avoided cost categories or services, consistent with the LNBA methodology. Expected outcomes include validation and calibration of the LNBA methodology and recommendations on incorporating DERs into utility planning and operations.	Projects approved for all utilities in February 2017
D	Distribution Operations at High Penetrations of DERs	Demonstrate a system that can operate multiple DERs (both third-party owned and utility owned) to provide grid benefits and assess how high penetration of DERs will influence distribution planning and investments.	SCE and PG&E projects approved in February 2017, SDG&E projects not yet approved
E	DER Dispatch to Meet Reliability Needs	Demonstrate the ability to manage and operate multiple DERs using one or more dedicated control systems within a microgrid system, potentially with both third-party and utility-owned DERs supporting the customer loads. This demonstration may also define operational functionalities necessary to support situational awareness, coordination of DERs, and reliability services to be achieved.	None yet approved

Source: Lyons, Sturgill, and David 2017

The first set of demonstration projects (A) were intended to validate the integrated capacity analysis tools as tools to be used on the rest of the distribution system. These tools are meant to determine hosting capacity, system constraints, and potential impacts of DER integration under various scenarios. These projects concluded in December 2016 with the IOUs aligning on methodology (Integration Capacity Analysis Working Group 2017). The second set of demonstration projects (B) were intended to evaluate the use of the locational net benefits analysis tool for estimating the value of specific projects. This method is based on a Cost Effectiveness Calculator developed by the consulting firm E3 (used to screen energy efficiency programs) and includes enhancements for location-specific values (LNBAWG 2017).²⁷ Like set A, this second set of demonstration projects was concluded by December 2016.

The third set of demonstration projects (C) are intended to assess the ability of DERs to achieve net benefits outlined in the LNBA results. These projects are actual pilot projects to integrate DER into the distribution system to defer or avoid the need for new infrastructure. The projects were approved for all utilities in February 2017. Although still in development, they are already producing useful findings. PG&E is in early stages of soliciting offers to reduce demand in the El Nido substation area, with final decisions expected in April 2018 (PG&E 2017).

The SCE Preferred Resources Pilot (PRP) is a demonstration project seeking to use DER to offset 300 MW of demand in a densely populated area of Orange County covering 13 cities and 250,000 residential and commercial customers. The pilot focuses on using energy efficiency, demand response, renewable generation, and energy storage on the distribution system to offset demand. The most recent annual report (2016) noted 51 MW of resources deployed with 103 MW in the queue (SCE 2016). As part of the 51 MW, SCE piloted an LED Tube Retrofit program in 24 locations, producing savings of 557 kW. SCE also used competitive procurement to secure contracts for 24.3 MW of energy efficiency. Efficiency is a large part of the SCE PRP. Figure 7 shows the acquisition amounts toward the 2022 demand reduction goal as of the end of 2016.

²⁷ The locational net benefits analysis tool is discussed in greater detail later in this report.

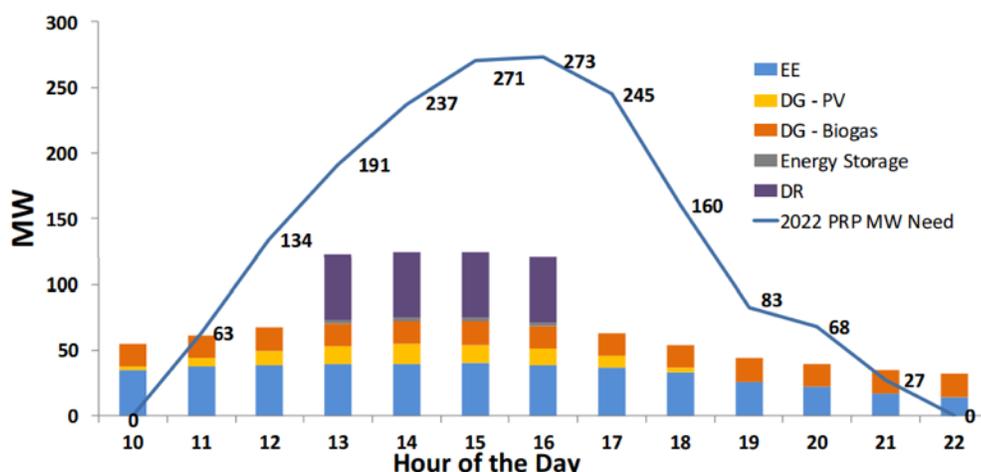


Figure 7. SCE PRP preferred resources acquisition amounts toward the 2022 PRP MW need. *Source:* SCE 2016.

The fourth demonstration project (D) in the California DRP proceeding is intended to evaluate the ability of the system to operate with multiple DERs at high penetration. The fifth demonstration project (E) is intended to evaluate the ability to manage the operation of multiple DERs using a platform or management system. For the fourth demonstration project, SCE and PG&E have approval, with SDG&E still awaiting a green light. No projects are approved for the fifth set.

New York

New York's Reforming the Energy Vision (REV) aims to reshape the utility business model in order to adapt to a changing energy landscape and reduce the state's environmental impact. The proceedings also aim to incorporate energy efficiency as an integral part of resource procurement and consideration for utilities in New York (New York PSC 2015). REV is driven by the overarching vision laid out in the New York State Energy Plan. The plan's 2030 goals are to reduce greenhouse gas emissions by 40% from 1990 levels, to achieve 50% renewable electricity generation, and to decrease building energy consumption by 23% from 2012 levels (New York State 2017). In order to do so, the framework takes a market transformation approach to energy efficiency, rather than the resource acquisition approach commonly used in the past.²⁸ Market mechanisms differ from procurement mechanisms in that they may also be administered by the system operator or regulator, and they rely more on market supply and demand to determine outcomes. This requires more sophisticated valuation methods; more rigorous evaluation, measurement, and verification (EM&V); and the development of market mechanisms and financing to fully integrate efficiency into the utility business model (EPPM 2017).

²⁸ See York et al. (2017) for information on market transformation.

Under the REV Framework, utilities are intended to become “distribution system platforms” (New York PSC 2015). This term encompasses the vision of a utility business model that goes beyond traditional generation or distribution. Specifically, utilities are able to earn shareholder incentives for alternatives to T&D projects (such as energy efficiency achievements) and can earn revenues for providing new grid and customer services such as data sharing. The Public Service Commission (PSC) will maintain energy savings targets and budgets for utilities into the coming years as the state transitions to the new model, with the intent that growth will happen via market mechanisms (New York DPS 2016a). Utilities are encouraged to go beyond these targets (New York DPS 2016a). The New York utilities’ electric efficiency targets for 2016–2018 range from 0.4 to 0.9% (ACEEE 2016). Set through a combination of existing energy efficiency efforts and those developed in its rate case, the targets remain largely constant between 2017 and 2020 (New York DPS 2018). The PSC, as well as related working groups and other stakeholders, have heavily emphasized the importance of shorter-term demonstration projects during the transition (NY DPS 2015a).²⁹ These projects are intended to provide near-term feedback to utilities, third parties, and regulators in order to determine what portions of the REV Framework are effective and what needs to be adjusted.

REV Framework Order One states that utilities will submit an annual Distributed System Implementation Plan (DSIP) (NY DPS 2015a). These plans are intended to create an integrated approach to system planning across different business areas of the utility and include planning for physical infrastructure, operations, and financial investments. Within each DSIP, “each utility will present its system needs, proposed projects, potential capital budgets, particular needs or portions of needs that could be met by DER or other alternative resources, and plans for soliciting such alternatives from the market” (New York DPS 2015b). The PSC’s guidance document for DSIPs states that the Commission staff “expects the utilities to include innovative solutions for integrating DER, including energy efficiency in ways that most effectively increase overall system efficiency and lowers costs for their system and customers” (New York DPS 2015a).

The Joint Utilities of New York filed a DSIP that presents a common framework for identifying projects suitable to be NWAAs.³⁰ This framework is then refined and tailored for each utility within its own plans (Joint Utilities 2017). This ensures a level of consistency across utilities in the state while maintaining flexibility across jurisdictions with very different needs.

Additionally, a staff white paper on ratemaking states that as utility efficiency programs move toward market-based acquisition approaches, programs should include “resource

²⁹ We discuss one of the demonstration projects, ConEd’s Brooklyn Queens Demand Management (BQDM) effort, in greater detail later in this report.

³⁰ Joint Utilities of New York include Central Hudson Gas & Electric, ConEd, New York State Electric & Gas, Niagara Mohawk Power, Orange and Rockland Utilities, and Rochester Gas and Electric. The framework can be found at jointutilitiesofny.org/wp-content/uploads/2016/10/3A80BFC9-CBD4-4DFD-AE62-831271013816.pdf.

acquisition programs or market-supplied programs targeted to specific distribution system needs identified in DSIPs” (New York DPS 2015a). The initial DSIPs provide a fairly high-level overview of the topics included in the guidance document by the PSC. The information is not very granular and does not often discuss energy efficiency programs or performance in detail (ConEd 2016; National Grid 2016a). The Acadia Center has recommended more granularity and data availability for the next iteration of DSIPs, to be filed in 2018 (Acadia Center 2017).

The new processes are also moving toward performance-based ratemaking, which allows utilities to earn on the basis of their achievement in certain metrics, such as energy savings. In this regard, the PSC adopted platform service revenues (PSRs) and earning adjustment mechanisms (EAMs) for ratemaking. PSRs allow utilities to collect revenue based on their actions as distribution system platforms, meaning that they may collect revenue from the market mechanisms they enact. For example, PSRs might include fees for energy engineering services for microgrids or data analysis, or they might include transaction or platform access fees (NY DPS 2015c).

EAMs allow utilities to earn up to 100 basis points for approved achievements in different areas. EAMs are meant to complement utilities’ efficiency implementation plans and to be reduced in importance as utilities move toward more market-based procurement mechanisms in conjunction with PSRs. The order specifically indicates that EAMs should be used for peak reduction and energy efficiency, in addition to other aspects of the REV goals (NY DPS 2015c). Utilities are just beginning to propose EAMs in their rate cases, so it is still too early to assess the success of the program. However the proceedings provide insights as to how utilities, regulators, and the public are approaching the system.

Most recently New York Governor Andrew Cuomo directed the development of a new energy savings target for 2025 in his 2018 State of the State address (New York State 2018). The governor highlighted the importance of energy efficiency in the areas of employment, economic impacts, and climate emissions reduction. The PSC and the New York State Energy and Research Development Agency (NYSERDA) are directed to utilize a stakeholder process to determine new efficiency targets by April 22, 2018.

Washington State

Regional resource planning in the Northwest is driven by the Northwest Power and Conservation Council (NWPCC), which was established by Congress in 1980 to develop a 20-year integrated resource plan covering four states (Idaho, Oregon, Washington, and western Montana). The council’s most recent energy plan calls for the development of 12,300 GWh of energy efficiency over a six-year period in the preferred resource strategy (NWPCC 2016). Only the Bonneville Power Administration, a federal power marketing agency, is legally required to acquire resources consistent with the council’s plan. However the resource development of both publicly owned and investor-owned utilities is strongly influenced by these plans. All four of the northwestern state commissions, including the Washington Utilities and Transportation Commission (WUTC), require investor-owned utilities to follow an integrated resource planning process similar to the NWPCC’s.

The WUTC's IRP process works in conjunction with the state's requirement that utilities include all cost-effective, reliable, and feasible available conservation resources in developing mandatory energy efficiency targets and in their resource mix. Within the transmission planning portion of the IRP, utilities must conduct a comparative evaluation of energy supply resources and improvements in conservation (Washington State Legislature 2017). However the transmission planning requirements within the IRP process are limited, and the IRP does not currently include requirements for distribution planning.

In 2016, the WUTC opened a regulatory proceeding to address potential changes to the IRP process in consideration of increasing penetration of DERs and modernizing the grid. The WUTC posed questions related to both energy conservation inclusion practices and the locational and temporal granularity of T&D system planning.³¹ The document posed the following questions related to these issues:

- Should the commission consider requiring requests for proposals (RFPs) for energy conservation when a resource need is identified, as is required for other resources? What planning cycle should it work on (in conjunction with the IRP, or a biennial conservation planning cycle)?
- Should the commission implement avoided-cost reporting requirements, and can calculations be standardized?
- Is full-scale distribution system planning feasible? What new technologies exist to help modeling? To what degree are utilities planning for electric vehicles, changes in end use, distributed generation, etc. in distribution planning? (Washington UTC 2016)

An overarching theme of stakeholder comments from the docket is that increased transparency in resource planning and avoided-cost calculations would be beneficial. Utilities stated they are planning for DERs within T&D planning processes but are not required to report on distribution plans and do not provide any specified level of detail within IRPs. Without distribution plans being made available to the public, it is difficult to know how utilities are valuing DERs in that context. In public comments, utilities have recognized the benefits of granular locational and temporal resource valuation. Avista and Puget Sound Energy both state they use sub-hourly data for valuation but note the high time and financial cost of granular distribution system planning (Avista 2016; PSE 2016).

Tacoma Power incorporates targeted voltage optimization practices as a part of its energy efficiency portfolio (Tacoma Power 2017). A budget for substation upgrades is incorporated into the utility's annual T&D system planning process. Three or four substations undergo voltage optimization in order to meet a portion of the targeted efficiency goals. This process

³¹ More recently, the WUTC proposed additional questions related to avoided-cost methodologies and the Public Utility Regulatory Policies Act (PURPA). However these apply only to generating facilities and not to demand-side resources.

is driven both by energy efficiency targets and by the engineering benefits of voltage optimization for system reliability (Tacoma Power 2017). Substations are chosen on the basis of technical feasibility, age of equipment, and technical measurement and verification requirements that load be balanced across different phases of the system. Adding voltage optimization technologies to older equipment that is already being upgraded adds little marginal cost, and thus these substations are addressed first. Additionally, some substations with modern voltage controls only need to be outfitted with communications technologies to enable a greater level of control. This targeted voltage optimization has resulted in first-year savings of 0.7 aMW from six substations (Mark Pigman, Tacoma Power, pers. comm., November 21, 2017).

Oregon

Pacific Power is piloting a screening tool to evaluate solar, energy storage and demand-side management opportunities relative to traditional opportunities within transmission and distribution planning (Pacific Power 2017). The tool evaluates load shapes, affected customers, and costs.³² This contributes to the company's decision making for targeted energy efficiency projects in constrained areas and is used in the company's 10-year capital planning process. The tool is a DER alternatives template that uses inputs such as hourly facility load data, annual solar data, and cost estimates for demand response solutions. In conjunction, the company plans to invest in advanced substation metering systems at locations with limited or no communication availability and to ensure that all the substation meters are enabled with remote communication capabilities to integrate with an automated data collection and management system.

In 2017 PacifiCorp, in collaboration with Energy Trust of Oregon, began implementing targeted customer-sited energy efficiency technologies to "understand and track whether these technologies have the ability to improve system operation during specific locational peak hours, with the possibility of deferring the need for system upgrades" (Pacific Power 2017). The current pilot program, which is still in its early stages, targets the North Santiam Canyon area with increased marketing and outreach for existing Energy Trust programs. The stated goals of the pilot are to:

- Measure and quantify the peak demand reduction that can be achieved through energy efficiency offerings in the identified geographic area.
- Document and evaluate the effectiveness of replicable targeted energy efficiency program design that can be rapidly deployed in targeted areas to reduce energy and peak demand at no additional cost.
- Develop processes for design and deployment whereby Pacific Power and Energy Trust staff take coordinated actions in support of the pilot project related to marketing, program delivery, and measurement of impacts.

³² For more information, see Pacific Power's *Smart Grid Oregon Annual Report*, edocs.puc.state.or.us/efdocs/HAQ/um1667haq11754.pdf.

- Determine what, if any, changes to existing program offerings and/or new offerings might make targeted deployment more effective (Pacific Power 2017).

This and future projects will help to validate the effectiveness of the DER screening tool and determine whether energy efficiency can improve system operations during specific locational peak hours. The utility states that “where feasible and cost-effective, DER solutions are expected to supplant traditional solutions for implementation” (Pacific Power 2017). Specifically, Pacific Power wants to evaluate the potential of energy efficiency for deferring traditional T&D system investments, looking particularly at the time needed for deployment and whether that may be accelerated. Later in the report, we discuss the Bonneville Power Administration’s non-wires alternatives program and an example of a deferred transmission project in Oregon led by BPA.

Minnesota

There are several policy and regulatory processes underway in Minnesota related to distributed resource planning, system planning, and the role of energy efficiency. In 2014, the Great Plains Institute and the Center for Energy and Environment convened multiple stakeholders including Xcel Energy to begin the e21 Initiative. The initiative aims to develop a new framework for utility regulation “that better aligns how utilities earn revenue with public policy goals, new customer expectations, and the changing technology landscape” (Christensen and Nordstrom 2014).

In 2015, the Minnesota Public Utilities Commission initiated a proceeding to consider grid modernization policies, with an emphasis on distribution system planning (Minnesota PUC 2016). As part of that docket, commissioners requested a report on integrated distribution planning. The report, prepared by ICF, recommended a phased approach (referred to as “walk-jog-run”) to the integration of DERs as DER adoption rates increase (De Martini 2016.) In a filing in response to the commission’s April 2017 comment period notice on distribution system planning efforts, Xcel Energy agreed with the ICF report, noting that the planning processes will need to evolve along with the degree of integration of DERs (Xcel Energy 2017b).

Minnesota state law requires Xcel to identify needed investments to modernize the transmission and distribution system by increasing energy conservation opportunities and through other means. Specifically, this includes investments to “facilitate communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies” (MN Statutes 2017).

Part of Xcel’s annual distribution system planning process is an analysis and solution identification phase. This includes investigation of alternatives to meet forecast load growth using location-specific studies. The process covers DER penetration expectations but does not explicitly consider energy efficiency programs. In the most recent Xcel distribution grid modernization report filed with the Minnesota PUC, there is an analysis of alternatives of mitigation strategies for feeders with constrained hosting capacity. However there is no mention of energy efficiency or conservation in the report, despite the state law that

specifically mentions increasing conservation opportunities. The part of the report related to DER focuses on assessing hosting capacity to accommodate the growth of distributed solar generation (Xcel Energy 2016).

Xcel is working with the Minnesota Center for Energy and Environment (CEE) on a multiyear research project to identify sites and opportunities for geotargeting energy efficiency, demand response, storage, and behind-the-meter distributed generation (Jenny Edwards, Center for Energy and Environment, pers. comm., December 13, 2017). The study is funded through the Minnesota state legislature.

Connecticut

The Connecticut General Statute mandates that distribution companies “shall determine whether demand-side management would be more cost-effective in meeting any demand for electricity for which the increase in capacity is proposed” (CT General Statute 2012). However Eversource, the state’s largest electric utility, has not had an instance of using targeted conservation and load management (C&LM) to defer capacity additions under its distribution system planning requirements. In a 2014 report, Eversource explained that the amount of available C&LM was insufficient for the required capacity additions and that C&LM does not contribute to increased reliability, voltage control, or grid modernization (CL&P 2014). The company accounts for energy efficiency in distribution planning within the load forecast rather than as a resource for meeting specific project needs (CL&P 2014).

The use of DSM resources within the distribution system is influenced by the process for evaluating these resources. Eversource annually reviews overloaded feeders through the Load Estimating and Planning (LEAP) report. The report informs the company’s Distribution Substation Plan, and C&LM resources are considered during that process in accordance with the Connecticut General Statute. The distribution engineering team identifies overloaded feeders and requests quarterly reports from the C&LM team on the amount of efficiency in place at that feeder (CL&P 2014).

The procedure for evaluating DSM resources states that “to maximize the potential for success, the aggregate MW savings requested needs to be modest.” Specifically, this means aggregated savings of 1–5 MW over a period of about five years. Targeted DSM measures are considered for projects that are a minimum of three years from implementation. Interim requests for targeted DSM projects can be submitted throughout the year. Should the project meet these initial criteria, a feasibility assessment is conducted that considers market size, customer types, previously implemented C&LM measures, C&LM budget availability, the economy of the targeted area, PV penetration, and C&LM projects by third parties (CL&P 2014).

Eversource coordinates this process across departments and regionally. The process for distribution feeder upgrades is initiated by the asset management department, coordinated with the field engineering and load forecasting departments, and monitored by company management. Additionally, load forecasting for energy efficiency is coordinated with the ISO-NE Energy Efficiency Forecast Working Group. The working group provides input to the company’s forecasts and uses the results, as well as results from the regional capacity auctions, to inform the annual Regional System Plan for transmission (CL&P 2014).

Massachusetts

In 2008 the Green Communities Act was signed, requiring all Massachusetts energy efficiency program administrators to acquire “all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply” (Massachusetts Legislature 2008). In 2012 this effort was furthered when the Massachusetts Department of Public Utilities opened a docket to investigate grid modernization in the state. The order states that grid modernization will help to “improve the operational efficiency of the grid, particularly during peak times when the grid is most stressed and electricity is most expensive” and that it will “reduce transmission and distribution system operation, maintenance, and construction by reducing electricity demand at times of system peaks” (Massachusetts DPU 2012). The order also states that grid modernization will help to “enhance the success of the Massachusetts energy efficiency initiatives” (Massachusetts DPU 2012).

In 2014, the Department of Public Utilities opened another docket requiring utilities to file 10-year grid modernization plans, focusing largely on reducing the effects of outages, optimizing demand, integrating DERs, and improving workforce and asset management (Massachusetts DPU 2014). The future of the grid modernization proceedings has been complicated, however, by the approval of Eversource Massachusetts’s rate case, which included grid modernization elements, exempting them from cost-effectiveness testing (Massachusetts DPU 2018). The grid modernization proposal did not explicitly include efficiency measures, but this could have implications for the future, as efficiency programs in Massachusetts are currently evaluated using cost-effectiveness testing.

In 2015 a group of utilities and stakeholders commissioned an *Avoided Energy Supply Costs* report that provides information on avoided electricity and capacity costs for use by program administrators (Hornby et al. 2015). A 2016 addendum to the report provides avoided energy cost data using a four-hour peak (from 1 pm to 5 pm on summer weekdays, and from 5 pm to 9 pm on winter weekdays). The report uses locational pricing from the region’s forward capacity markets to determine peak and off-peak avoided electricity and capacity prices for use by program administrators (Massachusetts DPU 2016).³³ This report is being updated, and the new edition will be released in 2018.

In the 2016–2018 state efficiency plan, program administrators discuss exploring geotargeted efforts to reduce constraints or yield additional benefits for customers in the region (Mass Save 2015). National Grid Massachusetts began one such geotargeted pilot to defer the construction of an undersea cable to Nantucket Island. The company identified the island as an area of high load growth in the near term and moderate load growth in the long term. In 2015 the company began implementing a non-wires alternative to constructing the cable, which they had determined would be needed for reliable service by about 2029 (Transmission Hub 2016). In addition to demand response efforts, the company is using

³³ These values can be found in the Addendum to Massachusetts DPU 2016.

enhanced efficiency initiatives such as CVR, electric vehicle off-peak charging initiatives, and enhanced customer outreach and education to reduce load by almost 5 MW by the end of 2019. The overall goal is to reduce load by 18 MW over 17 years (Mass Save 2015).

Vermont

Vermont has a long history of non-wires alternatives. The state has a unique utility industry structure, with distribution utilities; one single transmission utility, Vermont Electric Power Company (VELCO); and an energy efficiency utility, Efficiency Vermont. An unsuccessful proposal for a non-wires project in the 1990s led the state to reconsider its evaluation of future projects. In 2003 state regulators began to outline distributed utility planning processes with a docket that required integrated resource plans every three years (Neme and Grevatt 2015). The order requires that the plans identify constraints that could be addressed through non-wires alternatives. This process was further clarified in 2005 with the passage of Act 61, which requires state officials to advocate for equal treatment of traditional and non-wires T&D investments with least-cost planning principles. Act 61 also required VELCO to file long-range transmission plans and allowed the Public Service Board to determine Efficiency Vermont's budget with T&D deferrals in mind (Neme and Grevatt 2015).

In 2007 the Vermont System Planning Committee (VSPC) was convened to bring together stakeholders to plan for electric system reliability and operations (VSPC 2017). The VSPC consists of members from utilities (including Efficiency Vermont), regulators, and environmental advocates (Neme and Grevatt 2015). Additional dockets require prescreening for non-wires alternatives for transmission projects, later extended to sub-transmission and distribution projects.³⁴ For identified constraints, the VSPC works with Efficiency Vermont (in consultation with the distribution utilities and VELCO) to determine the technical savings potentials and estimated costs. Findings are incorporated into each utility's reliability plan, which is filed with the Public Service Board (Neme and Grevatt 2015).³⁵

Projects are evaluated using societal and ratepayer impact cost-effectiveness testing. Costs considered can also include environmental externalities and "other significant relevant costs and benefits particular to the set of alternatives under consideration" (Vermont PUC 2017). Vermont's state energy plan was updated in 2016 and provides additional guidance on how utilities should consider increasing DER penetration in their IRPs. This includes updating load forecasts based on advanced metering data (Vermont DPS 2016).

³⁴ The screening tools for non-transmission, sub-transmission, and distribution projects can be found at vermontspc.com/about/key-documents.

³⁵ A schematic representation of this process can be found at vermontspc.com/library/document/download/599/GTPProcessMap_final2.pdf.

Rhode Island

Rhode Island began a Power Sector Transformation Initiative in 2017, based on direction from the governor to design a new regulatory framework for the electric utility industry (Raimondo 2017). The initiative is driven by policy goals for a cleaner and more diversified grid and includes work streams related to beneficial electrification, grid connectivity and functionality, distribution system planning, and the utility business model. In September 2017 the initiative outlined energy efficiency measures that utilities can implement to earn performance incentives as a part of the change to the utility business model.

Under law, utilities must pursue all cost-effective energy efficiency before pursuing additional supply resources. As a part of this process, distribution utilities must consider efficiency, distributed generation, demand response, combined heat and power, and renewables in their planning processes and must submit system reliability procurement plans (SRPs) reflecting these considerations (Rhode Island PUC 2017b). The Rhode Island Office of Energy Resources states, “These ‘non-wires alternatives’ (NWAs) . . . are targeted toward reducing the peak loads on the electricity grid” (Caputo 2017a). The law states that NWA “approaches may include, but are not limited to” the following:

- Strategic promotion of customer-side NWA through investment or outreach by the distribution company or a third party:
 - Least-cost procurement energy efficiency baseline services
 - Peak demand and geographically focused supplemental energy efficiency strategies
 - Distributed generation generally, including combined heat and power and renewable energy resources
 - Demand response
 - Direct load control
 - Energy storage
 - Electric vehicles
 - Controllable or dispatchable electric heat or cooling
 - Alternative metering and tariff options, including time-varying rates
- Distribution company investment in grid-side tools and technologies:
 - Energy storage
 - Voltage management
 - Communications systems
 - Grid-optimization technologies (Rhode Island PUC 2017b)

National Grid Rhode Island is implementing an SRP pilot to defer or eliminate the need for a new substation feeder in the Tiverton/Little Compton region of its service territory. This project, called “DemandLink,” has been ongoing since 2012 (Rhode Island OER 2017). The project aims to defer the need for a new substation—at an estimated cost of \$2.9 million—by achieving 1 MW of load relief through 2018 (Rhode Island OER 2017). The region is a largely residential area with a summer late-afternoon/evening peak. The project uses energy efficiency and demand response measures focused on reducing load from air-conditioning and water heating (National Grid 2017b). To date, the program has achieved most savings through energy efficiency measures, including Wi-Fi-enabled thermostats, plug devices, and window AC unit rebates. Participation in efficiency programs has climbed by more than

50% since 2012, thanks to increased marketing and recruitment. The company is now introducing additional measures targeted at heat pumps, water heaters, and efficient dryers, and it has issued a contract for battery storage through a request-for-proposals process. The project achieved more than 600 kW of cumulative savings through 2015 and is on track to meet the 1-MW goal by the end of 2017 (National Grid 2017a). Figure 8 shows annual and cumulative summer demand reductions since 2012.

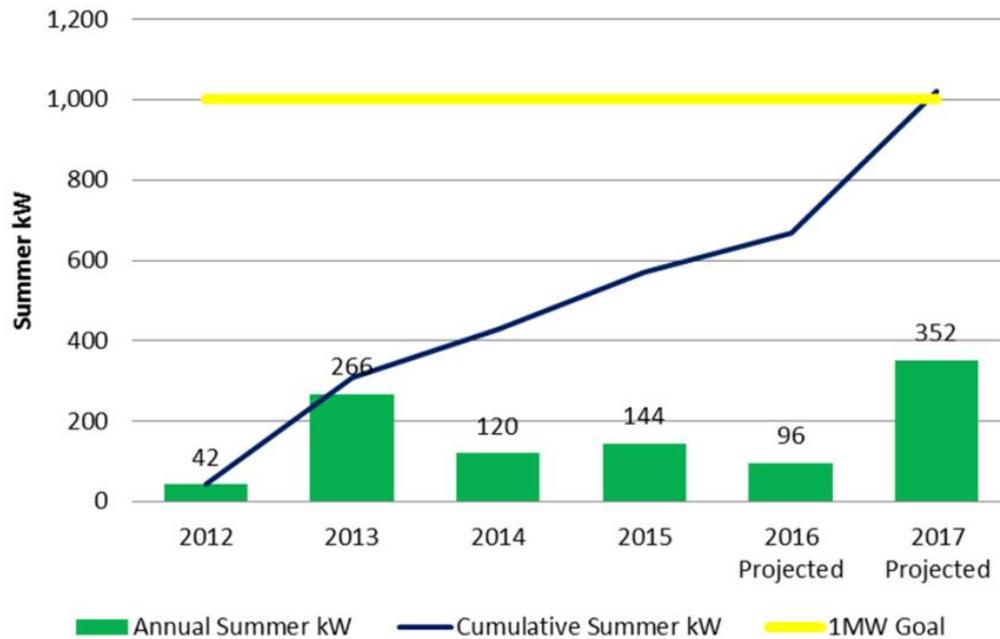


Figure 8. National Grid Rhode Island DemandLink savings. *Source:* National Grid 2016b.

The company also plans to implement, by 2020, a Rhode Island System Data Portal with a heat map to identify areas of high distribution system use and high demand growth, as well as areas where construction is physically constrained. This will be used to identify NWA opportunities (National Grid 2017a).

Valuing Energy Efficiency as a Distributed Resource: Time and Location

A key issue in moving forward with DRP is understanding the value of distributed resources that can help to defer more traditional distribution system investments. In the previous section, we outlined several state processes focused on the use of energy efficiency as a distributed resource in distribution system planning. Many of these state processes seek to integrate distribution system planning with other utility planning efforts, including efficiency program implementation and distributed generation interconnection.

In this section, we focus on methodological approaches to estimating the time and locational value of energy efficiency investments. First we explore recent research in this area, as well as some related efforts for valuing renewable energy that may be applicable. Then we examine a few state approaches to estimating time and locational value of energy efficiency to provide examples of methods and strategies.

IMPROVING VALUATION OF ENERGY SAVINGS

Regulators and utilities have traditionally measured the value of energy efficiency using several standardized benefit–cost tests, outlined in the *California Standard Practice Manual*.³⁶ These tests are intended to measure cost effectiveness of an energy efficiency measure or program from several perspectives, including those of participants, utilities, society at large, and utility ratepayers. Generally, the benefits in these tests are at the system level, including avoided cost of energy, generation capacity, T&D capacity, and others. The avoided costs of energy and generation capacity are often for marginal production units, which have been natural gas for most utilities (Baatz 2015). Some utilities calculate the avoided cost of energy using peak or off-peak estimates, but greater granularity is uncommon.

However the value of energy efficiency savings does vary by time of day and season. Energy savings during a utility-coincident peak are much more valuable than energy savings in off-peak periods. The savings also vary by end use, such as lighting or heating. For example, figure 9 shows illustrative hourly load profiles for three residential end uses.

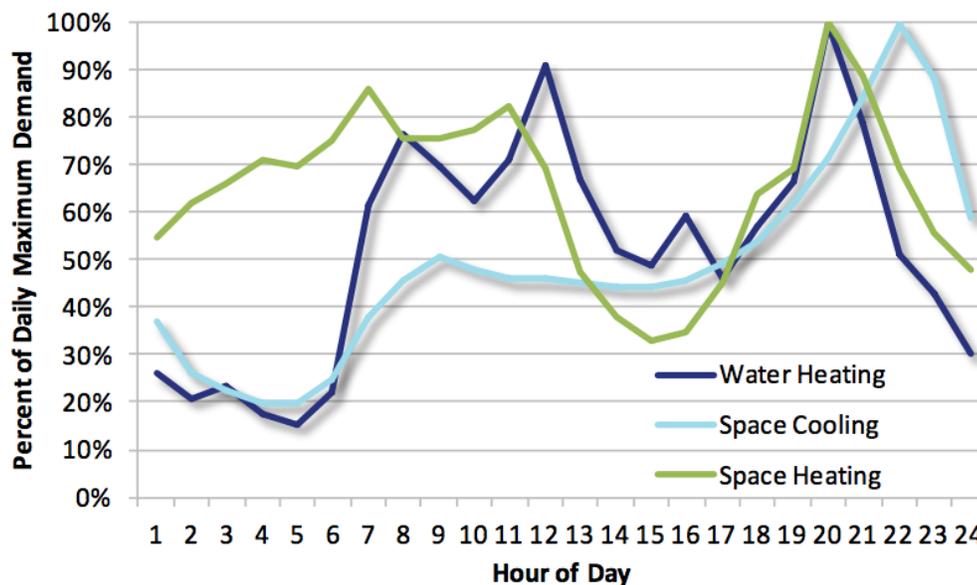


Figure 9. Illustrative hourly load profile for three residential end uses. *Source:* NWPC 2016.

The figure shows a morning and afternoon peak for all three end uses, but a much more defined afternoon peak for space cooling. The value of the energy savings for each of these three end uses will vary by hour and is dependent on system conditions. For example, if the system peak occurs at 8 pm, space heating and water heating will have a higher value than space cooling, based on the data presented in this figure. Benefits of peak demand reduction

³⁶ For more on these tests, see the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* at calmac.org/events/spm_9_20_02.pdf.

(as well as energy savings) materialize even if the overall levels of system efficiency, measured as a ratio of average load to peak load, nominally appear to decline.

The value of energy savings also varies by location. That is, energy prices and the value of demand reductions in avoiding T&D and generation capacity will depend on where those savings occur. A locational marginal price (LMP) is the marginal price for energy at the location (or node) where the energy is delivered or received (PJM 2017). An LMP is composed of the system energy price, the transmission congestion cost, and the cost of marginal line losses. Congestion costs are the result of a constrained transmission system forcing uneconomical dispatch of generating resources, resulting in higher-cost energy. These constraints are location specific, and energy savings have a higher value in congested areas. Figure 10 shows LMPs for the Midcontinent ISO market on September 7, 2011.

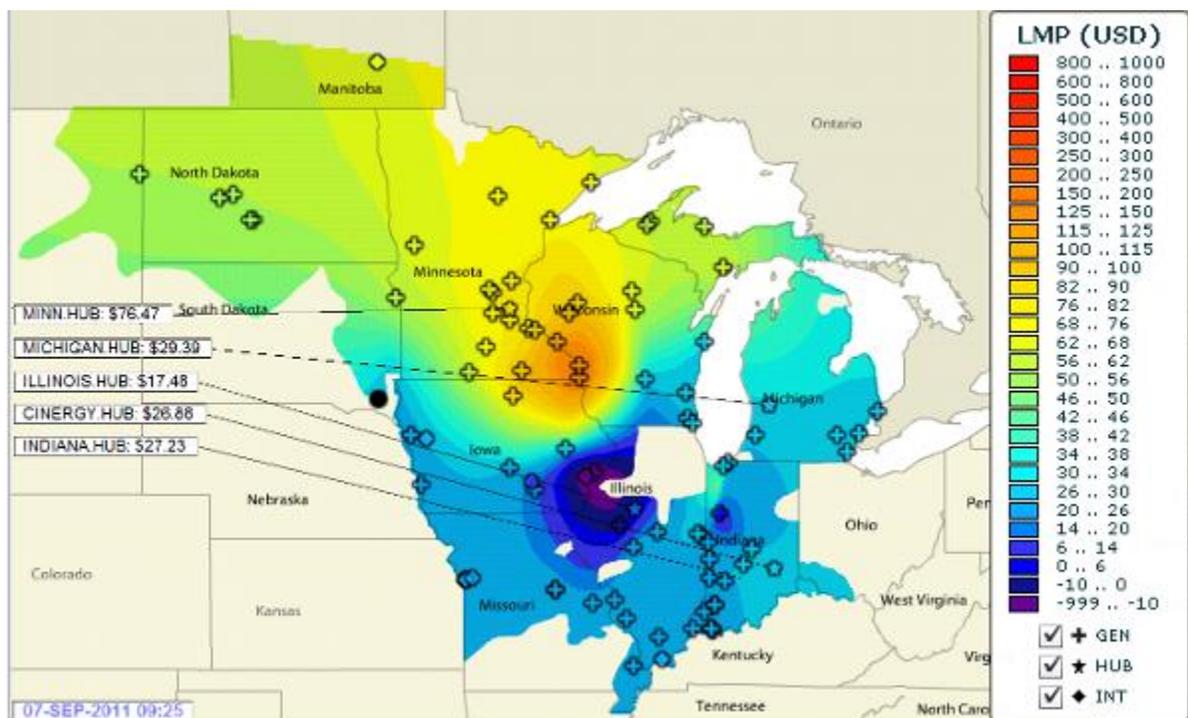


Figure 10. MISO real-time LMP on September 7, 2011 at 9:25 am. *Source:* EIA 2011.

This figure shows the differences in value at the wholesale or transmission level. The color differences denote changes in price for wholesale energy. At the time of this snapshot, prices were higher in Wisconsin than elsewhere in the MISO area, and prices ranged from negative to more than \$200 per MWh.

At a more granular level, the value of energy savings varies on the distribution system as well. Figure 11 shows an example of a distribution system. The colors represent potential constraints in future load scenarios, with red indicating areas where constraints are likely to arise soonest. These areas would have the highest locational value for distributed resources, determined by the characteristics of the specific distributed resource.

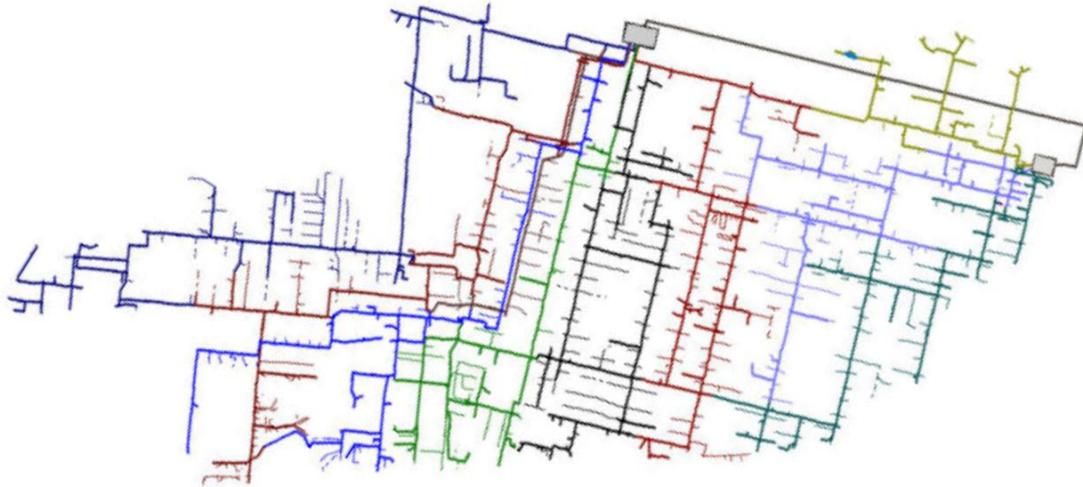


Figure 11. Sample distribution system. Red indicates areas where potential constraints exist. *Source: Eaton 2017.*

Estimates of avoided cost of T&D capacity are generally system-wide, based on average costs of new infrastructure.³⁷ For geographically targeted investments, such as the ConEd Brooklyn Queens Demand Management project, specific estimates were conducted to understand the potential costs of system upgrades. Several other utilities have completed similar estimates (Neme and Grevatt 2015). These specific estimates focus on the locational value of energy efficiency, often to defer or avoid construction of new distribution assets.

Much of the recent literature on time and locational value of DERs focuses on resources other than energy efficiency, such as PV solar and battery storage. While not specifically focused on energy efficiency, the studies suggest many useful approaches to determining the time and locational value of energy efficiency.

One potential advantage of energy efficiency when compared with other distributed resources is that energy efficiency does not require updates or modifications to the distribution system. A recent study evaluated the potential benefits of using DER to defer distribution system investments in ConEd and SCE service territories (Rogers 2016). The study showed, at least for these two systems, that while a moderate amount of available hosting capacity exists, infrastructure upgrades may be required to accommodate additional DER on the system. Energy efficiency deployment also does not require modifications to hosting capacity or other distribution infrastructure. Furthermore, energy efficiency can increase the hosting capacity of an area, allowing the installation of DER without increasing costs for new infrastructure to handle the new DER.

³⁷ See Baatz (2015) for more on utility methods of estimating avoided transmission and distribution capacity costs.

STATE AND UTILITY EXAMPLES

New York

Within the REV proceedings, the New York Department of Public Service (DPS) released a white paper outlining a methodology for conducting benefit–cost analysis (called the BCA Framework) of energy resources. The framework aims to build on the traditional cost-effectiveness tests used for energy efficiency portfolios, to create a more granular and accurate picture of the benefits a resource provides to the system. The methodology focuses on utility expenditures for the development of a distribution system platform, DER procurement through tariffs and competitive processes, and energy efficiency programs (New York DPS 2015b). As ordered in the framework, each utility must publish a BCA Handbook.³⁸ These are meant to clarify aspects of valuation specific to a utility’s territory or needs, to provide specific values for various resources, and to create an example portfolio with valuations included (New York DPS 2015b).

The framework outlines benefits and costs considered for different standard cost-effectiveness tests (rate impact measure, utility cost, and societal cost). Several of the benefits considered focus on time and location. Table 3 shows some of these benefits.

Table 3. Selected benefits under the New York REV BCA Framework

Benefit	Description
Avoided generation capacity (ICAP)	Calculated at the transmission level by approximating spot capacity auction market results based on forecast supply and demand curves. This does not adjust for forced outages (UCAP), as these adjustments do not change the ultimate resource clearing price. The BCA Framework notes that because the auctions take transmission constraints into account by creating zone-specific capacity prices, utilities should be careful not to double-count any avoided transmission capacity infrastructure costs.
Avoided energy (location-based marginal price, or LBMP)	Calculated using energy price forecasts from the wholesale energy market. This is the LBMP from the base case of the New York Independent System Operator’s Congestion Assessment and Resource Integration Study (CARIS). This study is conducted every two years and forecasts energy prices out to 20 years in 11 regional zones, based on areas of transmission congestion as well as specific resource proposals. The BCA Framework notes that avoided energy costs include costs for emissions compliance programs, transmission-level line loss costs, and transmission congestion costs that should not be double-counted toward other benefits. It also expresses that utilities should consider developing more granular methodology for calculating this benefit over time at the distribution level, for example down to the substation, feed, transformer, or customer level.

³⁸ An example of a utility BCA Handbook can be found at documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF0CC59D0-4E2F-4440-8E14-1DC07566BB94%7D.

Benefit	Description
Avoided transmission capacity infrastructure and operations and management (O&M)	Accounts for any additional benefits from avoided transmission capacity infrastructure and O&M not included in the avoided ICAP and avoided energy costs.
Avoided distribution capacity infrastructure	Calculated on the basis of the granular data utilities file with their Dynamic Load Management Filings with Modifications. The calculations include whether a load addition or reduction would trigger the need for additional infrastructure, based on the specific load and the equipment that serves it, the amount of available excess capacity, and the interconnection voltage.

New York's REV proceedings have also outlined a separate methodology for valuing resources as a replacement for traditional net energy metering valuation methodologies. The valuation process, called the "value stack," adds the value of multiple components of locational, temporal, and market value to come up with a single value for the resource. This includes the capacity value, the energy value, the carbon or environmental value, avoided distribution value, and other components. For now, this covers only generating resources and does not cover energy efficiency. However the goal is to apply this valuation methodology to all DERs with future orders (New York DPS 2016b). Current cost-effectiveness guidance for energy efficiency does not consider nonenergy impacts, with the exception of a \$15 carbon credit adder in relation to long-run avoided cost (Caputo 2017b).

Northwest Power and Conservation Council

The Northwest Power and Conservation Council considers the time value of conservation measures in regional power planning. Energy savings from specific measures are generally not uniform throughout the year. To consider these differences in the context of power planning, the NWPCC uses a peak capacity factor to determine the value of an energy efficiency measure or program during peak energy demand. NWPCC calculates the capacity factor as the peak savings in megawatts divided by the annual energy savings in average megawatts. The peak capacity factor for the energy efficiency measures considered in the most recent plan (the Seventh Power Plan) was 1.2 in the summer and 2.0 in the winter, showing the energy efficiency resources have a fairly significant impact on peak loads (NWPCC 2016). These values are then used to calculate the cost effectiveness of each measure for consideration in the power planning process.

This approach is an example of determining temporal value, but it does not capture differences in locational value. The NWPCC is currently engaged with stakeholders to update end-use load shape data for the region. This information will enhance the NWPCC resource planning process with a full data set of end-use load shapes for specific measures and building types for all 8,760 hours of the year. The data will further allow the NWPCC to estimate the full capacity value for energy efficiency.

Minnesota

Regulators required Xcel and other utilities to conduct a transmission and distribution avoided-cost study (Minnesota DOC 2016). For estimation of avoided T&D costs due to

energy efficiency, the utilities used the System Planning Method with Continuous Valuation. The Department of Commerce's Division of Energy Resources had recommended this system planning approach in its proposal filing of July 1, 2016 (MPUC 2016a). The DSM T&D study was submitted in July 2017 for Xcel, OtterTail Power, and Minnesota Power. The Commission ordered that the findings from this study be utilized beginning with the utilities' 2020 programs (Xcel Energy 2017a).

California

In California, the CPUC recommended an evaluation approach to assess the value of DERs in the context of the DRP process. The approach, known as locational net benefit analysis (LNBA), is based on a previously approved cost-effectiveness calculator modified to include location-specific values and additional avoided-cost components. The CPUC ordered the creation of a working group to assist utilities in demonstration pilots intended to implement the LNBA methodology. The working group was also expected to refine the methodology as needed. After completion of demonstration projects for the three investor-owned utilities, the working group concluded that the LNBA tool required further refinement before being used system-wide, but it may be used on a limited basis for DRP pilots.

Rhode Island

Projects in Rhode Island proposed under a utility's system reliability procurement plan (which must consider conservation resources) are evaluated using a new cost-effectiveness test called the Rhode Island Test. This test was put into place in 2017 as a way to capture the benefits of demand-side resources more fully than was possible with the traditional total resource cost (TRC) test (Rhode Island PUC 2017a). The new test includes carbon reduction values, which increase the net benefit calculation by about 65% for National Grid, as detailed below. The Rhode Island Test requires that NWAs compare the net-present-value benefit of deferring the traditional alternative over a set period of time, versus eliminating the project entirely with a net-present-value calculation of cost of the NWA. The benefit-cost analysis will also include "any other estimated benefits" (Rhode Island PUC 2017b). In addition to benefits such as avoided capacity costs, avoided ancillary costs, and avoided environmental externalities and compliance, the legislation states that other benefits may include "any site-specific, or option-specific benefits or costs directly attributable to the location of the project or the proposed alternatives" (Rhode Island PUC 2017b). These benefits must not already be accounted for in any other underlying programs such as the energy efficiency procurement plan. Utilities may propose a shareholder incentive for performance under the system reliability procurement plan. Annual reports and analyses of projects should include information on DER penetration and trends (Rhode Island PUC 2017b).

National Grid Rhode Island considered two new additional benefits in the cost-effectiveness analysis of its targeted DemandLink project under the Rhode Island Test outline. These are greenhouse gas reduction values and economic benefits (job creation, bill savings resulting in more spending on goods and services, and rate increases that reduce spending on goods and services) (National Grid 2017b). For 2018, this results in a benefit-cost ratio of 2.8, in comparison with 1.7 under the traditional TRC test (National Grid 2017c).

DISCUSSION

In part as a reaction to limitations in the traditional California tests, a new National Standard Practice Manual (NSPM) for cost-effectiveness testing was recently developed.³⁹ The NSPM provides an updated and more comprehensive and flexible approach for benefit–cost analysis, and one that can be better utilized for the assessment of energy efficiency as a distributed resource. Essentially, the NSPM provides a framework and process that a state can use to develop its own specifically tailored cost-effectiveness test for energy efficiency and other distributed resources. The aforementioned Rhode Island Test is a good example of a test that is compatible with this framework, and each of the state examples profiled above illustrate a tailored approach that could be developed under the NSPM.

Our state examples show that several states are working toward improving valuation of energy efficiency through consideration of time and locational value. The processes outlined earlier in this report also demonstrate that the primary commonalities among states pursuing this path are integration of planning processes and the development of screening tools to model various scenarios of DER integration. The state examples we reviewed further show that distributed resource planning and integrated distribution system approaches are in early stages of development. While there are several ongoing pilot projects and successful examples of utilities relying on efficiency as a distributed resource, these efforts too are still in early stages and should continue to be monitored for emerging best practices.

Not only are analytical approaches different among states, but regulatory approaches vary as well. For example, New York is seeking to develop a market-based distribution system platform, while California is continuing a central planning effort led by the CPUC and CEC.

Geotargeting

In previous sections of this report, we highlighted regulatory processes and policies and valuation methods for energy efficiency as a distributed resource. Here we discuss examples of targeted energy efficiency programs used to defer or avoid the need for new distribution or transmission infrastructure, also known as geotargeting. Utilities and system planners using energy efficiency to defer or avoid construction of new distribution and transmission assets is not a new practice. Several utilities, including National Grid New York, National Grid Rhode Island, and Consolidated Edison in New York, have engaged in this process for several years.

A 2015 study of geotargeting highlighted several examples of utilities using geographically targeted energy efficiency to avoid or defer T&D infrastructure investments (Neme and

³⁹ For more information on the National Standard Practice Manual, see nationalefficiencyscreening.org/national-standard-practice-manual/.

Grevatt 2015). The study found that energy efficiency can cost effectively defer some T&D investments. The efficiency programs leading to deferral were described as active or passive. Active deferral is defined as using geographically targeted energy efficiency programs to intentionally defer or avoid locational investments. Passive programs are defined as system-wide energy efficiency that is implemented for broader purposes but that also avoids or defers T&D needs as a secondary effect (Neme and Grevatt 2015). Most utilities consider the avoided T&D capacity benefits described as passive deferral, but very few use energy efficiency for active deferral.

In our data request, we asked utilities if they were engaged in using energy efficiency or other geographically targeted demand reductions to delay or avoid the need for distribution or transmission upgrades. While 16 utilities reported they did use geotargeting, there was wide variation in how extensively they used it. Several are in early stages and have not actually avoided system upgrades to date. For example, the Sacramento Municipal Utility District is studying how to reliability use geotargeted energy efficiency to defer investments. Virginia Electric and Power Company (Dominion Virginia and North Carolina Power) responded yes to the question and elaborated that the capability to geotarget load reductions is part of its Air Conditioner Cycling Program and Distributed Generation Programs. In the event that the capability is needed, it can be activated to reduce loads to accommodate geographically specific circumstances in areas that may be in need of system upgrades. The ability to target geographic areas was included in the design of the two programs to be able to provide load reductions in response to local, as opposed to system-wide, needs (M. Hubbard, manager of energy conservation, Dominion Virginia, pers. comm., October 30, 2017).

Several utilities are actively engaged in various stages of investigating geotargeting. Public Service Company of Colorado has proposed to the Colorado PUC a regulatory framework for geotargeting. The framework includes guidelines for the methodology, implementation, and evaluation of targeted DSM. In particular, the framework would authorize geotargeted customers to get higher rebates than other customers (Beaman 2017). Energy Trust of Oregon is doing a pilot project of geographically targeted energy efficiency in the Pacific Power service territory, at a location that the utility identified in its T&D planning. Arizona Public Service filed proposals for two programs that use geographically targeted demand reductions to delay or avoid the need for distribution or transmission upgrades, as part of its 2017 DSM implementation plan. The proposals are awaiting approval.

Utilities have implemented geotargeting to achieve cost-effective demand reductions. Here we provide specific examples for both distribution and transmission.

DISTRIBUTION

The best-known geotargeting effort is the ConEd Brooklyn Queens Demand Management (BQDM) project. The effort aims to reduce peak load by 52 MW in the designated BQDM territory by the summer of 2018 to defer an approximately \$1 billion traditional investment including building a new area substation (ConEd 2017b; ConEd 2014). Figure 12 shows the covered area.



Figure 12. BQDM neighborhoods. *Source:* ConEd 2017a.

In 2014 ConEd identified two substations in Brooklyn (serving customers in both Brooklyn and Queens) with sub-transmission feeders that would become overloaded by increased demand for electricity in the area in the future (ConEd 2014). The utility proposed to meet increased demand through targeted energy efficiency measures, demand management, distributed generation, and other solutions such as microgrids. The project specifically aims to achieve 41 MW of demand reduction with customer-side applications and the remaining 11 MW with nontraditional utility-side applications (ConEd 2014).

The project was originally projected to cost \$150 million for customer-side applications and \$50 million for utility-side applications; ConEd will recover these costs over 10 years through rates. To date, ConEd has spent \$56.86 million, with a remaining budget of about \$140 million. The project has achieved about 36 MW of peak load reduction, largely through the implementation of energy efficiency measures (ConEd 2017b). ConEd has obtained 19 MW of operational load relief from energy efficiency upgrades in the residential, commercial, and public building sectors (ConEd 2017b). It garnered these savings through additional incentives in the company's commercial direct-install and multifamily energy efficiency programs on the customer side, and voltage optimization and DER storage systems on the utility side. Outside of these programs, ConEd expects to achieve more than 2.0 MW of demand reduction by leveraging existing combined heat and power programs being run by NYSERDA (Subramony 2017). Figure 13 shows the 2018 planned BQDM resource portfolio throughout a peak summer day, with the greatest amount of relief needed during the period from 8 pm to midnight, as demand peaks around 10 pm (ConEd 2017b).

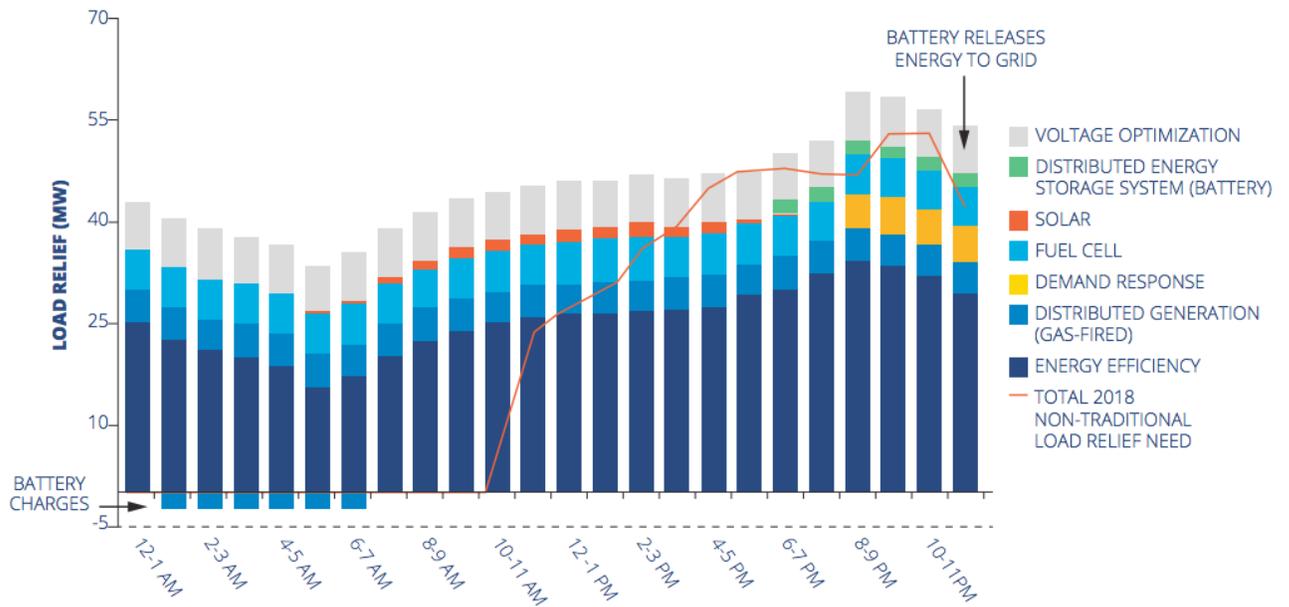


Figure 13. BQDM 2018 resource portfolio. *Source: SEPA 2017a.*

Within the energy efficiency portion of this portfolio, ConEd makes use of a variety of energy-efficient technologies and services. These include customer- and utility-side solutions. Table 4 shows more detail on BQDM program activity.

Table 4. BQDM energy efficiency activities as of Q3 2017

BQDM program	Design stage	Deployment stage
Customer-side solutions		
Commercial direct install		•
Multifamily energy efficiency		•
Residential energy efficiency program(s)		•
Bring your own thermostat adder (BYOT)		•
Virtual buildings audits		•
New York City Housing Authority		•
Direct customer activity		•
Dynamic resource auction		•
Fuel cells		•
City agency solutions		•
Commercial refrigeration		•
Combined heat and power		•
Battery storage		•

BQDM program	Design stage	Deployment stage
Utility-side solutions		
Distributed energy storage system		•
Distributed generation (DC-link)	On hold	
Voltage optimization		•
Solar photovoltaic pilot	On hold	
Fuel cell	On hold	

Source: ConEd 2017b

ConEd plans to continue active programs, implement CHP solutions, and work with other city agencies to achieve additional demand reduction, such as through interior and exterior lighting and HVAC measures at city agency facilities (ConEd 2017b). To date, 6,400 small business, 1,560 multifamily buildings, and 12,768 family residences are participating in the program. Energy efficiency measures in the small business and multifamily sectors have resulted in annual energy reduction of more than 157 GWh (ConEd 2017b).

TRANSMISSION

Utilities have also used energy efficiency and other demand-side solutions to avoid or defer transmission upgrades. In 2009 the Bonneville Power Administration (BPA) proposed the I-5 Corridor Reinforcement Project, a new transmission project along the I-5 corridor of Oregon and Washington. This project would create a 500-kilovolt, 79-mile line and associated substations at an estimated cost of \$722 million (Pesanti 2017). Based on long-term load forecasts, it was expected to meet both existing and new transmission service requests at a time of growing population and electricity demand in the region (BPA 2009).

In 2010 BPA commissioned a firm to evaluate non-wires alternatives to the I-5 project, including transmission system upgrades, demand response, and energy efficiency measures. The preliminary screening found that NWAs (including energy efficiency, demand response, and re-dispatching of generators to the north and south of the constrained path) would be able to defer the project for up to five years but would not be able to eliminate the need for the project (E3 2011). Figure 14 shows the NWA program peak savings and the annual requirement for peak savings.

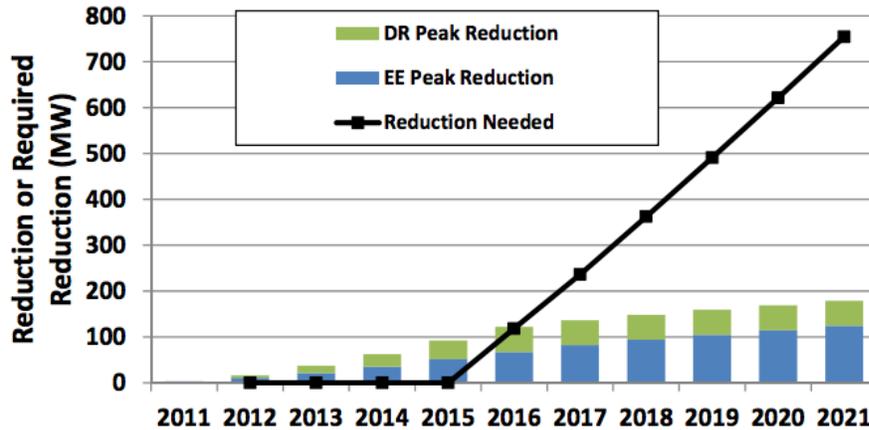


Figure 14. 2011 comparison of NWA program peak savings and annual requirements for peak savings. *Source:* E3 2011.

In a second assessment of non-wires alternatives, the consultant, Energy and Environmental Economics (E3), evaluated conservation potential using the estimated potential of cost-effective efficiency peak load reduction from utility programs. The identified potential estimate was conservative and therefore was considered to be incremental to current efficiency captured in the load forecast. E3 applied transmission deferral costs associated with this project as a benefit. Figure 15 shows measures considered in the potential study.

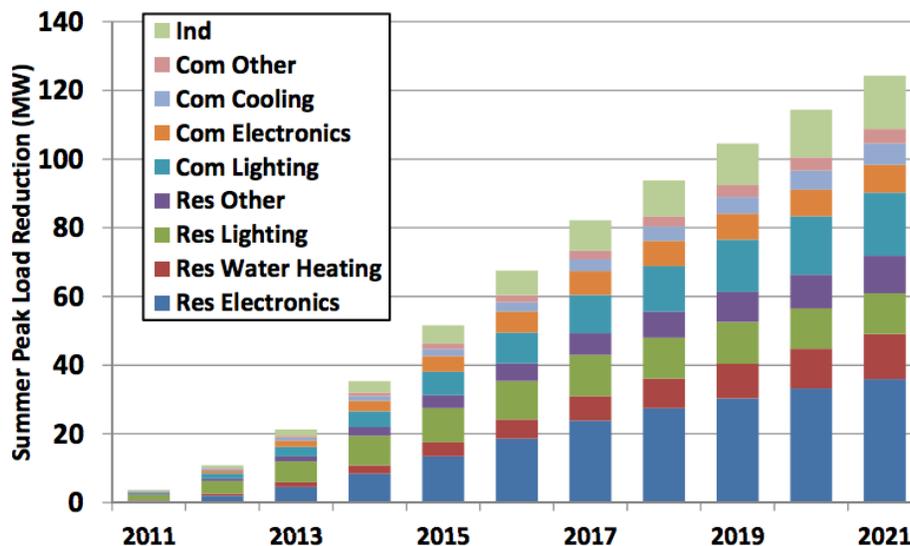


Figure 15. Greater Portland area cost-effective incremental summer peak demand reduction potential from conservation (2011–2021). *Source:* E3 2011.

BPA continued to solicit comments and evaluate alternatives through the development and release of a final environmental impact statement in 2016. In May 2017, the administrator and CEO of BPA signed a letter notifying the public of the decision to cancel the I-5 project (BPA 2017b). An independent review panel found that the project would provide capacity in excess of that required for regional reliability. In the letter, the administrator cited slower

load growth than in previous studies, changing risk tolerance levels, and the modernizing of grid technologies to help meet demand in congested areas. Specifically, the letter stated that BPA was considering “non-wires measures to manage generation and loads to reduce peak congestion” and that non-wires measures would launch in the summer (BPA 2017b). While the project was not being canceled solely due to the implementation of energy efficiency and demand response, demand-side measures were cited as a reason for slowing load growth and as a critical piece of the solution to meet reliability and customer needs.

BPA wants to ensure that it adequately considers non-wires solutions before investing in transmission projects. The organization recently moved the non-wires team from the energy efficiency department to the corporate level in order to better institutionalize non-wires alternatives across the functions of the organization (Neme and Grevatt 2015). This has led to additional non-wires projects and pilots (BPA 2017a).

Evaluating Efficiency as a Distributed Resource

In traditional energy efficiency program evaluation, third-party evaluators estimate annual savings impacts at the system level by using deemed values for installed measures.⁴⁰ This approach focuses on annual energy savings, with less focus on the savings differences based on time and location of measures. Many of these evaluations also estimate peak demand savings.

Utilities and system planners relying on energy efficiency as a distributed resource to defer or avoid specific infrastructure may require more time- and location-specific measurement and verification (M&V) methods. Advanced M&V, sometimes called M&V 2.0, has capabilities and tools that have the potential to address these needs. While advanced M&V is in the early stages of development, with much work still needed to develop and test protocols, practitioners are beginning to use it to estimate energy and demand savings.

In contrast to system-level evaluation, advanced M&V methods can make use of more detailed data for time and location. Advanced M&V comprises (1) automated analytics that can provide ongoing, near-real-time savings estimates, and (2) increased data granularity in terms of frequency, volume, or end-use detail (Franconi et al. 2017). To estimate time-specific energy savings, advanced M&V uses interval meter data with intervals as short as five minutes, whereas M&V 1.0 methods are generally based on monthly energy consumption data. To measure locational differences, the newer approaches base energy savings estimates on actual changes in measured energy consumption at the customer meter, taking into account where the metered energy savings are within the distribution system.

⁴⁰ Deemed values are often based on measured savings for a sample of participating customers. These deemed values are then used for a few years until a new study is conducted using measured savings from a new sample of participating customers.

The automated aspect begins with the capability to collect interval meter data remotely. Automated M&V measures metered energy consumption from large numbers of customers in energy efficiency programs (the treatment group) and compares their usage with that of nonparticipant customers (the control group) to develop savings estimates (NEEP 2016).

Meter-based measurement and verification methods can—and often do—help to validate and build confidence in energy savings estimates, and therefore in the time- and location-specific valuation of the savings. The evaluation results provide inputs into the valuation for the next planning cycle. The NWPCC’s efforts to engage stakeholders to update end-use load shape data, mentioned earlier in this report, is one example of evaluation results improving valuation in planning. Current practice uses spot metering and billing data. In contrast, advanced M&V technologies that enable the development of a full data set of end-use load shapes by measure and building type contribute to the quality of capacity savings estimates.⁴¹ In the *Energy Efficiency Market Procurement Recommendations Report* to the New York Public Service Commission, the Clean Energy Advisory Council writes that “a meter-based M&V standard for energy efficiency projects could likewise build credibility in the expected energy savings, thereby enabling more participants, more liquidity, and lower prices in an EEC [energy efficiency credit] program” (EPPM 2017). Another meter-based standard influencing both program design and evaluation practices is California Assembly Bill 802, which allows for normalized metered energy consumption (California Assembly 2015).

One of the primary purposes of demand response programs is to reduce peak demand during days and times when it is needed, such as on hot summer days when demand is high due to air-conditioning loads. Evaluators have developed EM&V methods to estimate demand reductions at specific times and locations for demand response programs. The evaluation method of the Dominion Virginia Power Residential Air Conditioner Cycling Program is one example of using evaluation results to measure the peak demand savings of a program. Within the Dominion program, residential customers are paid an incentive to allow the utility to cycle air-conditioning and heat pump systems during peak load events. Demand impacts are estimated using 30-minute interval data from advanced metering infrastructure (AMI) meters. Evaluators use regression models to compare the program participants’ energy consumption during peak load events with that of nonparticipants. The comparison groups are selected using statistical sampling techniques so that the two groups will be similar except for their participation in the program. Evaluators compare the actual customer load measured during peak events with a baseline reference load to determine peak savings (Dominion Virginia Power 2016).

While the promise of M&V 2.0 is substantial, there are a number of challenges to be addressed before it can reach its potential to support distributed resource planning efforts. One challenge is the availability of AMI. Advanced metering is important because it

⁴¹ See Light and Garth (2017) for an analysis of determinants of the quality of capacity savings estimates.

provides system planners and evaluators with more granular data and increases the speed of feedback, which helps with planning and delivering DERs. As of 2016, of 151 million electric meters, 70.8 million were AMI, meaning that more than half of all customer meters did not have two-way capability (EIA 2016). Another challenge is that M&V 2.0 delivers whole-building results around which some methodological and protocol issues are still under discussion.

Conclusions and Recommendations

Our national review of distribution planning processes shows that the majority of utilities are currently not using energy efficiency as a distribution system resource. States like California and New York are far ahead of most others in this area, but several additional states are in the early stages of implementing regulatory structures and valuation approaches for DERs within grid modernization proceedings. These proceedings are intended to adequately consider distributed resources as reliable alternatives to new infrastructure to meet growing demand. Several demonstration projects provide proof of concept that this can be done in a cost-effective way to avoid or defer construction of new distribution and transmission infrastructure.

Our review also documents advancements in estimating the value of energy efficiency in different times and at different locations. The improvements to valuation methods will allow system planners to use efficiency to cost-effectively reduce demand in areas and times of highest value. These valuation methods are also being used in combination with other enhanced planning tools to optimize least-cost or otherwise cost-effective planning processes. Finally, the early demonstration projects in New York and California document the high value of using energy efficiency as a distributed resource. The ConEd BQDM and SCE Preferred Resources Pilot projects have both relied heavily on energy efficiency as a highly cost-effective resource to meet their demand reduction targets.

These projects, along with several other ongoing pilots, offer evidence and guidance to other utilities and regulators early in the process of determining how to best utilize distributed resources in distribution system planning. As these planning processes become more integrated, these enhancements and lessons learned will also be critical for improvements to integrated resource and transmission system planning.

As a result of the research presented in this report, we offer the following recommendations for regulators and utilities:

Continue to enhance and improve valuation methods to capture the full value of energy efficiency. This includes improvements to measuring the time and locational value of energy efficiency, as well as improving load forecasting methods and approaches. These improvements will lead to more economically efficient outcomes in system planning.

Coordinate planning processes—including distribution, transmission, generation/resource, and energy efficiency—to improve outcomes. As the electric utility system continues to evolve, the work of these various departments will become more interdependent, requiring coordination during system planning. The inclusion of energy efficiency planning with other processes will also optimize cost-effective outcomes throughout the system.

Consider the National Standard Practice Manual as a tool for regulators and utilities to measure the cost effectiveness of energy efficiency investments. The NSPM provides an updated, more comprehensive, and more flexible approach for benefit–cost analysis than traditional California tests, one that can be better utilized for the assessment of energy efficiency as a distributed resource. Essentially, the NSPM provides a framework and process for a state to develop its own specifically tailored cost-effectiveness test for energy efficiency, which may also be applied to other DERs.

Use geotargeted energy efficiency as a complement to broad-scale or system-wide efficiency, not as a replacement. Our research shows energy efficiency can be used to actively defer specific distribution and transmission assets. Improved valuation methods also document that the value of efficiency is higher during specific times and in particular locations. While this can be used to enhance planning efforts, it is important to bear in mind that efficiency still provides significant value as a reliable system-wide resource, capable of reducing demand across an entire service territory and during all time periods.

The implementation of these recommendations should allow a more efficient planning process, specifically among distribution utilities and energy efficiency planners, along with other organizations. The improvement of valuation methods will also strengthen planning processes and rate design approaches in the distribution system. Ongoing efforts in leading states provide several frameworks for optimizing planning processes to incorporate energy efficiency and other distributed resources.

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Appendix A. Definitions of Distributed Energy Resources

The following are examples of definitions of DERs from across the United States, as collected by the National Association of Regulatory Utility Commissioners (NARUC) and from state-specific resources (NARUC 2016).

California Public Utilities Code. “Distributed resources’ means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.”

New York Public Service Commission (PSC). “Distributed Energy Resources (DER) . . . include Energy Efficiency (EE), Demand Response (DR), and Distributed Generation (DG).”

Lawrence Berkeley National Laboratory (LBNL). “Distributed Energy Resources (DERs) include clean and renewable distributed generation systems (such as high-efficiency combined heat and power and solar photovoltaic systems), distributed storage, demand response and energy efficiency. Plug-in electric vehicles are considered as part of distributed storage. While not included in the formal definition of DER, [the] report also considers the implications of customer back-up generation on grid operations.”

Electric Power Research Institute (EPRI). “Distributed Energy Resources (DER) are electricity supply sources that fulfill the first criterion, and one of the second, third or fourth criteria: 1. Interconnected to the electric grid, in an approved manner, at or below IEEE medium voltage (69 kV). 2. Generate electricity using any primary fuel source. 3. Store energy and can supply electricity to the grid from that reservoir. 4. Involve load changes undertaken by end-use (retail) customers specifically in response to price or other inducements or arrangements.”

Electric Reliability Council of Texas (ERCOT). “A generation or energy storage technology, or combination of generation and/or energy storage technologies, that is interconnected at or below 60kW, operates in parallel with the distribution system, and is capable of injecting electrical energy onto the distribution system.”

National Association of Regulatory Utility Commissioners (NARUC). “A DER is a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE).”

Minnesota Public Utilities Commission (PUC). “DER is described as supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or the utility side of the electric meter. Includes efficiency (end use efficiency), distributed generation (solar PV, combined heat and power, small wind), distributed flexibility and storage (demand

response, electric vehicles, thermal storage, battery storage), and distributed intelligence (information and control technologies that support system integration)" (De Martini 2016).

Smart Electric Power Alliance (SEPA). "Distributed energy resources are physical, as well as virtual, assets that are deployed across the distribution grid, typically close to load, which can be used individually or in aggregate to provide value to the grid, individual customers, or both" (SEPA 2017b).

Appendix B. Utility Data Request Responses

Table B1. Utility responses regarding energy efficiency in transmission and distribution system planning

Utility	State	Utility conducts T&D system planning	T&D system plans filed publicly	Energy efficiency considered in planning process	Energy efficiency used to avoid T&D system upgrades	Coordination between energy efficiency and T&D planning groups
Alaska Electric Light & Power	AK	yes	no	yes	yes	yes
Ameren	MO	yes	no	yes	no	no
Arizona Public Service	AZ	yes	yes	yes	yes	yes
Centerpoint	TX	yes	no			
Commonwealth Edison	IL	yes	no	yes	no	no
Consolidated Edison	NY	yes	yes	yes	yes	yes
Dominion Energy	VA, NC	yes	yes	yes	yes	yes
Energy Trust of Oregon ¹	OR	N/A		yes	yes	yes
Eversource	CT	yes	yes	yes	yes	yes
Indianapolis Power & Light	IN	yes	no	yes	no	yes
National Grid	MA	yes	yes	yes	no	no
National Grid	RI	yes	yes		yes	no
National Grid	NY	yes	yes	yes	yes	no
Northern Indiana Public Service Company	IN	yes	yes	yes	yes	yes
Northern States Power (Xcel)	MN	yes	no	no	no	no
Northern States Power (Xcel)	WI	yes	no	no	no	no
Northwestern Energy	MT	yes	yes	no	no	no
Oklahoma Gas & Electric	OK	yes	no	no	no	no
PPL	PA	yes	yes	no	no	no
Public Service Colorado (Xcel)	CO	yes	no	no	yes	no

Utility	State	Utility conducts T&D system planning	T&D system plans filed publicly	Energy efficiency considered in planning process	Energy efficiency used to avoid T&D system upgrades	Coordination between energy efficiency and T&D planning groups
Sacramento Municipal Utility District	CA	yes	no	yes	yes	yes
San Diego Gas & Electric	CA	yes	yes	yes	yes	yes
Seattle City Light	WA	yes	yes	yes	no	yes
Southern California Edison	CA	yes	yes	yes	yes	yes
Southwestern Public Service (Xcel)	TX, NM	yes	no	no	no	no
Tacoma Power	WA	yes	no		yes	yes
Tennessee Valley Authority	TN, KY, VA, NC, GA, AL	yes	yes	yes	yes	yes
Vectren	IN	yes	no		no	no
We Energies	WI	yes	yes	yes	no	no
Number of positive responses		29	15	18	15	14

Blank cells indicate no response. ¹ Energy Trust of Oregon is an independent program administrator and does not own or operate distribution; utilities conduct distribution and transmission planning in Oregon.

Appendix C. Utility Distribution System Planning Data Request

1. Does your utility conduct distribution and transmission system planning? If yes, are these plans filed publicly with a state regulator? If yes, please provide the docket or case number where these plans may be located.
2. Regarding distribution and transmission planning, are energy efficiency programs or other customer-sited demand reductions considered in these planning processes? If yes, please provide any documentation or docket/case numbers providing more detailed information on how efficiency is included in this process.
3. Is your utility currently engaged in using energy efficiency or other geographically targeted demand reductions to delay or avoid the need for distribution or transmission upgrades? If yes, please provide any documentation or docket/case numbers providing more detailed information on these efforts.
4. Is there currently coordination between the energy efficiency and distribution/transmission planning groups within your utility? If yes, please describe the coordination and structure, or provide any documentation or docket/case numbers providing more detailed information on these efforts.