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Monetization Methods for Evaluating Investments in Electricity System Resilience To Extreme Weather and Climate Change

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Abstract

Extreme weather events and associated damages have been increasing and these trends are expected to continue. Actions are being taken to enhance electricity system resilience. However, the justification for capital investments on resilience requires utilities to justify that the economic benefits outweigh the costs. This paper reviews the types of resilience measures being analyzed in cost-benefit analyses and addresses opportunities for improvement in characterizing the benefits for investments that enhance the resilience of electricity systems.

Keywords

Electricity Resilience; Cost-Benefit Analysis; Extreme Weather, Climate Change, Vulnerabilities, Adaptation

1. Introduction

Extreme weather impacts the electricity system across all regions of the United States and future damages are projected to increase in magnitude and cost (USGCRP, 2017; USGCRP, 2018; Zamuda et. al., 2018). Extreme weather events are the most common cause of larger-scale[1] power interruptions, and weather-related financial impacts to the power system have increased significantly over the past 20 years. Studies estimate annual multibillion-dollar costs to the U.S. economy (EOP, 2013a; Campbell, 2012; Larsen et al., 2017, LaCommare et al., 2018). One study indicated that the cost of power interruptions to residential customers from severe weather is $2-3 billion annually (Larsen et al., 2018), and the total U.S. cost of sustained power interruptions is estimated at $44 billion per year (LaCommare et al., 2018). For this reason, utility planners, regulators, and policy-makers are facing important decisions about future investments in the resilience of the U.S. power sector. Spending significant ratepayer funds on resilience often requires utilities to make a strong case that the economic benefits of the proposed investments outweigh their costs.

Cost-benefit analysis (CBA)[2] compares the costs of the proposed investments with the benefits the investments will generate. It is applied on a forward looking basis (i.e., ex-ante) to

[1] "Larger-scale" here refers to power outages that interrupt service of at least 300 MW or affect at least 50,000 customers.
[2] Also referred to as benefit-cost analysis, or "BCA"

investments that typically have large upfront costs, but have benefits that accrue over many years. CBA requires a pre-specified perspective, which defines whose costs and benefits to count, or who has "standing" (Boardman et al., 2006; OECD, 2018; NIST, 2018). The precise definitions of each perspective differ somewhat by state, but generally include the perspective of the utility (or program administrator), ratepayers (i.e. will rates increase?), and society as a whole. Other common perspectives for demand-side resources such as energy efficiency (EE) and demand response (DR) include the participant test (for program participants) and the total resource cost (TRC) test, which addresses the question of whether the EE or DR program reduces the utility system costs plus program participants' costs.

There is a large and evolving set of regulatory, academic, and private sector information detailing frameworks for how to measure resilience (i.e., "resilience metrics") and assess its value (NAS, 2017; Schwartz, 2019; Rickerson et al., 2019; LaCommare et al., 2017; Willis and Loa, 2015; SNL, 2014). Schwartz (2019) presents several different industry viewpoints on key questions related to utility investments to improve resilience. The authors of each perspective note the lack of a common definition, analytical framework, and metrics for resilience. Rickerson et al., (2019) reviewed the regulatory and academic literature for examples of valuing resilience specifically for distributed energy resources (DER).[3] The study compared four methods for estimating avoided interruption costs and assessed their usability for regulators. As Schwartz (2019) notes, distinguishing resilience from reliability, assessing metrics for measuring resilience, and developing common frameworks to evaluate the costs and benefits of these types of investments are rapidly evolving areas of research.

This paper reviews—at a high-level—many of the methods currently in use to monetize the benefits of a broad range of measures to enhance the resilience of the electricity system to extreme weather. It was compiled through a review of regulatory proceedings and peer-reviewed literature and input from regulators and electric utilities. For this analysis, we define resilience as: *the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions from naturally occurring threats or incidents* (EOP, 2013b)[4]. The 'electricity system' includes all infrastructure related to generating, transmitting, and distributing power to end-use customers.

2. Types of Resilience Investments

There are a variety of different categories of resilience measures (DOE 2010, DOE 2013, DOE 2015, Zamuda 2016, Zamuda et al., 2018, Schwartz 2019). For purposes of discussion, this paper divides resilience measures into three categories:

1. *System hardening*: measures that prevent damage to the electricity system and protect it from extreme weather hazards. Examples include targeted undergrounding; floodwalls;

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[3] DERs include distributed renewable generation resources (wind, solar, etc.), combined heat and power (CHP) natural gas turbines, energy efficiency, energy storage, electric vehicles, and demand response technologies.

[4] FERC defines resilience as the "ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event" (FERC 2018).

vegetation management; siting, design and construction; and wetlands restoration. The benefits of these measures come from reducing the frequency of interruptions, and the costs of repairing damaged electricity assets.

2. *Physical changes to prevent service interruptions (despite damage)*: measures that allow the grid to continue to deliver electricity to customers despite damage to its infrastructure. Examples include microgrids and distributed energy resources; improved system redundancy; advanced grid design; remote communications, monitoring and control technologies; community energy storage; and demand-side management (such as EE and DR). These measures could reduce the frequency or duration of interruptions, depending on whether the interruptions would be eliminated entirely, or if the system enhancements required a brief period to allow for power to be delivered from a different source or along a different route.

3. *Measures to improve recovery time and/or process:* measures that enable utilities to recover from system damage and interruptions more quickly or more efficiently. Examples include mutual aid agreements; damage prediction and response; increased labor force; and ensuring the availability of standby equipment for response (e.g., communication devices, fuel for service trucks, backup generators). These measures reduce the duration of interruptions.

The costs of various resilience measures will vary considerably based on a number of factors including the specifics of the project, capacity of the utility to install and maintain the measures, and the local site conditions. For example, vegetation management costs can vary widely depending on the terrain, vegetation, and type of activity (e.g., ground-to-sky clearance versus targeted tree removal).

3. Monetizing Benefits of Resilience Investments

While costs are generally straightforward to monetize and utilities often estimate them based on historical data and/or similar projects developed by other utilities, the benefits of investments in power system resilience may be more difficult to monetize and to include within a formal cost-benefit analysis framework (LaCommare et al., 2017). A number of benefit categories have been considered in CBAs, including: (1) avoided utility costs; (2) avoided customer interruption costs; and (3) non-interruption-related societal benefits.

3.1 Avoided Utility Costs

Avoided utility costs are savings that utilities realize over time from resilience investments. The cost savings could be from capital or operations and maintenance (O&M) expenses. Benefits associated with avoided utility costs found in the CBA literature include:

- Reduced costs of restoration, equipment repair, and equipment replacement. If interruptions occur less frequently, the utilities will spend less money restoring power and replacing equipment. Second, better intelligence into where interruptions are likely to occur can yield reduced labor costs from more optimal staging of repair crews

(AVANGRID, 2016; PUCT, 2009; ConEd, 2015).

- Avoided vegetation management costs through undergrounding transmission and distribution lines and equipment (MGRTF, 2012).
- Avoided revenue loss when utilities are not delivering electricity to customers during a service interruption and thus are not generating revenue from customers' electricity consumption (FEU, 2008; Allen et al., 2017).
- Avoided wholesale power purchases for vertically-integrated utilities. Extreme weather events, including heat waves and droughts, could negatively impact electricity production capacity in generation units that rely on surface water for cooling (Sathaye et al., 2011). This risk can lead to a shortfall of electricity needed to supply customers. To address this, utilities may have to purchase more expensive electricity from the wholesale market. Vertically-integrated utilities could thus include this premium—or, the difference in cost between wholesale and internally-generated electricity—as an avoided cost (Allen et al., 2017).
- Avoided legal liabilities from damage and injuries caused by electricity infrastructure. California is seeing significant activity related to wildfire liability and damages. In January, 2019, PG&E filed for bankruptcy due to damages from the Camp Fire estimated at over $50 billion (Bloomberg, 2019). Rules and case precedent regarding damage liability and socialization differ depending on state, so it is important to understand any recent state-specific changes to case law and the implications for conducting a CBA if this type of benefit is to be included. The regulatory literature review did not find any specific CBAs where reduced wildfire liability was included as a benefit. However, PSI (2006) reported on undergrounding lines in Florida and estimated reduced litigation costs for the utility from fewer contact fatalities and serious accidents involving the general public and contractor employees.
- Some utilities are incentivizing customer investments in DER to increase resilience of the electricity system (SCE, 2017) (ComEd, 2017) (Misbrener, 2017). The resilience benefits stem from avoided customer interruption costs and are discussed in the next section.[5] Utilities may also realize additional energy and capacity benefits from DERs not directly related to resilience. There are established analytical protocols in a number of states for calculating the benefits of EE and DR—and some protocols extend to other types of DER (E3, 2016). Rickerson et al., (2019) examines current analytical practices for valuing DER resilience.

3.2 Avoided Customer Interruption Costs

Utility customers incur economic costs when their power is interrupted. These costs are known as customer interruption costs (CIC), or the "value of service" (VOS), and include costs to both residential and non-residential customers. CIC estimation methods entail differentiating between short-duration and long-duration, widespread interruptions. There is no standard for determining the threshold that delineates short-duration from long-duration interruptions—24 hours is occasionally used as an arbitrary threshold. During a short-duration interruption,

[5] See Rickerson et al., 2019 for a thorough review of resilience valuation specifically for DERs.

customers incur “direct costs,” which arise from the interruption of power to their facilities. Direct costs include net revenue losses, equipment damage, response costs and inconvenience costs for customers who lose power (Sullivan and Schellenberg, 2013) (Billinton et al., 1993).

Long-duration, widespread power interruptions cause customers—and society more broadly—to incur both direct and indirect impacts (Larsen et al. 2019). Indirect impacts become significant after some time threshold and occur when businesses and households experience economic disruptions because other companies, organizations, and institutions do not have power (Sullivan and Schellenberg, 2013) (Sullivan et al., 2015). These losses are due to connections between firms and sectors and the resulting economic production disruptions that propagate across firms and industries via market interactions. Connections can occur between firms in the relative prices of goods and the quantities of inputs bought or outputs sold. They also occur between individuals and firms in the form of lost jobs and wages and reduced consumer spending. Interruption costs associated with public institutions are also considered indirect costs, as individuals and firms incur costs from the absence of critical public services such as water treatment and emergency services. Indirect impacts are thus not limited to the customers within a utility service area and can propagate to a wider geographical area (Sullivan and Schellenberg, 2013).

Interruption costs vary considerably among different stakeholder groups. For example, a residential customer may not incur significant costs or be inconvenienced by shorter-duration interruptions. On the other hand, a large industrial customer may incur substantial costs from loss of production due to frequent, momentary interruptions. Customer interruption costs vary among customers even within the same customer class. A person who leaves home to work in an office during the day may have a very different CIC than a day trader operating out of a residence.

3.2.1 Avoided Costs from Short-Duration Interruptions

Utilities face a tradeoff when selecting a CIC monetization method for short-duration interruptions—between the level of CIC granularity within their service territories, and the budget/timeline for obtaining CICs. Estimates with a high-level of granularity are able to represent interruption costs for a subpopulation of customers by aggregating the interruption costs for the individual customers in the subpopulation. Estimates with lower granularity rely on average CICs for more broadly-defined customer types or from CIC studies conducted in other parts of the U.S. Conducting a CIC study can cost between $500,000 and $1 million and take 6-9 months from the beginning of the study design process to publishing the final results (Sullivan et al., 2018). If the process is too costly (or time consuming), utilities have the option of using existing data from CIC studies completed outside of their service territory, including the use of interactive tools such as the online Interruption Cost Estimation (ICE) Calculator (http://icecalculator.com). The ICE Calculator uses data from 34 existing CIC studies that employed similar, survey-based methodology (Sullivan et al., 2015). A limitation of the ICE Calculator is that it cannot reliability estimate interruption costs for long duration interruptions at this point, given the lack of survey data on outages longer than one day.

3.2.2 Avoided Costs from Long-Duration, Widespread Interruptions

Two current methods in the regulatory and academic literature for quantifying economic losses of long duration, widespread power interruptions (or the avoided economic losses from investments in power system resilience) are regional economic models and survey-based CIC studies. There are known shortcomings with these approaches and their application in regulatory filings is sparse (Sanstad, 2016) (Sullivan et al., 2018) (Larsen et al. 2019).

Regional economic models attempt to capture both direct and indirect impacts of interruptions that occur over longer durations and at larger geographic scales. There are a number of different model types—each with a different system for representing the economic interactions that occur between firms or sectors of the economy.[6] Researchers have applied regional economic models to estimate losses from both actual and hypothetical long-duration, widespread power interruptions (Rose et al., 2007) (Rose et al., 1997) (Rose and Guha, 2004) (Greenberg et al., 2007) (Mantell et al., 2013) (Fox-Penner and Zarakas, 2013). Some regional economic models can separately estimate impacts on employment from major power disruptions (Mantell et al., 2013). Regional economic models generally measure a specific event in a specific geographic area and thus do not yield standardized measures similar to the ICE Calculator (e.g. dollars per unserved kWh) that could be applied to a variety of interruption scenarios. These models also function at the regional level and lack the granularity that could be useful for utilities in estimating impacts.

Survey-based studies of long-duration interruptions have also been used to estimate the direct costs of long-duration interruptions. For example, Sullivan and Schellenberg (2013) used hypothetical interruption scenarios ranging from 24 hours to 7 weeks for a study in downtown San Francisco. They used the literature on regional economic models to develop a scaling factor, which they used to estimate the indirect costs from the direct costs. Baik et al., (2018) used surveys of residential customers to estimate long-duration interruption costs in the Pittsburgh metropolitan area. Survey methods alone will likely not accurately measure indirect costs over longer-term interruptions—particularly for non-residential customers—as these customers may not fully recognize or value the upstream and downstream economic impacts of the interruption.

3.2.3 Avoided Impacts to Critical Facilities

"Critical facilities" provide for the basic needs of society and include fire service, emergency medical service (EMS), hospitals, police, wastewater treatment, water provision, and electric power. Utilities sometimes face investment decisions where they prioritize hardening of certain components of the electricity system which supply power to critical facilities, as they are important for the health, safety, security and survival of residents during a severe weather event. Various utilities discuss identifying critical facilities in regulatory documents. ComEd, in

[6] Sanstad (2016) has a thorough description of regional economic models and their application to electricity supply disruptions.

its microgrid application, proposes using a microgrid to power an “oasis” of critical infrastructure (ICC, 2017). Connecticut’s Two Storm Panel recommends several selective hardening efforts in its final report (TSP, 2012).

Critical facilities may suffer direct costs from a short duration interruption, which would be captured in a typical CIC study. However, for long-duration, widespread interruptions, customers incur costs (inconvenience, health, safety) from the critical facilities not having power and thus not operating at full (or perhaps even partial) capacity. Regional economic models do not have the level of granularity needed for undertaking this type of analysis. Furthermore, these models assess the impacts to the economy, whereas the benefits of maintaining critical infrastructure—while they can be converted into dollars—are generally realized by improving health, safety and security. A methodology for quantifying the benefits of selective hardening measures within a region would be useful for determining which assets to prioritize for hardening.

The broader literature does have methods of monetizing the benefits of critical facilities. FEMA has a BCA software tool for performing benefit-cost analysis for applications submitted under FEMA’s Hazard Mitigation Assistance Grant Programs. The software uses a set of standard economic values with accompanying documentation that describes methods employed for estimating impacts from losing critical facilities (FEMA, 2016).

3.3 **Non-Interruption-Related Societal Benefits**

Non-interruption societal benefits are those which accrue to society from the resilience investment that are unrelated to the loss of power. These types of benefits impact public safety, private property, and the environment. In some cases, avoided interruptions are the primary purpose of the resilience investment and these types of non-interruption societal benefits are positive externalities. However, utilities can also invest in resilience for the primary purpose of avoiding injuries and/or property damage.

3.3.1 Safety: Avoided Injuries and Fatalities

Utilities may make resilience investments for the primary purpose of increasing safety or avoiding property damage (e.g., more aggressive vegetation control in high fire hazard areas). If adequate data exists, utilities can monetize these benefits. While a literature review did not uncover examples where utilities attempted to convert avoided injuries or fatalities to a monetary value, utilities have quantified the expected number of prevented injuries and fatalities (PG&E, 2017). Ascribing a dollar figure to a life or an injury can be a sensitive topic. However, the federal government assigns values to statistical lives and injuries regularly—and provides guidance to agencies for which values to use. For example, the Value of a Statistical Life (VSL) is a tool for conducting a CBA. The latest guidance from the EPA recommended a VSL estimate of $7.4 million ($2006) and inflated to the year of the analysis. [7] For injuries, the Abbreviated Injury Scale (AIS) offers a standardized approach for estimating the severity and

[7] EPA 2019. https://www.epa.gov/environmental-economics/mortality-risk-valuation

economic cost of various injuries, using the results of economic research (Rice et al., 1989) (Miller et al., 1989)[8].

3.3.2 Avoided Aesthetic Costs

In some cases, investments in resilience can lead to avoided aesthetic costs—or improvements in the value of property (Larsen 2016). Researchers using hedonic pricing techniques have found that views of electricity infrastructure can have a significant negative impact on property prices (Des Rosiers 2002) (Sims and Dent 2005). In these examples, property losses ranged from -5% to -20%--with higher losses for properties that are closer to electricity infrastructure (e.g., transmission lines). For example, converting overhead power lines to underground lines or investments in other non-wires alternatives (e.g., DERs) can enhance the aesthetics of private property and these benefits can be included in a formal CBA.

3.3.3 Avoided Property Damage

In California, much of the focus on resilience measures—such as more aggressive vegetation management—is to prevent utility infrastructure from causing wildfires which have devastating impacts to safety and private property. Preventing wildfires was discussed earlier from the perspective of the utility reducing legal liability. From a societal perspective, the benefits of avoided property damage could be monetized and considered in the analysis. No examples were found in the literature of utilities incorporating property damage estimates into CBAs for resilience investments.

3.3.4 Ecosystem Benefits

Investments in resilience can yield benefits for local ecosystems and the services they provide. For example, undergrounding electric infrastructure can reduce the mortality rates of wildlife such as birds and squirrels that are impacted by overhead utility infrastructure (Larsen, 2016). Integrated vegetation management programs can reduce adverse environmental impacts and stabilize ecosystems (MOU, 2016).

Wetland restoration, particularly in the coastal environments subject to subsidence, sea level rise and storm surge, can serve as a resilience measure to protect utility infrastructure and provide benefits of enhancing ecosystem services. Established CBA methods exist for quantifying ecosystem services and Goulder and Kennedy (2011) provide a thorough discussion of issues involved in doing so within a cost-benefit framework. Some utilities have either addressed ecosystem benefits qualitatively, or relied on existing research from economists studying a specific geographic area of interest. For example, Entergy, after Hurricane Katrina, performed a cost-benefit analysis in partnership with America's Wetland Foundation (Entergy and AWF, 2010) and used estimates of ecosystem service benefits from Costanza et al. (1989) and Schuyt and Brander (2004). Outside of economic studies, there are decision support tools

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[8] One study assumed that a significant conversion from overhead to underground lines would actually increase risk to workers (Larsen 2016). This study used VSL and accident incident rates (and costs) from the U.S. Occupational Safety and Health Administration (Larsen 2016) to estimate annual morbidity and mortality costs.

available that can help evaluate ecosystem services. For example, the EPA provides a Rapid Benefit Indicators (RBI) decision tool to assess ecosystem benefits of site restoration and develop non-monetary indicators as a first step towards monetary valuation (Mazzotta, 2016).

3.3.5 Avoided Emissions

There are opportunities to include the benefits of reducing emissions of GHGs and other pollutants (SO_2, NO_x, and particulate matter) as co-benefits, especially for investments in resilient DERs. Some states provide guidance on how to quantify emissions benefits for DERs in the form of standard practice manuals or cost-effectiveness spreadsheet models utilized by commissions for the regulated utilities (BCA Handbook, 2018; CPUC, 2017). These standard practice manuals help determine:

- Whether to include any avoided emissions benefits in the calculation
- How much of the avoided emissions benefit is already included in the energy price
- The source of information to use for valuing the stream of emissions benefits in future years
- How to quantify the cost of additional emissions from the resource (e.g., combined heat and power systems) being brought online

3.4 Summary of Benefits

As the examples throughout this discussion illustrate, the benefits of investments in resilience depend heavily on the specifics of each project. Table 1 provides a summary of benefit values found in the literature.

Table 1: Summary of Benefit Values Found in Literature

Benefit Type	Benefit Amount	Source
Avoided Legal Liabilities	\$87,100 per mile - reduced litigation from fewer contact fatalities and serious accidents	PSI (2006)
Avoided Vegetation Management Costs	\$3,000 - \$12,000 per mile for distribution; \$300 - \$9,000 per mile for transmission	PUCT (2009)
Avoided Revenue Loss	\$0.09-\$0.32 per kWh (Range of System Average Rates Across U.S.; average SAR = \$0.13)	EIA (2019)
Avoided Short-Duration Customer Interruption Costs: Medium/Large C&I (>50,000 annual kWh)	\$12-\$37 per unserved kWh (interruptions lasting 30 minutes - 16 hours)	
Avoided Short-Duration Customer Interruption Costs: Small C&I (<50,000 annual kWh)	\$214-\$474 per unserved kWh (interruptions lasting 30 minutes - 16 hours)	Sullivan et al. (2015)
Avoided Short-Duration Customer	\$1.3-\$5.9 per unserved kWh	

Benefit Type	Benefit Amount	Source
Interruption Costs: Residential Customers	(interruptions lasting 30 minutes - 16 hours)	
Avoided Long-Duration Customer Interruption Costs	$1.20/kWh (for high priority services) to $0.35 (for low priority services) (interruptions lasting 24 hours; Allegheny County, PA)	Baik, et al., (2018)
	$190M-$380M (24-hour interruption) $4.4B-$8.8B (7-week interruption) (downtown San Francisco)	Sullivan and Schellenberg (2013)
Safety: Avoided Injuries and Fatalities	Fatality: $7.4 million ($2006) Injury: up to $7.4 million ($2006)	EPA (2019) Rice et al., (1989)
Avoided Aesthetic Costs	Avoided loss in property values due to overhead electricity being undergrounded: 5-20% increase in property value	Des Rosiers (2002); Sims and Dent (2005); Larsen (2016a) (2016b)
Ecosystem Benefits	Depends on ecosystem, location and other factors.	
Avoided Emissions	$5,800 per ton - SO_2 from coal plants	NAS (2012)
	$1,600 per ton - NOx from coal plants	
	$460 per ton - PM-10 from coal plants	

4. Recommendations

4.1 Connecting Measures with Impacts

Investing in one or more resilience measures often has the benefit of interruptions occurring less frequently and/or for shorter periods than would have occurred without the investment. This leads to avoided costs for customers and utilities. An important component of a CBA is thus an estimation of the impact of the resilience measure on the baseline level of interruptions. System hardening measures will generally reduce the frequency of interruptions, while measures that reduce recovery time will reduce interruption duration. When multiple measures are considered together—such as vegetation management and advanced grid design—care must be taken not to double count the interruption reductions.

A review of the impacts of measures on the expected set of power interruptions is important for being able to proceed from proposed investment to monetized benefit. To estimate these measure impacts, utilities can rely on experience with prior investments, other utilities' experience with resilience investments (FPSC, 2018), engineering or other studies (Short, 2014), and grid simulations. There is a need to better collect and share infrastructure damage and associated societal impact data after extreme weather events to assess the effectiveness resilience measures. Pre- and post-event data should be collected to determine performance of the measures, assess the accuracy of CBA estimates, and improve the decision-making process. It is especially important for utilities to share both success stories and challenges. If a particular investment significantly improves resilience during a major weather event, the industry as a whole can learn from these experiences and use the results to improve and refine future CBA studies to make the business case for additional investments.

4.2 Refining Monetization Methods

The review of the literature and current practices revealed opportunities to refine methods for conducting CBAs for investments in resilience. These opportunities include filling gaps in data or methods and adopting (or adapting) existing methods from the peer-reviewed literature for monetizing benefits.

A number of CBAs referred to certain types of benefits only qualitatively, while the broader peer-reviewed literature contained limited examples of methods for monetizing those benefits. Specifically, avoided injuries and fatalities, avoided impacts to critical facilities, avoided aesthetic costs, ecosystem benefits, and avoided property damage had limited or no monetization examples in the literature. While utilities may be reluctant to include benefits related to avoided injuries (both fatal and nonfatal) in their publicly-filed business cases, regulators may consider these types of benefits when deciding whether to approve the proposed investments. CBAs could value avoided impacts to critical facilities and prioritize infrastructure for selective hardening (or backup power supply) that would be critical for public health, safety and security during extreme weather events. Some utilities are already starting to work with municipalities and government agencies to improve the prioritization process and further collaboration and data sharing could be explored.

Opportunities exist for valuing the benefits of ecosystem services, including wetlands restoration and alternative vegetation management practices. Ecosystem services can be geographically specific and coordination with researchers and public agencies could ensure they are being valued properly.

Additional research should be undertaken to advance our understanding of the impacts of long-duration, widespread interruptions. Survey-based customer interruption cost studies have generally measured direct costs from interruptions which last 24 hours or less. However, we found limited information on the direct and indirect impacts of long duration, widespread interruptions. Information on these impacts (or avoided impacts) of long duration, widespread interruptions is an important benefit to consider as utilities invest more resources into technologies, processes, and infrastructure that make electricity systems more resilient.

5. Conclusion

The increasing frequency of extreme weather events and their impact on the electricity system highlight the growing importance of utility resilience investments. Sound methods for quantifying the costs and benefits of these investments will help to ensure that utilities and their ratepayers do not over- or under-invest in resilience measures. Methods and tools exist that are useful for conducting CBAs, but there are opportunities to develop better methods and tools, as well as adapt methods from other fields. Collaboration between utilities, regulators, research institutions, and other stakeholders will help to improve the methods, facilitate data sharing, and develop standardized approaches for conducting resilience CBAs. This should allow utilities to conduct these analyses more efficiently, to trust the accuracy of the results, and to compare the results to those of other utilities.

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Disclaimer

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Myles Collins is a Managing Consultant in Nexant's Utility Services group. His focus at Nexant is on applied valuation methods for reliability and resilience investments. He led two large customer interruption cost studies for value based reliability planning and worked with colleagues at Nexant and Lawrence Berkeley National Laboratory to update a guidebook for electric utilities for estimating power system interruption costs. Before coming to Nexant, Myles worked for five years at Southern California Edison (SCE), where he led strategy, planning and analytics projects. Myles holds a Ph.D. in Policy Analysis from the Pardee-RAND Graduate School and a Master of Public Policy from UCLA.

Stephanie Bieler is a Consultant in Nexant's Utility Services group, where she focuses on demand side management (DSM) measurement and evaluation projects as well as market strategic assessments and planning. Her work includes the evaluation of the Southern California Gas Smart Thermostat Load Control Program and Southern California Edison's Real Time Pricing program. Stephanie additionally conducts demand response (DR) market potential studies, estimating the technical, economic, and achievable potential for DR programs. She has also focused on estimating customer interruption costs (CICs) for value based reliability planning. Prior to joining Nexant, Stephanie earned her Master's degree at Stanford University, where she specialized in resource management, geographic information systems, and advanced statistical analysis.

Shannon Hees is a Consultant with Nexant's Behavioral Science and Analytics group. She is experienced in a broad range of demand side management (DSM) and data analytics for the energy industry, including locational DER valuation, DR cost effectiveness, load forecasting, program planning, and evaluation of demand response and energy efficiency programs. She has been working closely with others at Nexant to produce in-depth studies related to outage costs and grid resiliency.

Josh Schellenberg is Senior Vice President of Advanced Analytics at Nexant. He leads a data science and policy analytics team that focuses on advancing the use of applied econometrics and machine learning applications for electric and gas utilities. With over a decade of analytics and policy experience in the utility industry, Josh has leveraged a data-driven approach to address rapidly emerging grid modernization challenges, including distributed energy resources, grid resilience, asset management and customer engagement. Working with Lawrence Berkeley National Laboratory and the U.S. Department of Energy, Josh developed the Interruption Cost Estimate (ICE) Calculator (available at icecalculator.com), which utilities worldwide have used since 2011 to prioritize reliability investments. Josh has also advised President Barack Obama's Council of Economic Advisers on estimating the economic benefits of increasing electric grid resilience to severe weather.