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Cost-Benefit Analysis of Electricity Resilience Projects: State of the Art and Gap Analysis

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Abstract

Purpose of Review: Utilities and regulators must weigh the benefits of electricity resilience projects against their costs, which would be passed on to customers. Cost-benefit analysis (CBA) is an appropriate method for assessing this tradeoff. In this paper we review the literature on CBA of electricity resilience projects and analyze gaps in the available methods and tools.

Recent Findings: The costs of resilience projects are typically straightforward to estimate but their benefits — particularly the avoided costs of power interruptions — are complex to quantify and monetize. A common perception among practitioners is that current CBA tools are not sufficiently mature to be adopted into real-world practice.

Summary: We propose an electricity resilience CBA framework consisting of several elements: risks, physical impacts, power interruptions, economic impacts, and resilience projects. While methods for some elements are well-developed, there is a need for novel approaches to value avoided power interruptions, integrate multiple risks and benefit streams, and incorporate uncertainty.

Keywords: Resilience; Cost-benefit analysis; Reliability; Power interruption; Value of lost load; Extreme weather

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Introduction

Power system resilience is an emerging area for researchers and practitioners alike. Resilience itself is not a novel concept and is widely referred to in other types of systems, including other forms of infrastructure. Though a consensus definition of resilience for electric power systems has not been established, the National Infrastructure Advisory Council defines resilience as the “ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event” [1].

Distinguishing resilience from reliability can be challenging, and much of the recent literature on resilience has attempted to establish a clearer division between the two [2, 3]. Typically, reliability is concerned with shorter-duration, routine interruptions that may have localized impacts, while resilience refers to widespread, higher-impact events that generally occur less frequently. Utilities are expected to maintain a certain level of reliability, but power system resilience standards are not yet common. However, power system reliability and resilience are closely intertwined, as improvements in power system resilience often improve reliability as well, and vice versa. Recently, researchers and practitioners have suggested that reliability and resilience be considered as part of a continuum or as complements to one another [4].

This paper adds to the existing literature on power system resilience, which includes several previous review papers on this general subject, by focusing specifically on cost-benefit analysis (CBA) of electricity resilience projects. In this study we review the limited examples of electricity resilience CBA in the literature, propose a general framework for electricity resilience CBA, and then review some of the major approaches, methods, and tools that researchers have developed for each element of the framework. Lastly, we identify gaps in the literature and high-priority research directions for improving economic valuation methods and supporting effective decision-making on electricity resilience projects.

There are a wide range of measures that utilities can implement to improve grid resilience, depending on the system’s vulnerabilities and the specific threats faced by the system. Resilience enhancements can generally be classified as either planning-based or operation-based [5]. Planning-based resilience improvements include hardening measures such as undergrounding transmission and distribution lines, upgrading poles using stronger and more durable materials, and elevating or relocating substations vulnerable to floods. Operation-based resilience enhancements include network reconfiguration, microgrid islanding, mobile energy resources, and load restoration strategies.

Some resilience improvements can be made at relatively low costs. Implementing operational resilience measures, such as optimizing power restoration processes, does not necessarily require large capital investments. However, other measures, like undergrounding power lines, require significant upfront investments. These costs may then be passed on to utility customers, leading to increased rates. Regulators must carefully evaluate resilience enhancement proposals and make tradeoffs between cost and resilience.

In principle, CBA is well-suited to analyzing potential resilience projects and deciding whether they should be implemented. CBA is distinct from other project evaluation paradigms in that it estimates both the benefits and costs of a project in dollars. If the benefits exceed the costs then the project should be approved; otherwise, the benefits do not justify the cost of project implementation. Some major advantages of CBA relative to alternative paradigms, such as least-cost planning and budget allocation approaches, are its abilities to determine the economically appropriate level of spending on electricity resilience and to incorporate multiple benefits (e.g., avoided power interruption costs, avoided system restoration costs, operational cost savings) in common, monetary units. While least-cost planning to achieve a specified standard is how utilities have historically approached decisions about traditional reliability interventions, there is currently no consensus on the metrics that should be used to define a resilience standard or their appropriate levels. Similarly, approaches based on allocating a fixed budget by ranking projects according to their effectiveness at enhancing resilience are complicated by the necessity of determining the budget, which should itself be set to balance resilience benefits and spending. Therefore, CBA is an appealing paradigm for electricity resilience decision-making and is our focus in this paper.

State public utility commissions that regulate the electricity industry in the U.S. have recently pushed utilities to provide CBAs to support their proposed resilience investments. For example, as the New York Public Service Commission (NYPSC) describes in an order that it issued in December 2024, New

York utilities must include “an estimate of the costs and benefits of the improvements proposed” in their required resilience plans, “especially regarding undergrounding electric transmission and distribution lines” [6]. In the same year, the Vermont Public Utility Commission approved only a subset of the resilience projects that were proposed by the state’s largest utility, noting that the utility should conduct and present a CBA to justify approval of a more expansive and costly resilience program [7]. While some utilities have performed CBAs, in numerous instances utilities have offered pushback against CBA requirements by arguing that the existing methods, tools, and data are inadequate and/or not ready for real-world use [8]. In some cases, regulators have been sympathetic to these arguments. For example, in the New York case, the NYPSC stated, “The Commission agrees that there is a lack of guidance to provide a [CBA] associated with resiliency-related projects. We note that a great deal of research is currently being performed on this subject and direct the Utilities to keep abreast of ongoing studies” [6]. Therefore, our review of methods and tools that researchers have developed for electricity resilience CBA addresses a timely and practically important subject.

In this paper, we begin by identifying and summarizing examples of electricity resilience CBA that appear in the research literature. Next, we present a high-level framework for conducting CBA of electricity resilience projects. We then review the most relevant prior research on each of its individual elements: risks, physical impacts, power interruptions, and economic impacts. Finally, we offer a critical perspective on the strengths and limitations of established methods for electricity resilience CBA and identify high-priority areas for future research.

Examples of Electricity Resilience CBA in the Literature

Most of the existing work that employs CBA to evaluate resilience investments is in domains other than electricity. However, there are several examples in the literature that use CBA to assess electricity resilience investments. Here we briefly summarize each example, and then we return to them in later sections to describe the varying approaches they follow to handle specific elements of our broader CBA framework.

Larsen [9] conducts a systematic evaluation of undergrounding transmission and distribution lines from the perspective of maximizing net social benefits. He incorporates estimated costs and benefits from five different impact categories. The identified cost impact categories are life cycle assessment, health and safety, and ecosystem restoration, and the benefit impact categories are avoided outages and aesthetics.

CBA is also demonstrated as a tool to compare a set of proposed resilience measures. Ryan and Stewart [10] use CBA to assess the effectiveness of different adaptation strategies for power distribution infrastructure, including adjusting pole condemnation criteria, reducing inspection intervals, and increasing the standard size grade for future power pole installations. They consider the relative performance of each strategy over a given monitoring period, focusing on the average net present value over a distribution of climate projections.

There are examples of resilience CBA that focus specifically on evaluating the net benefits of microgrids. Balducci et al. [11] present a framework for economic evaluation of microgrids. This includes an assessment of microgrid resilience benefits, in addition to the economic benefits from providing grid services during normal operations. The framework is applied to a proposed microgrid project in Massachusetts, and the project’s resilience is assessed over a series of representative outage scenarios. Ortmeyer et al. [12] perform a CBA to compare combinations of generation and distribution systems in a proposed microgrid design. They assess nine different design configurations, and estimate the benefits associated with major power outages to determine the number of power outage days required to reach parity between benefits and costs.

Baik et al. [13] estimate the resilience benefits of adding battery storage to existing residential rooftop solar PV systems in each county of the continental U.S. They model the frequencies of long-duration (at least 24 hours) power outages based on historical data, use a detailed storage dispatch model to project how much the solar-plus-storage system would mitigate outages, and then monetize these avoided outage costs using state-specific values of lost load. The authors find that resilience benefits tend to justify only a fraction of the costs of battery storage — 14% on average across the continental U.S. — but with

considerable regional heterogeneity. Note that Baik et al. [13] do not quantify other (i.e., non-resilience) value streams produced by residential solar-plus-storage systems, such as electricity cost savings, or consider the grid-scale reliability challenges associated with high shares of variable renewable energy.

Other researchers attempt to integrate CBA with least-cost planning by using Optimization via Simulation (OvS) frameworks. Lagos et al. [14] propose a framework using a multi-stage OvS approach for determining resilience enhancements. In this framework, the first level proposes network investments, and the second level evaluates the associated resilience level improvement. Their case study considers a set of 14 candidate enhancements, which include new lines, hardening buses, and new backup distributed generation, and assesses the system’s resilience to earthquakes. Ciapessoni et al. [15] similarly propose and demonstrate a CBA methodology for resilience investments that is based on OvS. The proof of concept applies the methodology to a test system exposed to wet snow events, where the available resilience strategies are two hardening measures (reinforcement of overhead line subcomponents and antitorsional devices), a preventative redispatch measure, and a corrective load shedding measure. In both cases, the method yields an “optimal” portfolio of resilience enhancement measures. One of the challenges in applying an OvS approach to resilience investments is identifying an appropriate objective function for optimization. Potential objective functions include maximizing a resilience metric, as in [14], while [15] explores maximizing the Total Net Benefit (TNB) and System Utility Indicator (SUI).

In addition to the data-intensive, computational modeling approaches covered up to this point, researchers have also contributed theoretical variants of electricity resilience CBA. Horing et al. [16] develop a stylized general equilibrium model to evaluate the costs and benefits of adaptive resilience measures for the power system. The focus of their study, which includes a numerical parameterization of the analytical model, is the effectiveness of public safety power shutoffs, which reduce the risk of wildfire occurrence but have inherent economic output and welfare impacts. Zhu and Leibowicz [17] present a CBA framework based on a Markov decision process that features uncertainty in the effective life of resilience upgrades and models sequential decision-making. They demonstrate this framework through two case study applications, analyzing proposed substation elevation and transmission hardening measures. In assessing the avoided costs of power interruptions, they account for impacts across different customer classes by incorporating reduced economic activity for commercial and industrial customers and diminished quality of life for residential customers.

There is a growing literature focused on defining, measuring, and improving power system resilience. Much of the work to date has been around assessing resilience and the efficacy of different resilience projects. As utilities look to implement resilience improvements, there is a growing need for tools and methodologies to evaluate these proposals and new examples of CBA in the literature are likely to emerge.

Framework for Electricity Resilience CBA

There is no single blueprint for conducting electricity resilience CBA. The examples in the literature exhibit different levels of detail and incorporate a wide range of methodologies. We propose a comprehensive CBA framework that is composed of several interacting elements, as shown in Fig. 1. Our framework is inspired by examples of CBA found in research and practice, and is designed to be general and flexible enough to encompass diverse approaches to electricity resilience CBA. Different implementations of CBA may choose completely different methodologies for modeling any one of the elements, and some CBA examples may follow approaches that allow them to skip over an element entirely.

The first element in our proposed CBA framework is to identify and assess the *risks* to the power system. Depending on the application, these risks could include extreme weather events such as hurricanes or ice storms, or physical or cyberattacks on the grid. Next is to model the *physical impacts* of the resilience event on the power system, such as the distribution lines and substations that it renders non-operational. After estimating the physical impacts, the next element in the sequence is to determine the resulting *power interruptions* that occur across space and time. Finally, the costs of these power interruptions must be monetized by estimating their *economic impacts*. *Resilience projects* produce benefits in the form of

avoided power interruption costs if they intervene at the level of one of the CBA elements to reduce the ultimate economic impacts of power interruptions.

Different resilience projects target different elements of our CBA framework. Vegetation management programs could reduce the likelihood of wildfires, thereby reducing risks. Undergrounding distribution lines aims to reduce the physical impacts of resilience events by protecting these lines from high winds and falling trees, hence reducing the frequency of outages. Operational resilience measures such as network reconfiguration and microgrid islanding can reduce the magnitudes and durations of power interruptions. Projects intended to mitigate the economic impacts of whatever power interruptions do occur include installing backup generation and/or storage at critical infrastructure facilities (e.g. hospitals) and relocating particularly vulnerable customers (e.g. the elderly) when they lose power during an extreme heat or cold event.

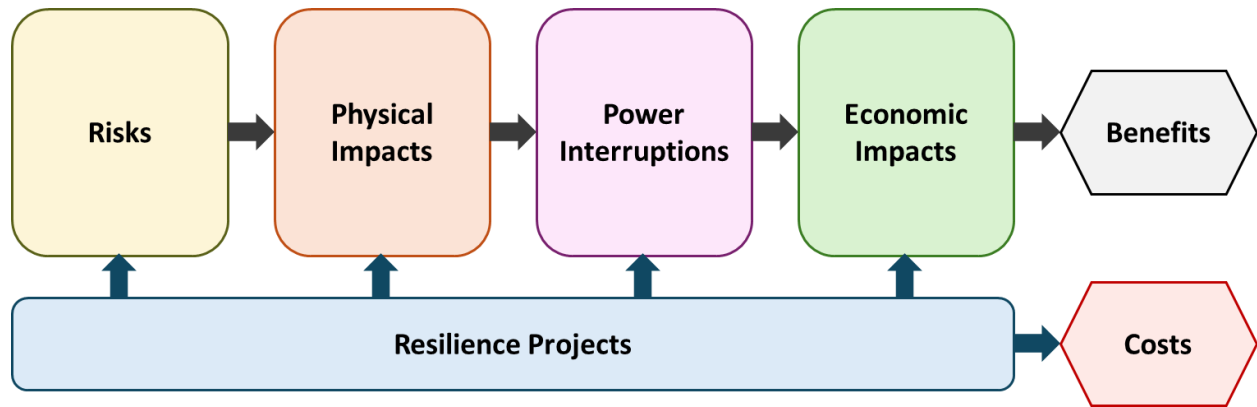


Fig. 1 Framework for electricity resilience CBA

It is important to note that the economic impacts element is what clearly distinguishes CBA from other paradigms that could be used to analyze electricity resilience projects. By contrast, the other elements of our framework are common to many possible paradigms. For instance, the least-cost planning and budget allocation paradigms would also require the modeling of risks, physical impacts, and power interruptions, as well as the abilities of resilience projects to mitigate these interruptions.

Review of the Literature on Each CBA Element

Risks

Electric power systems face risks from extreme weather events, as well as from deliberate human attacks. The methods for modeling risks vary depending on the specific threats that a power system faces. Some weather events that threaten large-scale impacts on power systems include extreme heat and cold events, high winds during storms and hurricanes, heavy snow and ice accumulation, lightning strikes, and flooding. The literature on extreme event modeling has been developed to explore the impacts of extreme weather on power system resilience. In a broader survey of the state of the art in power system resilience, Bhusal et al. [5] categorize and describe extreme event modeling approaches in existing power system resilience studies, including weather-related events, cyberattacks, and physical attacks.

There are publicly available tools for modeling some types of extreme weather. The Federal Emergency Management Agency (FEMA) maintains HAZUS-MH (multi-hazard), extending the original HAZUS earthquake model to include flood and hurricane models [18]. HAZUS is designed to support natural hazard mitigation and decision-making. The HAZUS flood model quantifies flood hazard, defined as the relationship between depth of flooding and annual probability of inundation exceeding that depth [19]. HAZUS also includes a hurricane hazard model, consisting of a wind field model and a storm track model, which together assess how wind, pressure, and rainfall may be distributed over a large geographic

area [20, 21]. The U.S. Department of Agriculture maintains wildfire simulation tools within FlamMap, including the FARSITE simulator [22], which provides a CFD-based approach to simulating wildfire spread. Sohrabi et al. [23] demonstrate the use of FARSITE to develop wildfire scenarios for evaluating power system vulnerabilities. After using weather data to parameterize the simulator, they generate wildfire ignition scenarios and use FARSITE to determine the progression of the wildfire. They are then able to integrate the wildfire simulation with spatial grid data to identify impacted components and simulate the effect on power system operations.

Other models and methodologies are demonstrated in the literature for various types of extreme events, including wildfires, snow, and ice. For example, Tapia et al. [24] adapt and demonstrate a stochastic wildfire simulation method, generating fire spread scenarios to identify transmission and generation contingencies. Abdelmalak et al. [25] develop a spatiotemporal ice storm model for generating ice storm scenarios, using statistical analysis of past events to parameterize the model. Yang et al. [26] propose a probabilistic model to derive the joint probability distribution of ice and wind loading on transmission infrastructure.

It is important to note that many of the tools employed in the existing power system resilience literature are used for scenario generation, simulating what an extreme event might look like. The probability of that scenario occurring may not be directly assessed, since the focus of the assessment is the performance of the resilience enhancement in the case of an extreme event. For example, the wildfire simulation methods described above do not include an assessment of the probability of ignition but rather focus on modeling how a wildfire might spread from a given ignition point. However, when assessing the overall costs and benefits of a resilience enhancement, the frequencies or likelihoods of extreme events and their evolution over time become more important to include. Some existing tools can provide this information, such as the HAZUS flood and earthquake models that characterize flood or earthquake hazards as either probabilistic or deterministic events, depending on the needs of the user [27, 28].

While weather-related events can cause widespread power interruptions, there are also concerns around resilience to cyberattacks, especially with an increasing penetration of advanced monitoring and control devices on the grid. Methods for modeling cyberattacks require an understanding of the specific system vulnerabilities being exploited by attackers. Venkataramanan et al. [29] develop a set of cyberattack scenarios to evaluate the cyber-physical resilience of a microgrid system. Xiang et al. [30] use a semi-Markov process to model intrusion processes for a load redistribution attack.

The CBA examples in the literature, which we highlighted earlier in this paper, demonstrate varied approaches for hazard modeling, some of which explicitly account for the uncertainty of extreme events. The flexible OvS framework proposed by Ciapessoni et al. [15] allows for the integration of a probabilistic hazard model, and the proof of concept utilizes a probabilistic wet snow model derived from a reanalysis dataset and an ensemble of climatological models. Lagos et al. [14] also incorporate a probabilistic threat model, though their case study focuses on earthquakes. More specifically, they develop a Monte Carlo model that generates magnitude, location, and attenuation, based on established distributions and geographically suitable models used to simulate earthquakes. Finally, one of the case studies presented by Zhu and Leibowicz [17], centered around a proposal to elevate a substation, is parameterized based on data from a utility filing by Entergy, where the probability of flooding is based on floodplain analysis.

Physical Impacts

By modeling physical impacts, it is possible to link together risks and their subsequent effects on power system operations. The types of physical impacts and vulnerable assets vary depending on the specific type of extreme event. For example, substations are susceptible to failure from flooding but may be less affected by winds or extreme temperatures. One helpful paradigm for thinking about potential physical impacts are “stressor-response” relationships that link stressors like temperature, precipitation, lightning, and wildfires with the responses of the infrastructure assets that they affect [31].

The most common way to model asset-level failures is through fragility curves, which are used in a wide array of resilience-oriented power system studies. Generally, fragility curves are functions that relate

the failure probability of an asset to some variable that measures the magnitude of an extreme event (e.g., wind speed, ice accumulation). The impact of a grid hardening project can be captured through a change in the fragility curve, such that the failure probability is reduced for a given event severity. Serrano-Fontova et al. [32] comprehensively review fragility curves defined for power system components, categorizing the curves according to the extreme event and the system component subject to each type of event.

Some of the available tools for hazard or threat modeling include built-in capabilities for estimating physical infrastructure damage. For example, HAZUS includes fragility curves for various electric power system assets, including substations, distribution circuits, and generation plants [28]. Fragility curves and failure probabilities have been integrated into some examples of resilience CBA in the literature. The simulation method described in [14] includes a vulnerability assessment for various power system components. More specifically, the components are assigned failure rates conditional on the occurrence of a natural hazard, in this case an earthquake, based on fragility curves.

Note that for some types of resilience enhancements, such as undergrounding power lines or upgrading power poles, the enhancement will directly affect the way that component failures are modeled. For example, in one of the case studies presented in [17], the “disaster” is defined as the destruction of electric infrastructure (a physical impact), rather than the weather event that causes the destruction (a risk). The probability of a “disaster” occurring is then based on the utility’s expected failure rates for existing and hardened infrastructure, which are calculated using a probabilistic hurricane model and historic damage data. The authors assume that the expected failure rate for the hardened infrastructure is an order of magnitude lower than that of the existing infrastructure.

Beyond fragility curves, there are other methods for modeling physical impacts based on weather or climate models. Ryan and Stewart [10] focus on economic evaluation of adaptation strategies for timber power poles, so their work incorporates detailed statistical models of timber decay and deterioration that are linked to climatic factors that include humidity, temperature, and wind. Aside from component-level failure models, there are also approaches that model system-level, or aggregate, failures through either statistical regressions or tree-based mining models, though these approaches are used less frequently than fragility curves [5].

Power Interruptions

To estimate the economic impact of improving power system resilience, it is important to study how resilience interventions affect the actual behavior of the power system. Direct simulation of the power system can produce results for the magnitude and spatiotemporal distribution of power interruptions, including cascading outages driven by asset failures. Bhusal et al. [5] provide a high-level review of methods for modeling the power system in resilience-focused studies. They point out that the network configuration and key constraints differ when modeling transmission versus distribution systems. In addition, modeling approaches may implement varying levels of technical and operating constraints and may rely on different solution algorithms.

Power flow models are a key tool for assessing the resilience of both bulk power and distribution systems. The main differences among power flow models are the level of complexity and the degree of approximation. AC power flow models are generally more detailed than DC power flow models, which are less complex, but both are used in resilience assessments [5].

Modeling the post-event power system restoration process helps characterize the durations of power interruptions, which are critical determinants of the avoided power interruption costs that a resilience intervention would achieve. Optimal restoration is a well-studied topic in the power system resilience literature. Cavdaroglu et al. [33] address the restoration of interconnected infrastructure systems after a non-routine disruption, integrating the interactions between power and telecommunications systems in their restoration and scheduling model. van Hentenryck and Coffrin [34] study the application of mathematical programming to transmission system repair and restoration after a significant disruption. They note that both subproblems, scheduling the repair and sequencing the restoration, are computationally challenging. Moglen et al. [35] present a framework for identifying an optimal power grid restoration plan, including a

heuristic restoration strategy that operators could implement relatively easily if explicitly optimizing in the aftermath of a disaster is too challenging. They then extend their framework to model the simultaneous restoration of power and wireless communication networks, considering the dependence of the latter on the former [36].

In addition, restoration processes can be the focus of resilience-enhancing strategies. For example, Bie et al. [37] propose a resilient load restoration algorithm, using distributed generation and network reconfiguration. They evaluate the effectiveness of the algorithm under a deterministic hazard scenario by modeling a distribution system using a single-phase equivalent to a three-phase AC power flow.

In lieu of detailed power system modeling, it is possible to estimate power interruption magnitudes and/or durations based on historical outage data. [10] follows this approach in its CBA, using data to estimate the numbers and types of customers impacted per power pole failure. [17] adopts a similar method, estimating the number of customers served per substation or served by a percentage of the transmission system. A drawback of this approach is that it cannot capture the systemic nature of a power system, in which the impacts of asset failures can propagate through the network and cause outages whose magnitudes, locations, and durations depend on the system as a whole.

Several of the CBA examples identified earlier in this paper model power interruptions without including detailed modeling of the event that causes the interruption. One method for doing this is through econometric modeling. Larsen et al. [38] develop an econometric model that correlates annual weather measures, including heating and cooling degree-days, lightning strikes, and wind speeds, with various utility-related variables, including customers per line mile, electricity delivered, and transmission and distribution expenditures. [9] uses this model to estimate outage frequency, thus incorporating weather information without explicitly modeling any extreme events. Baik et al. [13] estimate the frequencies of long-duration power interruptions using historical interruption data that the U.S. Department of Energy collects from utilities. Since they focus on a behind-the-meter resilience strategy (i.e., adding battery storage to residential PV systems), they assume that historically observed patterns in electric grid outages will persist, and use a detailed storage dispatch model to assess how much the solar-plus-storage systems would reduce the power interruptions experienced by the homes that host them. Other approaches, like the microgrid evaluation in [11], use randomly generated outage scenarios to assess how the system responds to a range of conditions. The challenge then lies in quantifying the probability of such an interruption event occurring.

Economic Impacts

The final element of a comprehensive resilience CBA is an analysis of economic impacts. This includes the assessment of costs and benefits, which involves quantifying and monetizing the benefits associated with resilience. This step marks the key difference between CBA and other approaches for evaluating resilience projects. Most analyses of resilience enhancements in the literature are focused on establishing the general effectiveness of resilience strategies, rather than determining their economic value.

Some economic impacts are relatively simple to assess, while others require more complex modeling approaches. The costs of implementing a resilience project are typically straightforward to estimate in advance. To the extent that a resilience intervention mitigates the physical impacts of risk events on grid assets, one benefit will be a reduction in direct restoration costs, which are the costs associated with repairing and replacing damaged assets to restore the power system to full functionality. As shown in [39] and [8], data on direct restoration costs stemming from past extreme weather events are widely available because utilities present them to regulators in seeking to recover these restoration costs from customers through electricity rates.¹ Quantifying and monetizing the avoided costs of power interruptions, which a resilience intervention should make less frequent and/or severe, is a more difficult task when it comes to valuing the benefits of resilience and is our main focus here. Macmillan et al. [40] review methods and

¹ Note that rate recovery processes may provide incentives for some utilities to inflate the costs associated with power system restoration. Researchers could play a role in determining unbiased values for restoration costs.

modeling techniques for estimating the costs of power outages and discuss the relative strengths of different approaches. Table 1 previews the information that we provide in this section by identifying some categories of benefits that are ascribed to common resilience measures and which of the CBA examples highlighted earlier explicitly consider them.

Table 1 Categories of benefits of electricity resilience projects and CBA examples that consider them

Benefit Category	CBA Examples
Avoided Power Interruption Costs	Baik et al. [13] Balducci et al. [11] Ciapessoni et al. [15] Horing et al. [16] Lagos et al. [14] Larsen [9] Ortmeyer et al. [12] Ryan and Stewart [10] Zhu and Leibowicz [17]
Avoided System Restoration Costs	Ciapessoni et al. [15] Ryan and Stewart [10] Zhu and Leibowicz [17]
Electricity Cost Savings (normal operations)	Balducci et al. [11] Ortmeyer et al. [12]
Avoided Impacts to Critical Facilities	Ortmeyer et al. [12]
Aesthetic Benefits	Larsen [9]
Avoided Ecosystem Restoration Costs*	Larsen [9]

*Depends on context. For example, adding new overhead lines may result in higher ecosystem restoration costs than adding new underground lines (leading to avoided costs), but undergrounding existing overhead lines might simply add costs.

The value of lost load (VOLL) is a concept from the power system reliability literature and is meant to monetize the societal benefits of reduced power interruptions. More specifically, the VOLL represents a customer's willingness-to-pay to avoid a power interruption (e.g., in dollars per kWh). Gorman [41] provides a critical review of VOLL, noting that the value varies across customer types and the context of consumption, such as geographic location, interruption duration, and timing of the interruption. Lawrence Berkeley National Laboratory (LBNL) maintains an Interruption Cost Estimate (ICE) Calculator, which allows users to obtain estimates for the cost per event, cost per average kW, and cost per unserved kWh. Users can define various model settings, including the timing and seasonality of the interruption and more detailed characterization of residential and non-residential customers [42]. LBNL continues to update its ICE Calculator based on methodological refinements and surveys of additional customers. A few of the CBA examples use some version of the ICE Calculator estimates, either directly or as a starting point for further VOLL calculations [13, 11, 12, 17].

It is worth noting that while most VOLL estimates have been obtained through survey-based research methods, researchers have made several attempts to estimate the VOLL using revealed preference approaches that leverage observational data on the decisions and transactions of market participants. For example, Caves et al. [43] study industrial customers' decisions about whether to participate in interruptible service programs that offer discounted electricity rates in exchange for customers agreeing to reduce their demands when the utility calls on them to do so. Harris [44] arrives at a VOLL estimate by analyzing consumer purchases of backup generators. Similarly, Brown and Muehlenbachs [45] estimate the VOLL by examining the effects of California's Public Safety Power Shutoffs, intended to prevent wildfires, on customers' decisions about whether to adopt home battery storage systems.

Monetizing the costs of power interruptions by directly applying VOLL estimates such as those in the ICE Calculator is really only valid for shorter-duration interruptions, as long-duration power

interruptions tend to produce indirect spillover effects that ripple through the economy, and which are not reflected in customers' responses to VOLL surveys [42]. Researchers propose using macroeconomic models to overcome this limitation in evaluating the economic impacts of longer-duration interruptions. There are different kinds of macroeconomic models that can estimate the broader economic impacts of power interruptions. Sanstad [46] reviews different types of regional economic models, identifying the primary types of models as input-output (I-O), computable general equilibrium (CGE), and macro-econometric. Sanstad goes on to provide examples of each type of model applied to long-duration power interruptions and then identifies future research needs for improving regional economic modeling in this domain.

Recognizing the limitations of VOLL when applied to widespread, long-duration interruptions, Baik et al. [47] outline a hybrid approach that uses customer interruption cost surveys (of the type employed to estimate VOLL) to parameterize and calibrate CGE models, which can then be used to estimate direct and indirect costs for a regional economy during widespread, long-duration power interruptions. These models include assumptions about how firms and households will adapt their behaviors during and after a power interruption, with responses including input substitution or physical relocation. Sue Wing et al. [48] extend this work further by elaborating and quantifying both the supply-side and demand-side responses associated with widespread, long-duration interruptions. They apply this approach to a case study of Commonwealth Edison in the Chicago metro area to demonstrate how adjustments from all types of customers generalize to economy-wide effects, which could potentially lead to large losses. In the case study, the power interruption is abstracted from any specific extreme event and simply modeled as a loss of power for a fixed duration. In addition, they develop a counterfactual scenario to analyze how increased penetration of backup generation would influence the economic impacts of the interruption.

However, there are a few challenges that remain in implementing CGE methods for power system resilience CBA. First, CGE modeling requires significant modeling expertise, computational resources, and data availability. In addition, since CGE models do not represent the power system, resilience projects that involve grid hardening or other physical changes to infrastructure cannot be explicitly represented in CGE models. It should be possible to overcome this limitation by coupling power system models and CGE models, but this remains for future work.

Beyond the economic benefits associated with avoided power interruptions, there have been efforts to quantify and monetize other potential benefits. These benefits vary based on the specific resilience intervention. For example, in Larsen's CBA for undergrounding transmission lines [9], he incorporates aesthetic benefits from removing overhead lines in the form of improved property values. Resilience interventions that involve energy storage, such as microgrids or distributed energy resources, have additional benefits from their normal operating modes, such as electricity cost reductions [11, 12]. Gorman et al. [49] investigate tradeoffs between the resilience benefits and electricity bill saving benefits of residential solar-plus-storage systems, depending on how their charging and discharging are controlled. Their results show that control strategies that emphasize bill savings generally produce larger benefits than those that maintain ample stored energy in case it is needed for backup power. Some resilience investments, such as undergrounding, may result in operations and maintenance cost savings, though this potential benefit has not been estimated [9]. Zamuda et al. [50] survey different benefit categories and methods for monetization.

Discussion

In the broader power system resilience literature, the individual elements of our electricity resilience CBA framework are generally well-developed. There are several high-level papers on resilience assessment that highlight the first three elements of the proposed framework: modeling risks, physical impacts, and power interruptions [5, 51]. The strands of the research literature that develop key tools for these elements — natural hazard scenario generators, fragility curves, power flow models, power system restoration models, and so on — are fairly mature and firmly established. The key feature of CBA that distinguishes it from other approaches for evaluating electricity resilience projects is its inclusion of economic impact valuation, quantifying and monetizing the benefits that resilience interventions would

realize. The research on economic impact valuation features some notable gaps that should be addressed, and the need to ultimately quantify and monetize the benefits of avoided power interruption costs also suggests specific research needs in the preceding elements.

While VOLL estimates are grounded in substantial research and are easy to apply in practice, they are limited in their ability to capture the full, economy-wide impacts of widespread, long-duration interruptions. Researchers are actively working to develop and refine macroeconomic models (e.g., CGE models) that estimate these economy-wide costs, inclusive of spillover effects that ripple across sectors and locations. Research on macroeconomic models for electricity resilience CBA should focus on realistically characterizing the behaviors of households and firms on both planning (preparing for potential risk events) and operational (reacting to an event) timescales, and coupling these economic models to power system models in which grid hardening resilience projects can be explicitly represented. Model developers could provide software interfaces that make it easier for users to create input datasets to apply macroeconomic models to assess resilience projects in a new region. At the same time, recognizing that utilities may lack the resources to become macroeconomic model users, it would be valuable for researchers to derive general “rules of thumb” for how much larger the full, economy-wide impacts of major power interruptions tend to be than the direct impacts captured in VOLL estimates.

In addition, there is a need for better representation of uncertainty in resilience CBA. For example, it can be challenging to determine the probability that an extreme event will occur, or the frequency with which an event of a given severity will take place. By their nature, the risk events that are most relevant to electricity resilience occur infrequently, which makes it challenging to estimate their probabilities using historical data. Many of the existing software tools for threat modeling are used to generate hazard scenarios without assigning a probability to the occurrence of each scenario. To make these software tools more useful for resilience CBA applications, the addition of uncertainty quantification is a critical need.

Finally, most resilience studies are focused on a single type of threat or hazard, but in practice resilience projects can provide benefits across multiple types of events and may even offer non-resilience benefits, such as improvements to system reliability or reductions in electricity investment and operating costs. Therefore, there is a need for approaches that allow for the straightforward incorporation of multiple risk types and benefit streams, without double-counting or overestimating benefits. The CBA examples that assess microgrids with energy storage provide an idea of how to evaluate multiple value streams, as energy storage is known to have benefits that include reliability enhancement and congestion relief.

Conclusions

CBA is a useful tool for assessing power system resilience investments, as it enables decision-makers to compare the various costs and benefits associated with a proposed resilience enhancement project. Decision-makers can also compare several resilience enhancements to see which provides the greatest net benefit or has the highest benefit/cost ratio. To date, examples of CBA in the literature demonstrate a wide range of approaches, with differing levels of detail in modeling risks, physical impacts, power interruptions, and economic impacts.

However, though the literatures on some elements of electricity resilience CBA are well-developed, there are still areas that require further development, especially if the methods are to be made accessible to industry practitioners and regulators. For example, when it comes to valuing the full, economy-wide costs of power interruptions, researchers have yet to develop tools that practitioners could easily adopt and use. For this reason, there are few examples of CBA that integrate the state of the art across all elements. Notably, the framework for CBA described in this paper provides a flexible foundation for incorporating novel methods, estimating the economic benefits of resilience projects, and ultimately making decisions about which resilience interventions to implement. In other words, practitioners can augment their current analyses, which may already include elements such as risk analysis and VOLL estimation, with new tools and methodologies as they become available.

By improving the available tools for conducting electricity resilience CBA, we can enable utilities and system planners to better assess the impacts associated with resilience investments, and to compare the

effects of alternative projects. In addition, a fully developed set of valuation tools can provide transparency around the costs and benefits of resilience measures, allowing regulators to effectively evaluate proposals and ensure that investments are worth the increased costs to ratepayers.

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Note: **Key References** (marked with • or ••) are annotated with [blue text](#)

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