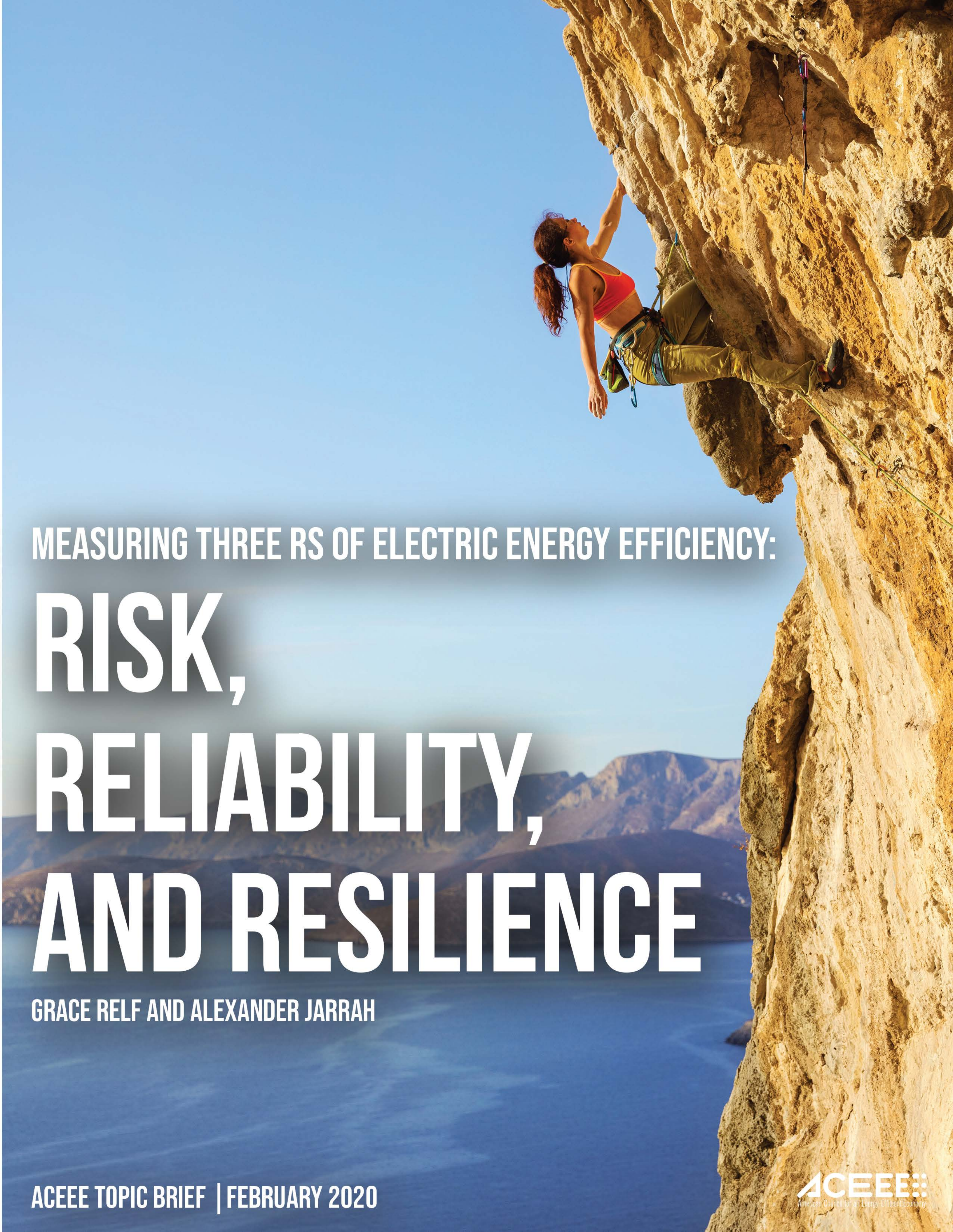

MEASURING THREE RS OF ELECTRIC ENERGY EFFICIENCY:

RISK, RELIABILITY, AND RESILIENCE

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ACEEE Topic Brief

American Council for an Energy-Efficient Economy

Measuring Three Rs of Electric Energy Efficiency: Risk, Reliability, and Resilience

Grace Relf and Alexander Jarrah

Key Findings

This brief presents lessons and replicable practices for stakeholders looking to quantify risk, reliability, and resilience (three Rs) in their cost-effectiveness tests for energy efficiency. While collectively called the three Rs, these efficiency impacts are all critical and distinct components of utility system benefits. Risk covers exposure to factors that will undesirably increase system costs or adversely affect service; reliability pertains to low-impact, high-probability events; and resilience covers high-impact, low-probability events. Our research findings indicate that:

- **Few states are quantifying the three Rs in their cost-effectiveness tests.** Seven states include risk as an impact in their primary cost-effectiveness frameworks, three include reliability, and none includes resilience. New England states are taking steps to begin quantifying all three impacts. Within the somewhat limited data set of quantified values, the assessed values for risk and reliability are fairly wide ranging because they are specific to the landscape of each utility.
- **Industry needs consistent methodologies for quantifying the three Rs.** While frameworks are available for quantifying each impact, lack of data and limited resources make it challenging to operationalize them. An important first step is to define the impacts to avoid double counting costs and benefits.
- **New quantification methodologies will be required going forward.** Utilities and regulators should clearly define the scope of each impact. Customer impacts and the interactive effects of multiple distributed energy resources are particularly challenging and costly to quantify. Alternative methods like proxies or adders may be necessary.

Contents

Introduction

Increasingly frequent catastrophic weather events like forest fires, winter storms, hurricanes, and flooding that cause power outages are costing the country hundreds of lives and billions in damage annually (Silverstein, Gramlich, and Goggin 2018). At the same time, distributed energy resources (DERs) that provide variable power flow to the system are coming online as customers increasingly seek low-carbon power sources. Although they bring many benefits, DERs also create new challenges for grid operators who must balance supply and demand. These recent trends are leading to an increased focus on the multiple benefits that energy efficiency delivers to the electric system and to customers and society. In addition to creating jobs, reducing carbon emissions, and improving public health, efficiency contributes to the stability and resilience of the electric grid by reducing overall energy usage and peak demand.

COST-EFFECTIVENESS TESTING

To deliver energy efficiency using ratepayer funds, utilities and program administrators must demonstrate to regulators that the expenses are prudent and the benefits outweigh the costs.

The *National Standard Practice Manual* (*NSPM*) *for Assessing the Cost-Effectiveness of Energy Efficiency* sets forth the following key principles, including:

- Energy efficiency should be treated as a resource and compared consistently with other utility resources.
- A jurisdiction's primary cost-effectiveness test should account for its energy and other applicable policy goals and objectives.
- Cost-effectiveness practices should be symmetrical, including or excluding both costs and benefits for each relevant type of impact.
- Cost-effectiveness practices should account for all relevant material impacts, including those that are difficult to quantify or monetize (NESP 2017).

Quantifying all the relevant benefits of efficiency—including the full range of utility-system benefits and nonutility impacts that align with state policies—is critical to demonstrating the value of the resource to a state in its cost-effectiveness analysis.

This brief focuses on three utility-system impacts of energy efficiency that are important to account for and help ensure alignment with the *NSPM* principles:

- *Risk*. Exposure to factors that will undesirably increase system costs (e.g., fuel costs) or adversely affect electric service. We focus on financial and operational risks affected by energy efficiency, including fuel-mix diversity, reliance on long lead-time investments, and climate or environmental compliance costs.
- *Reliability*. The system's ability to ensure adequate and dependable power supply in response to high-frequency, low-impact events.
- *Resilience*. The system's ability to withstand or recover from low-frequency, high-impact events.

This brief presents lessons and replicable practices that jurisdictions can use to quantify these three Rs in their cost-effectiveness tests for energy efficiency and other DERs.[1] We focus on energy efficiency but recognize that the three Rs should be considered across utility planning, including for other utility investments and customer-sited DERs (discussed in the text box below). We begin by reviewing the full range of utility-system impacts of energy efficiency and the growing focus on quantifying the three Rs. For each of the three impacts, we provide a definition, context for its increasing importance in the energy system, energy efficiency's contribution to the impact, and how that contribution can be quantified for cost-effectiveness tests. Where applicable, we include existing values for the impacts by providing an overview of states that currently quantify them and details on how they do so.

Distributed Energy Resources (DERs)

DERs, including demand response, solar, storage, and other renewable generation, provide variable power flow to the system and create new challenges for grid operators balancing supply and demand. These resources present opportunities to increase benefits to the system and customers, but they can also increase the risk that infrastructure investments could become unnecessary, or stranded assets, in the future, as discussed in the section on risk.

However DERs also include customer-sited resources like energy efficiency and the resources described above that can reduce risk and improve reliability and resilience of the energy system. DERs are frequently sited close to customers and often decrease peak demand (FERC 2018). DERs also reduce reliance on fuels like natural gas and are more modular than other resources. These attributes can lessen the need for additional large generating resources. Those resources with the ability to operate independently of the larger grid, like some solar photovoltaic systems, can decrease the chances of power supply interruptions, increasing system reliability. DERs can also be deployed within microgrids, which may be able to operate during larger grid outages.

When deployed in an integrated way with energy efficiency, these effects can be additive (York, Relf, and Waters 2019). Efforts to quantify and include these impacts in utility planning and decision making are increasing. In this brief, we focus largely on energy efficiency but include a section at the end on considerations for other DERs.

Cost-Effectiveness Testing and Accounting for Utility System Impacts

Cost-effectiveness tests (also called cost–benefit analyses) are used in utility resource planning to determine how much energy efficiency will be included in the future resource mix and which programs will go forward. Therefore capturing the full costs and benefits is critical to deploying energy efficiency as a resource in the energy system. Costs and benefits should be considered symmetrically, and states should use recent data that are specific to the jurisdiction to quantify impacts, consistent with the *NSPM* principles. Where data are not available, other methods, such as proxies, can be used to account for relevant costs and benefits to recognize that the benefit is not zero, even if hard to quantify.

[1] As noted, programs that combine energy efficiency offerings with other DERs can create interactive effects. Those other DERs may also individually deliver impacts from one or more of the three Rs. We do not address these cases here but note their inclusion in the forthcoming *NSPM for DERs*: nationalefficiencyscreening.org/the-national-standard-practice-manual-for-ders/.

This brief focuses on impacts to the utility and its system, which covers energy generation, transmission, and distribution. Utility system costs include

- Incentives or rebates paid to customers
- Labor and other administrative costs of running programs
- Evaluation, measurement, and verification (EM&V) costs
- Other technology and shareholder incentive costs

While such utility system costs are typically well-known and easily tracked and calculated, the utility-system benefits of energy efficiency can be much more difficult to quantify. They include

- Energy costs
- Capacity costs
- Transmission and distribution (T&D) costs
- Environmental compliance
- Price suppression
- Line loss costs
- Market transformation
- Ancillary services
- Renewable portfolio standard (RPS) compliance
- Avoided credit and collection costs
- Reduced risk
- Increased reliability
- Increased resilience (NESP 2019)

While quantifying the full range of these impacts is important, only Rhode Island's test includes every one of them. Other states include only some, most commonly avoided energy, capacity, and T&D costs. Figures 1 and 2 show the number of states accounting for each utility system cost and benefit.

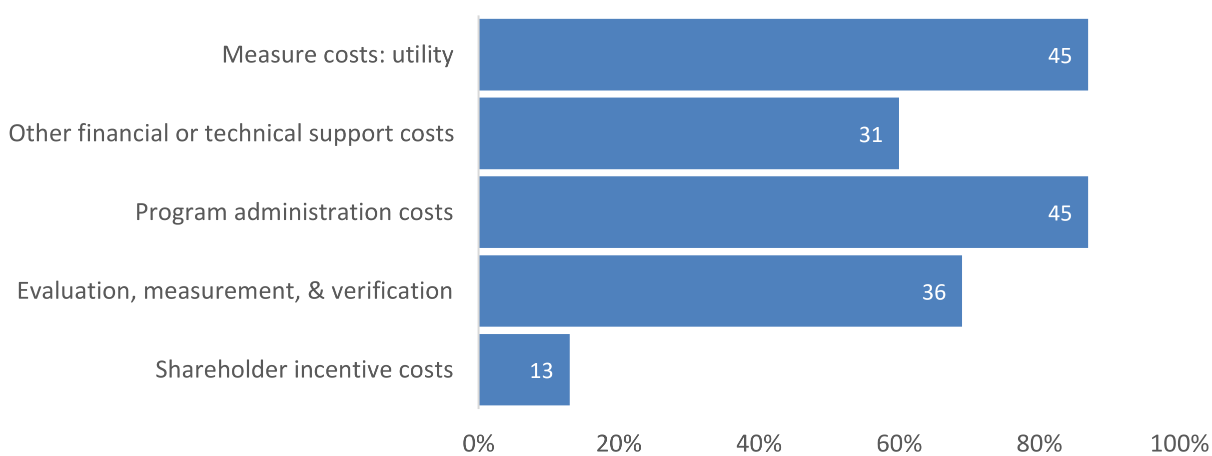

Figure 1. Number of states accounting for utility system benefits of energy efficiency. *Source:* NESP 2019.

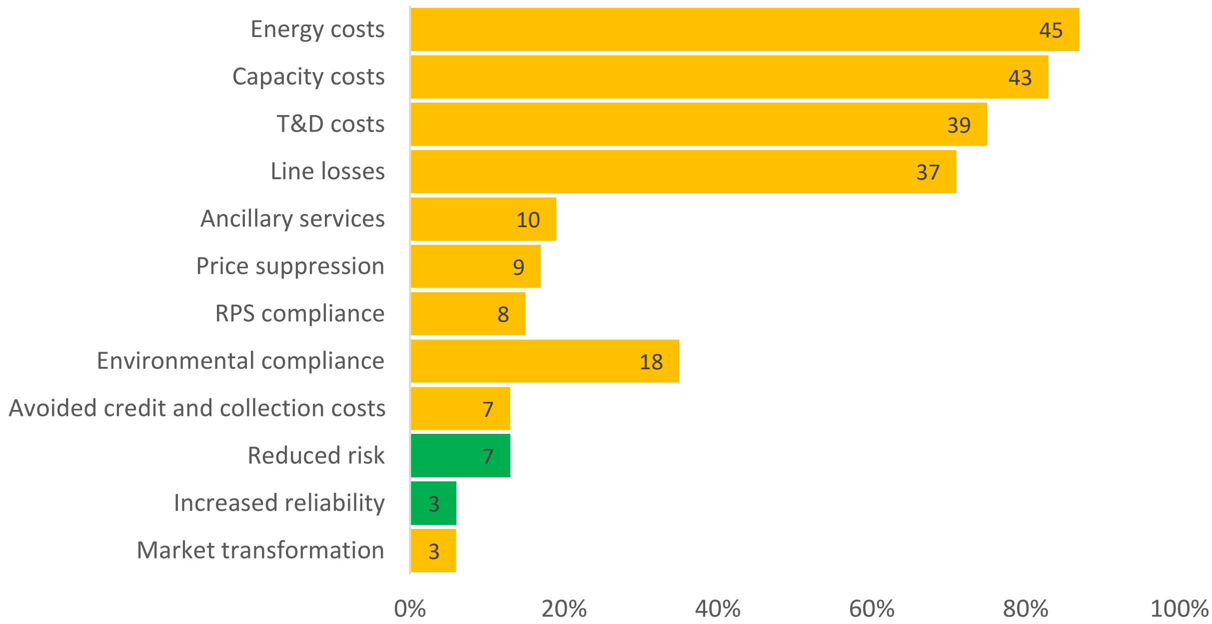

Figure 2. Number of states accounting for utility-system benefits of energy efficiency. ***Source:*** **NESP 2019.**

Of these benefits, this brief focuses on risk, reliability, and resilience, given increasing attention to these issues in public discourse but limited application as of yet in cost-effectiveness testing. Only a few states account for the three Rs in their benefit–cost analyses of efficiency investments. According to the Database of State Efficiency Screening Practices (DSESP), only seven states account for reduced risk, three account for increased reliability, and no states currently account for resilience. These states account for those impacts in the framework but may not yet be quantifying any value for the impact.

Research and Scope

To complete this study, we reviewed literature and studies on risk, reliability, and resilience in the energy sector. We used the DSESP to determine which states include these impacts in their cost-effectiveness tests and reviewed each case to determine those with adequate information and data to include as examples in the brief. Although risk, reliability, and resilience are also important issues in the US territories, we focused this research on only the 50 US states. To gather data for analysis and discussion, we relied on publicly available energy efficiency filings, regulatory orders, and legislative documents. Subject matter experts and key stakeholders provided additional context and confirmed accuracy of information in the example states. This brief considers mainly electric energy efficiency, although we include one example from the natural gas sector as the lessons may be applicable to that sector as well.

Next we provide more detail on each risk, reliability, and resilience.

Risk

WHAT IS IT?

Utility systems face a large number of risks every day. Here we focus on risks specific to the electric utility system, which we define as exposure to factors that will undesirably increase system costs or adversely affect electric service. These include financial risk (passed on to either shareholders or customers) and operational risk, both of which have negative effects on customers. These risks should be a primary concern of utilities and their regulators, and the impacts of energy efficiency on these risks should be quantified in efficiency cost-effectiveness testing. Utility planning typically uses scenario or sensitivity analyses to account for the many uncertainties the business faces. For example, many future utility costs and conditions are uncertain, such as costs to comply with future climate change policies, T&D systems costs, and economic growth. While poor reliability and resilience pose both financial and operational risks to the utility, we address them separately.

All businesses face risk from changing prices for their supply commodities. This is particularly important for utilities that rely on fuels in global markets with fluctuating prices. Utilities often pass fuel-price risks on to ratepayers through adjustments to customer bills, exposing ratepayers to risks taken on their behalf by their utility.

Energy efficiency can address some major financial and operational risks to the utility system caused by rapid change in the energy sector. Regulatory changes, such as rate structure changes and new and changing environmental regulations at the local, state, and national levels, pose an increasing financial risk for utilities. These changes can affect cost recovery of existing investments and create the potential for stranded assets. Utilities also face increasing operational risks from catastrophic weather and cyberattack events (Chambers 2018; Kerr 2018).

RISK IN CONTEXT

In 2019, utilities continued to rely on natural gas for 44% of generation capacity across the United States (Deloitte 2019). Reliance on natural gas for fuel beyond a regional threshold can be risky to utilities because natural gas is subject to supply constraints or interruptions and prices fluctuate over time, as shown in figure 3. Natural gas can be subject to accidents and interruptions in supply infrastructure and to storage and distribution constraints (Young, Elliott, and Kushler 2012).

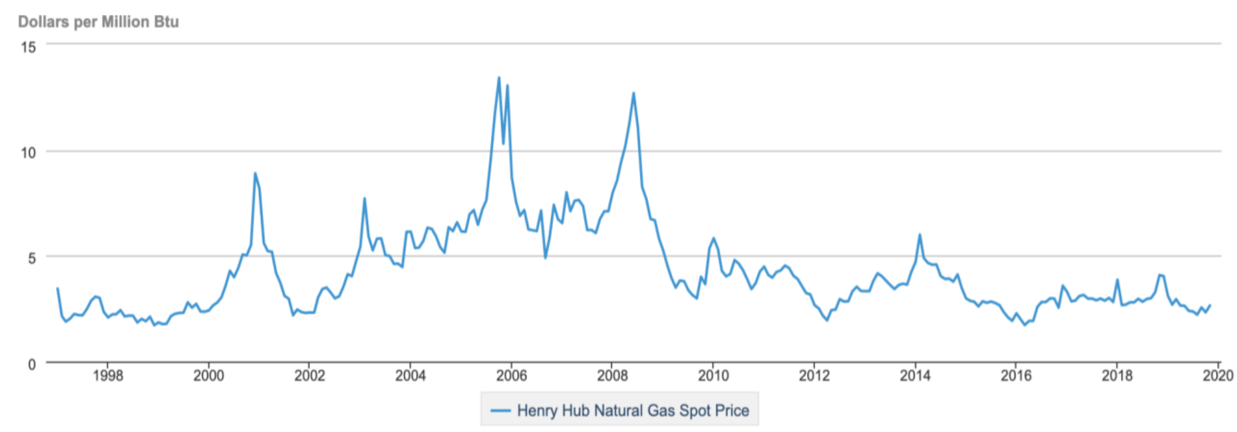

Figure 3. Monthly natural gas prices for Henry Hub, 1997–2020 ($ per mmBTU). *Source:* EIA 2020b.

The United States is in a period of relatively low and stable natural gas prices due to increased supply from fracking and other domestic resources. However, over the past 30 years, prices fluctuated significantly from under $2 per MMBtu to over $14 per MMBtu (Young, Elliott, and Kushler 2012). While some analyses show that natural gas prices will remain low in the coming years, projections depend on variables that may shift, including the global availability of natural gas and the availability of other resources such as liquefied natural gas, and on technological advances and an uncertain regulatory environment (EIA 2020b; Young, Elliott, and Kushler 2012).

Some regions rely more heavily on natural gas and face growing constraints on infrastructure. New England has identified natural gas availability and price spikes as a major risk to the region (ISO-NE 2020). Heating demand during cold periods in winter has required utilities to use all of the available pipeline infrastructure, leaving little or no capacity to import additional natural gas to meet electricity demand. This has led to increased natural gas and wholesale electricity prices and increased emissions from relying on dirtier fuels in place of natural gas for heating and power generation (ISO-NE 2020). Natural gas prices spiked to over $285 per MMBtu on January 5, 2018 from an average of $10 per MMBtu during regular conditions in December 2017 (ISO-NE 2018b). In New England, such wholesale price spikes have been driven by low fuel availability during extreme cold weather events, which is an increasing concern as climate change leads to more cold spells (e.g., polar vortexes) (ISO-NE 2020). This situation is not unique to New England as extreme temperature events are occurring across the country. For example, utilities in Michigan asked customers to reduce energy use in response to extreme winter temperatures and supply constraints from a gas compressor facility fire in 2019 (Siacon 2019; Irfan 2019).

The risk of stranded assets associated with investments in existing capital infrastructure, like generating power plants and pipelines, is also a growing financial concern. Utilities are increasingly committing to mandatory (state policy) or voluntary carbon reduction goals and are reducing fossil fuels as part of the resource mix (SEPA 2020; EIA 2019a). The proliferation of renewable and distributed energy resources due to lower costs and customer demand is also increasing the risk of stranding existing assets and the need to recover costs associated with decommissioning old power plants more quickly.

Without appropriately considering energy efficiency and other low-cost alternatives to new fossil fuel buildout, new investments in capital infrastructure also run the risk of becoming stranded. A recent study shows that utilities and investors have over $70 billion planned for investments in new gas-fired power plants through 2025. The analysis reveals that portfolios of renewables, storage, and demand-side management can often more cost effectively provide the same reliability services, including energy, capacity, and flexibility. Such clean-energy portfolios could render 90% of proposed new combined cycle natural gas capacity uneconomic as early as 2035, before the end of their useful lives (Dyson, Engel, and Farber 2018). Utilities and their shareholders may bear the brunt of those costs, but regulators may allow utilities to recover some or all of those costs from customers (T&D World 2018; Kerr 2018).

Compliance costs for climate policies also pose a financial risk to utilities. Some states, like Washington and Oregon, have unsuccessfully considered implementing carbon pricing schemes. Others, like Virginia and New Jersey, have recently joined a regional carbon trading program. Overall, an increasing number of states are committing to low- or zero-carbon futures (C2ES 2020).

Utilities will need to comply with these policies through investments in low-carbon resources like energy efficiency.

RISK AND ENERGY EFFICIENCY

We focus on utility-system risks that are mitigated by reduced demand or the other benefits of energy efficiency. These include supply price volatility risks and risks associated with investment in capital assets (i.e., the risk that they will become stranded assets or will pose financial costs to comply with environmental policies) due to changing regulatory environments, the increased proliferation of DERs, and increased climate commitments and policies. Risks related to catastrophic weather and other events that result in outages are included in energy efficiency's impact on reliability and resilience.[2]

Energy efficiency can reduce exposure to risk in three main ways:

- It diversifies the resource mix as a cost-effective distributed resource and reduces reliance on fuel sources that can be subject to limited availability and fluctuating prices.
- It is a modular resource that can reduce reliance on long lead-time investments, which can affect risk in multiple ways.
- It is a carbon-free resource, reducing the risk of current or future costs of compliance with climate or environmental policies.

Energy efficiency diversifies the resource mix as a cost-effective distributed resource and reduces reliance on fuel sources that can be subject to limited availability and fluctuating prices.[3] Heavy reliance on a single fuel source leaves utilities vulnerable to price fluctuations and supply interruptions. Energy efficiency reduces reliance on fuels that are subject to these factors, thereby reducing those risks. In addition, portfolios of energy efficiency resources that produce savings over time act as a long-term contract for electricity at a fixed price, and the costs are not affected by price changes in other resources. Therefore efficiency can act as a hedge against price spikes (Baatz, Barrett, and Stickles 2018; EPA 2018).

Energy efficiency is a modular resource that can reduce reliance on long lead-time investments, which can affect risk in multiple ways. Capital investments such as power plants are expected to run for many years (often up to 40 years or more), enough time to adequately recover fixed (e.g., construction) and variable (e.g., operating and maintenance) costs according to plans approved by regulators. These investments require long-term projections of demand, which are unlikely to be precise and thus pose the risk that the infrastructure may become unnecessary and that costs will not be recovered for the stranded asset (Dyson 2017; EPA 2018). Changing environmental and climate policies and regulations create the additional risk that large generating assets may not comply with

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[2] Utility customers also face individual risks, some of which can be addressed through energy efficiency. For example, strategic energy management is a tool that industry can use to reduce risk exposure to changing fuel prices (Naumoff and Shipley 2007). However this brief does not focus on reduction in risks to individual customers as it is not yet considered in cost-effectiveness testing and is not a utility-system impact. This area should be considered for future exploration and inclusion in cost-effectiveness tests.

[3] A diverse fuel supply also contributes to strengthened energy security by reducing vulnerability to attacks or disasters. Energy security is an important element of risk but is classified as a different impact of energy efficiency than reduced risk in the DSESP.

future regulations unless they exempt existing assets ("grandfathering"). As a more modular resource that can be acquired in small increments with shorter installation times than generating resources, energy efficiency both lowers demand and reduces the need for long lead-time investments (Lazar and Colburn 2013).

Energy efficiency is a carbon-free resource, reducing the risk of current or future costs of compliance with climate or environmental policies. While current compliance costs are captured in a separate category from risk in energy efficiency cost-effectiveness testing, called *avoided environmental compliance costs*, this does not account for future compliance costs (Nadel and Ungar 2019).

Risk in Cost-Effectiveness Testing

In line with the multiple risks faced by utilities, states consider the impact in different ways in their cost-effectiveness tests. In Oregon, the value is calculated as a fuel-price volatility risk-reduction value, described in more detail below. In New England, the value is called the *wholesale risk premium*, which represents the price premium of fixed retail electricity contracts over wholesale prices. The premium reflects the risks that the supplier will bear additional costs not considered in the negotiated contract price and that the entity will need to procure additional expensive resources to meet unexpected demand or will have to offload excess supply into a weak market. The regional study on avoided costs of energy efficiency looked at wholesale market prices and supplier bids and found a premium ranging from 5% to 10%. The study assumes an 8% wholesale risk premium but recommends that utilities calculate the premium specific to their contracts (Knight et al. 2018). Other jurisdictions, like Washington and Washington, DC, include risk reduction through a proxy value, like a percentage adder to energy efficiency's other benefits.

Only seven jurisdictions (the District of Columbia, Massachusetts, New Hampshire, Oregon, Rhode Island, Vermont, and Washington) directly include risk as a utility-system impact in their primary cost-effectiveness test, but not all have quantified a value to date. Vermont and DC use proxies to quantify risk while the other states monetize the impact (NESP 2019). The states that consider risk as an impact of energy efficiency are clustered in the Northeast and the Pacific Northwest. Four of these jurisdictions use the total resource cost (TRC) as their primary test, and five states monetize risk in their cost-effectiveness tests. Table 1 shows entities that have quantified the value for energy efficiency's reduced risk.

Table 1. Quantified values for energy efficiency's risk reduction

Entity	Value of reduced risk from efficiency	Context
District of Columbia Sustainable Energy Utility	5%	Proxy for the value of reduced risk as an adder to the other benefits of energy efficiency (DC SEU 2016)
Maryland*	$0.007/kWh	Included as an adder to avoided cost of energy calculation to reflect the avoided costs of both avoided business risks and avoided ancillary services
NW Natural	$0.37/MMBTu	Levelized average fuel-price risk avoidance used in integrated resource planning and cost-effectiveness testing for natural gas energy efficiency (NW Natural 2018)

Entity	Value of reduced risk from efficiency	Context
Northwest Power and Conservation Council	$0.02/kWh	Accounting for reduced risk of efficiency in utility resource planning compared to other resource options (ETO 2017)
Pacific Power	$0.00145/kWh	Levelized average fuel-price risk avoidance used in integrated resource planning and cost-effectiveness testing (ETO 2017)
Portland General Electric	$0.0058/kWh	Levelized average fuel-price risk avoidance used in integrated resource planning and cost-effectiveness testing (ETO 2017)
Vermont	10%	Costs of energy efficiency are reduced by 10% in cost-effectiveness testing; reduced risk made up about 1.2% of total avoided costs in Lazar and Colburn 2013.

*This is not shown as a separate impact in the DSESP because it is included as a portion of the avoided energy costs.

Going forward, utilities may be able to borrow from established approaches to quantifying risk. For example, the North American Electric Reliability Corporation (NERC) has a long history of risk assessment for the bulk power system. Their probabilistic analyses may lend methodologies to risk analysis for other levels of the energy system (D. Violette, Lumina, director of energy, pers. comm., December 2, 2019). Other established approaches utilities could adopt include more broad analyses of energy risk premiums, which assess the costs of the instrument (e.g., energy efficiency) against the expected cost of the commodity being hedged (e.g., wholesale energy prices). One such method uses value-at-risk (VaR) analyses, which is well established in energy markets and provides an upper bound of the risk of financial loss in different investment scenarios (Baatz, Barrett, and Stickles 2018).

Using this approach, researchers estimated VaR to utilities from volatile wholesale energy prices, or an estimate of "the price that participants may be willing to pay to avoid price fluctuations" (Baatz, Barrett, and Stickles 2018). In 1999, researchers determined a VaR of 50% of the cost of acquisition on average across the year, although this varied significantly across periods, depending on levels of demand. This means that utilities should be willing, on average, to spend about half the cost of the energy acquisition price on energy efficiency to avoid price volatility (Baatz, Barrett, and Stickles 2018).[4] Using a VaR approach, stakeholders could define a standard level of acceptable risk in energy efficiency technical reference manuals to determine inputs for cost-effectiveness testing. An example of this approach used to assess the value of demand-response resources can be found in Violette, Freeman, and Neil (2006).

[4] The authors note that this is not an exact calculation of efficiency's risk-reduction value but is an upper bound for what utilities may pay to avoid volatile costs. They also explain how two other methods may be applied to calculate efficiency's risk-reduction value, although these have significant limitations. One compared the cost of a financial hedge against rising electricity prices with the cost of energy efficiency that achieved the same outcome. The other looked at natural gas futures contracts compared with natural gas price forecasts to determine what generators would be willing to pay for avoided price volatility. For additional information, see Baatz, Barrett, and Stickles (2018).

OREGON

Energy Policy Landscape

Oregon has a comprehensive energy efficiency policy landscape. Energy Trust of Oregon is a nonprofit organization that provides energy efficiency services for customers in the state in coordination with the investor-owned utilities. Energy Trust of Oregon has adopted energy efficiency resource goals for electric and gas investor-owned utilities operating in the state. Through 2019, the electric savings goal is 1.4% of sales (ACEEE 2019). Oregon also reduces utility disincentives to support energy efficiency through a sales normalization adjustment, which is a revenue-per-customer decoupling tool.

Cost-Effectiveness Testing in Oregon

Oregon uses the TRC test as its primary cost-effectiveness test and the utility cost test as its secondary test. The state allows its utilities to include the value of reduced risk in energy efficiency cost-effectiveness testing. Energy Trust of Oregon defines this value as the "value of fuel price risk avoidance" (ETO 2017, 5). In previous cost-effectiveness methodologies, the value of reduced risk was bundled with transmission and distribution credits and generation deferral. However, by 2016, generation deferral became increasingly important in Oregon, so the state broke out each credit individually. Oregon has monetized the value of reduced risk since 2016, more fully capturing the full benefits of energy efficiency in cost-effectiveness tests.

When calculating avoided costs of electricity and natural gas, the Northwest Power Act requires that utilities grant energy efficiency a 10% cost advantage over generation resources. This 10% is applied to all avoided cost components except risk reduction, because it is believed to be captured in the 10% credit (ETO 2017).

Results

Each Oregon utility oversees an assessment of its own unique risk-reduction value. The calculations and what is factored into each value are calculated as part of the utilities' integrated resource plans (IRPs). Table 2 outlines this value for the electric and natural gas utilities in Oregon that have conducted fuel-price risk-avoidance assessments.

Table 2. Risk benefits of energy efficiency in Oregon

Utility	Sector	Value of reduced risk from efficiency
Pacific Power	Electric	$1.46 per MWh (levelized)
PGE	Electric	$5.08 per MWh (levelized)
NW Natural	Gas	$0 (2016), $0.37 per MMBTu (2020)

Source: ETO 2017; NW Natural 2018.

NW Natural determines a fuel-price risk-avoidance value in its IRP, which it then passes on to the energy efficiency administrator for cost-effectiveness testing. To calculate the value, called a *hedge value*, the company determines the difference between the long-term fixed-price financial hedge quote and projected gas prices and includes transactional costs, called the *credit facility* (NW Natural 2016).

In its 2016 IRP, NW Natural used a value of $0, projecting a negative risk-reduction value since "the dynamics [of the current natural gas market] are such that long-term hedges can be procured lower than forecasted spot prices over the hedge period" (NW Natural 2018, 4.4). In other words, because forecasted natural gas prices are relatively stable, investing in energy efficiency carries more financial risk for the utility than purchasing gas at spot market prices. Because the risk-reduction value is supposed to be a benefit, the Energy Trust assigned NW Natural a value of $0, helping energy efficiency be more cost competitive (ETO 2017). In its 2018 and 2020 IRPs, the company reassessed this value and for 2020 determined it to be $0.37 per MMBTu (NW Natural 2018).

DISTRICT OF COLUMBIA

The District of Columbia Sustainable Energy Utility (DC SEU), which was created by the Clean and Affordable Energy Act of 2008, provides district residents and businesses with clean energy services, including energy efficiency (DC SEU 2016). The district has implemented decoupling for electric utilities only. Although the District of Columbia does not have a district-wide energy efficiency resource standard, the DC SEU's contract with the Vermont Energy Investment Corporation (VEIC) includes performance incentives for achieving electricity and natural gas consumption reduction goals (DC SEU 2016).

DC SEU's contract with VEIC requires the use of the societal test for cost-effectiveness testing. Since 2016, the District of Columbia has recognized the benefit of "energy efficiency and conservation in addressing risk and uncertainty" in its societal cost test (DC SEU 2016, 55). DC SEU considers risk a difficult benefit to calculate, so its contract with VEIC assigns a proxy to the value of reduced risk as an adder of 5% of the energy efficiency's other benefits (DC SEU 2016).

VERMONT

Vermont has a robust energy efficiency policy landscape, boasting a third-place finish in the *2019 State Energy Efficiency Scorecard*. The state's energy efficiency resource standards require electric utilities to show annual incremental savings of 2.4% of annual sales through the 2020 period (Berg et al. 2019). The state's electric and natural gas IOUs are decoupled, and VEIC, the administrator for the state energy efficiency utility, Efficiency Vermont, can earn incentives for performance (ACEEE 2019).

Efficiency Vermont uses the societal cost test as its primary cost-effectiveness test, as required by the public service commission, and the state allows energy efficiency utilities to include the benefits of reduced risk in these tests. Vermont defines *risks* as those "associated with investments in supply-side resources that are avoided by investing in demand-side management" (Vermont Public Utilities Commission 2015, 9). According to the Public Service Commission, this risk adjustment is not distinct from the wholesale risk premiums discussed in the New England Avoided Energy Supply Component Study, but other stakeholders asserted that the two deserved separate values (Vermont Public Utilities Commission 2015). The commission decided to include only a single value.

Vermont calculates risk via a proxy. Vermont designates this value as a risk adjustment that reduces the cost of energy efficiency measures by 10% (Vermont Public Utilities Commission 2015). This adjustment reflects the "ability to readily increase or decrease program activity to meet needs, the incremental nature of energy efficiency impacts, and the limited risk of stranded assets" (Lazar and Colburn 2013).

Reliability

WHAT IS IT?

The reliability of the electric system refers to the frequency, extent, and duration of power outages (DOE 2017). In contrast with resilience, reliability typically covers high-probability, low-impact events. The US Department of Energy defines *reliability* as "the ability of the system or its components to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components" (DOE 2017). *Reliability* has a specific definition for utilities. NERC defines a *reliable electric 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).[5]

Reliability has two key features:

- *Adequacy*. Having sufficient resources available to meet electric demand at appropriate voltage and frequency levels
- *Operational security.* The ability to withstand disturbances like short circuits and weather-related damages.

For planning purposes, utilities are required to maintain reserve margins (capacity in excess of what would be required for peak load) as one reliability backstop measure (Baatz 2015). To measure operational reliability performance on an ongoing basis, utilities and system operators use standard metrics, most of which focus on the extent, frequency, and duration of power outages and occur at the distribution level.[6] In energy efficiency cost-effectiveness testing, adequacy is addressed in avoided capacity costs, which are commonly accounted for. Energy efficiency can deliver reliability beyond adequacy. This reliability improves operational performance beyond a necessary threshold the utility would have acquired anyway, is classified as increased reliability, and is not commonly accounted for in cost-effectiveness tests.

RELIABILITY IN CONTEXT

Reliable power is critical to nearly every aspect of the US economy and to our daily lives. Using standard metrics developed by NERC to measure frequency, duration, and extent of outages, the US Department of Energy (DOE) determined the nation's electric service has been highly reliable over the past century (DOE 2017). However other research shows that US customers experience power outages at much higher rates than other developed countries (Chittum and Relf 2018). This poor reliability costs the United States billions of dollars annually. Estimates vary, but most studies show that power outages cost us more than $100 billion per year (Chittum and Relf 2018). Most reliability issues do not stem from the generation level of the energy system, in part because of a strong and sustained emphasis on maintaining adequate generation supply reserve margins. Instead, most reliability problems experienced in the United States stem from the distribution

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[5] NERC is an entity designated to uphold reliability standards for operators of the bulk, or wholesale, electricity system such as regional transmission organizations (RTOs) or independent system operators (ISOs). At the distribution level, regulated utilities are responsible to regulators or government entities for delivering electricity in a reliable way to customers.

[6] These metrics include system average interruption duration index (SAIDI), customer average interruption duration index (CAIDI), and system average interruption frequency index (SAIFI) (Relf, York, and Kushler 2018).

system. Ninety percent of power outages occur at this level, and most are caused by routine events such as disturbances to distribution infrastructure from things like squirrels, equipment failure, and adverse local weather. These routine factors account for about half of outage minutes (outage frequency) but have a smaller impact on duration of outages (outage magnitude), which is affected largely by extreme weather (Silverstein, Gramlich, and Goggin 2018).

ENERGY EFFICIENCY AND RELIABILITY

Energy efficiency has clearly demonstrated its ability to provide reliability benefits to the electric system over the course of many decades (Relf, York, and Kushler 2018). Energy efficiency impacts reliability in three main ways:

- For planning and adequacy, it reduces overall demand and offsets generation at the bulk system level that would otherwise be needed, effectively increasing the system's existing reserve margin.
- It can participate directly in certain wholesale electricity markets, which are designed to ensure adequate resources are available for present and future needs.
- Operators can geographically target energy efficiency to address particular system needs at the T&D levels.

For planning and adequacy, energy efficiency reduces overall demand and offsets generation at the bulk system level that would otherwise be needed, effectively increasing the system's existing reserve margin. The reserve margin is a reliability indicator, correlating with improved system operations. This effect is compounded as energy efficiency avoids additional line losses, the ~5% (or more) of energy that is lost as electricity moves over the T&D systems (EIA 2020a). In cost-effectiveness testing, this is accounted for as avoided capacity costs.

Energy efficiency can participate directly in certain wholesale electricity markets, which are designed to ensure adequate resources are available for present and future needs. In those markets, energy efficiency is subject to rigorous EM&V requirements and has proven to be as reliable as generation resources (Relf and Baatz 2017). In New England's market, energy efficiency is assigned an availability value of 100%, meaning that it is available to be called on 100% of the time. This is the highest value of any resource included in the auction (Relf and Baatz 2017). Energy efficiency made up 1.7% of total capacity resources in the Mid-Atlantic's most recent auction, and energy efficiency and demand response combined made up 11.6% in New England (PJM 2019; ISO-NE 2019). In 2019, the wholesale electricity market in Texas set a new record peak demand and called an emergency during a heat wave that caused reserve margins to fall and capacity prices to spike (Walton 2019). During such events, the grid operator can call on all available resources to meet demand, including demand-side resources. Such temperature-related events, including extreme heat and cold, are increasing (Silverstein, Gramlich, and Goggin 2018).

Operators can geographically target energy efficiency to address particular system needs at the T&D levels (called nonwires solutions) (Relf, York, and Kushler 2018). NWSs are part of the utility resource planning process, but this effect can also occur without directly targeting efficiency as an operational improvement to reliability. NWSs are typically deployed as a cost-effective solution in response to an identified reliability need, such as in areas of new demand or forecasted growth with constraints on the corresponding distribution system. In cost-effectiveness testing, this is accounted for both as avoided T&D costs, which captures the direct avoided costs of the physical assets, and as increased reliability, which captures the additional reliability benefit that efficiency provides by being sited close to the customer. For example, energy efficiency can reduce load-related stress on infrastructure such as equipment failure, insulation degradation, and line sag (Knight et al. 2018). The use of NWSs is growing, and along with other distribution-level resources like solar, storage, combined heat and power, and demand response, energy efficiency has been a contributing resource in many of these projects (SEPA 2018). Energy efficiency measures can also affect load shapes in different ways and can accrue at peak times, depending on the affected end use, contributing additionally to increased reliability (Frick, Eckman, and Goldman 2017). Data on end-use load shapes are necessary to fully quantify this effect. Figure 4 demonstrates this effect and shows a load and savings load shape for water heating throughout the day.

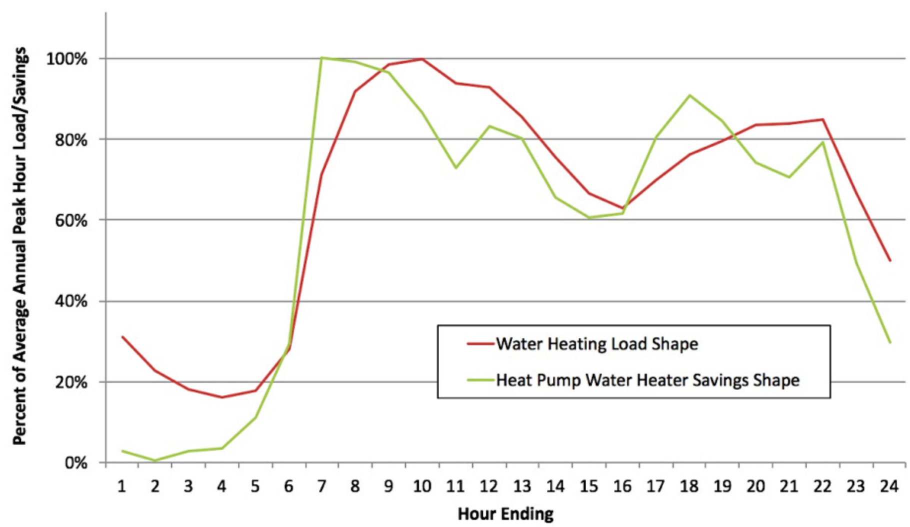

Figure 4. Water-heating load and savings throughout the day. *Source*: Frick, Eckman, and Goldman 2017.

Many examples demonstrate energy efficiency contributing directly to system reliability. In the 2000s, operators in California were able to quickly ramp up energy efficiency programs to help avoid rolling blackouts in response to changing market conditions (Kushler, Vine, and York 2002). The Brooklyn-Queens Demand Management (BQDM) project run by Consolidated Edison (ConEd) is a high-profile NWS in New York where energy efficiency has contributed most of the resources needed to offset the need for a $1-billion substation upgrade (ConEd 2019). In February 2019, ConEd also received approval to deploy over $220 million in targeted energy efficiency and electrification as a nonpipeline solution to partially meet growing natural gas peak demand (Narbaitz and Sloan 2019). For additional examples, see SEPA (2018) and Relf, York, and Kushler (2018).

Reliability in Cost-Effectiveness Testing

The operational reliability benefits of energy efficiency are not commonly or adequately quantified and used in cost-effectiveness testing despite their demonstrated value. Nearly all states include avoided generating capacity costs in their calculation of benefits and most states quantify avoided T&D costs from efficiency, both of which are important to improved reliability (NESP 2019). However these assess the direct costs of those avoided physical assets rather than the additional reliability benefits of reduced frequency, extent, and duration of outages that may be unique to efficiency. For example, the Regulatory Assistance Project (RAP) analyzed the monetized values of each utility system benefit of energy efficiency according to Efficiency Vermont's 2010 energy efficiency filing, as approved by regulators. In this study, RAP calculated the value of avoided transmission and distribution capacity[7], but this did not fully value the reliability benefits of efficiency, such as increased energy security (Lazar and Colburn 2013).[8] Other efforts to quantify efficiency's additional contribution to system reliability are limited.

Only three states (Arizona, Massachusetts, and Rhode Island) include reliability as a direct utility-system impact that could be quantified in their primary cost-effectiveness tests (NESP 2019). While Arizona and Rhode Island could theoretically include the impact, Massachusetts is the only state to have quantified the impact beyond avoided capacity and T&D in its testing to date. Values used in Massachusetts range from $0.10 per kW-year to $8.28 per kW-year, varying according to the characteristics of the wholesale market, including whether the resource was chosen in the market (shown in figure 5).

Two of these three states are in New England and participate in the region's wholesale energy market. Massachusetts uses the TRC as its primary test, while Rhode Island uses a state-specific test developed to meet its unique policy goals. Arizona uses the societal cost test as its primary test. The state's Administrative Code specifies that cost-effectiveness impacts may consider "costs and benefits associated with reliability, improved system operations" (ACC 2018). While this benefit has not yet been quantified in testing, the state's largest utility, Arizona Public Service, undertook a geo-targeted energy efficiency pilot in 2018 that aimed to provide information on the reliability of load reductions at the substation level to inform future planning, such as an NWS. Results from the pilot are not yet available (APS 2018).

We provide additional detail on the approach Massachusetts takes to quantify the value of reliability from energy efficiency.

MASSACHUSETTS

Energy Policy Landscape

Massachusetts policies require that utilities procure all cost-effective energy efficiency resources before considering costlier supply-side resources, and an energy efficiency resource standard sets savings targets for electric and gas utilities at about 2.7% and 1.25% of retail sales, respectively, for the 2019–2021 period (General Court of the Commonwealth of Massachusetts 2008; Gold, Gilleo,

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[7] To calculate this value ($23.19 per MWh), RAP assumed a 15% reserve margin and levelized the cost over the measure life and divided by the annual energy savings. The study found that calculating the marginal rather than average avoided line losses, as well as the increased reserve margin benefits from energy efficiency, provides about a 44% increase to the total generating capacity value (Lazar and Colburn 2013). Taking the marginal values into account helps to recognize energy efficiency's contributions to reducing demand at peak times and in locations with a specific need, making it more valuable.

[8] Increased energy security is classified separately from increased reliability in the DSESP and is not considered in this brief. It is defined as "the impacts on energy security and energy independence resulting from energy efficiency investments. A more efficient system requires less inputs to generate energy, which leads to less imported fuel and greater energy independence" (NESP 2019). Rhode Island is the only state to include energy security as an impact in its test and defines it as reduced need for foreign energy imports. The state monetizes this value based on oil savings in MMBTU multiplied by $1.83 (NESP 2019).

and Berg 2019). These goals aim to help the state meet multiple policy objectives, including aggressive greenhouse gas reduction goals. The state uses a regional capacity market to acquire the necessary levels of available capacity, including a reserve margin to ensure system reliability.

Massachusetts also has growing concerns about winter reliability constraints. ISO New England's 2018 *Operational Fuel Security* report found that, in each scenario studied, the dual threats of coal, nuclear, and oil-fired power plant retirements and fuel supply constraints to natural gas–powered generation would lead to an inability to meet electricity demand by the mid-2020s. The study also determined that New England is vulnerable to winter-long outages at some natural gas–fueled generation plants (ISO-NE 2018a). Cold snaps are leading to overreliance on natural gas pipelines, creating concerns about reliability and price spikes and causing the state to depend on oil or imported liquid natural gas for electricity, which increases emissions (ISO-NE 2020). In its most recently approved three-year energy efficiency plan, the Massachusetts Energy Efficiency Advisory Council specifically notes that "natural gas constraints in recent winters have resulted in significant cost impacts to electric and gas ratepayers" (MA EEAC 2018). In response, they note that efficiency measures should increasingly target winter peak demand periods and that administrators should use updated avoided energy supply costs (MA EEAC 2018).

Cost-Effectiveness Testing

Massachusetts's primary method for cost-effectiveness testing is a modified TRC test. The 2019–2021 Three-Year Plan, required by the Massachusetts Green Communities Act, allows utilities to include the value of increased reliability in energy efficiency cost-effectiveness testing (Mass Save 2018). The state uses a regional study of avoided costs for both electric and natural gas as inputs to the cost-effectiveness tests. In that study, *reliability* is defined within the context of three components: the value of lost load, the value of transmission and distribution reliability, and the value of generation reliability. The value of generation reliability is explicitly quantified and used in cost-effectiveness testing (Knight et al. 2018). This value captures the improved effect "of increased reserve margins resulting from energy efficiency on generation reliability" (Mass Save 2018, 168). To quantify this value, the study used a marginal reliability index from the regional wholesale energy market that assesses how reliable the system is at different levels of cleared capacity. That figure was then multiplied by the value of lost load and the market's clearing price (Knight et al. 2018). The value of lost load aims to capture the cost to consumers of a power outage and varies considerably depending on who is affected and the length of the outage.

T&D reliability is not quantified for cost-effectiveness tests. The study notes that isolating the causes of T&D outages is complex because many factors are responsible. The study did not find a strong enough effect between reduced load from energy efficiency and T&D outages to recommend including that value in cost-effectiveness tests (Knight et al. 2018).

Results

In 2018, the 15-year levelized benefit of increased generation reserves through energy efficiency measures was $0.65 per kW-year for resources that are chosen in the regional wholesale market (cleared resources) and $6.60 per kW-year for those that are not (uncleared resources). Figure 5 outlines future reliability values for cleared and uncleared energy efficiency resources.

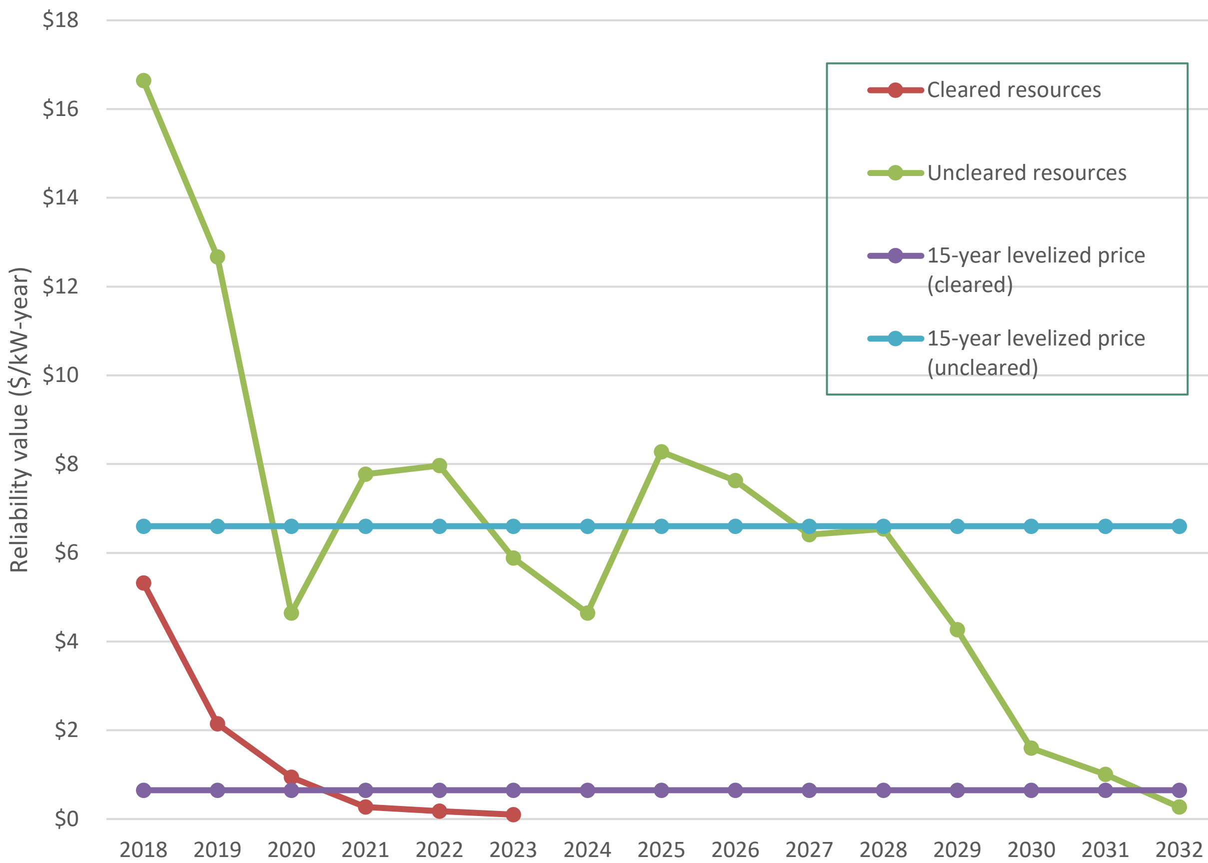

Figure 5. Reliability values of cleared and uncleared energy efficiency resources. ***Source:*** **Knight et al. 2018.**

In its analysis, Knight et al. (2018) discusses why uncleared energy efficiency has a higher reliability value than cleared energy efficiency. All cleared resources, including energy efficiency, contribute directly to system reliability by helping to meet the state's reserve margin. Energy efficiency resources that do not bid into the market also improve reliability and result in overprocurement of capacity relative to load. Therefore reliability is improved because the system simultaneously reduces electric load and increases electric generation supply.

Resilience

WHAT IS IT?

In general, resilience is the system's ability to withstand and recover from high-consequence but low-probability events. In the context of energy efficiency, clearly defining the scope of resilience is important to enable a jurisdiction to accurately quantify costs and benefits because jurisdictions think about resilience in various ways, depending on the events, duration, location, and level of the system involved. For example, some definitions of resilience consider actions taken before, during, and after an event that reduce the risks or impacts of the event. Other definitions focus more strictly on the ability to recover from the event (Larsen et al. 2019).

In addition to temporal considerations, stakeholders have varying definitions of the geographies or system levels affected by resilience. Because outages caused by transmission system failures tend to be more infrequent but higher consequence, resilience efforts have traditionally focused on the bulk power system (Silverstein, Gramlich, and Goggin 2018). Although closely related to resilience, reliability typically covers issues with the distribution system because those tend to be low-consequence, high-probability events such as adverse weather and squirrels (Chittum and Relf 2018). According to Silverstein, Gramlich, and Goggin (2018), “reliability covers those long-term and operational steps that reduce the probability of power interruptions and prevent loss of customer load, while resilience measures reduce damage from outages and hasten restoration and recovery to shorten outage durations.”

Silverstein, Gramlich, and Goggin (2018) suggest a customer-centric framework in which impacts are measured according to the user’s experience and the customer’s ability to survive during an event affecting service. These are all acceptable ways to consider a system’s resilience, and while state policymakers and utility regulators have increasingly begun to address resilience, no single definition has gained consensus (Rickerson, Gillis, and Bulkeley 2019). As noted, jurisdictions should clearly define resilience in the context of energy efficiency.

RESILIENCE IN CONTEXT

The energy sector is increasingly focused on resilience because catastrophic events are gaining in both frequency and magnitude (figure 6), and plans for recovery from these events are becoming more important (Silverstein, Gramlich, and Goggin 2018). Major events like these contribute to about half of outage minutes. Concerns over cybersecurity, or human-caused events, are also growing (DOE 2020).

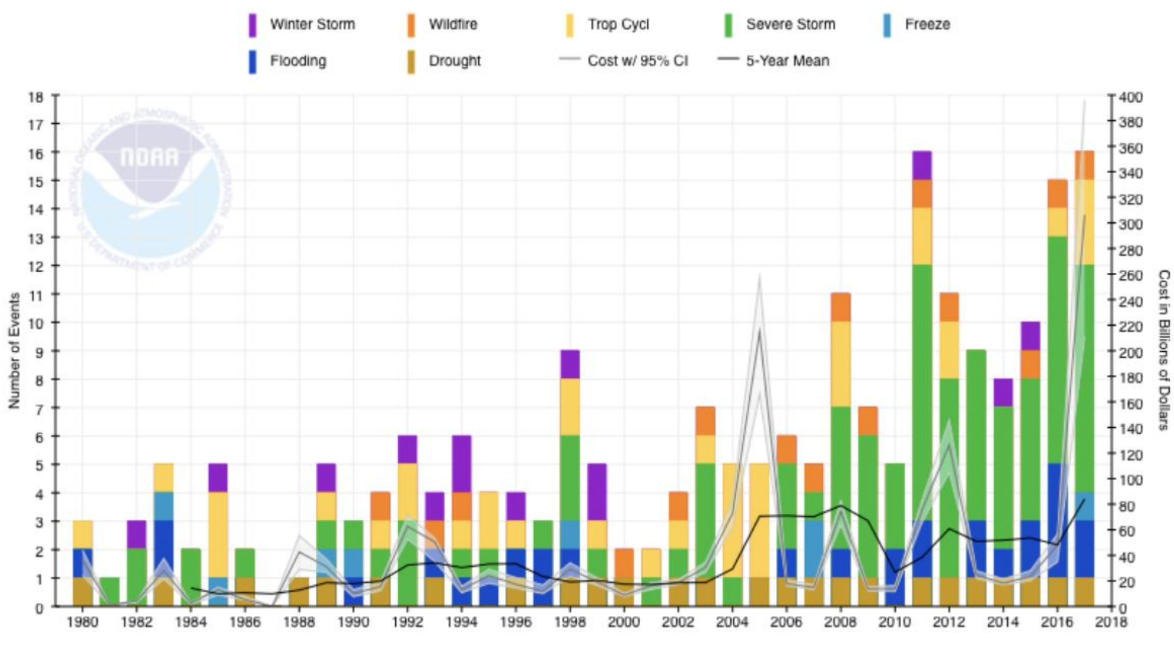

Figure 6. Billion-dollar disaster event types by year. *Source:* Silverstein, Gramlich, and Goggin 2018.

Entities on many different levels are concerned about improving energy resilience. For communities facing increased threats, energy is critical to keeping systems like emergency services, public transportation, health-care facilities, and businesses functioning (Ribeiro et al. 2015). Cities are especially concerned with maintaining power at critical facilities like shelters, wastewater treatment plants, and hospitals. Businesses, especially those that require uninterruptible “perfect power" such as data centers are concerned with lost production, lost revenue, and opportunity costs associated with power outages and may choose to install backup generation systems or other technologies that protect from outages. The insurance industry is also increasingly concerned with resilience as payouts related to catastrophic events increase (Mills 2012). In 2017, the Federal Energy Regulatory Commission (FERC) opened a proceeding to examine resilience in the bulk power system (FERC 2018).

RESILIENCE AND ENERGY EFFICIENCY

Energy efficiency contributes to resilience in three main ways:

- *It reduces demand, which allows facilities to install smaller backup power sources at lower cost to meet critical loads*. Backup generator fuel or other power supplies will also last longer when serving more-efficient loads (Agan 2019).
- *Lower demand and energy-efficient building systems that can operate in energy-saving mode (i.e., equipment or appliances that can continue to operate while drawing less power) allow generating resources to restart more easily after blackouts.* These first two aspects are particularly relevant for costs and recovery time when jurisdictions create disaster mitigation and recovery plans (Relf, York, and Kushler 2018).
- *From a customer perspective, energy-efficient building shells and appliances can help to improve survivability and allow customers to live safely in their homes longer during outages.* Efficient buildings with good insulation and ventilation better maintain comfortable temperatures and humidity levels. Energy-efficient refrigerators help food and medicine to last longer without spoiling (Silverstein, Gramlich, and Goggin 2018).

RESILIENCE IN COST-EFFECTIVENESS TESTING

Efforts have been made to value the resilience benefits of different energy resources, but no methodology is yet widespread or commonly used and accepted. For calculating and measuring resilience, DOE, the American Council for an Energy-Efficient Economy (ACEEE), and Sandia Labs have all produced theoretical frameworks for assessing resilience metrics (Chittum and Relf 2018). These frameworks focus on similar metrics, including costs associated with downtime or lost power relative to costs of more-resilient measures implemented (Rickerson, Gillis, and Bulkeley 2019; Vugrin, Castillo, and Silva-Monroy 2017). The National Association of Regulatory Utility Commissioners (NARUC) found that while resilience is not yet being considered by regulators in proceedings related to DERs, other efforts to value resilience outside of the regulatory context can be adapted for that purpose, each with pros and cons (Rickerson, Gillis, and Bulkeley 2019).

These values tend to be specific to the affected loads and regional geographies, making it difficult to compare values. For example, the costs of lost power to critical facilities like hospitals and wastewater treatment plants will be much higher than for other buildings like commercial properties. Because of the variation across jurisdictions, no common estimates of downtime costs are available. However DOE 's Interruption Cost Estimate (ICE) Calculator and insurance company Hartford Steam Boiler's blackout risk model offer potential tools that jurisdictions may be able to use for efficiency cost-effectiveness testing.[9] First, *resilience* must have a clear definition to maintain

[9] These tools can be found at icecalculator.com/ and munichre.com/hsb/en/services/blackout-technology.html, respectively. The ICE Calculator models the cost of energy reliability issues for up to 16 hours

the same assumptions about the kind of resilience (customer, system, or otherwise) stakeholders are referring to and the conditions and time frames it applies to. Clearly defining the parameters also avoids double counting reliability benefits, which are closely related to resilience, and ensures that the utility and its customers are paying for appropriate resilience investments.

No states currently include resilience benefits in cost-effectiveness testing. Rhode Island's Working Group has identified resilience as a benefit–cost category included with distribution system and customer reliability, but it has not officially included resilience in testing to date. The group lists attributes associated with this impact category, some of which could be applied specifically to resilience. For example, costs associated with lost power for critical facilities is a concern for longer-term events. For the other factors listed, distinguishing between what is implemented for reliability and what is for resilience is important. For example, many microgrids are deployed specifically for resilience purposes (the system's ability to withstand and recover from high-consequence but lower-probability event), whereas distribution improvements are typically to maintain reliability (the system's ability to prevent and recover from low-consequence and higher-probability outages and events).

While the costs and values for resilience are often specific to both system characteristics and events, investments in resilience could have potentially important effects on the magnitude of costs from catastrophic events. Jurisdictions have options as to how or whether to value resilience, each with pros and cons, and additional work may be needed to create standard resilience metrics or values (Rickerson, Gillis, and Bulkeley 2019).

Rhode Island: Increased Reliability and Resilience

Energy Policy Landscape

Rhode Island is among the states leading the way in state energy efficiency policy and tied for third in the *2019 State Energy Efficiency Scorecard* (Berg et al. 2019). The state's energy efficiency resource standards call for electric and natural gas savings of 2.5% and 0.97% of retail sales, respectively, through 2020. Rhode Island has a favorable business model for energy efficiency and demand flexibility, with decoupling for electric and natural gas utilities and shareholder incentives for both energy and demand savings (ACEEE 2019).

Rhode Island has become increasingly focused on energy reliability, resilience, and DER deployment, especially at critical facilities, after experiencing a growing number of multi-day power outages over the course of many years due to extreme weather events (Celtic Energy 2017). The state passed the Resilient Rhode Island Act of 2014, focused on coordinating governmental climate change efforts (Rhode Island General Assembly 2014). In 2017, the Rhode Island Public Utilities Commission (RIPUC) formed a working group to understand the costs and benefits of energy system activities. The working group created a list of goals that addressed the following question: "What can and should the new electric system be able to accomplish?" The working group's first goal was to "provide reliable, safe, clean and affordable energy to Rhode Island customers over the long term" (Rhode Island 4600 Working Group PUC 2017, 3). The working

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based on reported system data, including standard NERC metrics, the area's economic makeup, backup generator availability, and the costs of downtime to different sectors. Hartford Steam Boiler's blackout risk model assesses business impacts and economic losses from power outages at the zip code level (Chittum and Relf 2018).

group developed a report to the commission on how to better evaluate the impacts (both the benefits and costs) of utility technologies, programs, and investments and how rate design could evolve in Rhode Island over time (Rhode Island 4600 Working Group 2017).

Cost-Effectiveness Testing in Rhode Island

Drawing on the working group's final report, the commission adopted a state-specific benefit–cost framework for all utility filings, including energy efficiency (and other DER) cost-effectiveness testing. Although "reliability/resilience" is included as an impact in the test, Rhode Island does not quantify the impact because "the value of a cost or benefit may vary by time, location, electrical product . . . technology, or customer" (Rhode Island 4600 Working Group 2017, 7). Instead of assigning fixed values to reliability and resilience, the working group offers an array of calculation methodologies (discussed below) that can be used to value impacts in its benefit–cost framework, including reliability and resilience. To date, these have not been included in energy efficiency cost-effectiveness tests (B. Trietch, Rhode, administrator of energy programs, Island Office of Energy Resources, pers. comm., December 16, 2019).

Calculation Methodologies

The working group identified "distribution system and customer reliability/resilience impacts" as a benefit–cost category in their framework, which was accepted by the commission, noting that further development was needed (Rhode Island 4600 Working Group 2017). The attributes and drivers of this impact are

- Outage costs and value of uninterrupted service
- The probability and duration of outages
- Customer voltage and power quality impacts
- Distribution improvements and microgrid costs (Rhode Island 4600 Working Group 2017)

The report suggests tools to quantify these impacts, including interruption cost estimators, distribution planning studies, power quality assessments, and customer value of uninterrupted service studies. The authors note that challenges to quantifying reliability and resilience remain because they require detailed planning studies and customer surveys as well as advanced metering infrastructure, which remains at less than 1% penetration in the state (Rhode Island 4600 Working Group 2017; EIA 2019b). While no Rhode Island utilities have yet quantified energy efficiency's reliability or resilience contributions as defined above, the state's Energy Efficiency and Resource Management Council has proposed requiring ongoing reviews of the Rhode Island test to ensure that it is continuously evolving and meeting the council's goals (Rhode Island EERMC 2019; B. Trietch, Rhode Island Office of Energy Resources, pers. comm., December 16, 2019)

Valuing the Three Rs for all DERs

The changing energy landscape is creating new threats and opportunities for utilities across the country. Climate change and its impacts pose a growing threat to the utility industry in terms of increased catastrophic events that threaten reliability and/or resilience and therefore pose financial risk to utilities. Evolving environmental regulations and increasing renewable and distributed energy resources deployed to mitigate emissions are requiring utilities to pursue new strategies for meeting customer needs.

These changes challenge the traditional utility business model. However they also present opportunities for utility business growth. Some resources, such as electric vehicles and electrified equipment that enable demand response, can create additional revenue opportunities for utilities. This type of electrification is an important tool to reduce emissions. However it is critical that utilities manage this growth in a way that does not exacerbate peak demand, which contributes to high customer costs and emissions (Golden, Scheer, and Best 2019). In addition, when deployed either individually or in an integrated manner with energy efficiency, DERs contribute to the three Rs considered in this brief. In particular, DERs can be deployed together to address time- or location-specific reliability concerns, such as during peak periods or in constrained areas (York, Relf, and Waters 2019). For example, energy efficiency deployed in advance can reduce the load to be served by backup generators, microgrids, or renewable energy systems, thereby decreasing their costs (Agan 2019).

In addition, new technologies such as DERs that enable a two-way power flow on the grid create new opportunities and challenges for meeting reliability standards. Resources that can operate independently of the grid and that provide power closer to customers can reduce the potential for outages due to interruptions associated with T&D infrastructure, such as tree limbs falling on primary distribution lines (Silverstein, Gramlich, and Goggin 2018). They also reduce losses and can reduce system peak, both of which contribute to increased reliability (FERC 2018). Advanced software and technologies like advanced metering infrastructure (AMI) give operators more visibility into the system. However, even with this improved visibility, operators face challenges and uncertainties in balancing supply and demand surrounding variable power sources and emerging technologies like storage and electric vehicles. Reliability continues to be a critical policy objective, especially at the distribution level, to protect against these growing threats and to minimize the impacts of both the relatively routine outages that impose economic costs and inconvenience on customers and the less-frequent but high-impact outages with attendant high economic costs and even lives lost. This requires coordination across supply, demand, and customer-sited resources.

Methods to quantify the impacts of integrated DER deployments in a rapidly changing landscape are growing but are not yet widespread. As utilities increasingly deploy these DERs in conjunction with energy efficiency, sharing stakeholder experiences, data, and methodologies for considering the interactive effects of DERs on risk, reliability, resilience, and other impacts will be important.

Approaches to quantifying the three Rs for efficiency and other DERs may also differ from quantifying each impact individually in cost-effectiveness testing. For example, California is facing unique and severe climate change threats, such as wildfires and drought. The state is working to weave climate resilience throughout its (and utilities') operations and to unify climate assumptions through modeling and annual climate reporting and is beginning to embed climate resilience as an impact in planning decisions. As part of this effort, the California Energy Commission provides a load forecast used in utility resource planning that includes estimated impacts of climate change on heating and cooling degree days, and thus demand (CEC 2018). The utilities' integrated resource plans, in turn, inform granular avoided costs used for efficiency cost-effectiveness testing. Therefore, while the avoided costs do not explicitly include climate resilience impacts, other avoided costs have carbon impacts embedded (J. Knapstein, E3, personal communication, December 11, 2019). Additional efforts are under way to align benefit–cost analysis approaches and inputs through a common resource valuation method (Randol, Ralff-Douglas, and Zanjani 2018).

The DSESP confirms that California does not explicitly include any of the three Rs in its cost-effectiveness tests (NESP 2019). While the approach California is taking has some benefits, such as unified modeling and assumptions across the state and across energy resources, "climate resilience" has not been uniformly defined by utilities, and modeling assumptions are not always transparent.

Rapid changes in the energy sector require that utilities address the expanding threats to their business and the services they provide to customers. Utilities must take advantage of the opportunities available to mitigate those threats. Energy efficiency is a key tool in doing so, and to fully deploy cost-effective energy efficiency, quantifying its effects on the three Rs in cost-effectiveness screening is important. This brief provides information on the current landscape of those impacts. Next, we describe some key conclusions and areas for future research.

Conclusions and Key Takeaways

Utility energy efficiency programs provide several important benefits to the utility system in terms of reduced risk and increased reliability and resilience. However these benefits have largely been left out or undervalued in typical assessments of energy efficiency cost effectiveness. In the case of burgeoning DERs, these benefits are increasingly relevant and extend beyond utility-system impacts to host customers.

Few states are quantifying the three Rs in their cost-effectiveness tests. In their cost-effectiveness frameworks, seven states include risk, three include reliability, and none includes resilience in their primary tests. Assisted by the regional Avoided Energy Supply Components Study, the New England states are leading by taking steps to begin quantifying all three impacts (Knight et al. 2018). The study provides values and frameworks that all states in the region can rely on or adjust to reflect the situation in their own jurisdiction. In the Northwest, Oregon and Washington are also driven to include reduced risk as an impact by a regional requirement. Entities with a regional view may be instrumental in helping to get these impacts included and quantified in cost-effectiveness screens.

The use of proxies or adders for hard-to-quantify impacts is common, in particular in the case of reduced risk associated with efficiency investments. While the data set is somewhat limited, the assessed values for risk and reliability are fairly wide ranging because they are specific to the landscape of each utility. Measuring impacts on an even more granular level, taking into account the time, location, and types of events being considered, can increase the assessed value, as in RAP's analysis of Vermont. Table 3 shows the range of values we found for each of the three Rs.

Table 3. Efficiency's three-R impacts and assessed values

Three-R impact	Benefit of energy efficiency	States where the primary test includes the impact	Assessed values	Additional information
Risk	• Provides resource diversity • Modular resource that reduces reliance on long lead-time investments • Reduces future environmental compliance costs	• DC • MA • NH • OR • RI • VT • WA	Range from $0.0015 to $0.37 per kWh; also included as 5% (increased benefits) and 10% (reduced costs) proxies	Assessed values quantify fuel-price risk avoidance and avoided ancillary services and avoided business risk (together).
Reliability	• Increases reserve margins • Participates in wholesale energy markets for reliability • Meets targeted reliability concerns	• AZ • MA • RI	Avoided capacity and T&D costs are commonly valued; values for reliability value beyond avoided capacity range from $0.10 per kW-year to $8.28 per kW-year in Massachusetts	Massachusetts uses a marginal reliability index, which assesses how reliable the wholesale system is at different levels of cleared capacity. That figure is multiplied by the value of lost load (captures the cost to consumers of a power outage) and the market's clearing price (Knight et al. 2018).
Resilience	• Reduces load to be served by backup power sources • Facilitates easier power restoration • Improves building survivability	None	N/A	Rhode Island includes "reliability/resilience" as a category in its test but has not yet quantified it.

Utilities and regulators should share methodologies for quantifying the three Rs. Outside of New England's regional avoided cost study, no common methodologies for quantifying any of these three impacts are available. In Oregon, utilities calculate risk-reduction values internally, leading one natural gas utility to use a value of $0. While frameworks are available for quantifying each impact, it remains challenging to operationalize them due to lack of data and limited resources. As observed in Rhode Island, collecting the necessary data to quantify the three Rs can be costly and time consuming because intensive survey or other research approaches may be required. Sharing methodologies for quantification and sharing data sets can help utilities and regulators feel more confident in the values and methodologies they are using and can reduce barriers to including these impacts in tests (Rickerson, Gillis, and Bulkeley 2019).

New quantification methodologies will be required going forward. Utilities and regulators should clearly define the scope of each impact. For example, risk as an impact is not well defined outside of fuel-price volatility, although energy efficiency can also decrease risk in other ways. Jurisdictions have different definitions for resilience. Some consider resilience impacts as before, during, and after events. For others, resilience applies only to impacts after an event. For all three impacts, whether to include the effects on participants or customers must be considered. While the three impacts are commonly classified as utility system impacts, energy efficiency can reduce risk and improve reliability for business and customers, and in particular in combination with other DERs. Customer impacts are frequently more challenging and costly to quantify. Doing so may require the use of alternative methods, such as proxies or adders.

The changing energy landscape, increased need for climate change policies, and increasing penetration of DERs are creating many challenges and opportunities for utilities and their regulators. Effective management of these resources, including fully quantifying their impacts, is critical to maximizing potential benefits to meet policy objectives.

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