Current Practices in Distribution Utility Resilience Planning for Winter Storms

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List of Acronyms

ADMS	advanced distribution management system
AMI	advanced metering infrastructure
CAIDI	customer average interruption duration index
CBA	cost-benefit analysis
CEMI	customers experiencing multiple interruptions
CMI	customer minutes interrupted
DER	distributed energy resource
DPS	Department of Public Service
EAL	expected annual losses
EMS	energy management system
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
FEMA	Federal Emergency Management Agency
FLISR	fault location, isolation, and service restoration
GDO	Grid Deployment Office
GIS	global information system
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor-owned utility
ISO	International Organization for Standardization
LiDAR	light detection and ranging
LBNL	Lawrence Berkeley National Laboratory
MAIFI	momentary average interruption frequency index
MED	major event day
MREA	Minnesota Rural Electric Association
NCEI	National Centers for Environmental Information
NERC	North American Electric Reliability Corporation
NESC	National Electrical Safety Code
NOAA	National Oceanic and Atmospheric Administration
NRI	National Risk Index
PNNL	Pacific Northwest National Laboratory

RAMP	Risk Assessment and Mitigation Phase
RTU	remote terminal unit
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCADA	supervisory control and data acquisition
SCE	Southern California Edison
SRP	Storm Resilience Program (used by Unitil)
STAPLEE	social, technical, administrative, political, legal, environmental, and economic
SWEC	Southwest Electric Cooperative

1 Introduction

This report is part of a series of hazard-focused case studies examining common practices in electric utility resilience planning. We use standard terminology defining resilience as the ability to anticipate, withstand, absorb, and recover from hazards that cause long duration outages. We distinguish between reliability and resilience using Institute of Electrical and Electronics Engineers (IEEE) 1366-2022,[1] which defines major events as an event that exceeds reasonable design and/or operational limits of the electric power system. Resilience planning is focused on major event days and reliability planning is focused on nonmajor event days. Utility resilience plans are assessed according to common resilience components identified in existing resilience frameworks.

The focus of this report is on winter storms in which the primary hazards are heavy snowfall, freezing rain, ice, extreme cold, severe wind, and flooding. These hazards can also contribute to generation shortages, resulting in bulk power system impacts that have consequences for the distribution system, such as load shedding. Stand-alone reports focusing on wildfires and nonwinter storms have been published in parallel with this report. This report can be used as a starting point for understanding potential investment prioritization processes and investment options. This report is intended to improve utility resilience planning by supporting constructive dialogue among utilities, regulators, and other stakeholders.

1.1 Approach

The hazard-focused resilience reports are based on a review of each utility's publicly available distribution resilience plan or hazard-specific planning report and interviews with utility representatives (see Appendix A). All utilities reviewed in this report were contacted. Utilities that responded were asked for feedback on our approach and the accuracy of our findings. All utilities were assessed according to six resilience planning components: 1) preliminary hazard characterization, 2) attribute metrics, 3) performance metrics, 4) threat risk analysis, 5) investments, and 6) investment prioritization. These components were adapted from those identified in existing resilience frameworks, as described by the Electric Power Research Institute (EPRI),[2] Sandia,[3] and others.[4] Section 1.3 describes the utilities that were selected for this report, and the remainder of this report considers the utilities' resilience planning practices according to the six resilience components. We first provide a brief description of these components. Further details on resilience components and resilience investment prioritization can be found in Appendix C. This report is focused on resilience *planning*, so we do not include detailed information on *operating* procedures during major event days (such as event response

[1] "IEEE Std 1366™-2022, IEEE Guide for Electric Power Distribution Reliability Indices," 2022.
[2] J. Tripolitis, S. Martino, and J. Wharton, "Distribution Grid Resiliency: Prioritization of Options" (Electric Power Research Institute, 2015).
[3] Jean-Paul Watson et al., "Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States," September 1, 2014, https://doi.org/10.2172/1177743.
[4] Paul De Martini, Newport Consulting, and Jeff Taft, "Distribution Resilience and Reliability Planning" (Pacific Northwest National Laboratory, January 2022).

management, training, situational awareness, and coordination between utilities in mutual assistance programs).

Preliminary hazard characterization is a process used by utilities to determine the relative risk of different hazards and to determine where to focus resilience investments. Because there are many hazards, preliminary hazard characterization tends to be qualitative and based on engineering judgment more than detailed analysis. For example, a utility might perform a climate change risk assessment and determine rising temperatures carry a "low risk" and increased flooding carries a "high risk."

Attribute metrics measure system characteristics that may be beneficial to resilience.[5] We suggest utilities collect metrics for each resilience phase, and we refer to anticipate, absorb, withstand, and recovery metrics throughout this report. These phases are further described in Appendix C.2, and system resilience curves illustrating the effects of investments to address each phase are shown in Figure 1. Attribute metrics can provide utilities with options to improve their performance metrics. For example, the percentage of underground laterals is a metric that describes the ability of a utility to withstand strong winds. If a utility has a poor Tree-system average interruption duration index (SAIDI) score, it might consider increasing the number of underground laterals.

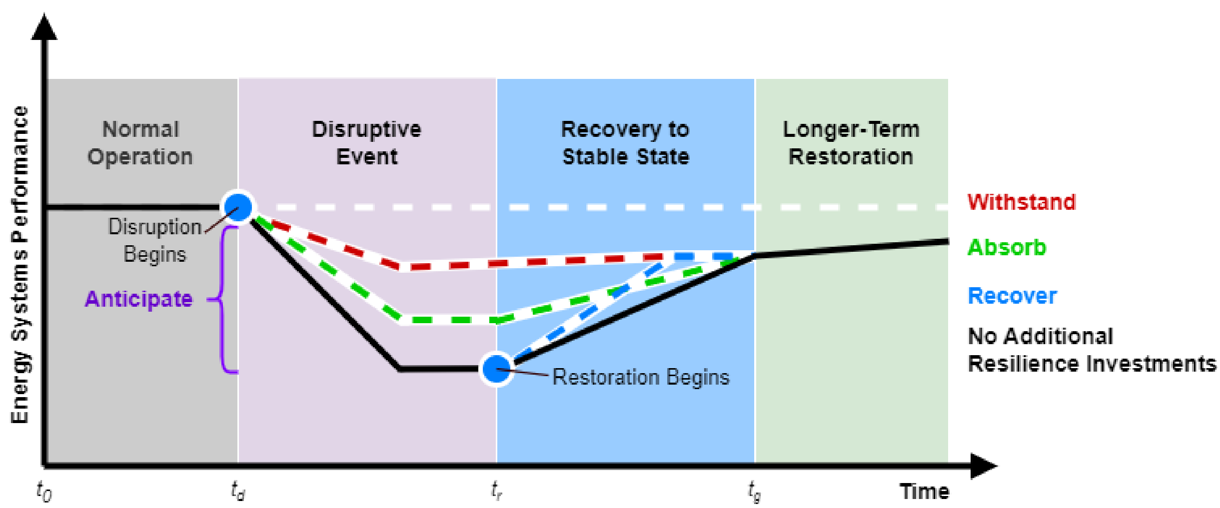

Figure 1. System resilience curves for the effects of investments to withstand, absorb, recover, or anticipate. Investments to withstand result in system performance avoiding some impacts altogether while not necessarily improving recovery rates. Investments to absorb the impact of an event will arrest the decrease in system performance and reduce impacts to system users until a stable state can be attained. Unlike investments to withstand, investments to absorb may limit a reduction in performance or allow for accelerated recovery without altogether avoiding hazard impacts. Investments to recover accelerate the rate of recovery but may not result in an impact reduction at the time of the event. Investments to anticipate can support the system's abilities to withstand, absorb, or recover.

[5] Caitlin Murphy et al., "Adapting Existing Energy Planning, Simulation, and Operational Models for Resilience Analysis," February 25, 2020, https://doi.org/10.2172/1602705; Laura Leddy et al., "Measuring and Valuing Resilience: A Literature Review for the Power Sector," September 5, 2023, https://doi.org/10.2172/1999382.

Performance metrics measure a utility's status in achieving its core objectives (e.g., affordability, safety, reliability, resilience, equity). Major event day (MED)-SAIDI is an example of a resilience performance metric.

Threat Risk Analysis is analysis used to quantify the probability, consequence, and vulnerability (i.e., risk) of a threat. It can be performed using historical data or simulations and can be used to determine how system changes (e.g., a new investment) affect risk. A historical risk analysis might assess customer outages caused by strong winds on single-phase laterals and recommend undergrounding. A forward-looking simulation might analyze the same threat but could also consider expected increases in wind speeds from climate change. Threat Risk Analyses can include simulation to quantify the effects of various investments on system performance.

Investment considerations are provided in this report. We provide common categories (e.g., vegetation management) and examples of investments utilities are making to improve resilience in their service territory. A utility that has considered a variety of investments is likely to achieve more cost-effective solutions.

An *investment prioritization* process identifies cost-effective investments to minimize risk. Ideally, this prioritization process will demonstrate the cost and effectiveness of investments with respect to specific performance metrics. It is also important that these investments are not made in isolation. Resilience investment prioritization is more effective when integrated into existing planning processes (e.g., capacity planning or asset management) and when it considers multiple utility objectives (e.g., reliability, cost, and equity). Cost-benefit analysis (CBA) is one form of investment prioritization.

There are overlaps and relationships between the resilience components listed here. *Preliminary hazard characterization* and *threat risk analysis* exist on a spectrum. *Preliminary hazard characterization* is primarily needed to focus the *threat risk analysis* on hazards with the greatest risk. *Attribute metrics* and *performance metrics* also exist on a spectrum. For example, "Tree-SAIDI" is a popular performance metric that also provides insight into system characteristics (i.e., high Tree-SAIDI scores imply high tree coverage and a need for improved vegetation management). A resilience workflow often exists between *attribute metrics, threat risk analysis,* and *performance metrics. Attribute metrics* can provide actionable changes that can be evaluated with a *threat risk analysis* tool, which then outputs predicted changes in *performance metrics.* The cost of achieving a given *performance metric* improvement can be used to rank the cost-effectiveness of the investment. If the performance metric is associated with a monetary benefit, a CBA can be conducted. Both cost-effectiveness and CBA can be used to support *investment prioritization*.

Table 1 lists the resilience components and describes some of the questions that can help evaluate utility resilience planning. The resilience components are agnostic to hazard type and can be used as a template to analyze resilience reports for any hazard.

Table 1. Rubric for assessing utility resilience plans. Resilience components and suggested questions are provided that can help utilities develop cost-effective resilience strategies.

Resilience Component	Suggested Questions
Preliminary Hazard Characterization	• Is risk defined? • Does the definition of risk include the probability, vulnerability, and consequence of each hazard? • Are multiple hazards considered in the characterization? • Does the characterization identify high-risk hazards? • Are emerging risks considered proactively?
Attribute Metrics	• Are attribute metrics used to characterize system strengths and weaknesses in the face of specific hazards? • Are attribute metrics collected that describe the system's ability to anticipate, withstand, absorb, and recover? • Are attribute metrics collected in a manner consistent with utility and industry standards? • Are attribute metrics used to guide investment decisions? • Data hygiene: Are data of sufficiently high resolution? Is data coverage sufficient?
Performance Metrics	• Are performance metrics defined? • Are the performance metrics used to measure how well a utility is meeting its resilience objectives? • Are the performance metrics used to track how well a utility is meeting other objectives, such as equity, clean energy, and reliability? • Are the resilience performance metrics applicable to all hazards or are they developed specifically for one hazard? • Data hygiene: Are data of sufficiently high resolution? Is data coverage sufficient?
Threat Risk Analysis	• Is risk defined? • Does the definition of risk include the probability, vulnerability, and consequence of each hazard? • Does the risk analysis use historical data? • Does the risk analysis use forward-looking simulation? • Data hygiene: Are data of sufficiently high resolution? Is data coverage sufficient? • Are customers and communities engaged to determine or validate consequence valuation?
Investments	• Are there investment considerations in multiple categories of investment type? Categories may include vegetation management, overhead hardening, undergrounding, network redundancy, grid modernization, operations, advanced resource planning, forward-looking analysis, and nonelectric grid physical infrastructure. • Are utility or industry standards used to guide investments?

Investment Prioritization	• Are investments prioritized according to their cost-effectiveness? • Does the investment valuation consider multiple objectives that are supported by a single investment? • Do investment decisions reflect feedback from community engagement efforts? • Are investment decisions made in isolation or as part of the regular planning process?

1.2 Takeaways

The following takeaways reflect themes observed among the six utilities reviewed.

- **Standardized nationwide metrics for utility losses and risks from various hazards can benefit from further development.** The Federal Emergency Management Agency's (FEMA's) National Risk Index (NRI) and Expected Annual Loss (EAL) are incomplete indicators of disaster risk; they do not reflect losses to utility assets or many of the indirect losses to the communities they serve. Alternative metrics that capture community losses, use sufficiently high-resolution data, include forward-looking considerations, and compare different hazards were not identified. See Appendix B for more information on EAL, opportunities for improvement, and comparisons of EAL by hazard.

- **Many of the utility reports reviewed responded to recent events and do not include a preliminary hazard characterization.** Some of the reports are a direct response to a single event whereas others are prompted by a series of events occurring in a season. Preliminary hazard characterizations are missing from some of the reports reviewed; however, utility interviews indicated preliminary hazard characterizations occur in independent utility processes. Exceptions are the Southwest Electric Cooperative (SWEC) and Minnesota Rural Electric Association (MREA), which describe preliminary hazard characterizations that consider additional hazards in the reviewed reports. A thorough preliminary hazard characterization can allow utilities to identify risk before it occurs.

- **Though winter storms are not a new hazard, utilities are experiencing new impacts because of new characteristics of winter storms.** In the Midwest and the Northeast, warmer average winter temperatures have resulted in icing of conductors in areas where previously drier conditions prevented ice accretion. Wetter, heavier snow more often results in contact between overhead infrastructure and vegetation. The Electric Reliability Council of Texas (ERCOT) has experienced unprecedented generation shortfall because of prolonged periods of extreme cold. Load shedding is a critical and last-resort tool to avoid more widespread blackouts and unplanned outages in such cases, and distribution system operators are challenged to implement load shedding dispatches for the first time. New metrics and tools are needed to minimize the impacts of prolonged periods of service interruption.

- **There is a growing need for hazard-specific attribute metrics and performance metrics describing distribution system resilience.** A wide range of investments is being made for winter storm resilience, but we did not observe the robust use of attribute metrics to guide those investments or performance metrics to predict or track the effectiveness of those investments. Utility interviews revealed that a standardized set of hazard-specific metrics can assist utilities in tracking and communicating system needs and improvements in severe winter storm conditions. Though standards such as IEEE 1782-2022[6] may be followed, some utilities stated current standards are insufficient to capture the impacts and challenges of emerging hazards such as generation shortfall resulting from extreme cold.

- **Most utilities are not performing forward-looking threat risk analysis.** Utilities might benefit from having industry-standard, openly available tools to perform forward-looking analysis focused on winter storms. No power-system-specific tools and analyses modeling forward-looking winter storm hazards were identified.

- **Most utilities are not using investment prioritization processes.** SWEC and Unitil are exceptions. Unitil performed individual cost-benefit analyses on several investment types—including vegetation management, undergrounding, and additional circuit ties—prior to heavily concentrating efforts on vegetation management because of its cost-effectiveness. SWEC incorporates multi-objective planning by using social, technical, administrative, political, legal, environmental, and economic (STAPLEE) factors in its investment prioritization. Overall, multi-objective planning—which requires investment prioritization—is rare.

- **Utility resilience investment prioritization would benefit from research on the impacts of long-duration outages.** We observe utilities that report customer interruption costs and other performance metrics using methods and data based on short-duration outages.

1.3 Utility Selection

Utilities were selected based on the relevance of winter storms as a hazard for their service territory, availability of published materials regarding utility storm resilience investments, and diversity in the group of utilities selected. The service territories of these utilities are shown in Figure 2 with their EAL, calculated from the census tract EAL provided by FEMA. We recognize the limitations of the EAL (or any one metric) in accurately capturing storm risk, but we use it here to convey the diversity of included utilities and the risk they face. These comparisons are not intended for utilities to comprehensively assess risk or to support or oppose the prudence of utility spending. See Appendix B for more information on the EAL metric, opportunities for improvement, and comparisons of EAL by hazard.

[6] "IEEE Std 1782-2022 (Revision of IEEE Std 1782-2014) IEEE Guide for Collecting, Categorizing, and Utilizing Information Related to Electric Power Distribution Interruption Events," 2022.

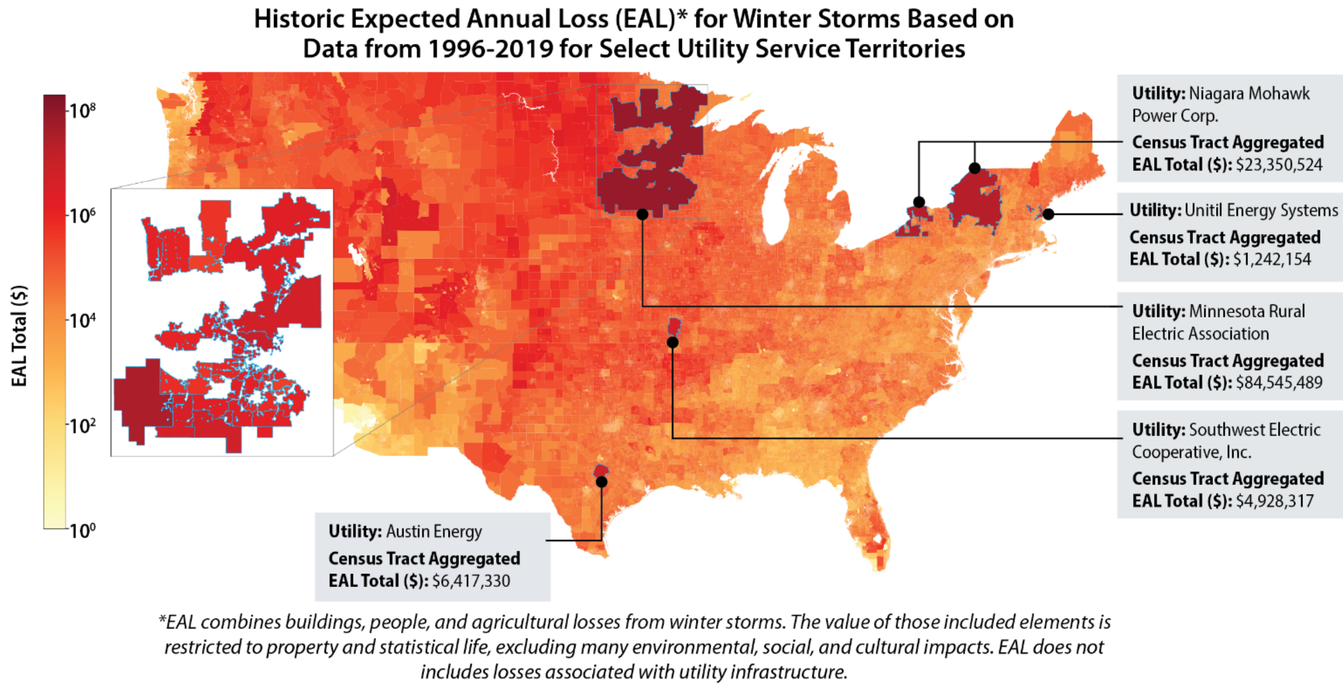

Figure 2. FEMA Expected Annual Loss for the United States.[7] EAL is a relative measure of risk that estimates the average economic loss in dollars resulting from natural hazards each year. The EAL quantifies economic losses from consequences of buildings, agriculture, and people. See Appendix B for more detail.

Context for winter storm hazards facing each utility is provided in Table 2. The motivation and context for the resilience reports used as sources in this case study are given in Table 6 in Appendix A.

Table 2. Selected utilities, resilience report context, and reported spending. Information here is provided by the utility documents listed in Table 6 and FEMA's National Risk Index.

Utility	Utility Hazards and Spending
Southwest Electric Cooperative (SWEC)	• Based on historical records, SWEC states severe winter weather events will cause average annual damages of $217,000. • SWEC's service territory includes counties at the greatest risk of ice storms in the United States (Greene County is at the 100th percentile). Camden County is at the 99th percentile of risk because of winter weather.

[7] "Map | National Risk Index," accessed April 7, 2023, https://hazards.fema.gov/nri/map.

Minnesota Rural Electric Association (MREA)	• From 1999 to 2011, FEMA provided $24 million to Minnesotan electric cooperatives for disaster recovery and protective measures. Sixty-two of the estimated 84 hazard mitigation projects involved converting overhead lines to underground lines. • From 2013 to 2022, cooperatives in Minnesota received funding for recovery from disasters related to 11 events. An electric cooperatives' infrastructure damage costs can make the local county eligible for Presidentially Declared Disasters. • Cooperatives in Minnesota serve counties in the 100th percentile of risk from cold waves (Hennepin), 99th percentile of risk from ice storms (Anoka), and 98.1 percentile of risk from winter weather (Nobles).
Austin Energy	• Spending for resilience investments was not provided. • Austin Energy's service territory was impacted by Winter Storm Uri in February 2021. Instructions from ERCOT required Austin Energy to shed load in such a manner that Austin Energy was unable to rotate customers. Austin Energy's service territory includes Travis and Williamson Counties. Williamson County has high risk indices for winter weather at the 99th percentile and cold wave at the 96th percentile. The February 2021 winter storm resulted in outages for 4.5 million Texans and numerous deaths.[8]
Unitil	• Unitil reports yearly spending at the end of its Storm Resilience Program to be $1.897 million. Unitil estimates the average customer's monthly bill impact is $0.24. • Hurricane Irene and an October snowstorm in 2011 caused widespread damage and outages and led to a storm resilience pilot. Unitil's service territory includes Worcester County, which is in the 73rd risk percentile for cold waves, 97th percentile for ice storms, and 82nd percentile for winter weather.
Niagara Mohawk Power Corp.	• Niagara Mohawk reports spending $863 million on storm hardening and $99.6 million on resilience from 2020 to 2024. • Several winter and spring storms in 2018 led to significant outages across New York state, including Winter Storm Riley (500,000 peak outages); Winter Storm Quinn (162,000 peak outages); two windstorms resulting in peak outages of 126,000 and 160,000, respectively; and a severe thunderstorm and tornado that caused 188,000 peak outages. Niagara Mohawk's service territory includes Erie County, with a 98th percentile risk for cold wave, 89th for ice storms, and 98th for winter weather.

[8] Final Report on February 2021 Freeze Underscores Winterization Recommendations. North American Electric Reliability Corporation (NERC), November 16, 2021.

2 Preliminary Hazard Characterization

In this section, we review the preliminary hazard characterization process for all utilities. Appendix C.1 contains additional details on the preliminary hazard characterization process, and Appendix D.1 describes how preliminary hazard characterization is included in different resilience frameworks.

We observed a complete preliminary hazard characterization performed by SWEC and MREA. The Austin Energy, Unitil, and Niagara Mohawk resilience reports are a response to past winter storm events and do not contain a preliminary hazard characterization. Interviews with Unitil revealed climate scenario planning and physical risk assessments are performed for winter storms, hurricanes, and sea level rise. These hazards are prioritized in board meetings and informed by climate data and circuit performance. Additional hazards are being considered for future planning.

SWEC classifies all hazards that have impacted their service area in the past as historical hazards. These historical hazards include tornadoes, severe thunderstorms, high wind, hail, flood, levee failure, and severe winter weather. SWEC provides a detailed discussion and simulation results for these historical hazards (see Section 4 for additional detail). Nonhistorical hazards are hazards that have not occurred in the past; earthquakes, dam failure, wildfire, and sinkholes are classified as nonhistorical hazards. A generic damage factor is applied to all assets to account for these nonhistorical hazards.

MREA's preliminary hazard characterization is based on a survey conducted with 47 of the 51 cooperatives in the state. The survey identified flooding, windstorms, tornadoes, wildfires, and winter storms as the most impactful hazards, with the impacts of winter storms ranked as the most severe with the greatest frequency.

One relevant takeaway from utility interviews is there is a growing concern about the increasing frequency of extreme events and the adequacy of existing practices in representing this increase. Austin Energy noted as winter storms become more common, they increase the system average outage duration threshold required to be designated a MED. Non-MED metrics then increase because days that were previously considered MEDs are included in non-MED calculations.

3 Metrics

In this section, we summarize the attribute and performance metrics identified in these reports.

3.1 Attribute Metrics

We observed the use of attribute metrics by Niagara Mohawk and Austin Energy. Niagara Mohawk collects anticipate, withstand, and recover metrics. For example, the metric "road access [to power lines and other assets]" allows Niagara Mohawk to better coordinate restoration. These metrics are summarized in Table 3.

Attribute metrics were not identified in SWEC's report. Fewer metrics were identified for winter storm resilience plans than were identified for the other hazard reports in this series (wildfires and nonwinter storms). Low attribute metric coverage may prevent utilities from identifying cost-effective solutions for winter storm resilience investments. For example, Unitil writes about the challenge of tracking the performance of its Storm Resilience Program (SRP) without granular information about outage cause: "Without data showing locations of tree-related trouble, an outage affecting a large amount of customers Pre-SRP could be related to numerous cases of tree damage, and that same outage Post-SRP could be related to only one case of tree damage." In all interviews, utility representatives stated IEEE 1782,[9] the standard for reporting outage causes, is used.

Table 3. Attribute metrics identified in the utility reports. Metrics with an asterisk (*) are both performance and attribute metrics.

Utility	Attribute Metrics	Resilience Category
Austin Energy	Outage tiers: Large groups, medium groups, small groups, or single; this describes the number of customers impacted by an outage*	Absorb/Recover
Unitil	Snow loading of vegetation	Anticipate
	Ice accretion on trees and conductors	Anticipate
	Leaf-off and leaf-on days; leaf-on days result in a greater likelihood of branches breaking	Anticipate
	Snow and ice-loading characteristics by tree species	Anticipate
	Tree-species-specific outages	Anticipate
	Regrowth rate of vegetation	Anticipate
	Forest mortality rate	Anticipate
	Volumetric measures of vegetation in different clearance zones (cubic feet removed)	Anticipate
	Circuit criticality based on customers served and critical loads	Anticipate/Absorb

[9] IEEE Std 1782-2022 (Revision of IEEE Std 1782-2014) IEEE Guide for Collecting, Categorizing, and Utilizing Information Related to Electric Power Distribution Interruption Events.

	Tree pest infestation with species-specific targets	Anticipate/Withstand
	SRP/non-SRP and storm/non-storm circuit customer minutes interrupted (CMI)*	Anticipate/Withstand
	SRP/non-SRP and storm/non-storm circuit system average interruption duration index (SAIDI)*	Anticipate/Withstand
	SRP/non-SRP and storm/non-storm circuit system average interruption frequency index (SAIFI)*	Anticipate/Withstand
	SRP/non-SRP and storm/non-storm circuit customer average interruption duration index (CAIDI)*	Anticipate/Withstand
	Tree-related events per mile*	Anticipate/Withstand
SWEC	Not listed in publicly available documents	N/A
MREA	Percent of system overhead	Anticipate/Withstand
	Age and condition of power line	Anticipate /Withstand
	Population affected by targeted undergrounding	Anticipate/Withstand
Niagara Mohawk Power Corp.	Deteriorated assets (i.e., asset age)	Anticipate
	Hazardous vegetation	Anticipate
	Probability of substation flooding	Anticipate
	Bad pole codes: includes damaged conductors, insulators, pole materials, and assets with deteriorated or missing elements (e.g., bonding, grounding, lightning arresters)	Withstand/Absorb
	Number of faults	Withstand
	Road access	Recover

3.2 Performance Metrics

The performance metrics calculated during a storm response are identified and presented in Table 4. Notably, Unitil reports trends in its MED restoration time, cost, and number of line crews deployed in the field to show the effectiveness of its SRP. However, the Unitil report states it is "difficult to prove what might have happened had the company not undertaken the Storm Resilience Program" and attributes a less-than-expected reduction in outages following the SRP to a "lack of data being collected during storm events, and lack of opportunity to collect the data." SWEC did not report any performance metrics. An absence of hazard-specific performance metrics will make it difficult to track the effectiveness of resilience investments.

Utility interviews point to the need for performance metrics that can capture generation shortfall and load shedding. For example, regarding its response time metric in Table 4, Austin Energy representatives noted T_{MED}[10] values are changing in large part because of generation-level events rather than transmission and distribution events (i.e., not just typical MED outages). According to Austin Energy, traditional reliability metrics such as SAIDI, SAIFI, CAIDI, momentary average interruption frequency index (MAIFI), and customers experiencing multiple interruptions (CEMI) are not applicable to generation-level outages such as those experienced during Winter Storm Uri. In such scenarios, bulk power system constraints dictate distribution system outages. Because Austin Energy was dependent on ERCOT during Uri, it could not estimate restoration timelines for customers.

[10] T_{MED} is defined in IEEE 1366 and is calculated with the following formula: $T_{MED} = e^{(\alpha + k\beta)}$ where α is the average of the logarithms of daily SAIDI values, β is the standard deviation, and k is 2.5, a multiplier selected so the expected number of MEDs is 2.3 per year.

Table 4. Performance metrics identified in the utility reports. Metrics with an asterisk (*) are both performance and attribute metrics.

Utility	Performance Metrics
Austin Energy	Response time
	Outage tiers: large groups, medium groups, small groups, or single; this describes the number of customers impacted by an outage*
Unitil	MED restoration times
	MED restoration cost
	MED restoration number of line crews
	Non-MED outages per circuit per year
	Non-MED outages per mile per year
	Non-MED average customer minutes of interruptions per year
	Non-MED average customer minutes of interruptions per year per mile
	SRP/non-SRP and storm/non-storm circuit CMI*
	SRP/non-SRP and storm/non-storm circuit SAIDI*
	SRP/non-SRP and storm/non-storm circuit SAIFI*
	SRP/non-SRP and storm/non-storm circuit CAIDI*
	Customer calls
	Outage and work location
	CMI per event
	Events per mile
	Tree-related events per mile*
	Internal and external cost savings
SWEC	Not listed in publicly available documents
MREA	Outage duration
	Duration required to access and repair failed equipment
Niagara Mohawk Power Corp.	SAIFI (used for evaluation of additional fuses to isolated smaller areas when faults occur and for evaluation of additional recloser installations)
	Customers interrupted
	Customer minutes interrupted (CMI)
	Number of extended-duration interruptions
	Restoration time

4 Threat Risk Analysis

In this section, we review the historical and simulated threat analyses used by the utilities. A clear definition of risk is important for performing threat risk analysis. However, in the reports we reviewed, we did not observe threat risk analysis that includes probability, vulnerability, and consequence, as defined in Appendix C.3. We also did not identify the use of any threat risk assessment standards or frameworks (e.g., ISO-31000). See Appendix D.3 for more information on resilience frameworks. All utilities reviewed in this report use specific weather event data or historical data to inform their investment plans and do not include a forward-looking analysis.

4.1 Historical Analysis

Most of the utility resilience reports and historical analyses we reviewed are a response to recent winter storm events, with the exceptions of SWEC and MREA.

Austin Energy's report examines the consequences of Winter Storm Uri and documents 19 observations about system performance and customer impact for critical consideration to improve future resilience. Staff accounts are used to support these observations. These observations are each addressed directly with specific investments to improve system resilience (listed in Table 5 in the next section).

SWEC's service area uses data reports from National Oceanic and Atmospheric Administration (NOAA) and National Centers for Environmental Information (NCEI) to estimate an expected 1.8 winter weather events per year. MREA uses survey data from participating cooperatives to estimate the probability of winter hazard. MREA predicts one ice or snowstorm on average and one major blizzard per year. SWEC also predicts a 12% probability severe winter weather will result in damage to assets in its service territory. This prediction is based on data from 1997–2016 winter weather events, but no analysis is done to identify the specific consequences of these events. MREA does not perform a specific vulnerability or consequence analysis; however, 68% of the 2023 survey participants responded winter storms posed the highest potential to impact their service territory. Unitil's SRP was initiated following major storm events of 2011. The threat risk analysis presented in the 2019 report attributes a downward trend in restoration costs and crew deployment numbers on major event days to this SRP. Unitil's 2020 report uses light detection and ranging (LiDAR) data to correlate outages to vegetation conditions before and after SRP efforts. Niagara Mohawk performs threat risk analysis to determine flood risk, but analysis for threats specific to winter weather were not addressed in this report.

4.2 Forward-Looking Analysis

Forward-looking threat risk analysis that accounts for changing grid or weather conditions in the future was not observed in the resilience reports we reviewed, but utility interviews revealed such analyses are present in some resilience programs of the utilities surveyed. Some perform risk evaluation to understand system performance with the inclusion of new investments. Other examples of forward-looking threat risk analysis are available in the Distribution Utility Resilience Planning reports for wildfires and for hurricanes and nonwinter storms. Utility interviews also revealed a gap in the availability of forward-looking analysis tools for severe winter storms. Neither commercially available nor open-source tools (such as those identified to analyze wildfire risk) were identified in the literature or in discussions with utility representatives. Many interviews emphasized changing winter storm conditions that can impact power system performance, such as warmer temperatures resulting in heavier, wetter snow or ice accretion because of an increased presence of moisture in areas that used to be drier. Forward-looking simulation is needed to capture such phenomena that was uncommon in the past but will be more frequent in the future.

5 Investments

Utilities categorize their investments in different ways; these investments generally fit into the categories listed in Table 7 in Appendix C.4, Investments. These are the specific actions and infrastructure investments the utility can make to improve system resilience. We categorize these investments as vegetation management, overhead hardening, undergrounding, network redundancy, nonelectric grid infrastructure, grid modernization, forward-looking analysis, advanced resource planning, and operations.

Specific storm-related resilience investments cited by the utility winter storm resilience reports are listed in Table 5. This table can also be used to determine which investment categories are most common. For example, all reviewed utilities use vegetation management, and most utilities focus efforts on overhead hardening. Austin Energy is the only utility reviewed with investments covering all categories identified. No standards guiding investments were identified in the documents reviewed. Niagara Mohawk incorporates external design standards (from North American Electric Reliability Council [NERC] and National Electrical Safety Code [NESC]) for transmission assets but internally define standards for the distribution system. All these standards are used to harden their assets.

Table 5. Resilience investments made, considered, or proposed by utilities reviewed and their corresponding investment categories.

Utility	Investment	Category
Austin Energy	Greater clearances between trees and wires.	Vegetation Management
	Emergency tree pruning to remove damaged vegetation.	Vegetation Management
	Breaker refurbishment and maintenance improvements.	Overhead Hardening
	Anti-galloping devices.	Overhead Hardening
	Doubling the number of circuits to increase load-shedding resources and improve outage rotation capabilities. This better isolates critical loads that cannot be load shed, increasing noncritical loads that can be shed. If the load available for emergency load shedding is greater than the amount dispatched, customers can be rotated and outage time shared across a population.	Network Redundancy
	Emergency management system (EMS)/supervisory control and data acquisition (SCADA) system load-shed application.	Grid Modernization
	Advanced Distribution Management System (ADMS) Field Client (a web-based app that field personnel can use to access ADMS).	Grid Modernization

	Increased automation by integrating ADMS and advanced metering infrastructure (AMI) head end.	Grid Modernization
	Automatic switching to backup circuits serving critical infrastructure.	Grid Modernization
	AMI targeted load shedding.	Grid Modernization
	AMI meter polling to identify outages.	Grid Modernization
	Resilience hubs (in collaboration with other city departments).	Grid Modernization
	Backup and portable generators.	Advanced Resource Planning
	Commercial and industrial load curtailment.	Operations
	Reclosers and alternative relay settings to mitigate cold load pickup.	Operations
	Improvements to Austin Energy's Outage Map.[11]	Operations
	Wellness checks performed for customers in Austin Energy's medically vulnerable registry.	Operations
	Resilient communications to customers for information about warming centers and outages.	Operations
Unitil	Criticality-based vegetation management with ground-to-sky clearance.	Vegetation Management
	Engagement/outreach for permitting: tree councils, town meetings and planning boards, tree wardens, concerned citizens, state land management (U.S. Department of Transportation; state parks), and resulting coordination of wood waste management.	Vegetation Management
	Customer education on tree maintenance.	Vegetation Management
	Tree maintenance to promote tree health.	Vegetation Management
	Workforce development and retention program.	Vegetation Management
	Tree growth regulation (herbicide application).	Vegetation Management
	Species-specific pruning and maintenance.	Vegetation Management
	LiDAR data to assess vegetation trimming conditions.	Vegetation Management/Grid Modernization
	Dashboard for vegetation management.	Vegetation Management/Grid Modernization

[11] "Austin Energy Outage Map," accessed May 14, 2024, https://outagemap.austinenergy.com/.

	Circuit ties on radial circuits for increased switching operations.	Operations/Network Redundancy
	Upgraded voltage of 4-kV circuits.	Overhead Hardening
SWEC	Ecologically neutral herbicides.	Vegetation Management
	Enforce and expand right of way.	Vegetation Management
	Looped feeders to supply critical infrastructure.	Network Redundancy
	Elevated or underground interstate or major highway crossings spans.	Overhead Hardening/Undergrounding
	Large-gauge guy wires to improve structural support.	Overhead Hardening
	Replacement of damaged poles with higher-rated poles.	Overhead Hardening
	Coordination with local emergency management.	Operations
	Geographic information system (GIS) technology to identify failures and reduce outage response time.	Grid Modernization
	Improved communications for outage events.	Grid Modernization
	Improved management systems for outage data and damages directly related to natural hazards.	Grid Modernization
MREA	Convert overhead lines to underground lines in areas that have been subjected to repetitive damage.	Undergrounding
	Increased recurring vegetation management planning and operations.	Vegetation Management
	Hazard identification, mapping, and related activities for the implementation of targeted mitigation.	Grid Modernization
	GIS software, hardware, and data for mitigation.	Grid Modernization
	Update SCADA system in distribution substations to allow transfer of data to field crews in addition to dispatchers in the offices.	Grid Modernization
	Fault location isolation and service restoration (FLISR).	Grid Modernization
	Installation of electronic sectionalizing devices.	Grid Modernization
	Incorporation of SCADA with sectionalizing devices.	Grid Modernization
	Load reduction strategies.	Grid Modernization
	Looped communications.	Grid Modernization

	Remote facility control.	Grid Modernization
	Installing distributed energy resources (DERs).	Grid Modernization
	Load reduction strategies.	Grid Modernization
	Adding electrical loop feeds.	Network Redundancy
	Designing overhead power lines with shorter spans.	Overhead Hardening
	Breakaway conductors.	Overhead Hardening
	Improved guys/anchors.	Overhead Hardening
	Using fiberglass, steel, or composite material for structures.	Overhead Hardening
	Using larger-diameter power poles.	Overhead Hardening
	Using specialized overhead conductor.	Overhead Hardening
Niagara Mohawk Power Corp.	Tree-resistant conductors.	Vegetation Management
	Class 5 pole replacement with stronger Class 3 poles.	Overhead Hardening
	Grade B construction for hardening more locations.	Overhead Hardening
	Enhanced lightning protection to improve feeder performance.	Overhead Hardening
	Backup generation.	Network Redundancy
	Updated substation site planning to incorporate flood mitigation.	Advanced Resource Planning
	Participation in Edison Electric Institute Spare Transformer Equipment Program.	Advanced Resource Planning
	FLISR—automated switches and remote control to minimize interruptions.	Grid Modernization
	Increased storage.	Grid Modernization
	Subtransmission automation.	Grid Modernization
	Line sensors for real-time data.	Grid Modernization
	Remote terminal units (RTUs)/emergency management system (EMS).	Grid Modernization/Operations
	Increased operational awareness.	Operations
	Reclosers.	Operations

6 Investment Prioritization

The investments listed in Table 5 represent some of the possible investments a utility can make to improve winter storm resilience. How utilities select investments varies; considerations found in the reviewed documents include risk reduction, utility worker safety, cost, community input, and other multi-objective considerations.

SWEC performs a qualitative cost-benefit analysis (CBA) for all investment options. Its analysis is based on experience performing certain actions and the potential number of beneficiaries. Investment decisions are based on criteria with considerations for STAPLEE factors. MREA recognizes priority rankings as a planning tool that will be particular to each electric cooperative with cost estimates for different investment solutions but does not provide details on the ranking process. MREA recommends cooperatives identify lists of pre-hazard mitigation projects for FEMA, including CBAs for each project, that would address common natural hazards affecting the grid. Unitil estimates the value of avoided CMI because of its SRP and calculates avoided costs of $1.02M (direct internal) with the Interruption Cost Estimate calculator. Similar analyses were performed for undergrounding, circuit ties, and grid modernization efforts; vegetation management was the most cost-effective and therefore the focus of the SRP. Austin Energy and Niagara Mohawk do not mention an investment prioritization process in their resilience reports.

In general, fewer investment prioritization processes were identified for winter storms than for other hazards. We observed many winter storm resilience reports are a reaction to recent events, which may also be leading to reactive investment processes.

7 Conclusion

This report analyzes the winter storm resilience of several utilities according to the resilience components shown in Table 1. Key takeaways are listed in Section 1.2. The utilities we reviewed varied widely in the investments made and approach to winter weather resilience, but there are opportunities for improvement for all utilities. Preliminary hazard characterizations are not consistent but could be key to anticipating the impacts of these events. Standardized, comprehensive data collection covering each aspect of resilience (i.e., anticipate, withstand, absorb, and recover) can support the creation of attribute and performance metrics that inform historical and forward-looking risk threat analysis. No forward-looking analyses were identified; utilities could benefit from standardized risk analysis approaches and off-the-shelf tools to support threat risk analyses. Finally, planning can benefit from a multi-objective approach that incorporates resilience to credible hazards to inform investment decisions.

Appendix A. Utility Sources

Our literature reviews focused on one document per utility; we relied on utility interviews to provide additional context and available resources. Many utilities do not share all relevant information in public-facing documents.

Table 6. Selected utilities, sources, and resilience report context.

Utility	Source and Document Context
Austin Energy	*February 2021 Winter Storms: After-Action Report* details the investments and actions taken to improve the Austin Energy system after Winter Storm Uri. This report is motivated by the winter storms from February 11 to 20, 2021, during which 220,000 customers' service was interrupted. Austin Energy representatives were interviewed, and feedback was included.
Niagara Mohawk Power Corporation	Niagara Mohawk's *Storm Hardening and Resilience Plan* details hardening measures including a budget, timeline, and major performance benchmarks to bolster resilience against winter and spring storms. Filed in July 2019, this plan responds to Recommendation No. 88 detailed in the New York Department of Public Service's (DPS's) April 2019 Storms Investigation Report. DPS cited a "slow and inadequate response" of some electric utilities to these storms, triggering an investigation of major New York utilities. Niagara Mohawk—a subsidiary of National Grid—is one of several utilities investigated and ordered to submit a hardening and resilience plan to prepare for future storms.
Southwest Electric Cooperative	A statewide summary of mitigation plans was planned and adopted by the cooperative's governing officials.
Minnesota Rural Electric Association	Minnesota's Hazard Mitigation Plan was initiated by the Minnesota Division of Homeland Security and Emergency Management in the Rural Electric Cooperative Annex. The development of an electric cooperative annex to the State of Minnesota Hazard Mitigation is in response to the passage of the Disaster Mitigation Act of 2000. Because of the annex, rural electric cooperatives can be covered under the State All-Hazard Mitigation Plan and be eligible for FEMA's Hazard Mitigation Assistance Program. MREA representatives were interviewed, and feedback was included.
Unitil	Hurricane Irene and an October snowstorm in 2011 caused widespread damage and outages and led to a storm resiliency pilot. In 2014, the pilot was turned into a full storm resiliency program. This report is a proposal to accelerate the 10-year program and complete it in 2020 (rather than 2021). In 2020, Unitil published a Storm Resiliency Program Analysis and Assessment report. This included a historical benefit analysis. Unitil representatives were interviewed, and feedback was included.

Appendix B. Expected Annual Loss Calculation for Utilities

B.1 Definition

Expected annual loss (EAL) total represents the average economic loss in dollars resulting from natural hazards each year. It is calculated for each hazard type and quantifies loss for the following consequence types: buildings, people, and agriculture.[12] The EAL data is from FEMA's National Risk Index (NRI) data resources.[13] The EAL data correspond to specific threats whereas a hazard type can consist of multiple threats, e.g., the threats associated with storms can include hail, strong winds, and flooding.

EAL spans a large range for all hazards reviewed in this series of reports. The average EAL of the service territories reviewed for winter storms is lower than that of wildfires and nonwinter storms, but the range of winter storm EALs is comparable to that of other wildfires and nonwinter storms. EAL is an indicator of the expected severity of hazards but does not reflect losses to utility assets or revenue.

Several limitations of EAL restrict this metric's ability to capture risk:

- Loss data from 1996 to 2019 are used to calculate EAL. For many hazards, this dataset does not capture the range of values that has been seen historically. For example, the fire regime of certain areas, such as those west of the Cascades, exceeds this time frame.
- EAL is limited to buildings, people, and agriculture. The value of those included elements is restricted to property and statistical life, excluding many environmental, social, and cultural impacts.
- More precise and accurate hazard modeling can be performed for smaller geographic scales. This can include higher flame length resolution, dead fuel accumulation for wildfires, and the incorporation of predictive weather and climate models.

[12] Federal Emergency Management Agency. (n.d.) Expected Annual Loss. Retrieved 11 July 2023 from https://hazards.fema.gov/nri/expected-annual-loss.
[13] Zuzak, C., E. Goodenough, C. Stanton, M. Mowrer, A. Sheehan, B. Roberts, P. McGuire, and J. Rozelle. 2023. National Risk Index Technical Documentation. [NRI Shapefile Census Tracts Data] Federal Emergency Management Agency, Washington, D.C. Retrieved 9 June 2023 from https://hazards.fema.gov/nri/data-resources#shpDownload.

B.2 EAL Calculation by Census Tracts

Census tracts are small, relatively permanent subdivisions of counties or other similar entities. They are designed to be relatively homogenous with respect to population characteristics, economic status, and living conditions.[14] Accordingly, each consequence type should be relatively uniform across a census tract. Thus, it is reasonable to assume EAL is distributed uniformly across a census tract for ease of calculation.

The calculation of EAL total for a specific hazard type for utilities is described in two steps:

1. For each census tract, the census tract EAL total is calculated. Census tract EAL total is the sum of EAL total for each threat included in the hazard type.
2. For each utility, the EAL total is the sum of a proportion of the hazard type EAL total for each census tract intersection with the utility's service territory. The proportion is a spatial proportion calculated by

$$Service\ Territory\ EAL = \sum_{\substack{\forall\ hazard\ (h),\\ \forall\ census\ tract(ct)}} \left(\frac{area_{st} \cap area_{ct}}{area_{ct}}\right) \times EAL_{ct,h} \qquad \text{Equation 1}$$

where *st* denotes a utility's service territory.

[14] U.S. Census Bureau. (1994, November). Geographic Areas Reference Manual, Chapter 10: Census tracts and block numbering areas. Retrieved 11 July 2023 from https://www2.census.gov/geo/pdfs/reference/GARM/Ch10GARM.pdf.

Appendix C. Distribution Resilience Framework Components

Utility investments and investment prioritization for several use cases (wildfires, winter storms, and nonwinter storms and hurricanes) are evaluated according to common components found in resilience frameworks. Here we define the different components of the framework that will be applied to each hazard case.

C.1 Preliminary Hazard Characterization

Preliminary hazard characterization is a process used by utilities to determine the relative risk of different hazards and where to focus resilience investments. Because there are many hazards, this preliminary hazard characterization tends to be qualitative and based on engineering judgment more than detailed analysis. It is a hypothesis-driven scoping exercise designed to inform utilities where more detailed analysis is needed, which is ideally performed with the *Threat Risk Analysis* defined in Appendix C.3. For some utilities, the preliminary hazard characterization is directly related to threat risk analysis, and there may not be a clear distinction between these processes. A typical outcome of a preliminary hazard characterization is a categorical label for the risk level associated with different hazards. For example, a utility might perform a climate change risk assessment and determine rising temperatures carry a “low risk” and increased flooding carries a “high risk.” This assessment may lead to a detailed *Threat Risk Analysis* and *Investment Prioritization* to determine cost-effective options for managing flooding.

C.2 Metric Stack

Attribute Metrics

Attribute metrics help characterize systems and describe the ability of utilities to anticipate, absorb, withstand, and recover from hazards. Attribute metrics can provide utilities with options to improve their performance metrics. Examples of attribute metrics include the following:

- Percent undergrounded lines
- Right-of-way width (vegetation)
- Asset failure probability

These resilience capabilities (anticipating, absorbing, withstanding, and recovering from hazards) are further defined as follows:

- **Anticipation** describes the likelihood or nature of an impact because of a hazard. Anticipation metrics can be used to identify improvements in all resilience phases, including the ability to withstand, absorb, and recover more effectively—for example, asset ignition probability. Anticipation metrics are sometimes referred to as “driver metrics.”
- **Withstand** describes a system’s ability to avoid impact from a hazard altogether. An example is the percentage of undergrounded lines, which can describe the ability of the lines to withstand strong winds.

- **Absorb** describes the strategic acceptance of hazard impacts. Resilience hubs are one example of an investment that helps utilities absorb threats. Resilience hubs may not support normal system operations during a hazard, but they reduce the consequence of the damage incurred by those impacted.
- **Recover** is defined by the phase immediately following a disruptive event. Investments to improve the rate of recovery can be described by attribute metrics such as crew repair time.

The impact of investments to do each of these things is shown in Figure 1. It should be noted some investments may fall into multiple categories.

Performance Metrics

Performance metrics track a utility's progress toward improvements in its core objectives (e.g., affordability, safety, reliability, resilience, equity). Examples of performance metrics include the following:

- Restoration time
- Crew repair time
- Total number of customers deenergized

Comparing Attribute and Performance Metrics

Some metrics can be described as both attribute and performance metrics. For example, restoration time could be used by regulators to track utility performance during major storms, but it could also be used to describe the system a utility has in place to restore power. If the restoration time is subdivided into different restoration phases (e.g., determining outage locations, travel time, repairs), utilities would have further actionable information about where to invest and how to reduce overall restoration time.

Performance metrics are more widely used than attribute metrics because they can help utilities and regulators understand if they are meeting their core objectives. However, a shortcoming of performance metrics is that they do not necessarily tell utilities *how* to make improvements. Because attribute metrics characterize systems, they are typically more helpful at determining a set of options for improving performance. Historical and forward-looking threat risk analysis can be used to draw inferences between improvements in attribute metrics through investments and improvements in performance metrics.

C.3 Threat Risk Analysis

Threat risk analysis is the processes utilities use to identify exposure to threats, including whether their entire territory is exposed to a threat or if there are specific areas that can see a greater impact. There are two categories of analysis: historical analysis and simulations. Historical data can be inputs to simulations.

An example of historical analysis occurred during Superstorm Sandy. Questions included which substations were impacted, what was the water level, and what was the extent of the damage because of salt water.

An example of simulation occurs during floods—if flooding occurs because of inland precipitation, a simulation can identify which areas will be flooded and what the water level would be.

Historical analysis and forward-looking simulations have different strengths. Historical analysis is based on historical data and impacts, so it offers compelling evidence for making investments. Forward-looking simulations are more speculative, but they provide a broader risk assessment and can account for changing conditions (e.g., climate change) that may not be captured with historical data.

A threat risk analysis examines the components of the risk equation, defined in Equation 2. A threat risk analysis identifies major threat factors and the likelihood of their impact for a particular hazard. A threat risk analysis can characterize the current state of the grid or identify how a component of the risk equation can be manipulated to minimize the risk with potential investments.

$$Risk\ =\ Probability\ x\ Vulnerability\ x\ Consequence \qquad \text{Equation 2}$$

The components of the risk equation and examples of how a threat risk analysis might be applied to each are as follows:

- **Probability** is the likelihood of the occurrence of a hazard. An example of an investment to mitigate risk through reducing probability is reducing recloser shots or using PSPS to minimize the probability of ignition.
- **A vulnerability** in a system has a high likelihood of failure in the event of a hazard. An example of an investment to mitigate risk through reducing vulnerability is undergrounding lines so they cannot be damaged by wind.
- **Consequence** is the impact resulting from a hazard and can include physical impacts such as damage to assets or outages, economic impacts from loss of service or restoration costs, or social impacts from outages or system damages. Social impacts can be validated and informed through community engagement. An example of an investment to mitigate risk through reducing consequence is the use of distribution automation to reroute power to customers during outages on other distribution network assets.

Threat risk models can use the performance metrics identified in Appendix C.2, which can quantify the outputs of the threat risk analyses and therefore the impact of possible resilience investments. Threat risk analyses consider the change in risk because of investments that mitigate hazards.

C.4 Investments

These are the specific actions and infrastructure the utility can focus on to improve system resilience. Depending on the hazard, these investments could target various levels of utility infrastructure and community support (Table 7).

Table 7. Utility investment categories and examples of investments that fall into each category.

Category	Examples
Vegetation	Targeted vegetation management Widening right-of-way for lines
Overhead Hardening	Pole materials (e.g., steel poles) Fire wrapping poles
Undergrounding	Targeted undergrounding
Network Redundancy	Split network Adding primary feeder loops within and between networks Ties between exposed substations Ties between exposed distribution networks Additional distribution substations
Nonelectric Grid Physical Infrastructure	Floodwalls at substations Debris booms near fire damaged area More frequent equipment maintenance to mitigate increased equipment wear
Grid Modernization	DER and nonwires alternatives AMI for targeted load shedding Microgrid formation Automated switching operations Energy storage, on-site generation Resilience hubs
Forward-Looking Analysis	Stochastic event analysis Hazard modeling and analysis Debris flow exposure projections Coastal storm exposure projections
Advanced Resource Planning	Mutual aid assistance Resilient supply chains
Operations	Training and threat response Emergency drills

C.5 Investment Prioritization

This includes any process to examine the impact of an investment and possibly its cost. Investments can be prioritized by cost, risk reduction, other benefits, or some combination of these investment impacts. Prioritization can be done with the sole objective of hardening a system against a specific threat or can be a part of a multi-objective framework. An investment that supports multiple objectives might support both resilience and other system objectives, such as clean energy or grid equity. In all cases, investment decisions can be informed through stakeholder engagement such as community outreach to evaluate the potential impact of such investments on community well-being.

Appendix D. Distribution Utility Resilience Frameworks

In this section, we review existing resilience frameworks that can be applied to distribution utility resilience planning. These resilience frameworks are ISO 31000,[15] the bowtie method,[16] California's Risk Assessment and Mitigation Phase (RAMP)[17] Avista's "Wildfire Resilience Framework,"[18] Sandia's "Conceptual Framework for Developing Resilience Metrics,"[19] the Western Coalition's "West-Wide Wildfire Risk Assessment" framework,[20] FEMA's "Local Mitigation Planning Handbook[21] and Pacific Northwest National Laboratory's (PNNL's) "Integrated Resilience Distribution Planning" report.[22] Although not described as a framework, we also include EPRI's "Distribution Grid Resiliency" reports[23] and LBNL's utility case studies on economic impacts from damage to infrastructure during extreme events[24]. Several of these resilience frameworks are shown in Figure 3 through Figure 7. This section is not intended as a critique of these frameworks or to inform the development of a new framework. Rather, these frameworks were reviewed to identify similarities and resilience planning components that enable comparisons among utilities. In contrast to the resilience frameworks in Figure 3 through Figure 7, we do not focus on workflow, which can provide utilities with valuable insight such as the iterative nature of resilience planning. We next review the selected resilience components.

D.1 Preliminary Hazard Characterization

The first comparison component is preliminary hazard characterization. This component is useful for utilities that do not yet know which hazards have the greatest risk in their service territory. For example, utilities trying to understand the risks of climate change often perform a preliminary hazard characterization to assess heat waves, precipitation, extreme weather, and other climate change risks. This component may also be useful for utilities that may have a sense of which hazards have a high probability of occurrence in their territory but do not know which of their assets is vulnerable to these hazards. For example, a utility may face an increased risk of flooding but may need to identify which of its assets is subject to corrosion from salt water. Two utility examples of preliminary hazard characterization are provided by

[15] https://onlinelibrary.wiley.com/doi/10.1111/j.1539-6924.2010.01442.x
[16] For the history of this method, see https://en.wikipedia.org/wiki/Bow-tie_diagram
[17] https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/risk-assessment-mitigation-phase/sce-ramp/sce-2022-ramp
[18] https://www.myavista.com/-/media/myavista/content-documents/safety/2023-wildfire-resiliency-report_011923_final.pdf
[19] https://www.energy.gov/oe/articles/conceptual-framework-developing-resilience-metrics-electricity-oil-and-gas-sectors
[20] https://www.thewflc.org/sites/default/files/WWA_FinalReport_3-6-2016-1.pdf
[21] https://www.fema.gov/sites/default/files/2020-06/fema-local-mitigation-planning-handbook_03-2013.pdf
[22] https://gridarchitecture.pnnl.gov/media/advanced/Integrated_Resilient_Distibution_Planning.pdf
[23] https://eprijournal.com/making-distribution-grids-stronger-more-resilient/
[24] https://emp.lbl.gov/publications/case-studies-economic-impacts-power

Southern California Edison's (SCE) Climate Adaptation Vulnerability Assessment reports[25] (Figure 3) and Duke Energy's 2022 interim report on climate risk and resilience. Duke determines asset vulnerability from exposure to hazards, sensitivity of assets to that exposure, impact from events, and consequences associated with those impacts. This vulnerability then informs resilience planning.

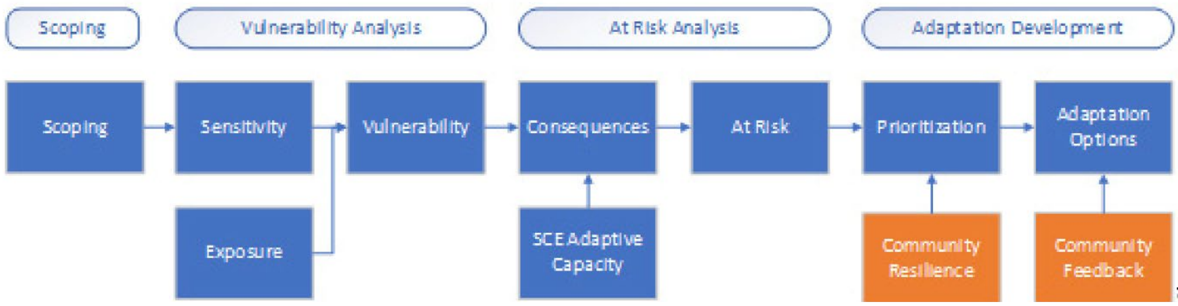

Figure 3. SCE Climate Adaptation Vulnerability Assessment, a preliminary hazard characterization framework.

Southern California Edison Company (SCE). 2022. Climate Change Vulnerability Assessment Pursuant to Decision 20-08-046. Rosemead, CA: SCE.
https://edisonintl.sharepoint.com/:b:/t/Public/TM2/EY7Wy9MCrcVGl7XKg_tczQoBM0k8RKtJhwvWlf6qxlJvbg?e=ptXS0i

We observe preliminary hazard characterization in several of the resilience frameworks. In ISO 31000:2009 (Figure 5), it is described as "Establishing the context" and "Risk Identification." In SCE's bowtie implementation, it is described as "Exposure." Sandia (Figure 5) has phases for "Defining Resilience Goals" and "Characterizing Threats." Task 5 of FEMA's Local Mitigation Planning Handbook is to perform a risk assessment, which includes the hazard identification worksheet.

[25] https://www.sce.com/about-us/environment/climate-adaptation

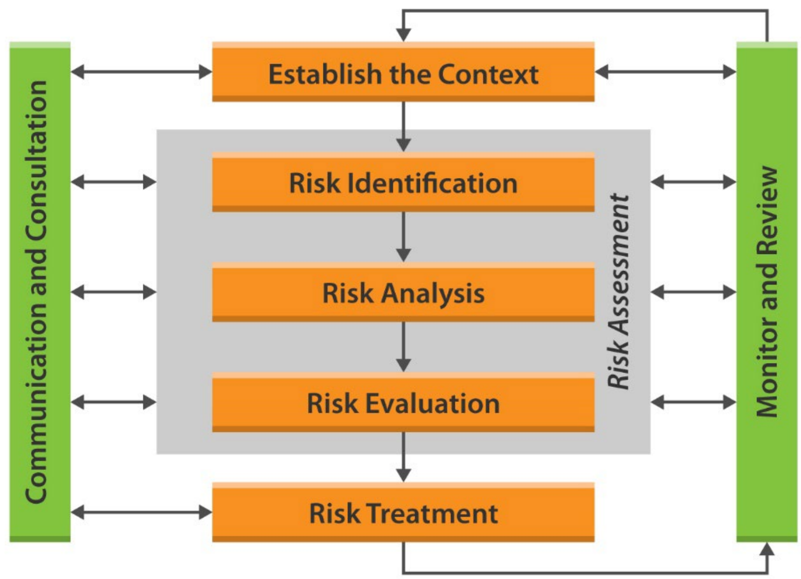

Figure 4. Adapted from ISO 31000:2009 Risk Management Framework.

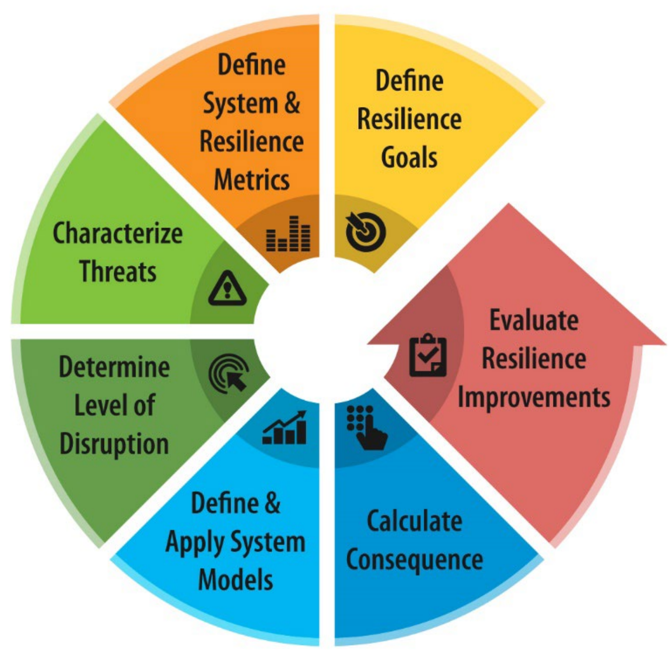

Figure 5. Adapted from Sandia's Resilience Framework.

D.2 Attribute and Performance Metrics

The second comparison component is the use of attribute and performance metrics. Attribute metrics help characterize systems and describe the ability of utilities to anticipate, absorb, withstand, and recover from hazards. Attribute metrics can provide utilities with options to improve their performance metrics, which track a utility's progress toward improvements in its core objectives (e.g., affordability, safety, reliability, resilience, equity).

Attribute and performance metrics are less common in the resilience frameworks that we reviewed. Metrics are not mentioned in ISO 31000:2009. Though utilities must collect environmental data (e.g., surface fuels) for the "West-Wide Wildfire Risk Assessment" resilience framework (Figure 6), power system attribute metrics and performance are not part of the framework. In its Local Planning Mitigation Handbook, FEMA writes the "planning team may develop a list of metrics to evaluate progress toward goals on an annual basis" but does not elaborate on suitable metrics. In contrast, both attribute metrics and performance metrics are fundamental components of the SCE RAMP. SCE releases a yearly set of performance metrics and the driver metrics that are analogous to anticipation metrics. Avista describes metrics as important for "understanding the risk" of hazards but appears to focus on performance metrics. Metrics development is a fundamental component of the Sandia risk framework. Guidelines for performance metrics are provided, but attribute metrics are not mentioned. Without attribute metrics describing a system's ability to anticipate, withstand, and recover, engineers will have less insight into potential actions to improve performance metrics.

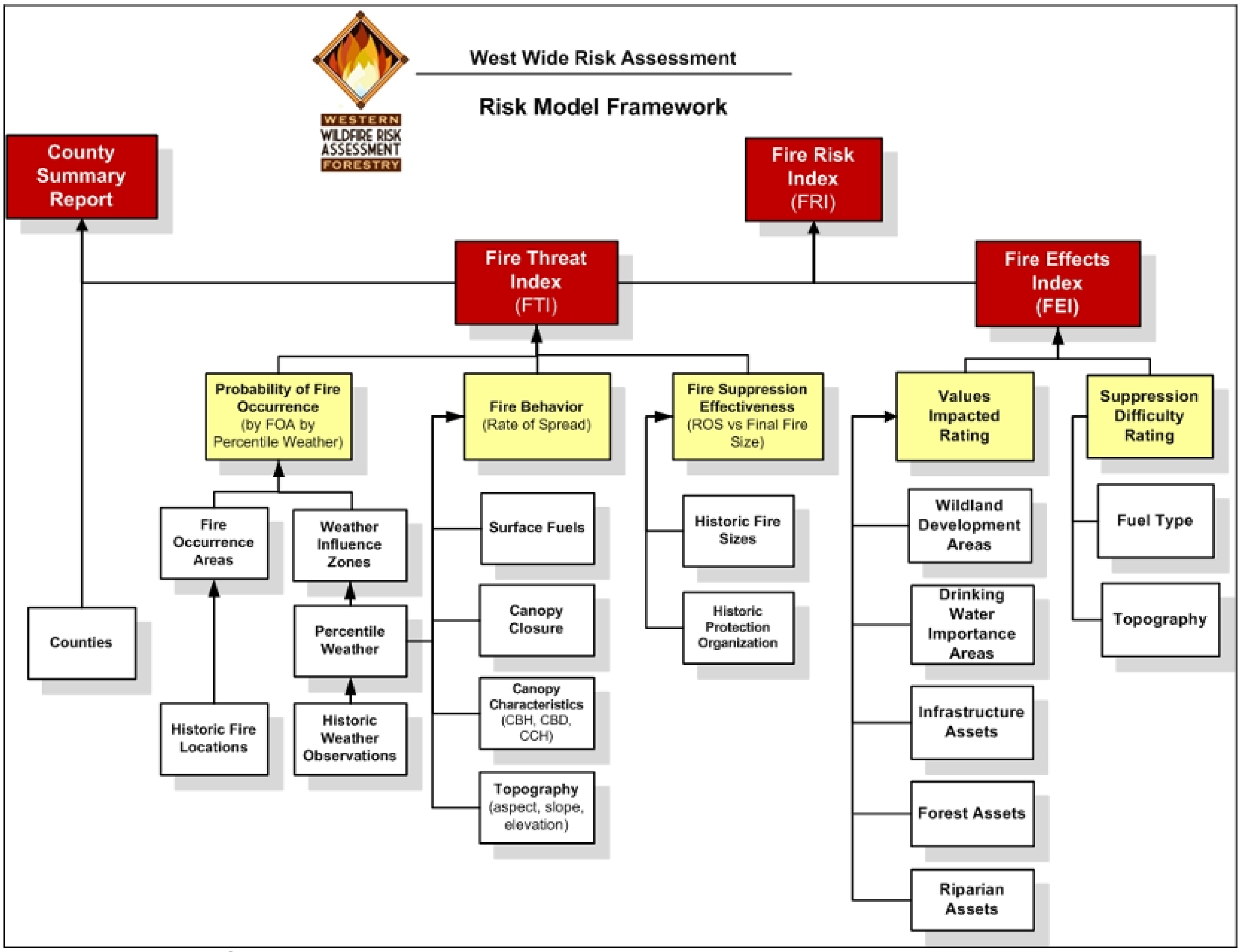

Figure 6. Western Coalition's "West-Wide Wildfire Risk Assessment" Framework.

Oregon Department of Forestry. 2013. West Wide Wildfire Risk Assessment: Final Report. State of Oregon, Department of Forestry.

https://www.thewflc.org/sites/default/files/WWA_FinalReport_3-6-2016-1.pdf

D.3 Threat Risk Analysis

The third component is threat risk analysis, which can be performed using historical data and simulations. This is analogous to the risk analysis and the application of system models described by ISO 31000:2009 and Sandia, respectively. Although threat risk analysis is not mentioned explicitly in the bowtie method, the SCE RAMP uses simulations extensively to predict wildfire risk. The Avista framework mentions “planning for the probability of events,” which could include historical and simulated analysis.

Few of the frameworks we reviewed make a clear distinction between historical and simulated analysis; we make this distinction because each approach has strengths. Historical analysis is grounded in utility experience, which can carry more weight during decision-making processes. In contrast, simulations enable forward-looking analysis, which is becoming more important as local weather and climate patterns change. One exception is FEMA. After making suggestions to describe hazards and identify community assets, FEMA recommends analyzing the risk of different hazards with historical analysis and using forward-looking scenario analysis where data do not exist, such as for low-frequency, high-consequence events.

To perform a threat risk analysis, a clear definition of risk is needed. We define this as the product of probability, vulnerability, and consequence (Equation 2). ISO 31000:2009 defines risk as “the effect of uncertainty on objectives.” This definition is appropriate for an industry-agnostic standard but may be too abstract for utility engineers. SCE, Avista, and FEMA consider all elements of risk but use different terminology. Probability and vulnerability are included in the driver metrics whereas financial, reliability, and safety consequences are considered. Avista defines risk as the product of probability and financial impacts; it also makes a distinction between inherent and managed risk, which is analogous to vulnerability in our risk definition. The West-Wide Wildfire Risk Assessment includes probability in its Fire Threat Index whereas vulnerability and consequence are captured by the Fire Effect Index. FEMA uses “extent” to describe the magnitude of a hazard, “previous occurrences” to estimate probability, “identification of community assets” (i.e., people, economy, built environment, natural environment) to estimate consequence, and “exposure” to describe vulnerability.

D.4 Investment Considerations

The fourth comparison component is the consideration of a variety of resilience investments. This component is not mentioned in the ISO 31000:2009, Avista, and bowtie resilience frameworks, but it is often included in resilience reports. The FEMA Local Mitigation Planning Handbook discusses mitigation options, but specific investments are not suggested and the handbook’s scope is not targeted for electric utilities. In its distribution grid resilience reports, EPRI covers various investment options extensively. These resilience investment options include overhead structures, vegetation management, undergrounding, modern grid technology, and storm response practices. We adopt several of these categories in Table 7.

D.5 Investment Prioritization

The fifth component is investment prioritization that 1) identifies cost-effective investments for minimizing risk or applies CBA, 2) is integrated into existing planning processes, and 3) considers multiple utility objectives. Investment prioritization is not mentioned by ISO

31000:2009, Avista, bowtie, Sandia, or the “West-Wide Wildfire Risk” frameworks. However, it is a fundamental component of the EPRI Distribution Grid Resilience report, the PNNL Integrated Resilience Distribution Planning report, SCE’s RAMP, FEMA’s Local Mitigation Planning Handbook, and Lawrence Berkeley National Laboratory’s (LBNL’s) case studies. The integration of resilience planning processes into existing planning processes and consideration of multiple objectives within a “cost-effectiveness” framework is also integral to the PNNL Integrated Resilience Distribution Planning report.

Although CBAs are an effective way to investment prioritization, they can be challenging to implement. LBNL examined the ability of seven utilities (Florida Power & Light, Con Ed, AEP Texas, CenterPoint Energy, SDG&E, Unitil Energy Systems, Inc. of New Hampshire, and BGE of Maryland) to prioritize resilience investments using CBA. Though most utilities can collect costs associated with extreme events, few estimate the economic and societal benefits of avoided outages. LBNL found CBAs were performed only in New York, Texas, and Maryland, but the benefits were based on short-duration outages and did not include long-duration outage costs. LBNL writes, “The case studies indicate a clear need to develop new estimates of avoided economic impacts of power interruptions on residential, commercial, and industrial customers as well as the broader economy.” CBAs can be challenging to conduct because of the lack of avoided cost estimates for long-duration outages and the difficulty of valuing some utility objectives (e.g., equity). In its Integrated Distribution Planning Framework, PNNL recommends a cost-effectiveness analysis that is based on stakeholder input to prioritize investments based on “value-spend” efficiency scores. All FEMA grants require FEMA-approved CBA and provide a CBA toolkit. FEMA also recognizes communities “face challenges with demonstrating cost-effectiveness of their projects”[26] and offers a variety of alternative CBA methods and “streamlined” methods for predefined investments.

[26] https://www.fema.gov/sites/default/files/documents/fema_alternative-cost-effectiveness-methodology-for-FY2022-BRIC-and-FMA.pdf

Background on GDO

The U.S. Department of Energy's Grid Deployment Office (GDO) works to provide electricity to everyone, everywhere by maintaining and investing in critical generation facilities to ensure resource adequacy and by improving and expanding transmission and distribution systems. Working in strong partnership with energy sector stakeholders on a variety of grid initiatives, GDO supports the resilience of our nation's electric system and deployment of transmission and distribution infrastructure. GDO's priority is to develop and deploy innovative grid modernization solutions to achieve the administration's clean energy goals and mitigate climate change impacts while ensuring the availability of clean, firm generation capacity, such as hydropower and nuclear energy.

GDO's work within the Transmission, Power Generation Assistance, and Grid Modernization Divisions will ensure all communities have access to reliable, affordable electricity by leveraging unique authorities to:

- Improve resource adequacy by maintaining and investing in critical generation facilities
- Support the development of nationally significant transmission lines
- Drive transmission investment

Background on National Renewable Energy Laboratory

The National Renewable Energy Laboratory (NREL) is the U.S. Department of Energy's primary national laboratory for renewable energy and energy efficiency research. From scientific discovery to accelerating market adoption, NREL deploys its deep technical expertise and unmatched breadth of capabilities to drive the transformation of our nation's energy resources and systems. NREL's innovations span the spectrum of clean energy, renewable electricity, and energy efficiency. The laboratory is home to three national research centers—for solar, wind, and bioenergy—and several programs that advance cutting-edge research in areas such as strategic energy analysis and energy systems integration. At NREL, we are transforming energy.

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