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Regulatory Mechanisms to Enable Investments in Electric Utility Resilience

Designing Resilient Communities: A Consequence-Based Approach for Grid Investment Report Series

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ABSTRACT

In 2019, Sandia National Laboratories contracted Synapse Energy Economics (Synapse) to research the integration of community and electric utility resilience investment planning as part of the Designing Resilient Communities: A Consequence-Based Approach for Grid Investment (DRC) project. Synapse produced a series of reports to explore the challenges and opportunities in several key areas, including benefit-cost analysis, performance metrics, microgrids, and regulatory mechanisms to promote investments in electric system resilience. This report focuses on regulatory mechanisms to improve resilience. Regulatory mechanisms that improve resilience are approaches that electric utility regulators can use to align utility, customer, and third-party investments with regulatory, ratepayer, community, and other important stakeholder interests and priorities for resilience.

Cost-of-service regulation may fail to provide utilities with adequate guidance or incentives regarding community priorities for infrastructure hardening and disaster recovery. The application of other types of regulatory mechanisms to resilience investments can help. This report:

- characterizes regulatory objective as they apply to resilience;
- identifies several regulatory mechanisms that are used or can be adapted to improve the resilience of the electric system—including performance-based regulation, integrated planning, tariffs and programs to leverage private investment, alternative lines of business for utilities, enhanced cost recovery, and securitization;
- provides a case study of each regulatory mechanism;
- summarizes findings across the case studies; and
- suggests how these regulatory mechanisms might be improved and applied to resilience moving forward.

In this report, we assess the effectiveness of a range of utility regulatory mechanisms at evaluating and prioritizing utility investments in grid resilience. First, we characterize regulatory objectives which underly all regulatory mechanisms. We then describe seven types of regulatory mechanisms that can be used to improve resilience—including performance-based regulation, integrated planning, tariffs and programs to leverage private investment, alternative lines of business for utilities, enhanced cost recovery, and securitization—and provide a case study for each one. We summarize our findings on the extent to which these regulatory mechanisms have supported resilience to date. We conclude with suggestions on how these regulatory mechanisms might be improved and applied to resilience moving forward.

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EXECUTIVE SUMMARY

In 2019, Sandia National Laboratories (Sandia) contracted Synapse Energy Economics (Synapse) to research the integration of community and electric utility resilience investment planning.[1] The research was funded by the U.S. Department of Energy (DOE) and conducted as part of the Grid Modernization Laboratory Consortium (GMLC), under the project named Designing Resilient Communities: A Consequence-Based Approach for Grid Investment (DRC).

The primary objective of the DRC project is to understand and provide guidance on the challenges and opportunities facing communities and electric utilities seeking to coordinate energy-related resilience efforts.[2] The project seeks to demonstrate an actionable path toward designing resilient communities through consequence-based approaches to grid planning and investment, and through field validation of technologies with partners that enable distributed and clean resources to improve community resilience. As part of the DRC project, Sandia is partnering with a variety of government, industry, and university partners to develop and test a framework for community resilience planning focused on modernization of the electric grid.

In support of DRC, Synapse produced a series of reports to explore challenges and opportunities in several key areas, including benefit-cost analysis, performance metrics, microgrids, and regulatory mechanisms. This report focuses on regulatory mechanisms that electric utility regulators can use to align utility, customer, and third-party investments with regulatory, ratepayer, community, and other important stakeholder resilience interests and priorities.

Cost-of-service regulation may fail to provide utilities with adequate guidance or incentives regarding community priorities for infrastructure hardening and disaster recovery. The application of other types of regulatory mechanisms to appropriately incentivize resilience investments can help. This report:

- characterizes regulatory objective as they apply to resilience;
- identifies several regulatory mechanisms that are used or can be adapted to improve the resilience of the electric system—including performance-based regulation, integrated planning, tariffs and programs to leverage private investment, alternative lines of business for utilities, enhanced cost recovery, and securitization;
- provides a case study of each regulatory mechanism;
- summarizes findings across the case studies; and
- suggests how these regulatory mechanisms might be improved and applied to resilience moving forward.

We find that regulatory mechanisms are not currently structured or applied to effectively address resilience, nor do incentives align well with the resilience goals of ratepayers and community representatives. Overall, our research indicates that application of regulatory mechanisms to resilience investments is in the early stages and there are few case studies. Where regulatory mechanisms are applied to resilience, other goals than resilience have been the primary goal and

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[1] In this research, municipal governments are considered communities due to their broad lens into local, public efforts and investments as well as their decision-making authority. Municipal governments include communities that are both urban and rural and both large and small.

[2] Department of Energy. *New GMLC Lab Call Awards for Resilient Distribution Systems*. September 4, 2017. Available at: https://www.energy.gov/articles/new-gmlc-lab-call-awards-resilient-distribution-systems.

resilience has not been well integrated. Additionally, in our case study on tariffs, resilience was not a regulatory objective.

The limited data thus far suggest that, as applied to date, no single mechanism achieves all regulatory objectives and associated desired outcomes. Additionally, no regulatory objective and associated desired outcomes are achieved by all the mechanisms. Lastly, all the regulatory mechanisms fell short in two areas: (1) requiring consideration of and comparison of the full range of investments utilities and third parties can make to address resilience challenges (referred to as investment diversity) and (2) partnering with stakeholders and considering their viewpoints (referred to as stakeholder input).

As currently implemented, each mechanism has shortcomings and therefore may not enable full resilience investments. With improvement, these regulatory mechanisms have the potential to address resilience goals. However, multiple approaches may need to be implemented together to address resilience more fully.

It is not our expectation nor is it necessarily a goal that every type of regulatory mechanism can or will achieve every desired outcome. Some regulatory mechanisms are better able to achieve some outcomes than others. The purpose of this assessment is to facilitate discussion about the objectives and outcomes that are most important for jurisdictions seeking to address resilience and about the best means to achieve those objectives and outcomes. We expect that different jurisdictions will have different priorities. Therefore, we expect jurisdictions to use different regulatory mechanisms to achieve their resilience goals.

ACRONYMS AND DEFINITIONS

Acronym or Term	Definition
behind-the-meter	on the customer-owned portion of the grid; see also customer-side of the meter investments
CAIDI	customer average interruption duration index
continuity	providing uninterrupted electricity of sufficient quality to end-use customers
COSR	cost-of-service regulation: a regulatory mechanism that resets rates in occasional rate cases to allow utilities the opportunity to recover their incurred costs.
customer equity	balancing the interests of different constituencies
customer-side of the meter investments	investments on the customer-owned portion of the grid; see also behind-the-meter
DER	distributed energy resource
distribution utility	a utility that owns and operates infrastructure for distributing electricity to end-use customers but does not own the means of producing or transmitting electricity over the bulk transmission grid
enhanced cost recovery	mechanisms that address the speed or certainty of cost recovery
extreme event days	days in which threats test the reliability and resilience of the electric grid
fairness	a state in which no individual or group (*e.g.*, customers in total or in part, utility shareholders) unduly shoulders risks or retains the benefits of utility activities
front-of-meter	on the utility-owned portion of the grid; see also utility-side of the meter investments
IDP	integrated distribution planning
IGP	integrated grid planning
integrated planning	comprehensive forms of planning including integrated distribution planning, integrated resource planning, and integrated grid planning
IOU	investor-owned utility
IRP	integrated resource planning
islandable	able to disconnect from the electric power grid, such that a facility or group of facilities retain power during an outage on the grid

Acronym or Term	Definition
just and reasonable rates	considering the costs and benefits of investments
MAIFI	momentary average interruption frequency index
MRP	multi-year rate plan
normal days	days in which the electric grid does not experience threats or does not experience any disruptions from threats
prudence	a criterion that calls for decisions to be reasonable given all information reasonably known or knowable at the time that the decision is made
public interest	promoting the well-being of the public generally, and utility customers more specifically
PBR	performance-based regulation: an approach to regulation designed to strengthen utility performance incentives
regulatory mechanisms	tools that utility regulators can employ to align utility, customer, and third-party investments with regulatory, ratepayer, community, and other stakeholder interests and priorities
resilience	the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions[3]
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
tariff	the pricing structure, terms, and conditions that a utility uses to charge customers for service
threat assessment	an analysis of the likelihood of occurrence and consequences of extreme events in an area, generally a service territory or jurisdiction
threats	events that can disrupt the performance of the electric grid, *e.g.*, human-made threats such as cyber-attacks, and natural threats such as major storms, earthquakes, and wildfires
utility-side of the meter investments	investments on the utility-owned portion of the grid; see also front-of-meter.
vertically integrated utility	a utility that owns and operates generation, transmission, distribution equipment and makes retail sales directly to customers

[3] U.S. Office of the Press Secretary. 2013. *Presidential Policy Directive/PPD-21 -- Critical Infrastructure Security and Resilience.* February 12. Available at: https://obamawhitehouse.archives.gov/the-press-office/2013/02/12/presidential-policy-directive-critical-infrastructure-security-and-resil.

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1. INTRODUCTION

1.1. Purpose

In this report, Synapse assesses the effectiveness of a range of utility regulatory mechanisms for evaluating and prioritizing utility investments in grid resilience. Resilience is defined by the U.S. Department of Energy (DOE) as "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions."[4,5]

Under cost-of-service regulation (COSR), investor-owned utilities (IOU) may be more motivated to make certain types of investments, specifically capital investments. This is because the company making these investments is allowed to earn a rate of return on the capital invested (the utility's "rate base").[6] The more IOUs make capital investments in generation, transmission, and distribution equipment, the more profit the utilities and their shareholders are allowed to earn.[7] Utilities are also motivated to boost earnings by increasing total revenues, which can be accomplished by increasing electricity sales or adding new customers. Overspending on capital improvements and increasing electricity use can result in higher bills for ratepayers.

COSR may fail to produce outcomes that provide the greatest benefit to society. For example, while providing substantial benefits to society in general, customer- or third-party-owned distributed energy resources (DER) such as energy efficiency and distributed generation reduce utility sales. This reduction in utility sales impacts revenues and profits under COSR. If sales stagnate or decline, the utility may be faced with lower revenues, profits, and shareholder values. As a result, utilities under COSR are generally not incentivized to encourage growth in DERs.

To counterbalance these disincentives from COSR, regulators have adopted other regulatory mechanisms that can replace or augment COSR to better align utility investments with regulatory, ratepayer, community, and other important stakeholder interests and priorities. Among those interests and priorities are an increased demand for resilience.

This report explores several additional types of regulatory mechanisms that can be used to improve resilience. These include performance-based regulation (PBR), integrated planning, tariffs and programs to leverage private investment, alternative lines of business for utilities, enhanced cost recovery, and securitization. First, we characterize regulatory objectives which underly all regulatory mechanisms. We then describe these types of regulatory mechanisms, provide a case study for each

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[4] U.S. Office of the Press Secretary. 2013. *Presidential Policy Directive/PPD-21 -- Critical Infrastructure Security and Resilience.* February 12. Available at: https://obamawhitehouse.archives.gov/the-press-office/2013/02/12/presidential-policy-directive-critical-infrastructure-security-and-resil.

[5] Resilience is distinct from reliability, which is defined by the DOE as "the ability of the system or its components to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components." Reliability benefits are often realized when the consequences of more frequent, short-duration outages, referred to as major event days, are avoided. While reliability is addressed by utilities and regulators as part of the regular course of business, the consequences of resilience events are longer-duration and/or more widespread and considered to be outside of the norm.

[6] Specifically, when a utility's allowed return on equity is greater than the cost of capital, utilities have a financial incentive to maximize their capital expenditures in order to increase value to investors. This is referred to as the Averch-Johnson effect.

[7] Under COSR, rates are set to allow the utility to recover its prudently incurred costs established at the time of the rate case (during a "test year"), including the cost of raising capital from investors. The actual profit earned by the utility between rate cases is dependent on the revenues it collects and the costs it incurs during the intervening years.

one, and summarize our findings and conclusions—including suggestions for improvement and application moving forward.

1.2. Report Organization

The remainder of this report is organized as follows:

- Section 2 is an overview of the objectives of utility regulation and provides examples of how they relate to resilience.
- Section 3 describes regulatory mechanisms that may be used to improve resilience.
- Section 4 includes case studies of regulatory mechanisms that may improve resilience.
- Section 5 summarizes the key findings from the case studies.
- Section 6 Conclusions.

2. REGULATORY OBJECTIVES

Regulators balance and apply several widely accepted principles across all regulatory mechanisms. One of regulators' top priorities is to ensure that utilities provide uninterrupted, high-quality electricity services to customers. Regulators are also charged with setting reasonable rates and promoting equity across customers. They also seek to ensure that utilities make sound decisions, are financially solvent, and can earn a reasonable return on their investments. As an overarching objective, regulators are typically charged with protecting the public interest, which is a broadly defined term meant to include well-being of all people, within and outside of the utilities' service territory.

For this report, we focus on several key regulatory objectives that apply to many areas of utility regulation, but which may be particularly important for resilience investments. These include the following:

- *Continuity of electric service* is the ability of the electricity system to provide uninterrupted electricity of sufficient quality and quantity to end-use customers. Continuity includes restoring service as quickly as possible when disruptions occur, including disruptions characterized as "acts of god".
- *Ensuring reasonable rates* requires consideration of the costs and benefits of investments. Sandia National Laboratories' report titled *Application of a Standard Approach to Benefit-Cost Analysis for Electric Grid Resilience Investments* provides more information on the costs and benefits associated with grid resilience.[8] For rates to be reasonable, they must also be based on sound utility investment decision-making, which considers all information reasonably known or knowable at the time that decisions are made. In addition, reasonable rates ensure the utility remains solvent without reaping excess profits. This implies that utilities should consider all relevant risks and a comprehensive set of technologies and options to identify and prioritize solutions before commitments to invest are made.
- *Customer equity* requires balancing the interests of different constituencies. Fairness across customer classes generally calls for distribution of costs consistent with cost causation. Decisions about cost allocation across customer classes can be informed by cost-of-service studies and rate and bill impact analyses. Fairness across multiple generations of customers requires that the cost of a capital investment is recovered over its useful life.
- *In the public interest* means that an investment promotes the well-being of the public generally, and utility customers more specifically. In some instances, the public interest includes environmental issues such as decarbonization objectives, public health issues, and job creation.

To ensure these regulatory objectives are met, performance measurement and evaluation should be established. The principle of *measured and measurable* applies to all the above and thus is considered a cross-cutting objective.

[8] Sandia National Laboratories. 2021. Application of a Standard Approach to Benefit-Cost Analysis for Electric Grid Resilience Investments. *https://www.synapse-energy.com/sites/default/files/Standard_Approach_to_Benefit-Cost_Analysis_for__Electric_Grid_Resilience_Investments_19-007.pdf*

3. REGULATORY MECHANISMS FOR ACHIEVING RESILIENCE OBJECTIVES

For this report, we conducted primary and secondary research to identify a range of regulatory mechanisms that jurisdictions have applied or are considering applying to improve resilience outcomes. We sought regulatory mechanisms that enable utilities to move from one-off investments to territory-wide planning and strategies; thus, we excluded pilots, which allow regulators to explore different approaches but can be temporary and limited in scope and scale.

In this section, we describe regulatory mechanisms that are or can be designed to improve electric system resilience. These include COSR, PBR, integrated planning, tariffs and programs to leverage private investment, alternative lines of business for utilities, enhanced cost recovery, and securitization. We note that these mechanisms are not mutually exclusive and can be used in combination with one another. While certain mechanisms such as integrated planning can be applied to municipal utilities and cooperatives, the others are most commonly applied to entities with a profit motive, *i.e.*, IOUs.

3.1. Cost-of-Service Regulation

Under COSR, rates are designed to recover IOUs' reasonable expenses, capital costs, and a return on capital investments. In principle, the utility's rate of return reflects the compensation that investors (shareholders, bond holders, or lenders) demand, given their perception of the risk they face in providing capital to the utility. When the return to the utility exceeds its cost of attracting capital, COSR provides utilities with incentives to make capital investments.[9]

COSR incorporates reviews of the prudency of investments and expenses within a rate case. In general, prudence calls for decisions to be reasonable given all information reasonably known or knowable at the time that the decision is made. However, in practice, prudence has somewhat different meanings in different states. The timing of rate cases varies by state, with some jurisdictions requiring periodic rate cases (*e.g.*, every year to every several years) and others leaving the timing of rate cases to the discretion of the utilities. The prudency review can result in disallowances, in which regulators do not allow the utility to recover specific costs that were deemed imprudent. While this review may curb the capital bias somewhat, it is an imperfect tool. Utilities understand their costs and opportunities far better than those outside their business, including regulators.

However, many resilience improvements involve capital investments and COSR may incentivize utilities to make these investments if they believe that the costs of the investment will not be disallowed. Within a COSR framework, regulators can encourage such investments by making clear that resilience is an obligation of the utility, in the public interest, and that recovery of reasonable related costs will be allowed. Absent other regulations or standards, resilience expenditures that do not earn a return (such as operations and maintenance) are less likely to be pursued under COSR, to the potential detriment of society. COSR is the baseline to which alternatives and additions to COSR are discussed in the rest of this report, therefore no case study is provided.

[9] Aas, Dan, and Michael O'Boyle 2016. *You Get What You Pay For: Moving Toward Value in Utility Compensation: Part 2 – Regulatory Alternatives.*

3.2. Performance-Based Regulation

Performance-based regulation (PBR) seeks to emphasize and strengthen utilities' incentives to achieve public policy goals.[10] PBR restructures utility financial incentives so that the utility benefits financially from making progress toward these on public policy goals. PBR commonly includes two components: performance incentive mechanisms, which provide financial rewards and/or penalties for performance in specific areas; and a multi-year rate plan (MRP), which typically caps the revenues that the utility can collect each year. Performance incentive mechanisms are financial motivators, such as a bonus return on equity (ROE),[11] that encourage the utility to achieve specific performance targets. The primary rationale for incentives is to encourage utility upper management to provide the support necessary to make institutional change and shift the business model to align with performance areas, such as resilience. The size of shareholder incentives should be kept as small as possible to reduce customer costs while still providing a meaningful signal to management. Incentives should be tied to desired performance outcomes (such as reductions in CAIDI) related to state goals, rather than just expenditures.[12]

The MRP sets a moratorium on rate cases for a set period of time (the stay-out period), which gives the utility time to achieve longer-term objectives and encourages cost efficiencies by allowing the utility to retain all or a portion of cost savings during that period.[13] This incentivizes the utility to develop innovative, least-cost solutions rather than focus primarily on traditional capital investments. MRPs may also include mechanisms, such as decoupling, that can address the utility's resistance to resilience measures that reduce sales.[14] Decoupling mechanisms provide utilities with stable revenues while making them financially indifferent to implementation of energy efficiency programs and other DERs that reduce sales.[15] MRPs can also allow for adjustments to the allowed ROE between rate cases to better reflect changes in the cost of capital.

Regulators can use PBR to encourage utility investments in resilience. Some jurisdictions are considering how to create performance targets and financial incentives to align utility performance with resilience goals. See Section 4.1 on Hawaii's experience with PBR and resilience.

3.3. Integrated Planning

Integrated planning is a powerful tool for addressing resilience. Through integrated planning, utilities forecast future system needs and use this information to identify and evaluate a range of solutions. Integrated planning practices often consider a range of possible futures, which could include extreme events and the system's ability to withstand and recover from these events. Integrated planning practices are more comprehensive in that they consider a wider range of solutions (including customer-side solutions) to the challenges utilities face. Integrated planning processes

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[10] Lowry, Woolf, Schwartz, 2016, p. 1

[11] Return on equity (ROE) is a measure of financial performance calculated by dividing net income (e.g., assets minus debt) by shareholder equity in an investor-owned utility. The authorized ROE is regulated by the state regulatory commission. A bonus ROE is some amount above the authorized ROE that is allowed for typical investments.

[12] Incentives that are based on dollars spent are problematic because they generally encourage the utility to spend more money in order to reap greater profits without necessarily increasing benefits to ratepayers and society. Incentives should only be provided for activities or investments where the utility company plays a distinct, clear, and necessary role in bringing about the desired outcome, and where there is sufficient regulatory oversight and stakeholder input.

[13] MRPs also often include an attrition relief mechanism, which adjusts rates or revenues to reflect inflation and other changes in business conditions during the stay-out period.

[14] Lowry, Woolf, Schwartz, 2016, p. 1

[15] Lowry, Mark, Tim Woolf, and Lisa Schwartz 2016. Performance-Based Regulation in a High Distributed Energy Resources Future. LBNL. https://emp.lbl.gov/sites/all/files/lbnl-1004130_0.pdf.

involve optimization of resources and consider costs and benefits to some extent, which helps to ensure rates are reasonable.[16]

There are several different types of integrated planning, depending on whether the utility is vertically integrated or distribution-only:

- Integrated distribution planning (IDP) identifies distribution grid needs under various scenarios and evaluates solutions such as changes to system configuration, infrastructure replacement, upgrades and modernization investments, and non-wires alternatives.[17] These studies are generally conducted annually with a 5- to 10-year planning horizon and with considerable input from stakeholders regarding planning assumptions. IDPs also tend to use forecasts with multiple load and DER scenarios to "to assess current system capabilities, identify incremental infrastructure requirements and enable analysis of the locational value of DERs."[18] California, Minnesota,[19] and New York are among the jurisdictions implementing IDP, and interest in this form of planning is growing.
- Integrated resource planning (IRP) is the most common form of integrated planning conducted by vertically integrated utilities. IRPs evaluate combinations of resources to meet energy and peak demand requirements, and some include one or more DERs. IRPs take a long-term perspective, typically covering a period of 20 years or more, and they are updated regularly (typically every 2 or 3 years). IRPs consider the entire utility service territory, in contrast with the narrower, more granular view used for assessment of project proposals. The IRP process—the process used for developing, evaluating, refining, and accepting an IRP—is typically utility-led. Successful IRP processes have regulatory oversight and allow for robust stakeholder participation.[20] In the IRP process, participants compare combinations of resources in terms of resources' expected costs of meeting energy requirements, as well as for their performance with respect to other criteria such as environmental impacts.[21] IRPs typically consider existing laws and policies. They can address environmental, affordability, customer equity, and resilience concerns, although consideration of resilience is a new and relatively uncommon practice at present.[22]
- Integrated grid planning (IGP) seeks to combine IRP and IDP into a single planning exercise to develop an optimal portfolio of solutions to address resource, transmission, and distribution needs. IGP is not yet widely implemented but is underway in See Section 4.2 on Puerto Rico's experience with IGP and resilience.

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[16] *Id.*, p. 1-5.

[17] ICF International, *Integrated Distribution Planning*, Prepared for the Minnesota Public Utilities Commission, August 2016, at vi. Available at https://www.energy.gov/sites/prod/files/2016/09/f33/DOE%20MPUC%20Integrated%20Distribution%20Planning%208312016.pdf

[18] *Ibid.*

[19] The Minnesota Public Utilities Commission released its guidance for integrated distribution planning for Xcel Energy in an order on August 30, 2018 in Docket No. E-002/CI-18-251.

[20] Wilson, Rachel and Bruce Biewald 2013. *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans*. Available at www.synapse-energy.com.

[21] Bansal 2017. *Integrated Resource Planning.*

[22] NWPP 2019. Exploring a Resource Adequacy Program for the Pacific Northwest

3.4. Tariffs and Programs to Leverage Private Investment

To a limited extent, private entities are investing in resilience without regulatory or utility support. For example, hospitals are increasingly developing their own microgrids to ensure continuity of life-saving medical services during an outage. In some industries, businesses are investing in backup generation to avoid revenue losses associated with outages. These private investments provide resilience services to the host customer, but not to the grid.

Regulatory mechanisms can encourage or require utilities to procure resilience services from customers or third parties for the benefit of a broader set of customers or for the benefit of the grid. This type of regulatory mechanism could take the form of a centralized procurement, like a request for proposals or an auction, often with the goal of tapping into the innovation and efficiencies of the competitive market. Utilities and their regulators commonly use these procurement mechanisms for a wide range of services and products, such as energy efficiency installation and program administration. Installation of distributed solar and batteries owned by others is another example relevant to resilience. To the extent that the resilience programs or tariffs reduce utility revenue, a decoupling mechanism can help ensure its success.

Other forms of this type of mechanism include tariffs to compensate a wide array of customers for services such as net metering. Net metering is a widely used mechanism for compensating distributed generation owners for the surplus power that their systems provide to the grid, in which the value of that power is netted against the cost of power drawn from the utility. As another example of a regulatory mechanism that can stimulate and leverage private investment, New York's *Reforming the Energy Vision* (REV) proceeding has spurred the creation of the DER "value stack." As with net metering, New York's framework compensates DER owners for their output to the utility electric system. Unlike net metering, the value stack monetizes the value that DERs provide based on when and where they provide electricity to the grid. DER owners are compensated for that value through a bill credit. While New York's value stack does not specifically address resilience, this mechanism could be modified to encourage resilience investments by private entities.

3.5. Alternative Lines of Business for Utilities

Some jurisdictions are experimenting with allowing utilities to provide new services to customers or to third parties. Utilities can have a variety of roles in addressing market gaps, from facilitating third-party efforts to directly providing services or products to the retail customer. Utilities can also help to address public goods issues related to resilience.[23]

New business models for resilience could include provision of enhanced resilience services for certain customers through additional utility investments. These customers would then be charged more through a new tariff for the enhanced resilience. Alternately, a new business model could include the provision of new services to/from other entities, such as DER providers. For example, the utility could provide data regarding customers who might be good candidates for solar or energy efficiency products. In New York, the REV proceeding has sought to demonstrate innovative business models to provide new revenue opportunities for the electric utilities and for third parties. These include the Distributed System Platform (DSP), an "intelligent network platform that will provide safe, reliable and efficient electric services by integrating diverse resources to meet

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[23] A public good is one that is non-rival (one person's enjoyment of resilience does not deplete it for others) and non-excludable (a person cannot be excluded from enjoying the benefits of resilience investments.) Because of these qualities, general resilience investments that benefit all people in an area will frequently be under-provided by the market.

customers' and society's evolving needs."[24] As the DSP providers, utilities have a key role in fostering and enabling broad market activity, for example, by providing customer and system information that enables third parties to better target their services.

However, providing new services and products directly to retail customers can undermine the development of competitive markets. Utilities have monopoly status in electricity distribution, and this status would afford them advantages in related markets as well. If suppliers are already present in the market, the justification for a monopoly firm to enter these lines of business may be less compelling, as outlined in Section 4 case studies..

3.6. Enhanced Cost Recovery

Enhanced cost recovery mechanisms accelerate cost recovery, increase the certainty of cost recovery, or both. Enhanced cost recovery includes mechanisms such as accelerated cost recovery, pre-approval, and financial incentives for certain types of investments. These mechanisms can facilitate greater utility resilience investments by reducing the risk that utilities face regarding cost recovery for these investments, as described below.

- Accelerated cost recovery mechanisms address the timeliness of cost recovery. They include rate riders or trackers and accelerated depreciation. A rate rider or tracker allows certain costs to be flowed into retail rates in the same or the next period in which they are incurred. Through accelerated depreciation, the utility can depreciate the investment over a shorter time period than would otherwise be allowed. Typically, the depreciation period of an asset is similar to its physical life (*i.e.*, the length of time that the physical asset is expected to function based on engineering design standards), its economic life (*i.e.*, the length of time that the asset is expected to be financially viable), or a combination of the two. A shorter depreciation period than the physical or economic life improves cash flow, frees up capital sooner, and provides the utility with greater assurance that it will recover its costs. Both rate riders and accelerated depreciation can create undesirable rate impacts because rate riders decrease rate predictability and accelerated depreciation can result in rate shock to consumers. New Jersey provides its utilities with accelerated cost recovery for resilience-related investments, subject to certain conditions. This case is discussed in Section 4.4.
- Pre-approval of certain investments reduces the utility's risk that cost recovery for an asset will be denied. While the implementation or installation of the asset could still be found to be imprudent, this mechanism reduces or eliminates the risk that the utility's decision to make the investment in the first place will be found imprudent.

3.7. Securitization

Securitization is an alternative form of utility financing and may result in a lower cost of capital and reduced ratepayer burden. Unlike the other enhanced cost recovery mechanisms, securitization often requires a legislative mandate. In turn, securitization can enhance the certainty of cost recovery for utilities by legislative underwriting of debt obligations, which reduces the borrowing costs. It may provide utilities full recovery of the value of the assets, but not necessarily so (for instance, it may exclude profit). Motivated by the mounting threat of wildfires, California paved the way for securitization of resilience investments with two key pieces of legislation enacted in 2019. Senate Bill

[24] New York Public Service Commission. 2015. Order Adopting Regulatory Policy Framework and Implementation Plan. Case 14-M-0101.

901 established a requirement that state utilities file annual wildfire mitigation plans, thus opening a channel for the utilities to propose new investments in resilience. Assembly Bill 1054 authorized the issuance of "recovery bonds" to keep investments in covered conductors and vegetation management out of utility rate base. For additional context on securitization, please refer to the case study in Section 4.5.

4. CASE STUDIES

In this section, we present a case study for each mechanism (other than COSR) to better illustrate the mechanism. In selecting the case studies, we sought non-pilot initiatives in a range of locations that are facing a variety of threats. We sought case studies for both distribution-only and vertically integrated IOUs.

Our case studies include:

- Performance-based regulation in Hawaii
- Integrated planning in Puerto Rico
- Tariffs and programs to leverage private investment and alternative lines of business for utilities in Vermont
- Enhanced cost recovery in New Jersey
- Securitization in California

Within each case study, we review the mechanism and then offer key findings. The key findings are organized into the four regulatory objectives: (1) continuity of electric service, (2) reasonable rates, (3) customer equity, (4) public interest. We also provide findings on the ability of each mechanism to address the cross-cutting objective of measured and measurable.

4.1. Performance-Based Regulation in Hawaii

Vulnerable to both natural disasters and fossil fuel market volatility, Hawaii provides a compelling case for the transformational promise of distributed renewable energy. Over the past decade, the Public Utilities Commission has launched several proceedings, including an integrated planning process, to update its regulatory framework to better suit a grid with increased renewable and distributed generation (see text box on following page). While none of these efforts have singularly targeted resilience, the commission has emphasized resilience as a key policy goal for this transformation.[25]

In launching its *Proceeding to Investigate Performance-Based Regulation* in 2018, the commission noted that:

> PBR attempts to address some of the issues and disincentives inherent in traditional cost-of-service regulation ("COSR") through a set of alternative regulatory mechanisms intended to focus utilities on performance and alignment with public policy goals, as opposed to growth in capital investments or other traditional determinants of utility earnings under COSR.[26]

Later, the commission specifically named resilience as one of its policy goals, writing that PBR "offers regulators a way to restructure utility financial incentives to achieve specific, identified desirable or beneficial outcomes, such as meeting renewable energy targets, reducing greenhouse gas emissions, or improving reliability and resilience."[27] In a subsequent proposal, commission staff provided more justification for focusing on resilience, noting its importance "in light of the risks

[25] Docket 2018-0088. Instituting a Proceeding to Investigate Performance-Based Regulation. Order 35411. April 18, 2018.

[26] Ibid.

[27] Ibid.

facing the electric power system, heightened further by Hawaii's geographic isolation and exposure to natural disasters."[28]

Hawaii's multi-pronged approach to resilience

Over the past decade, the Public Utilities Commission has launched several proceedings to update its regulatory framework. The aim is to respond to the grid transformation already underway more effectively and to further promote the integration of renewable and distributed generation, as required by state policy. While none of these efforts have singularly targeted resilience, the commission has emphasized resilience as a key policy goal for this transformation. Examples of recent proceedings in this vein with ramifications on grid resilience include:

- The ongoing IGP initiative, which began in 2018 in Docket 2018-0165, and its predecessor, the Power System Improvement Planning (PSIP) process, which ran from 2014 through 2017 in Docket 2014-0183: The groundwork for these modernizing efforts was laid in Commission Decision and Order No. 32052 in Docket 2012-0036, issued in 2014. This order rejected the utility grid plans that were the product of the IRP process in 2012 and 2013. The new approach to planning, as laid out in Decision and Order No. 35268 in Docket 2017-0226, is designed to effectuate the utilities' grid modernization strategy, *i.e.*, to prioritize investments to address service quality issues resulting from DER growth and then identify and assess grid modernization investments based on their contribution to Hawaii's 100 percent renewable energy goal.
- A targeted DER docket (No. 2019-0323): This opened in 2019 to address technical, economic, and policy issues associated with DER. Earlier proceedings had established tariffs for the procurement of energy and grid services from DER (Docket No. 2014-0192) and set incentives for the companies to enter into renewable power purchase agreements, including those with third-party DER aggregators (Docket 2017-0352).
- A proceeding to establish a microgrid services tariff that has been open since 2018 (Docket 2018-0163): This follows a legislative act that promoted microgrids as a solution to improve community energy resiliency and a potential mechanism for helping Hawaii to progress toward its ambitious renewable energy goals set by Act 200.

Many of the issues that have been taken up in separate proceedings are also being addressed in the PBR docket opened in 2018. This effort is a kind of "big tent" where the various related issues can be hashed out together toward a more complete (and more transformational) regulatory structure.

[28] Docket 2018-0088. Staff Proposal for Updated Performance-Based Regulations. February 7, 2019.

The commission issued its Decision and Order No. 37507 for the PBR proceeding in December 2020, establishing the key features of the new regulatory regime.[29] The PBR framework for Hawaii's vertically integrated utilities will include many interacting parts. Among other things, it will feature an MRP, revenue decoupling, an earnings-sharing mechanism, and performance metrics. Many of these elements have existed in some form in Hawaii for years, but the current proceeding aims to step away from COSR and the companies' potential capital bias by making their earnings largely independent of their expenditures.[30]

Included in the Decision and Order No. 37507 is an initial set of new performance metrics accompanied by performance incentives.[31,32] The commission has also directed the formation of a "Post-D&O Working Group," which is to assist in implementing these new performance metrics and address other outstanding issues in PBR design and implementation. The working group is expected to be a fixture of PBR regulation in Hawaii and has been authorized to propose new performance metrics as it sees fit.

In the nearer term, the working group will focus on providing recommendations to the commission on additional performance metrics that should be incorporated into the PBR framework in spring 2021. These recommendations are likely to be founded at least in part on the existing proposals of the various parties. The commission issued a decision in April 2021 that established a wider set of "Prioritized Performance Mechanisms," which will be reflected in the utilities' tariffs by June 2021.[33]

Though none of the preliminary performance metrics included in the Decision and Order No. 37507 address resilience, it is possible that the wide slate that will be implemented in the first part of 2021 will include resilience metrics.[34] Most of the parties participating in the PBR proceeding proposed performance metrics for resilience. Examples of suggested resilience metrics include:

- System islandability: capacity that can be islanded (sometimes specified as a microgrid), the percentage of vulnerable customers and critical functions served by islandable generation, and other related outcomes.
- Training and planning: staff training and completion of vulnerability assessments.
- Grid modernization: circuit automation, remote control capability, and other features that may expedite recovery and prevent outages.

[29] Docket 2018-0088. Decision and Order No. 37507. December 23, 2020.
[30] The utility has operated under a set of performance incentive mechanisms targeting reliability and customer service since 2018. See Docket 2013-0141, Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited. Order 34514. April 27, 2017.
[31] Within the PBR proceeding in Hawaii, performance metrics paired with performance incentives are termed performance incentive mechanisms.
[32] This set consists of a metric relating to accelerated achievement of the state's renewable portfolio standard, a metric for procurement of grid services from DER, a metric for timeliness in interconnection of DERs, a metric for low- and moderate-income customer participation in energy efficiency programming, and a metric for utilization of advanced metering infrastructure.
[33] Docket 2018-0088. Decision and Order No. 37787. May 17, 2021.
[34] It seems unlikely that any of resilience performance metrics will be tied to performance incentives in the near term. In earlier guidance during the PBR proceeding, the commission instructed the parties to focus on proposing metrics with incentives for the outcomes of DER asset effectiveness, interconnection experience, and customer engagement.

- Resilience outcomes: reliability indicators (SAIDI, SAIFI, etc.) adapted to the resilience context, with a focus on specific circuits, outage days, and vulnerable populations.[35]

Outside of the realm of performance mechanisms, the proposed PBR structure may also promote resilience as a secondary benefit by expediting the transition to a more distributed and renewable grid. PBR in Hawaii could lead to increased customer investment in DERs by inducing the utility to adopt a friendlier posture toward these resources—both by rewarding the utility for utilization of these DERs for system purposes and by countering the potential utility bias *against* customer-sited generation.[36] Since the MRP and decoupling provisions of the PBR regime will provide the utility with a mostly predetermined level of revenues, independent of how the utility provides service, the utility is incented to choose least-cost solutions. While the utility may still face variable costs associated with procurement of energy, capacity, and grid services from DERs, there may also be capital savings associated with choosing DERs over other types of investments that would benefit the utility.

The critical role that DERs may play in the future resilient Hawaiian grid was highlighted in the 2018 Act 200, which ordered the commission to develop a microgrid tariff. The act noted that microgrids "can facilitate the achievement of Hawaii's clean energy policies by enabling the integration of higher levels of renewable energy and advanced distributed energy resources," and subsequently stated that "the legislature believes that the use of microgrids would build energy resiliency into our communities." [37] The initial slate of performance metrics approved with the Decision and Order includes a metric and incentive for acquisition of grid services from DERs, which could ultimately spur customers to invest in these resources. In the future, the PBR framework is likely to include additional DER-related performance metrics and performance incentives.[38]

While the MRP may promote distributed resources, and more generally, alternative solutions, by countering utility capital bias, the fact that revenues are relatively fixed for the utility under the MRP could also inhibit investments in grid resilience. Moreover, the utility's incentive to cut costs could come at the expense of system reliability and resilience. To help obviate these challenges, the new regulatory structure includes a vehicle for recovery of nonroutine expenditures—the Exceptional Project Recovery Mechanism. The Decision and Order No. 37507 explains that the Exceptional Project Recovery Mechanism is intended to facilitate recovery of "exceptional" costs, including both capital investments and operations and maintenance spending. The EPRM could potentially be used for recovery of direct resilience investments and investments in grid modernization that will enable the integration of additional DERs.[39]

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[35] For details on the specific proposals of the various participants, see the Phase I Statements of Position filed in March 2019 and Phase I Reply Statements of Position filed in April 2019, as well as the Phase II Statements of Position and Phase II Reply Statements of Position filed respectively in June 2020 and August 2020 in Docket 2018-0088.

[36] Under cost-of-service regulation, utilities may be inclined to prefer utility-scale solutions to DERs because only the former provides the opportunity to increase revenues through investing capital to grow rate base. Meanwhile, DERs can represent a double-whammy for utilities—investments in DERs do not grow rate base, and DER growth may result in falling energy sales.

[37] HB 2110 HD2 SD2 Act 200.

[38] The utility has already enjoyed incentive earnings opportunities for procurement of renewable energy, grid services, and energy storage services from third parties. See Docket No. 2017-0352. Order No. 36604. October 9, 2019.

[39] The EPRM is the successor to the Major Project Recovery Mechanism. Examples of exceptional costs and expenses potentially qualifying for recovery through this mechanism include costs and expenses for infrastructure necessary to connect renewable energy projects, for projects that make it possible to accept more renewable energy, and for grid

Key Findings

Continuity of Electric Service

PBR in Hawaii was not designed to address resilience concerns. It was instead intended to promote grid transformation, with resilience included among the goals set for the future grid. Meanwhile, separate, ongoing regulatory efforts—meant to be complementary to the PBR proceeding—have prioritized resilience.[40]

While no explicit threat assessment has been conducted in conjunction with the PBR development process, the commission has acknowledged the specters of extreme weather and natural disasters that confront the islands.[41] Moreover, some stakeholders have proposed metrics that would track the companies' efforts to assess grid vulnerability; implementing such metrics would help to ensure that assessments of vulnerability are conducted on an ongoing basis.

Since resilience is often at odds with the incentives to cut costs inherent in an MRP, the emergent PBR regime includes a special mechanism for recovering exceptional costs such as resilience investments. It will be interesting to see how well this serves to counter the potential for eroding quality and continuity of service resulting from utility cost-cutting under the MRP, as well as whether it counters potential voltage and power quality issues that may arise from greater adoption of DERs encouraged by the incentives under PBR.

Existing reliability metrics, with penalty-only incentives, will be continued in the new regime and should serve as at least a partial bulwark again erosion of system reliability.

Reasonable Rates

In contrast to the regulatory vetting of utility investment that occurs under COSR, little scrutiny of company spending is expected under the new PBR regime. Instead, the utility, its customers, and third parties are expected to separately assess private costs and benefits prior to making investment decisions. Since rates reflect utility investments under a COSR paradigm, the question of whether rates are just and reasonable is ultimately a matter of whether the underlying investments were found to be cost-effective. Under PBR, by contrast, rates are assumed to be just and reasonable provided that the utility meets policy commitments and performance standards.

To the extent that the utility conducts its own business case analyses, these internal benefit-cost assessments are unlikely to incorporate the same policy considerations and associated values as a benefit-cost analysis submitted for regulatory review to support a utility investment proposal. Alternative solutions are considered in Hawaii's IGP process; however, the IGP process is largely separate from and appears to have limited impact on the PBR process.

There are limited instances in which the benefits and costs of utility actions may be subject to more formal review. Incentives that are provided to the utility—including for DER-related outcomes—might be calibrated to underlying costs and benefits, though the initial set of incentives included in

modernization projects. Examples of expenditures not qualifying for EPRM recovery include "routine replacements of existing equipment or systems with like kind assets, relocations of existing facilities, restorations of existing facilities, or other kinds of business-as-usual investments." See Docket 2018-0088. Decision and Order No. 37507. December 23, 2020.

[40] Docket 2017-0226. Instituting a Proceeding Related to the Hawaiian Electric Companies' Grid Modernization Strategy. Decision and Order No. 35268. February 7, 2018; Docket 2018-0163. Instituting a Proceeding to Investigate Establishment of a Microgrid Services Tariff.

[41] Docket 2018-0088. Staff Proposal for Updated Performance-Based Regulations. February 7, 2019.

the Decision and Order No. 37507 was not predicated on benefit-cost analysis. Moreover, applications for EPRM recovery must include "[a] business case study…identifying and quantifying all operational and financial impacts of the Eligible Project and illustrating the cost/benefit tradeoffs that justify proceeding with the project to the extent that such impacts can reasonably be determined."[42]

Customer Equity

The PBR framework could encourage the utilities to develop alternative rate designs which allocate costs differently for different types of customers. For example, performance incentive mechanisms can encourage the utilities to establish new tariff structures for certain resilience investments. Differential cost allocation through rate design has not been established yet in the PBR proceeding. However, there has been preliminary discussion of a microgrid tariff targeted to those who benefit most from the investment. It is not clear how the new tariff structures will impact equity.

Public Interest

In the commission's view, the "…old regulatory paradigm built to ensure safe and reliable electricity at reasonable prices from capital-intensive electricity monopolies is now adjusting to a new era of disruptive technological advances that change the way utilities make money and what value customers expect from their own electricity company."[43] The PBR proceeding envisions a grid transformed by distributed and renewable resources under a novel set of regulatory structures that can optimize value for customers and society. These changes to the grid are already afoot, but the commission intends for the new regulatory structure to further increase the profile of distributed and renewable resources in Hawaii. In a 2014 document that laid the strategic groundwork for the PBR transition, the commission articulated why renewable energy was such good policy for the islands: "Unlike many other jurisdictions where public policy goals to reduce harmful emissions from fossil-based electricity generation and increase use of renewable energy may conflict with economic goals to lower the cost of electricity, Hawaii has already entered a new paradigm where the best path to lower electricity costs includes an aggressive pursuit of new clean energy sources."[44] In sum, the increasingly distributed and renewable grid envisioned by the commission is expected to serve the public interest on several counts—leading to a reduction in electricity costs, a reduction in emissions, promotion of reliability and resilience, and an increase in customer control and choice.[45] In balancing multiple and sometimes competing priorities, a regulator may determine that a cost increase is reasonable for a more resilient electric power system.

Cross-Cutting: Measured and Measurable

Hawaii is likely to supplement its existing reliability metrics, comprised of penalty-only incentives, with additional metrics. The state may establish new metrics in the future to provide indicators of system resilience performance, potentially across many different performance dimensions with a focus on specific circuits, outage days, and vulnerable populations.

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[42] Docket 2018-0088. Decision and Order No. 37507. December 23, 2020

[43] Docket 2018-0088. Instituting a Proceeding to Investigate Performance-Based Regulation. Order 35411. April 18, 2018.

[44] Docket No. 2012-0036. Decision and Order No. 32052. April 28, 2014. Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities.

[45] Docket No. 2012-0036. Decision and Order No. 32052. April 28, 2014. Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities.

4.2. Integrated Planning in Puerto Rico

The catastrophic impacts of Hurricanes Irma and María on Puerto Rico in September 2017 were unprecedented. The entire island experienced a prolonged blackout with power restored in the last neighborhood 328 days after the storms hit.[46] While these two storms caused island-wide power outages, their damage extended well beyond the electric grid and created other life-threatening conditions that included a near complete absence of cell phone service, a lack of potable water, a fuel shortage, and debris clogged/washed out roads that hampered relief efforts.

Puerto Rico also lies along two fault lines and has recently experienced numerous earthquakes. The strongest seismic activity in over 100 years occurred on January 6 and 7, 2020 and caused not only another multi-day island-wide blackout, but significant damage to the Costa Sur power plant on the south side of the island that was nearest the epicenters. The system is 98 percent powered by fossil fuels such as oil and liquid natural gas (LNG), all of which are imported and which pose a challenge to system resilience when ports are unable to open (as occurred in the aftermath of the 2017 hurricanes).

Following these events and outages, the public utility serving the island—the Puerto Rico Electric Power Authority (PREPA)—proposed an approach to resilience investments in its 2019 IRP. The 2019 IRP was PREPA's second ever IRP, and the first to address resilience explicitly. The 2019 IRP proposed to enhance resilience through minigrids. The IRP describes dividing the island into eight minigrids, each of which has the generation resources to meet its own load if the island-wide transmission system connecting the zones is offline. Each minigrid would consist of hardened transmission and distribution from thermal generators to critical and priority loads (and the other customers on the same feeders), so that power would stay on or be restored quickly. The grid hardening would primarily consist of undergrounding lines and placing substations inside structures. PREPA designed these investments to provide uninterrupted power to critical loads during and after a Category 4 hurricane, with restoration within a week to priority loads and within one month for all loads. To assess the benefit of such investments, PREPA calculated the value of energy not served in each IRP scenario in the face of such an event.[47,48]

Many organizations filed for intervenor status in the IRP proceeding, of which 18 succeeded in their petition.[49] Three other organizations requested *amicus curiae* participation status and were successful

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46 Fernández Campbell, Alexia. 2018. "It took 11 months to restore power to Puerto Rico after Hurricane Maria. A similar crisis could happen again." *Vox,* August 15. https://www.vox.com/identities/2018/8/15/17692414/puerto-rico-power-electricity-restored-hurricane-maria.

47 PREPA adapted the value of lost load found in a New Zealand study to the mix of load types in Puerto Rico. The average value used in PREPA's IRP was approximately $32,000/MWh, with residential loads having a lower value (about $12,000/MWh), and small commercial and industrial having a higher value (about $84,000/MWh). When comparing IRP scenarios, PREPA calculated the value of energy not served by multiplying the unserved MWh by these values in the case of a major disruptive hurricane.

48 IRP, Section 6.3 and Appendix 1.

49 These include the Environmental Defense Fund, the Independent Consumer Protection Office (ICPO), the Solar and Energy Storage Association of Puerto Rico (SESA-PR), Grupo Windmar, EcoEléctrica L.P., Wärtsilä North America, Sunrun, Progression Energy, Empire Gas, Arctas Capital Group, AES Puerto Rico, National Public Finance Guarantee Corp, Shell NA LNG LLC, Caribe GE International Energy Services Corp, League of Cooperatives of Puerto Rico and AMANESER 2025, Renew Puerto Rico, a group of Local Environmental Organizations, and a group of not-for-profits. The local environmental organizations that petitioned to intervene as one group include: Comité Diálogo Ambiental,

in those petitions.[50] Each intervening and *amicus curiae* entity responded to different topics within the IRP, ranging from energy efficiency to assumptions and forecasts to new resource options and more.

There were also five public hearings across the island from February 11 – 25, 2020. All hearings were conducted in Spanish and were live-streamed and recorded.[51] Public sentiment toward PREPA's proposed IRP was generally not positive; participants expressed frustration that affected communities and the general public were not consulted at the outset of the plan's development.[52] Multiple members of the public also cited the lack of specificity in renewables integration in PREPA's proposal, which would hinder attempts to meet 100 percent renewable energy by 2050, per Puerto Rico's policy in Act 17-2019.[53] The public supported more distributed renewables and greater investment in energy efficiency while also citing the need to acknowledge the public health and environmental impacts of some of the proposed solutions.

This amount of public participation, both in the hearings and as intervenors, was significant in Puerto Rico. Intervening can be an expensive process for organizations to participate in. Given the high cost of engaging attorneys, it can be cost-prohibitive for smaller non-profits.

Puerto Rico's regulator, the Puerto Rico Energy Bureau considered PREPA's proposed minigrid and grid-hardening investments in the context of the rest of the IRP. The Energy Bureau and stakeholders filed numerous data requests, and stakeholders filed testimony regarding the minigrid proposals, followed by a week of technical hearings on the IRP in February 2020, including a half-day on the minigrid proposal. The Energy Bureau's final order included:

- Approval of spending to bring the distribution and transmission grids up to current codes and standards.
- Agreement that the electric system should be more resilient and that some level of additional investment is required to meet that goal.
- The creation of a new docket, an "optimization proceeding," to consider the options for increasing resilience. The docket will start with consideration of the San Juan/Bayamon region (which contains the bulk of the population, load, and economic activity). The primary question is how to coordinate and determine how much to invest in the two approaches to resilience:
    - Site-specific or microgrid resilience, with on-site generation and storage

Inc., El Puente de Williamsburg, Inc.- Enlace Latino de Acción Climática, Comité Yabucoeño Pro-Calidad de Vida Inc., Alianza Comunitaria Ambientalista del Sureste Inc., Sierra Club (Puerto Rico chapter), Mayagüezanos por la Salud y el Ambiente Inc., Coalición de Organizaciones Anti-Incineración Inc., Amigos del Rio Guaynabo Inc., Campamento Contra las Cenizas en Peñuelas Inc., and CAMBIO Puerto Rico. (Commonwealth of Puerto Rico Public Service Regulatory Board Puerto Rico Energy Board. July 29, 2019. Local Environmental Organizations' Petition to Intervene. CEPR-AP-2018-001.) The not-for-profits include Centro Unido de Detallistas, Cámara de Mercadeo, Industria y Distribución de Alimentos, Puerto Rico Manufactures Association, Cooperativa de Seguros Múltiples de Puerto Rico, Unidos Por Utuado, and the Instituto de Competitividad y Sostenibilidad Económica de Puerto Rico (Government of Puerto Rico Public Service Regulatory Board, Puerto Rico Energy Bureau. August 21, 2020. Final Resolution and order on the Puerto Rico Electric Power Authority's Integrated Resource Plan.)

[50] The three organizations are Rocky Mountain Institute, Asociación de Consultores y Contratistas de Energía Renovable de Puerto Rico, Inc., and Colegio de Ingenieros de Puerto Rico.

[51] Id. IRP Appendix B pg B-1, B-2.

[52] Id. B-1

[53] Autoridad de Energía Eléctrica, SB 1121, Puerto Rico Energy Public Policy Act, approved April 11, 2019. Available at https://aeepr.com/es-pr/QuienesSomos/Ley17/A-17-2019%20PS%201121%20Politica%20Publica%20Energetica.pdf.

- Resilience provided through central generation and a hardened transmission and distribution system (*i.e.*, the minigrid approach)

PREPA is a publicly owned utility, so there is no option to adjust shareholder incentives to affect utility behavior. PREPA has a history of running unbalanced budgets and racking up unsustainable debt,[54] and the regulatory commission has attempted to institute budget controls. However, the regulator's budget controls have not been the binding constraint. The bigger barrier at this point is simply the inability to borrow money due to the debt burden and the bankruptcy law,[55] which requires the utility to live within its revenue stream. However, as Federal Emergency Management Agency (FEMA) funds from Hurricanes Maria and Irma become available for hazard mitigation, PREPA has greater ability to fund resilience investments (and is simultaneously pressing up against the limitations on its spending set by the regulator).

Key Findings

Continuity of Electric Service

Within the IRP, PREPA assessed the impacts of the proposed minigrids on the functioning of the grid. The optimization proceeding will also consider grid operations. PREPA designed the resilience investments to provide uninterrupted power to critical loads during and after a Category 4 hurricane, with restoration within a week to priority loads and within one month for all loads. However, the IRP did not include, and did not appear to be informed by, a specific assessment of the risk of different types of threats and corresponding grid vulnerabilities. Since the hurricanes, Puerto Rico has experienced significant damage from an earthquake. Future work will likely reflect the threat of earthquakes as well.

Reasonable Rates

While PREPA showed that its proposal was less costly than being without power for a month (value of lost load), the IRP did not include a complete benefit-cost analysis.

The IRP did not consider more than one solution to the primary threats, thus providing part of the motivation for launching the optimization proceeding. The IRP also lacked specific resilience goals, as the level of desired resilience for planning purposes has not been established.

Customer Equity

PREPA proposed to differentiate investments by levels of criticality. However, there has been no consideration of how to allocate costs to different geographic areas or customer types. The process to determine criticality is not fully clear but are defined as basic resources that should either ride through the storm or must be available shortly after and are crucial for the restoration effort.

Additional funding sources will need to be pursued to avoid undue burden on ratepayers. It is likely that the amount of FEMA funding available for rebuilding and hazard mitigation will affect the path forward.

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[54] In July 2017, PREPA submitted a $9 billion bankruptcy filing under Title III of the federal Puerto Rico Oversight, Management, and Economic Stability Act (PROMESA).

[55] Puerto Rico Oversight, Management, and Economic Stability Act.

Public Interest

PREPA considered the minigrid proposal's implications for the electricity supply portfolio. For example, the solar and storage in microgrids would be part of the overall resource mix for the island, which then would lower the amount of utility-scale resources to be procured and operated.

According to regulations, the IRP is intended to serve "as an adequate and useful tool to guarantee the orderly and integrated development of Puerto Rico's electric power system, and to improve the system's reliability, resiliency, efficiency, and transparency, as well as the provision of electric power services at reasonable prices."[56] While the primary criterion for selecting a plan is ratepayer cost, PREPA is also required to consider reliability, short- and long-term risks, environmental impacts, transmission needs and implications, distribution needs and implications, financial impacts on PREPA, and the "public interest as set forth in Act 57-2014."[57] The IRP is the primary policy mechanism for ensuring that the electric resource planning is consistent with stated energy policy in the Commonwealth, including the renewable portfolio standard.

Cross-Cutting: Measured and Measurable

As the minigrid proposal was not approved, there are currently no explicit plans to track performance.

4.3. Leveraging Private Investment and Alternative Lines of Business for Utilities in Vermont

Green Mountain Power has launched two tariffed programs to encourage behind-the-meter storage. One encourages private investment by compensating storage owners for making their system available to provide grid services. The other represents a new business model for the utility: owning and operating behind-the-meter storage assets in customer buildings. Under normal operating conditions when the grid is not facing resilience threats, the behind-the-meter storage that these programs seek to incentivize will allow GMP to access storage devices during peak times, to avoid the costs associated with building out peak demand-related generation, transmission, and/or distribution infrastructure. Consistent with this objective, the utility will track metrics addressing capacity and discharge during system peaks and associated financial savings.

The programs also can provide backup power during outages for participating customers. As such, these tariffs incidentally address outages during grid disruption events, primarily those arising from natural threats. However, the tariffs do not guarantee resilience. Both tariffs state that "the battery equipment can be depleted at any time, [and customers] should not rely exclusively on the battery equipment to power life-supporting equipment."[58,59]

These tariffs represent an evolution from GMP's successful Tesla Powerwall 2.0 Battery Pilot program for residential customers.[60] The first, called the Bring Your Own Device (BYOD) program,

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[56] Regulation on Integrated Resource Plan for the Puerto Rico Electric Power Authority, Section 1.03. Available at https://energia.pr.gov/wp-content/uploads/sites/7/2018/05/Reglamento-9021-IRP-Ingles-Departamento-de-Estado.pdf.

[57] Id., Section 2.03(H)(2)(d).

[58] Green Mountain Power Corporation, Bring Your Own Device ("BYOD") Program, Second Revised Sheet, Effective On Bills Rendered on or after June 1, 2020.

[59] Green Mountain Power Corporation, Energy Storage System Service, Second Revised Sheet, Effective On Bills Rendered on or after June 1, 2020.

[60] Green Mountain Power. 2018 Integrated Resource Plan. Available at: https://greenmountainpower.com/wp-content/uploads/2019/03/IRP-Innovative-Customer-Programs.pdf.

will run through 2022 (perhaps longer, conditional on the commission's approval) and has expanded to include other storage systems. The program allows customers to enroll their own storage systems with GMP and, if eligible, receive incentive payments from GMP.[61] The second program is provided through the Energy Storage System (ESS) Tariff and will help deploy small-scale storage systems. The ESS Tariff provides an option to GMP's customers to lease a battery storage system from GMP. The leased battery storage system will consist of two Tesla Powerwall batteries and a gateway device. As with the BYOD program, the ESS Tariff will run through 2022, and perhaps longer (conditional on the commission's approval). These tariffs are described more below.

The BYOD Tariff

The BYOD tariff provides either (a) $850 per kW (up to 10 kW) for batteries with a storage duration of three hours, or (b) $950 per kW (up to 10 kW) for batteries with a storage duration of four hours. Customers located in constrained areas (as designated on GMP's website) receive an additional $100 for installations through the tariff.[62]

Customers are not required to have their own distributed generation (*e.g.,* photovoltaics) and there is no requirement that the residential system can island.[63]

The BYOD tariff was primarily developed to reduce peak demand-related utility costs. GMP experiences regional transmission costs related to its load at the time of summer peak, as well as monthly peaks. By having access to customers' storage systems during peak-related events, GMP can dispatch those systems to reduce its load during those events and thereby lower its peak-related costs. Maintaining connectivity is essential to the program and loss of connectivity results in a customer fee called the Access Disruption Fee. This fee appears to apply to only normal grid event conditions which allows the customer to solve the connection problem within 30 days of notification by GMP.

The ESS Tariff

The ESS Tariff provides two pricing options: GMP will pay the customer $55 per month for 120 months (amounting to $6,600 in total leasing payments) or a one-time upfront payment of $5,500. The program comes with an early termination disconnection fee of $450. Throughout the entire term of the lease, GMP will maintain ownership over the energy storage system.[64]

As with the BYOD tariff, the ESS tariff was developed to reduce peak demand-related utility costs by allowing GMP to access and control the leased energy storage systems during peak events. The program is also intended to provide participating customers with whole-home backup power during grid outages.

[61] Green Mountain Power Corporation, Bring Your Own Device ("BYOD") Program, Second Revised Sheet, Effective On Bills Rendered on or after June 1, 2020.
[62] Green Mountain Power Corporation, Bring Your Own Device ("BYOD") Program, Second Revised Sheet, Effective On Bills Rendered on or after June 1, 2020.
[63] Green Mountain Power. 2018 Integrated Resource Plan. Available at: https://greenmountainpower.com/wp-content/uploads/2019/03/IRP-Innovative-Customer-Programs.pdf.
[64] Green Mountain Power Corporation, Energy Storage System Service, Second Revised Sheet, Effective On Bills Rendered on or after June 1, 2020.

Key Findings

Continuity of Electric Service

The BYOD and ESS tariffs were not developed in response to a threat and were not specifically created to address resilience and reliability. This is evident from the design in that customers are not required to have distributed generation, and there is no requirement that the systems can island. However, GMP states that, where possible, it will avoid completely discharging a battery during or prior to a pending severe weather event in order to ensure that the battery can provide the customer with back-up power.[65] Further, the commission notes that these tariffs will allow GMP "to maximize the value of small-scale storage to shave peaks, save on power supply costs, integrate renewables, and provide reliability."[66]

Reasonable Rates

While the BYOD and ESS tariffs can facilitate resilience, the tariffs were primarily created to reduce peak demand-related utility costs. The commission states this directly: "the [BYOD and ESS tariffs are] designed to provide net positive benefits to all GMP customers."[67] GMP was able to sufficiently demonstrate that the tariffs are expected to provide net benefits in the form of savings on peak demand-related power supply costs. The commission notes that "[while] GMP did not provide in-depth analyses of all potential alternative pricing mechanisms, GMP provided reasonable support for the pricing mechanisms it has proposed as well as reasonable explanations for not choosing potential alternatives."[68]

The BYOD tariff provides an additional $100 per kW for installations in constrained areas. This additional incentive could result in more customers enrolling in constrained areas, which would reduce electric system costs and thus reduce rate pressure. The ESS program does not include a similar incentive for installations in constrained areas.

In its order, the commission addresses concerns about accounting treatment of small-scale battery installations and potential anti-competitive concerns, noting that "it is important to recognize the safeguards in place, especially the relatively short amount of time that the ESS Tariff will be offered to customers."[69] One party in the proceeding, Renewable Energy Vermont, expressed concerns that the ESS Tariff would provide GMP and the Tesla Powerwall with an advantage in the market and thus may allow the GMP-owned Powerwalls to dominate the market. As such, it encouraged the commission to disapprove the tariff. The commission addressed this issue in the order by stating:

> "While GMP and the Powerwall may initially have an advantage, GMP is playing a critical role in growing the fledgling battery storage market in Vermont, GMP is offering both the ESS Tariff and the BYOD Tariff simultaneously, and the ESS Tariff is limited in scope and duration. The Commission anticipates there will likely be a point in the future when the battery storage market is mature and it is no longer appropriate for GMP to provide small-scale batteries as an above-the-line offering, but there is nothing in the record to indicate that the battery storage market has reached that point. In fact, the testimony indicates quite the opposite. GMP has

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65 Green Mountain Power, BYOD Program Details, accessed December 30, 2020. Available at https://greenmountainpower.com/rebates-programs/home-energy-storage/bring-your-own-device/battery-systems/
66 State of Vermont Public Utility Commission, Final Order, Case No. 19-3537-TF, May 20, 2020. Page 17.
67 State of Vermont Public Utility Commission, Final Order, Case No. 19-3537-TF, May 20, 2020. Page 2.
68 State of Vermont Public Utility Commission, Final Order, Case No. 19-3537-TF, May 20, 2020. Page 23.
69 State of Vermont Public Utility Commission, Final Order, Case No. 19-3537-TF, May 20, 2020. Page 18.

reached less than 1% of its customers thus far through its various energy storage pilots."[70]

Finally, the commission addresses the way in which GMP is expected to add additional technologies to the tariffs over time: "GMP will seek to add additional technologies to the list of storage systems that can be integrated. An amendment to the list of systems eligible to participate in the BYOD Tariff will not require a full tariff amendment process, so new types of systems can be added to the tariff more rapidly."[71]

Customer Equity

Before its approval, GMP was required to proactively demonstrate to the commission that its proposed BYOD and ESS tariffs will provide a net benefit to all customers—participants and non-participants alike. The design of the BYOD and ESS tariffs allow customers with the greatest willingness to pay for resilience to make related improvements. This can lead to situations where customers who have unequal access to funding may not be able to acquire the improved resilience. Willingness and ability to pay are not the same.

The BYOD and ESS tariffs focus on smaller, residential customers. The BYOD tariff has a cap of 10 kW per customer, and the ESS systems are 10 kW systems. Both programs have total program caps of 5 MW per year. This program design is unlikely to offer enough capacity to serve the critical portion of loads for larger municipal customers that provide life-saving community services during outages, such as police and fire stations. Therefore, the ability of these programs to serve the broader public interest, as it relates to providing reliability to critical customers, is limited. We also note that this design likely does not give preferential treatment to critical customers. Moreover, the tariffs include language that battery equipment should not be used to power life-supporting equipment.

Public Interest

The programs provide support to other state policy goals. In line with the state's carbon emissions reduction goal, the programs may reduce carbon emissions by "[reducing] demand during the most emission-tensive peak demand periods and [recharging] during periods of lower emissions."[72] Additionally, while the order does not address employment impacts from the programs, the programs spur investments in small-scale storage and thus may help to create jobs in the "fledgling battery storage market in Vermont."[73]

Cross-Cutting: Measured and Measurable

Program performance is tracked primarily through the following metrics: (1) the number of monthly peaks during which discharge successfully occurred during the Regional Network Service peak and the total capacity available during discharge, (2) whether the batteries were successfully discharged during the Independent System Operator annual forward capacity peak and total capacity available during that discharge, and (3) the financial savings from peak shaving actually achieved. It remains to be seen how these metrics will be used.

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[70] State of Vermont Public Utility Commission, Final Order, Case No. 19-3537-TF, May 20, 2020. Page 25. The phrase "above-the -line" appears to mean the regulated utility ownership or provision of services.

[71] State of Vermont Public Utility Commission, Final Order, Case No. 19-3537-TF, May 20, 2020. Page 17.

[72] State of Vermont Public Utility Commission, Final Order, Case No. 19-3537-TF, May 20, 2020. Page 11.

[73] State of Vermont Public Utility Commission, Final Order, Case No. 19-3537-TF, May 20, 2020. Page 25.

4.4. Enhanced Cost Recovery in New Jersey

A series of severe weather events spanning from August 2011 through November 2012 caused extended outages for a high percentage of electric customers across New Jersey.[74] These events, especially Superstorm Sandy, proved highly disruptive to residents and businesses alike and highlighted that the electric utilities' "existing practices were not sufficient for such large weather events."[75] According to New Jersey law (N.J.A.C. 14:5-1.2), a "major event" is a "sustained interruption of electric service resulting from conditions beyond the control of the [electric distribution company], which may include, but is not limited to, thunderstorms, tornadoes, hurricanes, heat waves or snow and ice storms, which affect at least 10 percent of the customers in an operating area."[76] Collectively, the five major events that occurred within a period of 15 months impacted millions of customers in all of the state's four electric utilities.[77] For example, 71 percent of JCP&L's 1.1 million customers were without power after Hurricane Irene in 2011[78] and over 91 percent of PSE&G's 2.2 million customers experienced prolonged outages after Superstorm Sandy in late October 2012.[79]

The combination of the impact and frequency of these major events prompted action on the part of the New Jersey Board of Public Utilities (BPU) to address the impacts of major events. On January 23, 2013, the BPU issued an order on utility preparedness, communications, restoration/response, and post-event and underlying infrastructure issues. This order required the electric utilities "to take specific actions to improve their preparedness in response to extreme weather events [and] provide detailed cost benefit analysis associated with a variety of utility infrastructure upgrades."[80] It also called for the utilities to "carefully examine their infrastructure and use data available to determine how substations can be better protected from flooding, how vegetation management is impacting electric systems, and how Distribution Automation can be incorporated to improve reliability."[81]

The state's largest electric IOU, PSE&G, created a storm hardening/resilience proposal called "Energy Strong" that it submitted to the BPU within a month of the January 2013 order. Energy Strong included a plan to invest $1.703 billion for improvements to electric delivery infrastructure. On March 20, 2013, the BPU issued a related follow-on order regarding a BPU process for review of major event mitigation proposals in response to the PSE&G Energy Strong petition that "invite[d] all regulated utilities to submit detailed proposals for infrastructure upgrades designed to

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[74] These events include: (1) Hurricane Irene which occurred on August 28, 2011, (2) a snowstorm on October 29, 2011, (3) a derecho windstorm June 29 & 30, 2012, (4) Superstorm Sandy on October 29, 2012, and (5) Nor'easter Athena on November 7, 2012.
New Jersey Bureau of Public Utilities. March 20, 2013. *In the Matter of the Board's Establishment of a Generic Proceeding to Review Costs, Benefits and Reliability Impacts of Major Storm Event Mitigation Efforts.*

[75] New Jersey Bureau of Public Utilities. January 23, 2013. *Order Accepting Consultant's Report and Additional Staff Recommendations and Requiring Electric Utilities to Implement Recommendations in the Matter of the Board's Review of the Utilities Response to Hurricane Irene.* (Docket No. EO11090543)

[76] N.J.A.C. 14:5-1.2

[77] The four electric distribution companies operating in New Jersey are, in descending order by number of customers, PSE&G, JCP&L, ACE, and RECO.

[78] Emergency Preparedness Partnerships. August 9, 2012. *Performance Review of EDCs in 2011 Major Storms.*

[79] PSE&G. July 30, 2014. *Making New Jersey Energy Strong: Reliability & Resiliency in New Jersey.*

[80] New Jersey Bureau of Public Utilities. March 23, 2013 *Establishment of a Proceeding In the Matter of the Board's Establishment of a Generic Proceeding to Review Costs, Benefits and Reliability Impacts of Major Storm Event Mitigation Efforts* (Docket No. AX13030197)

[81] New Jersey Bureau of Public Utilities. *Order Accepting Consultant's Report and Additional Staff Recommendations and Requiring Electric Utilities to Implement Recommendations in the Matter of the Board's Review of the Utilities Response to Hurricane Irene.* (Docket No. EO11090543)

protect the State's utility infrastructure from future Major Storm Events."[82] In May 2014, the BPU approved a settlement agreement among the parties for the Energy Strong program.[83] The settlement included $420 million support for hardening of substations, $100 million for advanced technologies, and $100 million for contingency reconfiguration over a four-year program.[84]

The BPU (and many others) recognized the importance of facilitating and standardizing the process the process to review resilience infrastructure investment programs. The Infrastructure Investment Program (IIP or N.J.A.C. 14:3 2A) is a New Jersey law that established this desired regulatory framework for reviewing infrastructure investments and went into effect on January 16, 2018. The IIP provides a rate recovery mechanism that encourages and supports investment "in a systematic and sustained way to advance construction, installation, and rehabilitation of utility infrastructure needed for continued system safety, reliability, and resiliency, and sustained economic growth."[85] The IIP allows for accelerated rate recovery on eligible projects that are "related to safety, reliability, and/or resiliency; non-revenue producing; specifically identified by the utility within its petition…; and approved by the Board for inclusion in an Infrastructure Investment Program."[86] Electric utility projects that are eligible for the IIP include "electric distribution automation investments, including, but not limited to, supervisory control and data acquisition [SCADA] equipment, cybersecurity investments, relays, reclosers, voltage and reactive power control, communications networks, and distribution management system integration."[87] Subsequent to the law's passage, three of the New Jersey electric utilities submitted new proposals to the BPU for review.[88]

Per the IIP, a utility's petition must first propose an annual baseline spending level based on historical expenditures on projects like the ones being proposed through its IIP.[89] It falls to the BPU to ultimately establish the final annual baseline spending. If approved by the BPU, the IIP expenditures incremental to the annual baseline spending would be eligible for accelerated rate recovery.[90] The legislation further required that proposed programs pass a return on equity test to help protect ratepayers against excessive utility earnings. The board is required to hold public

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[82] New Jersey Bureau of Public Utilities. March 23, 2013 *Establishment of a Proceeding in the Matter of the Board's Establishment of a Generic Proceeding to Review Costs, Benefits and Reliability Impacts of Major Storm Event Mitigation Efforts* (Docket No. AX13030197)

[83] New Jersey Bureau of Public Utilities. May 21, 2014. *Order Approving Stipulation of Settlement in the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Energy Strong Program.* (Docket No. EO13020155)

[84] Specifically, the substation work included remediation of 29 substations for flooding events. The advanced technologies program was designed to equip stations with microprocessor relays and an expanded supervisory control and data acquisition (SCADA) system to help assess damage and prioritize restoration efforts more quickly. The contingency reconfiguration work included the addition of smart switches, smart fuses, adding loop scheme redundancy, and additional feeder reclosers. Notably, the utility "was to invest an additional $220.0 million into the electric portion of the Energy Strong Program related to substations, which would not be recoverable through the Energy Strong rate recovery mechanism."

New Jersey Bureau of Public Utilities. September 11, 2019. *Final Decision and Order Approving Stipulation in the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Second Energy Strong Program (Energy Strong II).* (Docket EO18060629)

[85] N.J. Admin. Code § 14:3-2A.1b (Lexis Advance through the New Jersey Register, Vol. 52 No. 18, September 21, 2020)

[86] N.J. Admin. Code § 14:3-2A.2a (Lexis Advance through the New Jersey Register, Vol. 52 No. 18, September 21, 2020)

[87] N.J. Admin. Code § 14:3-2A.2b (Lexis Advance through the New Jersey Register, Vol. 52 No. 18, September 21, 2020)

[88] Rockland Electric Company (RECO) submitted a storm hardening program that predated the IIP legislation.

[89] The IIP also states in section 2A.2 that "[a] utility shall maintain its capital expenditures on projects similar to those proposed within the utility's Infrastructure Investment Program. These capital expenditures shall amount to at least 10 percent of any approved Infrastructure Investment Program. These capital expenditures shall be made in the normal course of business and recovered in a base rate proceeding, and shall not be subject to the recovery mechanism set forth in N.J.A.C. 14:3-2A.6."

[90] N.J. Admin. Code § 14:3-2A.3 (Lexis Advance through the New Jersey Register, Vol. 52 No. 18, September 21, 2020)

hearings on such proposals, and applications must estimate the rate impact on customers. If approved, the utility is subject to reporting requirements.[91]

One drawback of the IIP is that only utility plans fall within the purview of the IIP. Consistent with the IIP, the BPU has been silent about consideration of proposals put forth by non-utility stakeholders, which could be lower-cost or more socially desirable than utility plans.

The Energy Strong II proceeding testimony also noted that replacing aging infrastructure is the utility's obligation, rendering the Energy Strong II proposal unnecessary "for the provision of safe and reliable utility service." Rate Counsel also argued that accelerated investment does not necessarily warrant accelerated cost recovery, especially since it would lead to ratepayers bearing higher costs sooner and more risk.[92]

The parties in the proceeding reached a settlement, and the BPU approved PSE&G's request for accelerated rate recovery. The expenditures deemed recoverable through the Energy Strong II Rate Mechanism include "actual costs of engineering, design and construction, and property acquisition, including actual labor, materials, overhead, and capitalized AFUDC [allowance for funds used during construction] associated with projects."[93] PSE&G can apply for six rate adjustments[94] through the term of the program provided it complies with the minimum filing requirements. The minimum filing requirements include quarterly reports outlining the quantity of work that has been completed, forecasted and actual costs-to-date, estimated project completion date, anticipated changes, and expenditures separated into material and other costs.[95] For major events, the quarterly reports are mandated to include outage duration results (SAIDI) for circuits improved by Energy Strong II, for more information on this refer to the Sandia National Laboratories report, *Performance Metrics to Evaluate Utility Resilience Investments Performance Metrics to Evaluate Utility Resilience Investments.*[96]

For non-major event performance, the stipulation requires that reports include standard reliability statistics (CAIDI, SAIFI, SAIDI, and MAIFI) for the circuits improved by Energy Strong II.[97] The BPU also required PSE&G to retain an independent monitor[98] to review Energy Strong II progress

[91] According to N.J. Admin. Code § 14:3-2A .6 h and i: "An earnings test shall be required, where Return on Equity (ROE) shall be determined based on the actual net income of the utility for the most recent 12-month period divided by the average of the beginning and ending common equity balances for the corresponding period. For any Infrastructure Investment Program approved by the board, if the calculated ROE exceeds the allowed ROE from the utility's last base rate case by 50 basis points or more, accelerated recovery shall not be allowed for the applicable filing period."

[92] Ibid.

[93] New Jersey Bureau of Public Utilities. September 11, 2019. *Final Decision and Order Approving Stipulation in the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Second Energy Strong Program (Energy Strong II).* (Docket EO18060629)

[94] Per the BPU Order rate adjustments will be calculated as: Revenue Requirement = ((Energy Strong II Rate Mechanism Rate Base * After Tax WACC) + Depreciation Expense (net of tax) + Tax Adjustments) * Revenue Factor

[95] Ibid. Attachment B, outlining the MFRs, also notes that the most recent 12 month income statement and balance sheet, 5 years' worth of categorized capital spending, any timeline updates for subprograms, calculation of the proposed rate adjustment with associated depreciation expense, citation of any local, state or federal funds/credits, revenue requirement calculations, and ROE test results that document that the ROE has not exceeded the latest base case by more than 50 basis points.

[96] Sandia National Laboratories report: Performance Metrics to Evaluate Utility Resilience Investments Performance Metrics to Evaluate Utility Resilience Investments. https://www.synapse-energy.com/sites/default/files/Performance_Metrics_to_Evaluate_Utility_Resilience_Investments_SAND2021-5919_19-007.pdf

[97] Ibid.

[98] N.J. Admin. Code § 14:3-2A.5c (Lexis Advance through the New Jersey Register, Vol. 52 No. 18, September 21, 2020)

and provide separate reports to the BPU, but the BPU did not specifically mandate that the monitor include information on reliability metrics.[99]

Key Findings

Continuity of Electric Service

As part of PSE&G's Energy Strong II petition, the utility included an analysis conducted by Black & Veatch titled *PSE&G's Substation Asset Risk Model*. This model calculates outage risk based on the probability of outage conditions as well as their nature and severity. This calculation took historical outage data from 2010 to 2016, with data from specific circuits and circuit segments, and applied it to the benefit-cost analysis forecast period. Specifically:

> To address probabilities of outage occurrences, the analysis assume[d] that the average yearly intensity of outage conditions during the past seven years continues over the approximately 20 year forecast period, that is, it is assumed that future outage occurrences are the same as those experienced in the recent past. One exception is the exclusions within the base case of Superstorm Sandy-level impacts (October 2012). However, the data for Superstorm Sandy impacts were used in a sensitivity analysis. Black & Veatch believe[d] that this approach of applying an average rate of outage experience based on seven years of actual major event experience (excluding Superstorm Sandy) provide[d] a reasonable way to consider the probability of future storms and major disruptions, and their degree of intensity and destructiveness.[100]

Black & Veatch employed the same risk model to analyze the petition's subprograms which included hardening substations, contingency reconfiguration and grid modernization. The risk model assessed the condition of the components within each subprogram, such as transformers, disconnect switches, bus ducts, and circuits. Black & Veatch compared the components posing the most risk with how much impact upgrading these components would have on the electric system's reliability. Based on its findings, Black & Veatch recommended which subprograms should be prioritized.[101]

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[99] The IIP includes a number of reporting requirements but gives the BPU a significant amount of discretion in what it ultimately demands of a utility. For example, the BPU can decide whether an independent monitor should be engaged to review a program's progress or not; it is not prescribed by the IIP.[99] Although the IIP petitions are public, much of the process and information associated with individual petitions are confidential and not transparent to other stakeholders. We do know that Black & Veatch proposed framing resilience within the context of a reduction in customer minute interruptions (CMI). "If the improvements support reductions in outage *frequency*, this is classified as *hardening* the system. ... If the improvements support the reductions in outage *duration*, this is classified as improving the system's *resiliency*."(N.J. Admin. Code § 14:3-2A.5c (Lexis Advance through the New Jersey Register, Vol. 52 No. 18, September 21, 2020).

[100] Public Service Electric and Gas Company. June 8, 2018. *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of The Second Energy Strong Program (Energy Strong II).*

[101] More specifically, Black & Veatch's risk model "generated a prioritized list of all the 32,785 substation assets included in the model based on the risk score, replacement cost, and other resource constraints. In the development of ES II, the model was used to assess the risk reduction achieved by replacing high priority assets and other assets that PSE&G will repair or install to promote system modernization or enhanced functionality…The risk reduction achieved by these substation replacement subprograms was compared to a "Do Nothing" scenario (as a baseline) to arrive at the relative risk reduction. Utilizing the Risk Model in this manner provided PSE&G a tool to develop the life cycle aspects of ESII that cost-effectively reduce its overall system risk."
Public Service Electric and Gas Company. June 8, 2018. *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of The Second Energy Strong Program (Energy Strong II).*

Reasonable Rates

All IIP petitions must include, "an engineering evaluation and report identifying the specific projects to be included in the proposed Infrastructure Investment Program, with descriptions of project objectives—including the specific expected resilience benefits, detailed cost estimates, in service dates, and any applicable cost-benefit analysis for each project."[102] The board has not adopted a consistent process for conducting cost-effective analysis, even though a standardized assessment would allow for a straightforward comparison of various initiatives and their performance across the four electric utilities. As part of PSE&G's Energy Strong II petition, the utility also included an analysis conducted by Black & Veatch entitled *Energy Strong II: Electric Cost-Benefit Analysis*.

In terms of costs allowed, projects must address safety, reliability, and/or resiliency and cannot be revenue producing. Only expenditures "in excess of the baseline spending levels established by the Board"[103] are eligible for accelerated rate recovery. The BPU has not mandated baseline spending amounts; the IIP only requires that at least 10 percent of baseline spending include similar projects as the IIP program. Otherwise, the utility is not beholden to consider cost-effectiveness rigorously. This could be perceived as a shortcoming of the IIP; the cost burden (which is higher than it would otherwise be) is ultimately passed through to ratepayers. Further, in the case of the IIP the cost burden is passed through faster than it would be in a regular base rate case. In other words, the IIP provides a mechanism for utilities to increase profits and potentially recover costs associated with investments that are not cost-effective. Once approved, an IIP program effectively shifts the burden of responsibility for determining prudency and reasonableness from the utility to the intervening parties. And while residents who have experienced numerous major events are eager to support resilience-related measures, as evidenced by the widespread support Energy Strong II received at public hearings, they may fail to consider the economic burden of a program like IIP on ratepayers. As Rate Counsel submitted during testimony, utilities can propose to do any of these investments through a base rate mechanism, which would be fairer and less costly to ratepayers.

In the case of Energy Strong II, and consistent with PSE&G's experience in the first Energy Strong program, PSE&G compared the alternatives of raising or eliminating any substations "that are below base flood elevations plus one foot"[104] based on the cost-effectiveness of the available solutions. Neither the original Energy Strong nor Energy Strong II explored the full range of alternatives to the options presented in the petitions. The Energy Strong II petition was informed by the Black & Veatch risk assessment but lacked analysis of alternatives.

Customer Equity

Within Energy Strong II, there were no proposals for differential cost recovery, such as allocating costs to different geographic areas or customer types to better align who pays for and who is expected to receive the benefits of resilience investments. Instead, all customers pay for the enhanced reliability and resilience associated with the investments, even though some customers may experience greater benefits than others.

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[102] N.J. Admin. Code § 14:3-2A.5b (Lexis Advance through the New Jersey Register, Vol. 52 No. 18, September 21, 2020)

[103] N.J. Admin. Code § 14:3-2A.3d (Lexis Advance through the New Jersey Register, Vol. 52 No. 18, September 21, 2020)

[104] Public Service Electric and Gas Company. June 8, 2018. *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of The Second Energy Strong Program (Energy Strong II).*

Public Interest

The infrastructure investments made by New Jersey's utilities to better withstand major events provide benefits to the general public in the form of greater reliability and resilience. However, it is difficult to determine whether these investments are truly in the public interest, as robust analyses of costs and benefits have not been performed, and alternatives to these investments have not been comprehensively analyzed.

The perception of employment benefits associated with a project of this size is also evident in the strong support Energy Strong II received at public hearings. Multiple unions and companies had representatives speak at the meetings on how Energy Strong II would be beneficial for their employees and thus the New Jersey economy.

Cross-Cutting: Measured and Measurable

The IIP includes several reporting requirements but gives the BPU considerable discretion in what it ultimately demands of a utility. For example, the BPU can decide whether an independent monitor should be engaged to review a program's progress or not; it is not prescribed by the IIP.[105] Although the IIP petitions are public, much of the process and information associated with individual petitions are confidential and not transparent to other stakeholders.

4.5. Securitization in California

> We do know that Black & Veatch proposed framing resilience within the context of a reduction in customer minute interruptions (CMI). "If the improvements support reductions in outage *frequency*, this is classified as *hardening* the system. ... If the improvements support the reductions in outage *duration*, this is classified as improving the system's *resiliency*."[1]

The interaction between the electric grid, housing trends, and climate change in California has resulted in a complex resilience challenge. A series of catastrophic blazes were caused by drier than normal winters and aging and overutilized transmission and distribution system infrastructure. But development trends in the state—largely in response to a highly competitive and expensive housing market—have exacerbated the damage caused by these wildfires. Approximately 25 percent of the state's population now resides in areas deemed to be high fire risk,[106] with Californians increasingly choosing to settle in the more vulnerable "wildland urban interface."[107]

Electric utilities have been held partially responsible for these major fires. A commission that was convened in 2018 to examine wildfire costs and cost recovery observed that utilities have "played a

[105] N.J. Admin. Code § 14:3-2A.5c (Lexis Advance through the New Jersey Register, Vol. 52 No. 18, September 21, 2020)

[106] Wildfires and Climate Change: California's Energy Future: A Report from Governor Newson's Strike Force. April 12, 2019. Page 1.

[107] Wildfires and Climate Change: California's Energy Future: A Report from Governor Newson's Strike Force. April 12, 2019. Page 1.

pivotal role," and suggested that they be at the head in mitigating risk.[108] But the solution is not as simple as assigning the companies responsibility for all fire costs. Indeed, acting out of concern for utility financial integrity and its implications for the ratepayer interest, state lawmakers have recently passed two measures that seek to strike a balance between protecting utility financials and promoting system resilience. Resiliency for the utility-system is multidimensional in California. While other jurisdictions are principally concerned with protecting their poles and wires from weather or bad actors, in California, policymakers are seeking resilience for the utility system, and resilience from the utility system. The grid is both a wildfire threat and threatened by wildfires. Mitigating the wildfire risk posed by utility infrastructure in turn promotes utility system resilience, by reducing the chance that wires and poles will become victims of utility-system sparked fires, and also by reducing the frequency of preemptive de-energization events. The bottom-line priority is minimizing costs to the ratepayer; consequently, the state has utilized securitization to limit costs, including removing utility profits, while expeditiously addressing the pressing resiliency threats.

Securitization is another form of utility financing (equity and debt) and may result in a lower cost of capital and reduced ratepayer burden. Under securitization, funds are typically raised through a bond issue, which is repaid over time through charges levied on all ratepayers. The savings to ratepayers comes from the lower borrowing costs achieved by securitizing the debt with an assurance of repayment. In many cases, this assurance comes from legislative underwriting, though this need not always be so.

Though most associated in the utility context with cost-recovery for stranded assets like aging coal and nuclear units, securitization may also be used to fund resilience investments—either proactively, such as in grid modernization or grid hardening, or reactively.

> In practice, securitization has more commonly been implemented after events, to cover the costs of storm damage and recovery. As such, California appears to be one of the first examples of securitization for preventative electric utility resilience investments.

Unlike other types of utility borrowing mechanisms, securitization typically require an act of the legislature. In California, the first law to open the door to securitized funding for wildfire resiliency was passed in 2018. SB 901 included several major provisions. It created a commission to study catastrophic wildfire costs and cost recovery (mentioned above), tasked most of the state's utilities with filing annual wildfire mitigation reports, and authorized utility recovery of wildfire costs deemed to be "just and reasonable"—potentially through securitization.[109] The measure also promulgated a stress test standard for utility liability for the 2017 wildfires, limiting utility financial responsibility to "the maximum amount the corporation can pay without harming ratepayers or materially impacting its ability to provide adequate and safe service."[110]

[108] Final Report of the Commission on Catastrophic Wildfire Cost and Recovery. Page 2.
[109] SB 901 also instituted a requirement that utilities hire independent evaluators to review respective wildfire mitigation plans, and also that utilities undertake safety culture evaluations.
[110] SB 901. Sec. 27, 451.2 (b)

SB 901 specifically indicated that the state would not be made the debtor of last resort for securitized costs. Instead, under the terms of the required financing order authorizing recovery of wildfire costs—typically through recovery bonds—the Public Utilities Commission would be obligated to maintain the associated fixed recovery charges (e.g., utility bill fixed fees) at a level sufficient to ensure that debt obligations are met.

The act established clear standards dictating when securitization might be approved. The mechanism should only be approved when recovery of the underlying costs is found to be "just and reasonable" and "consistent with the public interest," and when the securitization has the effect of "…reducing, to the maximum extent possible, the rates on a present value basis that customers within the electrical corporation's service territory would pay as compared to the use of traditional utility financing mechanisms…"[111]

A second piece of related legislation passed in 2019. Assembly Bill 1054 again articulated a reasonableness standard for utility recovery of wildfire costs, providing for utility recovery if its "conduct, related to the ignition, was consistent with actions that a reasonable utility would have undertaken in good faith under similar circumstances, at the relevant point in time, and based on the information available to the electrical corporation at the time, as provided."[112]

AB 1054 also established an insurance fund, the "Wildfire Fund," to help defray utility exposure to financial liability that otherwise would result in an increased cost burden on ratepayers. The law allowed that the fund could be supported by a charge on ratepayers, among other potential funding sources. Similar to SB 901, this second measure was motivated in part by concern over utility financial integrity in the face of the mounting wildfire threat:

> It is the intent of the legislature to provide a mechanism that allows electrical corporations that are safe actors to guard against impairment of their ability to provide safe and reliable service because of the financial effects of wildfires in their service territories using mechanisms that are more cost effective than traditional insurance, to the direct benefit of ratepayers and prudent electrical corporations.[113]

AB 1054 included a spur to utilities to invest in resilience, indicating that "…electrical corporations must invest in hardening of the state's electrical infrastructure and vegetation management to reduce the risk of catastrophic wildfire."[114] The measure expanded the scope of wildfire-related cost recovery that might be approved; whereas SB 901 had specifically discussed utility spending in response to past wildfires, AB 1054 provided that the commission could also approve "fire risk mitigation capital expenditures," as outlined in a wildfire mitigation plan.[115] But this directive came with a key limit: the major California IOUs were precluded from earning a return on each utility's first $5 billion in "safety investments."[116,117]

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[111] Ibid.
[112] AB 1054.
[113] AB 1054, Sec. 1, 5(b)
[114] AB 1054, Sec. 2(b)
[115] AB 1054, Sec. 9(2)
[116] AB 1054, Sec. 2(g)
[117] AB 1054 also created a safety certification that utilities could qualify for by satisfying wildfire mitigation, safety, and executive compensation requirements. Possession of a safety certification confers wildfire liability protection on utilities: "An electrical corporation bears the burden to demonstrate, based on a preponderance of the evidence, that its conduct was reasonable pursuant to subdivision (b) unless it has a valid safety certification pursuant to Section 8389 for the time

Following passage of AB 1054, the Public Utilities Commission initiated a rulemaking that resulted in a new section of the California Public Utilities Code. Section 8386.3 outlines responsibilities for the new Wildfire Safety Division, and, among other things, reiterated the requirement that the first $5 billion spent in sum by the state's large electrical corporations on "fire risk mitigation capital expenditures" be excluded from its "equity rate base." Instead, utilities were directed that these obligations could be met with a financing order.[118]

The Public Utilities Code outlines the requirements for the mandatory wildfire mitigation plans that California utilities must file. The plans must include metrics to evaluate plan performance and must also include "discussion of how the application of previously identified metrics to previous plan performances has informed the plan."[119]

In September 2018, Southern California Edison (SCE) filed an application for the Grid Safety and Resiliency Program. The application described how the Company had developed its proposal, which was predicated on a "risk-informed" decision-making process and consideration of multiple investment alternatives.[120] In formulating its proposed portfolio, the Company assessed historical wildfire data and associated statistical trends, identified various mitigation alternatives, and evaluated the "risk reduction (benefits) associated with each measure," considering for each measure, its "effectiveness, deployment timing, resource allocation, alternatives, and other constraints."[121]

In April 2020, the Commission approved SCE's program, the first utility filing resulting from this new legislation and PUC guidance. In its decision, the commission authorized $400 million of capital investments, mainly in covered conductors and other grid modernization improvements. SCE was also authorized to spend more than $70 million on vegetation management, all with the aim of bolstering fire prevention and suppression and improving overall system resilience.[122] Next, SCE petitioned the commission for a financing order to cover these expenditures and was granted the requested securitization in November 2020.[123,124] As required by AB 1054, the company does not earn a return on these expenditures, reducing cost to ratepayers relative to a case in which the utility uses another form of financing.[125]

period in which the covered wildfire that is the subject of the application ignited. If the electrical corporation has received a valid safety certification for the time period in which the covered wildfire ignited, an electrical corporation's conduct shall be deemed to have been reasonable pursuant to subdivision (b) unless a party to the proceeding creates a serious doubt as to the reasonableness of the electrical corporation's conduct." See AB 1054, Sec. 6 2(C)

118 California Public Utilities Code, Sec. 8386.3

119 California Public Utilities Code, Sec 8386

120 Prepared Testimony in Support of Southern California Edison Company's Application for Approval of Its Grid Safety and Resiliency Program. Page 28.

121 Ibid.

122 Decision 20-04-013. Page 10.

123 Decision 20-11-007.

124 In total, SCE was allocated $1.575 billion in equity rate base exclusion out of the total $5 billion exclusion. Application 20-07-008, Decision 20-11-007. Issued on November 10, 2020.

125 Combined, the more favorable financing terms associated with the bond issue and the elimination of SCE's profit on the investment are expected to save its customers about $173.5 million compared with other forms of financing. (Decision 20-11-007. Page. 2.) While SCE did not provide definitive rate impacts in its securitization proposal, it provided a methodology for future use in calculating rate impacts once the final terms of the recovery bonds had been set. SCE also provided a table of illustrative impacts that was conditional on several assumptions. Under these assumptions, rate impacts by rate class resulting from the securitization were expected to range from 0.0% to 0.3%. Direct Testimony Supporting Southern California Edison's Application for Recovery Bond Financing: Policy Overview. Exhibit SCE-06: Ratemaking (R. Thomas, SCE). Page 10.

Key Findings

Continuity of Electric Service

Securitization and other financial and regulatory provisions are intended to enable fast and efficient investment.[126] By easing access to utility funding for some types of resilience investments, securitization may help to support the capability of the electric system to provide uninterrupted service. Critically, securitization also protects the financial integrity of the utility, helping to ensure that today's cost of resilience investments does not imperil the ability of utilities to continue to provide reliable service in the future.

Reasonable Rates

SB 901 and AB 1054 established reasonableness standards for securitization of wildfire recovery and resilience costs. SB 901 stipulated that both the costs to be recovered and the bonds to be issued for securitization would be approved only if found to be "just and reasonable."[127] SB 901 also stipulated that securitization should proceed only if it is a least-cost solution.[128] Both of these measures effectuated the vision advanced by the Commission on Catastrophic Wildfire Cost and Recovery in its final report, which noted the need for reform in the approach to determining prudence for wildfire associated costs, to "ensure that ratepayers pay for just and reasonable investments (such as investments in prevention and safety) but do not pay for avoidable, imprudent behavior…"[129]

Customer Equity

Lawmakers and regulatory authorities were motivated to promote securitization by concern about the inequity of status quo socialization of wildfire costs. In the final report issued by the Commission on Catastrophic Wildfire Cost and Recovery, the authors noted a second objective for the reform was to "ensure cost recovery reflects the host of factors—including risky homeowner or renter behavior—that contribute to the extent of wildfire damage, and does not hold utilities solely liable in cases where other factors contribute to the magnitude of the damages."[130] The insurance fund in particular may mitigate against undue socialization of costs, especially those costs that are incurred as a result of risky private development choices. Additionally, SB 901 established that customers participating in California Alternative Rates for Energy or Family Electric Rate Assistance programs—programs that provide rate discounts—would be exempted from securitization fixed charges.[131]

Public Interest

SB 901 explicitly required that any bonds issues for securitization be "consistent with the public interest."[132] AB 1054 followed with more specific language about the types of measures that were in the public interest, stating that electric utility investments in grid hardening and vegetation

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[126] SB 901 requires the commission to establish "procedures for the expeditious processing of an application for a financing order, which shall provide for the approval or disapproval of the application within 120 days of the application."

[127] SB 901. 850.1 (3) A(ii)

[128] SB 901. 850.1 (3) A(ii)

[129] Final Report of the Commission on Catastrophic Wildfire Cost and Recovery. 16.

[130] Ibid.

[131] SB 901. 850.1 (4) (i)

[132] SB 901. 850.1 (3) A(ii)

management were safety measures of broad public interest and impact. This direction provided important guidance to electric utilities about the types of grid investments mostly likely to receive Commission approval.

Cross-Cutting: Measured and Measurable

As required under Public Utilities Code, utilities must submit wildfire mitigation plans that include metrics to evaluate plan performance. Also, the plan should describe how its development was shaped by the performance of metrics identified in previous plan(s).

5. FINDINGS

In this section, we accumulate our findings across the case studies. The table below, provides an illustration of these findings, which is then followed by further discussion.

To develop the table below, we break down each regulatory objective into a more concrete set of outcomes that facilitate greater consideration of resilience investments. We identified two or three outcomes for each regulatory objective. We then search for evidence of these outcomes in our case studies. Where we see evidence in one or more case studies, we check the box in the outcome for those case studies. Where evidence is lacking or not yet clear, we leave the box blank.

Table 1. Regulatory Objectives and the strongest examples achieved by each case study

Regulatory Objective	Desired Outcomes	Case Studies				
		PBR in HI	IRP in PR	BYOD and ESS Tariffs in VT	Enhanced Cost Recovery in NJ	Securitization in CA
Continuity of electric service	**Adequacy.** Requiring utilities to have sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency.[133]		X			
	Preparedness. Encouraging proactive planning, accounting for the likelihood of occurrence and consequences of extreme events, to avoid or limit the consequences of those events.				X	X
	Efficient Process. Facilitating timely approval of investments.			X		X
Reasonable rates	**Investment Diversity.** Considering a full range of investments utilities and third parties can make to address resilience challenges and allow for different resilience investment options to be compared to one another and to investments aimed at achieving other priorities.					
	Balancing Costs with Benefits. Applying benefit-cost analyses and including resilience costs and benefits.		X			
	Stable, Reasonable Rates and Bills. Evaluating rate and bill impacts for different types of customers.			X	X	
Customer equity	**Consideration of Vulnerability.** Providing support for specific geographies or customer types, such as critical customers, within a utility's service territory facing higher consequences from extreme events.		X			
	Differential Cost Allocation. Supporting differential cost allocation for geographies and customer types who benefit from resilience investments.			X		
Public interest	**Stakeholder Input.** Encouraging utilities to seek stakeholder input and partner with others, including communities and other stakeholders, to deliver resilience solutions.					
	Consideration of Other Policy Objectives. Considering whether investments support other priorities, such as resilience, sustainability, public health, and job creation goals.	X	X			
Cross-cutting: Measured and measurable	**Performance Measurement and Evaluation.** Establishing performance metrics to enable standards and targets and provide ongoing recurring assessment of utility resilience performance against these standards and targets.	X				X

[133] NERC 2013.

We find that regulatory mechanisms are not currently structured or applied to effectively address resilience. Overall, our research indicates the following:

- Application of regulatory mechanisms to resilience investments is in the early stages and there are few case studies. Where regulatory mechanisms are applied to resilience, grid resilience has not been the primary goal. Additionally, in one of the case studies we selected, the case study on tariffs, resilience was not a regulatory objective.
- The limited data thus far suggest that, as applied to date, no single mechanism achieves all regulatory objectives and associated desired outcomes. This is evidenced by the entries by column in the table above. None of the case study columns contain entries for all the rows. For each case study, at most two or three of the 11 rows of desired outcomes are populated.
- Additionally, no regulatory objective and associated desired outcomes are achieved by all the mechanisms. This is evidenced in the entries by row in the table above. None of the desired outcome rows contain entries for all the columns. At most, two of the five columns of mechanisms are populated.
- Lastly, all the regulatory mechanisms fell short in two areas: (1) requiring consideration of and comparison of the full range of investments utilities and third parties can make to address resilience challenges (referred to as investment diversity) and (2) partnering with stakeholders and considering their viewpoints (referred to as stakeholder input). This is evidenced by the lack of any entries for these rows.

Below, we summarize the key strengths and shortcomings of each mechanism. In the *Conclusions* section that follows, we discuss opportunities to address the shortcomings.

PBR in Hawaii

The design of PBR in Hawaii requires measurement of utility performance in areas of interest to regulators. Accordingly, PBR should perform well with respect to two desired outcomes in particular: *consideration of other policy objectives* and *performance measurement and evaluation*.

With respect to other desired outcomes, PBR's performance is less clear.

- In many cases PBR includes explicit incentives for utilities to avoid service degradation, particularly in terms of reliability measures. Coupled with integrated planning, Hawaii's PBR mechanism (including its provisions for alternative cost recovery) could proactively address resource needs, helping to promote system resilience and reliability. However, it is too early to tell whether PBR is accomplishing the desired outcome of *adequacy* in Hawaii.
- In general, PBR should promote the consideration of a comprehensive set of solutions and encourage innovation and cost efficiencies, pointing to a potentially solid foundation for energy decision-making and reasonable rates. However, it is too early to tell whether PBR is accomplishing the desired outcome of *investment diversity* in Hawaii.
- Also, there is no differential cost allocation implemented yet in Hawaii. As a result, the ability of PBR to address the desired outcome of *differential cost allocation* (an aspect of *customer equity*) is unknown.

It does not seem likely that resilience will be explicitly valued as a result of this proceeding so the desired outcome of *balancing costs with benefits* will not likely be achieved. To the extent that resilience outcomes are positive externalities not enjoyed by the utility, there is a risk that resilience will be given short shrift in future investment decisions. The Exceptional Project Recovery Mechanism may promote spending on resilience, but this remains to be seen.

One additional shortcoming of PBR is that its development and implementation can be a lengthy, time-consuming endeavor. As a result, PBR in Hawaii has not achieved the desired outcome of an *efficient process* to date. The time commitment also means that the desired outcome of *stakeholder input* may be more difficult to achieve.

IRP in PR

Historically, many IRPs failed to assess likely resilience risks and consider the full range of solutions, including those that address resilience.[134,135] While PREPA's IRP considered resilience and proposed a resilience solution, it did not optimize its solution. The pending Optimization Proceeding takes as given that a more resilient system is required. That proceeding seeks to strike an appropriate balance among approaches to adding resilience, *i.e.,* between a more centralized approach (based on hardening transmission and distribution systems) and a more distributed approach (based on site-specific resilient electric supplies using solar PV, batteries, and possibly backup generators). The PREB will consider the costs, performance, timeliness, environmental impacts, and co-benefits of different solutions in pursuit of an implementable and cost-effective solution—thus taking steps toward the desired outcomes of *balancing costs with benefits* and *consideration of other policy objectives*. Emphasizing service continuity in the face of a physical threat, the IRP and the Optimization Proceeding both address the desired outcome of *adequacy*.

IRP can be designed to consider and provide support for specific geographies or customer types, such as critical customers, within a utility's service territory that face higher consequences from extreme events. Another strength of PREPA's 2019 IRP is that it proposed to harden transmission and distribution from thermal generators to critical and priority loads. The IRP is achieving the desired outcome of *consideration of vulnerability*.

Weaknesses of PREPA's IRP include lack of consideration of a full range of investments (*investment diversity*) and lack of public engagement until late in the process (*stakeholder input*). The Optimization Proceeding may address these shortcomings.

Tariffs and Programs to Leverage Private Investment in Vermont

The tariffs perform more favorably regarding the desired outcome of *efficient process*. The commission is not involved in approving or denying an individual customer's BYOD storage asset, up to the max capacity for the program. This facilitates adding storage systems to the grid. In addition, the commission has established a framework for assessing and approving recovery of GMP's program-related costs on a timely basis. Also, the regulatory process includes consideration of bill impacts to participants and non-participants alike, thus assuring *stable, reasonable rates and bills*. And the mechanisms allow customers who receive resilience benefits to pay a greater portion of the cost, achieving the desired outcome of *differential cost allocation*.

However, there are several shortcomings to note. The design of the BYOD and ESS tariffs miss

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[134] Scheller, Maria and Ananth Chikkatur 2014. Integrated Resource Planning Models Need Stronger Resiliency Analysis. ICF.

[135] There are some notable exceptions to this. For example, Oregon's IRP planning process "requires that utilities take risks, their probabilities of occurrence, and the likelihood of bad outcomes into their choice of preferred resource plan." (Wilson, Rachel and Bruce Biewald 2013. Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans.)

achieving the desired outcome of *consideration of vulnerability,* as they do not consider whether customers have unequal access to funding to enable them to participate, nor do they allow for preferential treatment for customers who are likely to be disproportionately impacted by resilience events. Also, Vermont's BYOD and ESS tariffs were designed to incent only one type of solution; therefore, they were not designed to achieve *investment diversity*. Failure to consider different solutions could result in higher costs than necessary. Lastly, the tariffs do not achieve the desired outcome of *balancing costs and benefits*. While the tariffs provide a net benefit to all customers, these tariffs only consider costs and benefits during normal grid operations.

Enhanced Cost Recovery in New Jersey

Enhanced Cost Recovery can perform well for the desired outcome of *preparedness*. For example, New Jersey engaged in assessment of vulnerability before the IIP was enacted, providing guidance to utilities on resilience needs. In addition, the IIP calls for utilities to describe and assess how their proposals address resilience threats and provides an incentive to utilities for proactively addressing vulnerabilities.

Rate and bill impacts are assessed as a part of IIP proceedings, demonstrating attention to the desired outcome of *stable, reasonable rates and bills*. However, the mechanism is not achieving the desired outcome of *balancing costs with benefits*. Investment proposals could be improved by more uniform and more comprehensive assessment of costs and benefits. While participants in public hearings voiced support for the Energy Strong proposal, comments largely involved job creation; participation by those outside of labor interests appeared to be limited. Further, public input was not solicited until the utility had effectively set the proposal, thus effectively precluding consideration of other ideas.

Securitization in California

It is less clear whether utilities in jurisdictions other than California would be motivated to propose investments with no associated profit. In California, several factors motivated SCE to propose resilience investments. The threat of wildfires continues to be pressing in California, and SCE faces the ongoing problem of liability for fire damages; the determination that the utilities were partially responsible for wildfires over the last few years has likely spurred them to address system vulnerabilities. The securitization mechanism may be less effective where the threat of an extreme event is less likely and where such a determination is more difficult to make.

California's securitization policy is designed to expeditiously approve electric utility proposals for preventative resilience investments. In SCE's case, the efficiency of the process has borne out as intended, and the desired outcome of Efficient Process is a strength of this mechanism.

In California, the securitization policy is coupled with a requirement that utilities engage in wildfire mitigation planning. As a result, this mechanism performs well in terms of the desired outcome of *preparedness*. These mitigation plans must include metrics to evaluate plan performance, demonstrating an attention to the desired outcome of *performance measurement and evaluation* that is lacking in some of the other cases that we evaluated.

6. CONCLUSIONS

It is not our expectation nor is it necessarily a goal that every type of regulatory mechanism can or will achieve every desired outcome. Some regulatory mechanisms are better able to achieve some outcomes than others. The purpose of this assessment is to facilitate discussion about the objectives and outcomes that are most important for jurisdictions seeking to address resilience and about the best means to achieve those objectives and outcomes. We expect that different jurisdictions will have different priorities. Therefore, we expect jurisdictions to use different regulatory mechanisms to achieve their resilience goals.

However, we do see the regulatory mechanisms falling short of their potential to encourage resilience. As a result, current applications of regulatory mechanisms may not provide sufficient support for utility resilience investments.

Without improvement, these mechanisms may not sufficiently encourage the investments needed to meet customer resilience needs and expectations, or they may do so at higher cost to ratepayers than necessary. We offer the following suggestions:

- PBR requires substantial time and resources but can be implemented incrementally. For example, regulators can choose to develop performance metrics and implement reporting requirements at the outset, which will provide a base of data on which to develop other PBR elements. After a time, regulators can set performance standards and targets without financial rewards or penalties if desired. Then, financial incentives can be layered on if needed.
- While IRPs in many other jurisdictions do not address resilience, this shortcoming can be addressed in part by providing regulatory guidance on the methodology that utilities use for developing IRPs. For example, commissions can provide guidance on the form of reasonably anticipated scenarios that utilities should model in the IRP. Also, in light of rapid changes in the energy sector, IRPs can and should explicitly recognize and consider a range of potential risks, such as regulatory developments and resilience risks.[136] Further, IRPs should provide and assess a range of strategies for addressing those risks.[137] More deliberately including resilience considerations may improve the system's ability to withstand catastrophic events, for example by considering the potential for flooding, storm surge, or seismic events when siting power system infrastructure.[138] A full analysis of risks facing the utility and the electric system would also improve energy decision-making and provide a better foundation for just and reasonable rates. Regulators can require utilities to include resilience considerations and risk modeling within their IRPs. In addition, regulators can institute performance metrics that align with criteria for selecting an IRP plan and with policy priorities more generally. Performance metric data can be used to inform and refine future IRPs.
- Regarding tariffs, allowing utilities to engage in other business areas can be problematic, as the utilities' regulated monopoly positions gives them a potentially unfair advantage against other firms in the private market and may produce unreasonable rates. To address this concern, regulators could institute several protections. For example, regulators can require utilities to demonstrate that the market has not and will not develop to address the need before allowing the utility to launch a new business effort. Regulators can also limit the functions that regulated

[136] USAID. 2017. Integrated Resource & Resilience Planning (IRRP) for the Power Sector
[137] Wilson and Biewald 2013
[138] USAID 2017. Integrated Resource & Resilience Planning (IRRP) for the Power Sector

utilities can perform and set boundaries for utility affiliates. In any case, ongoing regulatory oversight is important.

- Depending on the design, enhanced cost recovery mechanisms can increase the utility's incentive to invest in capital measures. This could lead utilities to propose solutions that are more costly than necessary. Regulators can counter this with stronger, more consistent guidance and requirements regarding assessments of costs and benefits. To determine an enhanced cost recovery program's success, regulators should also be explicit about the performance metrics that the utility will track and report, and the frequency of reporting.
- Securitization could be paired with periodic vulnerability assessments and a clear mandate for addressing grid vulnerabilities to ensure other jurisdictions are motivated to propose resilience investments that may have no associated profit. However, spending needs to be monitored closely. Without thresholds or guidance, securitization could make the utility cost-insensitive in a way that could result in excessive spending.

Further, we note the following regarding the desired outcomes that were not achieved by any mechanism.

- Many of the regulatory mechanisms discussed can enable *investment diversity*, but we do not have good examples to date. Regulators can require utilities to identify a range of solutions and provide comparisons of the costs and benefits of these solutions using benefit-cost analysis. Regulators, utilities and other stakeholders can reference Sandia National Laboratories' report titled *Application of a Standard Approach to Benefit-Cost Analysis for Electric Grid Resilience Investments* for more information on the costs and benefits associated with grid resilience and an approach for how to include these costs and benefits in a benefit-cost analysis.[139] With improvements to benefit-cost analyses of resilience investments to capture more of the resilience-related benefits, tariffs can be deployed to recover resilience investment costs from those customers who benefit more.
- Consideration of stakeholder and public input is often limited and usually at the end of the process. This can effectively limit the diversity of investments to those put forth by the utility. In order to garner *stakeholder input*, regulators and utilities may need to communicate complex technical and economic concepts to a broader audience. Also, the most helpful stakeholder input is likely to arise from sustained participation, which can be difficult for populations that lack time and resources to participate in lengthy regulatory processes.

Progress is also needed on the cross-cutting desired objective of *performance measurement and evaluation*. A commission could consider requiring utilities to report resilience performance metrics. Sandia National Laboratories' report titled *Performance Metrics to Evaluate Utility Resilience Investments* includes a menu of performance metrics for grid resilience and an Excel-based tool visualizing these performance metrics in the form of reporting templates for regulators, utilities, and stakeholders to consider.[140]

Despite some of the shortcomings of the approaches used to date, we conclude that regulatory approaches included in this analysis have the potential to allow policymakers to address resilience and other regulatory goals. However, even with improvements, a single mechanism may not suffice.

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139 Sandia National Laboratories. 2021. *Application of a Standard Approach to Benefit-Cost Analysis for Electric Grid Resilience Investments.*

140 Sandia National Laboratories. 2021. *Performance Metrics to Evaluate Utility Resilience Investments.*

Regulatory mechanisms are not mutually exclusive and can be used in combination with one another. Multiple mechanisms may need to be applied to achieve all the desired outcomes.

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