Guidance for Grid Resilience Decisions in Rural Minnesota

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List of Acronyms

CAIDI	Customer Average Interruption Duration Index
CELID	Customers Experiencing Long Interruption Duration
CEMI	Customers Experiencing Multiple Interruptions
EAGLE-I	Environment for Analysis of Geo-Located Energy Information
FEMA	Federal Emergency Management Agency
FLISR	fault location, isolation, and service restoration
IDP	integrated distribution plan
IOU	investor-owned utility
I(t)	cumulative impact
MED	major event day
MSHMP	Minnesota State Hazard Mitigation Plan
OMS	outage management systems
O(t)	outage process
RP3	Reliable Public Power Provider (American Public Power Association program)
R(t)	restoration process
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

Executive Summary

This work focuses on the resilience of the electrical distribution grid in rural areas of Minnesota, where major weather events frequently cause long-duration power outages. Resilience investment decisions can be informed by the specific infrastructure of a utility territory and the community it serves. In the case of rural utilities, these traits include geographically dispersed feeders, sparsely populated areas with few customers per mile of infrastructure, and a customer base that is sensitive to decreases in energy affordability. It is challenging to prioritize and implement resilience upgrades in these circumstances, especially when the per-customer costs of these upgrades and investments are high and their benefits are difficult to quantify.

This report proposes metrics to characterize the resilience performance of distribution systems and better reflect the benefits of resilience investments for customers. We analyze outage and distribution network data from seven rural cooperative utilities to study the relationship between grid attributes and impacts from major wind events, and to demonstrate the application of new performance metrics that can inform resilience investments. We present a set of 14 underutilized resilience metrics designed to characterize performance, including potential consequences, during a major event.

First, we measure outages and restorations separately over time to establish several benchmarks that characterize how a major disruption evolves. We then measure the difference between customers experiencing outages and customers restored over time to establish performance benchmarks that characterize the resilience of the distribution system. Finally, we measure the relative access to electricity-dependent critical services over time, based on the spatiotemporal distribution of outages, to characterize the consequences of major disruptions on customers. Each metric is plotted below for an outage in rural Minnesota caused by a windstorm on May 12, 2022 (Figure ES-1). These curves yield additional benchmark metrics that allow utilities to more specifically track improvements to processes that operate separately but together influence the impacts and consequences of outages: the number, rate, and duration of outages; the number, rate, and timing of restorations; and the spatial distribution of outages in relation to critical services.

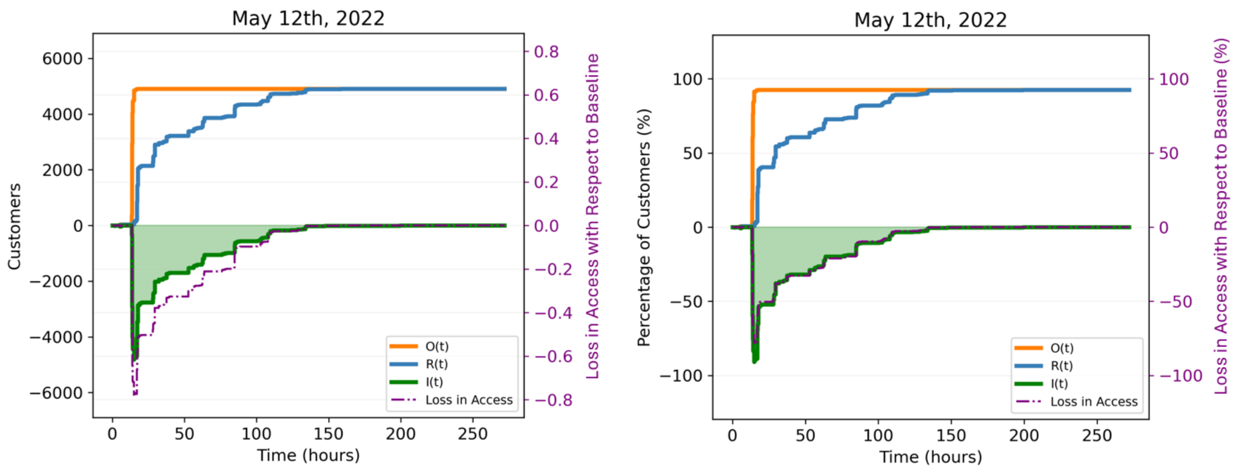

Figure ES-1. Outage process, O(t), restoration process, R(t), cumulative impact, I(t), and baseline access to services (purple) at each hour during a major wind-driven power outage in Utility A beginning on May 12, 2022. The lefthand plot shows all metrics in absolute values while the righthand plot shows them in values relative to baseline, or normal operating conditions.

Our analyses reveal several takeaways for strategic resilience planning:

- **Wind consistently poses the single greatest threat to rural utilities in Minnesota.** Utilities cite wind-related events as resulting in the most frequent adverse impacts to the power grid, and utility data confirms that wind contributes to a significant portion of outages. Wind speeds exceeding 40 miles per hour (mph) and wind gusts up to 70 mph are observed in electric cooperative territories, with exponential relationships between wind speed and outages demonstrated. State-wide data also show a frequent coincidence of outages and wind events.

- **Improvements in feeder performance in major wind events are associated with large increases in percentage of undergrounding, while smaller increases of undergrounding have minimal effects.** Considerable undergrounding efforts may be cost-prohibitive or limited by terrain. In such cases, targeted pole replacement can be a less costly strategy to enhance the resilience of an entire feeder.

- **For most utilities examined, longer overhead line segments correlate to increased outage frequency and duration.** In typical weather years, or those without major wind events, outage **frequency** is often correlated with feeder length, which may reflect an increased probability of faults with more exposed infrastructure. In years with major events, the relationships between outage **duration** and longer overhead lines become stronger and significant.

- **In rural utility territories, 92% of households have minimal access to critical services outside their home.** An interruption of power to customers in these areas can leave households with severely low access to services like food, medicine, healthcare, and safe indoor temperatures. **Critical service access** measures how easily households can meet their needs during normal conditions and **access hours interrupted** measures the potential consequences of long-duration power outages based on the disruption of critical services in specific locations. These metrics underscore the importance of considering resilience investments that reduce the potential consequences, rather than only the number and duration, of outages.

Utility engagement revealed that most rural electric cooperatives in Minnesota maintain the datasets required to calculate the 14 metrics presented in this report. For metrics describing grid impacts, this includes the number of customers impacted by a given outage, start time, and outage duration or end time. For critical service access and access interruptions, this includes additional information from public sources about the location of households and critical services. Given widespread data availability, utilities, regulatory organizations, and funding agencies can establish the benchmark metrics described here to more effectively prioritize or track the benefits of upgrades designed to improve distribution system resilience in rural Minnesota. Potential resilience investments and their relationship with these proposed benefits metrics are described in Table ES-1.

Table ES-1. Investments That Can Enhance Distribution System Resilience to the High-Priority Hazards Identified in Section 2.2, and Potentially to Additional Hazards Including Wildfire and Flooding.

“Measuring Benefits” describes the potential effect of each investment on the metrics proposed here.

“Forward-looking analysis” includes in-house or third-party hazard modeling and simulation tools, or analysis that considers anticipated threats.

Investments	Utility Implementation	Measuring Benefits	Additional Objectives Supported
Vegetation management: Enhanced tree trimming, increased right of way	Frequent among Minnesota utilities	Outage rate and outage duration decrease; access interruption hours decrease	Reliability
Overhead hardening: Pole replacement or repair, reconductoring with wires with increased wind ratings	Frequent among Minnesota utilities	Outage rate and outage duration decrease; access interruption hours decrease	Reliability
Undergrounding: In areas where access for vegetation management is difficult; undergrounding vulnerable lines or lines in critical areas	Frequent among Minnesota utilities	Outage rate decrease; access interruption hours decrease. In the event of an outage, restoration times (and therefore access interruption hours) can increase. Cumulative impact could still be reduced due to reduced outage rates.	Reliability and long-term affordability can improve, but cost-benefit ratios must be thoroughly evaluated
Network redundancy: Increased integration of tie-switches, looped feeders	Cited in investor-owned utility integrated distribution plans	Restoration rate increase; access interruption hours decrease	Reliability
Grid modernization: Fault location, isolation, and service restoration, enhanced outage management systems,[a] electronic sectionalizing devices	Cited in investor-owned utility integrated distribution plans	Restoration metrics improve; access interruption hours decrease	Reliability
Grid modernization: Battery energy storage systems for backup,	Cited in investor-owned utility integrated distribution plans	Outage rate, outage duration, restore duration, mean restoration time, and cumulative impact can	Reliability, state-specific energy targets

Investments	Utility Implementation	Measuring Benefits	Additional Objectives Supported
renewable energy integration [a]		decrease; Restore rate, time to first restore, can increase; access interruption hours decrease	
Grid modernization: Microgrids	None identified	Outage rate, outage duration, restore duration, mean restoration time, and cumulative impact can decrease; Restore rate, time to first restore, can increase; access interruption hours decrease	If renewable resources such as photovoltaics are included, state-specific energy targets can be achieved. Some utilities in other states have invested in microgrids because they have found them to be cost-effective in their most rural communities [1], [2]. Cost-benefit ratios for specific projects in Minnesota can be performed to better assess if this is a cost-effective option.
Grid modernization: Resilience hubs	Cited in investor-owned utility integrated distribution plans	Access interruption hours decrease	Reduction in disaster consequences experienced by households that may or may not be related to electricity availability
Operations: Mutual assistance programs, service truck operations for crews	Electric cooperatives and municipal utilities are participating in mutual assistance programs [3]. In interviews, cooperative representatives reported that allowing line workers to take trucks home reduced restoration times.	Restoration metrics may improve; access interruption hours decrease	Affordability
Advanced resource planning: Backup generation such as diesel generator sets for critical facilities	Municipal critical facilities or other municipal departments	Restoration metrics may improve; access interruption hours decrease	
Forward-looking analysis: None identified	None identified	Analysis techniques can impact outage metrics, restoration metrics, reduce cumulative impact, and service access	Any other objective prioritized in the analysis

[a] Cited in electric cooperative documentation [4].

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1 Introduction

This report identifies weather hazards that are most impactful to distribution systems across Minnesota, summarizes resilience planning activities by electric utilities, and presents an analysis of distribution grid performance during major weather events. The analysis draws upon data from seven electric cooperatives serving rural Minnesota and proposes novel metrics to support resilience decision-making. One such metric characterizes the relative consequences of long-duration power outages for households in rural Minnesota. This information is synthesized to provide considerations for resilience investment prioritization.

While this work considers all acute weather hazards, it focuses on major wind events, including windstorms and tornadoes, which are identified as high-priority hazards that directly impact the electric distribution system. Challenges to small utilities serving rural communities are highlighted. Electric distribution utilities in Minnesota comprise 3 investor-owned utilities (IOUs), 44 cooperatives, and over 120 municipal utilities. Minnesotan IOUs report 1.5 million customers via the U.S. Energy Information Administration's (EIA) Form 861, while cooperatives and municipal utilities, who are not required to file Form 861, separately report 853,000 and 386,000 customers, respectively [5], [6]. Cooperatives and municipal utilities are more likely to serve residential customers, while IOUs serve more commercial and industrial customers and areas with a higher population density. Most utilities, however, serve a mix of customer types

We provide considerations for resilience investment prioritization when service restoration can require crews to travel for hours between geographically dispersed customers, and where grid investments are more capital intensive with fewer customers per mile of distribution line. IOUs in Minnesota report 35 customers per mile of infrastructure, while cooperatives report 2-8 customers per mile. We include an assessment of the relatively higher potential consequences experienced by certain households during long-duration power outages based on their access to power-dependent critical services such as health care, fuel, safe indoor temperatures, and provisions like food and water. Identifying investment benefits such as avoided critical service disruption can help explain the full value of grid resilience projects in rural areas, where reliability-focused cost-benefit analysis may overlook key benefits. The assessment is also informed by a survey of current utility practices through review of planning documents and interviews with utility representatives. These insights shed light on current investment decision-making, metric usage, data availability, and how utilities consider the needs of the communities they serve.

Utility data are used to assess grid attributes and resilience to wind events to understand the current state of the grid and the potential consequences of long-duration power outages for rural households. Spatial analysis of households, critical services, and utility infrastructure indicates that 92% of households within the seven rural utility territories considered in this study have extremely limited access to critical services. This relatively low access to critical services across rural areas can lead to more adverse consequences from power outages for these households, and therefore more potential benefits from grid resilience investments that help avoid these consequences. Understanding the relationships between grid attribute metrics and resilience performance metrics[1] can help utilities, state energy offices, regulators, and decision makers prioritize investments to enhance grid resilience.

No single metric can capture a complete and detailed picture of distribution grid performance during major events. We present a set of resilience metrics designed to describe major power disruptions, which we define as the tails of a probability distribution of energy-related impacts caused by a major weather event. These metrics support strategic grid resilience enhancement. Interviews with utility representatives indicate that most utilities in the state maintain the data necessary for these metric calculations, suggesting that these metrics may be achievable for a significant number of utilities across the state.

While these metrics can track the benefits of resilience investments, using these metrics to target areas for resilience enhancement also requires decision-makers to manage the deep uncertainty inherent in estimating risk related to high-impact, low-frequency windstorms and tornadoes. Moreover, metrics demonstrating enhanced resilience to wind events are not the only relevant considerations: decision makers may also evaluate cost effectiveness, resilience to other hazards, and investments' benefits to other utility objectives.

2 Hazard Assessment

This section provides an assessment of weather hazards impacting electric distribution utilities in Minnesota based on detailed state-level analysis from the state, systematic evaluation from utilities, and publicly available outage and hazard data. We provide context for the remaining report sections, which focus on wind events and rural electric utility territories.

The Minnesota State Hazard Mitigation Plan (MSHMP) evaluates the probability and vulnerability associated with all hazards, documents simulation methodologies, and outlines data sources for 15 different weather-related hazards. It also estimates potential consequences from hazard events across many public and private sectors in addition to the electric grid [8]. The Minnesota Rural Electric Association contributed to the MSHMP with an annex that surveyed 47 cooperative utilities in Minnesota to evaluate the potential for hazards they are exposed to to disrupt service or damage grid infrastructure [4]. The cooperatives rank windstorms and tornadoes as the hazards that have historically caused the most damage to the grid. Though winter storms are not listed as a high-priority hazard in the MSHMP, winter storms are identified as the hazard with the greatest potential for adverse impacts [4]. The MSHMP Annex considers risks specific to energy infrastructure, rather than risks to people and assets more generally, providing an important perspective when developing grid resilience strategies.

These documents, combined with a preliminary analysis of coincident outages and weather events, indicate that wind events (windstorms and tornadoes), winter storms, and flooding are the primary contributors to power outages and utility infrastructure damage in Minnesota [9], [10]. The interconnected nature of hazards such as wind, flooding, and winter storms

[1] "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… Performance metrics track a utility's progress toward improvements in its core objectives (e.g., affordability, safety, reliability, resilience, equity)" [7].

emphasizes the need for broad risk assessments and resilience measures that enhance grid performance in the face of multiple types of hazards. Commentary from utilities, the MSHMP, our analysis of wind events in Minnesota, and the co-benefits of wind mitigations for other weather hazards lead us to focus on wind events as an immediate priority for grid resilience investment in our outage modeling and investment considerations (Sections 4, 5, and 6). As risks evolve over time, utilities and other organizations involved in grid investment decision-making can benefit from considering emerging threats such as increased precipitation, increased potential for wildfire, and extreme temperatures into their hazard assessment plans.

2.1 Natural Hazards in Minnesota

The MSHMP provides a thorough assessment of all hazards facing each county in Minnesota and commentary on how the probability and impact of each hazard might evolve. Natural hazards examined include:

- Flooding
- Wildfire
- Windstorms
- Tornadoes
- Hail
- Dam failure
- Extreme heat
- Drought
- Lightning
- Winter storms
- Coastal erosion and flooding
- Erosion, landslides, and mudslides
- Land subsidence
- Extreme cold
- Earthquakes

Flooding, wildfire, windstorms, tornadoes, hail, extreme heat, drought, lightning, winter storms, and extreme cold are identified as high-probability hazards in Minnesota. Among these, flooding, wildfire, windstorms, and tornadoes are additionally designated as hazards with high potential for mitigation. However, the MSHMP does not consider mitigation actions specific to the power grid. For grid resilience, other research has identified extreme heat, extreme cold, and winter storms as having high potential for mitigation, as grid mitigation strategies associated with these hazards are well understood, effective over long periods, and often federally funded [7], [11].

The numbers of presidential disaster declarations impacting Minnesota since 2019 are presented in Table 1. The MSHMP covers 2019–2023, while the table below includes two additional severe storm and flood events.

Table 1. Count of Presidential Disaster Declarations in Minnesota, January 2019–October 2024, by Hazard Type [12].

Declarations indicate that damage from these hazard events was extensive enough to require federal support to supplement county and state response and recovery activities.

Hazard Type	Count
Flooding	7
Severe storms	6
Straight-line winds	4
Tornadoes	2
Severe winter storms	1
COVID-19	1

The MSHMP also notes that not all severe weather events in Minnesota receive a federal disaster designation, even when recovery is costly. The count of presidential disaster declarations can indicate the frequency of severe events impacting Minnesotans but is not a complete picture of the hazard risk in the state.

The geographic distribution of frequency for high priority hazards in Minnesota provides important context for energy resilience planning. While the frequency of hazard events is clustered according to both the natural phenomena driving each hazard and the inherent bias present in hazard reporting processes, exposure and risk are clustered where buildings, people, and farmland intersect with high-severity hazard events (Figure 1). In Figure 1, Hazard frequency is based on historic records collected and processed in NOAA's Storm Events Database (windstorm, winter storm, and tornado) and probabilistic floodplain data from FEMA (flood) [13].

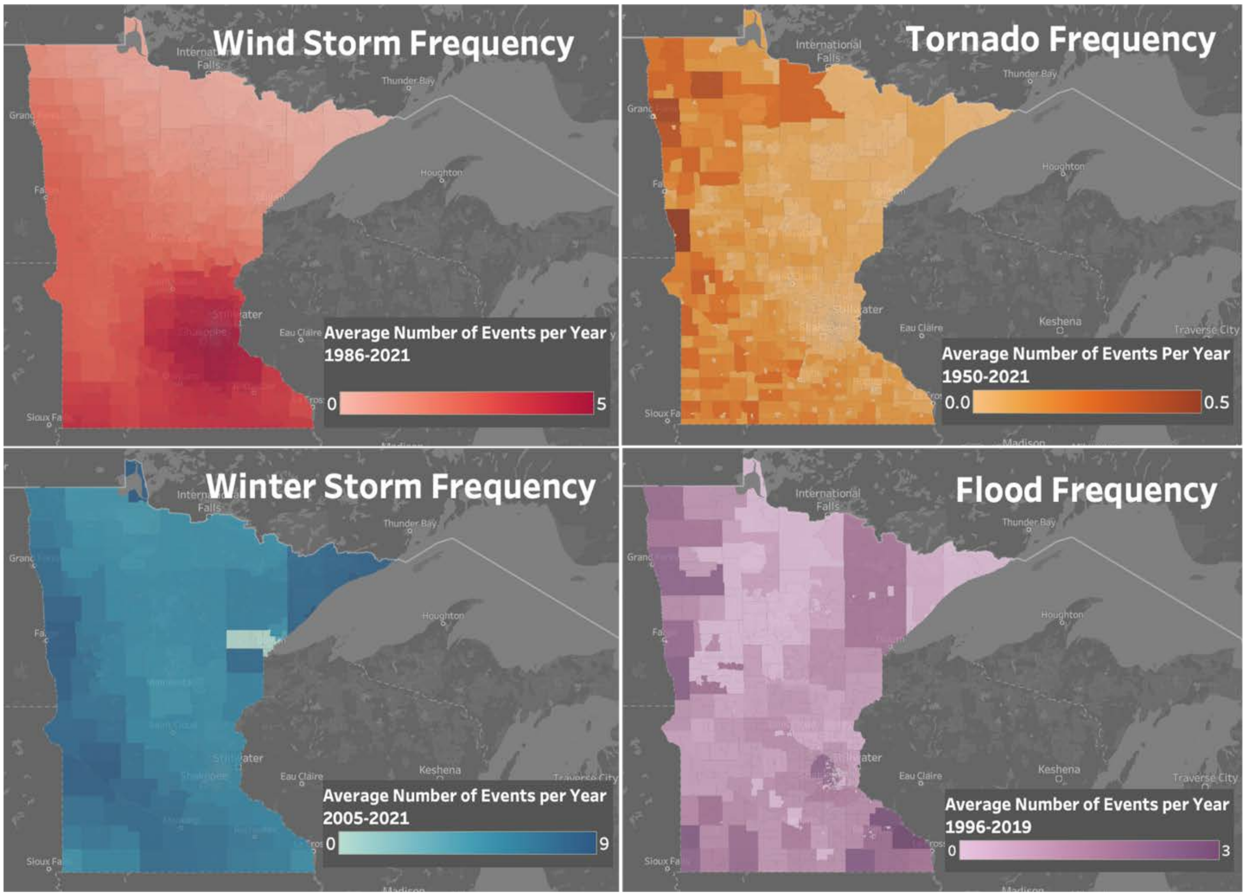


Figure 1. Geographic distribution of hazard frequency across Minnesota for four hazards. In high-frequency areas, wind events occur up to 5 times per year, winter storms up to 9 times per year, flood events up to 3 times per year, and tornado events every 2—3 years. Timelines correspond to the availability of reliable historic records for each hazard.

While robust data measuring the spatial extent and frequency of hazards are publicly available across the United States, data describing the spatial distribution, value, and vulnerability of electricity distribution infrastructure are not publicly available. The information described above about the temporal and spatial distribution of hazard frequency can inform energy resilience planning, but a more specific analysis of energy system risk and resilience opportunities requires data and information from electric utilities. In this report, we rely on utility experience documented through extensive interviews and detailed distribution system data collected from seven rural electric cooperatives across Minnesota.

2.2 Priority Hazards for Electric Distribution Systems

The Rural Electric Cooperative Annex of the MSHMP designates windstorms, tornadoes, and winter storms as hazards with the greatest future impact on utility infrastructure [4], and utility interviews conducted for this report support this designation. Outage data and frequency of disaster types resulting in presidential declared disasters also indicate that wind-related and winter storm events are the greatest drivers of power outages. Ice buildup, snow accumulation, and strong or high winds[2] can cause significant damage to overhead equipment.

High winds, which are common in both summer and winter storms, cause considerable damage to overhead power lines, especially in areas with older infrastructure. Windstorm damage to electric cooperative infrastructure has been so extensive that the associated recovery costs can trigger a presidential disaster declaration.[3] Three windstorms in 2022 resulted in customers experiencing weeklong outages. In May 2022, counties in western Minnesota experienced wind speeds of 70 mph and wind gusts of 94 mph. Buildings were damaged, debris and trees downed distribution lines, and thousands were left without power [15]. Incidents of strong winds in the past year have continued to leave hundreds, often thousands, of people without power [16], [17], [18], [19]. Tornadoes, though less frequent, can cause catastrophic damage to electric distribution systems, requiring significant resources to repair. Overhead infrastructure is often selected to withstand a specified force informed by common wind speeds, but major events may result in circumstances that exceed this specified wind loading or in vegetation or damaged building debris coming into contact with distribution poles and wires.

Winter storms are described as most severely impactful to the electric distribution system, although they are not the most frequently impactful [4]. These storms, which bring snow, freezing rain, and ice, can result in damage to overhead power lines. Ice storms are particularly problematic because the weight of ice buildup can cause power lines to snap or poles to break, leading to widespread outages. Ice and snow can also build up on vegetation, causing tree limbs to fall onto conductors, thereby damaging overhead equipment; this damage is exacerbated by wind conditions that often occur during winter storms. Municipal utilities and rural cooperatives have identified these hazards as some of the most destructive, particularly for overhead infrastructure. The majority of electric cooperatives report significant infrastructure damage from winter storms [4]. While cooperatives ranked winter storms as the most adversely impactful hazard, windstorms were ranked as the most frequent hazard to impact the grid and the leading cause of damage to the system. Wind and winter storms may have similar overall risk, but important differences in their risk components: Wind has a higher frequency, while winter storms have a higher consequence.

While the MSHMP identifies flooding as the most impactful hazard statewide, the Minnesota Rural Electric Association’s survey results show that utilities do not rank flooding as high as winter storms and wind event hazards because it does not result in as frequent or severe consequences for the power grid. Flooding is noted as a concern for utilities, but one that does not often lead directly to outages. Impacts are primarily erosion around poles and underground lines, increasing vulnerability to wind events that ultimately result in outages and more severe

[2] High-wind events include sustained windspeeds of at least 40 mph or gusts of at least 58 mph. Strong wind events include windspeeds lower than these specifications that still result in fatality, injury, or damage [8].

[3] presidential disaster declarations are declared after a preliminary damage assessment demonstrating that “effective response is beyond the capabilities of the State and the affected local governments or Indian tribal government and that supplemental federal assistance is necessary.” A subsequent declaration request must then provide an estimate of the amount and severity of damage, which can include assistance to private nonprofit organizations such as electric utility cooperatives [14].

damages. As flood plains change in Minnesota, proactive consideration of flood risks to utility infrastructure will become more important.

Because high winds often accompany and exacerbate the threats presented by winter storms and icing (e.g., galloping lines), grid resilience investments to mitigate wind hazards can benefit winter storm resilience. Wind resilience investments in upgraded pole classes and undergrounding can also provide flood resilience. For these reasons, resilience to wind events is highlighted in this report and analysis in Sections 4 and 5. Future work examining utility risk to other hazards, particularly those identified as high priority in the MSHMP such as flooding, wildfire, and extreme temperatures, will be beneficial in ensuring grid resilience in the future.

Electric utilities experience varying degrees of exposure to damage from the high-priority hazards described here. Figure 2 shows the coincidence of outages with wind events (including tornadoes, windstorms, and thunderstorms), flooding, and winter storms and icing. Combining past weather event reports with publicly available data on county-level power outages can highlight hazard risks more specific to energy systems.

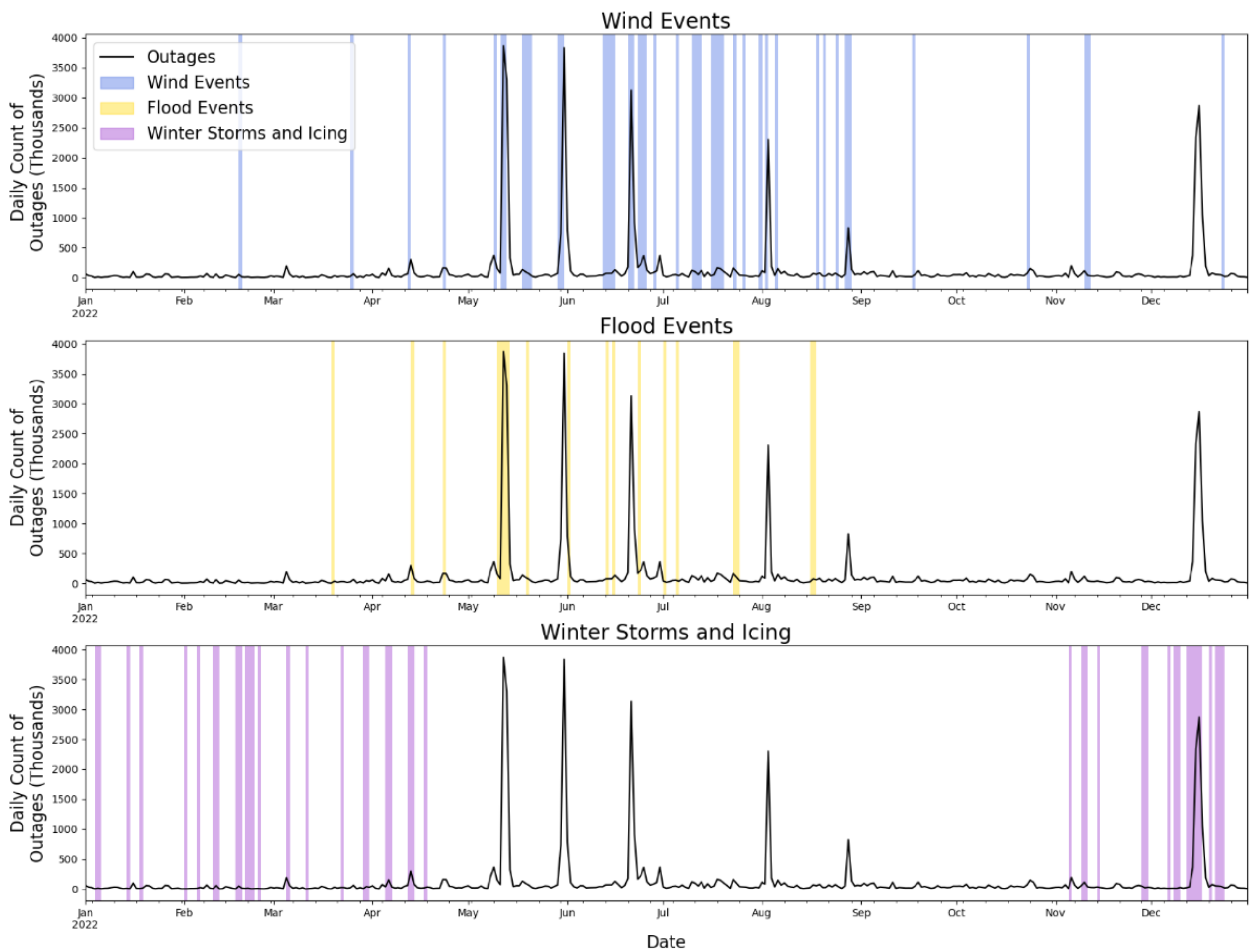


Figure 2. Count of power outages reported in in the Environment for Analysis of Geo-Located Energy Information (EAGLE-I) each day in 2022 for the state of Minnesota. Shaded rectangles represent events reported in the National Oceanic and Atmospheric Administration's National Centers for Environmental

Information Storm Events Database. Increased outages often coincide with these events. Flood and wind events often occur on the same days.

Figure 2 shows wind events often occurring at the same time as flooding or leading up to flood events. This supports documentation from the Federal Emergency Management Agency (FEMA) on presidential declared disasters, which indicates that wind hazards often accompany flood and severe storms. Both flooding and wind occurred in four of the seven flooding events that occurred in the past 5 years, and wind occurred with four of the seven severe storms events (see Table 1). Because of the coincident nature of flooding and wind events, it is challenging to use historical outage data to determine whether flooding or wind is most responsible for outages.

3 Utility Approach to Resilience

Electric utilities vary widely in their approach to resilience and the investments they select to support grid resilience to major weather events. Prior work identified common utility processes for resilience planning: hazard characterization, resilience metric selection and use, threat risk analysis, and investment selection and prioritization [7], [20], [21]. We reviewed publicly available planning documentation for distribution utilities in Minnesota to explore these resilience components [4], [22], [23], [24], [25], [26] [27], [28], [29] [30]. In Section 3.1, we review background on the regulatory and policy landscape that shapes resilience planning and reporting. This provides context for our findings of Minnesotan electric utilities' resilience investment decisions, related prioritization processes, and metric identification informing such investments.

Through partnering with several small electric cooperatives in rural Minnesota, we analyze outage data and system attributes to examine outage relationships to wind events, considerations for characterizing major wind events, and feeder attributes that may indicate vulnerability to such events. Finally, we investigate the risks that outages pose to communities throughout Minnesota to shed light on how resilience investments can ultimately provide benefits to the customers that rely on the grid.

3.1 Planning Processes for Electric Utilities

While each utility in Minnesota might have unique internal planning activities that drive resilience investment decisions and reporting, all utilities' resilience planning activities are influenced by regulatory measures, federal policy, state goals and statutes, and state and federal funding. Policy and regulatory requirements and motivators differ with utility classification. The Minnesota Public Utilities Commission regulates Minnesota's four electric IOUs and any municipal or cooperative utility whose members have decided to have their rates regulated [6]. Under this purview, the Minnesota Public Utilities Commission requires regulated utilities to submit an annual report of utility reliability performance from the prior year and an integrated distribution plan (IDP) every 2 years.

The annual reliability report includes standard reliability metrics for the utility's service area: System Average Interruption Duration (SAIDI), System Average Interruption Frequency (SAIFI), and Customer Average Interruption Duration Index (CAIDI). The report also includes the utility's methods for normalizing reliability data to account for major storms, identification of system interruptions and equipment failures, and an action plan for remedying any areas of noncompliance with state reliability standards.

Reliability metrics are also captured by the U.S. Energy Information Administration, which requires investor-owned utilities, demand-side management providers, wholesale power marketers, energy service providers, and energy power producers to report various energy industry data characterizing generation, transmission, and distribution activities in the United States and its territories [5]. The most recent available data set from 2023 included 13 municipal utilities and 26 cooperatives in Minnesota. Of the thirteen municipal utilities included, 10 reported the full set of SAIDI, SAIFI, and CAIDI metrics.

The three regulated IOUs that operate in the state submit IDPs to the Commission. The IDP provides details on how a utility plans to operate and maintain their distribution system, outlines any planned grid investments, grid modernization efforts, and integration of the distribution system with non-wires alternative and electric transportation planning [31]. During the regulatory process, stakeholders and members of the commission can review a utility's 5-year investment plan and provide testimony or comments. IDPs are not explicitly required to address resilience investments, but they offer insight on distribution spending and justification for investments, which often include resilience considerations. IDPs for all three IOUs that own and operate electric distribution systems were reviewed for information on resilience planning efforts.

The commission, along with each cooperative electric association, and municipal utility are required to adopt distribution standards for safety, reliability, and service quality (Minnesota Statute 216B.029) [12], however, municipal and cooperative utilities within Minnesota are not subject to the same regulations as IOUs. Municipal utilities are governed by either a local city council or a city utility commission. Cooperatives emphasize democratic control and elect representative cooperative members to govern. Each municipal and cooperative utility is responsible for their own planning and investment of their respective grids and is not required to submit formal reliability reporting, distribution planning investments, or grid-hardening plans to a regulatory agency. However, Minnesota cooperatives participate in activities led and documented by the Minnesota Rural Electric Association, including the MSHMP Annex. Cooperatives are eligible for FEMA disaster funding and submit documentation for damage recovery from such disasters.

In the case of municipal utilities, publicly available information on investments for increased grid resilience is scarce and does not appear to be coordinated on a larger scale beyond an individual local municipality. The most readily available information documenting municipal utility resilience considerations can be found within county hazard mitigation plans, which are submitted to FEMA every 5 years and include a plan of localized hazards, vulnerabilities, and mitigations. Counties across the United States must submit these plans to remain eligible for disaster mitigation grant funding. County hazard mitigation plans largely follow the structure and guidance of example mitigation measures that are found within the MSHMP. While these plans do provide additional information on overall multi-jurisdictional hazard coordination, information specific to municipal utility planning is extremely limited and follows a template approach reflecting the MSHMP guidance. Many of the municipal utilities contract with Minnesota State University to update county-level hazard mitigation plans.

3.2 Selecting Resilience Investments

Utilities consider a variety of hazards, but wind events and severe storms are the most cited in the cooperatives' annex to the MSHMP and in investor-owned utility IDPs [4], [22], [23], [24]. Utilities are investing in resilience with vegetation management, undergrounding, overhead hardening, and smart grid technologies. Enhanced sectionalizing capabilities and Fault Location, Isolation, and Service Restoration (FLISR) are cited in several documents but do not appear to be universal [4], [22], [23]. Utility reports cite these investment categories as providing resilience to wind events, winter storms, and icing. IOUs and some municipal utilities are making considerations for wildfire resilience, but reports indicate that these plans are in progress.

Table 2 summarizes trends in utility investments. Municipal utility and electrical cooperative resilience strategies emphasize vegetation management, strategic undergrounding, and overhead hardening. In interviews, utility representatives reported that line segments with historical outages or that require intensive pole repair or replacement are prioritized for undergrounding. Undergrounding might be limited by large amounts of bedrock in a service area. Cooperatives and IOUs are additionally proposing increasingly sophisticated and prolific rollouts of smart grid technologies such as remote sensors, advanced sectionalizing technology, often in tandem with increased FLISR capabilities, and battery energy storage systems (BESS) to provide backup capabilities. Forward-looking analysis was not identified in any utility documents.[4]

[4] "Forward-looking analysis" includes in-house or third-party hazard modeling and simulation tools, or analysis that considers anticipated threats.

Table 2. Resilience Investments Reported by Utilities

Investment Category	Specific Investments	Utility Implementation
Vegetation management	Enhanced tree trimming (e.g., increased frequency or increased right of way)	Frequent among Minnesota utilities [4], [22], [23], [24], [25], [26]
Overhead hardening	Pole replacement or repair, upgrading overhead conductors to those with increased wind ratings	Frequent among Minnesota utilities [4], [22], [23], [24]
Undergrounding	Undergrounding in areas where access for vegetation management is difficult, undergrounding vulnerable lines or lines in critical areas	Frequent among Minnesota utilities [4], [22], [23], [24], [25], [26]
Network redundancy	Increased integration of tie-switches	Cited in investor-owned utility IDPs [4], [22], [23], [24]
Grid modernization	FLISR, battery energy storage systems for backup, resilience hubs, enhanced outage management systems (OMS),[a] electronic sectionalizing devices,[a] renewable energy integration [a]	Cited in investor-owned utility IDPs [4], [22], [23], [24]
Operations	Mutual assistance programs, service truck operations	Electric cooperatives and municipal utilities are participating in mutual assistance programs [3], [30]. In interviews, cooperative representatives reported that allowing line workers to take trucks home reduced restoration times.
Advanced resource planning	Backup generation such as diesel generator sets for critical facilities	Municipal critical facilities or other municipal departments
Forward-looking analysis	None identified	Not applicable

[a] Cited in electric cooperative documentation [4], [27], [28], [29].

Municipal utilities repeatedly cite vegetation management and undergrounding overhead lines to mitigate wildfires, severe summer storms, and winter storms in hazard mitigation plans. Many hazard mitigation plans include back-up diesel generators as a stop gap measure for critical municipal facilities. These efforts are usually driven by a specific municipal department, such as fire or police departments, and not directly as a municipal utility strategy. Municipal utilities can earn a voluntary designation through the American Public Power Association's Reliable Public Power Provider (RP_3) program, which recognizes high performing utilities in four categories: reliability, safety, workforce development, and system improvement. Municipal utilities earn higher RP_3 program status by reporting reliability metrics, holding at least one disaster drill or exercise per year, and participating in mutual aid programs [30]. Nearly 80% of municipal utilities in Minnesota have signed American Public Power Association's mutual aid agreement to assist other utilities in restoring power during outages.

Minnesota's electric cooperatives emphasize measures such as storm hardening and enhanced OMS to mitigate the impacts of recurring hazards like winter storms, high winds, and flooding. For instance, East Central Energy, Arrowhead Electric Cooperative, and BENCO Electric Cooperative are concentrating on undergrounding vulnerable lines to reduce outages caused by windstorms and ice accumulation [25], [26]. Minnesota Valley Electric Cooperative is upgrading substations in flood-prone areas to strengthen reliability and minimize disruptions during major weather events [26]. Cooperatives are increasingly adopting smart grid technologies and renewable energy integration to modernize their infrastructure and reduce reliance on external power sources. Great River Energy, for example, is deploying advanced monitoring systems and integrating renewable energy sources to enhance system reliability and recovery times [27], [28]. Connexus Energy has prioritized the deployment of smart grid advancements and modernized infrastructure to improve restoration times and support renewable energy integration [29]. Arrowhead Electric Cooperative is deploying smart grid technology in critical areas [26].

The Minnesota IOUs similarly report vegetation management and undergrounding projects for resilience. All three IDPs report existing intelligent systems that support smart grid technologies such as OMS, advanced distribution management systems, and distributed energy resource management systems. All three IOUs propose smart grid investments, though each selects different types of technology. Xcel's IDP reports resilience hubs and FLISR [23]. Otter Tail's IDP includes remote sensors for fault detection, satellite data, drones, and new sectionalizing technology [24]. Minnesota Power is upgrading their OMS and FLISR [22]. Minnesota Power's IDP reviews several cost-benefit analyses for backup battery energy storage systems and FLISR projects. Reported benefit-cost ratios range from 0.75 to 6.95, indicating that even within a single service area, there is no one-size-fits-all approach to resilience.

3.2.1 Investment Prioritization

Common methods for prioritizing these investments include cost-effectiveness evaluations and cost-benefit analyses. Examples of these have been identified in investor-owned utility IDPs, although no specific instances were identified for municipal utilities. While municipal utilities may weigh benefits and costs of investments, robust public documentation of these decisions are not readily available.

Minnesota cooperatives are actively focusing on both short-term and long-term investments to address vulnerabilities in their energy systems. In the near term, their efforts center on improving outage response times and reinforcing existing infrastructure. Over the long term, many aim to expand the deployment of underground lines, smart grid technologies, and renewable energy integration to enhance reliability and reduce dependence on external power sources during emergencies [4]. These forward-looking strategies are designed not only to bolster grid resilience, but also to provide co-benefits such as reducing energy losses, lowering maintenance costs, and improving overall energy efficiency.

To prioritize resilience investments effectively, the cooperatives employ a multifaceted approach. First, they assess the vulnerability of critical assets to hazards like winter storms, flooding, and high winds. Using a risk-based framework, assets are ranked by the likelihood of failure and the potential impact on grid operations, with older, more vulnerable infrastructure—such as overhead lines—often targeted for upgrades. Second, standard reliability metrics like SAIDI and SAIFI are used in conjunction with historical weather data to identify consistently underperforming areas, which are flagged for immediate investment [29]. Community and member feedback also play a vital role, ensuring that investments address the needs of the most vulnerable populations, including rural and low-income communities disproportionately affected by prolonged outages [4].

Utility interviews also emphasize balancing resilience and affordability through targeted practices like data-driven pole inspections, vegetation management, and the strategic use of technologies such as advanced metering infrastructure, OMS, and drones. Their focus on mutual aid agreements, and proactive communication with members underscores a practical approach to enhancing grid reliability in rural, challenging terrains.

3.2.2 Current Metrics Used in Resilience Planning

Utility metrics that are reported and can be used for resilience planning have been identified in utility documents. We identify two categories of metrics used by utilities to prioritize the investments described above. Performance metrics describe the grid's performance and include the standard reliability metrics of SAIDI, SAIFI, and CAIDI. Resilience performance metrics can be restricted to grid performance in major events, such as major event day (MED) SAIDI or service restoration time on days exceeding the 95th percentile of outages. Attribute metrics measure characteristics of the distribution grid that may enhance grid performance, such as percentage of lines underground, and are actionable. Attribute metrics describe vulnerabilities or mitigations to hazards that might be expected to drive performance outcomes, which are measured with performance metrics. Performance and attribute metrics that utilities in Minnesota use and report are listed in Table 3.

In general, utility documentation describes the use of standard reliability metrics as indicators of system resilience: SAIDI, SAIFI, and CAIDI. Otter Tail highlights MED metrics and their association with ice storms. Xcel incorporated Customers Experiencing Long Interruption Duration ($CELID_{12}$) and Customers Experiencing Multiple Interruptions ($CEMI_6$) into their planning processes.[5,6] Percentage of lines undergrounded appears in investor-owned utility IDPs.

[5] CELID is the percentage of customers experiencing outages longer than a certain number of hours. The subscript denotes the length of the duration in hours.
[6] CEMI is the percentage of customers experiencing more than a specified number of interruptions in a year. The subscript denotes the number of interruptions.

Table 3. Metrics Identified in Utility Documents for Resilience Investment Tracking or That Have Potential Resilience Use Cases

Metric Type	Metric	Utility Tracking
Performance metrics	SAIDI, SAIFI, CAIDI	All
	$CELID_{12}$	Xcel
	$CEMI_6$	Xcel
	Outage duration	Electric cooperatives
	Outage frequency	Electric cooperatives
	Storm recovery time	Electric cooperatives
	Time required to access and repair failed equipment	Electric cooperatives
Attribute metrics	Percentage underground	All
	Age and condition of power line	Electric cooperatives
	Population affected by targeted undergrounding	Electric cooperatives

While there is a robust representation of system attribute metrics identified, publicly available documentation does not indicate if these metrics are used to analyze distribution system risk to weather events.

3.3 Challenges for Rural Systems

While the literature on challenges for distribution systems serving rural communities is limited, there are themes in system characteristics reported by utility representatives. Small utilities with fewer, geographically dispersed customers incur greater per-customer costs for many distribution system investments because upgrades and maintenance of a system with longer lines and fewer customers are more expensive per customer [32], [33]. In Minnesota, rural cooperatives interviewed reported 2—8 customers per mile of distribution infrastructure, while IOUs report 35 customers per mile in IDPs. Energy burden, or the percentage of household income spent on energy bills, in rural areas of the United States is 42% higher than in metro areas; utility representatives serving rural communities in Minnesota report that maintaining affordability is often the highest priority [32]. Representatives of rural utilities stated that this combination of higher upgrade costs and concern for affordability make it challenging for them to justify distribution system upgrades that would improve resilience.

Grid investments are often designed to provide benefits to the highest number of people. One in five Minnesotans live in Hennepin County, which includes the city of Minneapolis. Figure 3 shows that the highest numbers of outages per person do not necessarily occur in the most populous counties.

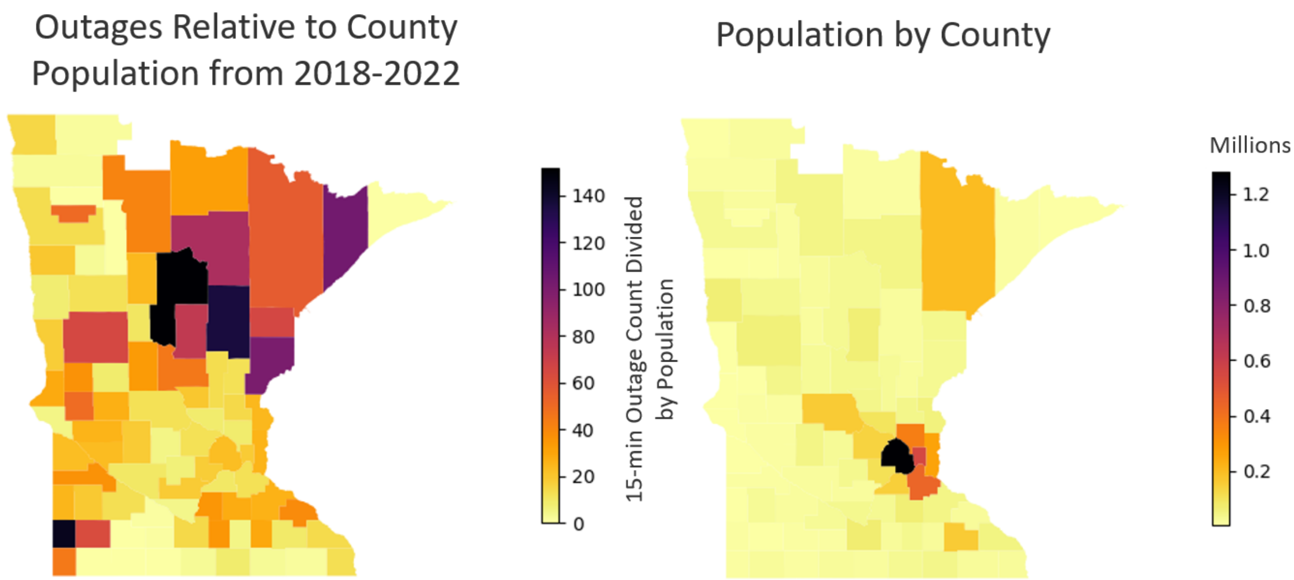


Figure 3. (Left) Outages reported in EAGLE-I data for the 5-year period from 2018 to 2022 normalized by population per county [9]. (Right) Population of each county.

In examining outages reported in 2022, separating these by metro and non-metro counties shows that certain events had varying impacts across these areas (see Figure 4). The metro counties—Anoka, Carver, Dakota, Hennepin, Ramsey, Scott, and Washington—encompass the Twin Cities' metro area (Minneapolis and St. Paul), a designation also used in state planning activities.

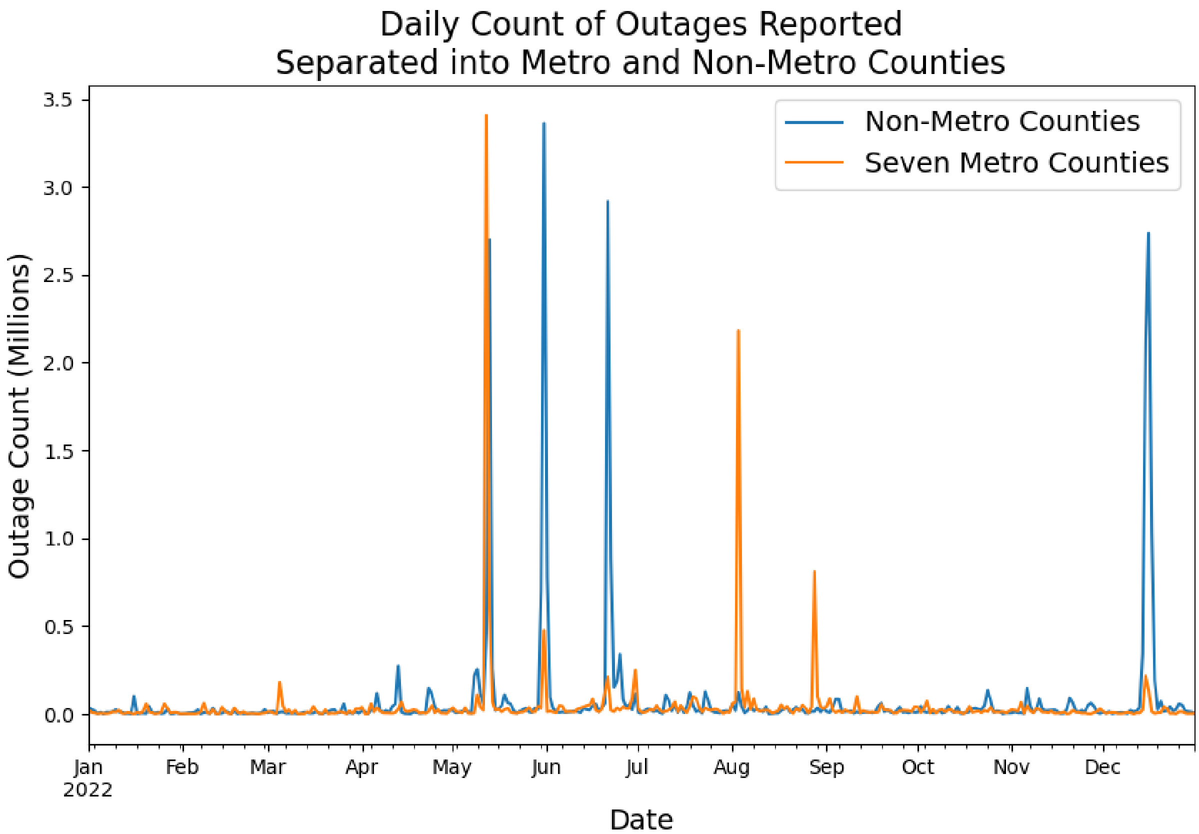


Figure 4. Daily count of power outages reported in EAGLE-I for 2022 separated into metro and non-metro counties. Metro counties, a designation used in state planning activities, include seven counties in the Twin Cities metro area.

Normalizing the outages by county population provides insight to the relative outage count experienced by residents of metro counties versus those of non-metro counties. Figure 5 shows that on average, residents of non-metro areas more impacted by power outages. With the data used in Figure 4 and Figure 5, it is impossible to say which individual customers experienced outages. It is possible that very few customers experience more outages, or that many customers experience few outages. Customer types (residential, commercial, industrial, or agricultural) are also unknown in this data-set. Assumptions should not be made about the distribution of hours of outage among residents in each county.

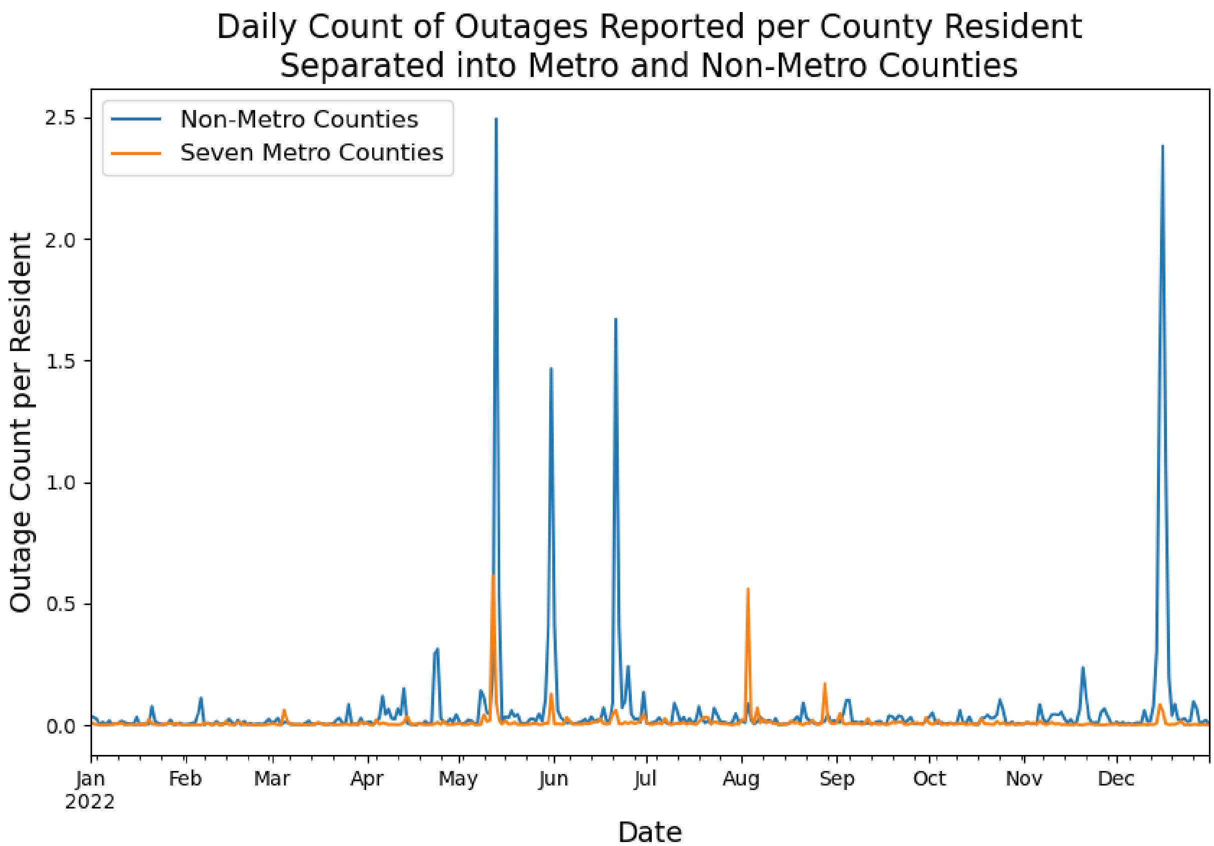


Figure 5. Daily count of power outages reported in EAGLE-I divided by county population for 2022, separated by metro counties vs. non-metro counties of Minnesota.

Given the long-duration power outages following major weather events in non-metro counties of Minnesota, combined with characteristics inherent to the utilities that serve rural communities (geographically dispersed feeders, smaller customer base, and pressures to prioritize affordable service) this report examines grid resilience investments that may provide the greatest benefit to rural communities.

4 Impacts of Wind on the Distribution System

An examination of the relationships between weather data, distribution system attributes, and outages can help to uncover the causal mechanisms of power outages. Here, we analyze outage records, weather data, and grid attributes of seven electric cooperatives in rural Minnesota. Outage data was provided for two years: one that participating utilities characterized as a typical year, and one that participating utilities identified as a year that the service area was impacted by major wind events. We verified that most of the weather-related outages faced by these utilities were related to wind during the time periods for which data were provided. We present a representative rural electric cooperative, referred to as Utility A, as a case study for a deeper examination of the impacts of wind hazards on the distribution grid. Utility A is situated in the west-central region of the state and serves a mix of residential, commercial, and industrial or agricultural customers. In May 2022, this service area was severely impacted by two wind events that received presidential disaster declarations 17 days apart. Utility A serves as a good representation of the challenges facing the seven utilities analyzed in this study; exceptions and findings from other utilities are highlighted here, with results for all seven included in the Appendix.

4.1 Wind-Related Outage History

Outage data consist of records for a major event year (2022) and a typical year (2023). Utility A records outages with 33 unique cause codes. Outages and a breakdown of their specific cause are shown in Figure 6. The majority of all outages in this dataset result from wind.

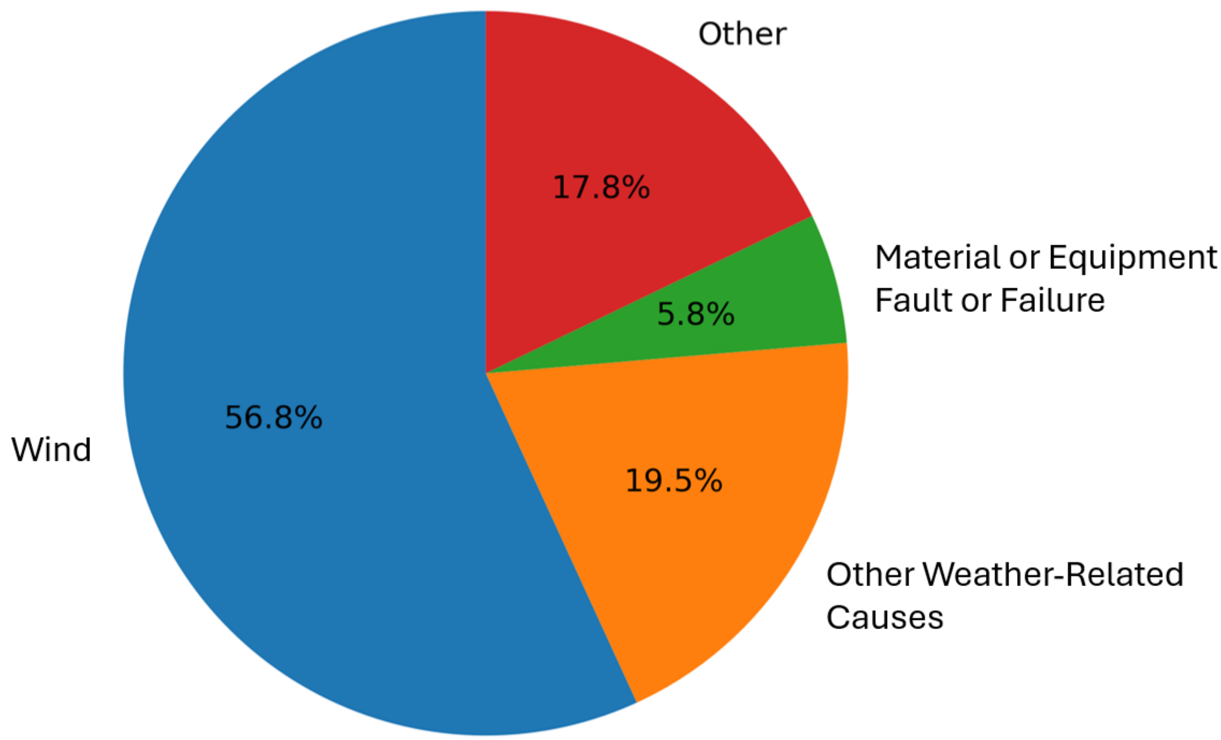


Figure 6. Breakdown of unplanned outages caused by wind, other weather causes, and equipment failure. “Wind” excludes tree incidents. “Other” includes causes that are not in the top three most frequent causes recorded, such as loss of supply, animals, motor vehicles, or farm equipment.

Outages are recorded by the nearest upstream isolating device that clears the fault. As a result, the location of the outage may differ from the actual fault location or origin of damaged infrastructure. Figure 7 shows outage hotspots within Utility A’s territory during the record period. Each red circle represents the location of an isolating device that recorded an outage, and the size of the circle represents the number of outages recorded by the device. To focus the analysis on weather-related outages, the outage causes represented in this map do not include planned outages, supply-side outages, or human- or animal-related outages.

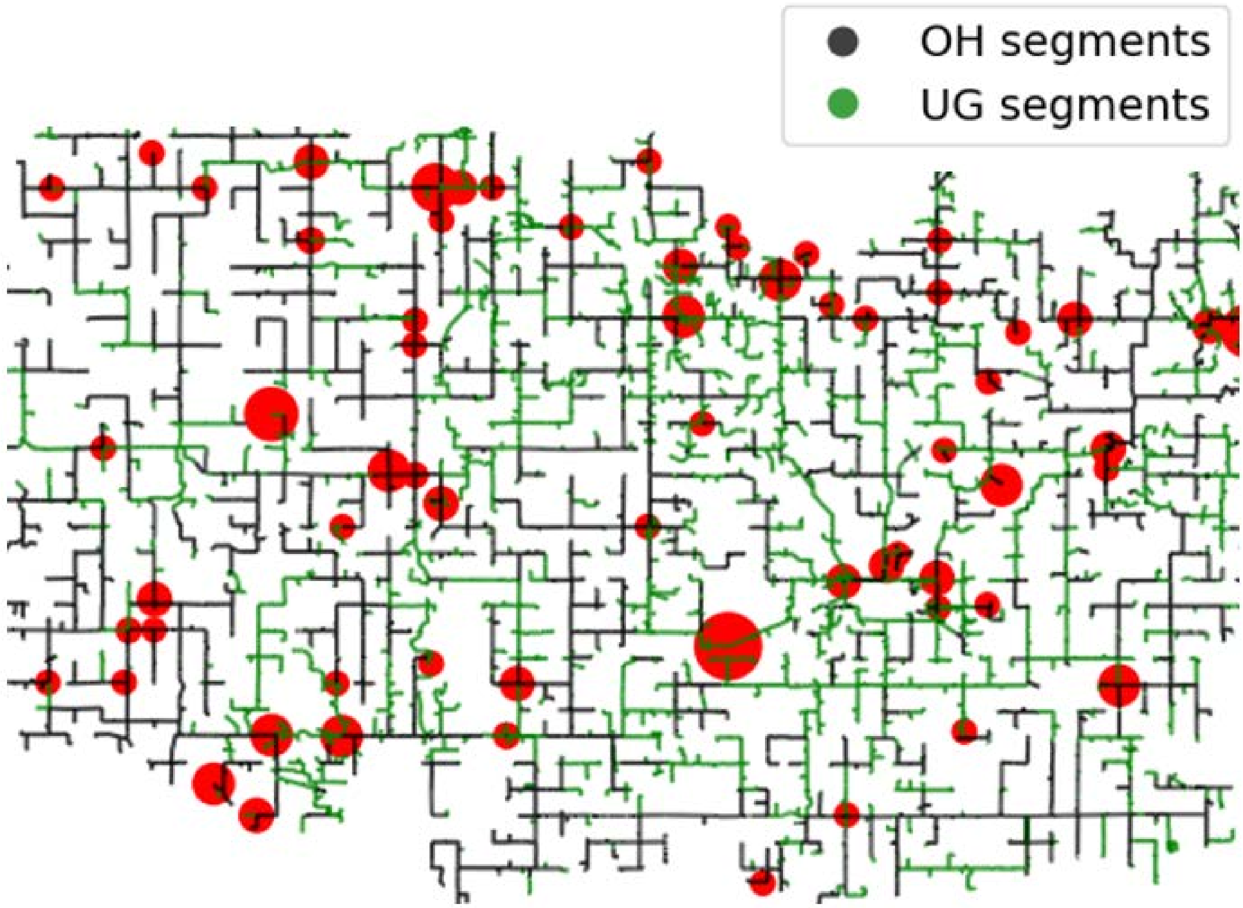


Figure 7. Outage hotspots within Utility A territory for 2022, the year in which major wind events impacted the utility. Each circle is the location of the fault isolating device and the size of the circle represents the number of times the device recorded the outage.

The most common cause of long-duration outages in Utility A is wind. We assess the correlation between wind speed, wind gust, and the number of outages and number of customers affected by outages per day in Utility A's distribution system. Local windspeed and wind gust values are obtained from historical weather station values [34]. There is a strong positive relationship between wind speeds greater than 40 mph and the number of outages (Figure 8). Likewise, there is a slightly weaker but strong positive relationship between wind gusts greater than 40 mph and the number of outages (Figure 8).

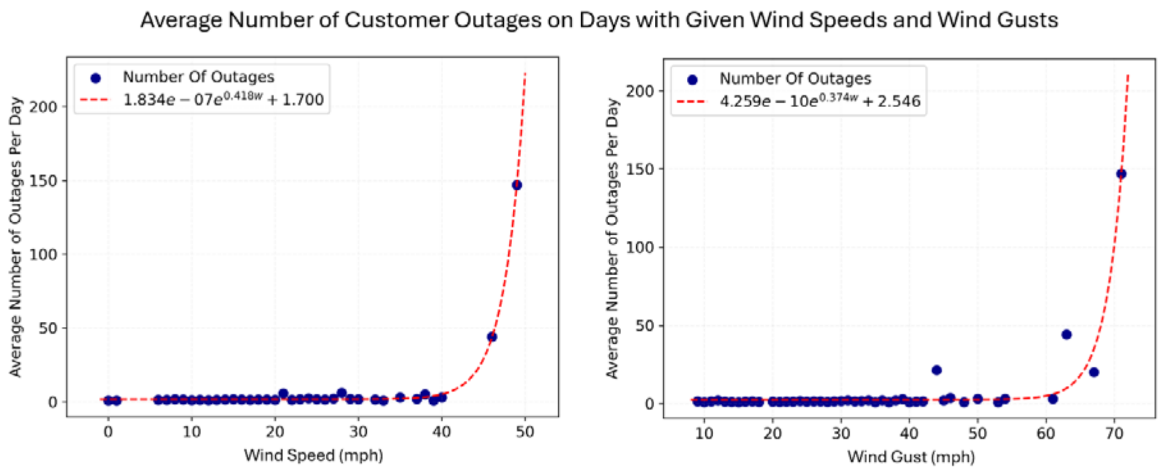


Figure 8. Relationship of wind speed and wind gusts with average number of outages per day.

Determining a threshold at which wind speed and wind gusts result in a well-defined increase in outage rates in individual utility territories can help define major wind events for more strategic resilience planning. These relationships between outages, wind speeds, and wind gusts indicate that increasing the ability of distribution infrastructure to withstand wind speeds and wind gusts greater than a threshold of 40 mph could have the greatest impact on reducing long-duration outage impacts in Utility A. Strategies Utility A might consider to mitigate these impacts include undergrounding, replacing poles rated for lower overhead forces with poles rated for higher overhead forces, and decreasing the distances between poles.

4.2 Distribution Grid Attributes and Wind-Related Outages

Examining feeder outages and attributes allows us to consider the attribute mix that can increase resilience during an major wind event. Outages during such events stem from the exposure of overhead infrastructure to strong winds and debris. We look at the impacts of undergrounding line segments and features of overhead infrastructure that can contribute to a distribution system's ability to withstand wind hazards to shed light on how undergrounding and overhead hardening can improve wind resilience.

4.2.1 Analysis of All Participating Utilities' Data

Participating utilities provided network models with underground lines, overhead lines, pole data, and outage information. There was a wide range in the percentage of lines underground in participating utilities' service areas (17%—58%). Poles supporting overhead infrastructure are designated with numbered classes from 1 to 7 based on the wind loads they are designed to withstand, with lower numbers indicating the ability to withstand stronger winds. Class 1 or 2 poles are more common in coastal regions with frequent and severe hurricanes [35]. Utilities in Minnesota tend to use poles with higher classes, generally ranging from Class 2 to Class 7, with most poles being Class 4 or 5.

We used utility data to calculate attribute metrics such as percentage underground, overhead line lengths, and pole attributes and examine the correlation of these attribute metrics with performance metrics such as outage count and duration on a per-feeder basis. Across utilities, we found significant correlations in feeder attributes and performance. We compared outage metrics with percent undergrounding, pole age, and overhead line lengths for each feeder and observed the following relationships:

- For most utilities examined, longer, continuous overhead line sections correlate to increased outage frequency and duration. In years more representative of typical weather years, or those without major wind events, outage count is often correlated to longer feeders, which may reflect an increased probability of faults with more exposed infrastructure. In years with major events, the relationships between outage duration and longer overhead lines becomes stronger and significant.

- As the percentage of underground lines of a feeder increases, outage durations generally decrease. There is one exception to this: For a single specific utility that provided data for our study, this relationship is inverted with increasing outage durations observed in feeders with more undergrounding. It is possible that the utility is prioritizing undergrounding lines that are more exposed, and that this prioritization is improving performance, but these feeders still experience more outages than others that are less exposed. This utility has 17% of its lines underground, which is the lowest of the set of participating utilities (median percentage underground of a system is 35%). In this system, feeders with more than 60% of their lines underground experienced zero outages.

- Clear correlations between outages and poles ages are often challenging to identify because the distribution of pole ages in a given system is often not normal or log normal. In cases where the distribution is normal, correlations are positive—i.e., older poles are associated with increased outage frequency and duration—but often not significant ($p > 0.05$). Pole age has a stronger relationship with outage duration in systems with less undergrounding, suggesting that pole maintenance and replacement may be more impactful for utilities with a limited ability to underground, while utilities with a high percentage of undergrounding will see a smaller shift in resilient performance from projects to upgrade poles in the overhead portions of their system. Pole age also becomes significant in years with major events, while there are not significant correlations between pole age and outages in typical weather years. While pole age is an indicator of condition, an older pole is not necessarily weaker. Stronger conclusions can be drawn from data that includes a measure of pole condition.

While these relationships indicate the impacts of grid-hardening strategies on grid performance, feeders with the greatest outage durations can have wide-ranging attributes. If a feeder is exposed to the most severe wind conditions, even those with favorable system attributes may experience damage or prolonged outages. This can be illustrated through a deeper examination of Utility A.

4.2.2 Analysis for Utility A

Utility A manages 84 unique feeders with 50% of their lines underground, putting Utility A's undergrounding on the higher end of the utilities studied. Utility A's distribution system includes nearly 28,500 poles constructed primarily from red pine. The average pole age is 23 years, and most poles are less than 40 years old, with a few older than 70 years old (Figure 9). Most poles are 35—40 feet tall and categorized as Class 4 or Class 5 (Figure 9).

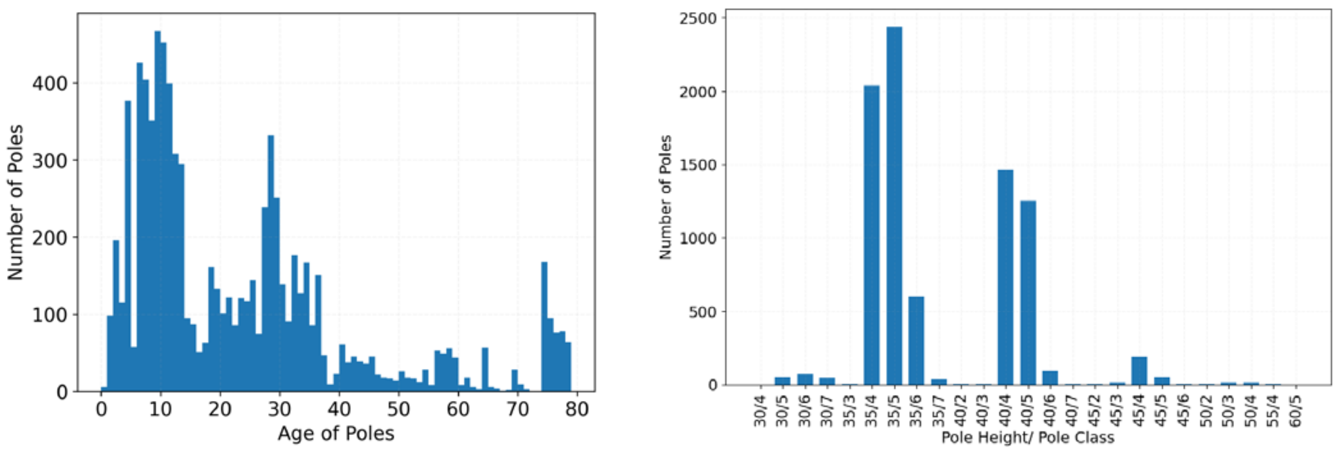


Figure 9. Distribution of pole age (left) height and class (right) in Utility A.

Figure 10 shows the total outage durations that each of these feeders experienced in 2022, the year in which this utility service area was impacted by two consecutive major wind events. These events provide an example of compounding damages to distribution systems from multiple events that may occur before system recovery from a single event is achieved. Feeders with zero hours of outage durations are geographically clustered in the southeast region of the Utility A territory, while feeders with the highest outage durations are clustered in the north and southwest regions, which could indicate the influence of windspeed distribution during storms.

Figure 10. Feeders with the most unplanned outage duration hours in a year with multiple major wind events (Presidential Declared Disasters). Grey feeders had zero hours of recorded outages.

Feeders with very high and very low outage durations are shown in Table 4 along with feeder attributes and outage metrics. Feeder number 1 has the longest total outage duration despite a high percentage of undergrounded lines and relatively short overhead line lengths. Pole age is not clearly differentiated from other feeders.

Table 4. Attributes and outage metrics of feeders experiencing the greatest outage durations in a year with major wind events and feeders experiencing no outages in the same year. Each row represents a unique feeder. Conditional color formatting indicates value relative to all feeders in the distribution system. Low outage metrics are green while high outage metrics are red. High levels of feeder attributes that are expected to result in increased resilience are green, while low levels are red.

Feeder Number	Percentile (Total Outage Duration)	Total Hours of Outages	Outage Hours per Mile	Percent Underground	Max Overhead Line Length (miles)	Median Pole Age (years)	Max Pole Age (years)	Outage Count
1	100%	812	10.34	67%	0.89	18	77	16
2	98%	702	9.20	23%	1.97	28	77	16
3	96%	690	9.82	22%	1.16	27	76	18
4	94%	644	17.61	45%	0.75	28	79	9
5	91%	553	12.27	32%	1.25	9	79	15
6	89%	535	15.87	48%	1.34	27	77	16
7	0%	0	0.00	44%	0.44	6	74	0
8	0%	0	0.00	44%	0.93	11	77	0
9	0%	0	0.00	29%	0.05	10	59	0
10	0%	0	0.00	37%	0.52	24	24	0
11	0%	0	0.00	29%	0.96	11	74	0
12	0%	0	0.00	87%	0.65	27	41	0

While there are statistically significant trends correlating these feeder attributes with outage count and duration, Feeder 1's outage history during these major wind events demonstrates that these are not perfect predictors when grid infrastructure is exposed to major wind events. Additional data to account for terrain, vegetation, and asset condition could reveal clearer interactions of feeder attributes and their relationship to wind resilience. Investments to absorb such events, rather than withstand them, can be considered to reduce restoration time (e.g., break-away ties on overhead wires) or impacts to customers (backup generation or priority restoration for critical community services) in such scenarios.

Undergrounding projects are common for utilities that endeavor to increase grid resilience; however, percent of underground lines alone is not a strong indicator of resilience to weather-related outages in this case. Figure 11 shows the number and duration of outages compared with the fraction of undergrounded lines for each of Utility A's feeders. For each feeder, the ratio of overhead to underground line length is computed and then grouped in bins.

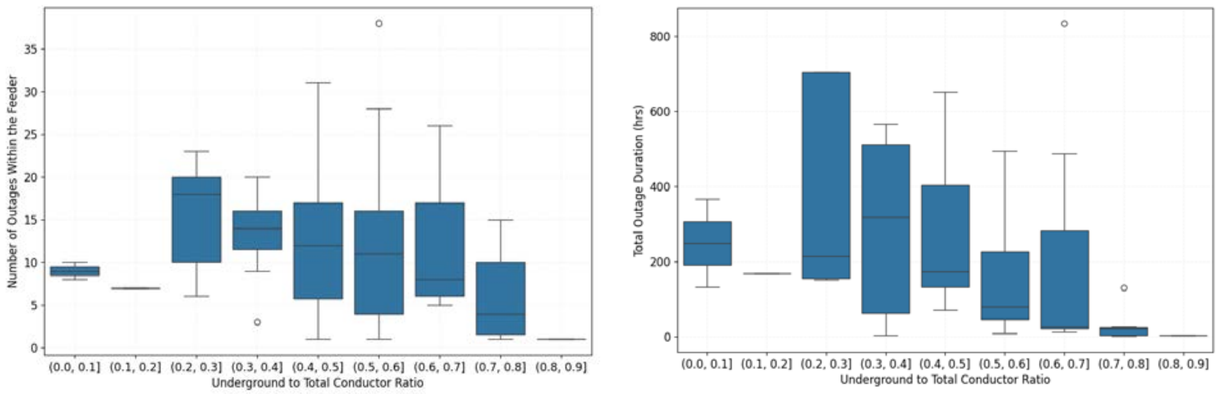


Figure 11. Comparison of ratio of undergrounded line segments length to overall line segments length with number of outages and total outage duration in each feeder.

Feeders with 50% to 60% of line segments underground observed similar number of outages compared to feeders with 40% to 50% of line segments underground, suggesting that relatively small increases in undergrounding do not achieve significant decreases in outage risk. Feeders with zero outages have a wide range of undergrounding, from 29% to 87%. Feeders in the top 10% of outage durations have a similarly wide range of undergrounding that overlaps with that of feeders with no outages, ranging from 22% to 67%. To increase the cost-effectiveness of undergrounding as a resilience strategy, undergrounding can be targeted to strategically benefit the most exposed portions of a feeder and can be paired with additional upgrades like decreased overhead line lengths and pole upgrades.

The typical lifespan of wooden poles are around 40-45 years [36], [37]. Although the average age of pole in Utility A is 23 years, there are many poles older than the lifespan of typical utility wooden pole. Feeders with high outage durations host some of the oldest poles in the system, with maximum pole ages ranging from 76 to 79 years, well above the 90th percentile of pole age (54 years) in Utility A (Table 5).

The average age of poles greater than the 90th percentile of pole age in Utility A was compared with the number of weather-related outages for each feeder (Figure 12. Comparison of average age of poles above 90th percentile number of outages and total outage duration in each feeder.). Outage count is higher in feeders with increasing average pole age above the 90th percentile age. Older poles can be more vulnerable to major weather conditions and result in more outages, even on feeders with higher relative percentages of undergrounded line. While age does not necessarily mean that a pole is in poor condition, it is an indicator of condition and wear that a pole may have been exposed to. Targeted pole replacement can be a cost-effective strategy to support resilience of an entire feeder.

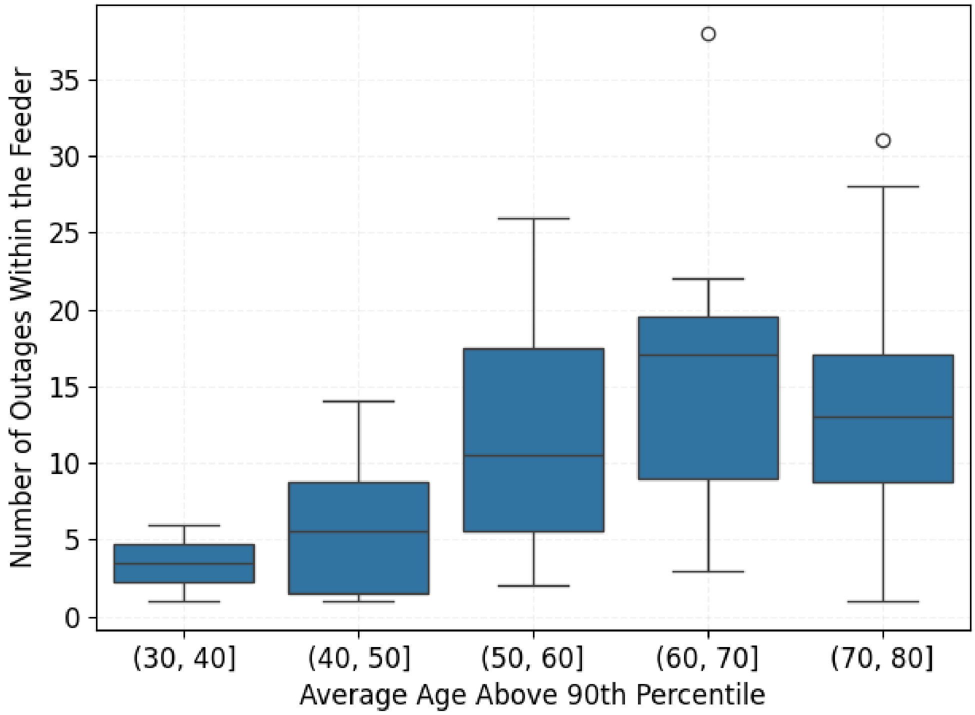


Figure 12. Comparison of average age of poles above 90th percentile number of outages and total outage duration in each feeder.

Pole maintenance or replacement and undergrounding are not mutually exclusive strategies, but complementary approaches that can be weighed carefully. Older portions of a feeder with some of the oldest overhead infrastructure in the system could be candidates for targeted undergrounding. If a utility's long-term strategy is to increase the portion of underground lines, prioritizing line segments with older assets due for replacement can be both cost-effective and resilience-enhancing.

5 New Performance Metrics for Grid Resilience

In Section 4.2, we examined the relationships between system attributes and performance on a per-feeder basis to better understand the relationships between wind hazards, distribution infrastructure, and outages. Attribute metrics like the ones used in Section 4.2 are related to, but do not directly measure, a system's performance during major events. Here, we introduce system-level performance metrics that communicate the resilience of a distribution system. Reducing the number of outages in a distribution system, the duration of outages for vulnerable customers, or the negative consequences of those long-duration outages, indicates increased resilience. Therefore, establishing and tracking performance metrics related to outage duration and consequences allows utilities to directly measure progress toward resilience goals. To quantify grid resilience—or the ability to anticipate, withstand, absorb, and recover from high impact, low frequency events—we summarize 14 underutilized metrics that capture grid performance in major weather conditions [38]. The data required to calculate these metrics were provided by seven Minnesota cooperatives serving rural communities. Interviews with utility representatives indicate that these data are maintained by most utilities in the state, suggesting that these metrics are achievable for all types of utilities.

5.1 Outage and Restoration Process: Grid Resilience Quantification Methodology

The performance of a utility during major weather events and other disruptions can be characterized in part by how quickly outages are restored. In fact, many utilities track recovery time as a performance metric (see Table 3Table 3). Restoration time can vary significantly depending on the extent of the hazard event and the location and severity of resultant damages to the grid. However, during major events, outages can accumulate even as restorations progress, making it difficult to accurately measure restoration time. The detailed timing of outages and restorations is complex to track and report when outages are numerous and widespread but characterizing the interaction between outages and restoration over time offers actionable information for resilience.

Researchers have developed an approach for analyzing the coincident accumulation of outages and restorations during major events to characterize the resilience of both transmission and distribution systems [39], [40], [41]. For each event, the outage process $O(t)$ measures the number of active outages recorded each hour using outage start times from utility data (Figure 13).

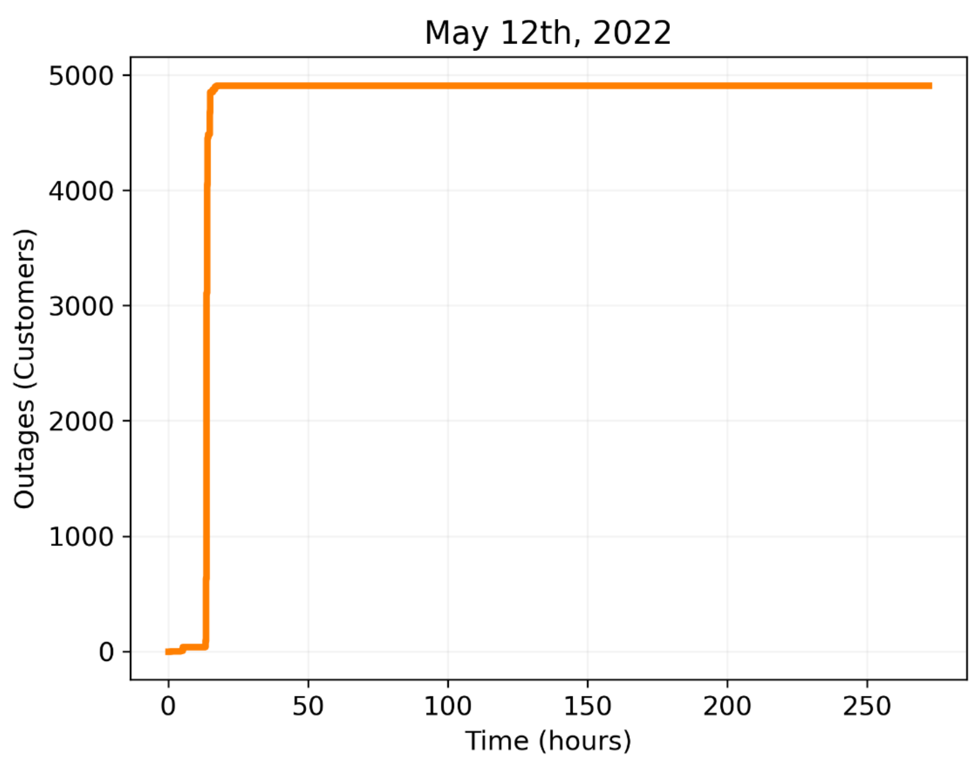


Figure 13. Outage process, O(t). Nearly 5000 customers were affected by outages during a windstorm on May 12, 2022, in western Minnesota. This plot shows the cumulative count of customers that experienced an outage that began during this windstorm. Some outages persisted for over a week.

Outage Process $O(t)$ Metrics:

- **Time over threshold (hours):** Time unrestored customers exceed the customer affected threshold value. The customer affected threshold can be set at any percentile according to utility preferences; for example, the Time over 95th percentile would be the number of hours that unrestored customers exceed the 95th percentile of customers affected in all hours of the event.

- **Outage duration (hours):** Total duration from the first outage to the start of the last outage
- **Outage rate (per hour):** Number of customers affected per hour, or the slope of $O(t)$

The restoration process $R(t)$ measures the number of restorations recorded as complete in each hour using outage end times, inferred from the outage start time and duration for each outage recorded (Figure 14). The restoration process concludes when all the outages are restored. Hence, the number of outages and restorations should be equal at the end of the event.

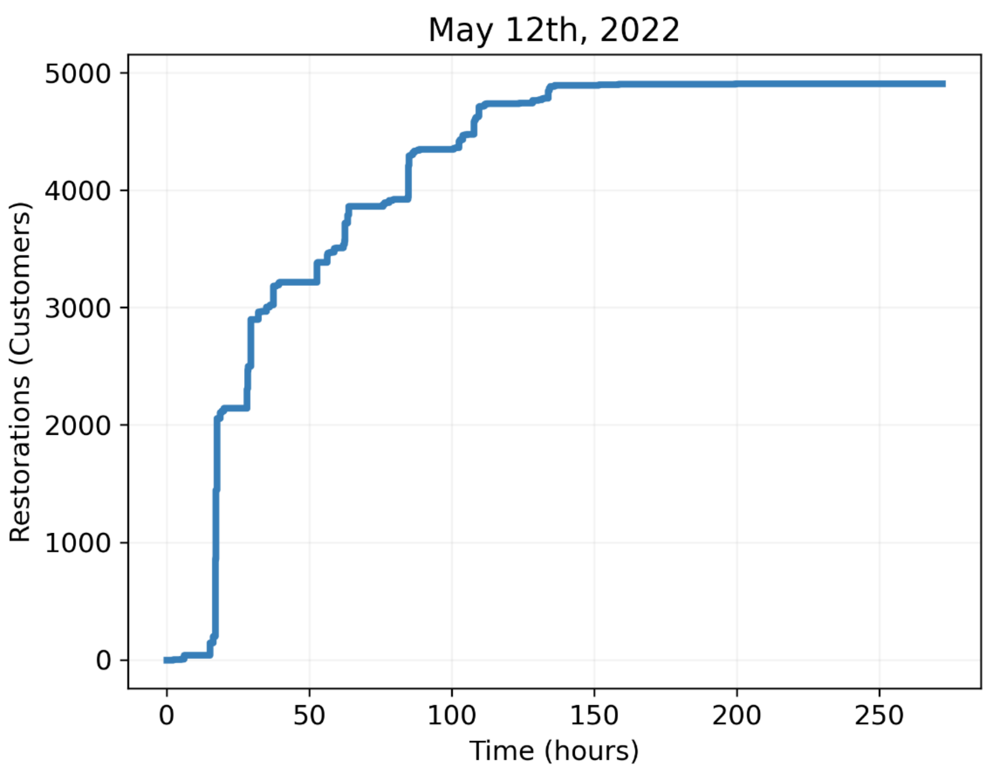


Figure 14. Restoration process, R(t). This plot shows the cumulative restoration of customers that experienced an outage that began during the windstorm on May 12, 2022.

Restoration Process $R(t)$ Metrics:

- **Time to first restore (hours):** Duration from the first outage start to complete the first restoration.

- **Restore duration (hours):** Total duration from the first restoration to the last restoration.
- **Restore rate (per hour):** Number of customers restored per hour i.e. slope of $R(t)$
- **Restore time – X% (hours):** Time taken to restore a given percentage of affected customers. For example, Restore time – 75 measures the number of hours before 75% percent of customers affected are restored.
- **Mean restoration time (hours):** Average restoration time calculated using geometric mean. Geometric mean is less affected by skewed data as compared to arithmetic mean and is therefore better suited to identify average restoration times when such times can vary significantly [41].

System resilience is represented with event-specific outage and restoration curves that provide a detailed view of how major power disruptions evolve and resolve. These disaggregated curves can be compared to generate a cumulative impact, $I(t)$, that characterizes the performance of the system over the course of an outage (Figure 15). The cumulative impact measures the number of non-restored outages over time—i.e., $I(t) = O(t) - R(t)$. The horizontal axis represents time (t) whereas the vertical axis can represent the number of outages, number of system elements [41], or number of customers [40]. Outage process, restoration process, and cumulative impact are measurements of the number of outages or restorations *over time,* and these time-dependent curves can be used to derive several discrete metrics describing the performance of a system during an outage.

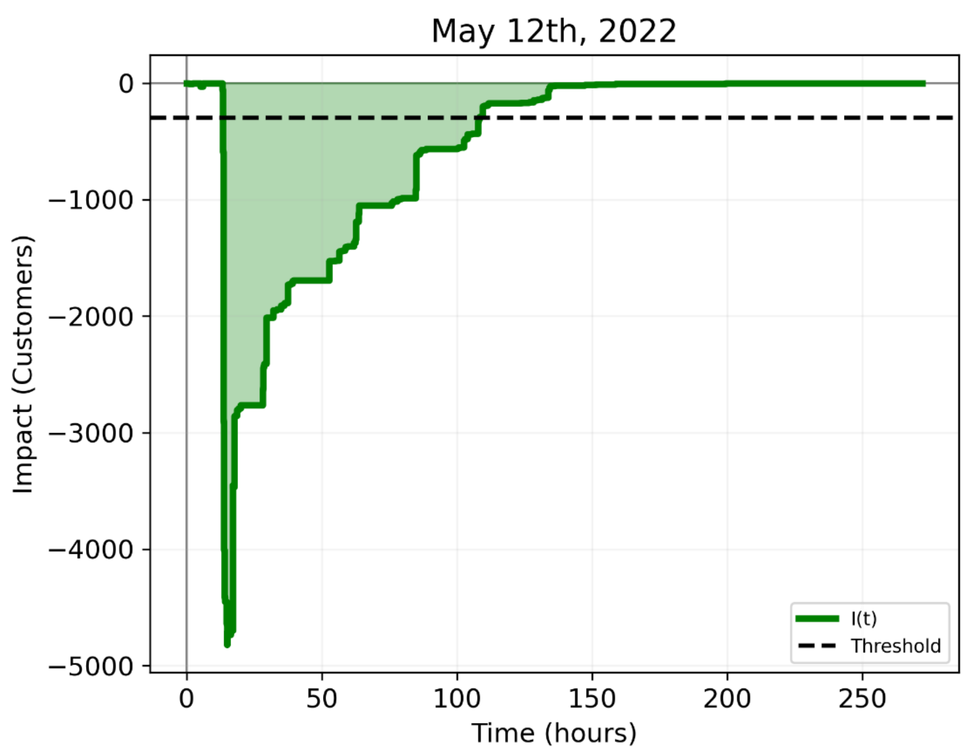


Figure 15. Cumulative impact, I(t). This plot shows the impact to customers over time due to outages that began during the windstorm on May 12, 2022.

Cumulative Impact $I(t)$ Metrics:

- **Customer hours interrupted:** Area above the performance curve i.e. total customer hours of outage
- **Event duration per customer:** Customer hours interrupted divided by affected customers, or the average length of outage per affected customer
- **Event duration (hours):** Total duration from the first outage to the last restoration

In this study, $I(t)$ is interpreted as the number of customers who remain without power at time t. For example, if $I(t = 10) = 100$, then 100 customers are still without power at the 10th hour of the event. The area above the $I(t)$ curve, which represents the total customer-hours of interruption, measures the cumulative impact of the outage over time, combining both the duration and the number of affected customers. This metric can be used to identify areas and/or investments that could maximize resilience by minimizing the duration and/or customers affected by major outages.

The outage process, restoration process, and cumulative impact were analyzed for major events in Utility A's service area in 2022 and 2023 (Figure 16). Major events are identified as days in which the number of outages, the number of customers affected by outages, and the total duration of outages are all greater than the 95th percentile of each metric for the period of record. The outage process on May 12 and July 25 shows a relatively short period in which outages occurred, while the restoration process that follows shows a relatively gradual restoration of outages. In contrast, the outage process on May 30 and June 20 shows initial increases in outages addressed immediately by an equal restoration process, followed by sharp increases in additional outages hours later and lagging restorations. The cumulative impact curves corresponding to these outages could be used to identify common visual patterns in the way outages evolve and associate those patterns with relatively higher or lower impacts and consequences.

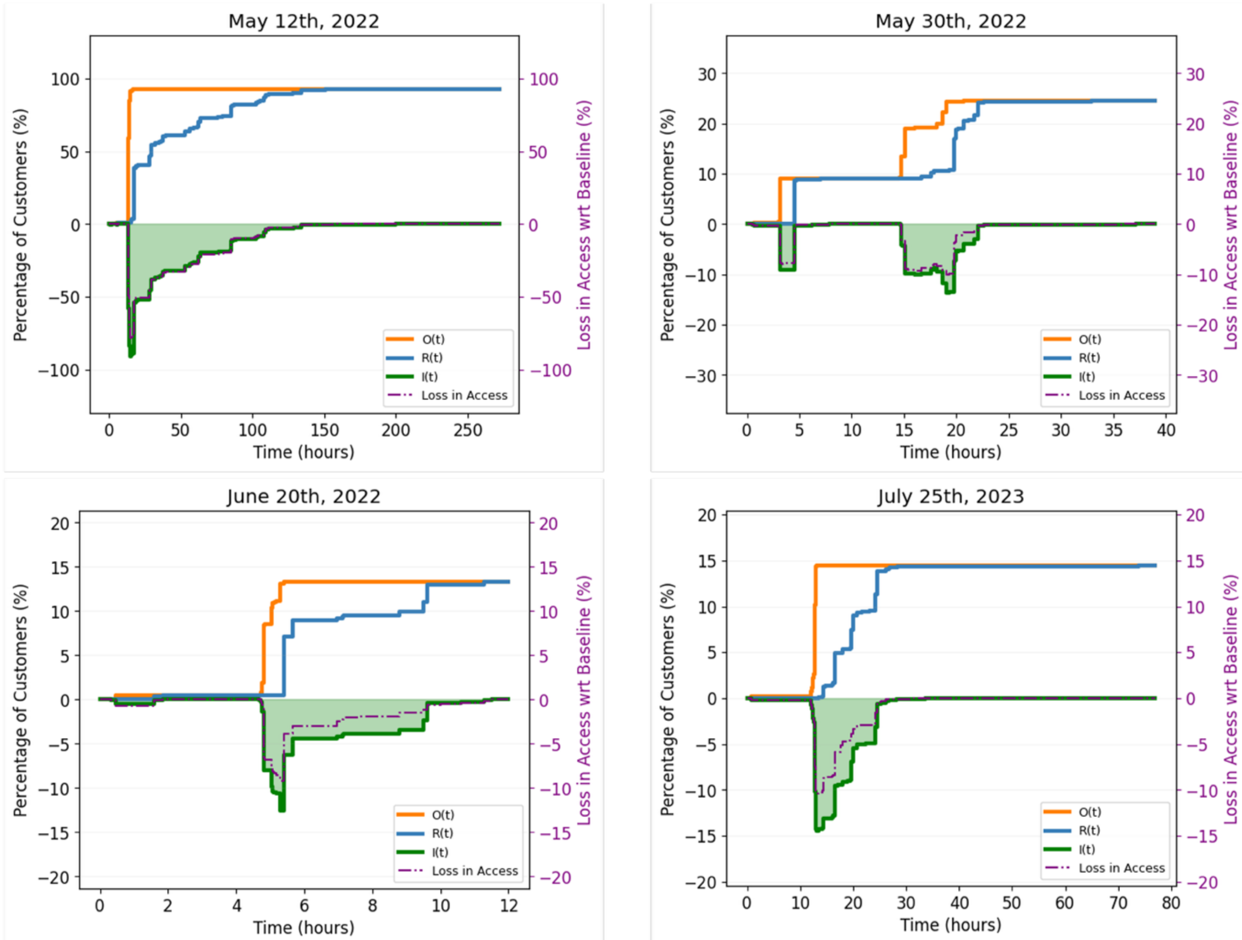


Figure 16. Outage process, restoration process, and cumulative impact for four major events in Utility A's service area. Here, major events are defined as those exceeding the 95th percentile of the number of outages, customers affected, **and** outage durations among all recorded outage events in 2022 and 2023. Access is also measured in purple on the righthand axis in each plot – see Section 5.2 for an explanation of this metric.

This analysis produces a set of performance metrics that help characterize the impacts of each major event to understand how investments could improve resilience by avoiding these impacts (Table 5). Metrics proposed in Table 5 can be used to describe and track the resilience of a system more specifically than typical reliability metrics. *Outage process* metrics measure a system's ability to withstand an major event, while *restoration process* metrics measure a system's ability to recover. A system with a relatively high proportion of undergrounding, prevalence of wind-resistant infrastructure, and frequent vegetation management is likely to have a lower *outage rate* and *outage duration* for wind-related events but may not necessarily exhibit high *restoration rates* and have long restoration times for those events. In contrast, distribution grids with advanced situational awareness, a large portion of looped feeders and tie-switches, remote-controlled switching equipment, and strategic microgrids are likely to have faster restoration rates and lower restoration times for major events.

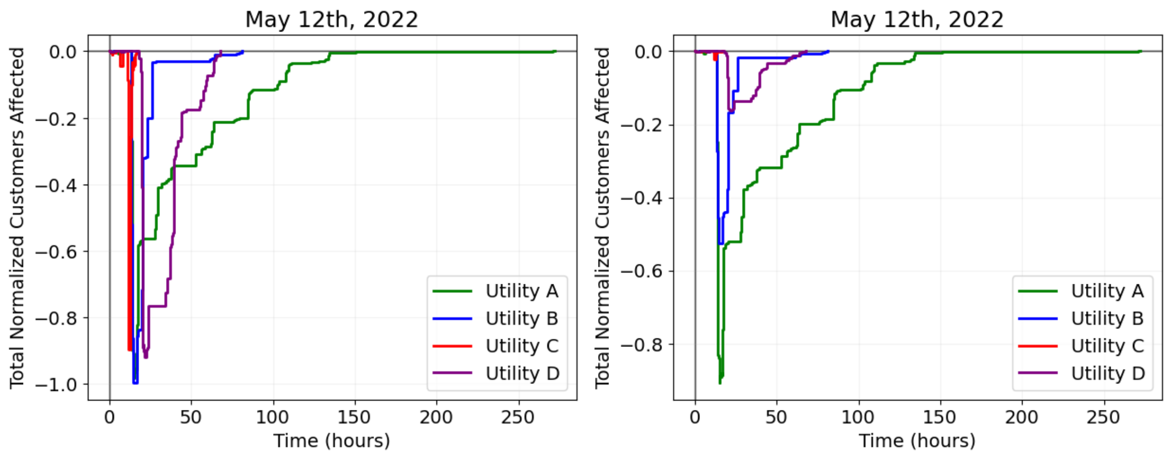
Table 5. Metrics computed from outage process, restoration process, and cumulative impact curves for four major events in Utility A's territory in 2022 and 2023.

Event	Outage Process			Restoration Process					Cumulative Impact		
	Outage Duration (Hours)	Outage Rate (Per Hour)	Number of Outages	Time to First Restoration (Hours)	Restore Rate (Per Hour)	Restore Duration (Hours)	Time to Restore 75% (Hours)	Mean Restoration Time (Hours)	Event Duration (Hours)	Customer Hours Interrupted	Event Duration per Customer (Hours)
May 12th, 2022	16.32	301	5,000	1.4	18	268.87	61.67	42.76	270.27	146,515.7	29.83
May 30th, 2022	21.75	60	1,250	1.58	36	36.28	19.42	2.97	37.87	4,020.98	3.09
June 20th, 2022	5.08	139	750	1.28	71	9.92	9.18	2.59	11.2	1290.2	1.82
July 25th, 2023	12.35	62	800	12.62	12	62.8	23.35	8.17	75.42	5,961.55	7.78

Outages create the largest impacts when both outage processes and restoration processes are prolonged. However, investments that improve outage processes can be different than those that improve restoration processes, in both location and design. For example, in rural utility territories, reducing crew travel times will improve restoration times. This can be accomplished through operational strategies, such as having crews take company trucks home or prepositioning repair crews in areas likely to experience high impacts. *Time over threshold*, or *time to restore 75% or 95% of customers*, allows utilities to evaluate response operations and identify when, where, and why delays in restoration efforts occur.

The metrics proposed in Table 5 can help utilities more successfully tie resilience investments to resilience outcomes by allowing them to track outages and restorations separately for investments likely to improve only one of these processes. Meanwhile, *cumulative impact* can be tracked to measure overall resilience improvements generated by many investments over time. By linking these metrics to infrastructure characteristics and operational practices, utilities can prioritize investments that maximize resilience.

Table 6 compares these performance metrics for four utilities affected by an major event on May 12, 2022. This was identified as a major event for all four utilities based on the 95th percentile threshold criteria of number of outages, number of customers affected, and outage durations. Figure 17a is normalized based on the total number of customers affected in each utility's territory, whereas Figure 17b is normalized based on the total number of customers served by each utility as obtained from U.S. Energy Information Administration Form 861 surveys [5]. Results indicate that Utility A was the most affected utility and Utility C was the least affected utility, and these differences are largely driven by the proportion of total customers affected in each territory. Restorations in Utility B did not start until we observed a peak in affected customers, while restorations in the other utilities started as soon as outages started. There could be several reasons for this, including automated restoration, remote sensing, and crew operational strategies which can assist in earlier restoration.



(a) (b)

Figure 17. Comparison of *I(t)* for four utilities for which May 12, 2022 was identified as an MED based on 95th percentile thresholds on number of outages, number of customers affected, and outage durations normalized by (a) total customers affected and (b) total customers served by each utility in 2022.

The outage process and restoration process metrics associated with these events for each utility reveal nonlinearities in the relationships between feeder impacts, outages, and restorations (Table 6).

Table 6. Comparison of Selected Resilience Metrics and Event Impact for Multiple Utilities Impacted by an Event on May 12, 2022

Utility	Feeders Affected (%)	Time Over Threshold (hours)	Average Customer Outage Hours	Outage Rate (customers per hour)	Restore Rate (customers per hour)	75% Customers Restore Time (hours)	95% Customers Restore Time (hours)	Geometric Mean Restore Time (hours)
A	64.18%	94.82	29.83	301	18	61.67	108.62	60.41
B	34.29%	12.58	8.68	126	22	22.27	25.38	26.64
C	21.82%	1.32	1.02	15	15	13.03	13.45	10.82
D	55.36%	39.07	18.96	78	25	43.12	58.37	35.26

Utility A had only 9% more feeders affected than Utility D, but differences in other metrics are significantly higher. Utility D has a 74% lower outage rate, 39% higher restore rate, 59% lower time over threshold, 36% lower outage hours per customer, and 46% faster 95% customers restore time than Utility A. If these two neighboring service areas experienced similar hazard exposure on May 12, an investigation of the planning and operational approaches of the two utilities could reveal practices that Utility A might adopt to improve recovery. In fact, these metrics can be used to analyze differences in hazard impacts across adjacent utilities to understand the extent to which differences in hazard severity or resilience investments are causing differences in utility performance.

It is important to note that the percent of affected feeders do not indicate the extent of infrastructural damages, which can happen in the absence of immediate outages, but can cause future outages when infrastructure must be replaced or repaired. These post-event outages caused by damage repairs are not considered in this analysis. For example, although 22% of feeders were affected in Utility C, less than 10% of total customers were affected (Figure 17b). This could mean that the utility had lower infrastructural damages or feeders with higher customer density were unaffected. High-level comparisons can provide insights into the performance and resilience assessment for multiple utilities affected by major events.

5.2 Critical Service Performance: Measuring the Consequences of Long-Duration Outages

Thus far, we have described metrics that characterize the impact of major events through the disruption of power delivery to customers. These metrics, however, do not differentiate between types of customers or loads. Metrics might indicate that a customer is without power, but they do not indicate whether the customer experiencing the outage is, for example, a grocery store or a pharmacy or a clothing boutique. As a result of this load agnosticism, these metrics cannot measure the potential *consequences* of different outages. Disruptions to electricity-dependent services, rather than to electricity itself, have significant consequences for the surrounding community: Long-duration power outages can decrease a community's access to health care, fuel, safe indoor temperatures, and provisions like food and water. The consequences of these outages may be greater in rural areas, where critical services outside the home are sparsely distributed, and a long-duration outage impacting a single feeder section can eliminate all basic services for residents.

This section describes *critical service access*, a new resilience metric that can be used to quantify the potential consequences of infrastructure disruptions by measuring the decreased access to critical services that can occur during power outages. Critical service access measures how easily households can meet their needs *during long power disruptions* relative to how easily households can meet their needs *during normal conditions*. This section presents baseline access to critical services for every household across Minnesota and uses that baseline to measure the potential consequences of long-duration outages for households in the Utility A service area, where detailed distribution system data were shared. This analysis demonstrates how critical service access can be used by utilities to compare the potential consequences of outage scenarios and the benefits created by grid investments that reduce those consequences.

Service access considers three types of services: services provided by locations people visit to meet a need (e.g., pharmacies), services dispatched to households from locations (e.g., fire stations), and services provided at households themselves (e.g., refrigeration). The metric reflects three core assumptions: 1) locations provide services that vary in type and quality; 2) the closer a household is to a location, the more value that location provides to that household; and 3) households have varying levels of need for different services. During a long power outage, critical service access varies from household to household depending on each household's needs and proximity to services. Critical service access also varies from hour to hour depending on which locations are without power.

In this study, household needs vary based only on the number of people in the household; future research will work to better characterize the heterogeneity of needs across households. For example, households with electricity-dependent medical devices, school-aged children, elderly residents, or those without access to personal vehicles have different baseline needs for services and therefore experience different consequences during power outages than households without these characteristics.

5.2.1 Baseline Access to Critical Services

This section describes the measurement of *baseline* critical service access, or how easily households in Minnesota can meet their needs *during normal conditions.* Baseline critical service access provides the reference point from which electrical system performance during major disruptions is measured. This metric uses publicly available location data for both residential and non-residential places in and around an area of interest (Figure 18). Data include 21 types of locations from public sources (see the Appendix). Locations are assigned a score of 0—5 in different categories of service, based on their type, to reflect the relative quality of service provided by that place (see the Appendix for scores). Table 7 shows the division of critical services into themes, categories, and subcategories used to compute critical service access. These hierarchical divisions in critical services allow the critical service access metric to be aggregated at different levels for analysis. For example, results can show impacts to food storage services alone, or impacts to all services associated with Provisions. Locations like gas stations or pharmacies may provide relatively low value across several service categories, while locations like hospitals may provide relatively high value in only one service category. These scores are assigned based on background research and prior stakeholder engagement but can be adjusted based on local conditions.

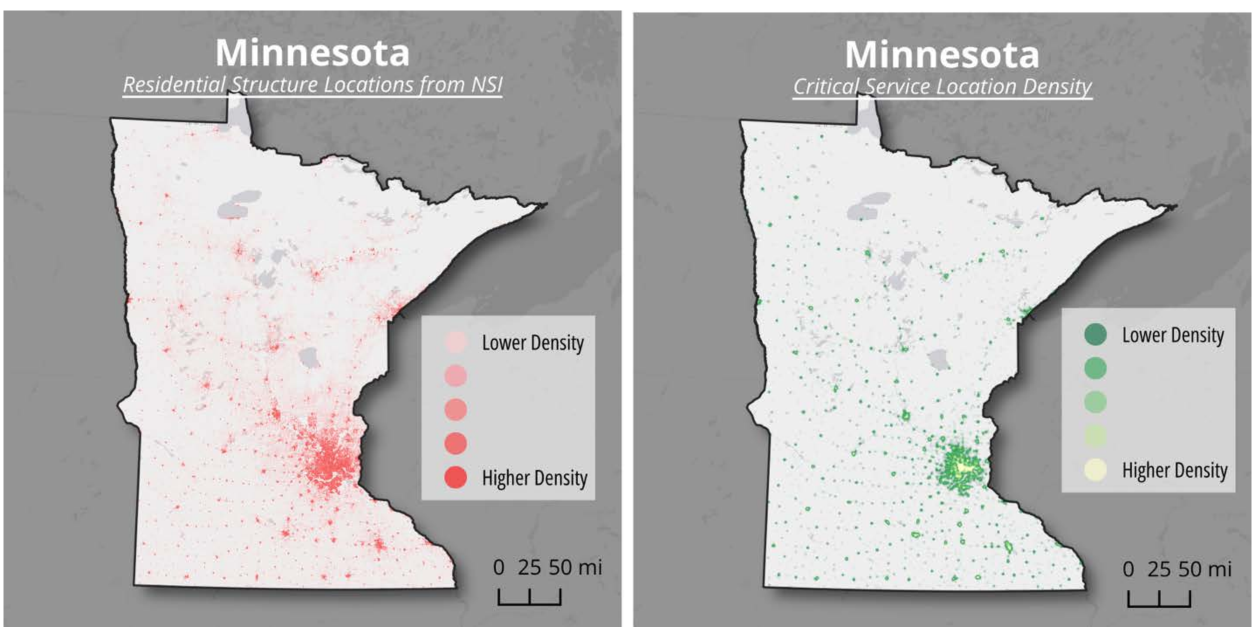


Figure 18. Spatial distribution of residential structures (left) and density of non-residential service locations (right) across Minnesota. Data sources are noted in the Appendix.

Table 7. Critical services are organized into themes, categories, and subcategories. These hierarchical divisions in critical services allow the critical service access metric to be aggregated at different levels for analysis. For example, results can show impacts to food storage services alone, or impacts to all services associated with Provisions. Locations are assigned scores of 0—5 in each of these themes, categories, or subcategories. See the Appendix for a table indicating the score assigned to each location in each service category.

Provisions	
Locations that support the acquisition and storage of supplies, including places that are open to the public during normal operations where residents can access food, gasoline, propane, or bottled water or other drinks for purchase or for free.	
Categories	**Subcategories**
Food & Water	Obtain, Store, Cook
Fuel	Obtain
Over-the-Counter Medications	Obtain
Health	
Locations that support the maintenance of health, including places that are open to the public during normal operations, where residents can access prescription medications, receive treatment for health conditions, or operate an electricity-dependent medical device.	
Categories	**Subcategories**
Medication	Obtain, Store
Healthcare	Procedure, Device
Public Safety	
Locations that help the city or county provide services residents rely on during normal operations and during emergencies. Includes places from which services are coordinated by government staff or dispatched to residents in need.	
Shelter	
Locations that support indoor safety and activities that take place in safe, indoor conditions. Includes staying warm or keeping cool, washing clothes or dishes or people, and charging networked devices that facilitate personal communication.	
Categories	
Heating & Cooling	
Hygiene	
Communication	
Workforce	
Locations that support the regular activities of residents, including schools, banks, childcare centers, and major employers, which may be paused temporarily during emergencies, but must resume for the community to return to normal.	

We used a routing algorithm to compute travel times between every residential location and nonresidential location via different modes of transportation (bike, car, public transit, and walk). Service scores are divided by the travel time between each pair of residential and nonresidential locations (using the minimum travel time among transportation modes). For example, pharmacies provide an overall critical service value of 11 across three subcategories: obtaining food, obtaining over-the-counter medications, and obtaining prescription medications. A pharmacy located 10 minutes from a household would provide a critical service value of 11/10 = 1.1 to that household. A pharmacy located 25 minutes from the same household would provide a critical service value of 11/20 = 0.55. When the critical service value provided by both pharmacies is aggregated, the household's total critical service access provided by these pharmacies is 1.65. The travel-time-weighted value of all critical service locations within a 60-mile radius of the household are aggregated to derive a total baseline critical service access for the household.

Nonresidential locations provide a travel time-weighted value to everyone living within a 60-minute drive time radius. Residential locations provide value only to people living on-site. The resulting value is a unitless, relative measure of an individual household's access to services during normal conditions. Individual household values can be aggregated across different geographic scales (e.g., a distribution feeder, neighborhood, county, utility service area, etc.) to describe the baseline critical service landscape of any area. See the Appendix for more service scores by location type and service themes, categories, and subcategories.

The spatial distribution of baseline service access across Minnesota households is shown in Figure 19. Households with relatively high access to critical services are concentrated in the Twin Cities area and in smaller towns along major roads across the state. Compared with households across the state, relatively few households in rural utility territories have high critical service access, and these households are concentrated along major roads adjacent to clusters of commercial buildings. However, this assumes that these households have access to personal vehicles as a mode of transportation, since rural areas have minimal public transportation options. This is an important consideration when determining how resilience investments will support households without access to a vehicle.

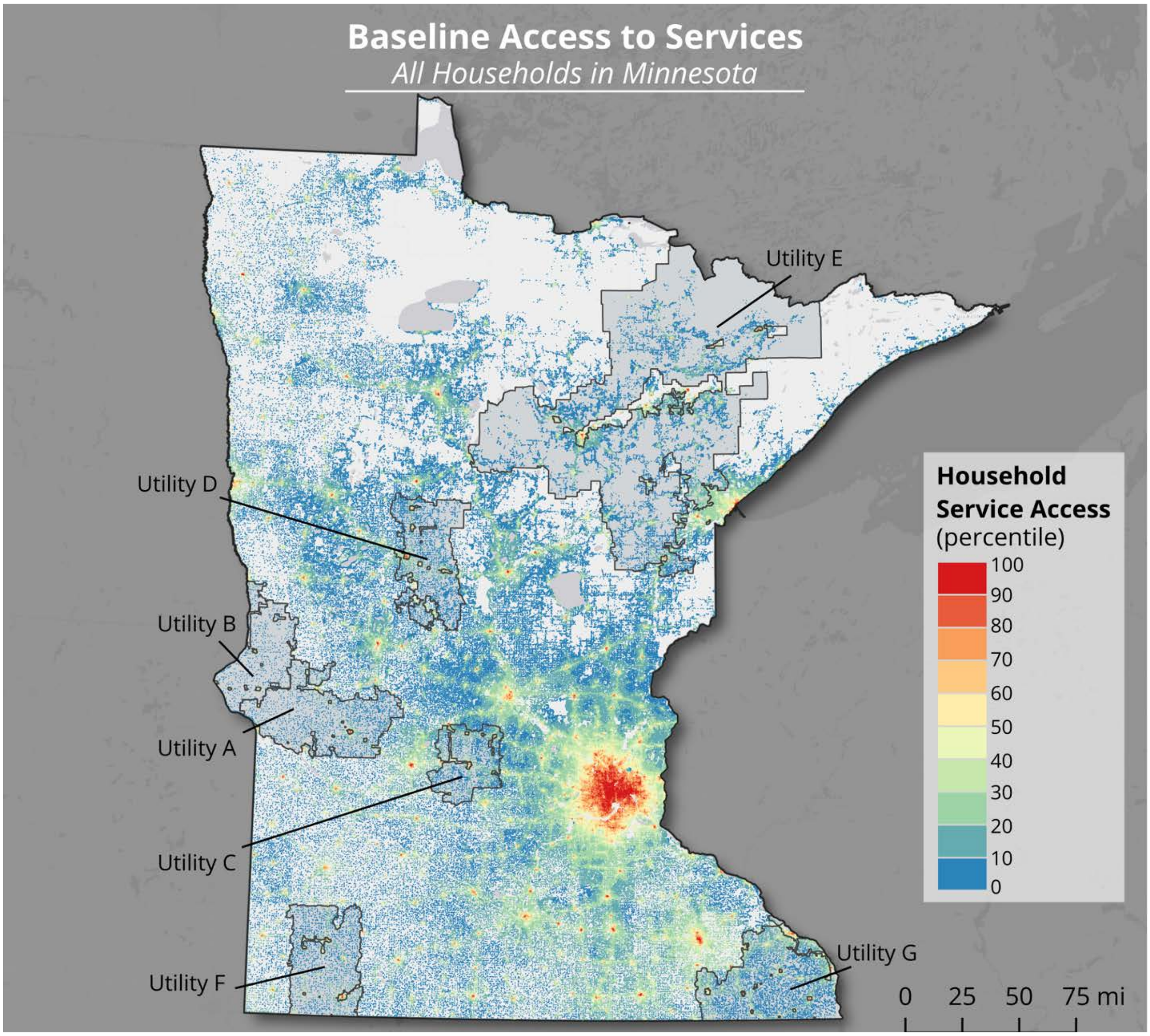


Figure 19. The distribution of critical service access at households across Minnesota. Utility territories considered in this study are marked in grey.

Figure 20 shows that rural utility areas have three times the proportion of households with critical service access below 40 (92% of households), compared with households across the state (31% of households). Only 8% of rural households have access above 40. Since each household has a critical service access score of at least 35 for the services provided onsite (storing food, storing medications, powering medical devices, heating and cooling, hygiene, and communications), these results indicate that rural households have minimal access to services provided outside the home when compared with households across Minnesota. The sparsity of non-residential services in rural utility territories significantly limits critical service access for rural households.

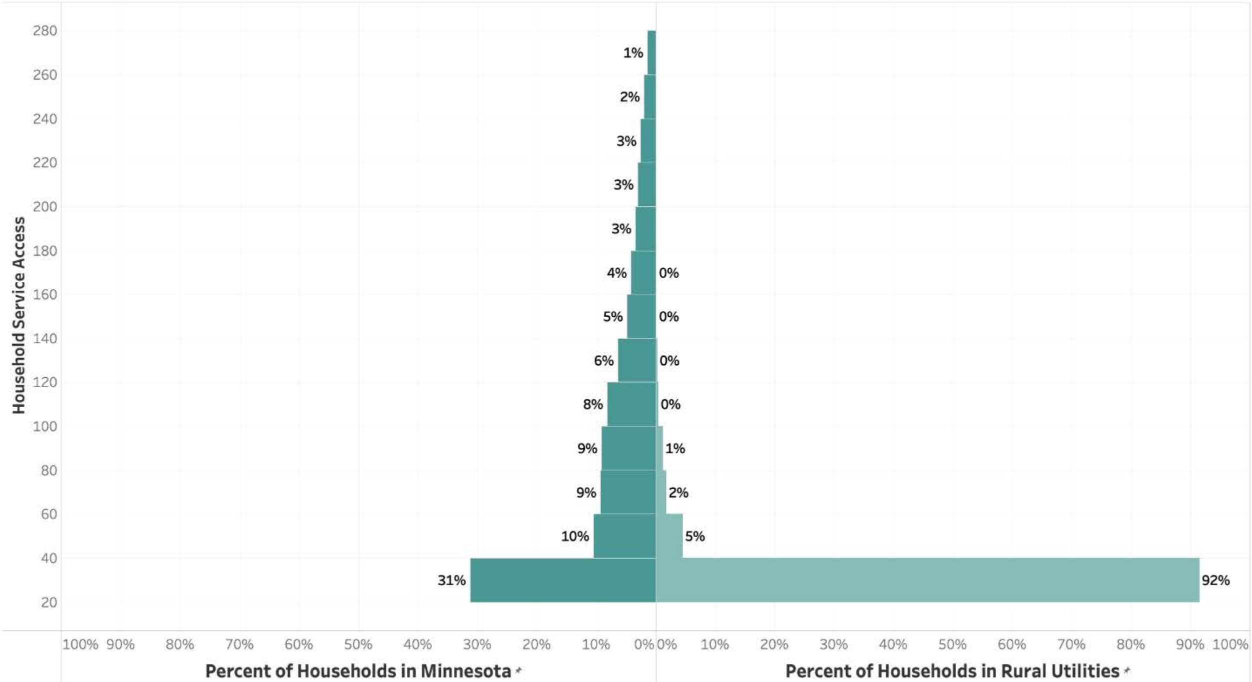


Figure 20. Statistical distribution of critical service access at all households across Minnesota (lefthand bars) and across more rural utility territories considered for this study (righthand bars). Note that the households shown in the righthand bars constitute a subset of the households shown in the lefthand bars.

This pattern is observed in the rural Utility A territory, where both residential and non-residential service locations are spatially dispersed, causing households to travel relatively longer distances for services provided outside their home. A relatively small number of households located in town centers like Benson and Morris have relatively high access to critical services. Remaining households throughout the Utility A territory have minimal access to critical services other than what their house provides them (Figure 21).

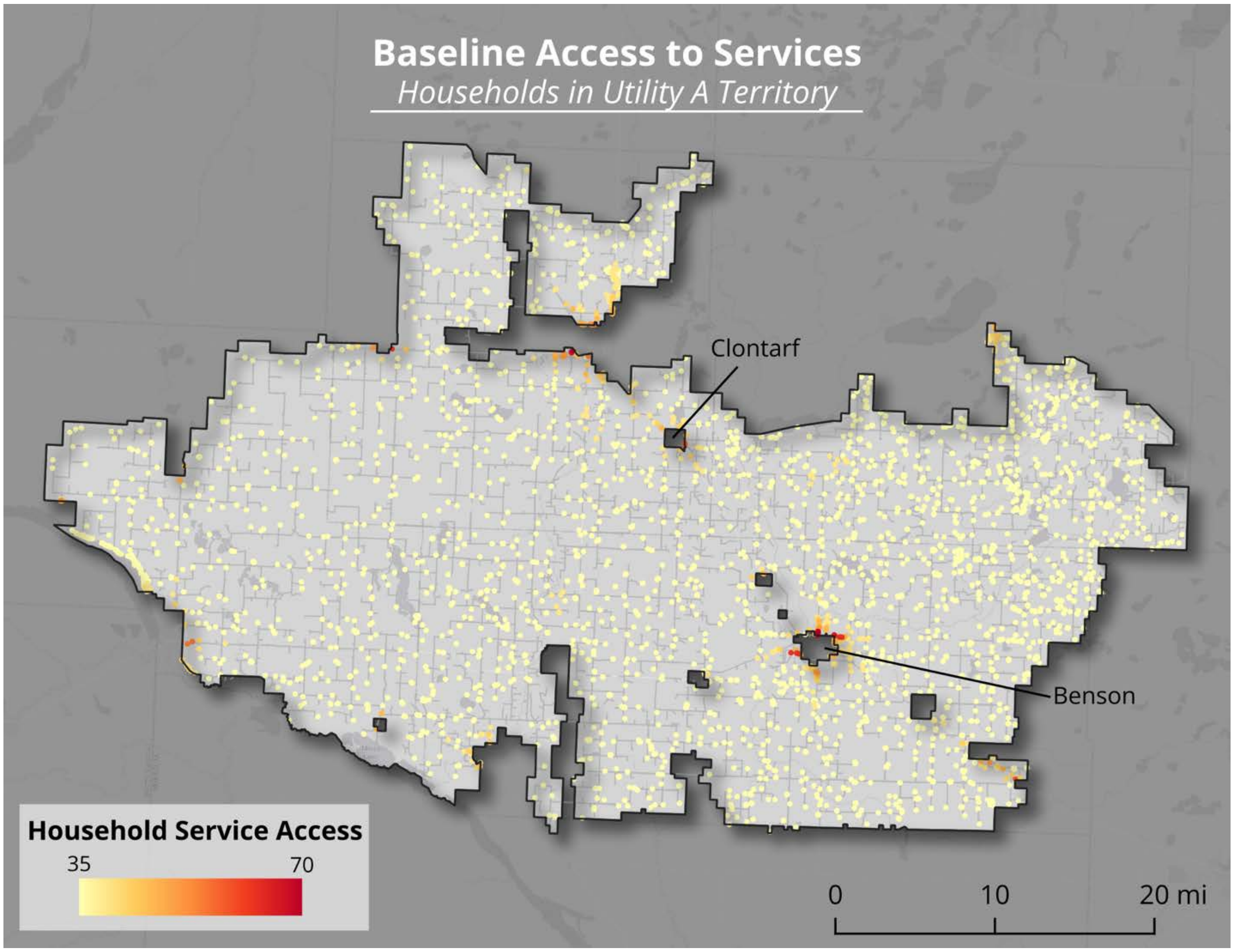


Figure 21. Baseline access to critical services for each household in the Utility A territory. Access is aggregated across all themes (provisions, health, shelter, public safety, workforce). Access is higher for households immediately proximal to clusters of non-residential service locations in the town centers of Benson and Morris, which are served by separate municipal utilities and therefore show up as gaps in the Utility A territory. Access at households farther from these centers is limited to the services provided on-site (e.g., food storage, shelter).

In fact, the handful of high value, centrally located facilities providing critical services for Utility A households are not powered by Utility A distribution infrastructure, but by municipal utilities carved out of Utility A's territory (Figure 22). Households rely on Utility A to power the electricity-dependent services they access inside their homes, but they rely on external utilities to power most of the electricity-dependent services they access outside their homes. This underscores the importance of holistic planning across utilities and other jurisdictional organizations, because resilience depends on infrastructure networks that extend outside utility territories.

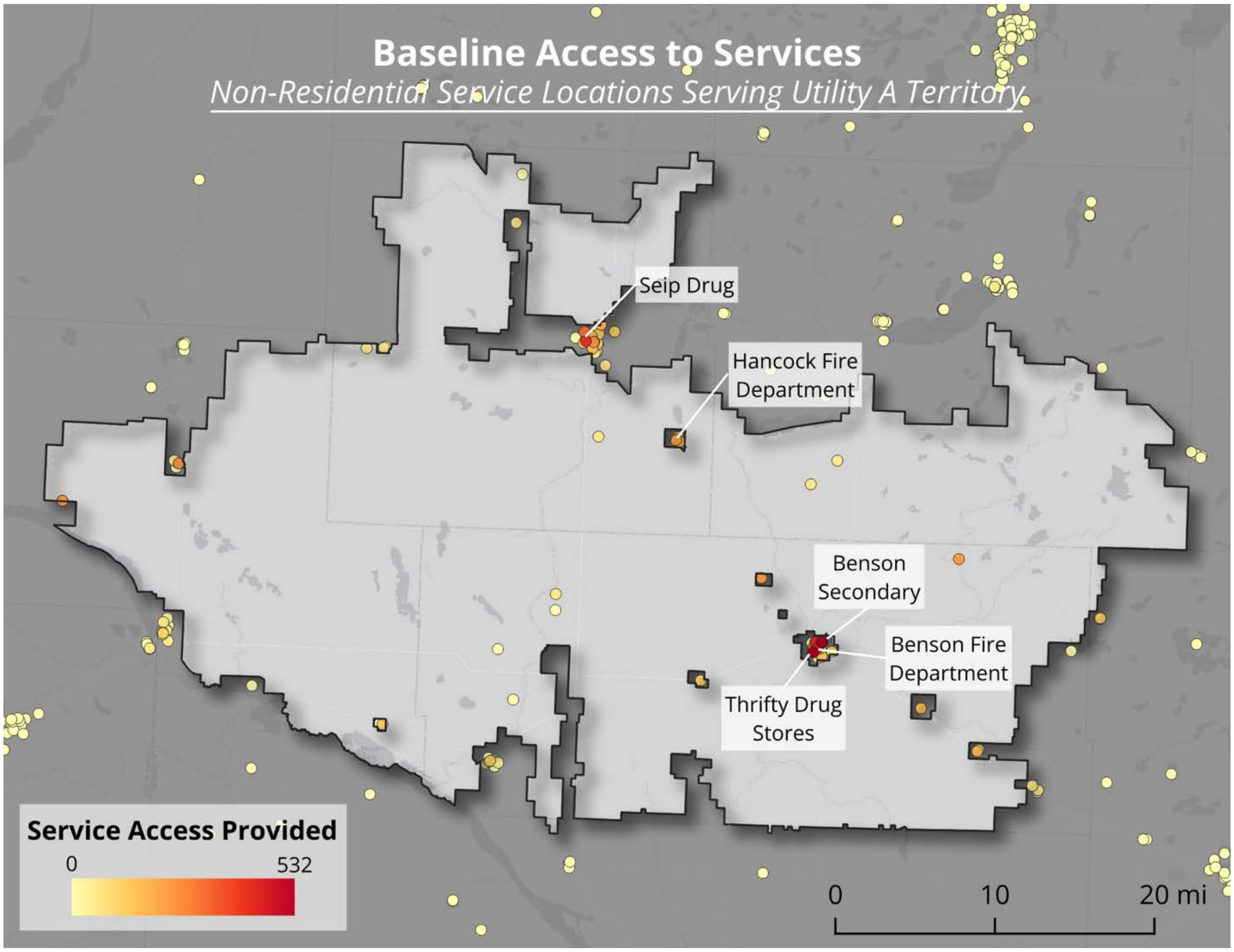


Figure 22. Non-residential service locations color-coded by their contribution to baseline critical service access for households in the Utility A service area. A handful of high-value service locations are labeled. Almost all locations are powered by separate municipal utilities.

Table 7 demonstrates the distribution of non-residential critical service locations across Utility A, municipal utility territories inside Utility A, and external utility territories. Over 99% of the non-residential locations where Utility A households access critical services are located outside the Utility A territory. However, the handful of locations powered by Utility A or by municipal utilities inside of Utility A provide 67% of the critical service access available to Utility A households outside their homes. This indicates the importance of proximity in the critical service access metric. The influence of Benson, Morris, and Hancock municipal utilities on critical service access in Utility A reflects the larger pattern of rural critical service access across the state: over half of the territory's critical service access is provided by small town centers that offer minimal support for households not immediately adjacent to them.

Table 8. Non-residential critical service locations and associated critical service access powered by Utility A, municipal utilities inside Utility A, or external utilities.

	Powered by External Utilities				Powered by Utility A	
	Benson, Morris, and Hancock Municipal Utilities		Other			
	Number of Locations	Critical Service Access Provided (%)	Number of Locations	Critical Service Access Provided (%)	Number of Locations	Critical Service Access Provided (%)
Place of Worship	10	5	3,306	2	10	5
Public School	9	16	3,172	7	2	3
Police Station	6	7	599	2	0	0
Hardware Store	6	4	1,504	2	1	0
Childcare Center	6	3	2,772	1	0	0
Shelter	5	0	1,016	0	1	0
Pharmacy	4	9	1,384	4	0	0
EV Charging Station	4	3	963	0	0	0
Fire & EMS	3	5	1,135	12	0	0
Hospital	2	3	206	1	0	0
Grocery Store	2	2	684	1	0	0
Emergency Operations Center	2	0	171	0	0	0
Bank	2	0	794	1	0	0
College/University	1	0	101	0	0	0
Urgent Care	0	0	93	0	0	0
Gas Station	0	0	689	0	0	0
Dialysis Center	0	0	9	0	0	0
Total	**62**	**59%**	**18,598**	**32%**	**14**	**8%**

Aggregating baseline critical service access across a utility's distribution feeders summarizes the spatial intersection between critical services, households, and electricity provision without having to visualize each of these data sources individually on a map. In the Utility A territory, feeders in the north power a relatively high proportion of residential locations, and therefore a relatively high proportion of the territory's baseline access to critical services (Figure 23). However, even these feeders provide only 5% of the territory's total critical service access, because non-residential service locations are largely absent from Utility A distribution feeders. Utility A provides power to only 14 non-residential service locations, including schools, churches, and a hardware store, and these locations do not contribute significantly to critical service access aggregated at each feeder. Most non-residential locations providing critical services to Utility A households are powered by separate municipal utilities (Table 8 above).

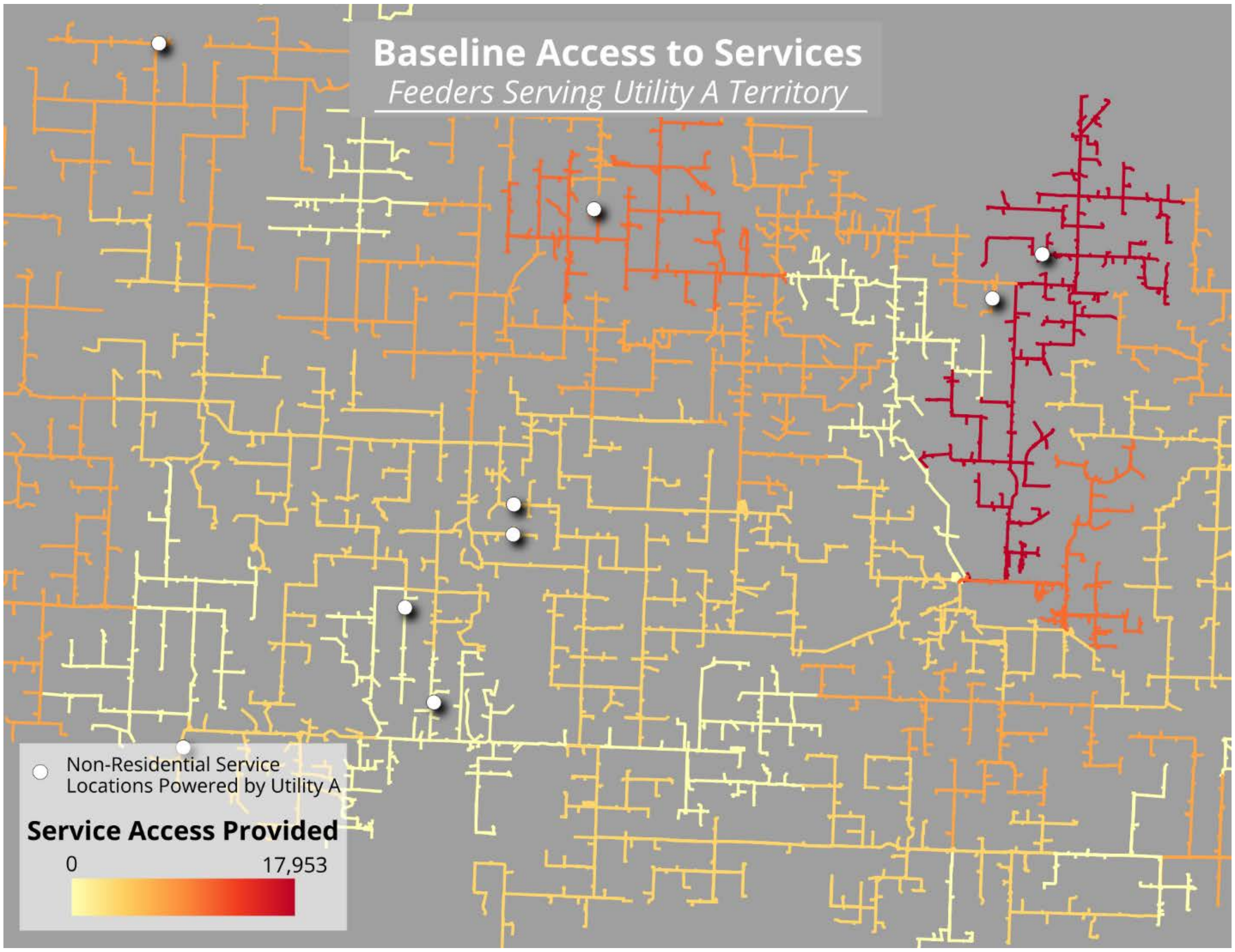


Figure 23. Baseline access to critical services aggregated by Utility A distribution feeder. Feeders contributing significant critical service access power a high proportion of the territory's residential locations, but very few non-residential critical service locations. A selection of the 14 non-residential critical service locations powered by Utility A are marked as white circles.

Baseline critical service access aggregated across an area of interest can help utilities understand which locations might be high priorities for resilience investment due to their high contribution to a community's service landscape. In Utility A, investments in the darker red feeders shown in Figure 23 could benefit households powered by those feeders by increasing the likelihood that those houses remain powered during long-duration outages. Meanwhile, investments at critical service locations powered by separate municipal utilities could benefit a wider range of households across the Utility A territory by increasing the likelihood that critical services shared by the community remain powered during long-duration outages.

The high number and spatial dispersion of residential locations relative to non-residential locations presents a trade-off for resilience investments. Increasing energy resilience at residential locations will increase access to critical services like safe temperatures, food storage, and communication during long-duration outages for many households. On the other hand, working with separate municipal utilities to increase energy resilience at non-residential locations clustered in town centers will increase access to critical services like emergency shelter, food and medicine, or medical treatment for a potentially larger number of households. However, in Utility A, where most households are located far from town centers, investments at non-residential locations may offer minimal benefits, while investments on feeders with high-residential density may offer higher benefits.

Baseline critical service access assumes that all residential and non-residential service locations have power. The spatial distribution of baseline critical service access, therefore, is not linked to grid performance. To measure the consequences of disruptions, this baseline metric must be combined with distribution system outage data to analyze how different outages affect the provision of power to critical service locations. Utility outage records allow us to compute each household’s access to critical services at each hour during major outages and identify areas that experience the worst potential consequences.

5.2.2 Access Interruptions During Long-Duration Outages

This section describes the measurement of *access interruptions,* or the potential consequences of long-duration outages for households. This metric combines baseline critical service access with distribution system outage data from utilities to measure the extent to which long-duration outages disrupt households’ access to critical services by making it harder for them to meet their needs.

In Utility A, outages are tracked at the customer level. We analyzed outage records for 2022 and 2023 to determine which locations—residential and non-residential—are without power in each hour of the 2-year period. Access to critical services is computed for each household in each hour based on the locations with or without power. Access interruptions are computed by comparing service access in each hour with baseline service access. This metric can be evaluated for individual households or for the aggregated Utility A service area to understand how the consequences of long-duration outages may differ between households, and how aggregated resilience metrics may obscure more spatially granular opportunities for investment.

Figure 24 shows the loss of power alongside the loss of access to critical services across Utility A during a major wind-driven power outage beginning on May 12, 2022. During the peak of the outage, 97% of customers were without power, but the system lost only 65% of its access to critical services. This demonstrates that not all customer outages contribute equally to consequences for households; outages at customer locations that do not contribute to the services measured by the access metric—for example, gyms, offices, or restaurants—do not decrease access to services. Furthermore, non-residential service locations powered by separate utilities in Morris, Benson, and Hancock (Figure 22) are assumed to be powered through the May 12 outage in this analysis, because feeder and outage data were not available for those utilities. Though these municipal utility territories likely experienced outages during the May 12 wind event, assuming these locations are powered allows us to isolate and measure their contribution to critical service access during a long power outage in Utility A. These results suggest that locations outside the Utility A territory protect 35% of Utility A's access to critical services during this outage. This critical service protection, which could be provided by microgrid technologies sited at clusters of non-residential service locations in Morris, Benson, and Hancock, could help Utility A households avoid consequences of long-duration, wind-driven outages like the one experienced on May 12th.

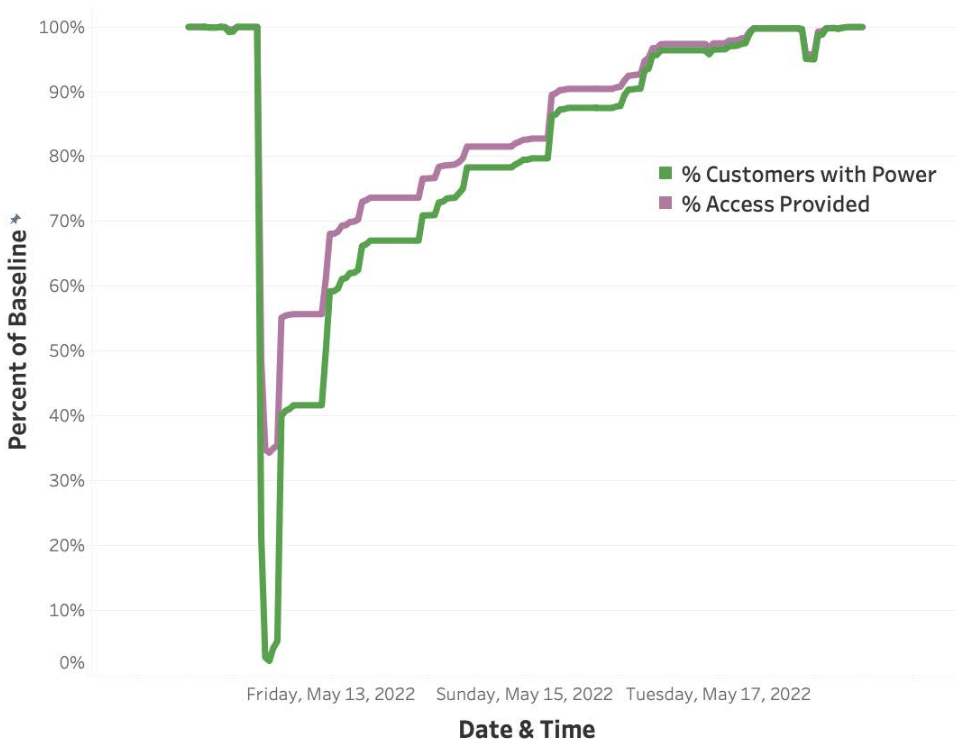


Figure 24. Percentage of customers with power (green) and percentage of baseline access to services (purple) at each hour during a major wind-driven power outage in Utility A beginning on May 12, 2022.

Evaluating loss of access by service category establishes more direct relationships between outages in Utility A and consequences for Utility A households. Figure 25 shows the loss of access to services during the May 12 outage across four critical service categories: provisions (food, fuel, and water), health (medical procedures, medicine, and medicine storage), public (fire, police, and emergency management), and shelter (safe temperatures, hygiene, and communication). Because critical services in the Public category are provided entirely by non-residential locations, and Utility A's territory includes almost no non-residential service locations, there is no measurable loss of access to services in the Public category.

All loss of access in provisions, health, and shelter categories is driven by power outages at residential locations, where some people cannot store food or medicine, power medical devices, use heat or air conditioning, or communicate via an internet connection for several days. Loss of access in these categories could be mitigated for households near pharmacies and shelters in Benson and Morris, which are assumed to be powered throughout the outage. However, in rural territories like Utility A, where most households must travel relatively farther to access shared services, the mitigation benefits provided by backup power at non-residential service locations may be relatively small.

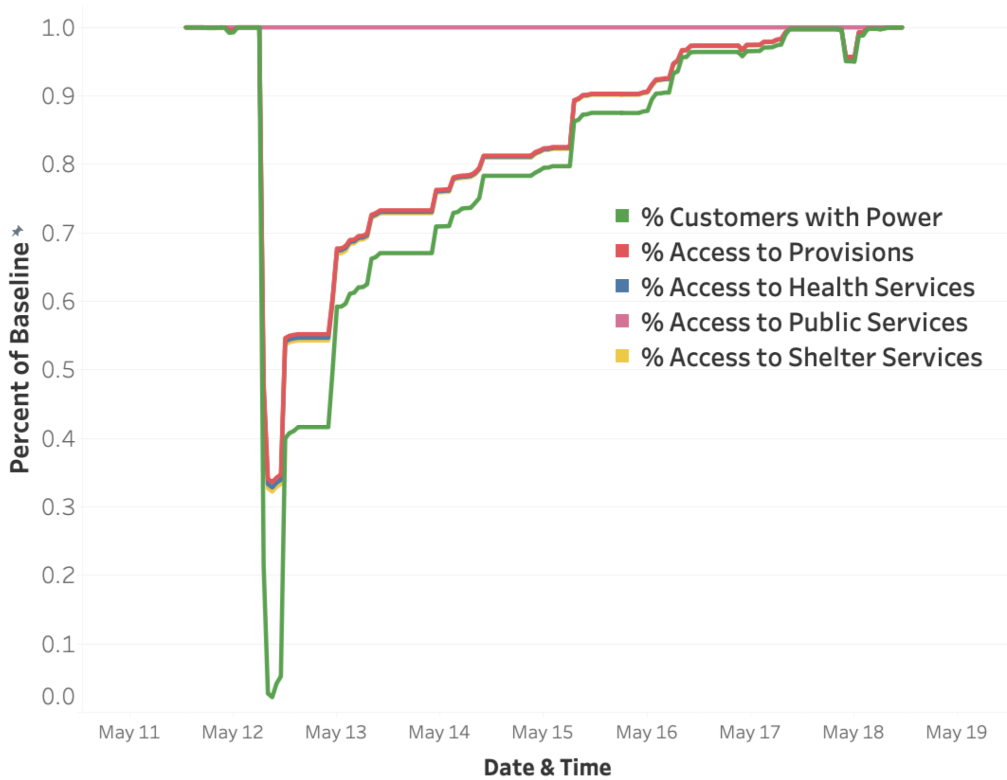


Figure 25. Percentage of customers without power (green) and percentage of access to critical services in the provisions (red), health (blue), public (pink), and shelter (yellow) categories for Utility A. In Utility A, all access to services in the provisions, health, and shelter categories is provided by residential locations, so loss of access in these categories follows a nearly identical trajectory on the chart.

Measuring the loss of access to services in smaller subcategories further illuminates the trade-offs between power at residential and non-residential locations. Figure 26 shows hourly access to critical services across Utility A in subcategories related to food: obtaining food, storing food, and cooking food. Because all locations where households can obtain food (e.g., grocery stores) are in Benson and Morris, which are assumed to be unaffected by the outage, households maintain 100% of their access to obtaining food. However, without power at most home, food cannot be safely stored or cooked at least 24 hours.

Figure 26. Percentage customers with power (green) and percentage of access to services relative to baseline in the obtaining food (yellow), storing food (red), and cooking food (red) subcategories in Utility A

Measuring each household's access to services at each hour throughout an outage can show which parts of Utility A's territory may experience the highest consequences. These consequences can be measured as the access to critical services at a specific hour of an outage, when access is at a minimum for the system or for specific households, or as the loss of access to critical services summed over the outage period (*access-hours interrupted)*. At the peak of the May 12 outage, over 2,500 households (59%) had less than 10% of their baseline access to critical services (Figure 27). The minimal access to services maintained at these households during the outage can be attributed to services assumed to maintain power in Benson and Morris, a 45-minute drive for many rural Utility A households. Figure 27 demonstrates the potential resilience benefits offered by backup power at these town centers: About 100 households closest to Benson and Morris and adjacent roads maintained 20%—50% of their baseline access to critical services, despite losing power at their homes.

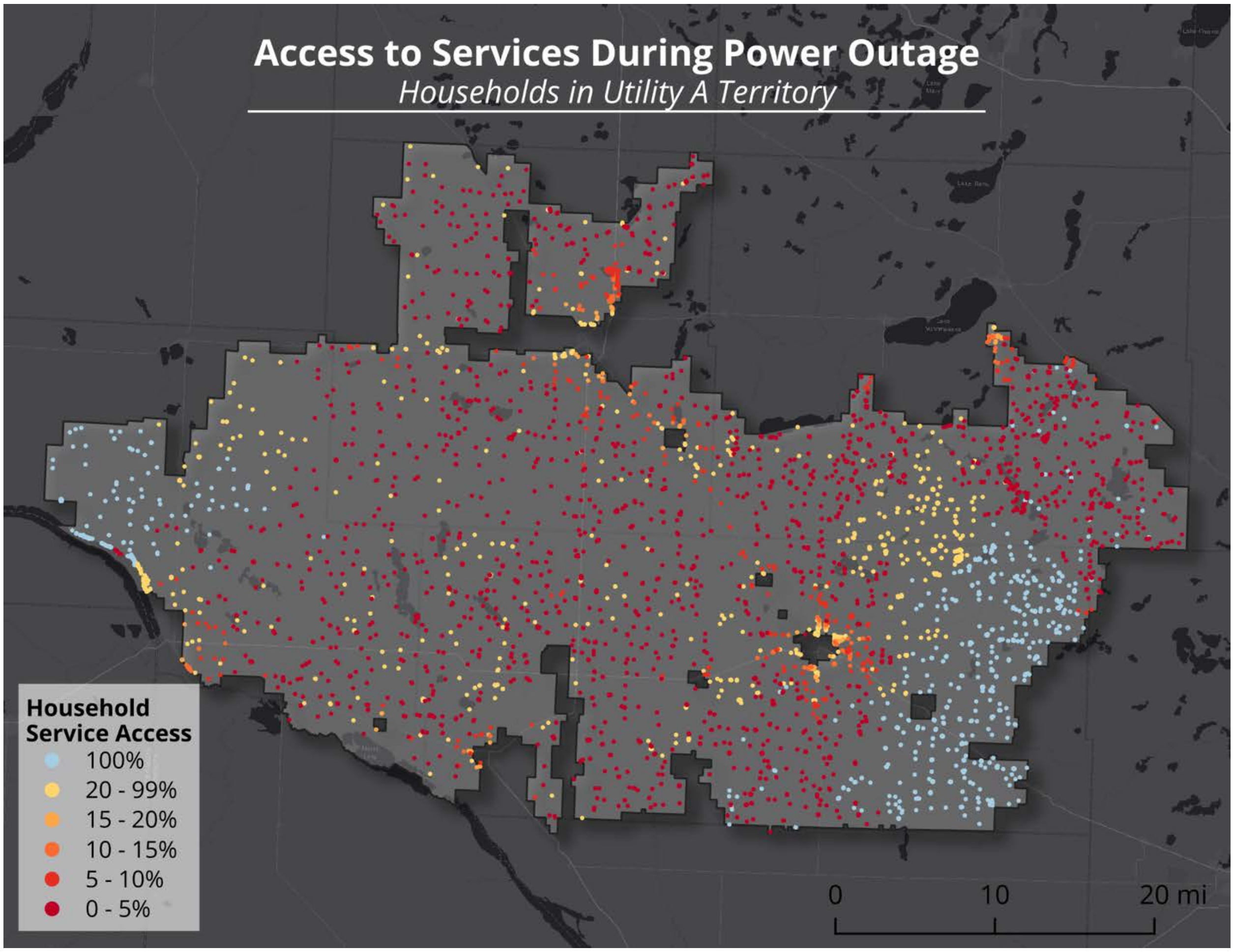


Figure 27. Map of household access to services relative to baseline at 8 p.m. on May 12th, during a major wind-driven power outage in Utility A.

The critical service access metric allows us to identify *major access interruptions,* which are defined as interruptions in critical service access that are long enough and severe enough to cause potentially harmful consequences. Duration thresholds beyond which a disruption could be considered significant were established for each service category using documented guidance ([42], [43], [44], [45], [46], [47, p. 0], [48], [49], [50], [51]). Utility A outage records were processed to derive a spatiotemporal database of outage status at every location contributing to critical services for Utility A for every hour in 2022 and 2023. At each hour in the database, each household's access to critical services is computed, relative to baseline, according to the locations with or without power in that hour. This time series is searched for days in which each household experiences a decrease in critical service access exceeding the 95th percentile of decreases over the period of record, in any category, lasting longer than the category-specific threshold.

Figure 28 shows the number of households experiencing a major access interruption in each hour for 2022 and 2023. The two access interruptions classified as major for the entire Utility A territory are annotated with vertical gray lines. This demonstrates that system-wide resilience metrics obscure outages that may be significant for specific households. Though only two interruptions were classified as major for the system, hundreds of households experienced major interruptions to critical service access on three additional days in 2022. Strategic resilience planning requires the identification of specific locations within a utility territory where outage consequences may be highest.

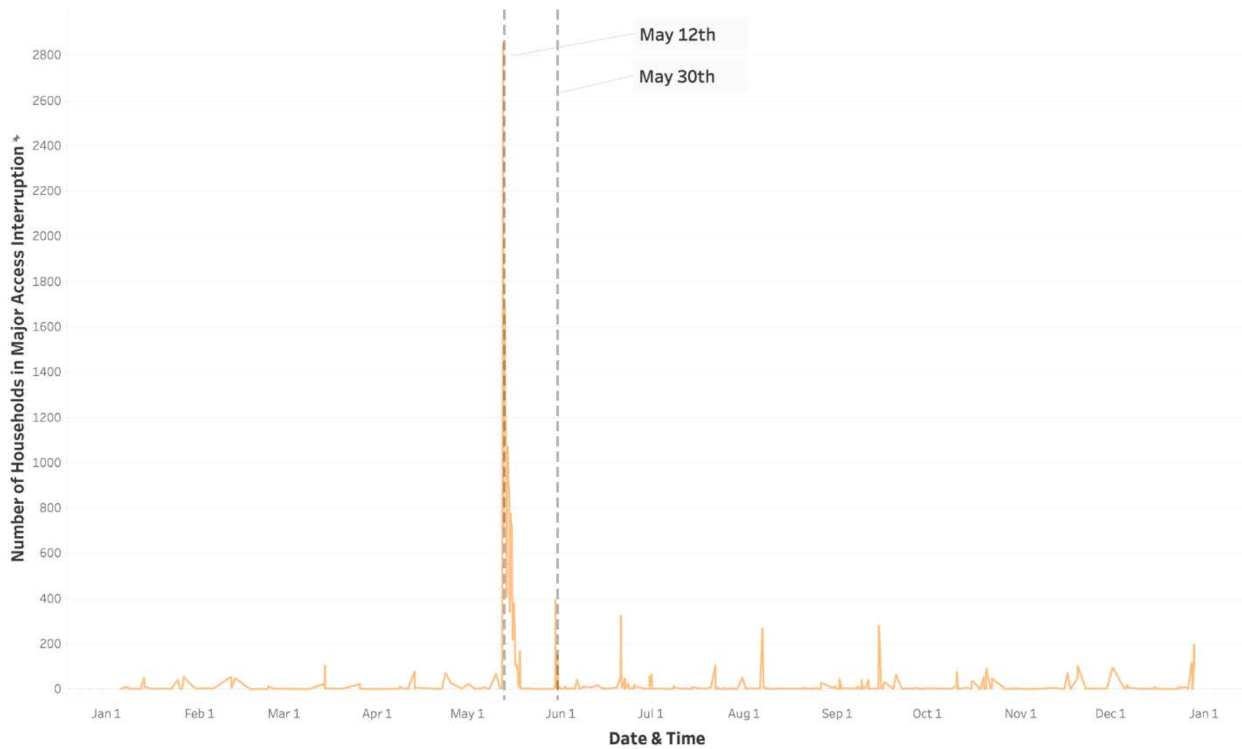


Figure 28. The number of households in Utility A experiencing an outage classified as a major access interruption for each hour in 2022. Days identified as major access interruptions for the system in aggregate are marked with gray dashed lines.

We aggregated major access interruptions across time to measure the relative access-hours interrupted for each house in the Utility A territory for 2022 (Figure 29). Annual access-hours interrupted reflect the likelihood, spatial extent, and duration of outages combined with the spatial relationship between households and critical services across a utility territory. Household-level access-hours interrupted can indicate where the consequences of long-duration outages are potentially highest. Households in the southwest, center, and northwest of Utility A experienced the longest and/or most severe interruptions in access to critical services in 2022. These households may also benefit the least from backup power at shared service locations in nearby towns like Morris, Benson, and Hancock due to relatively long travel distances between them.

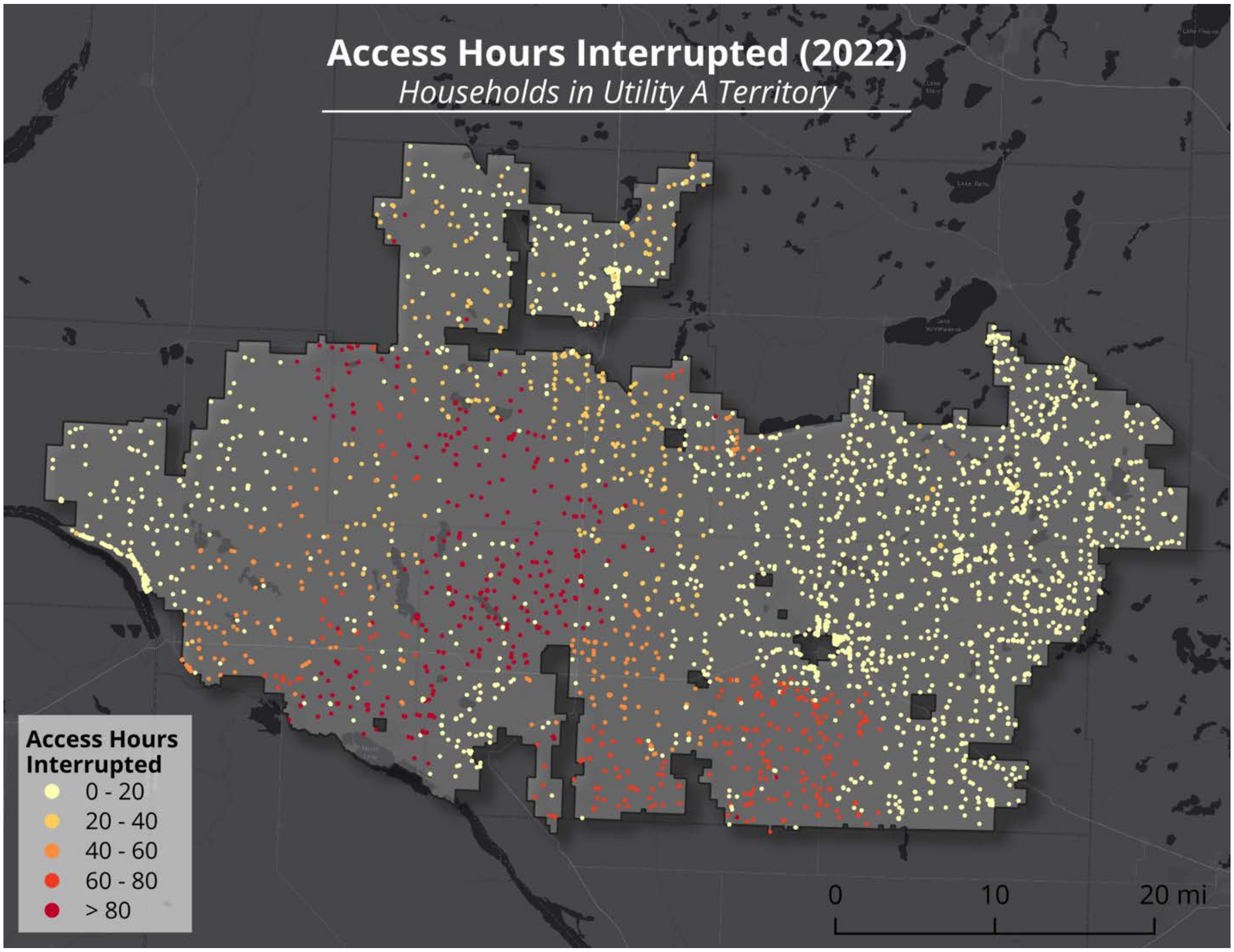


Figure 29. The number of access-hours interrupted in 2022 for each household in Utility A. Access-hours interrupted is computed by aggregating the hours classified as major access interruptions for each household based on outage records for 2022.

Aggregating this metric by feeder shows where in the distribution system households experienced the most significant disruptions to their critical service access in 2022 (Figure 30). Feeders in the south of Utility A experienced the most access-hours interrupted in 2022, and therefore the highest potential consequences of long-duration outages in that year. In contrast, feeders in the north host the highest share of Utility A's baseline critical service access (Figure 23). This highlights a core challenge of resilience planning in rural areas: Feeders that provide relatively high access to critical services during normal conditions may be restored sooner during long-duration outages, while feeders that provide relatively low access to critical services and host fewer customers per mile are likely to be restored later, creating potentially higher consequences for customers on those more remote feeders.

Resilience investments on feeders in the north (where baseline critical service access is highest) may create the highest absolute benefits for Utility A customers by maintaining low access-hours interrupted for the largest number of households. On the other hand, investments on feeders in the south (where critical service interruptions are highest) may create the largest relative reduction in potential consequences experienced by households on those feeders during long-duration outages. The northernmost feeder in Utility A hosts a high proportion of baseline critical service access *and* a relatively high number of access-hours interrupted, indicating that this feeder may be the highest priority for resilience investment in the Utility A territory.

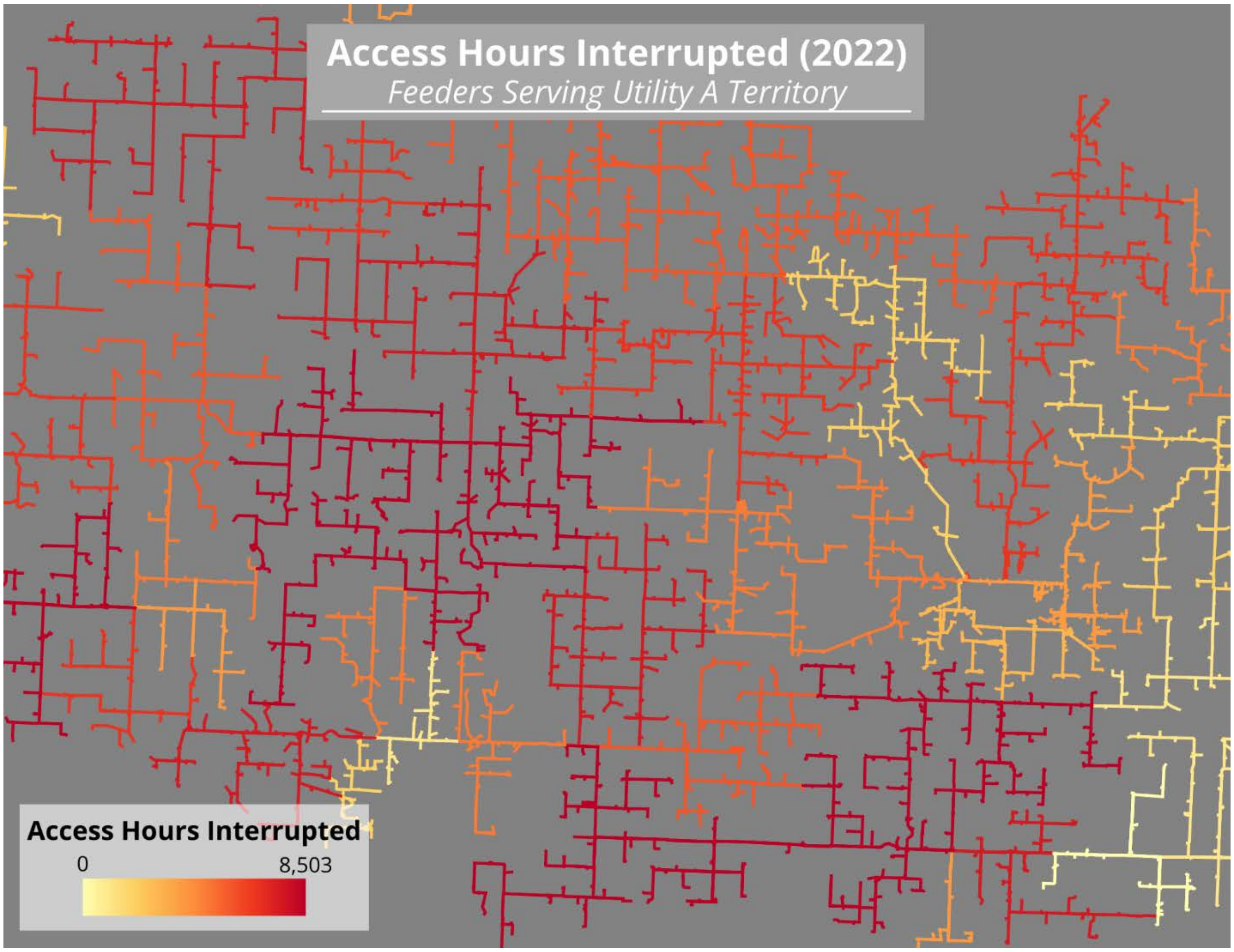


Figure 30. Access hours interrupted in 2022, aggregated by feeder in Utility A's service territory.

Mapping critical service access across Minnesota communities allows utilities, utility commissions, and Department of Commerce decision-makers to measure the critical services provided to residents by the electric system during normal conditions and during simulated or historic outages (where distribution system data are available). Analyzing critical service access across utility territories can help measure the potential consequences of long-duration power outages and design resilience investments that minimize those consequences. When service access data are combined with feeder-level outage and spatial data, the value of investment strategies can be measured based on the extent to which those investments prevent access interruptions at households. Measuring the potential consequences of long-duration outages for households allows utilities to plan for resilience more strategically than is possible with traditional system-wide reliability measurements, such as outage durations and the number of customers without power.

The access interruption metric provides a more consequence-focused measure of performance for utilities investing in increased resilience. This metric allows utilities to measure where, how, and how much their improvements might benefit customers by avoiding the consequences associated with households losing access to important electricity-dependent services. For example, in rural utility territories, backup power at clusters of non-residential service locations could help some nearby customers obtain food, medicine, fuel, medical care, or access safe indoor temperatures during a long-duration outage. However, increasing resilience for rural households might require distribution hardening or automation on feeders that experience the highest access-hours interrupted, to ensure customers can safely store food and medication and maintain safe temperatures at home. Utilities can also partner with emergency management agencies to strategically distribute electricity-dependent resources across a community to ensure minimal access to services is maintained.

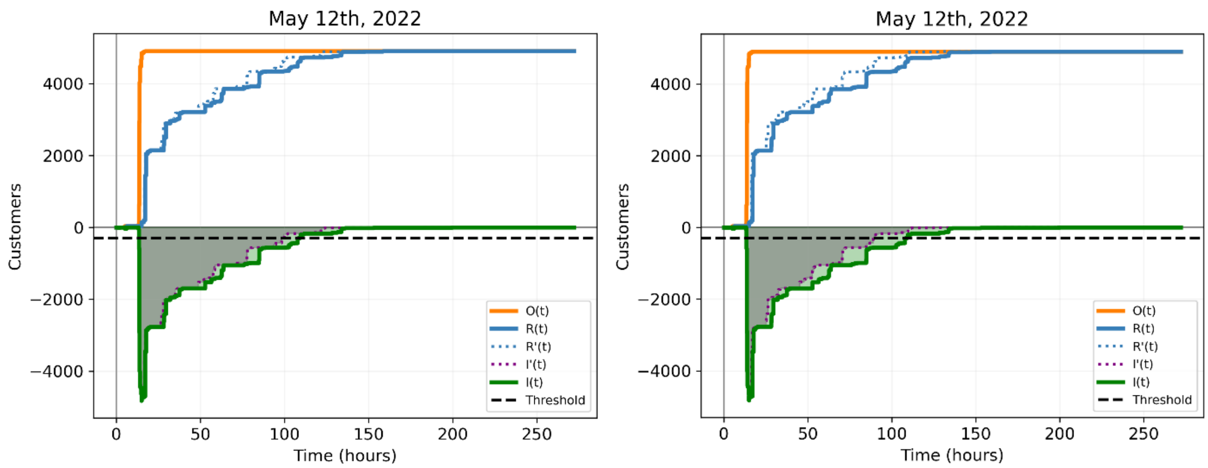
Evaluating household service access during power disruptions can also highlight opportunities to adjust restoration operations to restore access to specific service categories or to households with minimal access to shared service locations. Defining major access interruptions at the household-level can ensure that investments are targeted at the events, areas, and grid infrastructure that matter most to communities. Energy resilience investments that protect or restore access to critical services for a large number of households will change the shape of hourly critical service access curves during outages and reduce the annual access hours interrupted for many households, indicating meaningful benefits for customers.

6 Prioritizing Resilience Investments

Utilities face important trade-offs when it comes to selecting resilience investments. The upfront cost of undergrounding power lines, for instance, can be much greater than maintaining overhead lines, though the long-term benefits can include reduced maintenance and fewer outages. Modeling and simulation tools can be used to evaluate potential avoided costs and consequences of weather-driven damage and outages to calculate cost-benefit ratios of resilience projects or quantify potential benefits using resilience metrics like the ones presented in Section 5. Resilience investment strategies can incorporate both financial and social benefits; optimal approaches to balancing these objectives will depend on the utility service area, including customer density, terrain, and hazard exposure.

Section 5.2 introduces metrics for selecting areas or feeders for investments to enhance resilience. Here, we discuss what those specific investments can be and how an investment mix might be prioritized. While some benefits of investments in resilience are self-evident (e.g., undergrounding a section of a feeder will result in reduced outages in that particular section of feeder), the service access metric can measure the diffuse benefits that extend beyond the feeder itself. Some operational investments, like improving crew access to trucks to reduce restoration times overall, will also have benefits for the entire service area.

Section 5.1 introduces metrics that can be used to evaluate the impact of weather events to the distribution system and examine hypothetical improvements in a system’s ability to recover, or, how a utility might meaningfully target a specific aspect of resilience (restoration) through investments to improve restoration times.



a) 10% faster restoration

b) 20% faster restoration

Figure 31. Change in restoration scenarios (faster recovery is shown in the blue dotted lines; resulting improvement in impact is shown in the purple dotted lines) for the event on May 12, 2022, for Utility A

Figure 31 compares two scenarios: (a) utilities restoring outages 10% faster and (b) utilities restoring outages 20% faster. In these scenarios, outages that took 5 hours to restore now take 4.5 hours (10% faster) or 4 hours (20% faster) to restore. These hypothetical improvements to restoration time provide achievable targets and improve the resilience performance considerably, as shown in Table 9. The table also includes additional scenarios where 10% and 20% faster restoration scenarios are only applied to the 20 longest restorations as compared to each restoration. Restoration improvements can be targeted with advanced technologies like FLISR, remote switching and microgrids, or with simple operational adjustments, like allowing crews to take company trucks home at the end of a shift.

Table 9. Improvement in Selected Resilience Metrics for Multiple Restoration Scenarios

Scenario	Restore Duration (hours)	Time Over Threshold (hours)	Total Customer Outage Hours	Average Customer Outage Hours	Restore Rate (customer per hour)	75% Customers Restore Time (hours)	95% Customers Restore Time (hours)
Baseline	268.87	94.82	146,515.70	29.83	18	61.67	108.62
10% faster restoration	243.25	85.57	131,869.567	26.852	20	56.78	99.02
20% faster restoration	217.63	76.33	117,207.1	23.866	23	51.88	89.42
10% faster restoration for 20 longest restorations	243.25	94.82	144,713.028	29.46	20	61.67	108.62
20% faster restoration for 20 longest restorations	217.63	94.73	142,910.357	29.1	23	61.67	108.62

Investments that utilities are already considering are compiled in Table 2 in Section 3.2. Table 10 expands this to include potential investments that were not identified in current utility planning documents and details how they would shift the categories of resilience metrics presented in Section 5.1. These investments can often provide resilience in the face of multiple hazards. These are listed in Table 10 and can be considered when selecting investments depending on the expected likelihood of a hazard occurring in that service area. Additional utility objectives supported by each of these investments are also listed. Considering multiple objectives is important for prioritizing and selecting investments that cannot be accurately evaluated using standard cost-benefit analyses because their benefits cannot be quantified using standard methods.

Many of the investments in Table 10 are already being considered by many utilities, according to utility planning documents. We introduce microgrids and forward-looking analysis as additional options for consideration. Microgrids can be cost-prohibitive, but in rural areas may in fact be competitive with the many miles of undergrounding or overhead hardening required to enhance resilient power delivery to customers far from substations. When built with renewable energy resources such as photovoltaics, these can also contribute to specific energy targets such as those set by the state or utility. It is not uncommon for utilities to conduct some form of forward-looking analysis but omit results from planning documents. Out-of-the-box, forward-looking analysis tools have not been identified for every type of hazard, however methods for simulating and analyzing these impacts resulting from wind events and other hazards identified as high priority to utilities in Minnesota are available [7].

Table 10. Investments That Can Enhance Distribution System Resilience to the High-Priority Hazards Identified in Section 2.2.

Additional hazards that could become high priority in Minnesota in the future are listed if the investments could provide benefits to grid performance during and after those events. The expected influence on a core set of performance metrics presented in Section 5 is included.

Investments	Utility Implementation	Relevant High-Priority Hazards	Relevant Forward-Looking Hazards	Measuring Benefits	Additional Objectives Supported
Vegetation management: Enhanced tree trimming, increased right of way	Frequent among Minnesota utilities	Windstorms, tornadoes, ice, winter storms	Wildfire, extreme heat	Outage rate and outage duration decrease; access interruption hours decrease	Reliability
Overhead hardening: Pole replacement or repair, reconductoring with wires with increased wind ratings	Frequent among Minnesota utilities	Windstorms, tornadoes, ice, winter storms, floods	Wildfire	Outage rate and outage duration decrease; access interruption hours decrease	Reliability
Undergrounding: In areas where access for vegetation management is difficult; undergrounding vulnerable lines or lines in critical areas	Frequent among Minnesota utilities	Windstorms, tornadoes, ice, winter storms, floods	Wildfire	Outage rate decreases; access interruption hours decrease. In the event of an outage, restoration times (and therefore access interruption hours) can increase. Cumulative impact could still be reduced due to reduced outage rates.	Reliability and long-term affordability can improve, but cost-benefit ratios must be thoroughly evaluated
Network redundancy: Increased integration of tie-switches	Cited in investor-owned utility integrated distribution plans	Windstorms, tornadoes,	Wildfire, extreme temperatures	Restoration rate will increase; access	Reliability

Investments	Utility Implementation	Relevant High-Priority Hazards	Relevant Forward-Looking Hazards	Measuring Benefits	Additional Objectives Supported
		ice, winter storms, floods		interruption hours decrease	
Grid modernization: Fault location, isolation, and service restoration, enhanced outage management systems,[a] electronic sectionalizing devices	Cited in investor-owned utility integrated distribution plans	Windstorms, tornadoes, ice, winter storms, floods	Wildfire, extreme temperatures	Restoration metrics improve; access interruption hours decrease	Reliability
Grid modernization: Battery energy storage systems for backup**, or supporting renewable energy integration** [a]	Cited in investor-owned utility integrated distribution plans	Windstorms, tornadoes, ice, winter storms, floods	Wildfire, extreme temperatures	Outage rate, outage duration, restore duration, mean restoration time, and cumulative impact can decrease; Restore rate, time to first restore, can increase; access interruption hours decrease	Reliability, state-specific energy targets

Investments	Utility Implementation	Relevant High-Priority Hazards	Relevant Forward-Looking Hazards	Measuring Benefits	Additional Objectives Supported
Grid modernization: Microgrids	None identified	Windstorms, tornadoes, ice, winter storms, floods	Wildfire, extreme temperatures	Outage rate, outage duration, restore duration, mean restoration time, and cumulative impact can decrease; Restore rate, time to first restore, can increase; access interruption hours decrease	If renewable resources such as photovoltaics are included, state-specific energy targets can be achieved. Some utilities in other states have invested in microgrids because they have found them to be cost-effective in their most rural communities [1], [2]. Cost-benefit ratios for specific projects in Minnesota can be performed to better assess this as a cost-effective option.
Grid modernization: Resilience hubs[b]	Cited in investor-owned utility integrated distribution plans	Windstorms, tornadoes, ice, winter storms, floods	Wildfire, extreme temperatures	Access interruption hours decrease	Reduction in disaster consequences experienced by households that may or may not be related to electricity availability
Operations: Mutual assistance programs, service truck operations for crews	Electric cooperatives and municipal utilities are participating in mutual assistance programs [3]. In interviews, cooperative representatives reported that allowing line workers to take trucks home reduced restoration times.	Windstorms, tornadoes, ice, winter storms, floods	Wildfire, extreme temperatures	Restoration metrics will improve; access interruption hours decrease	Affordability

Investments	Utility Implementation	Relevant High-Priority Hazards	Relevant Forward-Looking Hazards	Measuring Benefits	Additional Objectives Supported
Advanced resource planning: Backup generation such as diesel generator sets for critical facilities	Municipal critical facilities or other municipal departments	Windstorms, tornadoes, ice, winter storms, floods	Wildfire, extreme temperatures	Restoration metrics will improve; access interruption hours decrease	
Forward-looking analysis: None identified	None identified	Windstorms, tornadoes, ice, winter storms, floods	Wildfire, extreme temperatures	Analysis techniques can impact outage metrics, restoration metrics, reduce cumulative impact, and service access	Any other objective prioritized in the analysis

[a] Cited in electric cooperative documentation [4].

[b] Resilience hubs use backup generation to provide power to strategically selected, co-located resources to enhance public safety during a blackout. Xcel's Resilient Minneapolis Project incorporates a microgrid with PV and battery resources that will be owned and operated by community partners [52], [53].

7 Conclusion

This work reviews hazards facing electric distribution utilities in Minnesota and current utility planning practices. Utility outage and distribution asset data are used to evaluate weather event impacts and identify resilience metrics that can be calculated with public data and outage data common to small utilities throughout Minnesota. These metrics can guide resilience strategies and cost-effective investment decisions, and, over time, measure improvements in system performance stemming from these investments. No one metric captures a complete picture of distribution grid performance. We present a set of resilience metrics designed to characterize performance during a major event. These metrics can be calculated by any utility recording customer outage start times, locations, and durations.

Windstorms and tornadoes are currently of the greatest concern to Minnesotan utilities. Winter storms are also high priority throughout the state but may be more critical to utilities in specific areas, while wind events are pervasive throughout the state. Other hazards identified include flooding, which is of greater concern in parts of the northern half of Minnesota. While flooding tends to degrade grid infrastructure, it does not always result in immediate outages. Future hazard concerns could include wildfire and extreme cold. With this in mind, we focused on wind resilience but evaluated investments that can provide resilience to multiple hazards. Our analysis indicates that increased resilience performance in rural utility territories during major wind events may depend on large resilience investments such as undergrounding high percentages of feeders. Considerable undergrounding efforts may be cost-prohibitive, especially for utilities serving areas with bedrock. Investments that increase resilience by decreasing restoration times, such as prepositioning restoration crews, could offer a less costly alternative.

In rural utility territories, the consequences of interruptions to electricity-dependent services can be severe, because baseline critical service access is already limited and households must travel relatively longer distances to meet their needs. Special consideration should be given to the trade-offs between investments that decrease power interruptions at homes and those that decrease power interruptions at clusters of critical service locations in town centers. Integrating critical service access into resilience strategies can ensure investments are targeted at avoiding the worst consequences of long-duration outages. These metrics can be used to characterize the benefits of resilience investments, tracking them over time and providing targets to assist in resilience strategy.

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Appendix

Utility Document Survey

Municipal Utilities

The most readily available information documenting municipal utility resilience considerations can be found within county hazard mitigation plans, which are submitted to FEMA every five years a plan of localized hazards, vulnerabilities, and mitigations. Counties across the United States must submit these plans to remain eligible for disaster mitigation grant funding. County hazard mitigation plans largely follow the structure and guidance of example mitigation measures that are found within the State Hazard Mitigation Plan. While these plans do provide additional information on overall multi-jurisdictional hazard coordination, information specific to municipal utility planning is extremely limited and follows a template approach reflecting the State Hazard Plan guidance and that many of the municipal utilities contract with Minnesota State University for updating county-level hazard mitigation plans.

Within the Hazard Mitigation Plans of Minnesota's rural electric municipal utilities, two strategies are cited repeatedly – vegetation management and undergrounding overhead lines to mitigate wildfires and severe summer and winter storms. Winter storms with heavy ice and high winds can cause outages from downed trees and branches breaking. Many Hazard Mitigation Plans include back-up diesel generators as a stop gap measure for critical municipal facilities. These efforts are usually driven by a specific municipal department, such as fire or police departments, and not directly as a municipal utility strategy.

Located in Wadena County, the City of Staples electric utility has self-identified another vulnerability—the potential for substation overload if one of two substations serving the area goes offline during a storm event. Although identified as a potential risk within the Wadena County Hazard Mitigation Plan local mitigation survey, it is unclear what steps are being taken by the City of Staples electric utility, if any, to reduce or supplement substation load.

Most municipal electric utilities have a tree trimming or vegetation management program to pro-actively reduce the likelihood of outages due to downed trees and branches. Beyond these maintenance activities, municipal utilities like the City of Staples are considering other measures such as updates to municipal tree ordinances to require a permit and city review before residents plant a tree within a city right of way that could potentially interfere with city infrastructure including power lines.

Municipal utilities can earn a voluntary designation through the American Public Power Association (APPA)'s Reliable Public Power Provider (RP_3) program, which recognizes high performing utilities in four categories – reliability, safety, workforce development, and system improvement.

RP_3 designation is valid for three years. Utilities that submit an application to APPA are scored by an 18-member panel of industry peers. Diamond status is awarded to utilities that score 98-100 points, Platinum 90-97 points, and Gold status 80-89 points.

Within the category of reliability, utilities are expected to collect reliability indices to demonstrate awareness of system performance through the use of reliability indices to track and report outages on a regular basis. Acceptable reporting indices include SAIDI, CAIDI, Average Service Availability Index (ASAI), SAIFI, and MAIFI. Secondly, each utility is asked to provide goals or targets for at least three of the above indices, demonstrating a commitment to system improvement [30].

A third component, documents if the utility has joined a national mutual aid network. Within FEMA Region V (which includes Minnesota, Wisconsin, Michigan, Illinois, Indiana, and Ohio), nearly 80% of municipal utility within Minnesota have signed APPA's mutual aid agreement to assist other utilities restore power during outages 11/24/2025 10:48:00 AM. Finally, utilities are evaluated on having a disaster plan in place and demonstrating preparedness by holding at least one disaster drill or exercise per year [30].

Minnesota utilities that achieved RP_3 status can be found below.

Table 3. Municipal utilities by RP_3 status.

Utility	Status
Alexandria Light and Power	Diamond
Austin Utilities	Diamond
Blue Earth Light and Water Department	Diamond
Detroit Lakes Public Utility	Diamond
Marshall Municipal Utilities	Diamond
Owatonna Public Utilities	Diamond
Rochester Public Utilities	Diamond
Shakopee Public Utilities	Diamond
Elk River Municipal Utilities	Platinum
Moorhead Public Service	Platinum
New Prague Utilities Commission	Platinum
St. Peter Municipal Utilities	Platinum
Willmar Municipal Utilities	Platinum
Hutchinson Utilities	Gold

Cooperative Utilities

Minnesota's electric cooperatives are undertaking strategic investments to address the vulnerabilities of their energy systems, focusing on both immediate improvements and long-term resilience enhancements. Short-term investments emphasize measures such as storm hardening and enhanced outage management systems to mitigate the impacts of recurring hazards like winter storms, high winds, and flooding. For instance, East Central Energy and

BENCO Electric Cooperative are concentrating on undergrounding vulnerable lines, a proven strategy to reduce outages caused by windstorms and ice accumulation [25], [26]. Similarly, Minnesota Valley Electric Cooperative is upgrading substations in flood-prone areas to strengthen reliability and minimize disruptions during major weather events [26].

In the long term, the cooperatives are increasingly adopting smart grid technologies and renewable energy integration to modernize their infrastructure and reduce reliance on external power sources. Great River Energy, for example, is reinforcing poles, deploying advanced monitoring systems, and integrating renewable energy sources to enhance system reliability and recovery times [27], [28]. Connexus Energy has prioritized the deployment of smart grid advancements and modernized infrastructure to improve restoration times and support renewable energy integration [29]. Federal funding plays a crucial role in supporting these efforts, as highlighted by Arrowhead Electric Cooperative's focus on leveraging federal programs to deploy smart grid technology and undergrounding lines in critical areas [26].

Investor-Owned Utilities

IOUs in Minnesota represent diverse customer bases and service areas. Xcel serves the Twin Cities and more populous regions, while Otter Tail serves more rural counties in western Minnesota in addition to those in North and South Dakota. Minnesota Power's service area includes a larger proportion of industrial customers. Nevertheless, there are common themes identified in all three IDPs. All three IOUs identify vegetation management and undergrounding projects for resilience, investment types that are common for municipal utilities and electric cooperatives as well. The Minnesota IOUs all invest in smart grid technologies, though there is variation in which technology. These are detailed in Table 11.

Table 11. Smart grid technologies identified in 2023 IDPs. These were described as enhancing system resilience or described as providing benefits in emergent scenarios, such as providing backup power when a primary source of power is lost in a weather event.

Investor-Owned Utility	Smart Grid Investments for Resilience
Minnesota Power	BESS for backup power
	FLISR
	OMS upgrade
Otter Tail	Remote sensors for fault detection
	Satellite data
	Drones
	New sectionalizing technology
Xcel (Northern States Power Co)	Resilience hubs[7]
	FLISR

These three IDPs also report existing intelligent systems that support smart grid technologies such as outage management systems (OMS), advanced distribution management systems (ADMS), and distributed energy resource (DER) management systems (DERMS).

Minnesota Power's IDP reviews several cost-benefit analyses for backup BESS and FLISR projects. These result in reported benefit cost ratios ranging from 0.75 to 6.95, indicating that even within a single service area, there is no one-size-fits-all approach to resilience.

Standard Reliability Metrics

Utilities often consider reliability metrics like SAIFI, SAIDI, and CAIDI as system performance indicators that can be used interchangeably with resilience metrics. In fact, reliability metrics obscure the impacts of major events on system performance by including customers and outages unrelated to long-duration outages. In many cases, major events are omitted altogether from the annual SAIFI, SAIDI, and CAIDI metrics reported by utilities.

A system with a SAIDI of two minutes for 364 normal days and 1,200 minutes for one major event day will have an annual SAIDI of five minutes if the major event day is included in the index calculation. While an average customer interruption of 1,200 minutes (20 hours) during a major event can lead to significant consequences, these potential consequences are obscured by a SAIDI value (five minutes) that averages normal days with major event days. Similarly, an

[7] Resilience hubs use backup generation to provide power to strategically selected, co-located resources to enhance public safety during a blackout. Xcel's Resilient Minneapolis Project incorporates a microgrid with PV and battery resources that will be owned and operated by community partners [52], [53].

event that affects one customer for 300 minutes (5 hours) generates the same SAIDI as an event that affects 60 customers for 5 minutes each, although the former event had the potential to cause more significant consequences due to its longer duration.

SAIDI and SAIFI also obscure the impact of outages on specific customers by averaging outages across all customers, including those not impacted by outages. While CAIDI addresses this issue by measuring only customers impacted by outages, CAIDI obscures the specific impacts of long-duration outages by averaging across all outages, regardless of duration. Customers Experiencing Long Interruption Durations (CELID) corrects this problem by considering only outages above a certain duration threshold. For example, CELID-12 measures the number of customers experiencing outages longer than 12 hours each year. However, applying the same duration threshold to an entire system obscures the range of outage durations that can cause consequences, depending on where outages occur.

Outage Analysis Methods and Results: Grid Data and Statistics

The outage data from participating utilities consists of the start date and time which corresponds to the time when a nearest upstream isolating device records the outage and the duration of the outage which corresponds to the time taken, either automatically or with the help or repair crews, to restore the outage for each outage records.

Although we filter the causes relating to weather-related outages, there could be erroneous data corresponding to both the weather data and the outage data. Furthermore, some outages could be triggered due an upstream transmission damage due to a windstorm in a neighboring territory.

The windspeed is measured at 10 meters above ground and wind gust is the maximum windspeed measured over a short amount of time. Typically, wind gust is reported if the maximum value sustains beyond 10-20 seconds.

To observe the impact of weather parameters on outages, we extract the weather parameters at each fault isolating device location and count the number of outages and number of customers affected in each outage day. The maximum value of windspeed and wind gust observed across all isolating device locations is then attributed as the maximum windspeed and wind gust observed on that day. To generalize the relation further, the windspeed and wind gust values are discretized to the nearest integer values and the number of outages corresponding to each of the discrete wind parameter values are averaged. Hence, the number of outages per day value of 50 in windspeed 47 mph means that when the maximum windspeed of the area around the territory of Utility A reaches 47 mph, then Utility A *can expect* to have around 50 outages on that day.

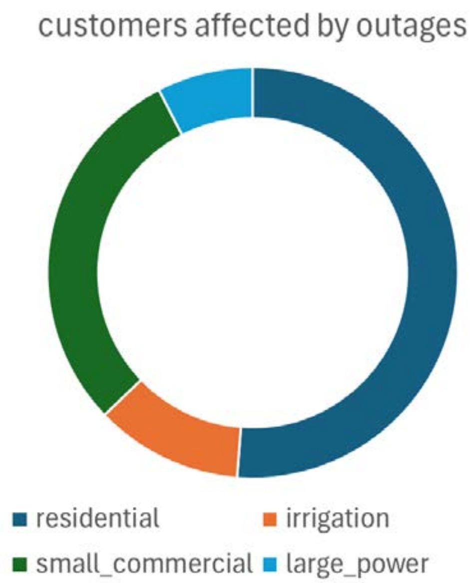
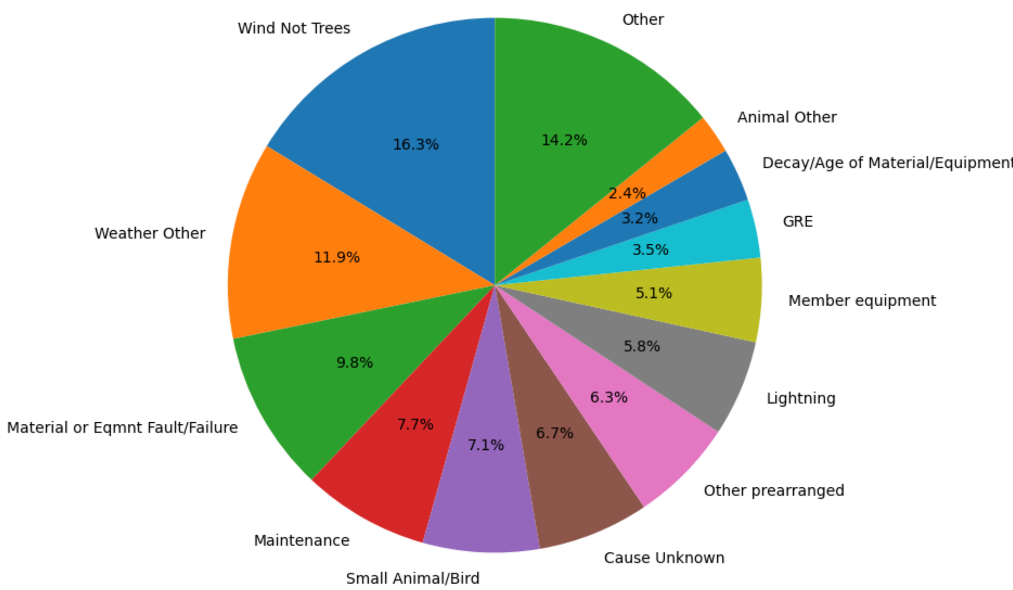


Figure 32. Outage count distribution by customer type.



Restoration and Outage Metric Analysis Methods and Individual Utility Results

In [2], a threshold is determined based on the number of customers affected and the time over the threshold is also reported as one of the resilience metrics. Here, we use the 95th percentile value of the customers affected each day and compute the time over the threshold metric for instances when $P(t)$ is less than this value.

Critical Service Access Methods

Critical Service Location Data Sources

Service Location Type	Data Source
Bank	HIFLD
Child Care Center	HIFLD
College or University	HIFLD
Dialysis Center	HIFLD
Dormitory	NSI
EOC	HIFLD
EV Charging Station	DOE
Fire & EMS	HIFLD
Gas Station	OSM
Grocery Store	USDA
Hardware/Outdoor Store	Overture Maps
Hospital	HIFLD / NSI
Multi-Family Residence	NSI
Nursing Home	HIFLD / NSI
Pharmacy	RxOpen
Place of Worship	HIFLD
Police Station	HIFLD
Public School	HIFLD
Single-Family Residence	NSI
Shelter	HIFLD
Urgent Care	HIFLD

Critical Service Scores

Non-Residential Service Locations		Provisions					Health				Public Emergencies	Shelter			Workforce	Total
Type	**Subtype**	**Cook Food**	**Obtain Food/Water**	**Store Food**	**Obtain Over-the-Counter Meds**	**Obtain Fuel**	**Obtain Prescription Meds**	**Store Meds**	**Healthcare Procedure**	**Operate Medical Device**		**Heating/Cooling**	**Hygiene**	**Communication**		
Bank	Bank	0	0	0	0	0	0	0	0	0	0	0	0	0	1	**1**
Child Care Center	Child Care Center	0	0	0	0	0	0	0	0	0	0	0	0	0	3	**3**
College or University	College or University	0	0	0	0	0	0	0	0	0	0	0	0	2	2	**4**
Community Center	Community Center	0	0	0	0	0	0	0	0	0	0	0	0	5	0	**5**
Community Center	Official Shelter	0	0	0	0	0	0	0	0	0	0	0	0	5	0	**5**
Community Emergency Hub	Community Emergency Hub	0	0	0	0	0	0	0	0	0	0	0	0	5	0	**5**
Convention Center	Convention Center	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Convention Center	Official Shelter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Dialysis Center	Dialysis Center	0	0	0	0	0	0	0	4	0	0	0	0	0	0	**4**
EOC	EOC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
EV Charging Station	EV Charging Station	0	0	0	0	5	0	0	0	0	0	0	0	0	0	**5**
Food Bank	Food Bank	0	3	0	0	0	0	0	0	0	0	0	0	0	0	**3**
Fire & EMS	Fire & EMS	0	0	0	0	0	0	0	3	0	5	0	0	0	0	**8**
Gas Station	Gas Station	0	1	0	1	5	0	0	0	0	0	0	0	0	0	**7**
Grocery Store	Large	0	5	0	1	0	0	0	0	0	0	0	0	0	0	**6**
Grocery Store	Small	0	4	0	1	0	0	0	0	0	0	0	0	0	0	**5**
Grocery Store	Superstore	0	5	0	1	2	0	0	0	0	0	0	0	0	0	**8**
Hardware Store	Hardware Store	0	0	0	0	3	0	0	0	0	0	0	0	0	0	**3**
Heating/Cooling Center	Heating/Cooling Center	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Hospital	Trauma I	0	0	0	3	0	5	0	5	0	0	0	0	0	0	**13**
Hospital	Trauma II/III	0	0	0	3	0	4	0	4	0	0	0	0	0	0	**11**
Hospital	Other Hospital	0	0	0	3	0	3	0	3	0	0	0	0	0	0	**9**
Hospital	Long Term Care	0	0	0	2	0	3	0	2	0	0	0	0	0	0	**7**
Hospital	Rehabilitation	0	0	0	1	0	3	0	1	0	0	0	0	0	0	**5**
Hospital	Psychiatric	0	0	0	1	0	3	0	1	0	0	0	0	0	0	**5**
Hospital	Military	0	0	0	1	0	3	0	1	0	0	0	0	0	0	**5**
Library	Library	0	0	0	0	0	0	0	0	0	0	0	0	3	0	**3**

Non-Residential Service Locations		Provisions					Health				Public Emergencies	Shelter			Workforce	Total
Type	Subtype	Cook Food	Obtain Food/Water	Store Food	Obtain Over-the-Counter Meds	Obtain Fuel	Obtain Prescription Meds	Store Meds	Healthcare Procedure	Operate Medical Device		Heating/Cooling	Hygiene	Communication		
Major Sport Venue	Major Sport Venue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Major Sport Venue	Official Shelter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Nursing Home	Assisted Living	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Nursing Home	Nursing Home	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Pharmacy	Pharmacy	0	1	0	5	0	5	0	0	0	0	0	0	0	0	**11**
Place of Worship	Official Shelter	0	0	0	0	0	0	0	0	0	0	0	0	3	0	**3**
Place of Worship	Place of Worship	0	0	0	0	0	0	0	0	0	0	0	0	3	0	**3**
Police Station	Police Station	0	0	0	0	0	0	0	0	0	5	0	0	0	0	**5**
Public School	High School	0	0	0	0	0	0	0	0	0	0	0	0	2	5	**7**
Public School	Official Shelter	0	0	0	0	0	0	0	0	0	0	0	0	2	5	**7**
Public School	Other School	0	0	0	0	0	0	0	0	0	0	0	0	2	5	**7**
Section 202 Housing	Section 202 Housing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Shelter	Shelter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Urgent Care	Urgent Care	0	0	0	0	0	2	0	2	0	0	0	0	0	0	**4**

Residential Service Locations	Provisions					Health				Public Emergencies	Shelter			Workforce	Total
Type	**Cook Food**	**Obtain Food/Water**	**Store Food**	**Obtain Over-the-Counter Meds**	**Obtain Fuel**	**Obtain Prescription Meds**	**Store Meds**	**Healthcare Procedure**	**Operate Medical Device**		**Heating/Cooling**	**Hygiene**	**Communication**		
Dormitory	5	0	5	0	0	0	5	0	5	0	5	5	5	0	**35**
Hospital	5	0	5	0	0	5	5	5	5	0	5	5	5	0	**45**
Nursing Home	5	0	5	0	0	3	5	1	5	0	5	5	5	0	**39**
Single Family	5	0	5	0	0	0	5	0	5	0	5	5	5	0	**35**
Multi-Family	5	0	5	0	0	0	5	0	5	0	5	5	5	0	**35**

Duration Thresholds for Major Critical Service Interruptions

Thresholds were assigned based when people would likely experience an adverse consequence if a service category was not available somewhere nearby at a given hour of an ongoing power disruption.

	Provisions					Health				Public Emergencies	Shelter			Workforce
	Cook Food	**Obtain Food/Water**	**Store Food**	**Obtain Over-the-Counter Meds**	**Obtain Fuel**	**Obtain Prescription Meds**	**Store Meds**	**Healthcare Procedure**	**Operate Medical Device**		**Heating/Cooling**	**Hygiene**	**Communication**	
Duration Threshold (Hours)	48	48	4	12	12	12	48	2	2	1	48	48	8	72

Cook Food, Obtain Food/Water, Store Medications, Heating/Cooling, Hygiene

Duration threshold: 48 hours
Source(s): Seattle Times, Fox 13 Seattle, Red Cross

Justification: These services are typically accessed in private, residential locations. If these locations are without power for an extended period, residents would need to access these services at locations where emergency management organizations have coordinated their provision, like resilience hubs. Seattle news and a personal interview with Issaquah, WA emergency management after November 2024 bomb cyclone reveals that resilience hubs and shelters open around 48 hours after widespread power outage begin. Red Cross indicates that post-storm shelters open within 72 hours of event. Took more conservative estimate. Lack of guidance for resilience hubs on the duration of a disruption that justifies opening - an area for more research.

Store Food

Duration threshold: 4 hours
Source(s): U.S. Department of Agriculture
Justification: USDA emergency guidance explains that food will last in a refrigerator for 4 hours.

Healthcare Procedure, Operate Medical Device

Duration threshold: 2 hours
Source(s): Bawaneh et al. 2019, Desalvo et al. 2014
Justification: Research suggests that outages two hours or longer at healthcare facilities are associated with a 43% increase in mortality. Research underpinning the creation of the Health and Human Services emPOWER Program cites the use of hospitals and shelters by people needing to operate electrical medical devices, which overwhelms medical staff and endangers patients. This latter research does not cite a timeline in which people leave their home to find a location to operate a medical device but underscores another mechanism through which these conditions could cause increase mortality.

Public Emergencies

Duration threshold: 1 hour
Source(s): FEMA 2014
Justification: Police stations, fire stations, emergency medical service dispatch, and emergency operations centers provide services identified by FEMA and the National Fire Protection Code 70 (National Electric Code) as those that might "require continuous operation for reasons of public safety." Hospitals, schools, and emergency shelters are also discussed as potentially belonging in this category, but those locations provide services addressed specifically in categories separate from "public emergencies."

Workforce

Duration threshold: 72 hours
Source(s): FEMA 2017, Urban Sustainability Director’s Network 2019
Justification: A "long-term interruption" is the subject of FEMA’s Power Outage Incident Annex planning document, defined as 72 hours or longer based on a list of previous

events referenced in the introduction. The Urban Sustainability Director's Network Resilience Hub Guide cites 72 hours as a common duration through which resilience hubs should be prepared to provide resources supported by backup power. This duration, however, does not provide an indication of *how long after a disruption begins* that hubs should plan to provide “Workforce” services like childcare or banking (internet communications). However, given that services in the “Workforce” categories are focused on the recovery phase of an emergency, after services addressing more acute needs have been stabilized, a duration longer than other categories was selected. Additional research should refine this duration.

Obtain Over-the-Counter Meds, Obtain Fuel, Obtain Prescription Medications

Duration threshold: 12 hours
Source(s): Ericson et al. 2022
Justification: No published guidance about the relationship between disruption length and adverse consequences in these critical service categories. Used the duration exceeded by 50% of major power outages reported by the U.S. Energy Information Administration.

Minnesota Grid Resilience Decision-Making Guide

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