Keeping the Lights On: Energy Efficiency and Electric System Reliability

Grace Relf, Dan York, and Martin Kushler

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529 14th Street NW, Suite 600, Washington, DC 20045
Phone: (202) 507-4000 • Twitter: @ACEEEDC
Facebook.com/myACEEE • aceee.org

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About the Authors

Grace Relf is a research analyst for ACEEE’s Utilities and Policy programs, focusing on utility-sector energy efficiency programs and initiatives such as rate design and utility resource planning. Prior to joining ACEEE, she worked at Karbone, Inc. as an energy and environmental markets analyst and broker, specializing in carbon, emissions, and biofuel credit markets. Grace earned a master of public administration in environmental science and policy from Columbia University in 2015. She also holds an honors bachelor of science with distinction in energy and environmental policy and an honors bachelor of arts in French from the University of Delaware.

Dan York is an ACEEE senior fellow engaged primarily in utilities and local policy research and technical assistance. He has extensive experience in tracking and analyzing trends and emerging issues in utility sector energy efficiency programs. Dan has a bachelor’s degree in mechanical engineering from the University of Minnesota. His master of science and PhD degrees, from the University of Wisconsin–Madison, are both in land resources with an emphasis in energy analysis and policy.

Martin Kushler is a senior fellow in ACEEE's Utilities Program. He advises on national studies of utility-sector energy efficiency policies and programs, and provides technical assistance to help advance efficiency policies and programs in many states. He previously directed the Utilities Program for 10 years. Prior to joining ACEEE, Marty was the supervisor of evaluation at the Michigan Public Service Commission. He earned a bachelor of arts, a master of arts, and a PhD from Michigan State University.

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Executive Summary

Energy efficiency has grown as an electric utility system resource since the 1970s, with a proven record of reducing electric system power demand and overall electricity consumption. In doing so, efficiency provides multiple benefits to both customers and utilities. The improved reliability of the electric utility grid is among these benefits.

Grid reliability depends on a balance between supply and demand, as well as on effective grid operation. Federal and state agencies have increased their scrutiny of grid reliability as a result of changes in the electricity industry and growing concerns about security, aging infrastructure, and adequate supplies. Ensuring the reliability of the bulk power system focuses on preventing uncontrolled loss of customer load over large areas. Historically much of the emphasis in assuring reliability has been on resource adequacy (sufficient supply resources), but industry leaders, regulators, and operators increasingly recognize that reliability depends on a mix of market approaches, technology enhancements, regulatory/operating rules, and demand-side management. Many tools and resources are now available to balance demand and supply and thus ensure bulk power system reliability.

Recent extreme weather events have also raised concerns about grid resilience, which is closely related to reliability. The focus of recent federal regulatory proceedings, resilience involves responding to severe threats to the grid and recovering from outages when they occur. While recent discussions of resilience have focused on electric supply issues, most outages occur at the distribution level and have little to do with generation availability or failure.

Grid Impacts of Energy Efficiency

Energy efficiency supports system reliability by reducing demand, which effectively increases the reserve margin and thereby offsets generation that otherwise would be needed. Efficiency can also function like a transmission and distribution (T&D) resource, reducing throughput needs on installed equipment. These reductions can delay, reduce, or offset the need for traditional grid infrastructure upgrades to handle increased power flows. In this way, energy efficiency can play a role alongside other distributed energy resources (DERs) to meet T&D system needs and maintain reliability.

Energy efficiency benefits the electric power system by reducing electricity consumption and peak loads in a reliable, predictable, long-term, and measurable way. The value of the demand reduction achieved by customer energy efficiency programs is a function of the amount, timing, and location of the savings, as well as the utility system's physical and operational characteristics such as the timing of peak demand (summer or winter and time of day), load factor, and reserve margin. Energy efficiency improvements that reduce load during times of electric system peaks are more valuable from a grid perspective than those that occur during off-peak periods. Similarly, additional value accrues to investments located in areas experiencing T&D constraints. The ways in which these reliability contributions are being valued can be difficult to find, vary across the country, and differ based on goals and market structure. Nonetheless, there are indications that these reliability benefits can be substantial.

The recent trend of adding connected and smart features to energy-efficient technologies promises additional reliability benefits. For example, ENERGY STAR©-certified smart thermostats save on average 8% of heating and cooling bills and can also function as a demand response resource. Optional connected criteria for ENERGY STAR electric vehicle supply equipment can enable two-way response to grid conditions, rapidly accepting power from or discharging it back to the grid.

Conservation voltage reduction/volt VAR optimization offers another opportunity in the efficiency-demand-response nexus and provides another grid management tool for system operators.

Efficiency's Grid Resilience Benefits

Energy efficiency can also increase the grid's resilience. Energy-efficient buildings and facilities have a lower power demand than less efficient ones. Coupled with smart controls, this lower power demand can provide a softer start to restore system power after an outage. This puts less stress on the system and facilitates a smoother, quicker restoration of power. In addition, homes and other buildings that have more-efficient building shells can help residents survive during an outage by creating more livable indoor conditions for longer periods. Similarly, critical infrastructure such as water pumping systems should be designed to be as energy efficient as possible to enable operation on limited or backup power resources.

Combined heat and power (CHP) systems are one type of energy efficiency resource with significant resilience value—at least for those customers served by the CHP equipment. These systems typically adapt quickly to changing loads and can disconnect from the surrounding grid if necessary. They also often rely on natural gas, which is provided through pipelines that remain operational during some types of grid failures. During and after Hurricane Sandy, for example, CHP enabled a number of critical infrastructure and other facilities to continue operation when the electric system went down.

Efficiency's Reliability Benefits

The history of utility energy efficiency programs provides clear examples of efficiency's reliability benefits, including

- Reducing system demand to offset otherwise needed generation, effectively increasing system reserve margins and supporting system operation
- Using geographically targeted energy efficiency as a non-wires alternative (NWA) to address T&D system needs and relieve grid congestion

Energy efficiency clearly demonstrated its ability to support electric system operation during California's 2000–2001 electricity crisis. During this time period, California and a number of other states experienced unprecedented electric system crises resulting from various market factors and system problems. In California, energy efficiency and demand management played key roles in addressing the system's reliability challenges during this crisis, and the state's utility programs achieved energy and demand savings that prevented rolling outages. California achieved this dramatic result because it was able to quickly ramp up existing programs to achieve high savings.

Today, four grid operators or regional transmission organizations (RTOs) allow energy efficiency to be included in capacity auctions for system resources. Efficiency suppliers (such as utilities, third-party administrators, and other energy efficiency companies) can submit bids into capacity auctions that would obligate them to reduce demand as specified as an alternative to bids for additional supply resources. To participate in the auctions, efficiency resources are subject to additional evaluation, measurement, and verification (EM&V) requirements on top of the reliability requirements for all resources.

The clearing prices for energy efficiency give it a market-based value as a capacity resource capable of contributing to grid reliability. In the New England capacity auction, efficiency is assigned an availability score of 100%, meaning that it is available 100% of the time, conclusively demonstrating its dependability and ability to support grid reliability.[1]

Using energy efficiency as a geographically targeted solution for relieving stress on T&D systems is a clear example of efficiency's reliability benefits. This includes the use of NWAs to avoid or defer more costly upgrades to T&D networks. NWAs can be highly cost-effective options; a prominent recent example is ConEdison's Brooklyn-Queens Demand Management Project. This project is using targeted energy efficiency to achieve a portion of the 52 MW of demand reduction needed to defer approximately $1 billion of new traditional distribution infrastructure.[2] Bonneville Power Administration, Energy Trust of Oregon, and Vermont also offer examples of NWA analyses and projects.

CHALLENGES

Despite the clear reliability benefits that energy efficiency can yield, such benefits are generally not adequately quantified and used for electric system planning and screening of efficiency measures and programs. Converting efficiency's acknowledged reliability benefits into dollar values is complex as it requires knowledge of the efficiency resource's time and locational value. Calculating that value is challenging because peak demand in the bulk power system often differs from the individual peaks of distribution feeders, and the load shape of energy savings from an energy-efficient technology may differ from the less-efficient technology it is replacing.

Given the complexity of quantifying energy efficiency's reliability benefits, various approaches exist depending on the nature of the need for the resource. For bulk system impacts, approaches include valuing reliability in cost–benefit analyses used to screen efficiency measures and programs (including for utility integrated resource planning) and capacity pricing options for ISO regions. Deferral of T&D investments requires a much more complex analysis. This involves developing scenarios that combine DERs to reduce

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[1] ISO New England, *ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit for the 2017/2018 Capacity Commitment Period* (Holyoke: ISO-NE, 2014). www.iso-ne.com/static-assets/documents/genrtion_resrcs/reports/nepool_oc_review/2014/icr_2017_2018_report_final.pdf.

[2] Consolidated Edison, *BQDM Quarterly Expenditures & Program Report Q1 2018* (Albany: New York Public Service Commission, 2018). documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B26094758-11F9-48AE-A6C6-5836916493BF%7D.

congestion, and then selecting the best bundle from the scenarios based on a combination of risk reduction and cost effectiveness.

Current efforts provide few examples of quantifying energy efficiency's reliability or related risk-reduction benefits. Some utilities and planning authorities have assigned values ranging from just over $1/MWh to $20/MWh for factors that account for reliability-related benefits of energy efficiency, including risk reduction and avoided T&D capital and operating expenditures.

Energy efficiency is typically undervalued for resource screening, analysis, and evaluation if its reliability benefits are excluded. The result is overinvestment in generation and T&D resources, and higher system costs that ultimately are borne by utility customers.

OPPORTUNITIES

Changes in technologies, markets, and regulations are creating new opportunities for energy efficiency to play a greater role in grid reliability. Integrated energy efficiency and demand response programs are growing and will give utilities and grid operators additional options for grid management and reliability. These programs can provide a broader set of benefits and greater customer value than standalone programs.

Recent Federal Energy Regulatory Commission (FERC) proceedings have yielded new insights and directions for addressing reliability and resilience concerns. Grid operators have agreed that ensuring reliability and resilience is not a matter of maintaining uneconomic power plants, but instead is a matter of minimizing disruptions to poles and wires. Grid operators, regulators, and other stakeholders should include energy efficiency as part of this national dialogue on maintaining grid reliability and resilience.

To capture the full range of energy efficiency's reliability benefits, we recommend the following:

- Integrated resource planning should fully value the reliability benefits of energy efficiency in the analysis and selection of resources.
- Evaluating non-wires (including targeted energy efficiency) alternatives to T&D investments should become standard practice.
- Capacity auctions and wholesale power markets should include efficiency as a resource. Those already doing so should expand efficiency resource additions as markets grow and efficiency provides a least-cost, reliable solution. Those currently not doing so should make efficiency eligible to participate in their markets.
- Energy efficiency and related customer program administrators should explore integrated efficiency/demand response programs. In doing so, they should also ensure that the rapid rise of smart technologies can deliver both efficiency and demand response benefits along with corresponding grid reliability benefits.
- Programs should target critical loads to make them energy efficient and thereby improve resilience.

The utility industry is undergoing fundamental transformations and requires significant investments to modernize the grid. Energy efficiency is a proven resource that is integral to such transformation and modernization. To capture the value of energy efficiency as a grid resource requires acknowledging and quantifying the full set of benefits that it provides. One such benefit is reliability. Clear examples demonstrate that this value, while not easy to quantify, can be substantial. We recommend that future efforts seek to quantify these impacts for specific systems or portions of systems based on some of the emerging methods we discuss.

Introduction

Providing safe, reliable, and affordable electricity has long been the fundamental objective of electric utilities. It is the foundation of utility regulation, and it guides the decisions that utility regulators make. The current US electric utility system provides electricity with high reliability, meaning that outages (loss of electric service) are rare. Most of the outages that occur are weather related and tend to occur on distribution networks in smaller, localized neighborhoods. Outages affecting larger areas—entire states or regions—are very infrequent.

The reliability of our electric grid is critical to today's economy. Our homes, businesses, industries, and communications all depend on electricity supplied by the grid. Outages, when they do occur, dramatically demonstrate this dependence and the high value associated with system reliability. Such occurrences also test the resilience of our electric utility systems. Reliability and resilience are closely related and overlap somewhat. Grid *reliability* depends on assuring a balance between supply and demand, along with effective grid operation. *Resilience* refers to the grid's ability to withstand and recover from extreme weather or other threats.[3] Resilience entails anticipating, preventing, minimizing, and responding to severe threats to the grid and recovering from outages when they occur. We discuss these concepts in more detail later in this report.

The bulk power system's reliability is undergoing increased scrutiny due to many changes underway in the electricity industry and growing concerns about security and aging infrastructure. In September 2017, the US Department of Energy (DOE) submitted a proposed rule to the Federal Energy Regulatory Commission (FERC) to provide payments to electricity generators that maintain 90-day fuel reserves onsite to improve the US power grid's resilience and reliability (DOE 2017). FERC rejected the proposal, but the issue and investigation, including subsequent FERC proceedings, demonstrated the high priority given to reliability (FERC 2018).

Reliability is a growing concern in part due to the rapid increase in variable energy resources, primarily wind and solar generation. Such resources have increased in the United States from approximately 10 GW in 2008 to approximately 100 GW in 2016 (NERC 2018). Integrating a rapidly growing number of variable energy resources will require "significant changes to traditional system planning and operation methods," according to one grid expert (Segal 2017—NERC UVIG Fall Technical Workshop).

The aging infrastructure of a grid built up over the past century is another major issue directly affecting reliability. Much of the existing grid technology and equipment needs to be replaced and upgraded. Antiquated and worn-out grid elements are vulnerable to malfunctions, which reduces reliability.

A majority of customer outages are caused by routine distribution-level events, such as isolated equipment failure, animals disturbing distribution lines and equipment, and

[3] Resilience also can be viewed from a customer perspective—that is, the customer's ability to withstand and recover from loss of grid power—but this report focuses on the reliability and resilience of the grid itself.

common weather events such as local storms. The duration of customer outages, however, is driven largely by the severity of weather events. Severe weather events are increasing, and have been linked to a 5–10% growth in the total number of customer outage minutes annually (Silverstein, Gramlich, and Goggin 2018).

Research Objectives and Methodology

This report examines energy efficiency's role in supporting electric power system reliability. While improving reliability is commonly cited as a benefit of increased end-use efficiency throughout our economy, it is difficult to quantify and apply in resource planning and decision making. We posit that this leads to undervaluation of energy efficiency as a viable, credible system resource in some states. Failure to adequately capture this value in cost-effectiveness screening means that fewer measures and programs will pass such tests. The overall result is that less energy efficiency is implemented than is cost effective; this, in turn, can lead to more costly investments in generation resources and/or transmission and distribution (T&D) infrastructure.

Our primary research objective here is to examine industry experience to date in documenting and quantifying the benefits of energy efficiency programs in maintaining and enhancing system reliability. Our overall research question was: *What is the role and value of energy efficiency for grid reliability?* We also address additional research questions, including

- How can the reliability benefits of energy efficiency be quantified?
- What data are needed to quantify and evaluate these reliability benefits?
- Are there examples available where the reliability benefits of energy efficiency have been quantified?
- If so, what values have been estimated for these benefits?
- Are energy efficiency's reliability benefits currently being included in cost-effectiveness screening? How? Do particular states show leadership in this area?
- Which types of energy efficiency measures and programs are the most effective at increasing reliability?
- Are there examples of energy efficiency programs and pilots that have specified reliability objectives?

To answer these questions, we conducted a literature review and interviewed a small group of experts on energy efficiency, resource planning, energy markets, and grid operations.

Our analysis addresses reliability and energy efficiency from different perspectives, including crisis conditions, grid congestion relief, energy efficiency measure screening, program evaluation, wholesale power capacity markets, and emerging technologies. We provide examples of how energy efficiency is being included as a system resource in grid operations, resource planning, and wholesale power markets. We also discuss how new technologies and the transformations underway in the electric utility industry are creating new opportunities for energy efficiency to play a larger role as a utility resource. This is particularly true for smart technologies, which can both improve energy efficiency and provide demand response capabilities. While we acknowledge the potential benefits of integrated programs that use smart technologies for both energy efficiency and demand response objectives, our focus here is energy efficiency. Demand response can be a valuable asset for grid reliability and resilience, but it is generally outside the scope of this report.

What Is Grid Reliability?

FERC oversees grid operations and regulates wholesale power markets. It has approved more than 100 mandatory reliability standards for the grid and has certified the North American Electric Reliability Corporation (NERC) as the entity responsible for ensuring reliability of the bulk power grid. NERC's role in the electricity industry is to improve the bulk power system's reliability and security in the United States, Canada, and part of Mexico. NERC is responsible for enforcing compliance with mandatory reliability standards and ensuring that regional transmission organizations (RTOs) and utilities make necessary upgrades to the bulk power system. The RTOs that actually manage and operate regional power markets in much of the United States are required to comply with NERC reliability standards (FERC 2016).

Grid reliability extends from regional bulk power markets to the distribution level—the local networks that provide power to individual customers. Electric utilities are responsible for the reliability of distribution systems—essentially the lines and equipment that bring power from transmission systems and associated bulk power markets to our homes, businesses, institutions, and industries. Most outages occur on distribution systems due to weather-related damage (Silverstein, Gramlich, and Goggin 2018).

For utilities and grid operators, *reliability* has a specific meaning—that is, the probability of the loss of load and system adequacy in serving load. NERC defines a reliable bulk power system as "one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the amount of available electricity" (Prince et al. 2015). According to NERC, reliability has two key aspects:

- *Adequacy.* Adequacy means having sufficient resources to meet a given level of demand with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. *Resources* here refer to a combination of electricity generating and transmission facilities that produce and deliver electricity, in combination with demand response programs, behind-the-meter generation, storage, and loads that collectively represent net demand for electricity. Maintaining adequacy requires system operators and planners to account for scheduled and reasonably expected unscheduled outages of equipment, while managing both supply and demand resources to maintain a constant balance between overall supply and demand.
- *Security.* For decades, NERC and the bulk power industry have defined *system security* from an operational perspective—that is, the ability of the bulk power system to withstand sudden, unexpected disturbances, such as short circuits or unanticipated loss of system elements due to natural causes. More recently, a second perspective on security has gained prominence—that is, the need to protect the grid from disturbances caused by humans launching physical or cyber attacks. In this report, we focus on the operational definition of security.

Resource adequacy is clearly critical to assure reliability, but there are other critical factors in maintaining grid reliability.[4] These other ancillary services include voltage support, frequency support, and load and resource balancing.[5]

Reliability of the bulk power system focuses on preventing uncontrolled loss of customer load over large areas. Historically much of the focus for assuring reliability has been on resource adequacy—that is, sufficient supply resources—but there is growing recognition among industry leaders, regulators, and operators that assuring reliability requires a mix of market approaches, technology enhancements, demand-side management, and regulatory/operating rules that facilitate more effective grid operation.

Resilience, which is closely related to reliability, is becoming a key focus of regulators, utilities, local governments, and grid operators, especially in the wake of recent devastating hurricanes and other extreme weather events that caused widespread power outages. Silverstein, Gramlich, and Goggin (2018) examine electric system resilience using a customer-focused framework. They observe that resilience is an element of reliability---consistent with a recent FERC order, which defines resilience as the "ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the ability to anticipate, absorb, adapt to, and/or rapidly recover from such an event" (FERC 2018, p. 13). A study of resilience by the National Academies of Sciences, Engineering, and Medicine echoes this perspective, noting that a resilient system is one that "acknowledges that such outages can occur, prepares to deal with them, minimizes their impact when they occur, is able to restore service quickly, and draws lessons from the experience to improve performance in the future" (NASEM 2017, p. 10).

While much recent reliability concern focuses on the adequacy of generation resources, Silverstein, Gramlich, and Goggin (2018) note that most outages are due to distribution-level problems. Thus, from a customer perspective, the framework to best assess the cost effectiveness of reliability or resilience measures is to estimate their impact on the probability of outage frequency, magnitude, and duration, and customer survivability.

As we discuss later, energy efficiency can contribute to strategies to improve system resilience in several ways. Energy efficiency itself plays no role in helping to maintain electric service once an outage occurs, with the exception of combined heat and power (CHP) systems that serve individual customers.[6] CHP is an energy-efficient way to produce both electricity and heat for building use, and it can often keep operating even without

[4] *Resource adequacy* is a common industry term that means having sufficient power supplies available to meet system demand.

[5] For additional information on electricity reliability, see research by Lawrence Berkeley National Lab's Electricity Markets and Policy group at emp.lbl.gov/research/electricity-reliability.

[6] Although other distributed energy resources—such as solar electric systems that include battery storage—could maintain electric service for individual customers as well, these generation resources are outside the scope of this report.

power from the electric grid (Chittum and Relf 2018). In this report, we focus on end-use energy efficiency and its role for reliability.

How Energy Efficiency Affects Electric System Reliability

Energy efficiency can affect electric utility system reliability in many ways. To examine this issue, it is useful to first identify *how* energy efficiency affects electricity demand on the grid.

In the broadest sense, improved energy efficiency in the US economy has had a significant impact on electricity demand, which has flattened out in recent years after decades of steady growth. However the focus of this report is how energy efficiency programs can be affirmatively used as a resource to affect the electricity demand of utility systems, whether individual service territories and distribution systems or regional networks (RTOs/ISOs).

Improving energy efficiency reduces the energy used for a given application or system. In aggregate, many such improvements also reduce electric power demand (as measured in watts or multiples of watts—or, at the system level, typically in megawatts). The exact amount of the reduction is a function of the type of energy efficiency improvement and its load shape. The demand reduction's value to the electric system is a function of amount, timing, and location. It also has a multiplicative effect; less energy used by energy-efficient components lowers the amount of energy losses in the T&D networks.

Energy efficiency can affect electric system reliability at two basic levels: (1) by offsetting supply resources at the electric-generation level; and (2) by reducing demand at the transmission and/or distribution system level. While any particular energy efficiency installation will have load impacts affecting resource needs for both supply and distribution, it is useful to understand how energy efficiency contributes to reliability at each of those levels.

Supply Impacts

An important component of electric system reliability is having sufficient electric-generation capability to meet system demand (as well as an adequate reserve margin—typically, about 15%). For at least the past few decades, energy efficiency has been recognized as a legitimate utility system resource that contributes to the electric system's ability to meet system demand and essentially be an energy efficiency power plant. Energy efficiency benefits the electric power system by reducing electricity consumption and peak loads in a reliable, predictable, and measurable manner according to the load shape of the specific end use affected.

Energy savings that result from energy efficiency improvements replace the power that a generation resource would otherwise have to produce. This yields a grid resource that can contribute to system reliability in the same way as adding generation capacity. To the extent that the energy efficiency resource is cheaper than adding new electric generation, energy efficiency helps the electric system achieve and maintain supply reliability at less cost.

Technologies and Programs Best Suited to Provide Reliability Benefits

Different energy efficiency measures and programs have different demand impacts. These impacts are a function of time-of-use—be it daily, weekly, or seasonally. Daily power demand follows fairly expected patterns: it is low during night-time hours, then quickly builds to peak demand during the daytime (or early evening for systems with high photovoltaic penetration). Other differences in peak demands are a function of seasonal variations in device and system use. Some technologies have the greatest demand impact during the summer cooling season, while others impact winter heating. As we now discuss, these impacts are analogous to the key types of generation resources.

Baseload Impacts

Energy efficiency's impacts on the grid can be likened to the principal types of electricity generation resources: baseload, peaking, and intermediate load. Baseload generation plants are those that run for extended periods (from weeks to a month or more). They generally shut down only for maintenance or repairs. Historically, these are large coal, hydropower, natural gas, and nuclear plants that generate electricity at low costs. Some types of energy efficiency reduce electricity use for long, uninterrupted periods. An example is energy-efficient lighting in commercial spaces that operate 24/7, such as hospitals and some retail and grocery stores. When aggregated across thousands of customers, both residential and commercial lighting efficiency programs generally yield savings akin to baseload generation even without 24/7 operation; in many applications, lighting is still a consistent contributor to the electric demand profile. For example, a program to promote compact fluorescent light bulbs (CFLs) provides savings throughout the day in both winter and summer (Neme and Grevatt 2015). Figure 1 shows this effect.

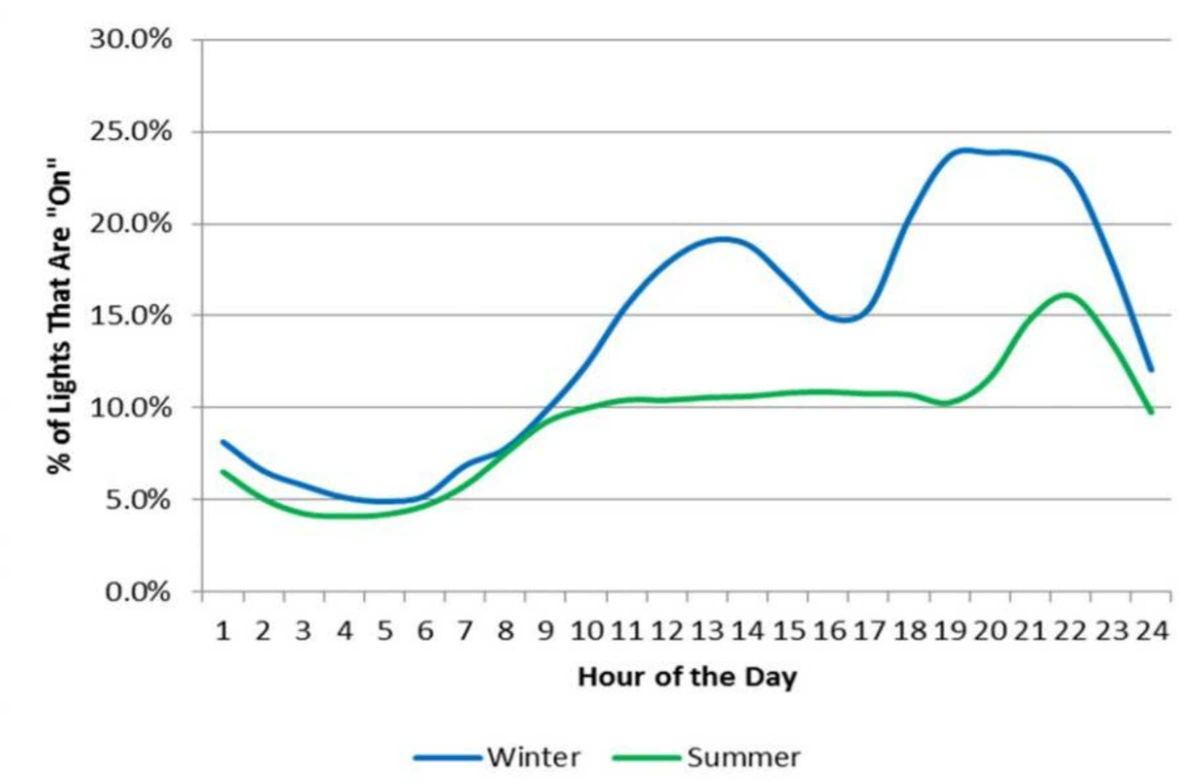

Figure 1. Average hourly CFL usage patterns. *Source:* Neme and Grevatt 2015.

Other programs that save energy continuously can also be considered baseload resources. A key example is data centers, which are high energy users that operate continuously and have a high demand for very reliable power. In 2014, US data centers accounted for approximately 1.8% of total electricity consumption; energy efficiency measures and energy management strategies can provide continuous savings and reduce energy consumption in data centers by 20–40% (DOE 2018).

Aggregated over a larger scale, energy efficiency can offset the need for baseload resources. In New England, for example, energy efficiency is expected to play a large role in the resource mix, resulting in energy savings of about 11,500 GWh by 2026 (ISO NE 2018a). Figure 2 shows the effect of energy savings on the projected annual energy use for ISO New England (ISO NE).

Figure 2. Projected annual energy use in ISO NE with and without energy efficiency. *Source:* ISO NE 2018a.

Although these savings include all sorts of resources, a significant amount is baseload. This load forecast informs the amount of capacity procured by ISO NE and the ISO's power and transmission system and reliability planning. In this context, energy efficiency can offset the need for additional traditional baseload resources. We discuss this further in the capacity markets section.

Peak-Demand Impacts

In contrast to baseload resources, peaking power plants are used for short periods when power demand on the system is highest. For many electric utility systems, this occurs on hot summer days when there is high demand for air-conditioning. Peaking power plants are expensive to operate.

Some energy efficiency improvements are load following, yielding high electricity savings during system peak. A clear example here is air-conditioning, whether small window units or large central chillers. High-efficiency units use less energy, which reduces summertime peak demand. Energy efficiency's peak-demand benefits have long been recognized; a 2001 study for the DOE noted that peak-demand reductions from energy efficiency measures could enhance electricity system reliability in areas experiencing generation shortages or T&D constraints (Osborn and Kawann 2001).

An earlier ACEEE analysis (York, Baatz, and Ribeiro 2016) compared various types of customer energy efficiency programs in terms of their peak-demand savings capabilities. The study classified programs according to how much peak-demand savings they achieved in conjunction with energy savings and program costs using two derived metrics:

- Megawatts saved per program dollar (annual program cost)
- Megawatts saved per gigawatt-hour saved (first-year savings)

Using these metrics, York et al. (2016) found that programs vary widely in their peak-demand reduction relative to energy savings, with values ranging from 0.10 to 0.45 MW/GWh and from 0.03 to 1.93 MW/million dollars. The programs in the study that had the greatest impacts on peak energy demand are those that impact air-conditioning loads. This research illustrates the variability among programs in terms of the relationship between peak-demand savings and energy savings. Some energy efficiency programs have negligible impact on peak-demand savings, while others have significant peak-demand impacts.

The timing of load reductions due to improved energy efficiency is closely correlated to the grid value of such a reduction. This, in turn, is closely correlated to an improvement's reliability value. Energy efficiency improvements that reduce load during times of electric system peaks are more valuable from a grid perspective than those that occur during off-peak periods (Mims, Eckman, and Goldman 2017).

TRANSMISSION AND DISTRIBUTION SYSTEM IMPACTS

The other important dimension of electric system reliability is having sufficient T&D capacity to reliably deliver power to end users. Inadequate transmission and/or distribution capability can cause reliability problems at local levels. To maintain system safety and reliability at a reasonable cost to customers, utilities carefully plan their T&D systems (Coddington, Schneider, and Homer 2017). The necessary T&D investments that their planning identifies are driven by factors such as infrastructure aging, unexpected equipment failures, the need to connect new generation, and the need to address load growth (Neme and Grevatt 2015). Neme and Grevatt (2015) note that "even if peak loads in a region are not growing *in aggregate*, they may be growing in a portion of the region to the point where they may be putting stress on the system"(p. 9). End-use energy efficiency can reduce the need for T&D investments driven by load growth, and utilities are increasingly considering it as a resource in their T&D planning processes.[7]

Historically, energy efficiency's impacts have typically been viewed without regard to the time and location of savings, but this is now changing as jurisdictions begin to account for these dimensions. Traditional cost–benefit tests typically evaluate benefits averaged across a system. Some utilities may assess avoided costs for peak and non-peak hours, but greater temporal or locational assessments are not yet common practice (Baatz, Relf, and Nowak 2018). From a distribution system perspective, however, the time and location of a saved kilowatt-hour (kWh)—and with it a reduction in power demand—can be very important. Typically, T&D systems are constrained at various points in their networks based on their equipment's ability to manage loads; overloaded circuits and power lines can result in outages. Reduced power demand in locations where such constraints risk overloading equipment are highly valuable from a grid perspective. Reduced loads also reduce T&D losses. It is also true that tailoring and targeting certain types of efficiency programs may provide the greatest benefit to a local constrained area, depending on the peak load timing and the affected end use (Neme and Grevatt 2015).

In recent years, there has been a growing awareness of energy efficiency's value as a distribution system resource. Through strategic targeting, or *geo-targeting*, energy efficiency improvements can be actively directed to particular geographic areas in which the distribution system equipment may not be able to handle localized peak loads, which may come at different times than bulk power system peaks (Neme and Grevatt 2015). This enhances the energy efficiency resource's value and is another way that energy efficiency contributes directly to electric system reliability. Many utilities are now pursuing geo-targeted energy efficiency for reliability purposes at both the transmission and distribution levels, giving rise to the popular term *non-wires alternatives*, or NWAs. We provide examples of NWAs later in this report.

As NWAs clearly demonstrate, energy efficiency can be a resource to help achieve electric system reliability, just like investments in generation supply and T&D infrastructure. To the extent that energy efficiency is cost effective and helps utilities avoid the need for generation and/or T&D investments, it provides a lower-cost means of achieving and maintaining distribution system reliability. Any assessment of energy efficiency's cost effectiveness should include consideration of those values, and utility supply resource planning and distribution system planning should fully incorporate energy efficiency as a resource component.

SUMMARY OF EFFICIENCY IMPACTS

From an electricity system reliability perspective, energy efficiency's principal impact is that, by reducing load, it increases the system's capability to serve demand reliably. For generation, this is known as the system's *reserve margin*—that is, the difference between actual demand on the grid and the amount of supply resources available to meet that demand. For the distribution system, it is known as the *distribution system reserve capacity*.

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[7] Neme and Sedano (2012) provide further analysis of energy efficiency as a T&D resource.

Having sufficient capability, for generation as well as for T&D system equipment, is critical to reliability. Maintaining these margins is the buffer that sustains the steady supply of electricity as demands and supplies fluctuate. By reducing overall load at times of system peak demand (be it the overall system peak or peak periods in distribution areas), energy efficiency helps address system adequacy, essentially increasing reserve margins and thereby increasing the system's capacity to respond to demand. To the extent that energy efficiency accomplishes this at a lower cost than adding generation supply and/or distribution resources, energy efficiency is a cost-effective reliability resource.

ENERGY EFFICIENCY AND RESILIENCE

As noted earlier, there is considerable interest in improving the grid's resilience—that is, its ability to withstand or recover from severe threats or catastrophic damages. Industry solutions typically involve various ways of hardening physical assets (e.g., generation, T&D equipment) and/or adding distributed generation equipment.

However end-use energy efficiency can contribute to resilience solutions in several ways. First, a facility (or microgrid) could use a distributed power source, such as a CHP, as a backup to grid service, with the backup source's size and cost dependent on the facility's efficiency level. Similarly, homes and other buildings that are more energy efficient would require a smaller, less costly backup source than those that were less energy efficient. Second, well-insulated building shells can improve resident survivability as such buildings can maintain livable indoor conditions for longer periods than inefficient buildings after an outage, depending on needs (Silverstein, Gramlich, and Goggin 2018). High-efficiency, well-insulated refrigerators and freezers also keep food from spoiling for longer periods, further affecting livability during an outage. Third, restoring power from generators in black start conditions can put high stress on the system. Having a lower load on the system due to energy efficiency could reduce that stress and allow for a softer start. This is particularly true for building systems that include smart controls, such as for lighting or HVAC, that can reduce load and operate in energy-saving mode in response to emergency conditions.

As this discussion shows, end-use energy efficiency can be part of a comprehensive set of solutions for resilience and a central part of maintaining electric system reliability over the long term.

Finally, CHP systems are an energy efficiency resource with significant resilience value for customers who use or are affected by CHP equipment. These systems often have the ability to adapt to meet changing loads quickly and to disconnect from the surrounding grid. CHP technologies often rely on natural gas, which is provided through pipelines that remain operational during grid failures. Finally, CHP systems are usually sited close to the consumption point, reducing the chances of falling tree limbs or debris disrupting power (Chittum and Relf 2018).

Experience with Energy Efficiency and Reliability

The history of utility energy efficiency programs offers clear examples of efficiency's reliability benefits, including

- Reducing system demand to offset generation that otherwise would be needed, effectively increasing system reserve margins and supporting system operation
- Using geographically targeted energy efficiency as an NWA to relieve grid congestion

The experiences we present in this section illustrate these uses of energy efficiency to address grid supply and delivery problems. In the case of crisis conditions and inadequate resource availability, energy efficiency can be integral to maintaining adequate reserves and avoiding outages. In the case of congested T&D systems, targeting energy efficiency improvements to specific locations can reduce electricity demand to relieve congestion and maintain service to customers.

CALIFORNIA ELECTRICITY CRISIS OF 2000–2001

Perhaps the most prominent example of energy efficiency's ability to help maintain system reliability occurred during California's electricity crisis of 2000–2001. During that period, California and a number of other states experienced unprecedented electric system crises resulting from various market factors and system problems. In 2000, California experienced rolling outages and had to triage public systems. Electricity costs suddenly increased dramatically, reliability dropped, and the economy suffered severe disruptions and losses.

During this crisis in California, energy efficiency and demand management played key roles in addressing the system's reliability challenges; they literally helped keep the lights on. ACEEE research (Kushler, Vine, and York 2002) on reliability-focused energy efficiency programs found that, in 2001, a set of efficiency and conservation programs and related efforts reduced demand by nearly 3,700 MW, an average of about 10% peak-demand reduction. They also reduced total electricity use by nearly 7%. Such savings were meaningful; they yielded much-needed system relief on reserve margins that were stretched very thin. Without such reductions, additional rolling outages likely would have occurred. With the reductions, California made it through the entire summer and remainder of 2001 without a single rolling outage, sparing the state potentially immense outage-related economic losses.

California's experience provides a vivid illustration of the reliability benefits of energy efficiency. California was able to achieve such a dramatic result because it already had a set of utility energy efficiency programs in place. The state was able to build on this existing infrastructure of utility programs, increasing program activity to serve more customers and achieve correspondingly high savings. In some cases, California's utilities boosted budgets for existing programs to increase their impact; in other cases, the utilities introduced new programs and initiatives. Statewide, the total funding for the full set of utility and related programs reached $971 million, more than doubling the pre-crisis program funding of approximately $400 million.

California's experience during its electricity crisis clearly demonstrated that energy efficiency programs can be selected and designed to achieve significant peak-demand reduction and associated reliability benefits. For summer-peaking utility systems, energy efficiency technologies that affect end uses coincident with this peak demand, such as air-conditioning and commercial lighting, offer the most reliability benefits. For winter-peaking utilities, the greatest reliability benefits come through technologies that are coincident with the system peak, primarily space heating and residential and commercial lighting.

NON-WIRES ALTERNATIVES TO SERVING LOAD

Using energy efficiency as a targeted solution for relieving congestion on T&D systems provides another clear example of energy efficiency's reliability benefits. Utilities may defer or eliminate the need for traditional investments in T&D infrastructure using nontraditional measures, such as long-term investments in energy efficiency (St. John 2017). These nontraditional approaches, when targeted in a specific area, are called non-wires alternatives, or NWAs. During their resource planning processes, utilities may uncover the need to replace or upgrade T&D system equipment. Examples of identified investment needs may include additional feeders at the distribution level due to increased demand growth, replacement of aging equipment, or the construction of a new transmission line to bring new generation to a growing city. However utilities are increasingly considering NWAs as cost-effective ways to defer or completely eliminate the need for these types of investments.

In certain jurisdictions, utilities are required under law to consider NWAs in their system planning and resource procurement processes. For example, Rhode Island utilities must pursue all cost-effective energy efficiency before pursuing additional supply resources, and distribution utilities must submit system reliability procurement plans (SRPs) reflecting these considerations (RI PUC 2017).

NWAs can include a variety of measures, including energy storage, demand response programs, renewable energy or distributed generation installations, and incrementally increased energy efficiency. To achieve the necessary energy savings or customer-sited generation, utilities may offer increased financial incentives or rebates, increased program marketing, direct customer outreach, or other strategies.

NWA projects have existed in the United States since the 1990s and their numbers are growing (Neme and Sedano 2012). GreenTech Media estimated that, as of mid-2016, 133 different NWA projects had been implemented or were in the pipeline, for a total of 1,960 MW of capacity (St. John 2017). Although still a small percentage of US capacity, the numbers are growing. For example, in 2016, natural gas combustion and steam turbines (frequently used only during peak hours) accounted for 202,050 MW of total US capacity, in contrast to the less than 2,000 MW of NWA capacity (EIA 2017). Although seemingly modest compared to the load served by turbines, it was nonetheless a 200% increase in NWA capacity from 2015 to 2016. NWAs directly address reliability risks or concerns that resource planners have identified, often including energy efficiency as a part of the portfolio. In the following, we offer examples of NWA programs that have used efficiency to achieve proven energy savings and thus successfully deferred or eliminated the need for traditional T&D investments.

New York's Reforming the Energy Vision

New York State is developing and implementing Reforming the Energy Vision (REV), a comprehensive energy strategy to meet overarching goals such as carbon emissions reductions, increased renewable energy penetration, and reduced energy usage across the state (New York State 2018). Under REV, utilities must submit Distributed System Implementation Plans (DSIPs) that identify beneficial locations for distributed energy resource (DER) deployment. This includes identifying "areas where durable reductions in demand through energy efficiency programs will have value to the distribution system and inform a utility's overall capital plan" (NY DPS 2015a. p. 7). The proceedings also emphasize the use of demonstration projects to prove the viability of various approaches, as well as to determine the efficacy of various program and market designs and quickly adapt or change aspects of them to increase their effectiveness. As the New York Department of Public Service states, "New York State is seeking demonstration projects to show how new projects can capture latent value on the grid, and how new business models can monetize and distribute that value across third parties, utilities, and customers" (NY DPS 2018).

Through both DSIPs and demonstration projects, utilities are pursuing NWAs that reliably meet demand by procuring DERs such as energy efficiency. The New York State Energy Research and Development Authority states that NWAs "lower costs and emissions while maintaining or improving system reliability" (NYSERDA 2018). Each New York utility has NWA projects underway.[8] We highlight two projects below.

ConEd's Brooklyn Queens Demand Management Project

Consolidated Edison (ConEd) is undertaking seven NWA projects of various sizes and purposes in various stages of development. Perhaps the best-known NWA project in the nation currently is ConEd's Brooklyn Queens Demand Management Project (BQDM). In 2014, ConEd identified two substations with subtransmission feeders in Brooklyn projected to become overloaded by increased demand for electricity in coming years (ConEd 2014). The project's original proposal aimed to reduce demand by 52 MW by summer 2018. The project is both on schedule for demand reductions and under the projected budget. BQDM was recently extended indefinitely beyond its original three-year scope, not to exceed its original $200 million budget (NY PSC 2017). This project defers traditional infrastructure needs that would have cost customers approximately $1 billion due to the difficulties of expanding distribution infrastructure in a dense urban environment.

BQDM is driven by the technical calculations needed to meet reliability standards. ConEd writes that, "After accounting for demand growth, [ConEd] forecasts that the total resource need for the subtransmission infrastructure servings [the substations] will be 69 MW above the system's current capabilities to meet reliability requirements by 2018" (ConEd 2014, p. 3). ConEd also notes that most of the solutions (41 of the 52 MW of demand reduction required) will come from customer-side demand reductions. The utility states that it may

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[8] NWA projects and utility-specific NWA websites are listed on the REV Connect website at nyrevconnect.com (NYSERDA 2018).

need to "retain some or all aspects of operation, maintenance, and technical support responsibility … to maximize reliability" (ConEd 2014, p. 19).

As of Q1 2018, ConEd has achieved 23 MW of operational load relief from residential, commercial, and public building energy efficiency measures. Another 17 MW of reductions come from voltage optimization.[9] In total, the program has achieved approximately 36 MW of demand reduction on schedule with the project timeline (ConEd 2018). It achieved this by implementing upgrades in residential, commercial, and public buildings, using additional incentives for commercial direct-install and multifamily energy efficiency programs. In addition to end-use energy efficiency, ConEd has used voltage optimization, demand response, CHP, and fuel cells. The project is a high-profile example of using energy efficiency to meet reliability requirements with growing demand.

New York State Electric and Gas Java Substation

New York State Electric and Gas (NYSEG) is also conducting a REV NWA demonstration project; this one specifically targets load relief and reliability and is scheduled to be operational by 2019. The Java Substation project aims to defer the need for a second transformer and a 12 kilovolt (kV) conversion for an area serving 1,665 customers. NYSEG has identified that the Java substation transformer bank has exceeded its nameplate rating and is a circuit with rapid load growth in the area. Resources including distributed generation, demand response, energy storage, energy efficiency, and other resources that can meet the identified reliability need are eligible under NYSEG's request for proposals (RFP). Any proposed resource must meet the outlined criteria in the RFP, including NERC and other reliability organizations' reliability standards (NYSEG 2016). The project aims to acquire NWA resources of approximately 6 MW through 2024.

NYSEG identified specific reliability risks including overload of the Java 0.8 kV transformer bank, reliability problems with the Java circuit, and potential transformer bank failure under an N-1 contingency. This means that, under such a contingency, NYSEG could lose either the transformer or the generator. To address these specific reliability needs in addition to general load relief, NYSEG's RFP requires a portion of the resource to be 100% reliable during the summer capability period. NYSEG is currently completing a final analysis of proposals, and expects to have the identified resources under contract by January 2019 (NYSEG 2018a).

Bonneville Power Administration: I-5 Transmission Project

NWAs are also used at the transmission level to meet customer demand using energy efficiency and other alternatives to defer traditional transmission infrastructure investments. The Bonneville Power Administration (BPA) is a nonprofit federal power marketing administration in the Pacific Northwestern; BPA recently cancelled a large transmission project, opting instead to use NWAs to meet the region's growing transmission needs. In 2009, long-term load forecasts showed that the region's growing electricity demand would require additional transmission infrastructure. To meet this demand, BPA proposed a 500-

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[9] Voltage optimization improves power quality and reliability and conserves energy using two technologies—capacitors and voltage regulators—that deliver energy at lower voltages (DOE 2015).

kV, 79-mile line and associated substations with a cost of approximately $722 million (Pesanti 2017). Called the I-5 Corridor Reinforcement Project, it was to serve as “a solution to preserve reliability, meet existing contract requirements, reduce curtailments, and serve demand on the transmission system” (BPA 2017, p. 1). The project planned to meet both current and future transmission needs in direct response to “an electrical reliability issue” in southwestern Washington and northwestern Oregon (BPA 2018).

In response to stakeholder concerns about the project, BPA commissioned a firm to evaluate NWAs to the I-5 project, including transmission system upgrades, demand response, and energy efficiency measures. The firm’s preliminary screening found that NWAs would be able to maintain system reliability for a few years, but would not be able to eliminate the need for the project. However BPA continued to solicit comments and evaluate alternatives up through the release of a final environmental impact statement in 2016.

In May 2017, BPA’s administrator and CEO signed a letter notifying the public of the decision to cancel the I-5 project. An independent review panel had found that the project would provide capacity far beyond that required for regional reliability. BPA stated that it could instead “meet its obligations to provide reliable, robust, transmission service in a more innovative and sophisticated manner without building a new transmission line” (BPA 2018). In the letter, the administrator cited slower load growth than in previous studies, changing risk tolerance levels, and modernizing grid technologies that could help meet demand in congested areas. Specifically, the letter noted that BPA was already doing or considering “non-wires measures to manage generation and loads to reduce peak congestion” (BPA 2017, p. 2).

Moving forward, BPA plans to maintain grid reliability and meet its reliability obligations by upgrading existing transmission infrastructure, updating business and commercial practices, and implementing a two-year pilot of NWAs to reduce peak demand for summer electricity (BPA 2018). While the transmission project is not being cancelled solely to implement energy efficiency and demand response, BPA does cite demand-side measures as a reason for slowing load growth and as a critical piece of the solution to meet reliability and customer needs.

Vermont’s System Planning Committee

Efficiency Vermont operates as an energy efficiency utility within Vermont’s unique electricity sector structure. In addition to Efficiency Vermont, the state has one transmission utility (Vermont Electric Transmission Company or *VELCO*) and many distribution utilities. Historically Vermont has been a leader in systematically implementing NWAs, with projects dating back to the 2000s. State laws require integrated resource plans every three years, and those plans must consider any constraints that might be met through NWAs. State officials also advocate for equal treatment of NWAs and traditional T&D investments. The Vermont Public Utilities Commission requires prescreening for NWAs for transmission projects, subtransmission projects, distribution projects, and geographically targeted NWAs. The prescreening process determines whether NWAs must be considered as solutions to identified grid reliability issues in conjunction with traditional investments. If a constraint is identified for a full NWA analysis, the utilities must develop a least-cost reliability plan to meet the identified needs (Vermont PUC 2017). The orders requiring consideration of non-transmission alternatives also require that projects recognize the reliability planning criteria of both the RTO and NERC (Vermont PUC 2017).

To ensure that these related planning processes work together, the collaborative Vermont System Planning Committee (VSPC) brings together stakeholders to plan for electric system reliability and operations (VSPC 2017). The VSPC's mission is to "ensure all options to solve grid reliability issues get full, fair, and timely consideration, and the most cost-effective solution gets chosen, whether it is a poles-and-wires upgrade, energy efficiency, demand response, generation, or a hybrid" (VSPC 2017). The VSPC consists of members from utilities (including Efficiency Vermont), regulators, and environmental advocates (Neme and Grevatt 2015). 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). In Vermont, NWA projects are evaluated using societal and ratepayer impact cost-effectiveness testing. Considered costs can also include environmental externalities and "other significant relevant costs and benefits particular to the set of alternatives under consideration" (Vermont PUC 2017, p. 2).

Responding to a proposed energy efficiency spending cap, VELCO quantified the value that energy efficiency has had for its transmission system: "In 2012 . . . Vermont's known energy efficiency commitments . . . resulted in $240M of infrastructure projects being removed from the list of upgrades that were identified as needs in previous studies" (Presume 2014, p. 3). These projects were cancelled because an update to energy efficiency forecasting determined that they were not necessary given known energy efficiency commitments. Further, future projections of energy efficiency resources from the RTO's forward capacity market resulted in an additional $160M in investments being removed from the list of proposed upgrades, a portion of which is direct savings to customers. These project deferrals are a direct result of energy efficiency resources impacting the region's load forecast. As VELCO notes, "All told, energy efficiency represented about 70% of the incremental resources that deferred nearly $400M of upgrades" (Presume 2014, p. 3). Still, this is likely an underestimation of the region's energy efficiency resources, as efficiency is typically underforecast in the region's load forecasting models (Relf and Baatz 2017). We discuss this in further detail later.

Lower Snake River Dam Replacement Study

In the Northwest, hydropower provides clean renewable energy to residents, but also creates problems for salmon and steelhead migration. The Northwest Energy Coalition, an alliance of organizations working for energy efficiency and renewable energy in the region, commissioned a study released in 2018 to determine the effects of removing four dams along the Lower Snake River (LSR). The study analyzes a range of portfolio options for replacing four LSR dams in Washington with a nameplate capacity of 3,000 MW. The study aims to determine whether these portfolios can meet the service area's demand needs without compromising power system reliability, while also minimizing or eliminating increases in greenhouse gas (GHG) emissions. The study considers a reference case scenario in which the dams remain in place, "non-generating alternative (NGA) portfolios" consisting of demand-side resource mixes including energy efficiency, demand response, battery storage, "balanced portfolios" consisting of new wind and solar and demand-side resources, and an all-gas portfolio. The portfolios were examined for reliability, emissions effects, cost effectiveness, and other benefits. Each of the portfolios, except the gas-only options, includes energy efficiency (Energy Strategies 2018). Table 1 shows the portfolios analyzed in the study.

Table 1. Lower Snake River dam replacement portfolios

Portfolio name	Non-generating alternative	Non-generating alternative plus	Balanced	Balanced plus	All gas
Demand response: summer (MW)	971	971	486	486	0
Demand response: winter (MW)	1,039	1,039	520	520	0
Energy efficiency (aMW)	320	880	160	160	0
Battery storage (MW)	100	100			0
Wind (MW)			500	1,250	0
Solar (MW)			250	750	0
Gas: combined cycle (MW)					500
Gas: reciprocating engine (MW)					450

Source: Energy Strategies 2018

The NGA portfolio includes all of the remaining cost-effective energy efficiency potential in the Northwest Power and Conservation Council's 7th Power Plan. The NGA Plus portfolio also includes the remaining efficiency identified as technically achievable.

Each of the portfolios was evaluated for reliability. In each case, the loss of load probability (LOLP) was lower than in the reference case of the dams remaining in place.[10] This means that the likelihood of load curtailments is lower in the replacement scenarios, and all such scenarios meet the 5% LOLP planning requirements. The NGA Plus portfolio, which has the most energy efficiency, has the lowest LOLP, indicating that it is the most reliable in terms of resource adequacy. This is because, unlike generation resources, energy efficiency does not have routine or unexpected outages associated with its ability to meet load. Additionally, the study found that every portfolio would meet NERC criteria for transmission system reliability including voltage requirements and transmission loading requirements.[11] Figure 3 shows the LOLP for each scenario.

[10] LOLP measures the probability that a utility's generation capacity will fall below its demand. Utilities use this data to assess investment plans under different scenarios of load growth and capacity investments to meet reliability requirements.

[11] Each scenario would require a new seven-mile 115 kV transmission line. The costs of this are included in each portfolio's cost assessment.

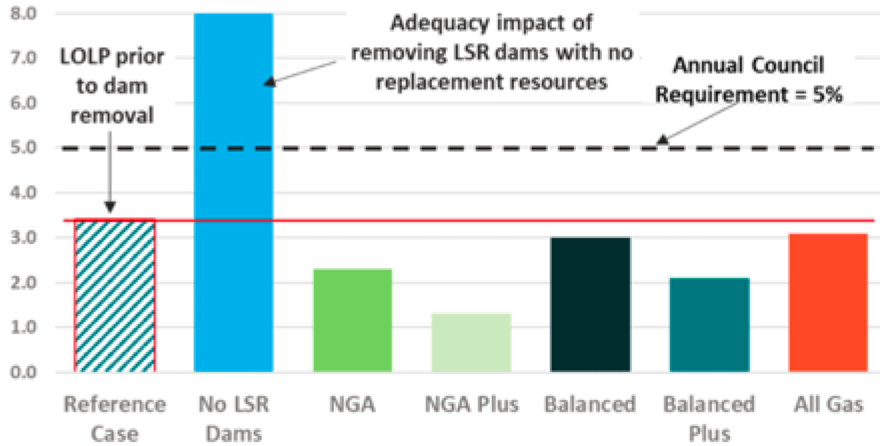

Figure 3. Resource adequacy performance of replacement portfolios (annual LOLP, %).
Source: Energy Strategies 2018.

This study shows that, in this area, non-generating resources can increase the reliability of load served in terms of resource adequacy compared to both the current hydropower resources and other renewable and gas options (Energy Strategies 2018).

Quantifying the Reliability Benefits of Energy Efficiency

Energy efficiency provides reliability value to the grid, its operators, and customers in many places along the system; this creates multiple channels for quantifying and valuing efficiency's reliability benefits. However current practices are not consistent or widespread across jurisdictions. Here, we address different ways that jurisdictions can value reliability, the data they need to do so, and examples of jurisdictions currently making such efforts. While energy efficiency's reliability benefits are well acknowledged, quantifying these benefits is difficult. In a manual assessing clean energy's benefits, the US Environmental Protection Agency (2011, p. 80) notes this fundamental challenge: "Converting reliability benefits into dollar values is complex, however, and the results of studies that have attempted to do so are controversial."

There are different approaches to valuing efficiency's reliability benefits for grid customers and operators. Examples that are currently in use across the United States include cost–benefit analysis, capacity pricing, and utility rates. Here we cover a few of these cases and the values assigned to efficiency's reliability benefits.

ENERGY RELIABILITY DATA

Data regarding the number, duration, and cause of power outages, as well as the associated economic losses help to inform avoided costs due to increased reliability. Tools exist for calculating these costs and losses, but they are not often applied specifically to the energy efficiency context.

Utilities collect and publish energy reliability data, including metrics on outage numbers and lengths, based on standard metrics used across the United States. Metrics that describe electric system performance include System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and Customer Average Interruption Duration Index (CAIDI).[12] Although utilities collect and report on these data, it is difficult to compare across jurisdictions due to differing reporting requirements. A total of 35 states have reliability metric reporting requirements, and about half of all states have reliability goals for their utilities (Rouse and Kelly 2011). Because these data are typically reported in aggregate across utility service-territories, rather than on specific constrained areas, such valuations are more granular and accurate.

Utilities also calculate reliability as a LOLP metric, which describes the probability that a utility's generation capacity will fall below its demand. Utilities use these data to assess investment plans under different scenarios of load growth and capacity investments to meet reliability requirements.

COST–BENEFIT ANALYSIS

Energy efficiency programs and projects funded by utility customer dollars are evaluated and approved by utility regulators using cost-effectiveness testing rules. States typically require that, to be implemented, a program's benefits must outweigh its costs at a certain threshold, using established frameworks to calculate the numbers. These frameworks should create an opportunity to value reliability benefits. In addition to customer-funded programs, other energy efficiency policies and programs such as building codes and appliance efficiency standards also impact end-use efficiency and energy savings and have associated reliability benefits. However, because they are not funded by utility customers, they are not subject to the same regulatory requirements.

California and National Standard Practice Manuals

Energy efficiency program evaluation is strongly rooted in the California Standard Practice Manual, which was developed in the 1980s and has been widely used ever since. This manual articulates how reliability benefits of distributed generation and demand response might be included in a cost–benefit analysis. Although reliability benefits and costs are considered for distributed generation and demand response, they have not been included in cost-effectiveness tests for energy efficiency in California (Morgenstern 2015). However the practices used to quantify demand response and distributed generation's reliability benefits are also applicable to efficiency resources. The manual discusses the benefits of avoided T&D costs; it also describes the benefits of increased system reliability as follows: "The reductions in demand and peak loads from customer option for self-generation, provide reliability benefits to the distribution system in the forms of:

a. Avoided costs of supply disruption
b. Benefits to the economy of damage and control costs avoided by customers and industries in the digital economy that need greater than 99.9 level of reliable electricity service from the central grid

[12] SAIFI is the number of times an average customer experienced an outage over the course of a year; SAIDI is the length of total outages (in minutes) that the average customer experienced over the course of a year; and CAIDI is the average length of a single outage that the average customer experienced over the course of a year (Rouse and Kelly 2011).

c. Marginally decreased system operator's costs to maintain a percentage reserve of electricity supply above the instantaneous demand
d. Benefits to customers and the public of avoiding blackouts." (CPUC 2001).

This gives an idea of how energy efficiency's reliability benefits might be quantified in cost-effectiveness testing, along with the data needed to do so. Many cost-effectiveness test frameworks also take into account avoided T&D, which is directly related to increased reliability spending, as these additional T&D investments would otherwise be necessary to maintain a reliable system.

In 2017, the National Efficiency Screening Project released a new National Standard Practice Manual (NSPM) for assessing the cost effectiveness of efficiency resources. The document provides a comprehensive framework for assessing the cost effectiveness of energy efficiency resources, which is the standard method utilities use to propose and implement efficiency programs with their regulators. The document provides information on elements that could comprise the range of costs and benefits included in the resource value tests that each jurisdiction chose. The manual states that a cost-effectiveness framework should consider a jurisdiction's policy and energy goals, such as improving system reliability. The manual also lists increased reliability as a utility system benefit that should be included in every cost-effectiveness test (NESP 2017).

The manual states that, "by lowering loads on the grid, efficiency can reduce the probability and/or likely duration of customer service interruptions" (NESP 2017, p. 54). It notes that this benefit will likely vary in magnitude depending on the system's overall reliability projected into the future. Further, such a benefit may overlap to some extent with other benefits such as reduced risk, avoided capacity costs, and/or avoided T&D costs. It is important to consider whether those factors are incorporated into a benefit–cost analysis in such a way that fully captures energy efficiency's reliability benefits. As we describe in the next section, however, states typically do not fully capture these reliability benefits of energy efficiency resources in their cost-effectiveness approaches.

The manual outlines methods for quantifying benefits that may be hard to monetize or quantify. These include using jurisdiction-specific studies, prudently using studies from other jurisdictions, using proxies (simple, quantitative values that can substitute for values not monetized by conventional means), using other quantitative or qualitative information, using sensitivity analyses, or setting alternative cost-effectiveness thresholds to account for non-quantifiable benefits (NESP 2017). It is critical that these benefits be considered for the measure's full life in order to capture the full benefits (Lazar and Colburn 2013). As data become more available for quantifying reliability benefits, jurisdictions will be able to use this information to include reliability in cost-effectiveness testing more accurately.

Reliability Benefits of Energy Efficiency in Cost–Benefit Analysis

Energy efficiency's reliability benefits include transmission cost savings, distribution cost savings, minimizing reserve requirements, decreased risk, increased energy security, avoided outages, and avoided restoration costs (Lazar and Colburn 2013). While reliability benefits are typically acknowledged, these are rarely quantified and included in cost-effectiveness analysis and screening. Avoided capacity costs (including avoided T&D costs) are used in such screening, but these values reflect market prices and marginal generation costs, which typically represent the value of electric power at peak demand. Such costs generally do not add values for reliability benefits—that is, the value of increased reliability on the system, which may reduce or avoid outages, or the avoided costs of reserve margins required with an otherwise higher load.

Quantifying such benefits is challenging and subject to wide uncertainty. One way to do it would be to apply an adder to the avoided capacity cost. Or, it might be possible to derive the value of an avoided outage and apply a corresponding benefit value into the cost-effectiveness screening of measures and programs. In this way, one could develop a portfolio from the ground up that places a higher value on peak-demand reduction. The resulting measures and program portfolios would thus have a higher proportion of energy savings programs that yield high peak-demand impacts.

Many studies (e.g., Sullivan, Schellenberg, and Blundell 2015) have quantified the costs of grid outages across times, locations, and customer classes. These studies are helpful for understanding the consequences of grid outages, but they do not specifically parse out the value of energy efficiency's contribution to reducing these outages and costs.

A few utilities do account for energy efficiency's risk-reduction benefit, part of which is attributable to increased system reliability and grid resilience. The Regulatory Assistance Project reports that the Northwest Power and Conservation Council (NWPCC) added approximately $20/MWh for risk reduction's value due to energy efficiency programs (Lazar and Colburn 2013). This value has gone down in recent years. For example, Pacific Power (a utility in NWPCC's territory) used a levelized average fuel price risk avoidance value of $1.46/MWh in its integrated resource plan, while Portland General Electric used a levelized value of $5.08/MWh (ETO 2017). The risk-reduction value is in addition to the avoided T&D capacity deferral value. Vermont includes $2.27/MWh for risk. Again, such values reflect a wide set of risk-reduction factors; improved reliability due to peak-demand reduction is just one of them. These examples illustrate how such benefits can be incorporated into the program screening and selection process. These two examples show a range of approximately $0.02 to $0.002 per kWh attributed to the value of risk reduction from energy efficiency resources.

One of the core principles of the new National Standard Practice Manual discussed above is that important costs and benefits should not be omitted from cost-effectiveness analysis because they are difficult to quantify (Woolf et al. 2017) In the case of reliability benefits, the value is certainly not zero. Sufficient information should be available for states to be able to at least establish an acceptable proxy value, and as more data become available, those estimates can be refined over time. The next section presents examples of states that are currently leading on the issue of quantifying reliability benefits.

SOME LEADING EXAMPLES OF INCORPORATING RELIABILITY BENEFITS

Efficiency Vermont

Vermont's Regulatory Assistance Project conducted a study of cost-effectiveness testing using the most complete data possible for Efficiency Vermont's 2010 efficiency portfolio. This effort did not quantify reliability benefits as a separate category, but valued attributes that contributed to increased reliability and contributed directly to system reliability, including T&D capacity savings, avoided reserves, and reduced risk. We describe these benefits below.

Efficiency Vermont reported avoided T&D capacity costs (not including maintenance expenses) as $23.5M, net present value. Levelized over the measure's lifetime, these savings came out to $3.20/MWh of savings for avoided transmission capacity and $19.99/MWh for avoided distribution capacity. Avoided generation reserves needed for unexpected or planned outages are additional savings from reduced peak demand due to efficiency. This results in generation capacity savings because the amount required to meet reliability requirements is lower. Efficiency Vermont assessed the value of avoided reserve costs as $0.67/MWh, levelized. It also valued reduced risk from energy efficiency measures to account for the incremental nature of efficiency impacts, the ability to readily increase or decrease efficiency activity to meet system needs, and the limited risk of stranded investments. These benefits came to $2.27/MWh, levelized.

Together, the benefits of avoided costs to maintain reliability based on these metrics comes to $26.13/MWh (or $0.026/kWh). The study recognizes that this does not fully account for all the benefits of efficiency, including additional reliability benefits such as energy security (Lazar and Colburn 2013).

California

As a part of many regulatory changes related to renewable energy and resource planning, California required each utility to file a distribution resource plan in 2015. The plans had to consider many aspects of integrating DERs into the distribution system, for example deploying DERs including energy efficiency in optimal locations. Utilities were also directed to conduct hosting or integration capacity analysis, which considers how much DER capacity the T&D systems can reliably accommodate under various scenarios. Utilities were further required to consider DERs' locational benefits as part of the process to determine where best to site resources. Locational benefits of these resources can include avoided substation and feeder infrastructure investments, avoided transmission capital expenditures, any societal avoided costs, and avoided public safety costs (Baatz, Relf, and Nowak 2018). California also conducts temporal analysis of the value of building codes and standards for energy efficiency. This analysis includes time-dependent marginal energy avoided costs. It also factors in the marginal cost of ancillary services (system operations and reserves) for reliability (E3 2017).

Additionally, utilities were required to propose demonstration projects in four areas: dynamic integrated capacity analysis, optimal location benefit analysis methodology, DER locational benefits, distribution operations at high penetration of DERs, and DER dispatch to meet reliability needs, which may show which operational functionalities are needed to provide reliability services with multiple DERs in various scenarios. The California Public Utilities Commission approved demonstration projects under the DER dispatch to meet reliability needs for Southern California Edison and San Diego Gas & Electric. Both projects deploy microgrids and do not incorporate energy efficiency in a major way (CPUC 2017).

The Pacific Gas and Electric (PG&E) distribution resource plan provides insight into how energy efficiency is being considered and valued for reliability on the distribution system. For example, PG&E's hosting capacity analysis expands on current reliability requirements to consider safety and reliability criteria such as islanding, transmission penetration, operational flexibility, transmission system frequency, and transmission system recovery under various DER penetration scenarios. PG&E's locational net benefits specifically include avoided distribution reliability and resiliency capital and operating expenditures. PG&E defines this metric as "avoided or increased costs incurred to proactively prevent, mitigate and respond to routine outages (reliability) and major outages (resiliency)" (PG&E 2015, p. 72). For example, this may include costs or avoided costs of a new or upgraded distribution line feeder. The plan also includes other metrics related to resource adequacy and reliability. Table 2 shows PG&E's consolidated components for locational impact analysis.

Table 2. PG&E's locational impact analysis components

Component	PG&E definition
Subtransmission, substation, and feeder capital, and operating expenditures (distribution capacity)	Avoided or increased costs incurred to increase capacity on subtransmission, substation, and/or distribution feeders to ensure system can accommodate forecast load growth
Distribution voltage and power quality capital, and operating expenditures	Avoided or increased costs incurred to ensure power delivered is within required operating specifications (i.e., voltage, fluctuations, etc.)
Distribution reliability and resiliency capital, and operating expenditures	Avoided or increased costs incurred to proactively prevent, mitigate, and respond to routine outages (reliability) and major outages (resiliency)
Transmission capital and operating expenditures	Avoided or increased costs incurred to increase capacity or transmission line and/or substation to ensure system can accommodate forecast load growth
System or local area resource adequacy	Avoided or increased costs incurred to procure resource adequacy capacity to meet system or California ISO-identified local capacity requirement
Flexible resource adequacy	Avoided or increased costs incurred to procure flexible resource adequacy capacity
Generation energy and greenhouse gases (GHGs)	Avoided or increased costs incurred to procure electrical energy and associated cost of GHG emission on behalf of utility customers
Energy losses	Avoided or increased costs to deliver procured electrical energy to utility customers due to losses on the T&D system
Ancillary services	Avoided or increased costs to procure ancillary services on behalf of utility customers
Renewable portfolio standard (RPS)	Avoided or increased costs incurred to procure RPS-eligible energy on behalf of utility customers as required to meet the utility's RPS requirements

Component	PG&E definition
Renewables integration costs	Avoided or increased generation-related costs not already captured under other components (e.g., ancillary services and flexible resource adequacy capacity) associated with integrating variable renewable resources
Any societal avoided costs that can be clearly linked to the DER deployment	Decreased or increased costs to the public that do not have any nexus to utility costs or rates
Any avoided public safety costs that can be clearly linked to DER deployment	Decreased or increased safety-related costs that are not captured in any other component

Source: PG&E 2015

PG&E continues to refine and develop this methodology, and it plans to release public tools for calculating these components toward the end of 2018 (PG&E 2018).

Energy efficiency is creating significant value for customers not only at the distribution level, but also at the transmission level. In March, the California grid operator (CAISO) approved the 2017–2018 transmission plan. The approval cancels or modifies previously approved projects to avoid $2.6 billion in future costs. The plan recommends cancelling 18 transmission projects in PG&E's service territory and modifying 21 others, as well as cancelling two projects in San Diego Gas and Electric's area. CAISO states that "The changes were mainly due to changes in local area load forecasts, and strongly influenced by energy efficiency programs and increasing levels of residential, rooftop solar generation" (CAISO 2018, p. 1). These avoided transmission projects are saving customers billions of dollars due to increased efficiency.

The Rhode Island Test

Rhode Island's distribution utilities are required to file annual system reliability and energy efficiency plans. In 2017, the state approved the Rhode Island Test, a new cost-effectiveness testing procedure. The test is based on National Standard Practice Manual practices and directs distribution companies to include hard-to-quantify efficiency impacts. According to the state's Public Utilities Commission, "Efficiency assessment practices should account for all relevant, important impacts, even those that are difficult to quantify and monetize" (RI PUC 2017, p. 2). In its 2018 plans, National Grid Rhode Island did not explicitly quantify reliability costs or benefits beyond what it had previously included in cost-effectiveness testing (such as T&D avoided costs or benefits) in its new Rhode Island Testing methodology. However it did include economic impacts (such as job creation) and GHG costs (NG RI 2017a and b). An earlier draft of the cost–benefit framework included "distribution system reliability loss/gain" based on local peak demand, asset age and condition, and energy to serve load; "distribution system resiliency loss/gain"; and "distribution system safety loss/gain" (RI PUC 2016). This leaves room for reliability benefits and costs to be included at a future time.

National Grid Rhode Island used the 2015 version of New England's Avoided Energy Supply Components Report to calculate portions of its 2018 cost-effectiveness tests. In 2018, the report was updated, and it now includes a "Value of Improved Reliability" section that aims to complement, but not duplicate, avoided costs. The value is calculated using the following:

- A value of lost load component
    - "Describes the cost to consumers of being unable to take power from the system" (p. 218)
- A generation component
    - "Provides estimates for the value of generation reliability that is not captured in existing energy and capacity markets. To the extent that load reductions increase reserve margins, reliability will improve as market capacity charges decline" (p. 224)
- A T&D component
    - "Aim[s] to isolate the additional reliability value of energy efficiency on these components of the electric system: . . . various types of weather (e.g., ice, wind), human error (e.g., vehicle collisions, inadvertent excavation of underground cables), vegetation (contact with standing trees, impacts from falling branches), and equipment failure (from load and/or age). Load-related stresses (e.g., insulation degradation, line sag) may increase the likelihood of equipment failure and some of the other outage causes." (p. 229)
    - The report determines that available data are not sufficient to quantify these impacts. (Synapse 2018a)

The report estimates a value of $0.65/kW-year for resources that cleared the capacity auction and $6.60/kW-year for uncleared load reductions. This value is a "15-year levelized benefit of increasing generation reserves through reduced energy usage" (Synapse 2018a, p. 14).

New York's Benefit–Cost Analysis Framework

Within the REV proceedings, the New York Department of Public Service (DPS) released a white paper outlining the Benefit–Cost Analysis (BCA) framework, a methodology for conducting benefit–cost analysis of energy resources. The framework is designed to apply to all resources that utility distribution system planning considers, including generating technologies, behind the meter technologies, energy storage, and NWAs such as demand response and energy efficiency. The BCA framework aims to build on the traditional cost-effectiveness tests used for energy efficiency portfolios to create a more granular and accurate picture of a resource's benefits to the system. The valuation methodology aims to give equal footing to any resource considered, as some resources may provide benefits or create drawbacks only at certain times or locations.

The framework outlines benefits and costs for various standard cost-effectiveness tests (Rate Impact Measure, Utility Cost, and Societal Cost), but the DPS adopted the Societal Cost Test (SCT) as the primary measure. Appendix A outlines the specific benefits and costs that the framework considers, including reliability benefits such as net avoided restoration costs and net avoided outage costs, as well as reliability benefits from avoided T&D losses.

In addition, each utility must publish a BCA handbook. These are meant to clarify valuation aspects that may be specific to a utility's territory or needs, to provide specific values for various resources, and to create an example portfolio of the valuations included (NY DPS 2015b). NYSEG and Rochester Gas & Electric (RG&E) included reliability and resiliency benefits in their 2018 BCA handbooks. Both utilities specify that this benefit will not be calculated for all DERs, and they do not mention whether it would apply to energy efficiency. The benefit calculation includes net avoided restoration costs and net avoided outage costs. Inputs to these include cost of change in crew time to restore outages, expenses associated with restoring outages, CAIDI, SAIFI, the reliability element's marginal cost, the value of electricity service to customers, and the average demand for electricity. The handbook notes that system-wide averages are not appropriate for these calculations and that they should be customer specific (NYSEG 2018b). ConEd included a similar benefit in its handbook.

The REV proceedings also outlined a separate methodology, the value stack, for valuing resources in order to compare options for addressing system needs in different locations as a replacement for traditional net energy metering valuation methodologies. The stack adds the value of multiple components of locational, temporal, and market value (including capacity value, energy value, carbon or environmental value, avoided distribution value, and other components) to come up with a single value for the resource. The framework does not currently cover energy efficiency and applies only to resources that are eligible for net energy metering. However the goal is to apply this valuation methodology to all DERs with future orders.

Capacity Markets and Pricing of Energy Efficiency as a Resource

In the previous section, we examined how program administrators can value and quantify energy efficiency's reliability benefits as they screen measures and evaluate programs for cost effectiveness, with a focus on end-use technologies. Here, we examine how grid operators and wholesale markets for power view and incorporate energy efficiency's aggregate impacts into their reliability planning processes. Examples include forecasts that inform how much demand the system must meet, and the markets that ensure resource adequacy to meet that demand.

RTOs and ISOs work to balance energy supply and demand within their territories.[13] There are six US ISOs regulated by FERC, and a Texas ISO regulated primarily by that state's utility commission. Regions of the country not served by ISOs have other regional reliability organizations that serve a similar function but do not meet all the criteria for becoming an ISO. In general, ISOs are required to facilitate nondiscriminatory access to electric transmission infrastructure by generators. FERC has designated 12 minimum ISO characteristics and functions, one of which is short-term reliability. Other reliability-related ISO functions include congestion management, parallel path flow, ancillary services, planning and expansion, and interregional coordination (FERC 1999).

[13] The terms RTO and ISO are used interchangeably.

Some ISOs use capacity markets to ensure bulk power system reliability.[14] *Capacity* is the maximum amount of electric power a unit can generate, measured in megawatts (MW). To meet the reliability requirement, an ISO must have an installed capacity sufficient to meet forecasted demand, plus a reserve margin. This reliability requirement uses load forecasts to account for outage risks, planned maintenance, possible shifts in demand (such as due to extreme weather) and other uncertainties (MISO 2017b). To ensure that reserve supply is adequate to meet reliability requirements, three ISOs—PJM, ISO NE, and New York ISO (NYISO)—run mandatory capacity auctions. The Midcontinent ISO (MISO) holds a voluntary capacity auction and the ISOs in California (CAISO), the Southwest, and Texas use alternative capacity procurement mechanisms (Relf and Baatz 2017). Each capacity market is structured differently; some aim to procure capacity for a few months in advance, while others aim to procure it for many years in advance.

In the PJM, ISO NE, MISO, and NYISO capacity auctions, suppliers with available capacity bid on the obligation to sell capacity when called upon. The ISO accepts the lowest-priced bids until the reserve requirement is met. The bid price of the last unit of capacity needed to satisfy that requirement is called the *clearing price*, and is awarded to all suppliers when their capacity is called upon. The capacity auctions are divided into zones, creating locational prices based on supply or transmission constraints or demand differences across regional areas.

All four of these auctions allow energy efficiency to participate[15]—that is, energy efficiency capacity suppliers (such as utilities and third-party administrators) are obligated to reduce demand rather than supply capacity. Critically, to avoid double counting, energy efficiency resources eligible to participate in capacity auctions must not already be accounted for in the load forecast. In PJM, individual efficiency resources are limited to four years of participation, at which point PJM asserts that load reductions would be accounted for in the load forecast. In ISO-NE, efficiency resources can participate for the full measure-life. Including efficiency as a demand-side resource in the load forecast provides the same benefits as including it as a supply-side resource through auctions. However resource providers have additional incentive to bid efficiency resources into the auctions, as auction payments provide added revenue for efficiency suppliers and can drive further investments in efficiency. This, in turn, can reduce direct collection of ratepayer funds through system benefit charges (Relf and Baatz 2017).

In addition to the general reliability requirements that apply to all resources, efficiency resources are subject to additional evaluation, measurement, and verification (EM&V) requirements to participate in the auctions. These requirements are meant to ensure that demand reductions will occur when necessary, as RTOs may find it more difficult to measure and assure the performance of demand resources in comparison with generation

[14] Due to a lack of data, the full efficacy of capacity markets as a cost-effective tool for ensuring resource adequacy compared to regions without capacity markets is not fully known. See GAO 2017 for more information.

[15] These ISOs sometimes report energy efficiency and demand response auction data together. For this analysis, we have separated out energy efficiency data and do not consider demand response.

resources (Relf and Baatz 2017). In PJM, EM&V requirements include a detailed EM&V plan 30 days prior to the auction, an updated report 15 days prior to resource delivery, and post-installation audits (Relf and Baatz 2017). Post-installation audits are used to ensure that efficiency resources are meeting their obligations to deliver capacity. These requirements are similar to the requirements in the other RTOs; ISO NE, however, also requires monthly M&V summary reports during the resource delivery period that detail demand reduction values. We discuss energy efficiency's performance as a reliable resource in relation to each auction below.

Capacity auctions provide quantifiable value for some of energy efficiency's reliability benefits. They also provide information on how ISOs can account for efficiency as a reliable capacity resource, such as by quantifying efficiency's outage rates and the performance of resources meeting their obligations. We discuss those values in the following sections. Although RTOs also allow demand response to participate in capacity auctions and meet emergency operational needs, we consider only energy efficiency in this report.

MISO's Planning Reserve Auction

MISO runs a voluntary auction that occurs two months in advance of when the capacity is needed. Load serving entities with reliability requirements can meet their obligations by providing MISO with a fixed resource adequacy plan (self-supply), through bilateral contracts with other entities or market procurement through the planning reserve auction (PRA). A residual auction occurs prior to resource delivery so that buyers and sellers can balance their portfolios. Energy efficiency resources participating in the auction must register two months prior to the PRA (MISO 2017c). In the 2016–2017 planning year, approximately 73% of resources were procured through the auction rather than through self-supply (Potomac Economics 2017).

Ninety-eight MW of energy efficiency were offered and cleared in the 2017–2018 planning year auction (MISO 2017a). The auction cleared at $1.50/MW-day. This equates to more than $50,000 in payments to energy efficiency providers. This was the first time energy efficiency resources had registered for the auction since the 2013–2014 planning year. Energy efficiency resources are limited to four years of auction participation; after that, they are accounted for in the load forecast (MISO 2017b). With very low clearing prices, it is likely that energy efficiency resource providers do not enter their resources in the auction because the payments are not equal to the time and resources needed to register resources for participation.

PJM's Base Residual Auction (BRA)

PJM's Base Residual Auction (BRA) has been in place since 2007, and it has allowed energy efficiency resources to participate since 2009. Unlike MISO and NYISO, PJM's auction occurs farther in advance of when capacity resources are needed. This allows buyers and sellers to better prepare for changes in demand and supply, as it can take time to build new power generation resources. To account for changes in the resource balance between the BRA and resource delivery, PJM holds three interim auctions where participants can reconcile changes in supply or demand obligations. Efficiency resources are limited to four years of auction participation, after which they are accounted for in the load forecast.

Facilitated by rule changes aimed at addressing system reliability, efficiency's participation in the BRA has been steadily increasing. This indicates that efficiency is a reliable resource. Figure 4 shows efficiency's participation in the BRA in committed MW and as a percentage of total resource s committed.

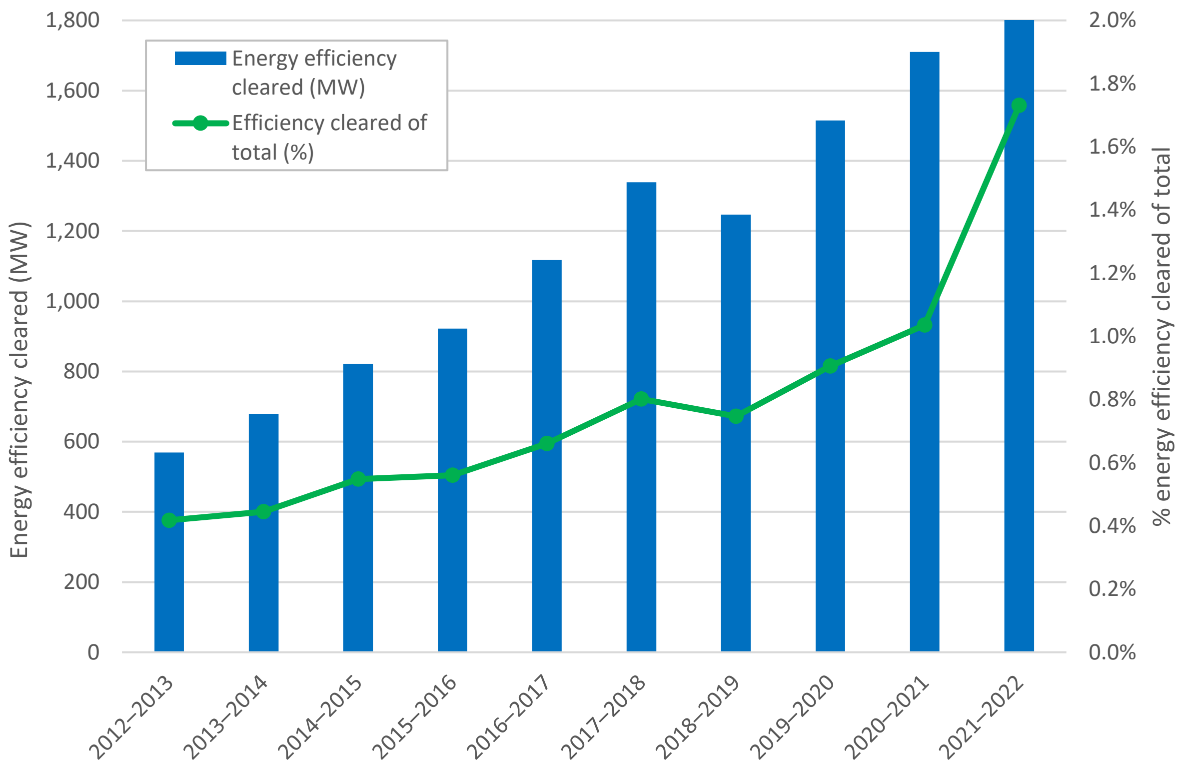

Figure 4. Energy efficiency cleared in the BRA. *Source:* Relf and Baatz 2017.

Efficiency has proven to be a very reliable resource in the PJM BRA. Although resources incur penalties for not delivering on committed obligations, other resources can meet these shortages. Since 2011, net replacements for generating resources have been negative, meaning that these resources have needed to be replaced. In that time, energy efficiency's net replacements have been positive in all but one year, indicating that efficiency is making up lost capacity due to underperforming generating resources. In 2015, energy efficiency provided almost 336 MW of the replacement capacity, which was over 22% of initial commitments by efficiency resources in the auction. This percentage went down in 2016 and 2017, when the rules changed and efficiency was able to replace only other efficiency resources. PJM asserts that the rule was changed to avoid double counting resources that were already included in the load forecast (PJM 2017). Figure 5 shows net replacements as a percentage of total commitments for the PJM resource mix in total and for generating and efficiency resources (Monitoring Analytics 2017).

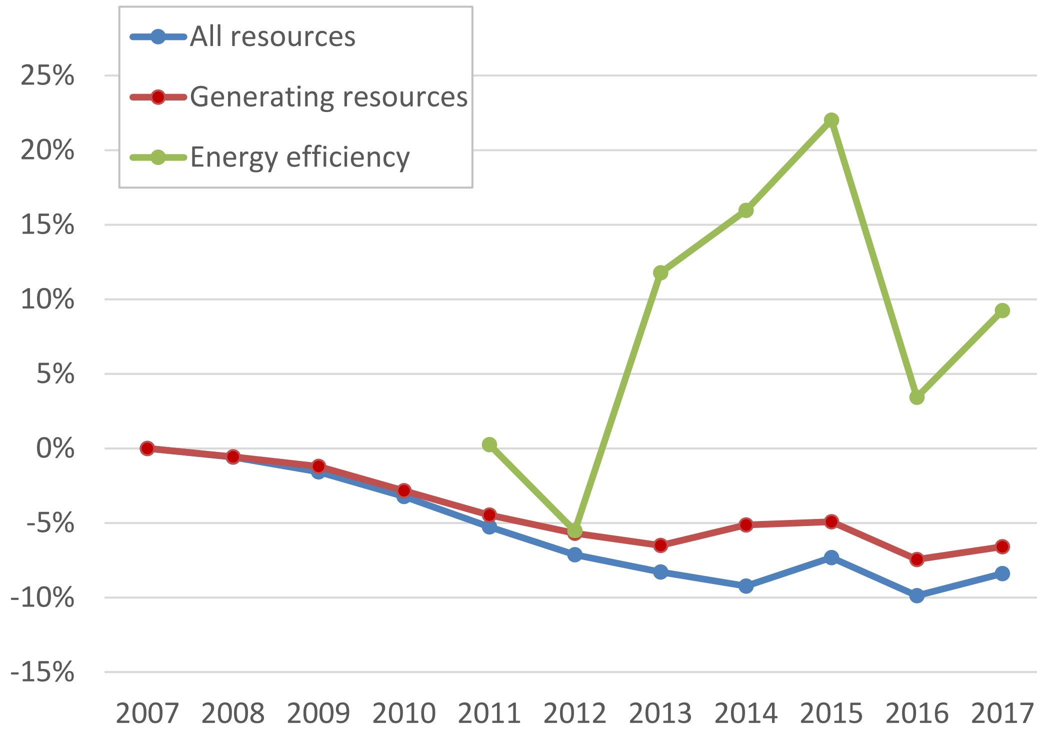

Figure 5. Net replacements as a percentage of total resource commitments. *Source:* Monitoring Analytics 2017.

Energy efficiency typically performs as well as generating resources in satisfying its capacity commitments. In addition to net replacements, PJM's market monitor evaluates commitment shortages, which are, "A failure to satisfy an RPM commitment for which replacement capacity was not obtained and for which Daily Capacity Resource Deficiency Charges are assessed" (Monitoring Analytics 2017, p. 8). In 2017, there were commitment shortages of 7.4 MW of energy efficiency resources, or 0.35% of all efficiency committed. Commitment shortages for efficiency have ranged from 0% in 2011 to 1.32% in 2013. This is similar to generating resources, which had commitment shortages ranging from 0% in 2009 to 1.12% in 2015. These figures indicate that both types of resources are performing reliably.

In response to the polar vortex in 2015, PJM implemented a capacity performance rule, requiring that resources be available year round, or be paired with a seasonal resource of the opposite season. PJM wrote that, "The polar vortex in the winter of 2014 revealed that stronger incentives are needed to encourage investment for better generation performance" (PJM 2015, p. 1). In 2015, 80% of resources clearing the auction needed to meet this requirement, and that requirement increased to 100% by 2017. PJM also stated that, "Capacity Performance works like an insurance policy; for a small cost, consumers have greater protection from power interruptions and price-spikes, especially when extreme weather challenges the grid" (PJM 2015, p. 1). While PJM's statements are mostly focused on generating resources, the rule applies to demand-side resources as well.

In the 2017 auction (the first year of the rule change), most of the energy efficiency resources offered (about 82%) were annual resources that were unaffected by the rule change.

However only 25% of summer efficiency resources offered in 2017 cleared the auction, likely because they were unable to be paired with winter resources. In reference to its demand resources (including demand response), the Potomac Electric Power Company wrote to the Maryland Public Service Commission that "Because the quantity of available winter resources was lower than the quantity of available summer resources, approximately 30% of the Companies' available summer resources clear[ed] the auction" (Pepco 2017, p. 2). Even with the rule change, the absolute amount of efficiency cleared in the auction increased, indicating that the resource is meeting the necessary reliability standards as defined by the capacity performance rule.

Energy efficiency's participation in the BRA, which is designed to meet reliability needs for the PJM region, provides direct payments to resource suppliers. This provides quantitative information on efficiency's reliability value to the grid. Table 3 shows the clearing prices in different BRA zones, as well as the payments to efficiency providers.

Table 3. Resource clearing prices by region and total payments to energy efficiency resource providers

Delivery year	Base payment rate ($/MW-day)	Mid-Atlantic payment rate ($/MW-day)	Eastern Mid-Atlantic payment rate ($/MW-day)	Payments to energy efficiency providers
2012–2013	16.46	133.37	139.73	11,561,513
2013–2014	27.73	226.15	245.00	18,323,569
2014–2015	125.54	127.00	127.00	37,776,814
2015–2016	125.11	156.57	156.57	47,748,214
2016–2017	59.37	119.13	119.13	34,219,748
2017–2018	117.04	117.04	117.04	57,067,110
2018–2019	160.51	160.51	221.16	86,010,807
2019–2020	93.97	93.97	113.74	79,629,496
2020–2021	76.53	86.04	76.53	66,961,965
2021–2022	140.00	140.00	165.73	173,503,979
Total				439,299,235

The payment rate is the clearing price. All prices shown in nominal dollars. *Source:* PJM 2017.

Clearing prices fluctuate based on market supply and demand within each zone. Over the course of efficiency's participation in the auction, providers have received nearly $613 million in capacity payments. These payments are not a main revenue source for providers, but they do provide additional revenue otherwise not captured.

ISO NE's Forward Capacity Auction

ISO NE's capacity auction is called the *Forward Capacity Auction* (FCA). The market has been in place since 2010, and ISO NE has allowed demand resources to participate since its inception. Efficiency resources can participate for their full lifetime (as opposed to the four-year limits in MISO and PJM), as long as they continue to meet EM&V requirements and verify demand reductions. In addition, New England has shown historically strong support for energy efficiency. These two factors likely contribute to the fact that FCA has a higher percentage of total resources made up by energy efficiency than either PJM or MISO.

In the 2017 auction for delivery years 2020–2021, efficiency made up more than 7.5% of FCA's total resources (Relf and Baatz 2017).[16] Efficiency has been steadily increasing in absolute quantity and as a percentage of total resources, and has almost quadrupled in absolute quantity from the first to the most recent auction. Table 4 shows the base payment rate for capacity resources and the associated payments to energy efficiency providers in the FCA.

Table 4. Payments to energy efficiency in ISO NE's FCA

Delivery year	Base payment rate* ($/kW-month)	Payments to energy efficiency providers
2010–2011	4.25	33,413,111
2011–2012	3.12	34,006,033
2012–2013	2.54	30,606,718
2013–2014	2.52	37,188,000
2014–2015	2.86	46,382,901
2015–2016	3.13	56,833,366
2016–2017	2.74	73,235,432
2017–2018	7.03	223,263,932
2018–2019	9.55	254,312,983
2019–2020	7.03	192,354,635
2020–2021	5.30	172,547,656
Total		1,154,144,766

*In ISO NE, the payment rate may differ from the auction clearing price based on adjustments to the clearing price following the auction. *Source:* ISO NE 2017a; ISO NE 2017b; DRWG 2017.

Over the course of the FCA, energy efficiency resources have received more than $1.1 billion in capacity payments.

Importantly, energy efficiency is considered the most reliable resource in the FCA. To calculate how much capacity each auction must procure to maintain reliability, ISO NE assigns each resource an availability factor, which it determines based on each resource's historic maintenance and forced outage rates (ISO NE 2016). For generating resources, the availability factor is based on the unit's most recent five-year historical scheduled maintenance data and NERC's Generator Availability Data System. Energy efficiency

[16] ISO-NE includes both distributed generation and energy efficiency projects as passive demand resources in its reports. For this calculation, we extracted all passive demand resources cleared and removed projects that we judged to be distributed generation based on the project name, leaving only energy efficiency projects.

(referred to as passive demand resources in ISO NE) is modeled as 100% available (ISO NE 2016). This means that fewer resources are needed to meet demand than relying on generation resources alone.

Additionally, audits of FCA resources have found that efficiency resources almost always exceed their capacity obligations. In 2012, for example, efficiency met 120.3% of its summer obligations and 152% of its winter obligations (Smith 2013). Figure 6 shows the audit's results for efficiency resources in 2013.

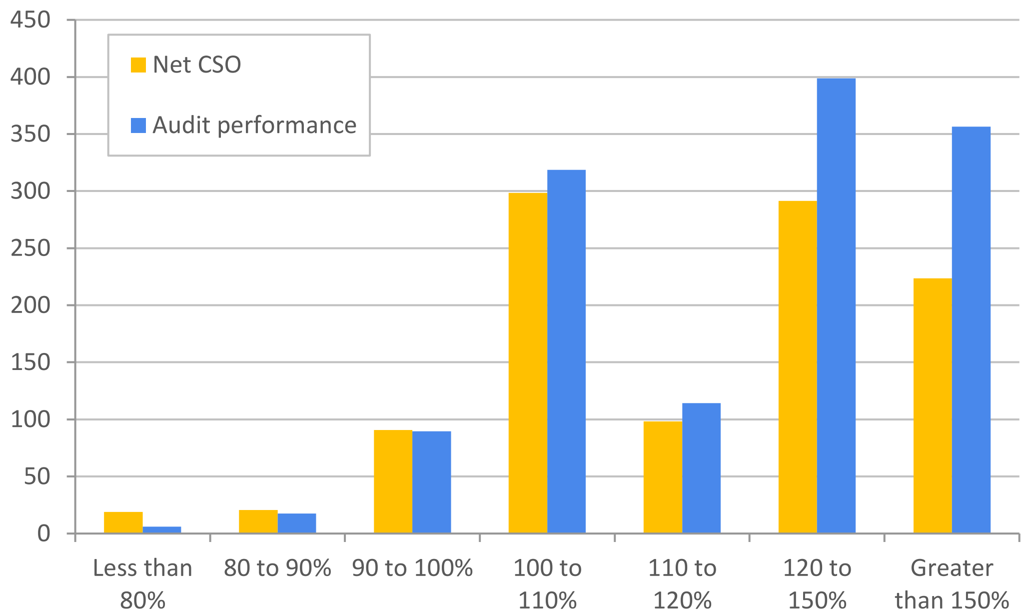

Figure 6. Efficiency resources performance during summer 2013 audit, clustered by resource performance. Net CSO is the capacity supply obligation; audit performance shows how much of the obligation was met. *Source:* Smith 2014.

ISO NE is actively engaged in processes to address system reliability. In January 2018, it released a report on operational fuel security that found that "the possibility that power plants won't have or be able to get the fuel they need to run, particularly in winter—is the foremost challenge to a reliable grid in New England" (ISO NE 2018b, p. 4). ISO NE is particularly reliant on oil-fired generation and on natural gas to meet peak demand, particularly in winter; as a result, pipeline capacity can limit its ability to meet electricity demand. ISO NE modeled 23 scenarios to determine a range of risk scenarios out to the winter of 2024–2025; the study found that, during that period, energy shortfalls would occur in almost every fuel mix scenario, requiring "frequent use of emergency actions," including blackouts (ISO NE 2018b, p. 5). All but one scenario resulted in public calls for energy conservation. The study relied on ISO NE's 2017 forecast of energy efficiency resources from 2021–2026, which shows that peak demand is forecasted to decline 0.7% from 2017 to 2026, and that total electricity consumption is tapering. The forecast also shows that efficiency will reduce peak demand by up to 3,907 MW in winter 2024–2025. Overall, the report highlights increased risk from fuel security shortfalls in region.

A review of this analysis by Synapse Energy Economics, however, found that the report is based on flawed assumptions and undervalues energy efficiency's contribution to the region's fuel security and electric reliability.[17] ISO NE has historically underforecasted efficiency resources and overestimates demand growth for both electricity and gas for all scenarios in the report. Synapse Energy writes that "Their demand estimates are superseded by ISO's own updated 2018 forecast for demand, which was not used in this analysis" (Knight 2018). ISO NE assumes that annual demand for natural gas by non-electric consumers will grow by 1.9%, yet it has increased by only 0.7% in recent history. Figure 7 shows the average difference between ISO incremental efficiency forecasts and how much new efficiency has cleared in the FCA.

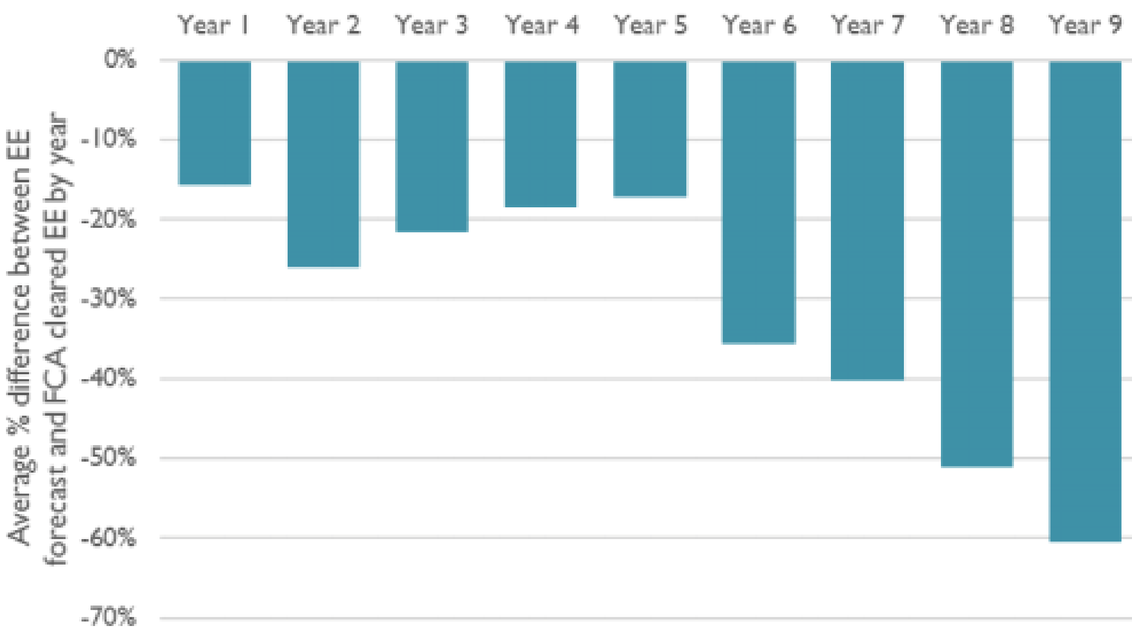

Figure 7. Average percentage difference between ISO incremental efficiency forecasted and cleared new efficiency in the FCA by year of forecast since 2012. *EE* stands for energy efficiency. *Source:* Synapse 2018b.

Inaccurate forecasts both undervalue the reliability benefits of efficiency measures currently in place and overestimate demand growth. This leads to overinflation of risk scenarios in the fuel security report.

DISCUSSION

As the examples above show, energy efficiency is increasingly integral to grid planning, operation, and market transactions, and yields clear benefits for grid reliability. The approaches to quantify these benefits include valuing reliability in cost–benefit analysis and capacity pricing. These approaches are somewhat indirect, however, and reflect the way that reliability factors into forecasting, capacity auctions, T&D system planning, and

[17] The report was funded by the New Hampshire Office of Consumer Advocates, Maine Office of the Public Advocate, and Vermont Energy Investment Corporation.

screening of energy efficiency and demand response measures. Figure 8 illustrates how the reliability benefits of energy efficiency touch on key elements of grid planning and operation.

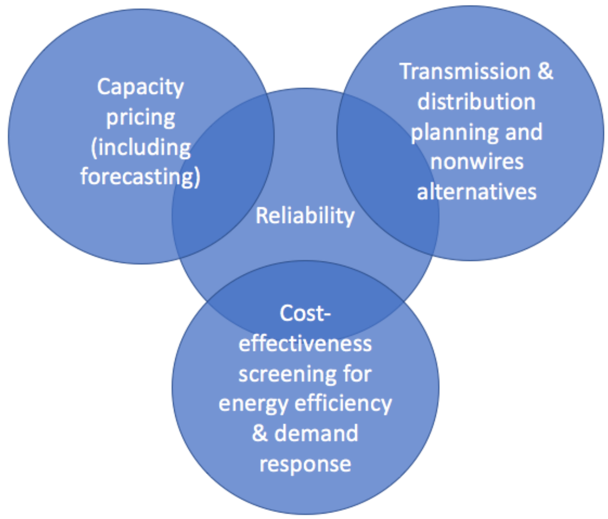

Figure 8. Energy efficiency and reliability in system planning and operation

Emerging Opportunities for Energy Efficiency and Reliability

The reliability and resilience of our electricity grid have become top-tier issues for several reasons. Catastrophic weather events have caused massive power outages affecting millions of customers. Rapid increases in DERs, including customer-owned solar and utility-scale solar and wind power, are changing the resource mix available to grid operators and introducing operational challenges related to their intermittent nature. At the same time, many existing fossil fuel power plants, particularly large coal-fired units, are retiring. On the demand side, rapid technological changes are underway as various smart technologies provide new two-way communications between customers and suppliers, as well as rich new sources of interval or real-time data on customer energy use. These are just some of the key changes that are transforming the electric utility industry. With these changes come new opportunities and challenges for energy efficiency and reliability.

Reliability and Wholesale Energy and Capacity Markets

Utility stakeholders are currently engaged in a national conversation about grid resilience, reliability, and the changing resource mix. Each type of resource has different impacts on grid operations and reliability. In response to this discussion, grid operators, regulators, resource owners, and others are considering how to compensate resources for their various attributes, including reliability, within their capacity and energy markets. The dialogue surrounding issues such as DER aggregation in wholesale energy markets and how to include state-supported resources within markets creates an opportunity to consider how policies affect the inclusion of demand resources such as energy efficiency in the resource mix. Changing market structures may give grid operators new or expanded opportunities to explicitly value and include energy efficiency in their market structures as a resource option to meet reliability objectives.

In fall 2017, a discussion about resource compensation began when the DOE proposed that FERC provide payments to ensure cost recovery to generating resources that had 90 days' worth of fuel on-site in wholesale energy markets (DOE 2017). FERC rejected the proposal, arguing that not all resources would be eligible to receive payments, even though they may have other resilience attributes (FERC 2018). The FERC proceedings gave rise to a few important trends. Seven grid operators submitted comments to FERC, in which they emphasized that ensuring resilience is not a matter of maintaining uneconomic power plants, but instead of minimizing disruptions to T&D poles and wires.

While these proceedings focused largely on resilience—which is a more holistic approach to power security—the concept is complementary to grid reliability. In our view, such conversations should include energy efficiency, which can reliably meet T&D infrastructure needs at a lower cost to customers (such as through NWAs). A greater nationwide attention to reliability can also help direct utility and non-utility program administrators to design and implement efficiency programs, codes and standards, and financing with reliability benefits explicitly in mind. As a NERC reliability official stated, "We can transition to a grid that has whatever fuel you really want to power the system by, but policy changes are needed" (Jackson 2018). This includes creating fuel- and technology-neutral reliability standards and policies for the bulk power system (Jackson 2018). Given the key role it can play in maintaining grid reliability and resilience, energy efficiency should be included in the ongoing national dialogue.

SMART GRID: INTEGRATING DEMAND RESPONSE AND ENERGY EFFICIENCY

Other policies and programs besides energy efficiency programs are typically pursued in planning for electric system reliability. Demand response and other types of load management directly address reducing peak demand. Further, utility investments in advanced meters are often justified largely on their reliability benefits. Advanced metering investments are part of a much larger effort to modernize the grid through smart technologies. These technologies can detect, communicate, control, respond to, and resolve system problems in near real time, which can help avoid system-wide outages (Executive Office of the President 2013). For example, advanced metering infrastructure (AMI) enables various technologies and services that customers can use to change their energy use in response to real-time data. For maximum impact, AMI must be coupled with communications, pricing, and controls.

Smart technologies that can provide two-way communications between customers and suppliers are transforming the electric utility industry. The resulting modernized grid will be capable of much more responsiveness and interactivity than the traditional grid. These technologies can detect, communicate, control, respond to, and resolve system problems in near real time, which can help avoid system-wide outages. They can also enable better integration of the many advancing energy resources, including energy efficiency, demand response, storage, onsite renewable energy, grid renewable energy, and onsite fossil fuel generation. Such integration will require changes in utility business models and regulation. As advanced meters replace traditional meters, utilities and grid operators will have access to much more granular customer data. Such big data create analytical capabilities both for customers and utilities to better understand and manage energy use.

Integrated energy efficiency and demand response programs are growing and will provide utilities and grid operators additional options for grid management and reliability in addition to the new capabilities provided by distributed energy and grid-scale renewable energy. These programs can offer a broader set of benefits and greater customer value than stand-alone programs. According to a recent scoping study by Lawrence Berkeley National Laboratory (LBNL), integrated energy efficiency and demand response programs must address regulatory and administrative barriers if they are to grow (Potter et al. 2018). The LBNL study also identifies the most promising technologies for integrated energy efficiency and demand response programs. These include:

- *Residential.* Home retrofits, HVAC controls, water heating, electric vehicles, advanced solar inverters, and battery storage.
- *Commercial and industrial.* Lighting systems and controls, retrocommissioning, energy management control systems, battery storage, and electric public buses.

Residential smart thermostat programs are the most prominent current examples of utility programs that address both energy efficiency and demand response capabilities.

Scale is a factor in achieving energy efficiency's reliability benefits for the grid. Sufficient total MW savings would be needed to have an impact on system load when reliability is threatened. For example, California's programs in 2001 are estimated to have delivered 15–20% peak-demand savings during critical times. This level of savings is not necessarily needed in other situations, but demand reductions of single-digit percentages likely would be needed as a minimum threshold to provide systemwide benefits. From a utility perspective, the impact must be at the relevant scale—whether at system or distribution level—of the targeted need. Program-level savings are the key in either case. The scale of addressing system peaks is larger than the scale needed to address targeted distribution-level peaks.

Conclusions and Recommendations

Energy efficiency has proven its value and capability as an energy resource that can improve and support electric system reliability. Reducing demand can increase reserve margins, which increases the adequacy of available resources to serve load. Resource adequacy is critical to assure grid reliability. Perhaps the most dramatic example is the experience during California's 2001 electricity crisis, which showed the ability of energy efficiency programs to yield significant reliability impacts. During that crisis, energy efficiency played a critical role in maintaining the required reserve margins to prevent system-wide outages, which would have had devastating impacts on California's economy. This experience provides a vivid illustration of energy efficiency's reliability value in aggregate. Energy efficiency is a resource option that can help achieve and support electric system reliability, just like investments in generation supply and T&D infrastructure.

Non-wires approaches to grid congestion provide another clear example of deploying energy efficiency as a resource to achieve a least-cost solution to T&D resource investments and upgrades needed for reliability. Integrated resource approaches to distribution planning are key to evaluate and implement energy efficiency as an alternative to upgrades and investments in "wires" and associated T&D infrastructure that otherwise would be needed to relieve congested parts of the grid.

A third prominent example area is energy efficiency's role in forward capacity markets, which has demonstrated the market value of energy efficiency resources. Providers of such resources with successful bids are being paid the value of this avoided capacity. The rigorous qualification and evaluation required for energy efficiency resources to participate ensure that the energy savings claimed in bids can be provided. As system operators have gained experience and confidence in energy efficiency as a grid resource, the amount of this resource clearing in these auctions has grown. Data and analysis from ISO NE's capacity auctions show that energy efficiency resources have been successfully delivered at 100% availability (ISO NE 2016).

Despite energy efficiency's proven value as a capacity resource and least-cost resource for NWA and other integrated resource solutions, energy efficiency is typically undervalued for resource screening, analysis, and evaluation. The result is overinvestment in generation and T&D resources and corresponding higher system costs that ultimately are borne by energy customers. We found few examples of states specifically quantifying energy efficiency's reliability benefits beyond the typical avoided capacity costs. Although its broader reliability benefits are frequently acknowledged, they generally are not quantified in screening analyses for the cost effectiveness of energy efficiency measures and programs.

To capture the full reliability benefits of energy efficiency, we make the following recommendations:

- Integrated resource planning should fully value the reliability benefits of energy efficiency in the analysis and selection of resources.
- Evaluating non-wires (including targeted energy efficiency) alternatives to T&D investments should become standard practice.
- Capacity auctions and wholesale power markets should include efficiency as a resource. Those already doing so should expand efficiency resource additions as markets grow and efficiency provides a least-cost, reliable solution. Those currently not doing so should make efficiency eligible to participate in their markets.
- Energy efficiency and related customer program administrators should explore integrated efficiency/demand response programs. In doing so, they should also ensure that the rapid rise of smart technologies can deliver both efficiency and demand response benefits along with corresponding grid reliability benefits.
- Programs should target critical loads to make them energy efficient and thereby improve resilience.

The utility industry is undergoing fundamental transformations and requires significant investments to modernize the grid. Energy efficiency is a proven resource that is integral to such transformation and modernization. To capture the value of energy efficiency as a grid resource requires acknowledging and quantifying the full set of benefits that it provides. One such benefit is reliability. Concrete examples demonstrate that this value, while not easy to quantify, can be substantial—and is clearly not zero.

We recommend that future efforts seek to quantify these impacts for particular systems and portions of systems based on some of the emerging methods we discuss. The full value of energy efficiency should be included in planning and decision making for a clean, smart, and reliable grid.

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Appendix A. New York's Reforming the Energy Vision BCA Framework

Table A1. Benefits and costs considered under New York's REV Benefit–Cost Analysis (BCA) framework

Benefit	Description
Bulk system benefits	
Avoided generation capacity (ICAP) Costs	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. BCA notes that, because the auctions account for transmission constraints 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 Prices, 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*. This study is conducted every other year, and forecasts energy prices out to 20 years in 11 regional zones based on transmission congestion areas and specific resource proposals. BCA 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 states that utilities should consider developing a more granular methodology for calculating this benefit over time at the distribution level, such as down to the substation, feed, transformer, or customer level.
Avoided transmission capacity infrastructure and 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 transmission losses	Accounts for any avoided transmission losses not accounted for in the avoided energy costs
Avoided ancillary services	Highly project specific. Accounts for reduction in required ancillary services (spinning reserves, frequency regulation, voltage and VAR support, etc.) from generators more closely following load. Utilities are asked to outline how this will be calculated in their filings.
Distribution system benefits	
Avoided distribution capacity infrastructure	Calculated based on the granular data that 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.
Avoided O&M costs	Determined using the utility's activity-based costing system or work management system
Avoided distribution losses	Calculated as "the difference in the amount of electricity measured coming into a utility's system from the NYISO or distributed generators and the amount measured by the company's revenue meters at customer locations"
Reliability and resiliency benefits	
Net avoided restoration costs	Calculated for projects that may result in reduced restoration times by comparing the number of outages and the costs of restoration before and after the project

Benefit	Description
Net avoided outage costs	Calculated based on a project's expected effects on the number and length of outages and the cost of each outage specific to customer class and region. BCA notes that the portion of avoided outage costs already included in the avoided T&D categories should not be double counted here.
Externality benefits	
Avoided GHGs, criteria pollutant, land use, and water use costs	BCA proposes three methods for calculating externality costs for comment from stakeholders (including avoided GHGs, criteria pollutants, and land and water usage): (1) Rely on the embedded costs in the LBMP. (2) Attempt to calculate a marginal damage cost to add to the costs embedded in the LBMP. (3) Apply the renewable energy credit price ($/MWh) for large-scale renewables to DERs.
Net nonenergy benefits	BCA proposes that net nonenergy benefits such as health impacts and employee productivity should not be monetized at this time.
Costs	
Program administration	Costs incurred to administer the program
Added ancillary services	Additional costs incurred for increased required services such as spinning reserve and frequency regulation
Incremental T&D and DSP	Any additional T&D costs incurred due to the project, such as the need to build additional infrastructure
Participant DER	Calculated as direct costs to the DER provider as well as 75% of any incentives paid to participants to account for participant opportunity costs
Net nonenergy costs	BCA proposes that net nonenergy costs such as indoor air pollution and noise pollution should not be monetized at this time.

Source: NY DPS 2015b