Investing in Power System Resilience:
A mixed methods approach to assessing the tradeoffs of resilience strategies

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Angelena D. Bohman

B.S., Mathematics, Boston College

Carnegie Mellon University

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Abstract

As modern American society has become increasingly dependent on the provision of reliable electric power, the importance of enhancing the resilience of the power system has grown. In years to come, stress arising from climate change, and the continuing risks of physical and cyberattacks on the system, will likely make resilience even more important. However, while the topic receives a great deal of attention, there is little rigorous analytical work that has assessed the efficacy and cost-effectiveness of strategies to increase power system resilience.

This research adopts a mixed methods approach to identify and assess strategies for improving the resilience of power systems and thus enhance planning as the power system evolves. Chapter 2 begins by reviewing a range of resilience strategies discussed in the literature that could be deployed on the grid. The literature on this subject is scattered and unsystematic in its treatment of cost and efficacy. This chapter contributes to the resilience literature by developing a comprehensive list of strategies and summarizing what is known about their costs and efficacy.

Chapter 3 has already been published in the journal *Risk Analysis*. It analyzes and compares a range of individual and collective strategies that could increase the resilience of power supply to residential customers on a distribution feeder by providing contingency power during large power outages of long duration. A typical (but hypothetical) town in the Upper Connecticut River Valley is modelled—we choose this region because it is susceptible to ice storms and hurricanes—to estimate the cost and performance of different resilience strategies, assuming that a large power outage of long duration occurs. This work showed the extent to which collective strategies are cheaper, and therefore highlighted the importance of developing institutional arrangements that make it easier for communities to implement those collective strategies.

Chapters 4 and 5 present the first systematic analysis of empirical data about the efficacy of different resilience strategies. To do this, Chapter 4 focuses on the state of Florida, which has required utilities to make substantial investments in storm hardening to improve the resilience of their systems in the face of tropical cyclones. While these utilities compile and report to the state Public Service Commission a phenomenal amount of data on the cost and performance of their

different resilience strategies, almost no analysis has been done on these data to assess whether and to what extent these investments are actually improving the power system's resilience. After compiling fifteen years' worth of these data for Florida's Investor-Owned Utilities, the exploratory data analysis shows that after accounting for tropical cyclone severity, undergrounding power lines, changing pole material to non-wood and installing advanced metering infrastructure across all customers likely improve average tropical cyclone restoration time (CAIDI). Increasing annual tree trimming on the other hand does not seem to have an impact on tropical cyclone CAIDI. However, to continue performing at current levels of reliability, these utilities will have to spend more on the same activities and even more on others to continue to address the impacts of climate change and the uncertainty they induce.

Informed in part by this applied data analysis, in work reported in Chapter 5 utility engineers were interviewed to extract their mental models of power system resilience, as well as their judgments regarding how to enhance resilience most effectively given the range of threats facing their systems. Operators were asked to consider the worst outage their system had experienced and then to elaborate on how implementing resilience strategies could have improved their response to this worst outage without financial barriers. Undergrounding power lines was the preferred strategy by interviewees, but also estimated to be the most expensive. Finally, participants were asked what technologies, policies and resources are especially needed by utilities to enhance their systems' resilience, and they suggested new rate designs to account for an increase in renewables, distributed energy resources, and electrification as well as defining new policy standards for new loads and distributed generation being added to their systems. They were additionally concerned with supply chain backlogs and having enough money to do the necessary upgrades on an aging system.

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List of Abbreviations

ACSR	aluminum conductor steel reinforced
AMI	Advanced Metering Infrastructure
ANL	Argonne National Laboratory
CAIDI	Customer Average Interruption Duration Index
CI	Customer Interruptions
CMI	Customer Minute Interruptions
coop	rural electric cooperative
DER	Distributed Energy Resource
DG	Distributed Generation
Duke/DEF	Duke Energy Florida
EEI	Edison Electric Institute
EIA	Energy Information Agency
EPRI	Electric Power Research Institute
FAWN	Florida Automated Weather Network
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
FLISR	fault location, isolation, and service restoration
Florida PSC	Florida Public Service Commission
FPL	Florida Power & Light
FPUC	Florida Public Utility Company
FPUC-NE	Florida Public Utility Company Northeast Division

FPUC-NW	Florida Public Utility Company Northwest Division
GIS	geographic information system
Gulf	Gulf Power Company
IOU	Investor-owned Utility
IVM	Integrated vegetation management
kW	Kilowatt
LBNL	Lawrence Berkeley National Laboratory
LLD-outage	Large power outage of long duration
muni	municipally run electric utility
MW	Megawatt
NERC	North American Electricity Reliability Corporation
NESC	National Electric Safety Code
NG	Natural Gas
NOAA	National Oceanographic Atmospheric Administration
NRECA	National Rural Electric Cooperative Association
NREL	National Renewable Energy Laboratory
PEF	Progress Energy Florida
PNNL	Pacific Northwest National Laboratory
PUC	Public Utility Commission
PV	Photovoltaic
RMI	Rocky Mountain Institute
ROW	Right of Way
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	supervisory control and data acquisition
TC	Tropical Cyclone
TECO	Tampa Electric Company
W	Watt

Chapter 1. Introduction

Most disruptions in electric power service are limited in scope and duration. However, large electric power outages of long duration (LLD-outages), which are defined as "blackouts that extend over multiple service areas or states and last several days or longer," are possible and do occur (National Academies [NASEM], 2017). When LLD-outages occur, they are typically caused by natural disasters including hurricanes, ice storms, floods, wildfires, and earthquakes. However cyber and physical sabotage, operator error and extreme temperatures can also cause cascading outages on the system. The cost of such outages can be great - vulnerable people die; food spoils; water, sewage or energy services fail; pipes freeze; economic output diminishes; and emergency services struggle (NASEM, 2017) - but such events have historically been rare. However, as the threat of LLD-outages increases due in part to the effects of climate change, aging infrastructure, and cyber-physical attacks, utilities should devote more attention to planning for extreme outage events. How to make the power grid more resilient is something utilities and policymakers alike are grappling with, but so far there is little conclusive evidence on whether current strategies are effective; what other advancements and protective measures are needed; and what outage mitigation efforts are worth the investment.

Part of the challenge when investing in resilience is that the concept itself encompasses multiple attributes, fulfilling each of which requires a different set of strategies. Some of these strategies look to reduce the probability of outages occurring in the first place, others aim to shorten restoration time, while others still provide contingency power where needed. Add to this the different social and physical environments in which American utilities operate (different customer socio-economic profiles, institutional arrangements, topography, vegetation, and soil characteristics, among others) and the fact that the performance of resilience strategies can vary under different outage scenarios means that comparing the cost-effectiveness of strategies is difficult[1]. Utilities use a range of metrics to evaluate the reliability of their system, but there are currently no agreed upon grid resilience metrics that enable cross-utility comparisons (U.S. GAO, 2021). Second, given the wide variety and use cases of grid resilience options, current grid

[1] For example, undergrounding power lines can reduce vegetation and wind related outages, but could increase problems for utilities during earthquakes or major flooding events.

resilience research tends to be focused on specific locations and is often undertaken in reaction to specific outage events. Therefore, when utilities and governments explore how to make their grid more resilient, the decision process is somewhat ad hoc and anchored on recent large outage events[2]. Because there are few data to reference when making these decisions (NASEM, 2021), decision-makers may rely on the same, small set of studies that employ assumptions that are not always applicable or appropriate.[3]

Resilience investment planning may be difficult, but despite the uncertainties, utilities must often make decisions about how to enhance the resilience of their systems. To that end, this dissertation aims to provide a better understanding of the tradeoffs among resilience strategies and the investments being made by utilities. Although some cross-cutting resilience strategies can provide protection against a wide range of outage causes, including deliberate attacks (cyber or physical), natural disaster outage events tend to be more predictable, have more publicly available data, and can more often be mitigated by similar sets of strategies (NASEM, 2021). Therefore, this dissertation focuses on the efficacy and cost of resilience strategies as they pertain to extreme weather and climate events.

Chapter 2 elaborates the resilience strategies available to communities: it is the result of a literature review on the efficacy and costs of every resilience strategy for which data are available. The results of this chapter showed that the focus of the resilience literature available tends to be on generation resilience. Although each generation technology requires a different approach, most resilience strategies can be applicable to all locations experiencing the same outage threat, likely contributing to this unbalance. Additionally, energy models that incorporate

[2] Florida, for example, in 2006 created a storm hardening program in response to devastating hurricanes in 2004 and 2005. These storm hardening initiatives were based on failures from those 2004-2005 hurricanes (Florida PSC, ORDER NO PSC-06-0144-PAA-EI, February 27, 2006). Additionally, New Jersey began a microgrid program right after Hurricane Sandy NASEM. (2017)

[3] For example, in the Edison Electric Institute's (EEI) 2006 assessment of undergrounding power lines (Out of Sight, Out of Mind?) it is noted that North Carolina's underground lines take on average 1.6 times longer to repair than overhead lines from 1998-2002. This number is used in cost-benefit studies of undergrounding done by FEMA (Federal Emergency Management Agency, 2008) and PEPCO in DC (Shaw Consultants International, 2010) even though the same EEI report says underground lines take 2.5 times longer to repair in Virginia in 2003. Additionally, FEMA HAZUS does model fragility curves for transmission lines and substations, but recent events such as Hurricane Maria in Puerto Rico have shown some of the limitations of these fragility assumptions (RAND contact). Regardless, these fragility assumptions are still used regularly in research (Argonne's National Lab HEADOUT model, Bennett et al., 2021; Breiding, 2013; Goodman, 2015).

resilience tend to exclusively focus on transmission and generation resilience due to modelling constraints (Bennett et al., 2021; Kelly-Gorham, Hines, Zhou, & Dobson, 2020, Argonne's National Lab HEADOUT model, Lawrence Berkeley National Lab FRONTIER model). Therefore, the next three chapters focus on distribution system resilience investments as they are the least studied, but also the most impactful given that most outages occur on the distribution system.

Chapter 3 describes a techno-economic analysis of strategies that a hypothetical community in New Hampshire could implement to reduce the consequences of 5,10- and 20-day long outages. The rest of the dissertation delves into the decisions that utilities are making about distribution resilience. Chapter 4 reports results from an exploratory data analysis on publicly available resilience data from Florida Investor-Owned Utilities that shows whether and to what extent these investments are achieving improved resilience. Finally, Chapter 5 uses highly structured interviews with utility operating personnel to extract their mental models of power system resilience, as well as their judgments regarding how to enhance resilience most effectively in the face of different threats facing their systems.

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Chapter 2: A review of the cost and performance of strategies that enhance power system resilience

2.1 Introduction

Electric utilities worldwide are facing concomitant challenges that threaten the reliability and resilience of their power systems. Chief among these challenges is climate change, which is affecting power systems in two ways. First, utilities are transforming their energy supply systems to emit less carbon. This often entails the deployment of electricity generation technologies which are often variable, intermittent, flexible, or distributed. Maintaining system resilience after deploying these technologies will require a high level of situational awareness and advanced control strategies, including automation to manage abnormal operations at sub-second timescales. Second, climate change will both change the "normal" environmental conditions for which utilities have optimized their operations and lead to an increase in the frequency and severity of extreme weather events that systems must withstand. Utilities must address these challenges while facing others—like aging infrastructure and regulatory reforms—that are also influenced by (or influence) their response to climate change.

As a concept, power system resilience is distinct from power system reliability. Resilience is a power system's ability to withstand and quickly recover from disruptions caused by major events such as extreme weather or attack. Reliability is the system's ability to provide power in adequate amounts and of acceptable quality to meet demand during normal operating conditions. Historically, major outage events have not been routine, but they have been common enough to warrant substantial investment by utilities and government over the previous two decades. Unfortunately, little effort has been made to compile information about what different utilities are doing; how expensive and effective these resilience investments have been; how utilities approach resilience investment planning; and what future threats they are most concerned about. The latter is especially relevant to policy makers and could help steer investments in not only technological innovation but also in regulatory capacity and broader coordination.

Here, we present what is—to our knowledge—a the most comprehensive, publicly available, review of the literature on investments in electric power system resilience designed to mitigate natural disaster caused outages. This review is broad in its scope: in addition to reviewing the academic literature on resilience strategies and their potential utility, it develops and presents a large database of the cost and performance of strategies that enhance power system resilience against natural disasters. This database can be leveraged by analysts in the future to better estimate resilience. It can also be used by utilities and policy makers to develop resilience investment portfolios that are more effective at achieving their power system objectives. The rest of this chapter is structured as follows: section 2.2 reviews the academic literature on resilience, presenting the range of frameworks that have been employed to think about, assess, and improve resilience. It also highlights the gaps that remain in the literature on resilience. Section 2.3 lists strategies to improve the cost and performance of generation assets. Section 2.4 focuses on strategies to improve transmission and distribution resilience. Section 2.5 provides an overview of cross-cutting strategies. Section 2.6 comprise concluding remarks and a list of promising directions for analysts in the future.

2.2 Literature review

Literature on power system resilience tends to fall into one of five categories. First there are studies that propose overarching frameworks that define resilience and what should be considered when increasing resilience, often quantifying the challenges of increased major weather events (Joint Task Force on Methods for Analysis and Quantification of Power System Resilience, 2021; Linkov & Trump, 2019; NASEM, 2017; The White House, 2013). However, such reports do not quantify the specific costs and benefits of individual resilience strategies. Studies which do that are typically conducted on behalf of a utility or Public Utility Commission and most often focus on similar sets of strategies: undergrounding power lines, changing pole materials, and vegetation management. Such studies are cited throughout this review. Next, there are post-mortem studies that review the specific impacts of a large outage event (Florida Power and Light, 2018b; Kwasinski, 2018; Kwasinski, Eidinger, Tang, & Tudo-Bornarel, 2019; Risk Management Solutions, 2008) which can provide insights to utilities on what needs to be fixed before a similar event occurs, but provide little insight into how to protect against different outage causes. Conversely, there are studies that group resilience investments and report the cost and efficacy of the whole investment (ConEdison, 2021; Nicolas et al., 2019; State of Florida Public Service Commission, 2018). Although these reports acknowledge that the resulting resilience is often greater than the sum of its parts, such reporting makes it difficult for any other utility to replicate because one cannot distinguish the impact of individual strategies. More recently, researchers have been exploring how to incorporate resilience strategies into power system modelling: Pacific Northwest National Laboratory recently launched the "Electrical Grid Resilience and Assessment System" model for Puerto Rico[4]. Similarly, Bennett et al., (2021) modelled undergrounding power lines and generation hardening for hurricanes in Puerto Rico using TEMOA (Tools for Energy Model Optimization and Analysis). Finally, Kelly-Gorham, Hines, Zhou, and Dobson (2020) used Computing Resilience Interactions Simulation Platform (CRISP) for considering how distributed batteries and solar photovoltaics could improve resilience during bulk system outages.

To our knowledge only two other studies have attempted to quantify the cost and benefits of a range of resilience options. Richard Brown (Quanta Technology, 2009) conducted a cost-benefit analysis on a wide range of strategies for hurricane resilience in Texas following the devastating impacts of Hurricane Ike (2008) on the Texas power grid. Although thorough in its resilience assessment, this analysis, now over a decade old, focused on hurricanes in Texas. More recently, the World Bank published two reports, one on the cost and efficacy of resilience strategies for multiple infrastructures including power systems (Miyamoto International, 2019), and one on assessing the threats to power systems (Nicolas et al., 2019). Both provide a good overview but focus on generation technologies. This review expands upon previous work to provide a current and exhaustive assessment of the cost and performance of generation, transmission, and distribution system resilience strategies.

2.3 Generation assets

2.3.1. Hardening of conventional generation

Compared to power lines, generation units are robust and have largely avoided big outages. However, when they do have outages, it can be devasting, as for example most recently the 2021 February freeze in the southern part of the US. 44% of outages were caused by generator units not sufficiently "winterized", while 27% of outages were due to natural gas fuel supply issues (NERC, 2021). Additionally, recent generator failures related to flooding from Hurricane Sandy in New Jersey (T. Johnson, 2012) and Hurricane Florence in North Carolina (Environmental Working Group, 2018), also remind us that extreme weather events can disrupt thermal power

[4] https://egrass.pnnl.gov

generation. Sieber (2013) outlines how weather-related events can impact generation facilities and their fuel supplies reproduced in Table 2.1.

Table 2.1 Weather related events and their impact on coal, gas, and oil-fired power plant installations (INST) and their resources (RES) Reproduced from (Sieber, 2013)

Event	Coil, gas, oil INST	Coal RES	Gas RES	Oil RES
Extreme Heat	Increased load due to cooling of buildings Influence on efficiency of steam and gas cycles	Self-ignition of coal stockpiles	Expansion in gas pipelines	Expansion in oil pipelines
Extreme Cold/Frost	Increased corrosion due to frost Influence on efficiency of steam and gas cycles	Freezing of coal to ground	Contraction in gas pipelines, loss of pressure	Contraction in oil pipelines, loss of pressure
Hail	Damage from direct hits Corrosion of buildings			
Heavy precipitation	Corrosion of buildings Accessibility concerns	Stockpiles need sufficient drainage Erosion of particles Reduced efficiency due to wet coal		
High wind events	Uplifting of roofs and tiles Damage to insultation and cooling towers	Damage to storage tanks by wind pressure or debris impact		Damage to storage tanks by wind pressure or debris impact
Thunderstorms with lighting	Direct hit to structures Overvoltage in distribution of electricity	Lightning hit of storage areas resulting in fire	Lightning hit of storage areas resulting in fire	Lightning hit of storage areas resulting in fire
Water temperature/ droughts	Impact water cooling systems			
Floods/ sea-level rise	Inundation of site	Inundation of stockpiles		Influence on storage tanks Collision with debris

When it comes to extreme temperatures, Murphy, Sowell, and Apt (2019) showed, using 23 years of data for 1,845 generators in PJM, that for many generator types the probability of unavailability increases both at very low temperatures and very high temperatures, meaning that at temperature extremes generator outages are correlated. So, events like the 2011 and 2021 freezes are likely to happen again if no adjustments are made. Because southern US generation facilities are often not enclosed in buildings to avoid overheating in the summer, other winter weather protection methods include (FERC and NERC, 2011):

- Heat tracing – the application of a heat source to pipes, lines, and other equipment that must be kept above freezing;
- Thermal insulation – the application of insulation material to inhibit the dissipation of heat from a surface; and
- Windbreaks – temporary or permanent structures erected to protect components from wind.
- Temporary heating - install portable heaters to maintain ambient air temperature
- Drain non-essential water systems and determine that the water in essential water systems [is] circulating.

The cost for winterizing generator units is estimated to be between $60,000-$600,000 per unit (kcentv, 2021).

Natural gas fuel supply was another problem during the recent Texas freeze event, which was due to a combination of decreased natural gas production, low pressure, and natural gas commodity and pipeline transportation contracts not allowing for flexibility. However, historically this interdependency with the natural gas system in the US has not caused many outages. Of the gas-fired power plant failures tracked by NERC from 2012-2018, only 5% of the MWh lost were due to fuel shortages (Freeman, Apt, & Moura, 2020). The authors additionally noted that securing firm contracts to ensure priority of natural gas went to electric utilities instead of private companies would have avoided many of these outages. Having generators that can run on more than one fuel type as well as fuel storage can help avoid fuel related outages for all types of thermal generation. For example, the Florida utilities use dual fuel generators at all generating facilities, so if the natural gas supply is cut-off, they are prepared to run on diesel and can do so without stopping to change fuel[5]. Similarly, Guam Power Authority (GPA) is in the process of building a 180MW generating facility that can run either on ultra-low sulfur diesel or natural gas (U.S. Energy Information Administration (EIA), 2020).

Lastly, the US Federal Emergency Management Agency (FEMA) has developed damage functions for flooding and earthquakes affecting conventional power plants. The FEMA HAZUS 2.1 manual for flooding estimates the damage power plants experience when inundated as shown in Table 2.2 (FEMA, n.d.-a). Functionality is assumed to be lost at 4 feet of inundation and that control and generation facilities are on the second floor. Strategies to mitigate flood damage include installing flood monitors, raising equipment, installing flood protection walls and ensuring power plants are not built on flood plains. Section 2.4.5 on hardening substations discusses these flood mitigation strategies further.

Table 2.2 FEMA HAZUS 2.1 model estimates for power plant damage based on flooding depth.

Depth(ft)	1	2	3	4	5	6	7	8	9	10
Percent Damage	2.5	5	7.5	10	12.5	15	17.5	20	25	30

Table 2.3 shows the damage and restoration times estimated by the FEMA HAZUS 4.2 earthquake model for power plants. Seismic anchoring is defined in the earthquake manual as "anchored equipment in general refers to equipment designed with special seismic tiedowns or tiebacks, while unanchored equipment refers to equipment designed with no special considerations other than the manufacturer's normal requirements"(FEMA, n.d.-b). The avoided damage benefits of seismic anchoring are seen at higher levels of peak ground acceleration (roughly 0.4 and higher), but FEMA estimates no difference in restoration time between earthquake hardened and unhardened facilities.

Table 2.3 FEMA 4.2 HAZUS model estimates for generation seismic damage and restoration time.

Distribution circuit Damage	Estimated median Peak Ground Acceleration (g) that	Estimated median Peak Ground Acceleration that	Median restoration time (days)

[5] Source: John Moura & Thomas Coleman NERC, Evaluating Severe Natural Gas Disruptions and Interdependency Impacts to Bulk Power System Reliability, Presentation to Carnegie Mellon University Electricity Industry Center, September 29, 2021

	would cause this damage on a substation with **unanchored/standard components**	would cause this damage on a substation with **anchored/seismic components**	
Slight: turbine tripping, light damage to the diesel generator, or by the building being in the Slight damage state	Small (<100MW): 0.10 Medium/large (>200MW):0.10	Small (<100MW): 0.10 Medium/large (>200MW):0.10	0.5
Moderate: chattering of instrument panels and racks, considerable damage to boilers and pressure vessels, or by the building being in the Moderate damage state	Small (<100MW): 0.17 Medium/large (>200MW):0.22	Small (<100MW): 0.21 Medium/large (>200MW):0.25	3.6
Extensive considerable damage to motor driven pumps, or considerable damage to large vertical pumps, or by the building being in the Extensive damage state.	Small (<100MW): 0.42 Medium/large (>200MW):0.49	Small (<100MW): 0.48 Medium/large (>200MW):0.52	22.0
Complete: extensive damage to large horizontal vessels beyond repair, extensive damage to large motor operated valves, or by the building being in the Complete damage state.	Small (<100MW): 0.58 Medium/large (>200MW):0.79	Small (<100MW): 0.78 Medium/large (>200MW):0.92	65.0

2.3.2. Hardening of nuclear power plants

Nuclear power plants are similar to fossil fuel generation in that they are already designed to be highly resilient, however they face the additional concerns of ensuring the water-cooling system for the reactors and diesel backup are equally resilient. Ali Ahmad (2021) showed that climate induced disruptions have increased from 0.2 outage per reactor-year in the 1990s to 1.5 in the past decade. He also indicated that the disruptions due to drought and heatwaves although historically rare are most disruptive because they affect the water-cooling system. Heatwaves and lack of rainfall across France in the summer of 2022 stretched the limits of nuclear plants, which were kept on even though they were discharging hot water into the rivers, which can endanger wildlife (Reuters, 2022). In the fall of 2022, France also has almost half of their nuclear fleet offline for maintenance due to corrosion, which had been deferred over the last decade and is exacerbated by river water levels decreasing due to 2022 heatwaves (France24, 2022). Although uncommon, extreme cold temperatures can also damage the water-cooling system. During the 2021 February freeze, one of the nuclear units, with a 1,300MW rating, at South Texas Project plant tripped due to feedwater pumps going offline. Researchers have been looking into alternatives to water cooling such as recirculating water (but this brings down thermal efficiency on an already expensive generation source) dry-cooling (but this relies on ambient air-temperature) and using other coolants than water (gases or liquid metal) but currently nothing exists commercially (Ahmad, 2021).

Hurricanes can cause damage as well, particularly due to flooding which moves debris closer to the water intake canals of the nuclear reactors. Adding flood protection such as earthen dams and sandbags can help prevent issues with the water system (Ahmad, 2021). Additionally, ensuring secure facilities can withstand high wind speeds is important, which usually already part of the design specifications. For example in 1992 when Hurricane Andrew damaged two nuclear power plants at Turkey Point Florida (Hess, 2016), the eye of the storm passed directly over the site with wind gusts up to 175 mph and still only caused damage to non-safety-related systems which included 6 damaged turbine canopies, radioactive-waste building ductwork failures, and the collapse of a high-water tank (Watson, 2018).

Lastly, nuclear plants are complex systems that are expensive to build. When everything is done by the book, current regulatory practices ensure safe and resilient systems, it's when humans error that can cause problems. For example, the Fukushima reactor meltdown, although triggered by the 2011 large earthquake and tsunami event in Japan, could have been avoided if safety protocols been followed correctly. They were not because of collusion between nuclear regulatory agencies and the nuclear power industry (Kurokawa & Ninomiya, 2018).

2.3.3. Hardening solar PV panels

The biggest threat to solar panels is large storm events that bring high winds and deposit large amounts of debris across solar farms and rooftops, destroying many of the panels. For example, during Hurricane Sandy ~5 percent of solar panels within a one million square foot rooftop array in New Jersey were damaged by wind (Watson, 2018). After Hurricane Maria in 2017, Puerto Rico lost about 40% of the islands PV power (Kwasinski, 2018; The Weather

Junkies, 2017). One of the utility scale plants in Puerto Rico was relatively undamaged, partially due to avoiding the eye of the storm, but also from using elevated panels to avoid flooding and "reinforced to withstand winds of category 5 hurricanes" (Kwasinski, 2018; The Weather Junkies, 2017)

Only a few studies have attempted to model PV wind damage from hurricanes. Goodman (2015) modelled a two-story residential home with a standard array of 20 modules. Through empirical experimentation, Goodman found that rooftop design and degree of tilt for rooftop PV panels caused a much larger variation in fragility curves than what current wind modelling suggests. Higher dimensional racking (2-D) (number of dimensions a structural member spans) does much better than the smaller designs, being able to withstand on average between 110-130 mph wind gusts compared to smaller designs that can withstand 70-90 mph wind gusts. Additionally, having a gentler slope of the rooftop (15 degrees instead of 30 or 45) increases ability to withstand higher wind gusts by about 20 mph. In addition to panels breaking due to wind damage, PV generation can be reduced during hurricanes due to cloud coverage. Cole, Greer, and Lamb (2020) showed that PV generation during 18 hurricanes from 2004-2017 in the US produced 18-60% of their clear-sky potential. However, they were able to rebound 72 hours after the storm had passed.

When it comes to deciding how to harden solar panels against tropical cyclones, reports from the National Renewable Energy Laboratory (NREL) (Belding, Walker, & Watson, 2020; Elsworth & Geet, 2020) and Rocky Mountain Institute (RMI) (Stone & Burgess, 2018) provide solutions and cost estimates:

- PV modules should be through-bolted to their racks and with all fasteners locked or torqued appropriately. Through-bolting costs 0.6¢/W for ground mounted PV and 0.7¢/W for rooftop mounted and fastener locking costs anywhere from 0.1-1.5¢/W.
- Use marine grade/stainless steel especially in areas exposed to corrosive salt water and likely costs 1.1¢/W for ground mounted PV and 1.2¢/W for rooftop mounted
- Ensure PV panels can withstand high wind pressures, NREL recommends greater than 3600 Pa, while RMI recommends 5,400 Pa ratings and cost 10¢/W more than traditional panels.

- Use a three rail instead of two-rail racking system for more attachment points and using tubular or square supports for the racking frame to prevent twisting. A third rail would cost an extra 5.9¢/W and tubular frame costs 12¢/W extra for ground mounted PV.
- Ground mounted PV systems also need to avoid flooding damage by ensuring equipment is elevated on pads (0.8-1.0¢/W) or encased in watertight containers as well as ensuring PV sites are not in flood prone areas.
- Ground mounted PV also can use a wind-calming fence, which is "made up of a porous material which allows lower pressure wind to pass through while higher pressure wind is deflected above the fence," and likely costs 6-14 ¢/W.

RMI estimated that a 1 MW solar system with extra hardening, would cost about $90,000, which is about a 5% increase in costs compared to a baseline 1 MW system.

Solar panels fare well in cold temperatures, but sometimes heavy snowfall can crack PV panels if the snow weight is not distributed evenly over the panels (Office of Energy Efficiency & Renewable Energy, 2017). To circumvent this, steeply inclined panels can help ensure that snow slides off panels before causing too much damage (Power Magazine, 2014).

Wildfires and extreme heat can also cause problems for solar panels. There is nothing readily available now, but researchers are looking at increasing temperature ratings for panels using heat-resistant material (Arpin et al., 2013) and installing devices that can automatically remove ash covering panels, which can decrease solar efficiency by 30% (Marsh, 2021).

2.3.4. Wind turbine hardening

Wind turbines are vulnerable to both high winds and freezing conditions. During Hurricane Maria, while a large 101MW wind farm located in Santa Isabel, Puerto Rico was largely intact after the storm, all 13 1.8MW turbines located in Punta Lima were destroyed. This area was impacted by stronger winds of 125mph compared to Santa Isabel (Kwasinski, 2018). During the 2011 February cold snap in Texas, 16% of wind non-winterized turbines failed – "709 MW due to blade icing and another 1,237 MW because frigid temperatures exceeded turbine limits" (Power Magazine, 2014). Additionally, the 2014 January Polar Vortex in the PJM region saw 1,000 MW of wind power cut out, which FERC speculates was due to turbines hitting their minimum operating temperature (typically designed to -10C) (Power Magazine, 2014).

To mitigate freezing temperatures, utilities can install “cold weather packages” to increase the ability of the wind turbines to function to -40C. Such packages can install parasitic power devices which will take energy from the turbine to use it to keep the turbine running, “active or passive de-icing or anti-icing systems for rotor blades, and heat, water-resistant coatings, and controlled blade acceleration/deceleration to shake the ice off” (Power Magazine, 2014). Golding, Kumar, and Mertens (2021) estimate that such de-icing measures would cost less than installing warming equipment in new turbines (~$400,000 per unit) and that retrofitting current units with warming equipment is infeasible.

When it comes to high wind events, there are several options to increase wind turbine resilience. First, increasing wind-rating design for turbines to meet hurricane force winds for new designs, which will likely increase onshore wind costs by 20-30%, but less for offshore (Rose, Jaramillo, Small, Grossmann, & Apt, 2012). Using “backup power, robust wind direction indicators, and active controls” are relatively low-cost ways to increase wind resilience (Rose et al., 2012). Additionally, Rose et al. studied the wind fragility of wind turbines that used external power in the form of a lead-acid batteries to operate a yaw motor to allow turbines to reorient themselves based on wind direction. Rose et al. showed that the benefits of yawing are regionally specific but can still reduce the probability of buckling by 8%-45% in all regions. They estimated a yaw motor with external power would add $35,000-$48,000 to the cost of the turbine (adjusted from original paper to 2020 USD) and an additional 1,400–2,400 kg to its weight.

In off-shore wind resilience to hurricanes, tower design is especially important as is how the turbine is anchored to the ocean-floor. Hernandez-Estrada et al. (2021) explore the advantages and disadvantages of using certain material for the tower, shown in Table 2.4.

Table 2.4 Pros and cons of using different material and design type of off-shore wind turbine towers. Reproduced from (Hernandez-Estrada, 2021)

Material	Design Type	Advantages	Disadvantages
Steel	Lattice	- Lower cost in construction and transport - Superior stiffness - Less wind load to the tower	- Vulnerable to fatigue - Not visually pleasing - Causes turbulence to the blades - Ice load in cold places
	Tubular	- Aesthetically pleasing - Predictable dynamic and fatigue properties - Convenient maintenance	- High transport and assembly costs - Expensive for very high towers

Concrete	On-site	- Superior stiffness - High durability	- Weather conditions vulnerability
	Precast	- Easy installation	- Vulnerable joints - High transport and assembly costs

So far wind turbines have remained undamaged from earthquakes, but Myers, Gupta, Ramirez, and Chioccarelli (2012) estimate that a 80 meter tall turbine placed on firm soil would likely not experience any damage until peak ground acceleration exceeded 0.5g, with a 50% probability of damage occurring at 1.5g.

2.3.5 Hydropower hardening

Hydropower facilities are suspectable to earthquakes, and the water required to operate such plants can be affected by floods and droughts. For example, droughts throughout the Western Interconnection in 2021 caused a 16% decrease from the average hydro generation produced in the region (Turner, Voisin, Nelson, & Tidwell, 2022). China's Yunnan province lost 30% of its hydro generation in 2020 due to droughts and Brazil experienced a 91-year low in water levels, which has made them consider building more thermoelectric plants(Bernstein, Spring, & Stanway, 2021). In Malawi, tropical storm floods broke through a protective dike and broke the water intake control mechanism, losing the country 130MW of power until the plant can be repaired (Masina, 2022). The 2008 Sichuan earthquake caused varying degrees of damage to 1,583 dams in China, which included "crest settlement, slope instability, cracks, leakage, failure of water discharge and power generation facilities" (Water Power Magazine, 2008). However, no dams were breached after this earthquake because the ones that were at high risk were emptied, showing the benefits of emergency reservoir discharge facilities (Water Power Magazine, 2008).

Little can be done to mitigate low water level impacts to hydropower other than considering climate projections and drought likelihood when siting new hydropower plants. To mitigate flood damage, utilities can build higher dams, increase reservoir capacity, increase number and height of flood walls, build upstream sediment control facilities, and modify turbines to allow for higher water flow rates (International Energy Agency, 2020). Additionally, the

World Bank estimated that increasing spillway capacity by raising the elevation by 2ft could allow an increase in water flow by 340-450 m^3/sec (Miyamoto International, 2019). They estimated this would cost 3% of initial capital costs and decrease probability of water spilling over the top from 10% to 5%.

Earthquakes can cause damage not only from the initial ground movement, but also land and rockslides damaging the facility (Dietler, Wieland, & Fuchs, 2017). Physical damage needs time to be fixed so it is important that water be managed appropriately, and spillways and low-level outlets can function after an earthquake to prevent a breach (Wieland, 2022). Simulating 10 different variations of earthquakes, Ghannaat, Patev, and Chudgar (2012) showed that concrete dam base sliding failures closely fit a Weibull curve with a shape parameter of 1.44 and a scale parameter of 0.54 and is reproduced in Figure 2.1.

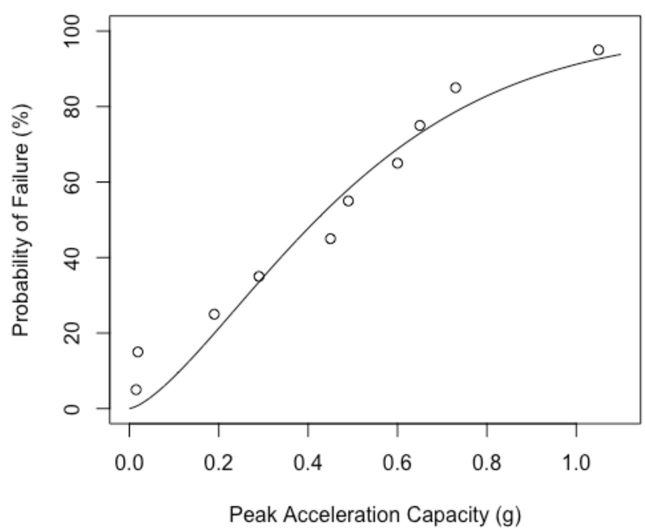

Figure 2.1 Reproduced fragility curve of concrete base dams from (Ghannaat et al., 2012). Simulating 10 earthquake types they showed dam failure due to peak ground acceleration follows a Weibull distribution with a shape parameter of 1.44 and a scale parameter of 0.54.

2.4. Transmission and distribution assets

When a major event hits, most outages affect the distribution system. Occasionally, the transmission system can also be badly damaged. This section provides a detailed look at clusters of investment strategies that have sought to enhance the resilience of the power system by targeting these two arguably most extensive and vulnerable parts of the grid.

2.4.1 Undergrounding

As the frequency and magnitude of weather events has increased, more utilities across the country have been looking to underground power lines as a strategy to reduce the frequency or intensity of outages. In general, undergrounding increases reliability, decreases the (considerable) costs of vegetation management, and is aesthetically preferred by customers (Hall, 2009). It can additionally reduce the number of outages caused by motor vehicle collisions with power system components and reduce live-wire contact (Quanta Technology, 2009). Additionally, Larson (2016) collected a national sample (~650 observations) of utility System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) values (including major event days) from 2000-2012 and analyzed regression models that included predictor variables of SAIDI and SAIFI. One such predictor variable was undergrounding transmission and distribution lines which showed that a "10% increase in the percentage share of underground line miles is correlated with a 14% reduction in the total annual duration of interruptions." However, undergrounding typically costs five to ten times as much per unit distance as overhead lines (EIA, 2012). Tables 2.5 and 2.6 show the wide ranges of costs for undergrounding transmission and distribution lines based on previous studies. Assuming approximately $1.2 million per distribution mile to underground, Quanta Technology (2009) estimated that undergrounding in residential neighborhoods would cost $3,100 per residential customer; undergrounding feeders, which are the lines leading into a residential neighborhood, would cost $14,000 per residential customer; and undergrounding commercial feeders would cost about $46,000 per commercial customer (costs converted to 2020 USD from original paper's 2009 USD). However, chapter five of this dissertation shows that these cost estimates for undergrounding may be out of date and that the cost to underground is decreasing.

When faults occur on underground lines, it can take much longer to restore power because locating and repairing faulty lines is often more difficult when they are underground. Similarly, operation and maintenance of underground lines can be more expensive and time consuming because often the system requires "more complex operational needs, such as visual inspection,… and specialized training/equipment for manhole/vault access" (Hall, 2009). For example, the Edison Electric Institute's (EEI) (B. W. Johnson, 2006) assessment of undergrounding power lines notes that North Carolina's underground lines took on average 1.6 times longer to repair than overhead lines from 1998-2002 and Virginia's took 2.5 times longer to repair in 2003. Additionally, a North Carolina study found that storm flooding can also have a huge impact on junctions in manholes and underground lines, causing significant damage if they are not adequately waterproofed and are not de-energized before the flooding occurs. This can be mitigated through flood monitors and sub-aqueous power lines that can be submerged in water (a newer technology being implemented by Florida Power & Light) (Gonzales & Switalski, 2018). Additional disadvantages to undergrounding include "stranded asset cost for existing overhead facilities; environmental damage including soil erosion, and disruption of ecologically-sensitive habitat; utility employee work hazards during vault and manhole inspections; reduced flexibility for both operations and system expansion; reduced life expectancy" compared to overhead lines (Quanta Technology, 2009). Disadvantages to undergrounding transmission include "technical challenges due to the high phase-to-ground capacitance." The National Electricity Safety Code (NESC) also has high design standards for extreme wind loading on transmission lines, rendering the added benefit of undergrounding minimal (Quanta Technology, 2009).

Additionally, undergrounding power lines in areas with earthquakes has the potential to be problematic. For example, when Christchurch, New Zealand experienced a magnitude 6 earthquake in 2011, Orion, one of the two distribution companies in Christchurch, had 50% of 66 kV underground cables with one-or-more faults; 5.5% of 11 kV and 0.6% of 400 Volt (J. M. Eidinger, 2012). In areas with liquification "essentially all the 66 kV buried cables failed" (J. M. Eidinger, 2012). Orion's overhead lines fared much better with "none of towers and poles supporting 66 kV overhead lines suffer[ing] damage, and only a few of the insulators and binders in 33 kV and rural 11 kV overhead lines [being] damaged due to liquefaction"(Kwasinski et al., 2019). Additionally, Kongar, Giovinazzi, & Rossetto (2017) determined that, in the case of this earthquake, liquefaction and peak ground deformation (PGD) showed good correlation with these underground line failures. Similarly, a case study on the performance of Pacific Gas and Electric's (PG&E) undergrounded lines' during the Napa 2014 earthquake in California determined that PGD is a good indicator for underground line failure, and that in the specific case of PG&E, undergrounded lines were placed in PVC ducts when buried, allowing them to accommodate approximately 10cm to 20cm of PGD in an earthquake (J. Eidinger & Tang, 2016).

The efficacy of undergrounding as a strategy to enhance resilience is case-specific and depends on many factors including "reliability history, location, soil conditions, vegetation, right-of-way, [and] criticality of load"(Musser, 2018). For example, in Florida, the Public Service Commission noted that, in recent storms, the causes of power outages in areas served by undergrounded lines included: storm surge; flooding; uprooting of trees; windblown trees or debris impacting certain underground-related equipment (such as pad mounted transformers); and outages of overhead facilities feeding underground areas (Florida PUC memo Feb 19. 2018 Docket No. 20170215-EU). Despite the limitations of undergrounding, Florida Power and Light (FP&L) found that during Hurricane Irma (which made landfall as a CAT 4 hurricane in 2017) underground laterals performed 6.6 times better than overhead laterals in terms of outages, and that the “single phase pad mount transformers for underground systems performed 3.5 times better than aerial transformers for overhead systems”(Rubin, 2018b). However, Gulf Power Company, another Investor-Owned Utility in Florida, found that undergrounding had not benefited its service territory much. In fact, the company has stated every year in its annual reliability reports—until 2018, when Florida Power & Light purchased it—that “the new construction growth of Gulf’s underground distribution facilities continues to outpace overhead construction due to customer demand based on aesthetics. However, continued analysis of the available overhead and underground data along with associated metrics does not support the use of underground construction as a storm hardening option at this time”(Gulf Power Company, 2018). Even within the same state and among utilities in relatively close proximity, the benefits of undergrounding could be different.

In 2014, the EEI reviewed 23 studies on undergrounding power lines and found that “undergrounding could be a viable solution to hardening the infrastructure through targeted or selective undergrounding rather than a total conversion. This might include placing the worst performing feeders, or feeder portions, underground or placing substation feeders that affected numerous customers underground”(Edison Electric Institute, 2014). They also recommended identifying critical support infrastructures and undergrounding feeders that served these areas. Additionally, given how expensive undergrounding projects are, “coupling such installations with other major excavation projects (such as roadwork, fiber optic cable installation and other construction) could also reduce the costs and disruptive impacts of undergrounding”(Edison Electric Institute, 2014).

Table 2.5. Cost estimates of undergrounding **transmission** lines. Costs have been converted to $\$_{2020}$ using the Bureau of Labor Statistics' Consumer Price Index Inflation Calculator.

Source	$\$_{2020}$ /mile	Cost assumptions
(Hall, 2013)	New construction: Urban: 4.02 -34.45 million Suburban: 2.64-34.45 million Rural: 1.61-31 million Convert overhead: Urban: 0.62 -13.78 million Suburban:1.26-12.63 million Rural: 1.26-6.89 million	Urban─150+ customers per square mile Suburban─51 to 149 customers per square mile Rural─50 or fewer customers per square mile
(KEMA Inc., 2012)	115kV XLPE: 36.5 million 115kV HPFF: 29.2 million 345kV XLPE: 42.7 million 345kV HPFF: 32.4 million XLPE: Cross-linked polyethylene cables HPFF: high-pressure, fluid-filled cables	Life Cycle Costs (LCC): 40-year time frame; capital recovery factor: 14.1% O&M escalation: 4% load growth: 2.03%; energy cost escalation: 1.2 % Discount rate: 8.0%.
(Commonwealth of Virginia Joint Legislative Audit and Review Commission, 2006)	7.5-13.5 million, new construction 230kV lines	accumulation of Dominion power studies some LCC costs some initial costs
(Florida Public Service Commission, 2005)	3.77 million remove and replace existing 138 kV overhead transmission facilities	a) planning and permitting; (b) labor to remove existing facilities; (c) new underground transmission facilities; (d) labor to install the new underground facilities; (e) trucks and other equipment to remove and install facilities; (f) credits for existing overhead facilities that could be employed in the future; (g) disposal of facilities that could not be employed in the future
(Public Service Commission of Wisconsin, 2011)	1.7-2.3 million for 69kV - 138kV lines	New construction, costs don't include terminals
(Larsen, 2016)	Min: 0.37 million Base case: 1.85 million Max: 3.33 million	cost of replacing overhead transmission lines with underground lines in Texas

Table 2.6 Cost estimates of undergrounding **distribution** lines. Costs have been converted to $$_{2020}$ using the Bureau of Labor Statistics Consumer Price Index Inflation Calculator.

Source	**$$_{2020}$/mile**	**Cost assumptions**
(Hall, 2013).	New construction: Urban: 1.31 - 5.2 million Suburban: 0.61- 2.64 million Rural: 0.34-2.1 million Convert Overhead: Urban: 1.15-5.7 million Suburban:0.36-2.78 million Rural: 0.18-2.25 million	Urban—150+ customers per square mile Suburban—51 to 149 customers per square mile Rural—50 or fewer customers per square mile
(City and County of San Francisco Board of Supervisors Budget and Legislative Analyst, 2015)	3 - 6.5 million (Comparison of multiple cities in California)	Includes cost of trenching the laterals and of connecting properties to the system.
(Florida Public Service Commission, 2005)	1.15 million convert overhead	Estimate includes (1) the cost of converting existing overhead facilities within subdivisions to underground and (2) the cost of converting the feeders which connect the subdivisions and commercial districts to the generation and transmission supply system from overhead to underground.
(Larson, 2016)	a) Min: 78,600 Base case: 393,000 Max: 706,000 b) Min: 67,000 Base case: 335,000 Max: 602,000 c) 1.55 million	a) Replacement cost of undergrounding Texas distribution lines b) Replacement cost of undergrounding Cordova, AK distribution lines c) LCC cost per mile of replacing Cordova, AK distribution lines
(Gonzales, A., & Switalski, C., 2018).	500,000 to over 4 million	Florida Light and Power cost to retrofit: taking above-ground lines and putting them underground
(McCharthy, 2011)	a) 312,000 low density rural areas; 2.86 million urban areas ; O&M $1300 mile per year b) 536,000 – 3.08 million c) new construction: 55,000- 2 million. Retrofit: 200,000 – 4 million d) average cost: 1.3 million	a) North Carolina Utilities Commission Study 2003: Capital cost to underground existing overhead b) Oklahoma Corporation Commission 2008 study: Capital costs c) Virginia Corporations Commission study 2005: includes materials, labor, administrative, contingency and acquisition of new easement costs.

		d) Maryland Legislative task force study in 2003: Average Capital cost
(Shaw Consultants International, 2010)	4.2 million + 1.4 million to underground Transformers	Cost to underground mainline. Includes conduit and cable, splice and manhole, and switch manholes
(Davis & Hansen, 2009)	680,000 - 700,000	American Electric Power's Public Service Co. of Oklahoma (AEP-PSO). Picked cheaper feeders to bury.

2.4.2. Replacing Wood Poles with Concrete, Steel or Other Materials

While wooden poles can be very strong, in many places across the US utilities are replacing wooden poles with concrete, steel, fiber reinforced polymer(composite), and ductile iron utility poles as a strategy to enhance resilience. Florida Power and Light, are removing and replacing Transmission wood poles with steel poles and distribution wood poles with reinforced concrete as their wood poles start to deteriorate (Florida Power and Light, 2018a). Additionally, Guam Power Authority (GPA), which experiences regular typhoons has replaced over 90% of their Transmission and Distribution poles with reinforced concrete rated for 170 mph winds (GPA, 2020 IRP). Florida Keys Electric Cooperative started installing ductile iron distribution poles in 2010 to help with hurricane resilience in the Florida Keys. Ductile iron is different from cast iron as the "graphite composition is manipulated into spherical nodules rather than flakes…. Which makes it slightly elastic and therefore resistant to cracking when under extreme force"(Kropf, 2011). Table 2.7 compares the pole materials, while tables 2.8 and 2.9 provide cost estimates from transmission and distribution pole replacement.

Table 2.7. The advantages and disadvantages of different pole materials

Material	Advantages	Disadvantages
Wood	-Easier to climb and have lower conductivity than steel (S. T. Smith, n.d.)	-Require treatment with decay-resistant substances to match the life-time of concrete or steel poles (Quanta Technology, 2009)
Steel	-Less susceptible to extreme weather (Lu & El Hanandeh, 2017)	-Higher cost than wood poles -"Un-natural" appearance (Char & Bilek, 2018).

	-Lightweight which makes them easier to transport and install (Lindemulder, 2017)	
Concrete	-Resistant to damage from insects and wildlife -Resistant to fire damage than wood poles -Less deflection than wood poles (Char & Bilek, 2018).	-Heavier than wood poles -Pole locations need to have vehicular access -Heavy equipment may be required to set larger poles (Char & Bilek, 2018).
Fiber reinforced polymer (composite)	-Lighter than equivalent wood poles–ideal for remote locations -Sectional or modular FRP poles good for sets in tight locations -Resistant to damage from insects and wildlife -Higher resistance to fire damage than wood poles (Char & Bilek, 2018).	-More flexible than wood poles -Multiple pole structures may be required for high loads (Char & Bilek, 2018).
Ductile iron	-Environmentally friendly, made from recycled material and 100% recyclable -Combine the physical strength of steel with the corrosion resistance of cast iron -Weigh about 50% less than comparable wood poles and far less than concrete -More cost effective than steel and concrete Have an expected lifespan of more than 75 years. (Kropf, 2011) -Resistant to damage from insects and wildlife -Resistant to fire damage than wood poles -Less deflection than wood poles (Char & Bilek, 2018).	-Heavier than wood poles (Char & Bilek, 2018).

It is important to note that in many of these cases, a one-for-one replacement with wood poles may result in a different system design than intended. Although NESC standards use strength factors between materials to encourage replacement with "wood equivalent" poles, for example "a wood pole must be 60% stronger, on average, to carry the same load as a concrete pole", this may not be enough to meet load and reliability goals (Lynch, 2018; Quanta Technology, 2009). For example, steel poles have different "modules of elasticity than wood poles, which of course causes different deflections and resulting stress throughout the structure"(Lynch, 2018).

Table 2.8. Cost of installing non-wood **transmission** poles. All costs have been converted to $$_{2020}$ using the Bureau of Labor Statistics Consumer Price Index Inflation Calculator.

Source	2020 $/pole	Cost assumptions
Summary statistics of the 2007-2020 Storm Protection Plan Annual Status Reports/Annual Reliability Reports, Florida Power and Light.[6]	In the last 15 years FP&L has spent an average of $26,000 per wood transmission structure replacement with steel. The minimum in 2009 at ~$10,000 and the maximum in 2020 at $61,000	Cost for replacement of transmission "structures" does not differentiate between poles and towers
(KEMA, 2012)	Overhead Transmission: 115kV Steel delta: 9.8 million/circuit-mile 345kV Steel delta: 15 million/circuit-mile	LCC cost: 40-year time frame; capital recovery factor: 14.1% O&M escalation: 4% load growth: 2.03%; energy cost escalation: 1.2 % Discount rate: 8.0%.
Summary statistics of the 2006-2020 Storm Protection Plan Annual Status Reports/Annual Reliability Reports, Duke Energy Florida (DEF).[1]	In the last 15 years DEF has spent an average of $92,000 per wood transmission structure replacement with steel. The minimum in 2007 at ~$38,000 and the maximum in 2020 at $256,000	"costs include maintenance pole changeouts, insulator replacements and other capital costs. The budget and actual figures also include DOT/Customer Relocations, line rebuilds and System Planning additions."
(Lynch, 2018)	(1) The overall cost of the wood poles alone for this design was approximately $295,000. The design resulted in 52 structures, with an average of 8.4 structures per mile. (2) same # of poles, but now steel with overall cost $345,300 ~ (3) The steel pole optimized design resulted in 35 structures with an average of 5.65 structures per mile. Total cost was $285,600.	An approximately six mile 161 kV single pole transmission line was designed using three approaches. First (1) the line was optimized using wood poles. The second (2) approach was to take the first wood pole optimized design and swap out the wood poles with 'wood equivalent' steel poles. And finally (3), this line was again optimized, this time with steel poles.
(Quanta Technology, 2009).	Wood Single Pole, 95' H4: estimate 14 structures per mile, ~$220,000 per mile.	All 4 pole types are theoretically designed to the same load and reliability standards. Each line is designed to 130 mph NESC

[6] Available: http://www.psc.state.fl.us/ElectricNaturalGas/ElectricDistributionReliability

	Concrete Single pole 105' G120: estimate 11 structures per mile, ~$310,000 per mile Steel monopole, 90' LD8: estimate 13 structures per mile, ~$300,000 per mile. Steel lattice tower, 90' DT800: estimate 12 structures per mile, ~$460,000 per mile.	using the same conductor, structure configuration, hardware, etc. Covers installed costs only.

Table 2.9. Cost of installing non-wood **distribution** poles. All costs have been converted to $2020 using the Bureau of Labor Statistics Consumer Price Index Inflation Calculator.

Source	**2020 $/pole**	**Cost assumptions**
(Salman & Li, 2016)	a) New Steel pole: 940 b) Replacement steel pole: 1500 c) Iowa 970; Florida 1,780	a) Purchase, shipping, handling & installation b) Remove, dispose old pole, Purchase, shipping, handling & installation c) LCC for distribution poles, 60 year time frame.
(Smith, S. T. ,(n.d.))	Steel: 1,370 Concrete: 1,750	Installed cost of a class 4, 45-foot-long pole.
(Braik, Salman, & Li, 2019).	Steel: Norman, OK: 3,299 Xenia, OH: 3,297 Tampa, FL: 3,295 Concrete: Norman, OK: 3,334 Xenia, OH: 3,332 Tampa, FL: 3,331	LCC per pole: The installation cost is assumed to be $2,500 per pole and replacement cost is assumed equal to $4,000 per pole for all types of poles. discount rate r is estimated to be equal to 5%. periodic maintenance cost not included. Service life assumed 60 years for all poles.
(Lu & El Hanandeh, 2017)	Steel: 1,621 Concrete: 1,847	LCC in Australia, 60-year life span. Includes pole material and manufacturing costs, installation, removal and disposal, carbon cost, and revenue.

When it comes to measuring the performance of steel/concrete vs wooden poles, there are few case studies and models to look to. Quanta Technology (2009) calculated the expected value of annual restoration of wood distribution and transmission structures based on hurricane occurrence and predicted failure rates which are reproduced Table 2.10.

Table 2.10. Quanta Technology (2009) failure rate assumptions for wood poles.

	Sustained windspeed (mph)				
	84.5	**103**	**120.5**	**143**	**168**
Distribution Failure Rate	0.35%	0.76%	1.60%	4.12%	11.79%
Transmission Failure Rate	0.12%	0.13%	0.77%	8.74%	34.64%

Post-storm analysis revealed steel transmission poles performed better than wood transmission poles during Hurricane Irma (State of Florida Public Service Commission, 2018). Duke Energy Florida had 27 wood transmission line poles fail and 1 steel transmission tower fail. FP&L had only 5 transmission wood pole failures. Duke and FP&L don't distinguish between wood and concrete distribution poles when examining outages. But for "hardened feeders" FP&L specifically reports that there were no concrete poles down, but 26 wood poles had collapsed (Florida Power and Light, 2018b). What constitutes hardened vs non-hardened for the distribution system relates to extreme wind loading not pole material.

In Salman (2014) fragility curves for steel vs timber distribution poles were derived (class 4 <60ft). New timber and steel are equally strong, however over time steel likely performs slightly better than timber, depending on how quickly the timber decays (which can be location dependent). Salman found that at 40 and 60 years, the steel fragility curve fell in between the two extremes for modelling timber decay, but steel was on the higher performing half of the timber fragility curve range.

Braik, Salman, & Li (2019) analyzed tornado wind load on distribution poles for wood, steel and prestressed concrete (PC) poles. First, they found that all types of utility pole fail at wind speeds 20mph less in a tornado than a hurricane. Similar to what we see in Salman (2014), when new, all three pole types have almost identical fragility curves. The fragility curves derived for 20, 40, and 60 years and across three different US states with different climates (Oklahoma, Ohio, and Florida) are reprinted in Figures 2.2-2.4.

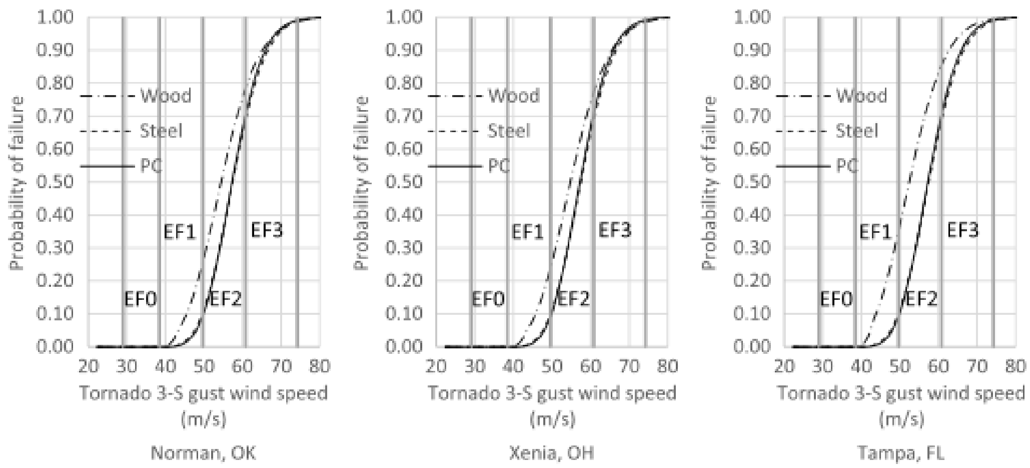

Figure 2.2 Comparing tornado fragility curves for wood, steel, and prestressed concrete poles at **20 years.** Reprinted from Braik AM, Salman AM, Li Y. Risk-Based Reliability and Cost Analysis of Utility Poles Subjected to Tornado Hazard. J Aerosp Eng. 2019;32(4). Copyright (2019), with permission from American Society of Civil Engineers.
DOI: 10.1061/(ASCE)AS.1943-5525.0001029

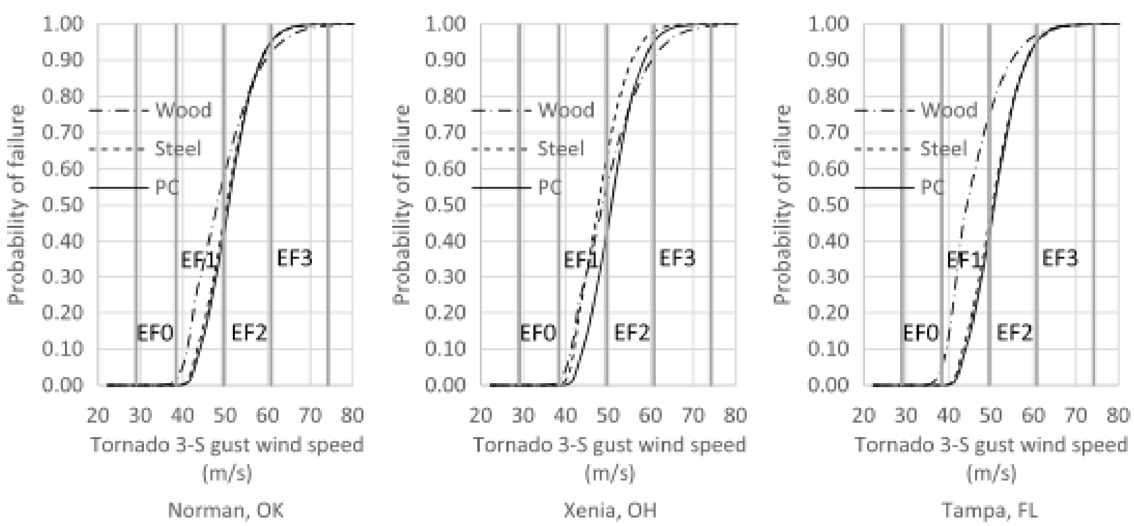

Figure 2.3 Comparing tornado fragility curves for wood, steel, and prestressed concrete poles at **40 years.** Reprinted from Braik AM, Salman AM, Li Y. Risk-Based Reliability and Cost Analysis of Utility Poles Subjected to Tornado Hazard. J Aerosp Eng. 2019;32(4). Copyright (2019), with permission from American Society of Civil Engineers.
DOI: 10.1061/(ASCE)AS.1943-5525.0001029

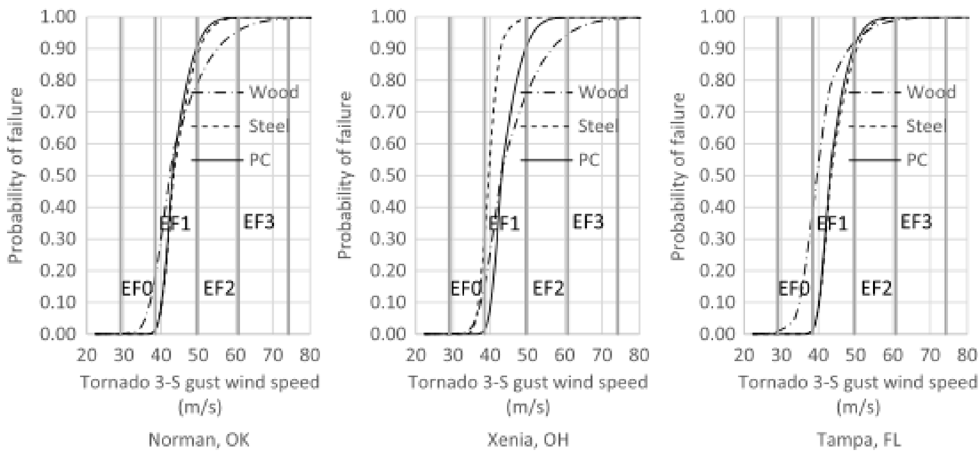

Figure 2.4 Comparing tornado fragility curves for wood, steel, and prestressed concrete poles at **60 years.** Reprinted from Braik AM, Salman AM, Li Y. Risk-Based Reliability and Cost Analysis of Utility Poles Subjected to Tornado Hazard. J Aerosp Eng. 2019;32(4). Copyright (2019), with permission from American Society of Civil Engineers.
DOI: 10.1061/(ASCE)AS.1943-5525.0001029

The author's interpretation of the graphs are as follows:

> At 20 years, the fragility of wood poles has increased compared with that of new poles whereas those of the steel and the PC poles almost remain the same. This is because corrosion in both steel and PC poles has not initiated yet. At 40 years and beyond, all the fragilities have increased, and the deterioration is highly affected by the location for wood and steel poles. The deterioration of PC poles occurs gradually after initiation because the corrosion initiation time was modeled as a random variable.

Also note that in the very humid climate of Florida, wood poles deteriorate faster than in Oklahoma or Ohio.

Finally, when considering earthquake hardening, initial research indicates steel distribution poles can withstand at least .4g PGA (Peak Ground Acceleration) more likely up to .6g (Babu, 2012).

2.4.3. Other Pole and Wire Hardening strategies

In addition to pole material there are several other strategies for distribution pole and wire hardening, including:

- a steel brace that is driven below the groundline and extends above the third-party attachments (guyed poles) or, alternatively, fiberglass wraps (Quanta Technology, 2009; Teoh, Alipour, & Cancelli, 2019)
    - also adding transverse guys to existing poles (one on each side) serves to transfer some or all of the stress from wind forces from the pole to the guy wires, (Quanta Technology, 2009)
- covered conductors – "a variety of conductor cable designs that incorporate an external polymer sheath to protect against incidental contact with other conductors or grounded objects such as tree branches." (Exponent Inc., 2021)
- shorter spans, which require more poles per line distance of distribution lines (Federal Emergency Management Agency, 2008; Quanta Technology, 2009; Teoh et al., 2019). Shorter spans between lines also increases the extreme wind loading rating of the circuit (R. E. Brown, 2009).
- reduced conductor size, which directly reduces the load on the pole but impacts the electric capacity of the line (Teoh et.al, 2019).
- reduced pole-mounted equipment, achieved by converting a three-phase pole-mounted transformer bank to a pad-mount unit (Teoh et.al, 2019; Quanta Technology, 2009)
- fewer third-party attachments (Teoh et.al, 2019; Quanta Technology, 2009)
- using heavier wire such as T-2 and ACSR for distribution (FEMA, 2008) and ACCC for transmission (Utility Dive, 2019)
- changing pole size depending on needs: shorter poles reduce exposure of lines to vegetation because the lines will sag and "blowout" less[7]. However shorter poles require more poles to serve the same line length and therefore more poles will be required to be installed and maintained (Puget Sound Energy, 2016). Additionally, larger poles can carry more weight (FEMA, 2008)
- dead-end structures (FEMA,2008)

[7] Blowout is defined as when wires to move side to side due to wind

- quick disconnect wire – researchers at EPRI and University of Florida suggest cables dropping when hit immediately will protect poles from also collapsing and dramatically reduce restoration time: “instead of taking 36 hours to fix a pole, it can take you two or three hours” to replace conductors (D. Brown, 2021).

There is little publicly available research into how well any of these strategies work as many utilities have not yet invested in most. Even those that have invested have either done so on a small scale or do not have the data required to assess how much *more* reliability has been gained through any one of these strategies. In a 2008 FEMA study of ice storms in Nebraska and Kansas, they estimated a utility could increase “the strength of distribution line by 66 percent” using the following mitigation methods together: “existing lines can be replaced by heavier wire, such as T-2 and ACSR…. creating shorter spans between poles, installing larger poles, and providing wind dampeners.”

In a more recent study, Exponent Consulting company (2021) conducted a literature review on covered conductors and found that they can reduce faults related to extreme heat (sagging of lines), ignition during wildfires, corrosion, wind damage from lines touching or trees falling on lines as well as protect line workers. Specifically, in Finland covered conductors only experienced 20% of the number of permanent faults compared to basic wire. Taiwan saw a decrease in SAIDI (86%) and SAIFI (75%) after increasing covered conductor from 0 to 55% of their system. EPRI estimated a reduction in 40% of tree-caused outages in US utilities. Finally, Australia saw a 90% decrease in wire ignitions during wildfires, although broken covered conductors actually increase ignition risk. The sheath layer itself could also pose new risks to the system, causing outages not originally a threat (ice in the sheath for example). Covered conductors are estimated to cost $430,000/mile by Southern California Edison (SCE). For comparison SCE estimated an average cost of $3 million/mile for undergrounding. The World Bank estimates that aerial bundled conductors (a type of covered conductor) costs between 2-15 times more as basic overhead wire (Nicolas et al., 2019).

Teoh et. al (2019) explore the fragility curves of distribution poles with ice and wind loading conditions, comparing different classes of poles, and comparing guyed and un-guyed poles. What differentiates classes of utility poles is the horizontal load capacity which translates to minimum diameters at both the top and bottom of the pole: top 0.218 meters (m), 0.202m, 0.186m, and 0.170m and bottom 0.331m, 0.311m, 0.291m, and 0.271m. Therefore, poles within a certain class can be a wide range of heights, but their diameter and load capacity are what differentiates them. The modelling done by the team first estimated damage curves by wind speed assuming ice on lines for the various classes and for guyed vs un-guyed poles as shown in the figures 2.5 and 2.6.

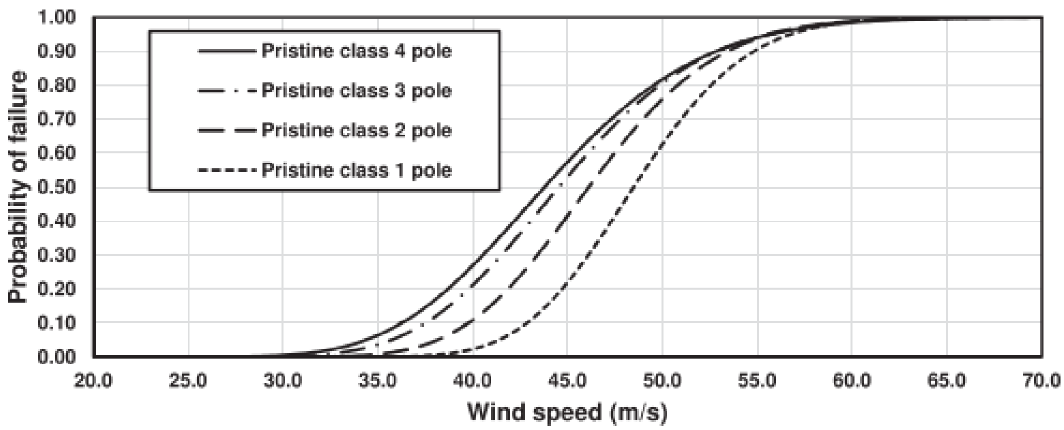

Figure 2.5 Fragility curves for new class 1- 4 Southern wood pine utility poles with combined wind and ice loading conditions. Reprinted from *Engineering Structures*, 197 (2019), Yee Er Teoh, Alice Alipour, & Alessandro Cancelli, Probabilistic performance assessment of power distribution infrastructure under wind events, Copyright (2019), with permission from Elsevier.

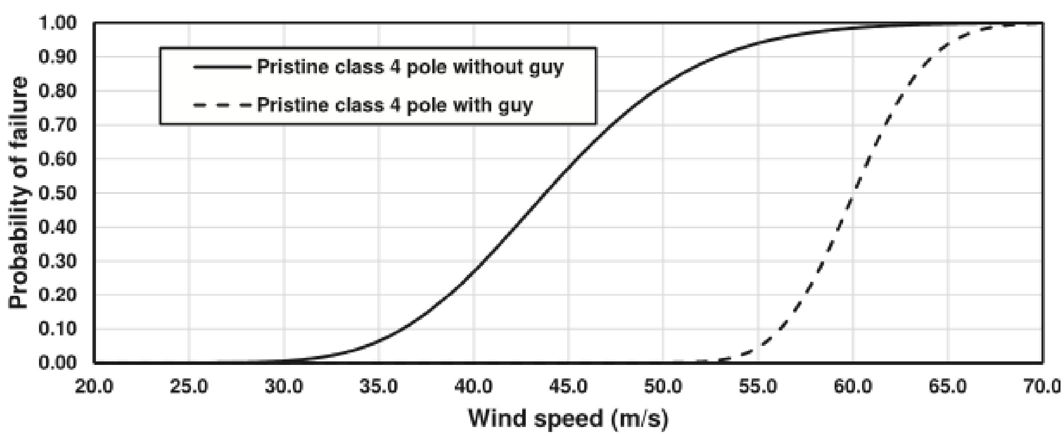

Figure 2.6 Fragility curves for class 4 Southern wood pine utility poles with and without guying for combined wind and ice loading conditions. Reprinted from *Engineering Structures*, 197 (2019), Yee Er Teoh, Alice Alipour, & Alessandro Cancelli, Probabilistic performance assessment of power distribution infrastructure under wind events, Copyright (2019), with permission from Elsevier.

After damage curve modelling, Teoh et. al did a life cycle cost analysis showing that utilities could reduce lifetime cost by 10% switching from class 3 to class 2 poles and reduce cost by 20-25% switching from class 3 to class 1. They earn the most benefit by adding guying to lower class poles and save 60-70% in life cycle cost. Utility company Eversource, in New Hampshire found similar results when studying their own system, that is “class 2 wood poles can withstand 60% greater force than smaller-diameter class 4 poles, improving outcomes during tree strikes or high winds”(TRC Consulting, 2021).

When it comes to earthquakes, FEMA HAZUS 4.2 model estimates damage to distribution circuits that have seismic anchored components and those that do not. Table 2.11 lists their damage estimates as well as restoration time estimates for distribution circuits damaged by earthquakes with varying peak ground accelerations.

Table 2.11. FEMA HAZUS 4.2 model estimates for distribution circuit seismic damage and restoration time.

Distribution circuit Damage	Estimated median peak ground acceleration (g) that would cause this damage on a circuit with **unanchored/standard components**	Estimated median peak ground acceleration (g) that would cause this damage on a circuit with **anchored/seismic components**	Median restoration time (days)
Slight: failure of 4% of all circuits	0.24	0.28	0.3
Moderate: failure of 12% of circuits	0.33	0.40	1.0
Extensive: failure of 50% of all circuits	0.58	0.72	3.0
Complete: failure of 80% of all circuits	0.89	1.10	7.0

Lastly, advancements in machine learning algorithms and unmanned aerial vehicles can be used to more quickly inspect and predict pole resilience (Alam, Zhu, Eren Tokgoz, Zhang, & Hwang, 2020).

2.4.4. *Vegetation management*

All utilities already do some form of vegetation management, and it is usually a large portion of their annual maintenance costs (EEI, 2014). However, vegetation related outages make up a majority of outages (Edison Electric Institute, 2014; State of Florida Public Service Commission, 2018) and reducing those outages with vegetation management can be more cost effective than other hardening strategies (like undergrounding) (EEI, 2014). There are multiple approaches to vegetation management, and which approach a utility should take is very location specific and depends on the type of vegetation, relationship with community, climate/weather and budget.

Trimming trees and mowing on a regular cycle is a standard strategy for vegetation management. For example, since 2006 Florida Power and Light (FPL) trims trees along distribution feeders on a 3-year cycle and distribution laterals on a 6-year cycle, with extensive "mid-cycle" feeder trimming in known problem areas throughout its system. Gulf Power Company, also in Florida, trims main line feeders on a 3-year cycle and trims laterals on a 4-year cycle since 2008. FPL spends roughly $4,000/mile annually on tree trimming and Gulf Power company spends roughly $3,000/mile annually.[8] Mechanical vegetation management is the most popular as it allows people to grow what they want near power lines, but it can be expensive; constantly requiring crews to manage growth and poses a safety risk to tree trimmers (Rancea, 2014). Deferring line clearance also increases future cost of maintenance as shown in Table 2.12 reproduced from Browning & Wiant (1997) and still a problem today (Appelt & Beard, 2006; Edison Electric Institute, 2014).

Table 2.12: The impact of deferred maintenance on the average time to prune trees for line clearance is projected by a regression equation in a study by Environmental Consultants in the Journal Arboriculture in 1997 (Browning & Wiant, 1997).

		Average time to trim trees per site (worker minutes)				
Utility	**Optimum trim cycle**	**On time**	**1 year past**	**2 years past**	**3 years past**	**4 years past**
A	5 years	68.9	84.9	98.7	109.6	116.2
B	5 years	56.9	68.8	79.2	87.1	93.2
C	6 years	43.3	50.5	56.3	60.8	64.0

[8] Data collected from Florida IOU annual reliability reports from 2006-2020 available: Available: http://www.psc.state.fl.us/ElectricNaturalGas/ElectricDistributionReliability

Another approach to vegetation management is to ensure that problematic vegetation is not planted near transmission or distribution line Rights of Way (ROW). There exist FERC standards for transmission vegetation management (FERC, n.d.), but because distribution falls under state purview, no standards exist for distribution lines. FPL implemented a Right Tree, Right Place program starting in 2006 which educates customers and local governments on which types of vegetation is appropriate to plant near powerlines; emphasizing to customers that this program can greatly reduce power outages, especially during large storms (Florida Power and Light, 2007). PG&E in California also has a similar program and California has laws restricting vegetation around distribution lines (Rancea, 2014):

- General Order 95, Rule 35 – requires an 18 inches minimum clearance between vegetation and wires carrying more than 750 V, at all times, regardless of location.
- Public Resource Code 4293 – requires a 4 feet minimum clearance between vegetation and wires carrying more than 750 V, in State Responsibility Areas (mostly outside urban area), which are under Department of Forestry and Fire Protection (CDF) jurisdiction.
- Public Resource Code 4292 – requires a 10 feet minimum clearance around the base of utility poles.

Additionally, expanding ROW can also reduce this problem. In 2016, Gulf began a pilot program where it purchased ROW on private land for vegetation management. Gulf successfully purchased easements on 20 miles of line giving Gulf the right to clear and maintain a 15-ft wide corridor on private property adjacent to the public ROW and Gulf's distribution facilities (Gulf Power Company, 2017). By 2019 they purchased easements on 150 miles of line (Gulf Power Company, 2020).

Despite FPL and Gulf's robust vegetation management programs, the average CAIDI for all vegetation related outages (including tropical storms) for the two utilities between 2017-2021 is actually *higher* than the average CAIDI for all vegetation related outages from 2006-2010. This result is not surprising, given that the 2018 Florida PSC Review of Hurricane Preparedness noted that "additional trimming by the utilities within their rights of way would not eliminate these [Hurricane] vegetation related outages."(State of Florida Public Service Commission, 2018)

When analyzing only "adjusted" vegetation-related outages (excludes outages from tropical storms) Gulf saw an on average decrease in vegetation CAIDI from 2006-2010 to 2017-

2021, but FP&L did not[9]. Conversely, Guikema, Davidson, & Liu, (2006) used statistical modelling to determine the effect of tree trimming on 648 circuits from Duke Power between 2000 and 2004. Excluding major event days – defined in this paper as "event for which the system-wide log(SAIDI) is at least 3.5 standard deviations above the longer-term mean of the system-wide log(SAIDI)" – they found that decreasing the time between trimming cycles by one year predicts a reduction of 13 vegetation related outages per month.

In addition to cycle trimming and plant placement, integrated vegetation management (IVM) also includes the use of herbicides to stop trees growing into lines: "An IVM-based strategy makes use of a variety of increasingly selective vegetation maintenance actions specifically targeting incompatible vegetation and promoting the development of compatible plant communities" (Goodfellow, 2019). Tree growth regulators for example can reduce tree growth and therefore trim time and also increase stress tolerance in trees, but they are still very new and public perception of herbicide usage is negative (Rancea, 2014). Any chemical environmental intervention must be treated with care. The integrated approach may have higher costs in the first 5 years but after 10 years can only half the cost of mechanical mowing annually (Goodfellow, 2019; The Utility Expo, n.d.).

Lastly, new technologies can help utilities take a reliability-based maintenance approach to vegetation management instead of usual annual requirements. Using vegetation management systems, utilities can identify which circuits are most at risk to vegetation related outages and focus priority trimming and other resources to those line sections (The Utility Expo, n.d.). For example, the Lake Region Electric Cooperative (LREC) in Minnesota Lake County implemented ARCT Inc.'s Arborcision system (a utility vegetation management tool). In the 5 years after implementation, they report that "Tree-related outages have been reduced by 30%, and total outage hours have decreased by 45%." Their vegetation maintenance costs have decreased from $2,400/mile to $500/mile (Thompson, 2015). Other technologies such as "remote sensing technology like LiDAR and satellite/aerial imagery provide useful information on the extent, location and maintenance requirements of vegetation throughout the utility's footprint." (The Utility Expo, n.d.) LiDAR is faster, provides more coverage, is more accurate and provides an audit trail compared to traditional ground-based techniques for assessing ROWs (Kurinsky,

[9] Data collected from Florida IOU annual reliability reports from 2006-2020 available: Available: http://www.psc.state.fl.us/ElectricNaturalGas/ElectricDistributionReliability

2013). LiDAR, however, is more expensive than traditional ground inspections ($\$_{2020}$ 400/circuit mile) “averaging $1,130/circuit mile [converted to $2020] for initial establishment and going as low as $306/circuit mile [converted to $2020] for subsequent fly-overs.” (T&D World, 2010) LiDAR costs are however trending down, and the costs are reflective of the number of circuits per corridor. Therefore, “the more circuits in a given corridor, the lower the per-circuit-mile cost.” (T&D World, 2010)

2.4.5. Moving and reinforcing substations.

In recent decades, a number of utilities have either moved or hardened substations that were located in areas vulnerable to flooding. For example, from 1998-2008 Texas utilities experienced 125 incidents of substation damage due to 14 named storms – 11.6% of that damage was attributed to flooding (Quanta Technology, 2009). The FEMA HAZUS 2.1 manual for flooding damage estimates substations experience 2% damage with flooding at 1ft inundation and incrementally increase to 15% damage at 10 ft inundation with functionality lost at 4ft of flooding depth and with control room damage at any inundation level (FEMA, n.d.-a). In addition to preventing flooding damage, avoiding placing substations on100-year flood plains avoids the higher land cost, the higher cost for transmission line taps and the higher cost for feeder extensions (Quanta Technology, 2009).

Often flood proofing existing substations requires elevating equipment. Entergy utility found that to raise certain substation components by 8 feet elevation would cost an initial ~$1 million per substation (converted to 2020 USD from original study) (Quanta Technology, 2009). Additionally, a utility could build a temporary or permanent protective berm around the facility (J. Smith, 2018), add sump-pumps (Boggess, Becker, & Mitchell, 2014), and install submersible equipment (EEI, 2014). FPL has identified 8-10 substations it plans to flood proof in Miami and the cost of the first hardening project completed in 2020 was $3.2 million (Florida Power and Light Company, 2021).

To move an entire existing substation to higher elevation can be challenging, because in most cases the vulnerable substation must remain in operation until switchover. Quanta found that building a new substation outside of a flood plain saves you ~$20,000 a year on substation repairs, assuming a 40-year lifetime, 10% discount rate, and a new substation costs ~$7.4 million with repair costs at roughly $2.5 million (converted to 2020 USD from original study).

Additionally, the Midcontinent Independent System Operator (MISO) has published a transmission cost estimation guide and their final substation estimate for upgrades and new construction are shown in Table 2.13 (MISO, 2019).

Table 2.13. Reproduced MISO cost estimate for upgrading substations and installing new ones. Cost in $2020 Million.

Substation Upgrades - Exploratory Cost Estimates							
Scope of Work	**69kV**	**115kV**	**138kV**	**161kV**	**230kV**	**345kV**	**500kV**
Add 1 position (ring bus)	0.7	0.9	1.1	1.2	1.4	2.4	3.6
Add 1 position (breaker-and-a-half bus)	1.1	1.3	1.6	1.8	2.3	3.7	5.4
Add 1 position (double-breaker bus)	1.2	1.5	1.8	2.2	2.5	4.0	5.8
Add 2 positions (ring bus)	1.5	1.8	2.3	2.6	3.0	4.8	7.3
Add 2 positions (breaker-and-a-half bus)	1.8	2.4	2.9	3.3	3.9	6.1	9.3
Add 2 positions (double-breaker bus)	2.5	3.1	3.8	4.3	4.9	8.0	11.7
New Substation - Exploratory Cost Estimates							
4 positions (ring bus)	4.7	5.5	6.4	7.0	7.8	11.0	15.8
4 positions (break-and-a-half bus)	5.8	7.0	8.0	8.8	9.9	14.7	20.8
4 positions (double-breaker bus)	6.8	8.1	9.3	10.4	11.8	17.7	25.6
6 positions (ring bus)	5.9	7.0	8.1	8.9	10.0	14.8	21.1
6 positions (break-and-a-half bus)	7.5	8.9	10.4	11.5	13.1	19.7	28.3

6 positions (double-breaker bus)	8.8	10.6	12.4	13.8	15.8	24.2	34.9

FEMA HAZUS 4.2 earthquake model estimates the damage to a substation with standard or seismic components as well as the expected restoration time shown in Table 2.14. Seismic anchoring is defined in the earthquake manual as "equipment designed with special seismic tiedowns or tiebacks, while unanchored equipment refers to equipment designed with no special considerations other than the manufacturer's normal requirements" (FEMA, n.d.-b). During the September 2011 Christchurch, New Zealand Earthquakes, 7 transformers across 3 substations tripped offl due to vibration affecting mercury-filled safety switches after experiencing peak ground acceleration of about 0.45g horizontal and about 0.80g vertical. These took 4 hours to repair and a program to replace these old relays with modern seismically rated models is underway. Further substation damage was avoided by investing in the reinforcement of 200 unreinforced masonry (URM) substation buildings in the last decade, costing NZ$6 million in total (Kwasinski et al., 2019).

Table 2.14. FEMA HAZUS 4.2 model estimates for substation seismic damage

Substation Damage	Estimated median Peak Ground Acceleration (g) that would cause this damage on a substation with **unanchored/standard components**	Estimated median Peak Ground Acceleration that would cause this damage on a substation with **anchored/seismic components**
Slight: failure of 5% of the disconnect switches (i.e., misalignment), or the failure of 5% of the circuit breakers (i.e., circuit breaker phase sliding off its pad, circuit breaker tipping over, or interrupter-head falling to the ground), or by the building being in the Slight damage state.	low voltage (34.5 kV to 150 kV): 0.13 medium voltage (150 kV to 350 kV): 0.10 high voltage (350 kV and above): 0.09	low voltage (34.5 kV to 150 kV): 0.15 medium voltage (150 kV to 350 kV): 0.15 high voltage (350 kV and above): 0.11
Moderate: failure of 40% of disconnect switches (e.g., misalignment), 40% of circuit	low voltage (34.5 kV to 150 kV): 0.26	low voltage (34.5 kV to 150 kV): 0.29

breakers (e.g., circuit breaker phase sliding off its pad, circuit breaker tipping over, or interrupter-head falling to the ground), failure of 40% of current transformers (e.g., oil leaking from transformers, porcelain cracked), or by the building being in the Moderate damage state.	medium voltage (150 kV to 350 kV): 0.20 high voltage (350 kV and above): 0.13	medium voltage (150 kV to 350 kV): 0.25 high voltage (350 kV and above): 0.15
Extensive: Failure of 70% of disconnect switches (e.g., misalignment), 70% of circuit breakers, 70% of current transformers (e.g., oil leaking from transformers, porcelain cracked), or by failure of 70% of transformers (e.g., leakage of transformer radiators), or by the building being in the Extensive damage state.	low voltage (34.5 kV to 150 kV): 0.34 medium voltage (150 kV to 350 kV): 0.30 high voltage (350 kV and above): 0.17	low voltage (34.5 kV to 150 kV): 0.45 medium voltage (150 kV to 350 kV): 0.35 high voltage (350 kV and above): 0.20
Complete: failure of all disconnect switches, all circuit breakers, all transformers, or all current transformers, or by the building being in the Complete damage state.	low voltage (34.5 kV to 150 kV): 0.74 medium voltage (150 kV to 350 kV): 0.50 high voltage (350 kV and above): 0.38	low voltage (34.5 kV to 150 kV): 0.90 medium voltage (150 kV to 350 kV): 0.70 high voltage (350 kV and above): 0.47

2.4.6. Distribution Automation

In 2016 the US Department of Energy's Office of Electricity Delivery and Energy Reliability released a report on distribution automation documenting the installation of 82,000 smart digital devices on 6,500 circuits over a 3-year period (US Department of Energy, 2016). Technologies of particular importance for use in outage management are remote fault indicators, smart relays, automated feeder switches and automated feeder monitors. These fault location, isolation, and service restoration (FLISR) technologies "can automate power restoration in seconds by automatically isolating faults and switching some customers to adjacent feeders." (US Department of Energy, 2016). Cost estimates for the implemented devices during the pilot program are shown in Table 2.15.

Table 2.15. Per Unit Cost ($2020) Estimates from the US Department of Energy Smart Grid Investment Grants pilot program implementation (SmartGrid.gov, 2015) All dollar figures are the total cost, which is the sum of the federal investment and cost share of the recipient.

Distribution Automation Asset	**Cost per unit ($2020)**
Automated Feeder Switches	54,147
Feeder monitors	24,850
Substation monitor	6,366
	Cost per Entity ($2020)
Distribution automation/Substation communication networks	9,555,191
Distribution management systems	9,010,452
IT hardware, systems, and applications that enable distribution functionalities	4,659,820

The utilities that piloted the FLISR technologies reported that in aggregate they found a 45% reduction in the number of customers interrupted and a 51% reduction in the customer minutes of interruption per outage event. Additionally, one utility indicated they spent approximately 560 fewer hours annually assessing outages. Three utilities reported a 17-58% improvement in SAIFI after implementing distribution automation. One utility reported benefits during an extreme weather event. Oak Ridge National Laboratory estimated the avoided damages with smart grid devices after a severe thunderstorm with 70 mph gusts impacted[10] Chattanooga Electric Power Board. They concluded there was likely a 55% reduction in customers without power, 28% reduction in outage minutes, and a 33% reduction in costs (Glass et al., 2015). As of 2018, Florida Power and Light has installed about 83,000 automated feeder and lateral switches (Keefer, 2018). In their post hurricane assessment reports, FPL indicated that during Hurricane Irma automated feeder switches avoided 546,000 customer interruptions (Florida Power and Light, 2018b). During Hurricane Hermine FPL reported automated lateral switches (ALS) avoided outages at a rate 1.8 times better than non-ALS lines, but that ALS lines performed equally as non-ALS lines during Hurricane Matthew (Florida Power and Light,

[10] Details of the storm were found using NOAA's storm events database: https://www.ncdc.noaa.gov/stormevents/

2018c). This could be due to Hurricane Matthew being a stronger tropical cyclone than Hermine, having almost double the maximum sustained wind speed, storm surge and rainfall within FP&L's service territory[11]. Quanta Technology (2009) additionally estimated that the combination of FLISR and a distribution management system could reduce restation time by 15% during Category 1 hurricanes and by 7% for Category 5 hurricanes.

It is important to remember that these technologies do not succeed on their own, but "rely heavily on robust communication systems to transmit large volumes of data, and effective systems integration to analyze data and provide actionable information for grid operators"(US Department of Energy, 2016). This includes outage management systems linked with GIS systems to specifically locate outages (EEI, 2014) and linked advanced metering infrastructure which allows utilities to see which customers have power (Quanta Technology, 2009). Additionally, with an increased adoption of smart grid technologies, the US power system is becoming more dependent on the availability of public communication systems and the Internet. This interdependency gives rise to two sources of vulnerability: the possibility of intentional or inadvertent disruption of controls to the power system and the quality of its data; the possibility that large scale power outages can result in substantial disruption of communication systems (NASEM, 2021).

Being able to transfer loads between adjacent lines requires more than just remote or manually operated switches but for the radial circuits to be configured in a way that they can connect and form a normally open tie which can be closed when a fault occurs. Determining how best to configure the distribution system with these tie lines can be challenging. Jooshaki, Karimi-Arpanahi, Lehtonen, Millar, & Fotuhi-Firuzabad (2020) explored optimizing where and how many manual switches, remote-controlled switched and tie lines should be added to a test case with 4 feeders, 14 feeder sections, and 14 nodes. They used mixed-integer linear programming to minimize the cost of device and tie line installation and maintenance costs, as well as minimize a "reliability-related cost", where the hypothetical utility earned revenue based on a reward-penalty scheme on measured SAIDI. They assumed manual switches cost $500 per device to install and $10 per year to maintain, while remote-controlled switches cost $4,700 to install and $94 per year to maintain.

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[11] Derived from National Hurricane Center Tropical Cyclones for both Hurricanes and comparing to service territory maps of FP&L and other utilities in Florida.

2.4.7. Pre-staging Equipment

Private and public distribution utilities routinely maintain stockpiles of equipment that they need for regular service and maintenance. Such stockpiles virtually always include replacement poles and associated equipment, circuit breakers and switches, transformers, and related gear. For example, Tampa Electric Company (TECO) has a four-day stock inventory of distribution equipment before hurricane season which includes splices, fuses, connectors, service clamps, brackets, wire, poles, and transformers." (Tampa Electric Company (TECO), 2006). Additionally, public power companies have compiled a guidebook titled *Restoration Best Practices* (American Public Power Association, 2018). They suggest the following best practices for pre-staging sites:

- Out of harm's way (if possible)
- Located in an area unlikely to be isolated or cut off from damaged areas
- Positioned to quickly respond to the highest likelihood for damages
- Sufficiently dispersed such that low-likelihood or non-forecast outcomes can also be addressed

While the situation varies somewhat by jurisdiction, stocks of replacement equipment can typically be included in the rate base of regulated utilities. Regulators generally defer to management on just how much equipment should be stockpiled. If a regulated utility wanted to dramatically expand such inventory as part of a resilience strategy, they would need to seek regulatory approval.

Transmission companies and vertically integrated utilities also maintain stockpiles to support regular service and maintenance of the high voltage system. The more expensive equipment to store include transmission conductors which cost between $2,000-$10,000 per 1000 feet depending on size, transmission structures which are ~$100,000-400,000 per mile, and voltage and current transformers (in sets of 3) on transmission lines range from $80,000 to $500,000 depending on the voltage of the circuit (MISO, 2019). Many high-voltage transformers are designed with site-specific electrical properties. However, Eversource Utility in New Hampshire noted that they are working on standardizing substation transformer sizes to streamline inventory and reduce event response time (TRC Consulting, 2021).

The issue of maintaining a stockpile of replacement transformers has been a recurring theme in reports from US National Academies (NASEM, 2017) and the Department of Energy (Office of Electricity Delivery and Energy Reliability, 2012). While DHS has demonstrated the ability to manufacture, transport, and install an emergency replacement transformer (DHS Science and Technology Directorate, 2014) no program to build a significant number of such devices has been implemented. The Edison Electric Institute has however developed, and maintains, a catalog of available transformers that could be made available in emergencies (Edison Electric Institute, n.d.-b; Walton, 2018). Argonne National Labs provided a detailed assessment of the status of a variety of supply chains and stockpiled replacement equipment in a 2006 report titled *National Electricity Emergency Response Capabilities* (Folga, McLamore, Talaber, & Tompkins, 2016).

In addition to spare parts, having standby equipment such as "mobile transformers, mobile substations and large generators" (EEI, 2014) can help get the system up and running when more serious and time-consuming repairs need to take place. Hamoud (2006; 2008) estimates mobile unit substations and transformers cost ~$2.5-5 million (converted to 2020 USD). The capital costs of backup generators for individual homes tend to be ~$1500 and larger 1-2MW systems that serve clusters of homes are ~$250,000 (Bohman, Abdulla, & Morgan, 2021).

Pre-staging equipment not only includes having electrical equipment on hand for faster restoration time, but also equipment needed to aid workers in the response such as: "extra trucks, supplied with necessary materials including maps, flashlights, mapping software, communication devices,…. crews should be armed with GPS devices as many will be unfamiliar with local roads and service territories…. fuel can become scarce after extreme weather events and thus utilities must secure enough fuel for its service trucks, either through on- hand reserves or emergency fuel contracts with suppliers" (EEI, 2014). Utilities could also consider using satellite communication for field crew instead of relying on telecommunication as many of those systems may be down. Quanta Technologies (2009) study estimated a 5-10% reduction in restoration time when using satellite communication.

2.4.8. Distributed Energy Resources

Distributed energy resources (DERs) can help communities ride through large power outages. Hanna, Disfani, and Kleissl (2018) analyzed the cost of reliable microgrids that incorporate various distributed energy resources, concluding in the process that the most cost-effective and reliable microgrids are ones where gas-fired turbines comprise the backbone generator, coupled with limited energy storage to ride-through the earliest stages of an outage. Narayanan and Morgan (2012) and Baik, Morgan, and Davis (2018) showed how an intact distribution system could be reconfigured to operate as an islanded microgrid. Bohman, Abdulla & Morgan (2021) assessed individual and collective contingency power options to supply residential customers during long power outages. Bohman, defining an "emergency load" at roughly 10% of an average home load in New England, explored the cost of investing in various backup power options across clusters of 1, 10, 100 and ~1500 residential homes assuming sectionalizing switches and smart meters can be used to intentionally island these portions of the distribution feeder. Results of this study showed that the cost of providing larger clusters with backup power could be 10-40 times less than that of individual backup generators per household over a 25-year lifetime (less than $2 per month per home). However, only conventional fossil fuel generators were cost-competitive[12]; ~$1,000-2,000 per household for clustered homes and ~$5,000-10,000 for a single home, to withstand 5-20 day outages in a 25 year time period. A PV+battery (lithium-ion) system designed to withstand multi-day outages in New England is cost-prohibitive (almost $50,000).

However, this may not be true in other locations and greatly depends on the size of system. For example, in Florida, a 10kW PV system is estimated to cost $18,000 and an additional $20,000 for the battery (Dean, 2017). In Puerto Rico, O'Neill-Carrillo and Irizarry-Rivera (2019) estimate that a 2kW PV system with a 10kwh battery (lead-acid) would be sufficient to meet the energy needs of a home and would cost about ~$7,000. Especially, since the cost of electricity is much higher in these island communities (~30 cents per kWh), a PV+ battery system can be cheaper (24 to 29 cents per kWh). O'Neill-Carrillo et. al envisioned a microgrid that "serves 700 houses, divided into 70 groups of 10 houses. Each of these groups is connected to its own distribution transformer, which serves as the connection point to the rest of the community microgrid. All of the transformers are connected by 4.16-kilovolt lines in a radial network."

[12] costs include fuel, maintenance, and capital costs

Additionally, each group of 10 would have an aggregate 10-20kW PV with 128 kWh battery storage system. Due to IEEE 1547 requirement for disconnecting distributed grid-tied PV systems, none of these PV strategies will work in an outage unless this rule is changed (Kwasinski, 2018). This was a large complaint of customers in Puerto Rico after Hurricane Maria whose rooftop PV systems survived the hurricane but would not work because of their connection to the bulk power grid. Additionally, Quanta Technology estimated that 20% DG penetration during a hurricane could reduce restoration by 10% for a category 1 hurricane up to 18% in a category 5 hurricane.

When considering earthquake survivability, Patel, Ceferino, Liu, Kiremidjian, and Rajagopal (2021) explored clusters of homes with rooftop PV in California. They defined the outage risk to a cluster with rooftop solar as the probability that the homes in a cluster will be unable to generate enough energy to meet their reduced load (one-third of normal levels) for at least one day in the aftermath of the earthquake. They explored different cluster sizes and different PV adoption rates of households considering an "overall" adoption approach which models household adoption by those with the highest bill savings potential across the *entire* community, and an "even" adoption model where homes with the highest bill savings within every resilience cluster install PV. Results show that risk decreases as rooftop solar adoption increases. Risk is lower and more evenly spread out with the even adoption rule, where there are pockets of disproportional high risk under overall adoption. Increasing the cluster size reduces risk slightly but after hitting a cluster of 15 homes risk reduction plateaus. Increasing the reduction load to one half of normal levels also makes it harder to meet necessary loads and increases risk.

Finally, using generation for clusters of users on a microgrid assumes that the electrical infrastructure connecting these homes remain intact, which is impossible to predict and could fail should a particular neighborhood experience a major outage-event. Installing microgrids also requires "considerable prior coordination, [resolving] the question[s] of asset ownership and cost sharing" (Bohman, 2021). Additionally, microgrids can pose new technical challenges: they require advanced sensing and control systems and present new challenges to system operations, including load balancing and additional cyber risks. As such, they can create new vulnerabilities. However, microgrids can provide considerable benefit outside of reliability by providing "reactive power and voltage control… [and] remov[ing] some of the load that would otherwise be served by the utility on the main grid, microgrids can reduce peak demand or area load growth and similarly help utilities avoid or defer new power delivery capacity investments" (EEI, 2014).

2.6 Cross-cutting resilience strategies

2.6.1 Demand Side Management

An important part of resilience is demand side management which can be split into two categories: energy efficiency and load response. Energy efficiency reduces the amount of energy that needs to be provided at any time which can be helpful when generation is lacking. Load response may require load shedding of entire customers to avoid worse failures. This can be done through several means: identifying critical loads on the system, offering "interruptible" rates to large customers and other forms of voluntary rationing (Frick, Carvallo, & Schwartz, 2021). Without these programs, critical loads could be shed, which happened in ERCOT during the 2021 freeze where some natural gas facilities were firm load shed (NERC, 2021). Newer technologies consider managing partial loads through thermostat, water heater or electric vehicle connection to reduce loads without having to turn off full connection to any individual customer. In most service territories, such programs are in early stages of implementation, but companies like EnergyHub[13] have already begun implementing DER management programs.

6.2. Emergency planning and government coordination

In 2006, the Florida Public Service Commission declared that all utilities in Florida needed to develop and maintain a natural disaster preparedness and recovery program and increase their coordination with local governments. All five of the investor-owned utilities hold regular workshops and hurricane drills to coordinate with local governments in emergency preparation: Emergency Operation Centers consist of stakeholders from multiple organizations. TECO budgets roughly $500,000 annually for emergency management which is "used to finance human capital and preparedness resources (i.e., emergency notification system, weather services, resilience management product, etc.), including internal and external training and exercises to test plans"(Tampa Electric Company (TECO), 2014).

[13] https://www.energyhub.com

U.S. utilities have a long tradition of providing mutual assistance for system recovery after major disruptions. EEI maintains a webpage with detailed on-line information about mutual assistance (Edison Electric Institute, n.d.-a). APPA provides similar details on mutual in the context of public power systems (American Public Power Association, n.d.). Of course, as the recent cases of disruptions in Puerto Rico and the Virgin Islands demonstrate, mutual assistance becomes more complicated in the context of power systems in remote locations and on islands. Power companies are generally responsible for restoration of service after a disruption and set aside an annual budget for emergencies that can cover more moderate outages. In unusual circumstance involving major disruptions, Federal assistance may become available if the damage crosses state lines and is widespread enough to warrant Federal assistance to restore power. However, Federal support for costs associated with power system recovery can only be provided once the president has invoked the Stafford Act a major disaster declaration or emergency declaration has been issued (U.S. Department of Homeland Security, 2017).

Utilities have identified lists of responsibilities, chains of command during outages and even instruction manuals for the repair processes, so everyone clearly knows their responsibilities during an emergency. Edison Electric Institute (2014) emphasized the importance of communicating to the public with “one-voice” and designating a central point of contact to communicate “with crews, state and federal government officials, news agencies and customers to ensure the continuity of communication and information for the most accurate assessments and response estimates.”

Finally, having a good workforce management system can streamline restoration time – Quanta estimates by 20%. A workforce management system should include applications that manage (Quanta Technologies, 2009):

- Track crews and trucks
- Spare parts inventory management
- Expertise matching and scheduling
- Work management (generate work orders and track their progress)
- Workforce management
- Resource management

2.6 Conclusions and future work

Despite increased interest in understanding the tradeoffs to increasing power system resilience, there is still very little empirical evidence to support any one strategy. Undergrounding power lines and changing utility pole material have the most robust literature base, but the cost estimates found have a wide range, and the benefits are still disputed. The other strategies reviewed typically have only one or two sources with empirical evidence and often pertain to a specific outage threat.

This review suggests that transmission and distribution hardening strategies could be beneficial in a wide range of outages and already have high deployment, making them currently the most cost effective. Generation resilience strategies, on the other hand, are much newer and therefore not as well tested, and also require specific enhancements for specific outage threats, making their investment potentially less worthwhile.

Our work can be used by analysts to input data into energy models that are increasingly considering a resilience component. For example, Lawrence Berkeley National Laboratory is using this data in their online resilience tool for islanded systems (Framework for Overcoming Natural Threats to Islanded Energy Resilience).

To continue to build this resilience database, further engineering analyses should be done on hardened systems, as more utilities default to higher standards. Additionally, collecting outage data from utilities on single events as well as information on their resilience initiatives can provide real world data on the cost and performance of resilience strategies.

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Chapter 3: Individual and Collective Strategies to Limit the Impacts of Large Power Outages of Long Duration[14]

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3.1 Introduction

Although the risks and costs of large power outages of long duration (LLD-outages) have become more salient, the research into mitigating such events is still limited. Several studies, especially by individual utilities, focus on preventing outages by assessing the effectiveness and feasibility of individual grid hardening strategies such as undergrounding lines or converting wood poles to steel (KEMA Inc., 2012; Larsen, 2016; State of Florida Public Service Commission, 2018). Especially prominent in academic research are microgrid reliability evaluation and investment planning models (Bagen & Billinton, 2005; Hanna, Disfani, & Kleissl, 2018; Wang, Li, Wu, Shahidehpour, & Li, 2013). Other studies evaluate how outages might be managed or mitigated. For example, Narayanan and Morgan (2012) and Baik, Morgan, and Davis (2018) showed how an intact distribution system could be reconfigured to operate as an islanded microgrid. Yang, Dehghanian, and Nazemi (2020) examined the utility of mobile power sources to mitigate the impacts of power outages resulting from earthquakes. This chapter focuses on analyzing and comparing strategies residential communities can use for mitigating the risk of LLD-outages.

The work reprinted in this chapter fills two important gaps in the literature. First, this paper addresses power resilience among typical residential customers in suburban and rural communities, which are often overlooked because outage costs can be higher and are more easily quantified for commercial, industrial, and critical infrastructures (Lawton, Sullivan, Liere, & Katz, 2003). There is growing interest among residential consumers in maintaining electric power service during an LLD-outage (Finkelstein, Kane, & Rogers, 2019; Merchant, 2017; Wood, 2019), and today there are a number of energy solutions that could meet that growing interest (MarketsandMarkets, 2019; Rodriguez, 2019). Second, instead of building microgrids that can serve a normal load with uninterrupted power, we determine how much power residential customers would need to meet their minimal needs during an LLD-outage, and then analyze individual and collective strategies to meet this emergency load. During an LLD-outage, access to even a small amount of power—enough to run a few lights, operate furnace blowers and pumps, and maintain critical services such as water, sewer, and basic communications—can be very valuable (Baik, Davis, & Morgan, 2018; Baik, Davis, Park, Sirinterlikci, & Morgan, 2020; Baik, Morgan, et al., 2018; Narayanan & Morgan, 2012), boosting the resilience of households to these disruptive events. By framing the problem in this way, we focus on "limiting the scope and impact of an outage" (NASEM, 2017) instead of preventing one altogether.

The chapter is structured as follows: the methods section describes how the representative communities were modelled and their emergency load profiles were developed. It also describes the data and methods used in selecting and evaluating a range of LLD-outage mitigation strategies. The results section presents an engineering-economic analysis of the various mitigation strategies: some of these could be adopted by individual households; some could be adopted by neighborhoods or the community at large. The concluding discussion elaborates on the strengths and limitations of the different mitigation strategies; the issues that individuals and communities would need to address to choose whether to invest in any of the mitigation strategies; and the policy implications of this work.

3.2. Methods

3.2.1 Building a Representative Community

We begin by sampling house types that exist in New Hampshire using the National Renewable Energy Laboratory's (NREL) ResStock database, which is a granular modeling tool of the U.S. housing stock. ResStock simulates several pre-defined types of houses, which differ in terms of house characteristics (e.g., size, vintage, heating source, appliance types) and generates their expected annual hourly load profiles. ResStock generates descriptions of these houses by sampling from its extensive database of different housing characteristics in different regions across the U.S.

We simulated a residential community that is representative of those found in Grafton County, NH in the upper Connecticut River Valley. We validated and modified the housing distributions based on property records and census data obtained for both a higher and a lower income town in the region. Details regarding these modifications can be found in Appendix A.

Although piped natural gas is not available in communities in the upper Connecticut River Valley, it is available in southern New Hampshire and of course is widely available in other parts of the country. Therefore, after considering the resilience options for our hypothetical community in the Upper Connecticut River Valley (Community 1), we subsequently consider resilience options for an identical community in which every house has access to piped natural gas (Community 2). We assume that all houses in Community 2 heat using natural gas instead of the heating fuel mix in Community 1, which is listed in Appendix A. In doing so, we consider the two extreme scenarios for household heating mixes across the country, acknowledging the diversity in natural gas availability across the U.S. Although natural gas infrastructure is quite robust (Freeman, Apt, & Moura, 2020), there is of course some possibility that certain large outages could disrupt the supply of natural gas – either directly or by interrupting supply of electricity to compressor stations in the gas system. In this case, the situation for Community 2 will look more like that for Community 1, with the exception that Community 2 is less likely to have invested in alternative fuel sources.

Research on distribution systems typically uses primary feeders as the unit of analysis (Marcos et al., 2017). As part of the Modern Grid Initiative, Pacific Northwest National Laboratory (PNNL) has created a distribution taxonomy that identifies 24 prototypical feeder models based on U.S. climate regions and customers served (Schneider et al., 2008). These include a particular distribution feeder type (number 7: R2-12.47-2) that is appropriate for our model community, which sits in climate region 2 (Northeast and Midwest). This feeder has a capacity of 6,100kW and serves a moderately populated suburban area. We follow PNNL's advice and load this feeder to 60% of its capacity by randomly adding our simulated houses onto the feeder until the peak load at some time during the year reaches 3.7MW. Our feeder thus serves 1,488 houses in Community 1, and because of the slightly lower loads associated with natural gas boilers and furnaces, 1,614 houses in Community 2. Limiting the total load on a feeder is standard practice to allow for future growth, contingencies, and the possibility of interconnecting adjacent feeders (a complication we do not explore in this analysis). For details on how the simulated feeder compares to real feeders in New England, see Appendix B.

3.2.2 Defining Household Emergency Loads

In order to choose how much power we need to provide during an LLD-outage, we begin by considering only the energy needed for basic survival. In freezing temperatures, households need enough heat to prevent hypothermia and frozen pipes (a thermostat setting of 50ºF (U.S. Department of Energy, n.d.)). In all conditions, households need enough power to support some minimal lighting at night and charge mobile devices. While we include a refrigerator load in summer, we do not include it in winter because outside temperatures are low enough to keep food from spoiling. We also do not include A/C in the summer load. Unlike winter, when freezing pipes are an issue, in hot summer weather residents can choose to leave their houses unattended to move to cooled spaces elsewhere. Further, while heat-related deaths can be a concern in New England, historically only about half of the homes have had air conditioning (Concord Monitor, 2017). Finally, despite the fact that Murphy et.al showed extreme temperatures increased the likelihood of generator failures (Murphy, Sowell, & Apt, 2019), these are not the only events that could lead to LLD-outages. Many LLD-outages are caused by large storms and natural disasters, rather than extreme temperatures. The electricity needs for an average home during an outage are shown in Tables 3.1 and 3.2. Appendix C discusses how these values were developed.

Table 3.1. The emergency demand for an average house when temperatures are below freezing.

	Appliance	Peak Load (W)
Heat (50ºF set point)	Oil Furnace	470
	Oil Boiler	135
	Propane Furnace	360
	Propane Boiler	50
	Natural Gas Furnace	400
	Natural Gas Boiler	50
	Other Fuel	0
	Charged Cellphone	15
	Minimal Lighting	120

Table 3.2. The emergency demand for an average house during warmer weather. Different refrigerator efficiencies are considered; these are denoted using their Energy Factor (EF), where $EF = (ft^3 \cdot day)/kWh$ (Lawrence Berkeley National Laboratory, n.d.).

Appliance		Peaking Load (W)
Refrigerator	EF = 6.7	200

	10.2	130
	10.5	110
	15.9	72
Charged Cellphone		15
Minimal Lighting		120

Heating houses with hydrocarbon fuels requires minimal steady state electricity (< 500W) to run furnace pumps or blowers. The issue of starting transients is discussed below. Households with more efficient refrigerators will require less power during an outage. Our assumptions regarding the mix of appliances are derived from the empirically grounded distributions in NREL's ResStock database.

We assume that all houses use efficient lighting such as compact fluorescent lamps (CFLs) and light-emitting diodes (LEDs), which use 20W for the equivalent lumens from a 100W incandescent bulb. Therefore, we assume 20W per light and that as many as six lights are on at any given time, giving us a peak lighting load of 120W. Charging a cellphone requires very little power (Helman, 2013). While we do not explore it further, note that as long a house remains below its maximum allowed amperage, customers could also cycle through other loads.

Using the wattage assumptions reported in Tables 3.1 and 3.2, we see that to meet the emergency demand most houses require roughly 600 running watts during an outage, regardless of season. This emergency load comprises about 10% of normal household load. We refer to this level of emergency service as the baseline load and, to account for unique electricity needs and uncertainties in the modelled load, we also consider loads that are 150% and 200% larger than this baseline, as shown in Table 3.3.

Table 3.3. Developing estimates of individual house emergency peaking loads. Values rounded to two significant figures.

		Baseline load (W)	**150% of baseline (W)**	**200% of baseline (W)**
Winter	Upper Bound	610	910	1200
	Lower Bound	190	280	370
Summer	Upper Bound	340	500	670
	Lower Bound	210	310	410

We exclude houses with electric heat,[15] which require substantially larger amounts of electric power for heating during winter (approximately 10kW). We assume that in cold weather these homes would rotate electric space heaters around rooms to prevent pipes from freezing during an outage (Farrell, 2019; Wilson Brothers Heating and Air Conditioning, 2016). Consulting online suppliers shows that space heaters use 1500 Watts; assuming three space heaters per electrically heated home translates to an emergency heating load of approximately 4.6kW in winter. Similarly, many homes in more outlying regions do not have piped water but rely on wells. The standard arrangement in these cases is either a jet pump at the surface or a submersible pump at the bottom of the well. These pumps typically use 700-1500 Watts while running and require a brief surge equivalent to 2000-2500 Watts when starting, according to equipment manuals consulted by the research team. Regardless of pump type, these pumps only run at brief intervals during the day and rarely or ever at night, because the pump only operates when the tank pressure drops below some preset value. Therefore, including intermittent well pump surge current is important for sizing individual emergency load for these homes, which translates to 2900-4600 watts, similar to that of the adjusted electrically heated homes. This intermittency also allows us to maintain a smaller collective load, described below, as it is unlikely well pumps would run concurrently, but should it happen the smart breakers described in Section 3.2.3 would trip and customers would need to shed some load before reclosing the breaker.

Using these estimates of household electricity needs in an LLD-outage, we employ a bottom-up approach to determining the load in multiple households. Specifically, we consider single homes and then clusters of 10, 100, and 1488 or 1614 (full feeder) houses to identify and evaluate the feasibility and cost of a variety of mitigation strategies. Table 3.4 summarizes the load we would expect for typical cold and warm weather outages in Community 1 across our three demand cases: baseline load, 150% of baseline, and 200% of baseline. It is clear from the numbers in Table 3.4 that cold weather loads will drive the sizing of the distributed generation options needed to survive an LLD-outage.

Table 3.4. Collective emergency loads for the universe of scenarios under investigation for Community 1. Values were rounded up to two significant figures.

[15] Because the region has some of the highest priced electricity in the country, very few houses in the region use electric heat.

		Emergency peak load (kW)		
	# of houses	Baseline load	150% of baseline	200% of baseline
Winter	10	8	12	16
	100	62	93	120
	1488	920	1400	1800
Summer	10	2	3	4
	100	23	35	47
	1488	330	500	670

Table 3.5 shows the winter demand for the same clusters of houses, this time in Community 2 which has natural gas heating. Summer demand remains the same as in Community 1 and is therefore not repeated in Table 3.5. In this case the winter load also drives the sizing of generation.

Table 3.5. Collective emergency loads for the universe of scenarios under investigation for Community 2. Values rounded to two significant figures.

		Emergency peak load (kW)		
	# of houses	Baseline load	150% of baseline	200% of baseline
Winter	10	4	6	8
	100	39	58	77
	1614	470	700	930

3.2.3 Identifying Outage Mitigation Strategies

A large number of commercially available distributed generators (DG) exist to serve loads of different sizes, including the ones described above. We assess four DG deployment scenarios on our model feeder; these are presented schematically in Figure 3.1.

1. Individual houses each purchase and use their own emergency generator fueled with gasoline, propane (LP), or diesel in Community 1. In addition to these fuels, Community 2 can use natural gas (NG). Alternatively, at the level of individual homes, we also consider solar photovoltaic (PV) systems complemented by batteries.
2. A 10-house “neighborhood” can be disconnected from the secondary line to operate as a microgrid served by a small, single-phase generator fueled with propane or diesel in Community 1. In addition to these fuels, Community 2 can use natural gas.

3. A 100-house "community" can be disconnected from the primary feeder to operate as a microgrid employing a three-phase diesel or propane generator in Community 1. In addition to these fuels, Community 2 can use natural gas.
4. A single, large, three-phase diesel generator or microturbine using compressed natural gas (CNG) could be located at the substation in Community 1. Community 2 can use piped natural gas for the microturbine. This single generator would be capable of serving the entire feeder if the distribution system remains intact.

In the three collective generation scenarios, we assume there are sectionalizing devices that can implement islanding or isolate sections of the feeder that are no longer intact (S&C Electric Company, 2019).

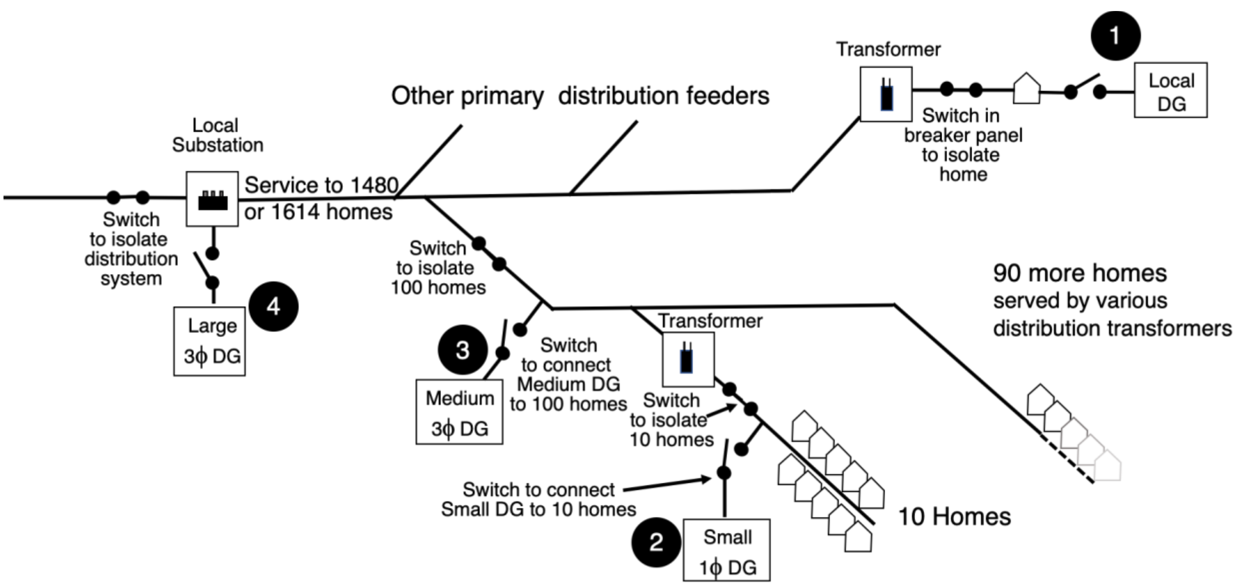

Figure 3.1. Diagram of our hypothetical feeder, depicting four plausible DG deployment strategies that supply limited power to households during an LLD-outage: 1) individual generators at each house; 2) a single-phase generator that serves 10 homes operated as an islanded microgrid; 3) a three-phase generator that serves 100 homes as an islanded microgrid; and 4) a three-phase generator at the substation that can supply the entire feeder. Sectionalizing switches and smart meters can be used to create microgrids or to isolate portions of the feeder that are not intact.

We use the emergency load values from Tables 3.3, 3.4 and 3.5 to determine the generation technology suitable for each deployment scenario. Backup motor-generators and microturbines are both sized to serve a load that is the product of the number of houses and expected peak emergency load, assuming the relevant portion of the feeder is intact. For generators deployed at individual homes, it is necessary to meet the surge current for starting larger appliances (e.g., pumps or blowers for heating systems and refrigerators); those starting wattages dictate the size of those generators.[16]

Sizing household PV+battery systems requires a prediction of how much power the PV system would produce. We use NREL's System Advisor Model (SAM) to estimate the size of the PV+battery system that would be required to meet our emergency demand for every hour in an average weather year. Given the northern location of our hypothetical community, winter days are short and there is a possibility of snow and ice build-up on PV arrays. Assuming the PV array is operative, meeting the average demand of a home heated with hydrocarbon fuels would require an 8-10kW PV system with an 8kW inverter and a 10-12kWh battery that has a 5kW power rating. This constitutes a very large residential PV+battery system—driven by New Hampshire's location and weather conditions. It is for this reason that we do not consider larger collective deployments of PV+battery systems.

Using these parameters for sizing DG, the suite of generation technologies that could plausibly cater to each deployment scenario at each emergency load level are summarized in Table 3.6.

Table 3.6. Distibuted generation (DG) technologies considered in this analysis.

DG Technology	**Deployment Scenario**	**Size (kW)**	
		Community 1	**Community 2**
PV+battery	Individual	8-10kW PV 10-12kWh battery	8-10kW PV 10-12kWh battery
Portable Gasoline	Individual	2.8-7.5	2.8-7.5
Portable Propane	Individual	3.3-6.8	3.3-6.8
Standby Diesel	Individual	5-7.5	N/A
	10 houses	10-20	5-10
	100 houses	65-135	40-80
	Full Feeder	1000-2000	500-1000
Standby LP/NG	Individual	5-7.5	N/A
	10 houses	10-20	5-10

16 Furnaces have starting wattage between 1400-2400W; boilers have starting wattage between 750-1500W; refrigerators have running wattage between 1200-2200W(Aloha Power Equiment, 2019; Energy Kinetics, n.d.; Generator Grid, 2019).

	100 houses	65-135	40-80
	Full Feeder	N/A	500-1000
Microturbine (CNG)	Full Feeder	5-10 200kW	3-5 200kW

Individual strategies can be implemented by households with the resources to adopt them. By their nature, collective strategies require a variety of prior arrangements between customers, with the local township, with the local utility, with third party suppliers, and probably with regulators such as the state's Public Utility Commission (PUC).

A key issue in the collective strategies is how to limit the current drawn by individual customers during an outage. In principle, one could use advanced digital controls to perform this function. Here, we adopt a much simpler solution. We assume that each home has a low-amperage circuit breaker that smart meters can switch to instead of the main breaker, limiting current draw by individual houses during the outage. While advanced smart meter technology has that capability, none is currently commercially available, though several ventures seek to introduce them soon, including Aclara Technologies LLC and Atom Power, among others (Greentech Media, 2012). Based on a private communication with a knowledgeable expert, we estimate the incremental cost of such a load-limiting circuit breaker to be approximately $100 per household and, as described in Appendix D, add this to the cost of deploying collective DGs.

3.3. Results

3.1 Cost analysis

We analyze the cost of implementing each strategy to mitigate LLD-outages that last 5-, 10- and 20-days, amortizing equipment costs over 25 years. We analyze these three outage durations because historically extreme outage events have left hundreds to thousands of customers without power in the U.S. for similar durations. In addition to the LLD-outage examples described in the introduction, Duffey and colleagues analyzed the restoration times for 13 extreme outage events between 2012-2018 which spanned 2-30 days (Duffey, 2019). If such outages occur during hot summer weather, residents could evacuate to seek shelter in cooled space that have power. Evacuation of people in cold winter weather is also possible, but in that case, houses must still be heated enough to prevent pipes from freezing and causing flooding. There is evidence in the literature that, even when they are advised to evacuate, many people may choose not to, either for financial or personal reasons (National Research Council, 2006). After some outage events, those who evacuated could find their houses inaccessible if the outage event significantly damaged other infrastructure and destroyed or blocked roads.

We consider a 25-year time period as that is the typical lifespan for a well-maintained generator and PV+ battery system. We include maintenance costs, which include the costs of regular test operations for generators and the cost of securing and storing enough fuel to meet load during these three LLD-outage scenarios we have analyzed. Because it is the only system that would run when there is no outage, the PV+battery system is the only DG that we use for peak shaving purposes throughout the year. The cost savings associated with this operation are subtracted from the total system cost.

The cost per household is calculated across DGs, deployment scenarios (i.e., number of houses served), outage scenarios (5-, 10-, and 20-day outages), and emergency loads required (baseline, 150% of baseline, and 200% of baseline). The resulting cost estimates can be interpreted as *preparedness* costs per household against LLD-outages in the next 25 years. In this study, we do not predict when or how many LLD-outages might occur. Therefore, should any outage occur (short or long) in the 25-year time frame, there would be a generator in place with enough fuel on hand to provide contingency power as long as that outage was less than 5, 10, or 20-days, depending on scenario. If multiple outages occur, there could be additional refueling costs and maintenance costs that are not incorporated. There will be additional costs if the backup generator run time exceeds the annual maintenance schedule guidelines or if biennial fuel replacement of gasoline and diesel already accounted for in this preparedness cost is not enough to meet the fuel needs for all outages in the 25-year period under consideration. Figures 3.2 and 3.3 along with Tables 3.7 and 3.8 present our cost estimates for each of the deployment scenarios and outage scenarios for Community 1. Figure 3.4 and Table 3.9 presents the same cost estimates for Community 2, in which all heating is provided with piped natural gas.

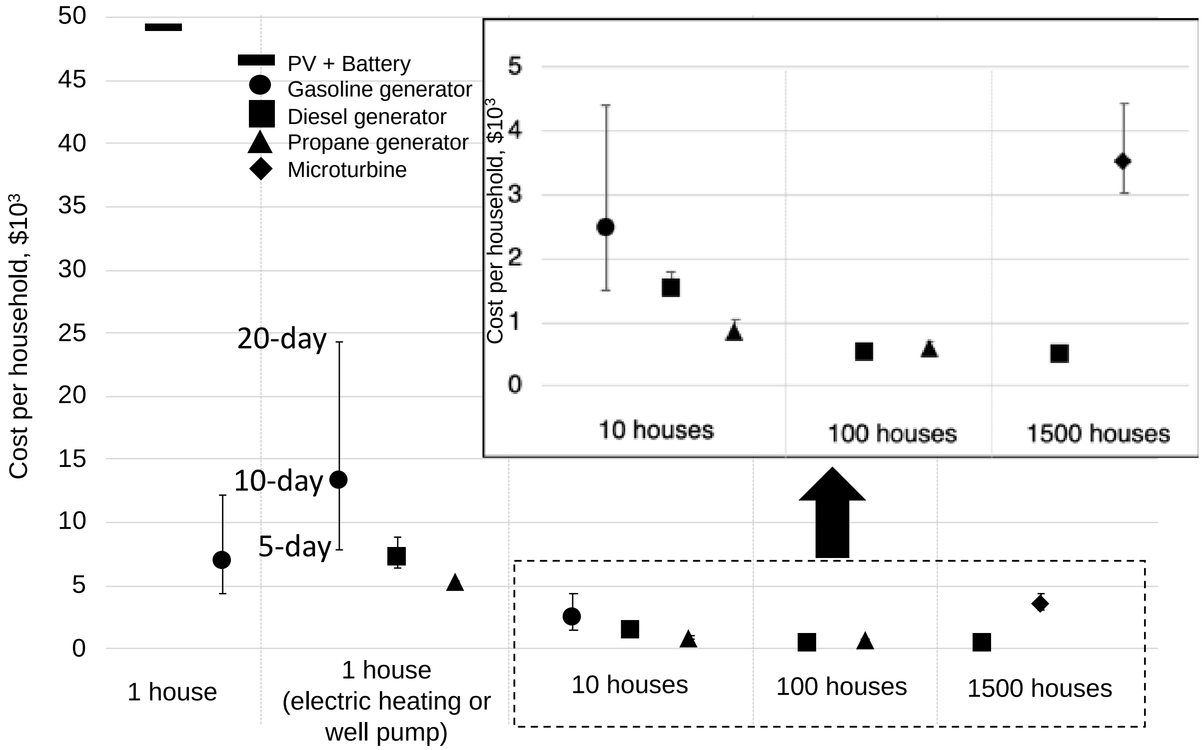

Figure 3.2. Total cost per household for each of the deployment scenarios across 5-,10-, and 20-day outage scenarios in Community 1. Analysis assumes a 5% discount rate and investments are amortized over 25 years. Service to 10 and 100 houses is via an isolated section of the feeder operating as a microgrid. Service to 1488 houses requires a large DG located at the feeder's primary substation. The shapes represent different DGs and the range covers multiple outage durations.

Table 3.7: Cost (in $\$10^3$) per household for 25 years of LLD-outage protection by contingency generation option at the *baseline load level for Community 1*. Results for both individual and collective scenarios are presented; values are rounded to two significant figures.

Generation	Individual	Individual (electric heating or well pump)	10-Houses*	100-Houses	Full Feeder (1488)
PV + battery	50				
portable gas 5-day	1.7	2.9			
portable gas 10-day	2.5	4.5			
portable gas 20-day	4.0	7.6			
portable propane 5-day	1.1	1.3			
portable propane 10-day	1.2	1.5			
portable propane 20-day	1.4	1.8			
standby diesel 5-day		6.5	1.4	0.48	0.46
standby diesel 10-day		7.2	1.5	0.54	0.50
standby diesel 20-day		8.8	1.8	0.66	0.58

standby propane 5-day		5.1	0.81	0.50	
standby propane 10-day		5.2	0.83	0.59	
standby propane 20-day		5.4	1.1	0.74	
Microturbine 5-day					3.0
Microturbine 10-day					3.5
Microturbine 20-day					4.4

* If the 10-house community chooses to convert from wooden poles to steel poles, we estimate the cost per household to be on the order of $7500 per house. If they choose to underground their distribution lines, we estimate the cost per household to be on the order of $250,000 per house.

Figure 3.2 and Table 3.7 shows that costs per household tend to decrease as the number of homes served collectively with a microgrid increases. Even accounting for potential cost savings from peak shaving, the cost of such a large PV+battery system that could reliably serve to provide backup power in an LLD-outage is much larger than that of a portable fossil fuel generator. In the case of gasoline and diesel generators, the high cost and variance across scenarios of different outage duration is due to the cost of refueling. Gasoline and diesel cannot be reliably stored for long periods and must be replaced, or polished in the case of diesel, every 2 two years[17], which means that LLD-outage preparedness requires periodic fuel replacement. Portable propane generators have the same capital cost as portable gasoline generators, (between $500-1000), but require no fuel replacement which makes them much cheaper over a lifetime. Standby generators are much more expensive than portable ones, but when used in the collective deployments result in a cheaper cost per household. Scenarios using standby propane generators cost less than scenarios using standby diesel generators in the 8 to 25kW range. However, as the systems get larger, the total costs of propane and diesel generators converge. Standby generators that can run on propane only scale to about 125kW, which is why only diesel fuel is considered in the full feeder scenario of Community 1. As far as strategies that serve the full feeder are concerned, diesel costs are approximately $500 per household ($1.70/month) across the three outage durations, while microturbines cost between $3,000 and $4,000 per household ($10-13/month).

[17] Diesel requires fuel polishing or replacement every 2 years (Generac Power Systems, 2010) and gasoline can last up to 2 years with an added fuel stabilizer.

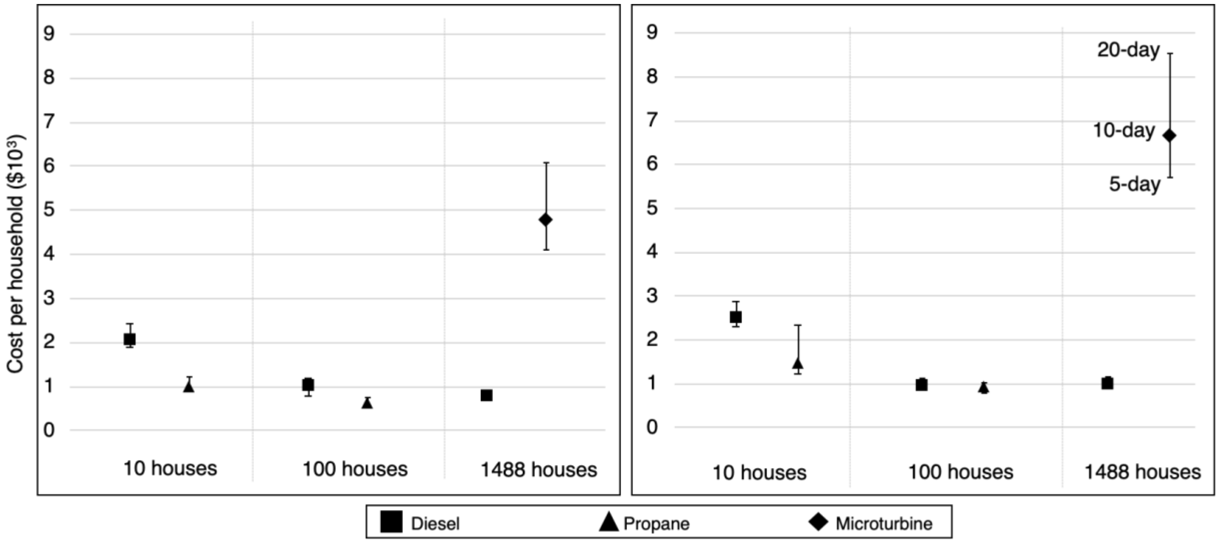

Figure 3.3: Total cost per household for each of the deployment scenarios across 5-,10-, and 20-day outage scenarios in Community 1—assuming that loads **(a)** 150% and **(b)** 200% larger than the baseline need to be met. Analysis assumes a 5% discount rate and investments are amortized over 25 years. Collective strategies supporting 10, 100, and 1488 houses are implemented as isolated microgrids. The shapes represent different DGs and the range covers multiple outage durations.

Table 3.8: Cost per household (in $\$10^3$) for 25 years of LLD-outage protection by contingency generation option at the *150% and 200% baseline load level for Community 1* for collective isolated microgrid scenarios. Values are rounded to two significant figures.

	150% baseline			**200% baseline**		
Generation	10 houses	100 houses	1488 houses	10 houses	100 houses	1488 houses
standby diesel 5-day	1.9	0.78	0.70	2.3	0.86	0.89
standby diesel 10-day	2.1	1.0	0.77	2.5	0.95	0.98
standby diesel 20-day	2.4	1.2	0.91	2.9	1.2	1.2
standby propane 5-day	0.94	0.51		1.2	0.81	
standby propane 10-day	0.99	0.61		1.4	0.92	
standby propane 20-day	1.2	0.71		2.4	1.0	
Microturbine 5-day			4.1			5.7
Microturbine 10-day			4.8			6.7
Microturbine 20-day			6.1			8.5

Figure 3.3 and Table 3.8 show the costs of systems that could supply enough power to meet 150% and 200% of the baseline emergency load for Community 1. Because individual DG sizes would not change, they are not depicted in this figure. While costs increase, cost comparisons across DGs do not qualitatively change in these scenarios. The lowest-cost options

are diesel and propane for 100-house communities and diesel for the full feeder. These options all cost approximately $1,000 per household ($3.30/month).

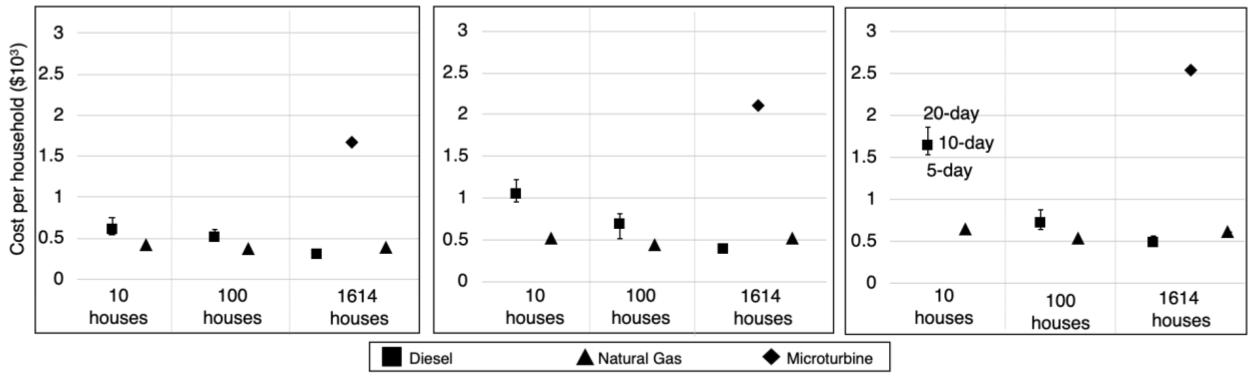

Figure 3.4: Total cost per household for each of the deployment scenarios across 5-,10-, and 20-day outage scenarios in Community 2. The three panels represent loads meeting **(a)** the defined baseline emergency load; **(b)** 150% of the baseline; and **(c)** 200% of the baseline. Analysis assumes a 5% discount rate and investments are amortized over 25 years. 10, 100, and 1614 houses are operated as isolated micro-grids. The shapes represent different DGs and the range covers multiple outage durations.

Table 3.9: Cost per household (in $\$10^3$) for 25 years of LLD-outage protection by contingency generation option across *all load levels for Community 2.* Only collective isolated microgrid scenarios are presented and values are rounded to two significant figures.

	Baseline			150% baseline			200% baseline		
Generation	10 houses	100 houses	1614 houses	10 houses	100 houses	1614 houses	10 houses	100 houses	1614 houses
standby diesel 5-day	0.54	0.47	0.29	0.96	0.52	0.36	1.5	0.64	0.44
standby diesel 10-day	0.61	0.52	0.31	1.1	0.69	0.39	1.6	0.72	0.48
standby diesel 20-day	0.75	0.61	0.35	1.2	0.82	0.46	1.9	0.87	0.56
standby NG 5-day	0.52	0.37	0.39	0.52	0.44	0.51	0.65	0.54	0.60
standby NG 10-day	0.52	0.37	0.39	0.52	0.44	0.51	0.65	0.54	0.60
standby NG 20-day	0.52	0.37	0.39	0.52	0.44	0.51	0.65	0.54	0.60
Microturbine 5-day			1.7			2.1			2.5
Microturbine 10-day			1.7			2.1			2.5
Microturbine 20-day			1.7			2.1			2.5

Figure 3.4 and Table 3.9 show total costs across emergency load scenarios implemented in Community 2, which is served by piped natural gas. Individual DG sizes would not differ from those serving Community 1 and are not depicted in this figure or table. In section 3.2.2, we observe that winter loads drive the sizing of backup generators. Every household in Community 2 is assumed to heat with natural gas. Therefore, their winter loads will be lower than those of many houses in Community 1, which explains why Community 2 costs are lower than

Community 1 costs across collective scenarios. The cost savings for microturbines are the largest, because a community with piped natural gas would no longer need to transport and store the compressed natural gas that fuels the microturbine, which lowers the cost to one third of that in Community 1. Natural gas generators with power ratings large enough to serve a full feeder (500-1000kW) have a much higher capital cost than diesel generators at this scale, which is why the diesel generator is still cheaper even with fuel replacement. However, when considering the extra logistical burden and air pollution that comes with using diesel generators, a community with piped natural gas may be willing to pay an extra $100 ($0.33/month) for a natural gas generator to be located at the substation. The cheapest options remain natural gas generators for clusters of 10 and 100 houses, and diesel generation for the entire feeder.

3.3.2 Sensitivity Analysis of Cost

A sensitivity analysis was conducted to explore the cost assumptions and to take into consideration the fact that the cost of energy technologies may change in the future. Maintenance, installation, and gaseous tank storage costs are somewhat uncertain, since they depend greatly on the provider. Fuel costs and utility electric rates can be volatile. Additionally, capital costs for PV+battery systems and microturbines are expected to continue to fall. But even if capital costs were to decrease by 50%, PV+battery systems and microturbines would remain more expensive than fossil fuel generators. Accounting for these uncertainties, the cheapest option remains collective deployments of fossil fuel backup generators for the full feeder. Considering the lower and upper bounds of these uncertain costs across all three emergency load scenarios yields a range of $330-1700 per household ($1.10–5.67/month) in Community 1 and $220-800 per household in Community 2 ($0.73–2.67/month). Detailed cost tables, including the lower and upper bounds used in the sensitivity analysis, are provided in Appendix E.

3.4. Discussion

The forgoing analysis assesses what *could* be done, but it does not address the issue of whether individuals in the community or the community as a whole *should* make any of these investments. The results do suggest that collective strategies on their own are significantly cheaper than individual strategies, but the adoption of collective strategies can be challenged by a range of other institutional factors there need to be further explored.

3.4.1 Individual Considerations

The analysis assumes that the simulated feeder remains intact during some or all of the LLD-outage. Depending on where and how the outage event occurs, this may not be the case, since a large storm that disrupts transmission lines is also likely to disrupt above-ground elements of the distribution system. Some newer subdivisions may have underground distribution systems, and some small sub-groups of homes with overhead lines may still be able to operate as isolated subsystems. If a small set of homes wanted to harden their local distribution circuit it would require further investment. For example, undergrounding costs in rural communities are reported to range between $0.1-2 million per circuit mile (Hall, 2009) and replacing wood utility poles with steel poles is reported to cost ~$1,000-2,000 per pole (Salman & Li, 2016). Even without these distribution investments, it may also be possible to restore many local distribution lines within a few days of an outage event, even if bulk supply remains unavailable. However, while all distribution system lines are out, only individual back-up systems would be available to provide contingency power. Ultimately, each individual home or business owner needs to consider their local distribution company's capabilities during an outage when deciding whether to invest in resilience strategies or which ones to favor.

Many new high-end homes in New England are being sold with a pad-mounted propane or natural gas fired generators already installed. Just as when car dealers bundle options into the overall price of a new vehicle, buyers typically do not go through a careful assessment of whether that incremental investment is worthwhile. They simply view the presence of a generator as an attractive attribute of the overall investment. Of course, the situation is different for home or business owners who do not already have either a pad mounted generator or a portable generator.

Providing minimal service to individual homes with gasoline generators would be problematic when outages last more than a few days. For example, a 5.5kW portable generator would require 300 gallons of gasoline during a 20-day outage as well as four to five oil changes. Keeping it running during such an outage is only plausible if the town has made prior arrangements to keep filling stations operating[18] and has reached prior agreements about fuel supply priorities with emergency responders and others.

Whether it is local or broader in extent, the direct cost of an outage will be a function of its duration and the season in which it occurs; we perform three calculations to develop a sense of outage costs. For outages with a duration of one day or less, we use the ICE calculator developed by Nexant for Lawrence Berkeley National Labs, apply SAIFI and CAIDI (Customer Average Interruption Duration Index) values (including major event days) of 1.87 and 610.6 for NH Liberty Utilities, and obtain an estimate of the average annual cost per customer, which is $38 in 2020 dollars. A Generac GP5500 portable generator (5500W running; 6875W starting) can be purchased for approximately $700. At an interest rate of 6%, the cost of purchasing the generator could be recovered in just under a dozen years. However, the cost of brief outages of the sort reflected in the ICE calculator are not the motivation for this paper. Baik et al.(2020) report an estimated customer willingness to pay of roughly $2/kWh for power during a 10-day outage in freezing weather (plus roughly $25/day to directly and indirectly support their communities). In our case, that translates to a customer willingness to pay of approximately $330 for a 10-day outage. Finally, suppose that a residential customer believes that a winter outage that lasts long enough to freeze the pipes in their home would result in $30,000 of water damage; that constitutes between 5% and 15% of the average value of homes in this region. In simple expected value terms, the annual cold weather outage probability would need to be approximately 0.02/year, or a pipe-freezing outage occurring only once every 50 years, to justify purchasing the generator.

3.4.2 Collective Considerations

Most of the collective options we have discussed are only feasible if a town has already adopted a set of plans and procedures to increase its resilience in the event of an LLD-outage. Additionally, implementing the collective strategies outlined in this study would require location-specific analysis of the costs and benefits and is likely more appropriate for denser communities. However, New England towns have a long tradition of developing such collective

[18] Examples of such arrangements already exist: The Fuel New York Initiative in 2013 allocates $17 million "to help retail gas stations improve their back-up power capacity so they can remain open during major storms."(Governor Andrew M. Cuomo, 2012)

actions. For example, we know anecdotally that, in the 1950s, most of the residents in the city center of Lyme, New Hampshire banded together to move most of their homes off of individual shallow water wells on to a cooperatively operated piped water system fed by a single, higher quality artesian well. More recently, several neighbors in Plainfield, Vermont have made arrangements to share output from a single photovoltaic system. The coordination and compliance challenges involved are another reason we focus on New England instead of assuming that our analysis is equally applicable nationwide.

In addition to siting the generators themselves, siting fuel storage can prove challenging. A propane tank designed to serve 100 houses throughout a 20-day outage needs to hold approximately 6,000 gallons of propane. This tank would be approximately 6 feet in diameter and 30 feet long (Roy E. Hanson JR. MFG, 2004). Safely and securely siting such a tank in a neighborhood would require careful, community-wide coordination.

In addition to the considerable prior coordination required, the question of asset ownership and cost sharing needs to be addressed for the collective DG scenarios. Under current regulatory arrangements in New Hampshire, for-profit distribution companies are not allowed to own generation. If a community organizes to increase its resilience in the event of an outage, they might be able to arrange for the state legislature to grant an exception; otherwise, they will need to create a management structure within their own community. This limitation disappears if the local distribution company is operated as a coop or a municipal entity; it might also be overcome if neighbors organize a cooperative arrangement.

There may also be cost-saving opportunities, so that residents would not have to pay for the full cost of resilience on their own. There exist local, state, and federal initiatives that may be willing to partially fund preventative mitigation strategies. The Federal Emergency Management Agency (FEMA), for example, gives out $2.5 billion annually in “Preparedness Grants” to enhance community resilience (FEMA, 2020).

In our analysis, the generators are only operated during an LLD-outage. However, at an average residential cost of 17.2¢/kWh (Global Energy Institute, n.d.), New Hampshire has some of the nation's most expensive electricity. It is possible that a private entity (or the town) might want to install DG that runs all the time and can sell some power back to the grid. Additionally, some utility companies have begun cost-sharing programs under which they subsidize the cost of DG purchased by customers and maintain the system, as long as they are allowed to dispatch it when needed[19]. An additional advantage of using generators for more continuous DG is that there is a lower risk that they would not be available to start when an outage occurs. However, continuous, primary generators must meet EPA Tier 4 emissions standards[20]. The standby generators used in our analysis only meet Tier 2 emission requirements, which are significantly less costly than Tier 4 systems, sometimes by half as much[21]. Were we to conduct a cost analysis with Tier 4 generators instead, microturbines might become more competitive (and all forms of generation potentially cheaper) once we include the benefit (i.e., the higher load factor) of running them as primary generators, and optimize their operations and interaction with the bulk power system, perhaps even with combined heat and power.

3.5 Conclusion

As modern society becomes ever more dependent on the availability of reliable electric power, the cost associated with large outages of long duration becomes a serious issue. While residential customers can take steps to protect themselves individually against such disruptions, our analysis finds that doing so can be 10 to 40 times more expensive than adopting collective options—providing impetus for utilities, regulators, and policy makers to make such collective options readily accessible to communities. Whether a community chooses to pursue such strategies depends on its assessment of the probability of disruption, the likely duration of the outage, the costs that will arise should a disruption occur, and the cost of undertaking preventive measures. While parts of that decision can be supported by analysis such as that presented here, reaching a final decision will require some form of analytical deliberative process (Arvai, 2003; Cox Jr., 2012; Renn, 2012). Developing and demonstrating such a process would be a valuable next step toward addressing this important issue.

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[19] Richard Sedano, Regulatory Assistance Project CEO, personal communication. November 20, 2019

[20] Generac Power Systems, personal communication. November 22, 2019.

[21] For example, a Tier 4 130kw generator can be twice as expensive as a similarly sized Tier 2 generator (Americas Generators, n.d.)

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Chapter 4: Investigation into the Effectiveness of Resilience Strategies: A Case Study of Florida Investor-Owned Utilities

4.1. Introduction

The recent push to increase the resilience of power systems begs two questions: first, are resilience strategies working where they have been already implemented? Second, even if they are working, are they worth the investment? In contrast to reliability, there has been little research on the efficacy of resilience strategies. Indeed, even the definition of resilience is not uniform across utilities and therefore resilience metrics can vary greatly. The focus on resilience is relatively new, the US Energy Information Agency didn't start collecting data on major outage events until 2013 (U.S. Energy Information Administration (EIA), 2021). Utilities and policymakers are now recognizing that major outage events could be becoming more of a problem due to an increase in the frequency and severity of natural disasters, infrastructure failures, and the threat of physical or cyber sabotage.

Research into the effectiveness of resilience strategies is hindered not only by the limited number of strategies that have been implemented, but also by the modest number of major outage events against which to evaluate performance. The causes and impacts of future major outage events are also uncertain. Even if some strategies are successful in the face of current outage threats, it is unclear how successful they would be in the future. Finally, much of the data that are required to study the efficacy of resilience strategies reside with utilities that are often wary of sharing them. Publicly available data come almost exclusively from utilities fulfilling a request made by their Public Utilities Commissions (PUCs). Despite the uncertainty about the efficacy of different strategies to increase resilience, utilities are already making large investments in them. For example, ConEdison in New York and Florida Power and Light in Florida each spent over $1 billion in 2020 alone on storm hardening (ConEdison, 2021; Florida Power and Light Company, 2021). These costs will eventually be passed to customers. There is a clear need for empirically grounded analytical work that addresses the question of how to increase the resilience of a power system. As elaborated below, using the detailed data that the Florida Public Service Commission has required investor-owned utilities (IOUs) to report each year, this chapter develops the largest database on resilience investments to date and conducts an exploratory analysis on these data to assess the effect of these investments.

Although there are a number of prior studies that have predicted outages based on properties of electric grids and their physical location (Kabir, Guikema, & Quiring, 2019; Ouyang & Dueñas-Osorio, 2014; Watson, 2018; Winkler, Dueñas-Osorio, Stein, & Subramanian, 2010), little work has been done to estimate how damage functions change once hardening strategies have been implemented (Goodman, 2015; Salman, Li, & Stewart, 2015; Teoh, Alipour, & Cancelli, 2019). Much previous work is based on simulated results, and the limited data that do exist are derived from a very limited set of experiences. For example, the data in Quanta Technology's (2009) benefit-cost analysis of hurricane resilience strategies are based on the aftermath of only one specific hurricane in Texas (Hurricane Ike, which hit the state in 2008). Similarly, the studies that exist on predicting hurricane outages use granular spatial modelling but on a very small set of hurricanes. For example, Tonn, Guikema, Ferreira, & Quiring, (2016) look at the impacts of Hurricane Isaac (2012) on Louisiana outages, and Nateghi, Guikema, & Quiring (2011) validate their modelling against Hurricane Ivan (2004). From a personal communication, I also understand that Argonne National Laboratory's HEADOUT model predicts hurricane outages based on data from 26 tropical cyclones (TC) between 2003-2017. Finally, Larson (2016) used a data set of approximately 650 observations to look at annual SAIDI and SAIFI values that included major event days and analyzed the impact of various factors on these metrics, including heating and cooling degree days, wind, precipitation, lightning strikes and undergrounding. He found that a "10% increase in the percentage share of underground line miles is correlated with a 14% reduction in the total annual duration of interruptions." However, this analysis includes all types of outages, making it difficult to pinpoint the circumstances in which undergrounding is effective.

The data used in this study are derived from the storm hardening and preparedness investments made by the five (now four) IOUs in Florida: Florida Power and Light (FPL), Duke Energy Florida (Duke), Tampa Electric Company (TECO), Florida Public Utilities Company (FPUC), and Gulf Power Company (Gulf, which since January 1, 2022 has become part of FPL). Due to the devastation caused during the 2004 and 2005 hurricane seasons in Florida, the Florida Public Service Commission (PSC) commenced in 2006 a series of storm preparation and hardening programs. The Commission required the IOUs to comply with specific hardening goals and increase the visibility of system performance during severe weather events. The specific hardening plans identified were an eight-year replacement cycle for wooden distribution poles (Florida Public Service Commission, 2006a), as well as the ten storm preparedness initiatives listed below (Florida Public Service Commission, 2006b).

1. A three-year vegetation management cycle for distribution circuits
2. An audit of joint-use attachment agreements
3. A six-year transmission structure inspection program
4. Hardening of existing transmission structures
5. A transmission and distribution geographic information system
6. Post-storm data collection and forensic analysis
7. Collection of detailed outage data differentiating between the reliability performance of overhead and underground systems
8. Increased utility coordination with local governments
9. Collaborative research on effects of hurricane winds and storm surge
10. A natural disaster preparedness and recovery program

In addition to requiring these investments, the PSC also wanted to start tracking all outages regardless of their cause. They therefore required utilities to report "actual" outages that consist of "normal day-to-day" outages (adjusted) and "excludable events", which they defined as:

1. Planned service interruptions;
2. A storm named by the National Hurricane Center;
3. A tornado recorded by the National Weather Service;
4. Ice on lines;
5. A planned load management event;
6. Electric generation or transmission events for Threats to Bulk Power Supply Integrity or Major Interruptions of Service[22]
7. Extreme weather or fire events causing activation of the county emergency operation center.

[22] Details available in subsections (2) and (3) of Rule 25-6.018 Florida Administrative Code: https://www.flrules.org/gateway/ruleno.asp?id=25-6.018

Annually since 2006, Florida IOUs have reported the progress and cost of each of the 11 resilience investments as well as the Customer Minute Interruptions (CMI)[23] and Customer Interruptions (CI)[24] for any of the seven excludable events outlined above.

In the context of these publicly available data, we define "resilience" as how well the Florida IOUs perform against the set of "excludable events", particularly any "named storm" event, as the 11 strategies in which investments are being made are designed to protect against TCs. The Florida PSC has already done some analysis on these data, releasing a study in 2018 that compared the performance of its IOUs against large hurricanes from 2004/2005 to 2016/2017 (State of Florida Public Service Commission, 2018). That study added resilience effectiveness data to the literature by comparing the performance of hardened and un-hardened power lines between the hurricanes of 2004/2005 and those of 2016/2017. However, utilities provided little detail on the difference between hardened and unhardened lines. Therefore, applying these results to other utilities is difficult. Additionally, comparing hurricanes that took different paths and had different windspeeds, storm surges and rainfalls is likely inappropriate. By analyzing the smaller TCs and depressions in addition to these major hurricanes, we have a much larger data set and include a subset of substantial storms against which utilities *should still* be able to demonstrate improved performance. Moreover, the PSC's 2018 study only looked at the effectiveness of hardening, not the cost of implementation or cost of outages avoided. Costs are important: utilities increased rates in 2020 because of storm hardening initiatives, and several large customers in Florida, including the Florida Office of Public Council, submitted filings against the IOUs declaring that their 2020-2029 storm hardening plans were too expensive and provided no clear justification in terms of their costs and benefits (Energy Central, 2020; Florida Public Service Commission, 2020b). Clearly, whether these have been good investments remains an open question which this work helps to partially answer.

[23] Customer Minutes of Interruption (CMI) is the number of minutes that a customer's electric service was interrupted for one minute or longer. (Defined in PSC Review of Annual Reliability reports)
[24] Customer Interruptions (CI) is the number of customer service interruptions which lasted one minute or longer. (Defined in PSC Review of Annual Reliability reports)

4.2. Methods

Using the self-reported excludable events in the annual reliability reports, from 2007-2021, 65 unique storms affected the state of Florida: 43 impacted FPL, 29 hit DEF, 29 hit Gulf, 13 hit TECO, 10 hit FPUC's northeast division in Fernandina Beach (FPUC-NE) and 20 hit FPUC's northwest division in Marianna (FPUC-NW). Of these 65 storms, 50 were named TCs by the National Hurricane Center and 15 fall under the category of excludable event: "extreme weather causing the activation of the county emergency operations center." These additional 15 were included because they were events that exhibit flooding and high winds. Figure 4.1 shows the distribution of storms by year over the last 15 years. The number of storms from 2007-2016 (76) is almost equal the number of storms from 2017-2021 (69), indicating that in recent years the frequency of severe storms has increase. Research by Emanual (2021) supports these findings, showing that storms in the North Atlantic have indeed become more frequent and more severe. However, this trend is not global, and therefore it is unclear to what extent climate change plays a role in this increase (Januta, 2021). This increase is another reason why it is important to understand the efficacy of resilience strategies

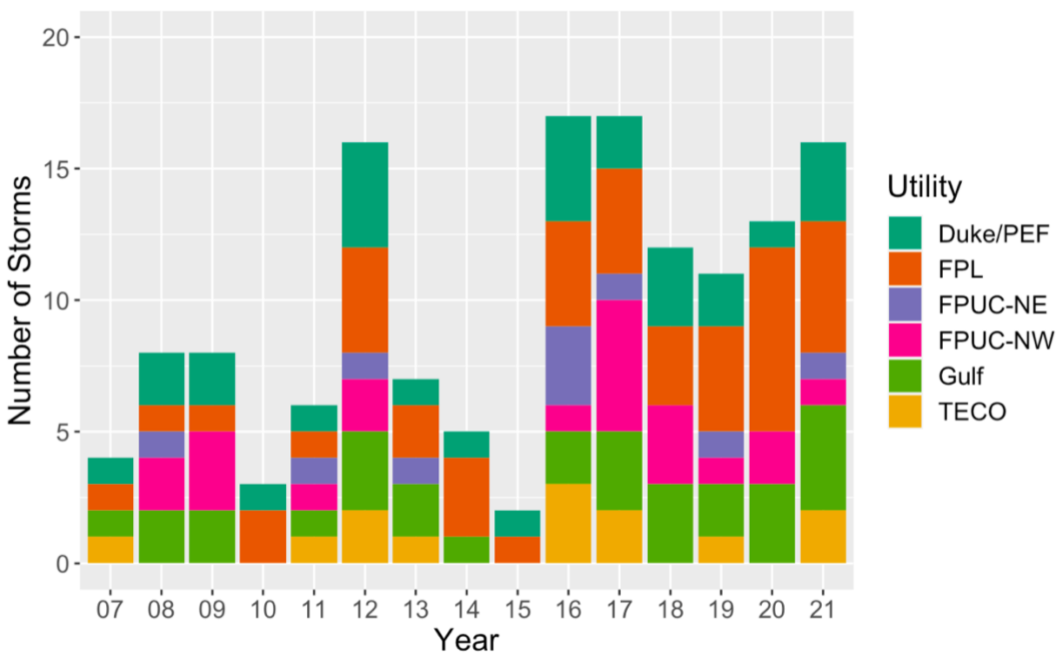

Figure 4.1. Number of storms annually that were considered "excludable events" for each Florida IOU. The number of storms in the first 10 years (76) is almost equal the number of storms in the last 5 years (69).

The area of impact and relevant weather data for each storm was found using the names and dates of the storms provided by the utility and searching both NOAA National Hurricane Center's TC Reports[25] and NOAA's Storm Events Database[26]. When these databases were missing information about a particular service territory, multiple sources were used to supplement. Among these are NOAA tides gauges[27] to estimate storm surge; the rain gauges from the University of Florida's Florida Automated Weather Network (FAWN) to estimate rainfall and storm duration[28]; the rain gauges from the Florida Data Climate Center at Florida State University[29]; the rain gauges from the South Florida Water Management government organization[30]; and historical wind and precipitation data from weatherspark.com. The latter source gets its weather data from NASA's MERRA-2 database[31]. MERRA-2 provides weather data at a 50km grid resolution and predominately collects data from airports. Using these databases, estimates for maximum 3-second wind gust at NOAA's standard 10m measurement height (in mph), storm surge (in ft), total rainfall (in inches), duration of rainfall (using as an indicator for "total storm" duration) and area of impact for each utility were collected.

The area of impact within each service territory was determined by first estimating which counties are served by each IOU. The service territory boundaries for the IOUs have not changed significantly in the last 15 years and are shown in Figure 4.2 from the Florida Public Service Commission's annual "Facts and Figures" reports. FPL owns the largest territory, covering the entire east coast and much of the southern part of the peninsula. Duke operates a large portion of the Big Bend and west coast of Florida, which previously belonged to Progress Energy Florida from 2004-2011. TECO operates Tampa Metro, Gulf operates much of the panhandle and FPUC owns two small territories around Fernandina Beach and Marianna. The only change in service territory happens between 2016 and 2018, where TECO lost territory in Pasco and Polk counties in 2017, and then lost all territory in Highlands County in 2018 to Duke. Additionally, although FPL's acquisition of Gulf was complete by January 1, 2021, they were separate ratemaking entities until January 1, 2022 (Gulf Power, 2021 Annual Reliability Report). Gulf filed its annual

[25] https://www.nhc.noaa.gov/data/
[26] https://www.ncdc.noaa.gov/stormevents/
[27] https://tidesandcurrents.noaa.gov/stations.html?type=Historic+Water+Levels#Florida
[28] https://fawn.ifas.ufl.edu
[29] https://climatecenter.fsu.edu/climate-data-access-tools/downloadable-data.
[30] https://www.sfwmd.gov/weather-radar/rainfall-historical/daily
[31] https://gmao.gsfc.nasa.gov/reanalysis/MERRA-2/

reliability report separately from FPL in 2021, which means this data analysis can treat Gulf and FPL as separate.

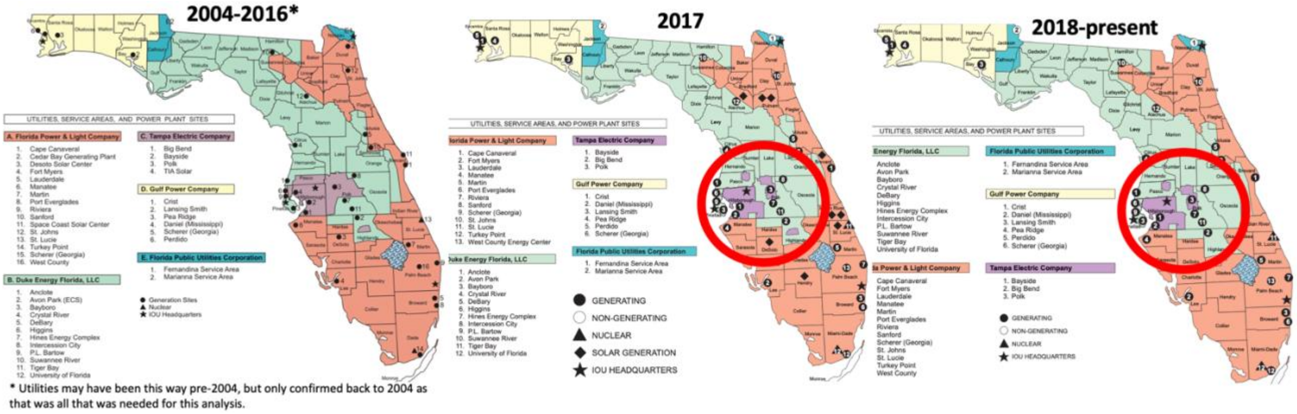

Figure 4.2. FPL service territory in orange, Duke's service territory in green, TECO's service territory in purple, Gulf's service territory in yellow and FPUC's service territory in teal/blue. The red circle indicates changes to TECO and Duke's service territories in the 2006-2021 time-period considered.

The counties that have more than one utility, are assigned to the utility that serves approximately the most customers in that county using US Census data and identifying the largest cities within in each county. This results in a total county count per utility and provides an overestimated total customer count based on the population of counties within the same service territory. The Storm Events Database provides county-level storm data. The population of each county impacted by a particular storm is noted, then summed across counties within the same service territory, and then divided by the overestimated customer count to calculate the fraction of the utility impacted by each storm. However, when gathering data for other storm variables (wind speed, rainfall, etc.), if a shared county reports an event, and the "less dominant" utility was the only one to list the event as excludable, it is assumed the weather event occurred in their territory. However, this shared county does not become a part of the calculation of the area impacted.

Although there are 145 storm observations in the data set, nine were removed because of lack of data provided by the utility. FPL failed to report individual CMI and CI values for the four named storms that occurred in 2019 and instead reported an aggregate CMI and CI. There is no way to disaggregate these values while maintaining the integrity of the analysis. Therefore, there are no observations for FPL in 2019. Similarly, from 2016 onward, TECO only reported the aggregate values for named storm events—sometimes, not even that. TECO experienced 3 named storm events in 2016, of which Hurricanes Hermine and Matthew were significant, so disaggregating CMI/CI values is difficult. Therefore, no 2016 storms involving TECO are included in the data set. Additionally, no storm reliability metrics were reported in TECO's 2017 annual report, though TECO stated they experienced Hurricane Irma and Tropical Storm (TS) Emily. However, the PSC review of the annual reliability reports in 2017 does have CMI and CI values for named storms and indicates that only Hurricane Irma was a problem for TECO. Absent other data, we assume the PSC numbers are correct. Similarly, in 2019 TECO reported no reliability metrics for TS Nestor, but the PSC review did have CMI/CI values for TS Nestor. Lastly, in 2021 there is an aggregate CMI/CI reported for Hurricane Elsa and a "2-day unnamed storm in April". I have included these values assuming all outages are due to hurricane Elsa instead of the "2-day unnamed storm in April".

4.3. Results

4.3.1. Analysis of the storms

First the severity and distribution over time of the 136 remaining storms is examined. The utilities are required to report total CMI and CI for the named storm events in each year. In all cases, except for those mentioned in section 2, they separated these values out by individual excludable storm. Dividing CMI by CI yields one of the three main electric reliability metrics: the customer average interruption duration index (CAIDI), which is commonly used by utilities to determine the average time it takes in minutes to restore power to a customer. Figure 4.3 shows the CAIDI for each storm, which is the dependent variable in this analysis. CAIDI is used rather than either the system average interruption duration index (SAIDI) or the system average interruption frequency index (SAIFI) because the latter two average over the size of the utility, represented by the number of customers, making it misleading to compare SAIDI and SAIFI of specific outage events across utilities of vastly different sizes.

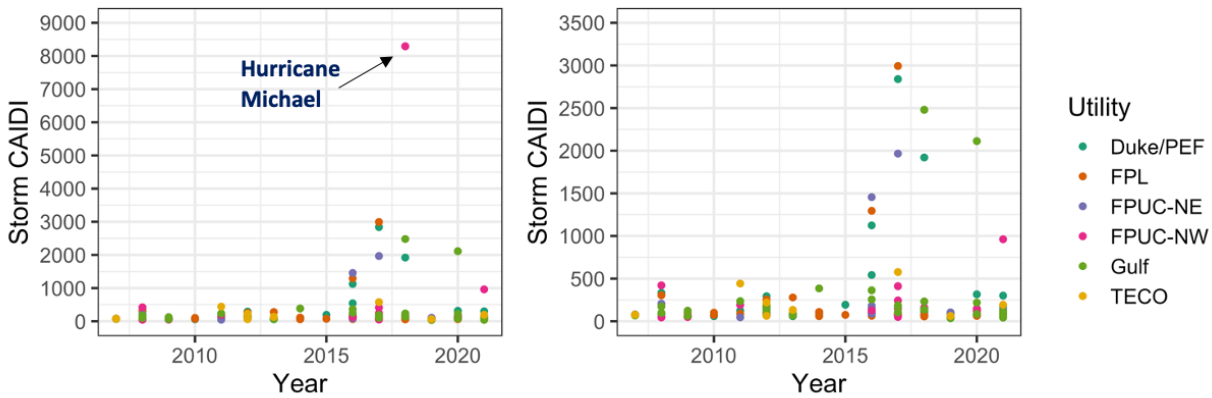

Figure 4.3. CAIDI of each named storm from 2007-2021. The graph on the left includes all 136 observations. The graph on the right graph removes Hurricane Michael's effect on FPUC-NW to enhance the visibility of the remaining observations.

Hurricane Michael is a clear outlier affecting FPUC-NW's service territory. According to the utility's reliability report for 2018, "the NW Division had the eye of hurricane Michael *demolish* its entire territory." In fact, this CAIDI value might not even capture the full extent of the storm, because outages were being experienced from October 10-December 31 of 2018, which suggests that repair efforts might have continued into 2019. If so, these were not reported in the 2019 reliability report. After removing this outlier to better visualize the other events, we see high CAIDI values are concentrated in 2016 and later. This may be due to one or more factors, including climate change and the increase in the frequency and magnitude of extreme weather events. Because of these few higher CAIDI values, the log of CAIDI is used in this analysis.

The goal of this chapter is to determine the effect of resilience investments on CAIDI. To do this, independent variables which are known to have an impact on CAIDI must be included. These variables are "confounders" and, in this analysis, all weather and climate related variables are taken to be confounders. A model is developed that accounts for the extent to which confounders contribute to CAIDI, and the extent to which the resilience variables under investigation *may* contribute to it. This allows us to see whether the changes in model performance (i.e. coefficients, standard errors, R^2) suggest that any of the resilience variables can account for the variation in CAIDI. It is important to clarify that this is not a predictive model: it only assesses the association between the resilience investments already made and the resulting CAIDI values.

The first, baseline model is below:

$$\begin{aligned} \ln(CAIDI) = \quad & \beta_0 + \beta_1 WindGust + \beta_2 StormSurge + \beta_3 StormDuration + \\ & \beta_4 Rainfall + \beta_5 ImpactedArea + \beta_5 RainDays \end{aligned} \tag{1}$$

"RainDays" refers to the average number of days annually within each service territory with more than 0.1 inches of rain, as collected from NOAA's National Climate Data Center (NCDC). In addition to storm attributes, this variable is included because Nateghi et al. (2011) included long-term precipitation patterns as a predictor of hurricane outages. Specifically, it is considered a way to account for different types of vegetation (i.e. the type of vegetation that can grow in an area depends on mean annual precipitation).

To ensure we fit the best model and have unbiased estimates, the residuals from the regression model need to be random and have a mean of zero. To check for this, we can look at a scatter plot and quantile-quantile plot (Q-Q plot)[32] of the fitted values from the regression vs. the jackknife residuals[33], as shown in Figure 4.4.

[32] A Q-Q plot displays the quantiles of two distributions against each other. This plot doesn't require an equal number of observations in each distribution to compare them.

[33] A jackknife residual is calculated as the residual (observation minus the predicted value for that observation) divided by the standard error of the residuals having removed the specific observation we're looking at from the regression. It is standard in statistical analysis to use jackknife residuals when model checking because it is independent of the units of the variables in the analysis (scale) and it is most sensitive to finding outliers in the data set (compared to standardized or studentized residuals).

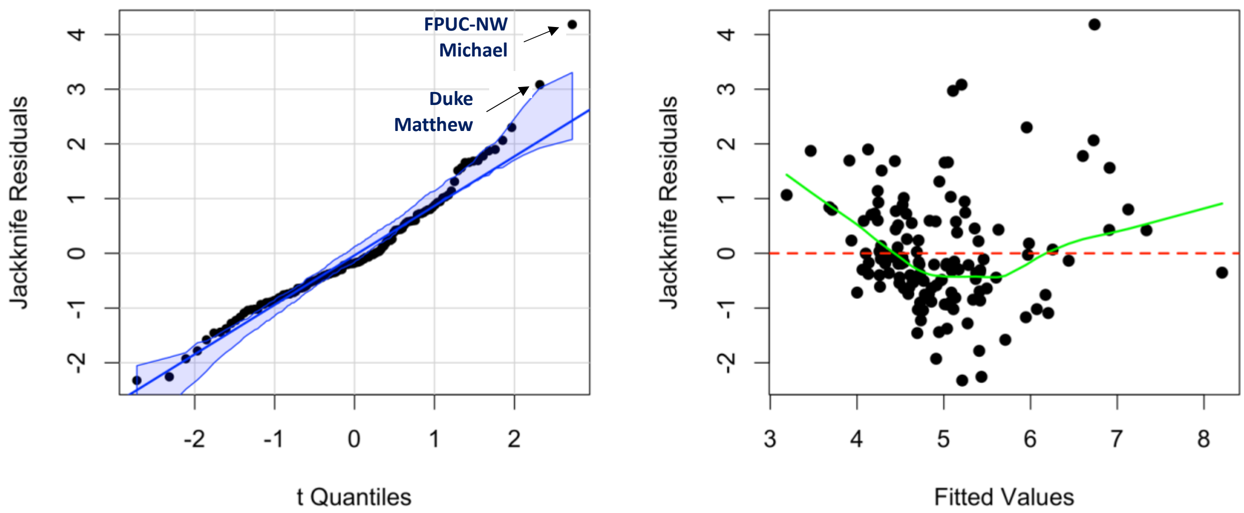

Figure 4.4. Plots of the residuals of the baseline model help test its goodness of fit. Left: Q-Q plot of the fitted values vs jackknife residuals. The straight blue line represents a normal distribution; the closer to the blue line the points are, the more closely the distribution resembles a normal distribution. There residuals are close to being normally distributed but with heavy tails with two big outliers: FPUC-NW's Hurricane Michael and Duke's Hurricane Matthew. Right: scatter plot of fitted values vs jackknife residuals. The red dotted line is plotted along the zero intercept, while the green line uses a smoothing function to visualize the variation in residuals. This model is heteroskedastic[34] and tends to underpredict very high and very low CAIDI observations.

There may be other variable transformations that can account for this heteroskedasticity (see footnote 17) in the residuals and thus improve on this model. Figure 4.5 checks the partial residual plots to determine if variable transformations are needed. These plots show the jackknife residuals of specific independent variable observations, which helps determine whether there is a pattern in the prediction that would call for a nonlinear relationship between that independent variable and the dependent variable.

[34] Heteroskedasticity means that the error variances change as a function of the regressors.

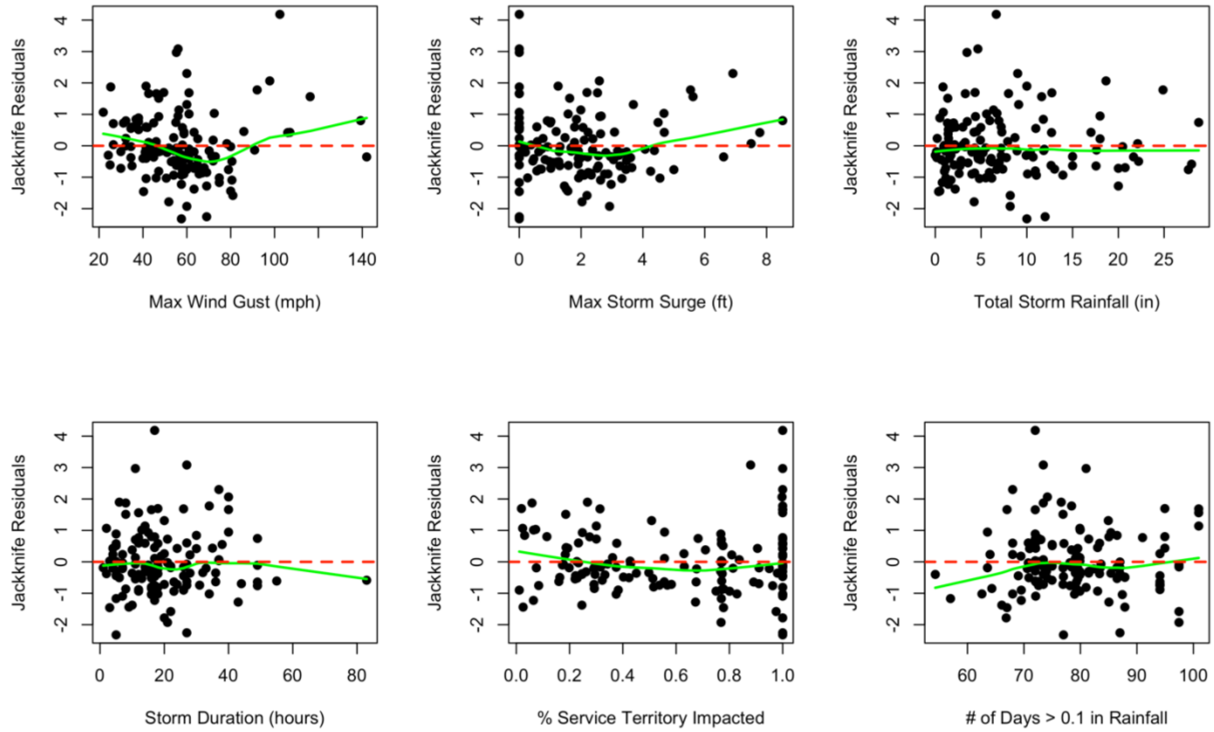

Figure 4.5. Partial residual plots of the storm attributes. The plots suggest that linear models are likely best, though there is heteroskedasticity in wind gust, storm surge and storm duration. The red dotted lines are plotted along the zero intercept, while the green lines use a smoothing function to visualize the variation in residuals.

Based on Figure 4.5, the linear model, without any variable transformations, is likely to perform best with these data. However, we can see heteroskedasticity in wind gust, storm surge, and storm duration, which is reflected in the fitted vs. residual plots in Figure 4.4. It's not surprising to see this in a data set of TCs in which there are a few particularly strong storms. We can use robust standard errors[35] to account for these heavy tails in the t-statistic of the regression model. Table 4.1 shows the regression results using robust standard errors.

[35] Instead of using the traditional standard error, which says that the variance of a coefficient is just a function of the average variability in the residuals, the robust standard error uses a weighted average of the squared residuals, where the weights are determined by the squared difference between the value of an observation and the mean.

Table 4.1. An initial, "baseline" model is developed and includes variables known to increase CAIDI. Robust standard errors are used to account for heavy tails in the residuals and heteroskedasticity. The dependent variable is the natural log of CAIDI.

	Coefficient	Standard Error	P-value
Max Wind Gust (mph)	0.031	0.005	0.000*
Storm surge (ft)	0.058	0.054	0.279
Storm Duration (hrs)	0.003	0.005	0.596
Total Rainfall (in)	-0.004	0.012	0.777
Area Impacted (%)	0.009	0.172	0.000*
# of Days >0.1 in of rainfall	-0.019	0.006	0.003*
N 136			
Adjusted R^2 0.61			
* P-value < 0.10			

Because the dependent variable is the natural log of CAIDI and the independent variables represent actual values, this is a log-level model. This means that every one unit change in the continuous independent variables is associated with 100 times the coefficient percent change in the dependent variable. For example, in this model an increase of 1 mph in wind gust equates to an increase of 3% in CAIDI. Max wind gust, area of impact, and number of days with >0.1 in of rainfall have the biggest impact on CAIDI. It's well-known that high winds greatly impact distribution systems, so it's unsurprising to find that winds are significant. Additionally, given the large differences in geographic size across utilities in this data set, it is also unsurprising that the percentage of the utility that was impacted by the storm would be statistically significant. Storm surge may not be statistically significant here because FPUC-NW, which has the largest CAIDI value by far, over 8000 CAIDI minutes, with the second closest recording 3000 minutes, always has a storm surge of 0ft, because it is land-locked. This leads to the question of over-fitting. We know from Figure 4.4 that FPUC-NW's Hurricane Michael and Duke's Hurricane Matthew are outliers in the model, but to measure how much influence these or other observations have on the regression model (i.e., the extent to which the outliers change the results of the model) we can use Cook's Distance calculation. This is a standard measure to check the influence of each observation on the regression model by summarizing how much the mean squared error changes when an observation is removed. Figure 4.6 shows the diagnostic plot result of calculating Cook's Distance for every observation in the data set.

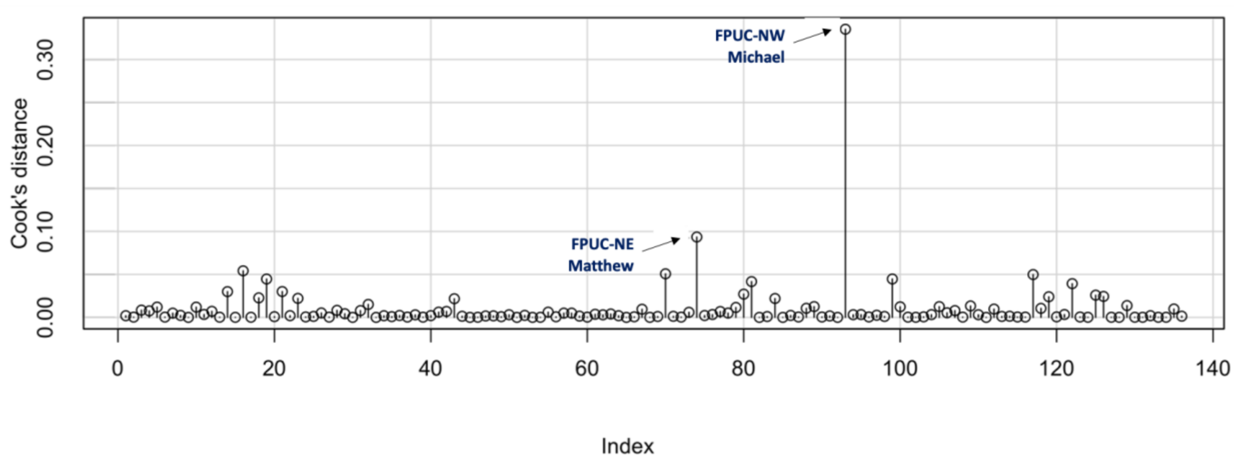

Figure 4.6. Cook's distance calculation for each observation in the data set. FPUC-NW's Hurricane Michael and Hurricane Matthew for FPUC-NE have the most leverage on the regression.

Hurricane Michael's effect on FPUC-NW has a large impact on the model, but removing it is inappropriate because this study is specifically investigating extreme events. The Cook's distance measurement is greater than 0.30 for this observation, which means it increases the mean squared error of the analysis by 30%. Hurricane Matthew's effect on FPUC-NE was a storm with high CAIDI values (1455) and one of the highest storm surges in the data set (7ft), but relatively low wind speeds (60 mph). These two outliers plus Hurricane Matthew's effect on Duke, which had a wind speed of 65 mph and a storm surge of 0ft, indicates that the model is having trouble reconciling the extreme storm surge values when they are producing very high CAIDI values (1000+) in all cases. Because of the large influence of Hurricane Michael on FPUC-NW, this observation is dropped from the data set and the regression rerun to make sure the model isn't overfitting.

Table 4.2. Setting the baseline model by including variables known to cause CAIDI, but dropped the extreme outlier of FPUC-NW's Hurricane Matthew. The dependent variable is the natural log of CAIDI.

	Coefficient	**Standard Error**	**P-value**
Max Wind Gust (mph)	0.026	0.004	0.000*
Storm surge (ft)	0.097	0.045	0.034*
Storm Duration (hrs)	0.001	0.005	0.790
Total Rainfall (in)	0.001	0.011	0.900
Area Impacted (%)	0.009	0.168	0.000*
# of Days >0.1 in of rainfall	-0.017	0.006	0.004*
N	136		

Adjusted R^2	0.61
*	P-Value < 0.10

The only substantial change is storm surge, which is now statistically significant. This is a good sanity check to know that storm surge does indeed have an impact in areas where it is experienced.

The only two variables that seem to have no impact are storm duration and total rainfall. This is likely because wind speed, area impacted, number of days with > 0.1 in of rainfall, and storm surge account for the variations in CAIDI much better than storm duration and total rainfall, even though they still have a slightly positive correlation, as expected and shown in Figure 4.7.

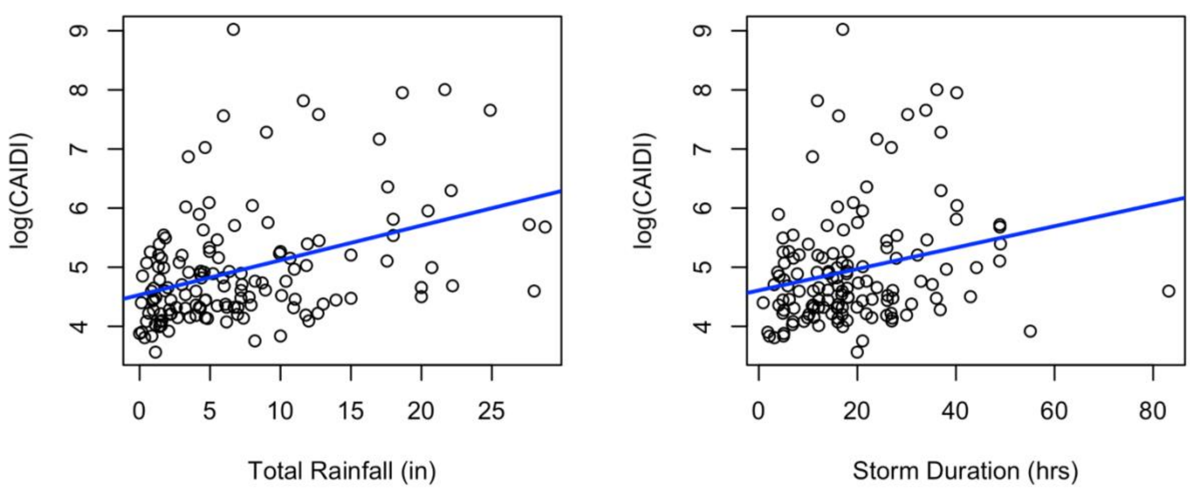

Figure 4.7. Left: the relationship between total storm rainfall and CAIDI. Right: the relationship between total storm duration and CAIDI.

The fact that rainfall and storm duration do not turn out to be statistically significant is not surprising, given that the combination of the two can lead to flooding, and flooding doesn't necessarily cause distribution system outages (except for some underground lines), but rather could prevent utilities accessing lines that are out due to other reasons such as wind. The NOAA storm events database does state when news sources report power outages and, although it is not a comprehensive list, almost every time they identify a power outage it is caused by poles or lines falling due to wind and debris. An outage was attributed to heavy rainfall only once during Tropical Storm Lee in 2011 in FPUC-NW territory: "These strong wind gusts, combined with periods of heavy rain and wet soils, led to numerous trees and power lines falling throughout the day and into the evening hours."

The checks above suggest that the results do make sense and we have settled on the best possible model without overfitting the data. However, after all of this we get an adjusted R^2 of 0.61, which means this model can explain 61% of the variability in CAIDI. One reason that R^2 is not higher is because the data only exist at the level of an entire utility service territory. Much more granularity – looking at specific circuits within a utility - would likely improve the result, but such data are not publicly available.

4.3.2 Differences in Utility

With the baseline model established, integrating utility and resilience variables in whose coefficient estimates we are interested in requires an unbiased estimate. To be unbiased, the model should have zero conditional mean errors, as estimated by looking at the residuals. However, the model also needs to adhere to the four Gauss-Markov assumptions:

1. Linearity in parameters, which means the model fits a form of $y = \mathbf{X}\beta$.
2. Random sampling: although this is not a random sample, we assume that the data *are* the population. In other words, we are not trying to make inferences about future tropical storms in Florida but only to understand what happened during the excludable storms of the last 15 years.
3. Avoiding omitted variable bias: ensuring that nothing excluded from the regression model is related to both the dependent and regressor variables, because it would bias the coefficient estimate of the regressor variable that was included. This is difficult, but managed by first including as many outage-causing storm variables as feasible. Second, there are differences within utilities that could impact both CAIDI and resilience investments, such as wealth and risk preferences of customers, geography, climate, business practices, and additional reliability or resilience investments, among others etc. Hence, the utility is included as a dummy variable. Finally, there are other time variants

to be considered: the frequency and magnitude of storms and changes in climate. Moreover, infrastructure, population density, and other things are also changing over time which can impact CAIDI and the resilience investments.

4. No perfect collinearity: no variables included are perfectly correlated with each other, which could happen when a dummy variable is misrepresented. Another issue which can arise that may prevent accurate estimates is multicollinearity, where the regressor variables are highly correlated with each other. When this happens, it is difficult to disentangle the estimated effect each has on the dependent variable and could also greatly increase standard error. Testing the correlation between each variable showed no great concern. The resilience variables included in this analysis (discussed further in section 4.3.3) are independent of each other: investing in one does not require investment in another.

How well the Florida IOUs are performing compared to each other is examined, after accounting for the severity of the storms they each experience. To do this, two new variables are added into the model: Utility and Storm Year. Including utility identifies the percentage differences in CAIDI across the utilities, and including the year the storm occurred is a way to account for changes over time, enabling us to get an accurate estimate on the qualities inherent to each utility. This model is shown in equation 2.

$$\begin{aligned} \ln(CAIDI) = \;& \beta_1 WindGust + \beta_2 StormSurge + \beta_3 StormDuration + \beta_4 Rainfall + \\ & \beta_5 ImpactedArea + \beta_5 RainDays + \beta_6 StormYear + \beta_7 Duke + \\ & \beta_8 FPL + \beta_9 \text{FPUC-NE} + \beta_{10} \text{FPUC-NW} + \beta_{11} Gulf + \beta_{12} TECO \end{aligned} \tag{2}$$

Q-Q and fitted vs jackknife residual plots are presented in Figure 4.8 to assess the residuals from the regression model.

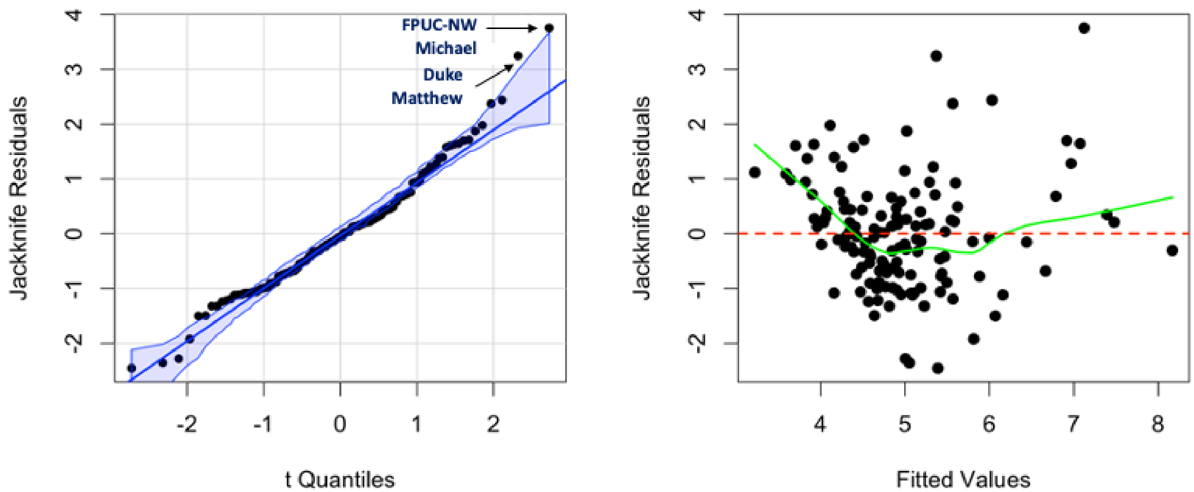

Figure 4.8. Checking the assumption of zero conditional mean of the errors. On the left is the Q-Q plot which compares the residuals to a normal distribution. The line has flattened after adding Storm Year and Utility dummies, but the wide tails persist. On the right is a plot of fitted values vs jackknife residuals showing the distribution of residuals is fairly even above and below zero, but still very heteroskedastic. The red dotted line is plotted along the zero intercept, while the green line uses a smoothing function to visualize the variation in residuals.

Compared to Figure 4.3, which shows these plots for the first model with just storm variables, the residuals appeared to have flattened and are more closely matched to a normal distribution. There are still clear outliers which are evident in the distribution's heavy tails and the residuals are still heteroskedastic. We can check again for variable transformations to address heteroskedasticity by looking at the partial residual plot of Storm Year, shown in Figure 4.9.

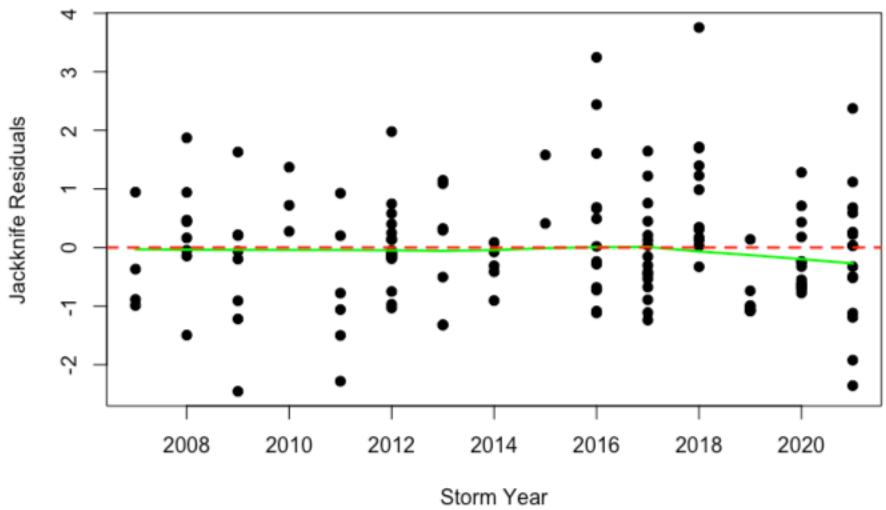

Figure 4.9. Similar to the storm variables, Storm Year has a linear relationship with ln(CAIDI) but is heteroskedastic because there were more storms in later years. Additionally, the model is slightly over-predicting CAIDI from 2019-2021, because the residuals are low.

No transformation is called for. The regression results are shown in Table 4.3

Table 4.3. Second model which includes the storm year and the utility as variables to account for changes over time and look at differences between utilities. Using robust standard errors to account for heavy tails in the residuals and heteroskedasticity. The dependent variable is the natural log of CAIDI.

	Coefficient	**Standard Error**	**P-value**
Max Wind Gust (mph)	0.030	0.005	0.000*
Storm surge (ft)	0.065	0.055	0.236
Storm Duration (hrs)	0.002	0.005	0.733
Total Rainfall (in)	0.008	0.011	0.529
Area Impacted (%)	0.008	0.276	0.004*
# of Days >0.1 in of rainfall	-0.024	0.007	0.001*
Storm Year	0.046	0.013	0.001*
Duke (Intercept)	5.135	0.180	0.000*
FPL	-0.409	0.177	0.022*
FPUC-NE	-0.197	0.340	0.563
FPUC-NW	0.117	0.341	0.732
Gulf	-0.199	0.207	0.337
TECO	-0.350	0.264	0.188
N	136		
Adjusted R^2	0.66		
*	P-Value < 0.10		

First, the R^2 value has increased to 0.66, which is unsurprising based on the residual plots in Figure 4.8. Second, the coefficients and standard errors on the original storm variables have not changed much, which suggests we've avoided multicollinearity. Next, note that the storm year variable is statistically significant and positive, which means the model is picking up the fact that in our data set storms are becoming more frequent and intense, which we saw in Figure 4.2. Additionally, we know that there are more data points in later years from Figure 4.1 and in 2010 and 2015 there are only storms in Duke and FPL's territory, which could be potentially biasing the data set.

Now that there is a dummy variable component to the model, the intercept must represent one of the utilities. In this case, the intercept is Duke. The variables in the model are mean-centered, which means that if all variables are held at their mean, the intercept (aka Duke) has an average CAIDI of $e^{5.135} = 170$. Then, the coefficients in Table 4.3 for the other utilities represent the difference in average CAIDI *from* Duke. Because this is a log-level model, the coefficients on dummy variables also need to be transformed for them to make sense: the percent change in y = $[100(e^{coefficient} - 1)]$. We can see that FPL has a statistically significant CAIDI value that is on average 33.6% less than that of Duke's Tropical Storm CAIDI average ($[100*(e^{(-0.409)} - 1)] = -33.6\%$). To better understand the CAIDI differences between all utilities, Figure 4.10 centers each utility respectively, and then shows the percent difference in CAIDI from the others.

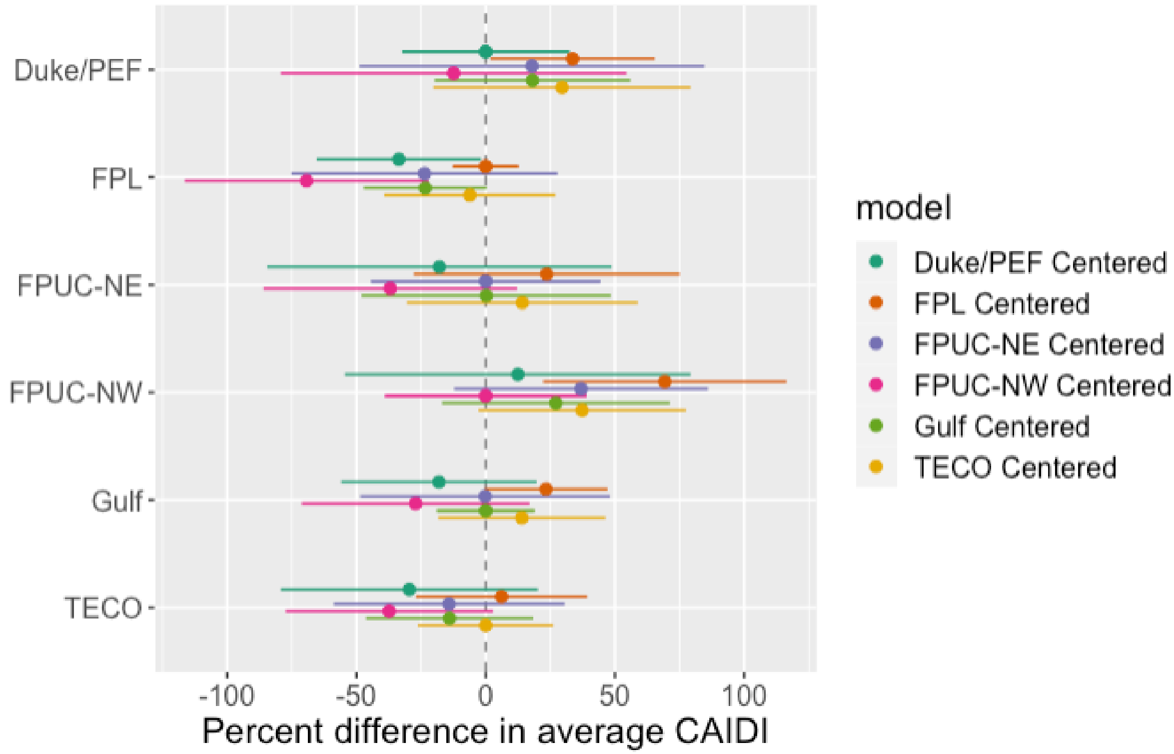

Figure 4.10. To see the differences in CAIDI between each utility pair, shown is the percent difference in CAIDI in reference to each utility. For example, in the top row, when Duke/PEF is the reference utility (set at 0 as shown by the teal dot and whiskers plots), the other 5 utilities are compared to Duke. For example, the CAIDI for FPL is approximately 30% lower than Duke's. The points represent coefficient estimates and the lines show a 90% confidence interval.

Many of the confidence interval lines cross zero in Figure 4.10, which means there is a >10% chance that in light of the various uncertainties the differences in CAIDI are random and not due to a "true" difference. However, we can see that FPL's performance is statistically significantly better than Duke/PEF and FPUC-NW. It would appear that FPL is doing better than all other utilities and FPUC-NW is doing worse than all other utilities. As discussed further in sections 4.3.3 and 4.3.4, FPL is investing in several additional resilience strategies in addition to those prescribed by the PSC. Some of these investments may be helping FPL improve their storm response when compared to the other IOUs. In addition, the extreme case of Hurricane Michael, which destroyed FPUC-NW's territory, may be affecting this result, making it appear like FPUC-NW performed worse than it did against other tropical storms.

Figure 4.11 reports the Cook's Distance calculation for the second model.

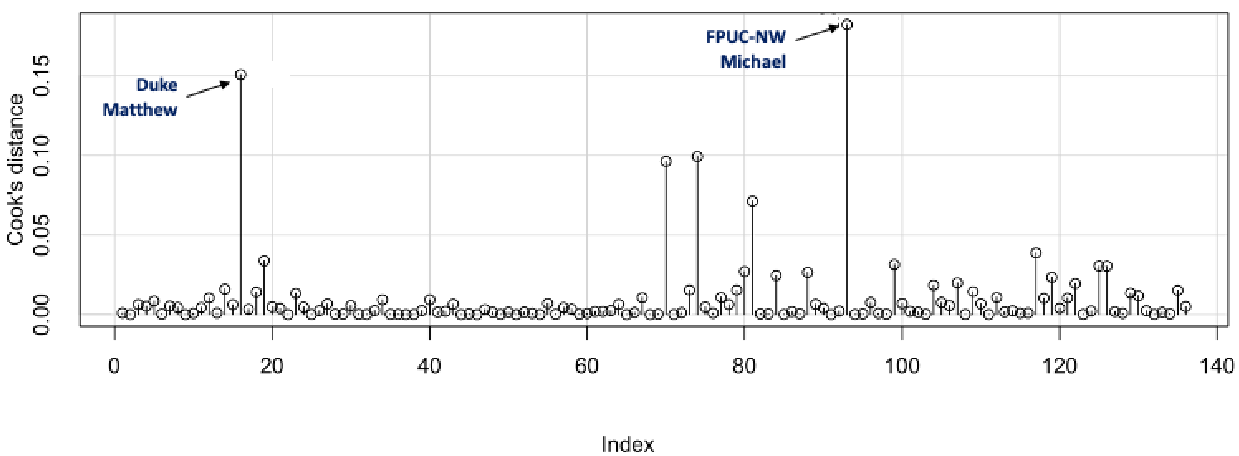

Figure 4.11. Cook's distance calculation for each observation in the data set. Hurricane Michael's effect on FPUC-NW and Hurricane Matthew's effect on Duke have the largest influence on the second model.

Since Duke/PEF appears to be doing slightly worse than many of the utilities, Figure 4.12 shows the results of removing the Hurricane Michael observation (left panel), and removing Duke's Hurricane Matthew (right panel).

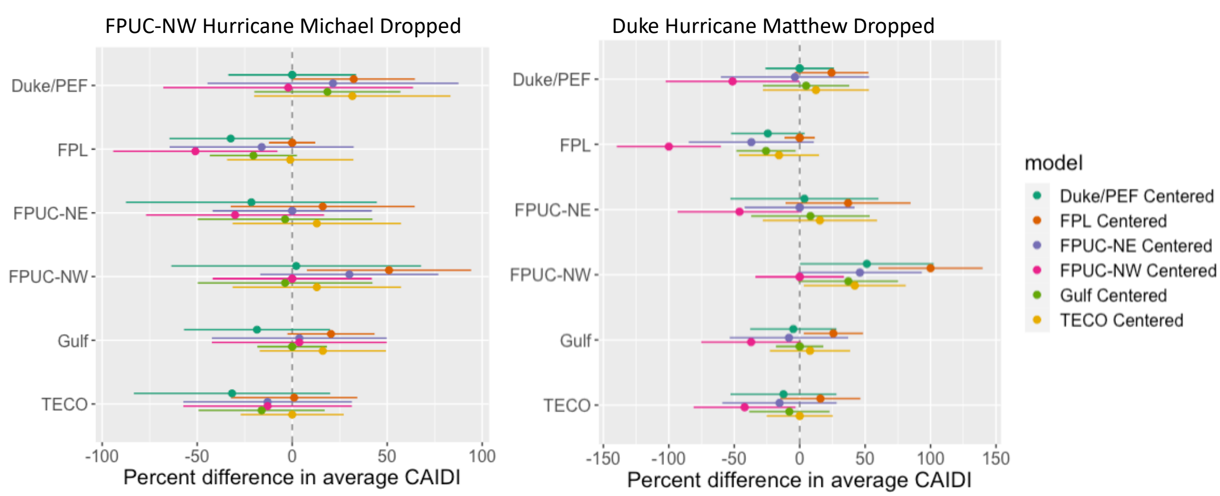

Figure 4.12. The same model as shown in Figure 4.10, but with the outlier Hurricane Michael FPUC-NW dropped on the left and Hurricane Matthew dropped on the right. To see the differences in CAIDI between each utility pair the figure shows the percent difference in CAIDI in reference to each utility. So, when Duke/PEF is the reference utility (set at 0) the teal dot and whiskers plots represents how the other 5 utilities compare to Duke. The points represent coefficient estimates and the lines show a 90% confidence interval.

Even after dropping FPUC-NW's Hurricane Michael observation, FPUC-NW on average is still not performing as well as the other utilities, although the magnitude of percent difference has decreased. For example, FPL had an average storm CAIDI value that was almost 75% less than FPUC-NW. With the outlier dropped, it is now roughly 50% less than FPUC-NW. Dropping Hurricane Matthew did make Duke/PEF's performance on par with four of the other utilities. However, FPL is still statistically significantly better, but the magnitude of the percent difference decreases in this case. As we know from section 4.3.1, Hurricane Matthew effect on Duke was a relatively large CAIDI value despite seemingly low storm effects. The storm variable estimates could be off given the sensitive nature of weather sensors, or they are accurate and something inherent to Duke makes them perform slightly worse. Of note, Duke took over Progress Energy Florida in 2013, so about one third of the data points come from PEF. And although the physical system wouldn't have changed much from 2012-2013, Duke might have initiated many internal changes that could impact these results, particularly in asset and outage tracking. Additionally, Duke covers an area close to the same size as FPL (27 vs 28 counties) but has far few customers (1.8 million vs 5 million), so it has a large system but less revenue to manage outages. Finally, TECO also seems to be performing slightly better than most of the IOUs. There is nothing in their reliability reports to indicate they are doing anything particularly different from the other utilities, but there could be initiatives or business practices not reported that improve their CAIDI values, or this could be something inherent to the communities they serve. However, TECO has the smallest representation in this analysis (8 observations), so this could simply be an artifact of the small data set.

4.3.3 Resilience strategy analysis

Next the resilience investments are considered by first reviewing the eleven identified by the PSC. For the purposes of this analysis, we focus on distribution hardening because the storm reliability CMI and CI values are for the distribution system. FPL does not report weather related transmission outages; FPUC-NW doesn't have any transmission; and the weather outages for transmission reported by the other utilities are a quarter of the number of weather outages on the distribution system, which gives an even smaller data set than the distribution one currently being analyzed. Nevertheless, spending on transmission hardening will be considered in the next section which addresses cost analysis.

Note too that more qualitative initiatives such as collaborative research, increasing coordination with local governments, natural disaster preparedness and post-storm data collection, are not represented in this analysis because it was too difficult based on the limited descriptions provided in utility annual reports and the lack of consistent reporting on spending for these activities. Future work should propose a way for utilities to produce more consistent data and then develop a way to incorporate these qualitative resilience strategies into resilience modelling. The addition of a GIS system is also not modelled because each utility finished initial input of all assets into a GIS system by 2009/2010, but also regularly updated and expanded their systems to support more robust outage management and asset management throughout the years. There is not enough detail on these upgrades to meaningfully track any added benefit in performance in the last 15 years by the GIS systems. However, as a supplement, I do include a variable on the fraction of customers with advanced metering infrastructure (smart meters) using EIA Form-861 from each of the 5 utilities. Smart meters increase visibility on the system by allowing the utility to know which customers are without power without requiring them to call in or dispatch a truck, which in turn helps them locate failures more quickly. AMI can also serve as a supplemental variable for GIS system implementation, because an affective AMI system does not work without a comprehensive GIS system.

That leaves the following utility described resilience strategies to consider:

a. Eight-year distribution wood pole replacement cycle
b. Three-year vegetation management cycle for distribution circuits
c. Collection of detailed outage data differentiating between the reliability performance of overhead and underground systems
d. Advanced metering infrastructure

The following sections provide details on the information provided about each strategy by the utilities and how these inputs were turned into usable variables in this analysis. The resilience variables are lagged by one year. In other words, for storms that occurred in 2007, it is assumed that each utility had their 2006 levels of resilience.

a. Eight-year distribution wood pole replacement cycle

Starting in 2006, (except for FPUC-NE, where the first data are from 2008), each utility began the 8-year distribution pole inspection cycle, which means that every pole on the distribution system will be inspected once every eight years, and when poles fail, they will be replaced by a National Electrical Safety Code (NESC) Grade B standard pole[36]. TECO, FPL, Gulf, and Duke all have policies as well to replace these poles with a non-wood pole. Because no information was provided annually about pole class or age distribution across the utilities, which would be a good indicator for how new and strong the pole fleet is, included instead is a variable that identifies the number of poles on the system made of wood. This comes from a form each utility filled in about their total wood poles and wood pole inspections in every reliability report, and how each utility's number of non-wood poles on the system was estimated is described below.

- FPL - The only year in which the total numbers of wood and concrete distribution poles were identified was 2014. From 2013 to 2020, the number of wood vs concrete distribution poles that were *inspected* was identified. Using the inspection ratio, totals from 2014 to 2020 were approximated. A line was fitted to the points from 2014 to 2020 and used the result to estimate values for 2006-2013.
- Duke – In the wood inspection section of their report, the total number of wooden poles on the distribution system are reported each year. This number was divided by total "owned" poles reported in the joint audit attachment section.
- Gulf – Gulf reports total wood pole count (transmission, distribution and lighting poles) in column A of the wood inspection table. In the separate transmission inspection section of the report, total transmission poles are reported. This total, which inconsistently includes either "wood" or "wood and concrete", was subtracted from the total number of wood poles. This new value, which should now just represent the total number of wood

[36] Grade B refers to the level of extreme wind-loading that the poles are rated to. For example, FPL wind loads up to 150 mph and TECO splits its service territory into 110 mph poles and 120 mph based on these guidelines

distribution poles, as reported in the joint audit section.

- TECO – TECO reported total vs wood distribution poles from 2006 to 2008, then again from 2014 to 2019. To estimate the values from 2009 to 2013, a linear decrease based on the 2008 to 2014 ratio was assumed. The number of wood poles but not the total number of poles is reported in 2020, which is assumed to be the same total as in 2019.
- FPUC –FPUC has all its distribution poles made of wood, except for 10 poles that were converted to concrete in FPUC-NW's territory from 2006 to 2007. This could be a reporting error, but a 2017 article mentions that FPUC was replacing failed wood poles with a "higher strength class wood pole" (Rivera-Linares, 2017). Thus it is assumed almost all poles are wood in both FPUC-NE and FPUC-NW.

Apart from FPUC, this variable of non-wood pole percentage accounts for not only the added resilience of non-wood pole material, but also stronger/newer poles added to the system, because only wood poles that fail inspection are being replaced with non-wood poles. Therefore, the resulting coefficient estimate of this variable will reflect the difference between failing wood poles and new non-wood poles, *not* between two new poles: one wood, one not.

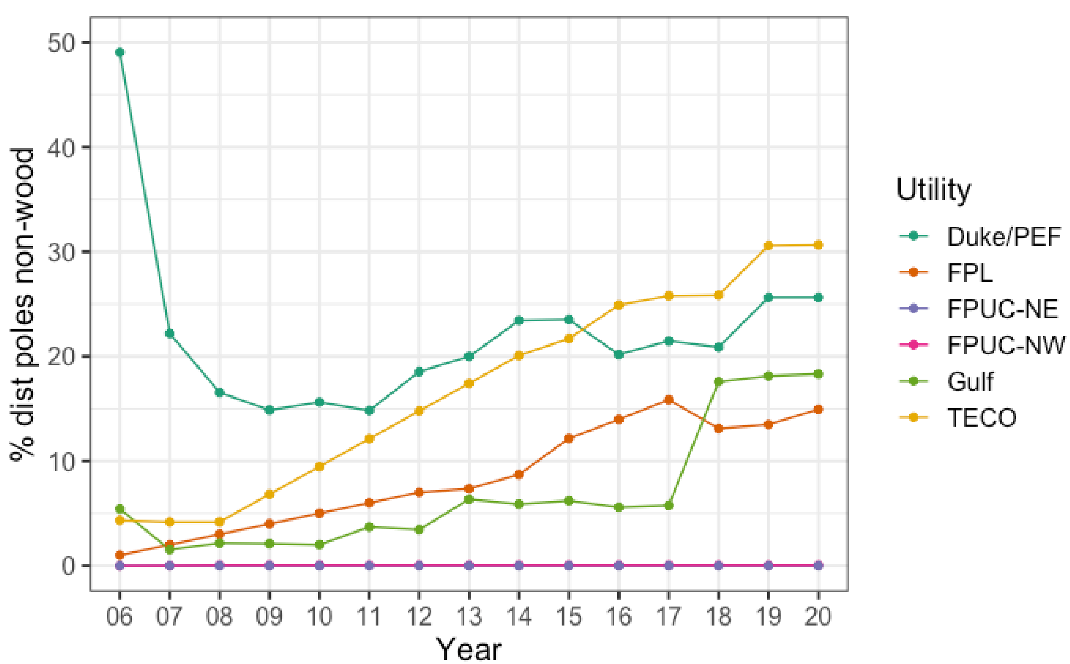

Figure 4.13. Changes in percent non-wood poles on the system from 2006-2020.

As Figure 4.13 shows, most of the utilities are increasing their percentage of non-wood poles each year, which makes sense because they all have some policy of replacing failed wood poles with non-wood, except FPUC. In 2006 and 2007 in Duke (then Progress Energy Florida), the calculations suggest they had significantly fewer poles that were wood, then in 2008 increased wood poles by 20%. This is likely an error based on estimating pole fleet while they were still collecting data to load into their GIS system and prior to finalizing an accurate count. For this reason, the ratio of wood to non-wood in 2008 is assumed to be the same in 2006 and 2007. Additionally, there is a slight decrease in non-wood poles starting around 2015 in Duke's territory. This decrease could be due to Duke Energy's acquisition of Progress Energy Florida in 2013, because its service territory could have changed in ways not visible in the map, or its reporting schemes could have changed. In 2017, Gulf's percentage of non-wood distribution poles increased drastically (>10%). This happened because the total number of distribution poles increased by approximately 30,000 between 2017 and 2018, but the total number of wooden poles stayed roughly the same. There is no clear explanation for why this happened: the number of customers didn't rise significantly. It could partially be due to the devastation of Hurricane Michael, where they had to replace 7000 poles on the distribution system (Florida Public Service Commission, 2020a). Or, it could be a reporting mistake. However, no adjustments were made to Gulf's numbers in the analysis.

b. Three-year vegetation management cycle for distribution circuits

Unless otherwise approved by the PSC, each IOU is expected to trim all feeder lines on a 3-year cycle and all lateral lines on a 6-year cycle. Duke and FPUC follow these vegetation cycles as prescribed. FPL follows this general cycle but also does extensive "mid-cycle" trims in known problem areas throughout its system. Gulf's vegetation management program consists of a three-year cycle on main line feeders, four-year cycle on laterals, and an annual cycle of inspections and corrections on main line feeders, which was approved by the PSC in 2008. In 2012, TECO was approved to do a 4-year trim cycle for both laterals and feeders. Annually, the total number of distribution miles trimmed by each utility (lateral + feeder) was calculated and divided by the total number of distribution miles they each have on their system.

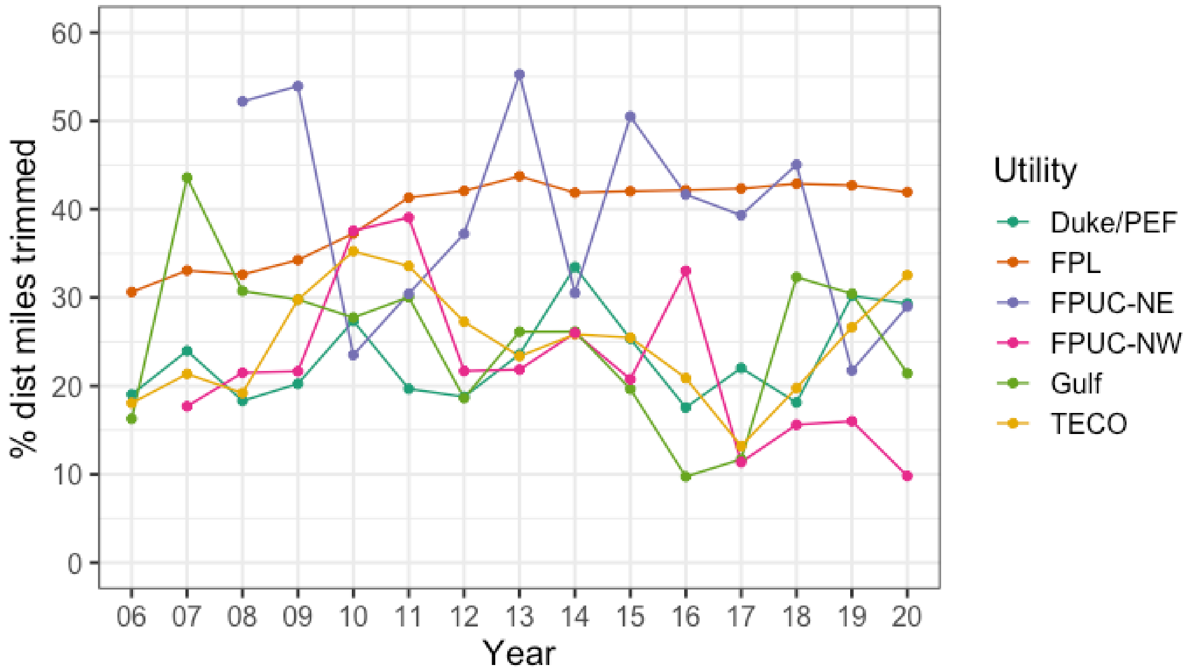

Figure 4.14. Annual percentage of distribution miles trimmed from 2006-2020.

FPL is the only utility that seems to consistently trim roughly the same amount of their system annually (~40%). The other utilities, although meeting their cycle requirements, seem to be able to trim more in some years in the cycle than in others. It is unclear what is causing this phenomenon.

c. Collection of detailed outage data differentiating between the reliability performance of overhead and underground systems

The utilities report miles, CMI, CI, N (number of outages) and L-bar (average minutes it takes to restore an outage) for overhead vs underground adjusted outages in the annual reliability reports (Duke is the only utility that reports "actual" outages). Although the outage information is useful for comparing underground and overhead performance, the percentage of underground vs. overhead lines on the system is the resilience variable of interest and is derived from the reported number of miles of overhead and underground lines.

FPL classifies its overhead and underground lines as follows:

> The majority of FPL's customers are fed from circuits that are a hybrid of both overhead and underground. The methodology used to classify a customer as fed purely overhead is as follows: those customers served by a feeder with combined feeder and lateral overhead miles greater than or equal to 95% of the total primary miles. Then, to classify a customer as fed purely underground: the customers served by a feeder with combined feeder and lateral underground miles greater than or equal to 95% of the total primary miles. Hybrid customers are those served by neither 95% OH [overhead] or UG [underground], but rather by something in between.

A Florida news article stated that, in 2019, 38% of FPLs distribution ("neighborhood") lines are underground to estimate the total miles of distribution lines that are underground on FPL's system (Pounds, 2019). This is corroborated by an FP&L press release in 2019 stating that "nearly 40%" of their distribution lines are underground (Florida Power and Light, 2019b). Assuming that, in 2020, exactly 40% of the distribution system is underground and knowing the percentage of distribution lines strictly underground (by FP&L's definition) from 2006 to 2020, the changes per year from 2006 to 2020 could be approximated. In 2006, the system had approximately 28% of distribution underground.

Reports by Duke Energy contain conflicting information on underground vs overhead miles. In attachment V in the appendix, they include the number of overhead vs. underground miles. However, in a separate section of their reports called "Storm Hardened Facilities", they include a percentage of distribution circuit miles underground. The actual miles listed in the appendix were used in this analysis, but this section implies undergrounding has increased from 41% of distribution in 2006 to 48% in 2019 and then decreased to 45% in 2020. The data from the "Storm Hardened Facilities" section says undergrounding has increased from 41% to 45.9% from 2006 to 2020.

Gulf values are based on reported overhead and underground miles up until 2019, when FPL bought Gulf and started using the same hybrid model described above. The 2019 underground percentage is estimated to be the same as 2018, and the value for 2020 is estimated by assuming that the reported decrease in "pure" OH lines between 2019 and 2020 was the result of undergrounding.

TECO reported overhead and underground miles from 2006 to 2013, but did not report these in later years. However, starting in 2017 there are tables in their report appendices describing each circuit and reporting the number of miles overhead and underground. Using these spreadsheets, the overhead and underground miles over all circuits were summed to determine the aggregate overhead and underground miles. Using the difference between the 2013 and 2017 values, the values for 2014, 2015, and 2016 were estimated through linear interpolation. Additionally, the percentage of lines underground seemed much too high in 2006 and 2007; the total number of distribution miles was reported as ~13,000 in 2006 and 2007 but ~10,000 afterwards. This is likely an asset tracking mistake, and therefore the 2008 values are applied to 2006 and 2007.

FPUC did not report underground or overhead miles in 2006 or 2007, so it is assumed these values are same as in 2008. Undergrounding changes are very small over the years. In fact, from 2016 to 2019, they used a table labelled as the "2014" values. They either forgot to relabel the table, but there were indeed no changes in those years, or they failed to update the table until 2020, where there is a slight increase in undergrounding in both divisions. So, the jump from 2019 to 2020 might have been realized more gradually over five years instead of one.

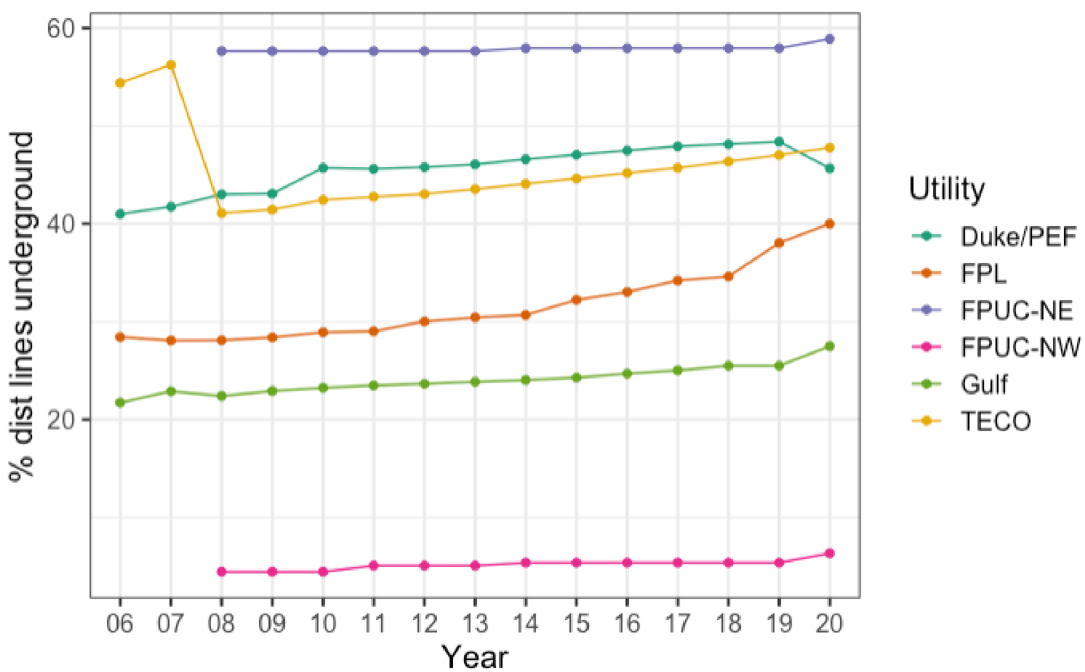

Figure 4.15. Changes in underground distribution lines from 2006-2020 by Utility.

FPUC-NE has the highest percent of underground lines at almost 60% which has remained relatively unchanged over the last 15 years, while FPUC-NW has the lowest percent of underground lines at around 5%. Other than FPL, which increased its underground lines from

28% to 40%, the utilities increased their undergrounding by less than 5% over 15 years. Additionally, Gulf has stated every year in its annual reliability reports—until 2018, when Next Era Energy (FPL) purchased it—that “the new construction growth of Gulf’s underground distribution facilities continues to outpace overhead construction due to customer demand based on aesthetics. However, continued analysis of the available overhead and underground data along with associated metrics does not support the use of underground construction as a storm hardening option at this time” (Gulf Power Company, 2018). Clearly, not all utilities thought it was a good idea to invest further in undergrounding.

d. Advanced Metering Infrastructure

EIA Form 861 collects data from utilities on various aspects of their systems, one being AMI. The number of AMI installed per year is divided by the number of customers to estimate the fraction of customers that had AMI installed. Utilities will often have more meters than customers: FPL and Gulf had years that reported more AMI installed than there were customers on the system. Given that we are interested in smart meters in the context of identifying locations with loss of service so as to speed restoration, when this started happening, ceiling of 100% of customers with AMI was applied.

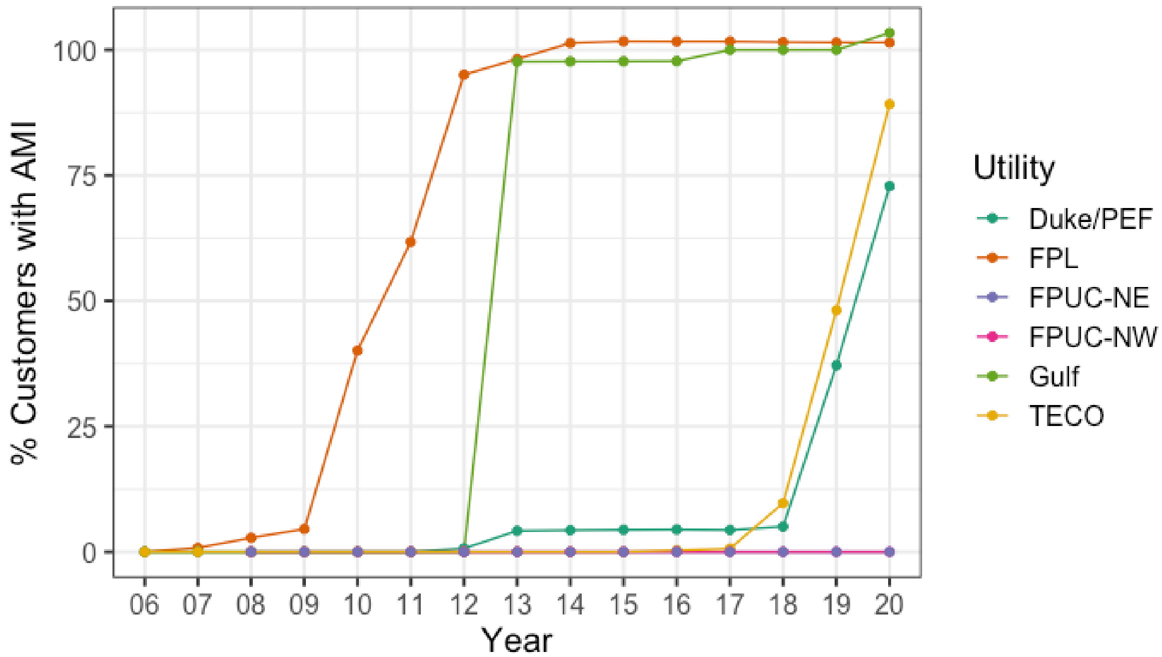

Figure 4.16. Percentage of customers with advanced metering infrastructure (AMI) per year from 2006 to 2020.

When a utility begins to adopt AMI, it usually takes it a few years to roll the systems out to all customers (or at least, to all customers that are willing to participate). This accounts for the large jumps in figure 4.16. FPUC did not install AMI during this time; Gulf and FPL installed AMI across their whole system by 2014; and Duke and TECO are still rolling AMI out but will likely finish by 2023.

The final model, which includes these four resilience strategies, is shown in equation 3.

$$\begin{aligned}\ln(CAIDI) = \quad & \beta_1 WindGust + \beta_2 StormSurge + \beta_3 StormDuration + \beta_4 Rainfall + \\ & \beta_5 ImpactedArea + \beta_5 RainDays + \beta_6 StormYear + \beta_7 Duke + \\ & \beta_8 FPL + \beta_9 \text{FPUC-NE} + \beta_{10} \text{FPUC-NW} + \beta_{11} Gulf + \beta_{12} TECO + \\ & \beta_{13} AMI + \beta_{14} Underground + \beta_{15} nonWood + \beta_{16} MilesTrimmed\end{aligned} \tag{3}$$

We test again the zero conditional mean of the errors with these newly added variables.

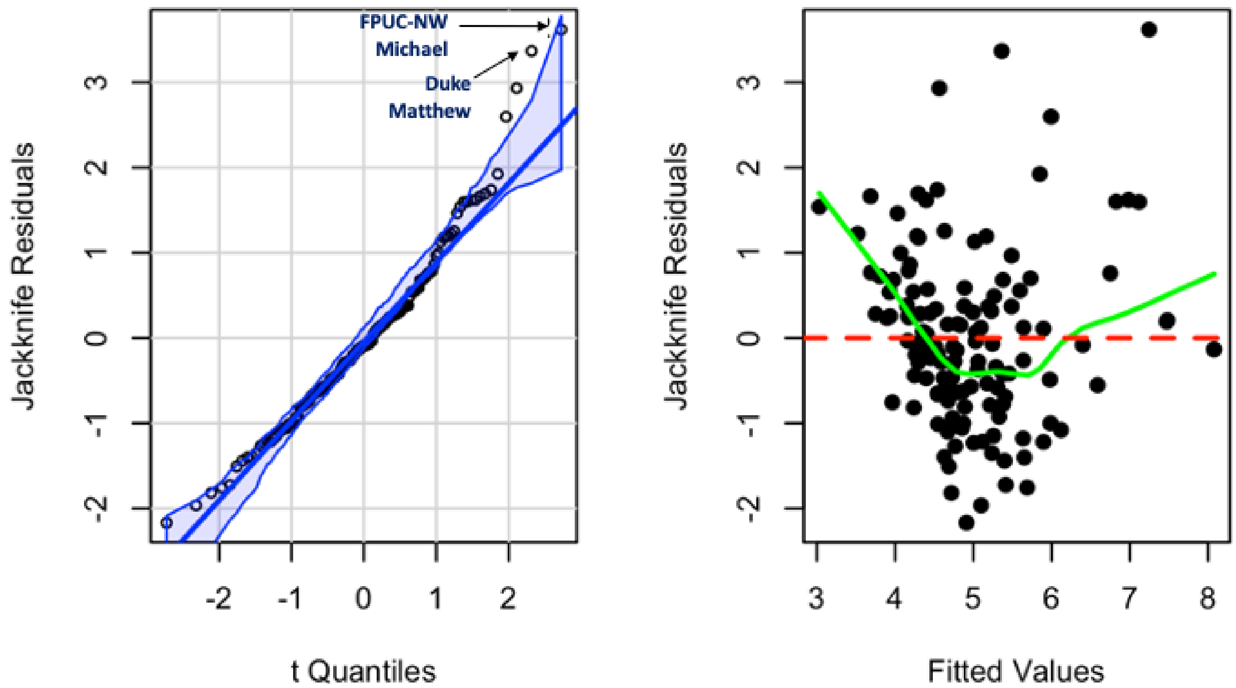

Figure 4.17 Left: Q-Q plot which compares the jackknife residuals to a normal distribution. The line has flattened even more by adding the resilience variables, but the wide tails persist. Right: fitted values vs jackknife residuals showing the distribution of residuals is fairly even above and below zero, but still very heteroskedastic. The red dotted line is plotted along the zero intercept, while the green line uses a smoothing function to visualize the variation in residuals.

This model seems to be the best model yet, but again we check whether there are variable transformations that could address some of the heteroskedasticity in the model.

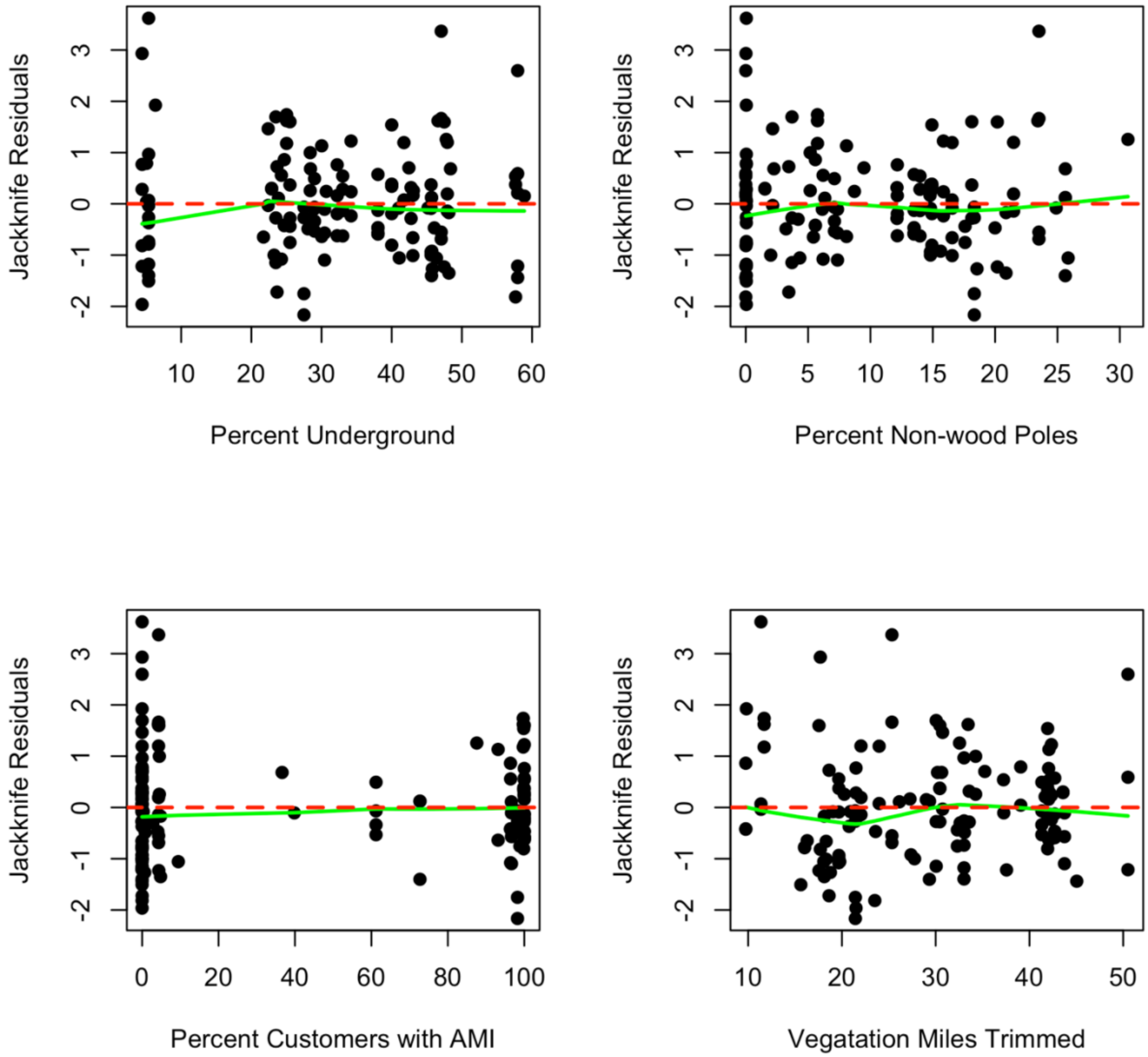

Figure 4.18 As with previous models, we see that the relationship with ln(CAIDI) is linear in all cases. The distribution is heteroskedastic in each resilience strategy. This is due to differences across utilities in terms of how much of each strategy is implemented. The red dotted lines are plotted along the zero intercept, while the green lines use a smoothing function to visualize the variation in residuals.

There are no obvious regressor transformations and we again address heteroskedasticity using robust standard errors to get correct estimates of the variance. This heteroskedasticity is due to differences across utilities in how much of each resilience strategy is implemented. Table 4.4 shows the regression results for this final model.

Table 4.4. The impact resilience strategies have on percentage changes in CAIDI. Robust standard errors are used to account for heavy tails in the residuals and heteroskedasticity. The dependent variable is the natural log of CAIDI.

	Coefficient	**Standard Error**	**P-value**
Max Wind Gust (mph)	0.030	0.004	0.000*
Storm surge (ft)	0.058	0.054	0.291
Storm Duration (hrs)	0.000	0.006	0.977
Total Rainfall (in)	0.009	0.014	0.520
Area Impacted (%)	0.009	0.003	0.003*
# of Days >0.1 in of rainfall	-0.021	0.007	0.003*
Storm Year	0.105	0.030	0.001*
Duke (Intercept)	6.069	0.474	0.000*
FPL	-1.201	0.482	0.014*
FPUC-NE	-0.211	0.498	0.673
FPUC-NW	-2.581	1.298	0.049*
Gulf	-1.490	0.664	0.027*
TECO	0.519	0.275	0.061*
% Customers with AMI	-0.004	0.002	0.139
% Distribution lines underground	-0.053	0.028	0.061*
% Distribution poles non-wood	-0.022	0.019	0.256
% Distribution miles trimmed	0.004	0.007	0.576
N	135		
Adjusted R^2	0.67		
*	P-Value < 0.10		

The R^2 has only slightly improved to 0.67, but this makes sense considering that the resilience variables are inherent to the utilities. Additionally, there is one fewer observation because FPUC-NE didn't start reporting resilience values until 2009, so Tropical Storm Barry in 2007 had no resilience values to be compared against.

Looking first at AMI, as the percentage of customers with AMI increases by 1%, the average CAIDI decreases by 0.4%. Thus, it appears that AMI may have a small positive impact, and considering the p-value, there is a 13.9% chance the effect observed is random. Additionally, AMI is likely only advantageous when a large percentage of customers have smart meters, because the closer to full system visibility the utility can achieve, the more effective smart meters are at restoring power.

Undergrounding has the largest impact on CAIDI of all resilience variables considered: an increase of 1% in undergrounding corresponds to a decrease of 5.3% in CAIDI and this result is statistically significant.

Apart from FPUC, all the utilities are increasing their percentage of non-wood poles which makes sense because they all have some policy of replacing failed wood poles with non-wood poles. As stated earlier, this variable is likely capturing not only the resilience of non-wood poles but simply replacing older or smaller poles with newer or potentially bigger ones. As the percentage of non-wood poles increases by 1%, the average CAIDI decreases by 2.2% with a 25.6% chance the effect is random.

Finally, it would appear vegetation miles trimmed annually is having little impact on CAIDI. While we know vegetation management is key to reducing outages, this variable only captures the miles trimmed in the year prior to the storm, so it is a one-year snapshot of potential resilience. Although trimming is required regularly, a one-year time scale is likely too small, especially considering the multi-year trimming cycle that the utilities employ. Further, vegetation miles trimmed only considers one aspect of vegetation management: although trimming or cutting back vegetation is the largest component of vegetation management, other strategies do exist. For example, in 2006, FPL started a "Right Tree, Right Place" educational program that encourages homeowners to plant certain types of vegetation away from lines to avoid outages. In 2016, Gulf began a pilot program where it purchased rights of way on private land for vegetation management. Gulf successfully purchased easements on 20 miles of line, giving it the right to clear and maintain a 15-foot-wide corridor on private property adjacent to the public right-of-way and Gulf's distribution facilities. By 2019, they purchased easements on 150 miles of line. This strategy has not been deployed yet at a scale large enough to register in these results. Finally, in large storms like those considered in this analysis, the larger problem stems from vegetation *outside* of the utilities' rights of ways. That vegetation gets torn out by high winds, travels far, and falls on or collides with power lines. The 2018 Florida PSC Review of Hurricane Preparedness specifically states that "additional trimming by the utilities within their rights of way would not eliminate these vegetation related outages."

It's important to note here that being able to interpret the natural log of CAIDI as a percent change in CAIDI only works when considering incremental changes (i.e., a 1% increase in x leads to some percent change in CAIDI)[37]. For example, going from 0% undergrounding to 100% underground does *not* lead to 500% decrease in CAIDI. To determine this large change from the model would require solving: ln(CAIDI) = 6.069 - 0.053*(100). In fact, Table 4.5 shows that the relationship breaks down quickly (5% increase) using the example of holding everything constant but increasing undergrounding.

Table 4.5. Showing the interpretation of the natural log as a percent change in CAIDI only works for incremental changes in the independent variables. For changes greater than 5%, equation 3 needs to be solved.

% Increase in Undergrounding	True predicted % change in CAIDI	Estimate predicted % change in CAIDI
1	-5.2	-5.3
2	-10.1	-10.6
3	-14.7	-15.9
4	-19.1	-21.2
5	-23.3	-26.5
6	-27.2	-31.8
7	-31.0	-37.1
8	-34.6	-42.4
9	-37.9	-47.7
10	-41.1	-53.0

It is important to examine what is happening with the dummy variables (utilities) in this model. The coefficients for each utility increased radically, implying 100-300% differences in CAIDI compared to the previous model. These dummy coefficients represent differences in percent CAIDI from the reference utility (in Table 4.4, the reference utility is Duke), assuming all other variables are held at their mean – that is, an “average” storm in an “average” year, with an “average” amount of resilience investments. Although the utilities all have similar variation in storms over the years, they do not have the same mix of resilience, as evident in Figures 4.13 to 4.16. Although we see similar trends in investments, they all begin from different places. This is accounted for in the regression model by adding the utility dummy, denoting that the intercept (mean CAIDI) is different for each utility, but the relationship between CAIDI and the individual resilience variables is the same regardless of utility. To visualize this, Figure 4.19 and 4.20 show

[37] This is because $\ln(x) \approx x-1$ when x is close to 1

the differences in relationship *just* between ln(CAIDI) and undergrounding across each utility (not accounting for storm severity).

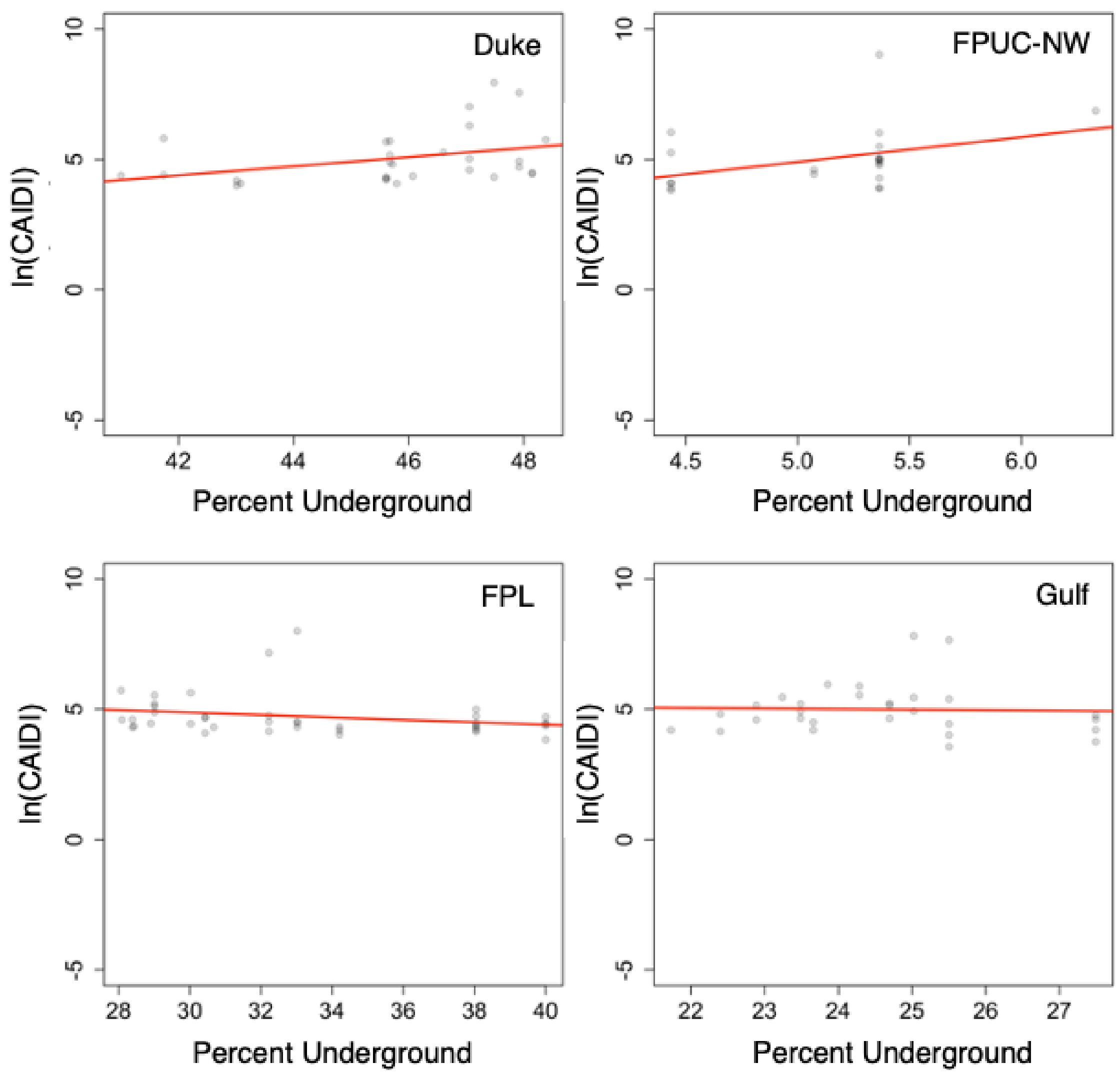

Figure 4.19. Illustrating the differences in slope relationship between undergrounding and CAIDI for the utilities with 20+ data points.

The relationship between CAIDI and undergrounding is roughly the same for FPL and Gulf. With so few observations, it is hard to obtain a clear picture, though the relationship appears to be relatively flat in all cases. This means that it is likely appropriate to think of undergrounding as having the same relationship with CAIDI regardless of utility. However, the x-axis values are very different, which means the intercepts will be very different. Figure 4.20 shows the same exact plots, but includes the y-intercept.

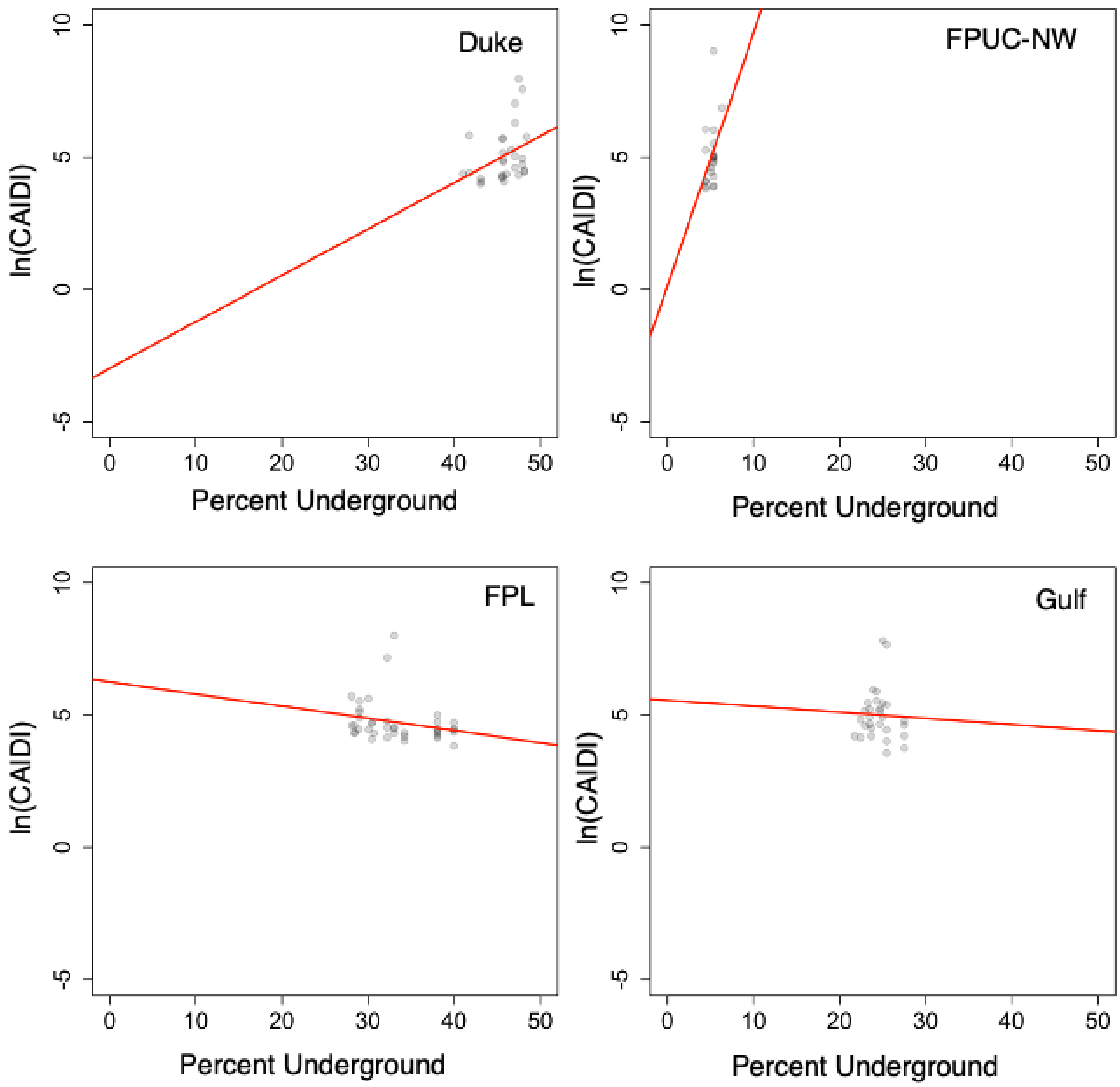

Figure 4.20. Illustrating the differences in intercept between undergrounding and CAIDI for the utilities with 20+ data points.

These models cross the y-intercept at very different points, which is why in the larger model (Table 4.4), we also see large intercept differences between utilities. In summary, because the utilities have a wide and often non-overlapping range of values for the four resilience variables, the dummy variables have to account for the fact that the model is predicting lower CAIDI values than is true for Duke and TECO, which tend to have higher values in all 4 resilience strategies, and predicting higher CAIDI values for FPUC-NW, which has almost none of these resilience strategies. Therefore, these dummy variables highlight not only "real" differences but also differences caused by model design. This means that the coefficients for the dummy variables in this model are meaningless, but they are included to account for such wide variation in investment.

We again look at Cook's Distance to see outliers in the model and to check for robustness.

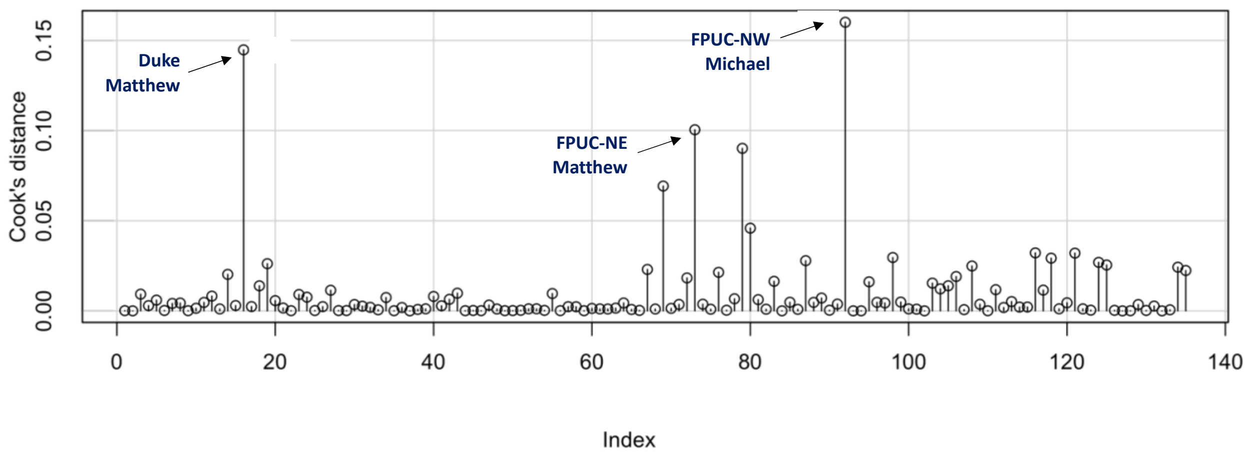

Figure 4.21. In considering the Cook's Distance, the same outliers are found as those seen throughout this analysis: Hurricane Michael's effect on FPUC-NW, Hurricane Matthew's effect on Duke, and Hurricane Matthew's effect on FPUC-NE.

The same outliers are still present, although the impact on mean squared error is more distributed than it was previously. Table 4.6 runs the same model as 4.4, but this time removes the outliers to check for model robustness.

Table 4.6. With outliers dropped, the model proves robust: the largest changes are in the p-values of AMI and non-wood poles. Robust standard errors are used to account for heavy tails in the residuals and heteroskedasticity. The dependent variable is the natural log of CAIDI.

		Original model	**FPUC-NW Michael dropped**	**Duke Matthew dropped**	**FPUC-NE Matthew dropped**
% Customers with AMI	Coefficient	-0.004	-0.002	-0.002	-0.003
	Std. Error	0.002	0.002	0.002	0.002
	P-value	0.139	0.314	0.289	0.148
% Distribution lines underground	Coefficient	-0.053	-0.048	-0.046	-0.054
	Std. Error	0.028	0.017	0.017	0.017
	P-value	0.061*	0.006*	0.007*	0.002*
% Distribution poles non-wood	Coefficient	-0.022	-0.028	-0.035	-0.024
	Std. Error	0.019	0.019	0.017	0.019

	P-value	0.256	0.143	0.050*	0.209
% Distribution miles trimmed	Coefficient	0.004	0.007	0.003	0.002
	Std. Error	0.007	0.007	0.007	0.007
	P-value	0.576	0.282	0.675	0.830
N	135				
Adjusted R^2	0.67				
P-Value < 0.10	*				

The coefficient estimates do not change much between models, but the p-values change substantially for the percentage of non-wood poles and percentage of customers with AMI. AMI and non-wood poles likely have some negative correlation with CAIDI, but because this is a small data set, the model has difficultly developing a confidence interval. We have established that undergrounding has a negative correlation with an increase in CAIDI after accounting for the severity of the storm. Finally, vegetation trimming seems to not have much impact on storm CAIDI, but this could be caused by several factors discussed earlier.

4.3.4 Cost Analysis

Having established the effect of various interventions on resilience in the face of TCs, We now seek to determine how much the IOUs have invested to acquire this level of resilience. Figure 4.22 shows the unit cost reported over time for various resilience investments across utilities. To adjust for inflation and bring all costs to January 2022 dollars, the Bureau of Labor Statistics' (BLS) Producer Price Index (PPI) for electric power distribution in the South Atlantic[38] is used. For the case of "transmission hardening," which involves changing wood structures to steel as well as changing ceramic insulators out for polymer-based ones, the BLS PPI for metal production is used.

[38] https://data.bls.gov/pdq/SurveyOutputServlet

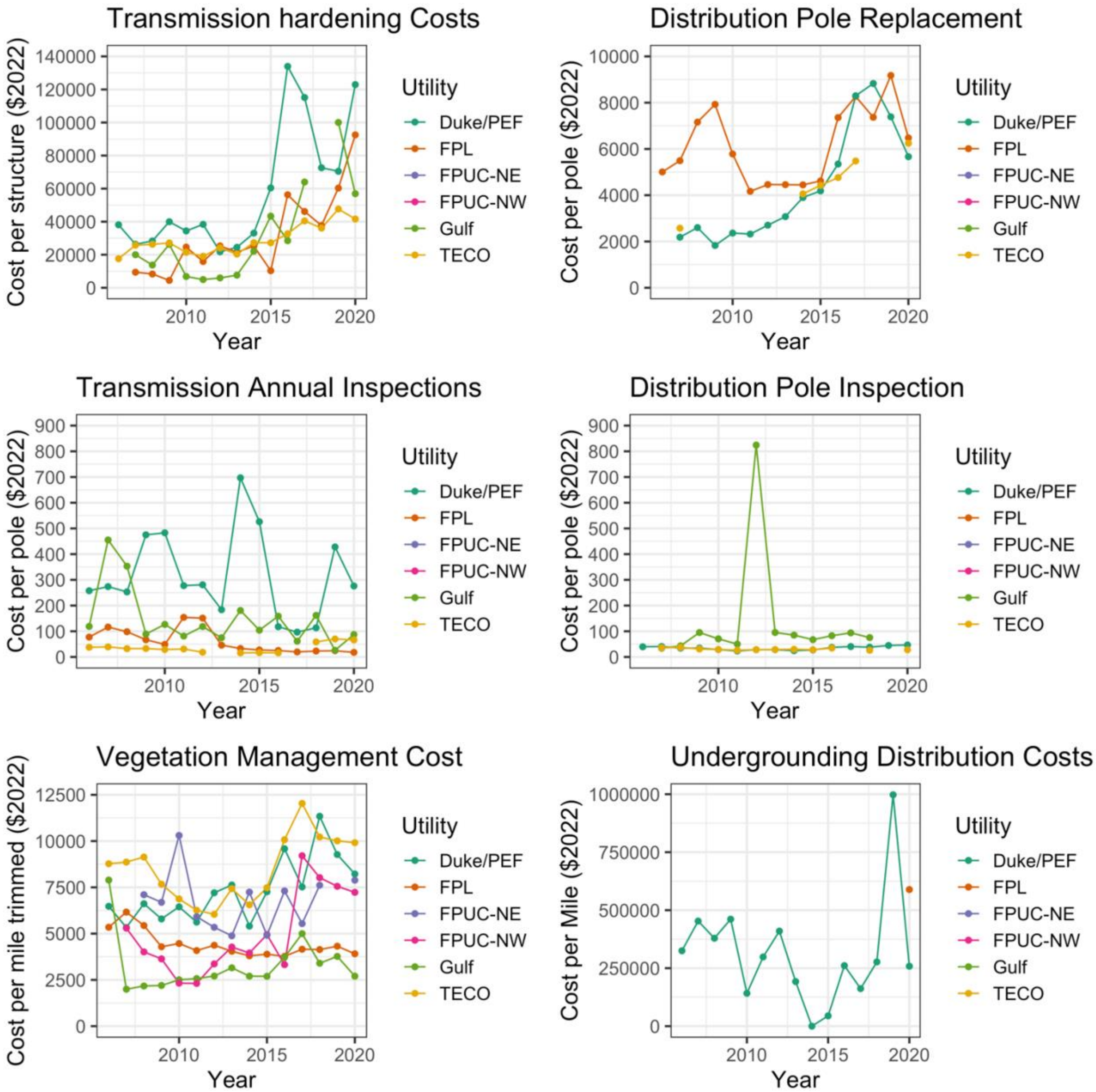

Figure 4.22. Unit cost of resilience strategies from 2006 to 2020. In most cases, the costs are increasing for each activity. Costs are adjusted for inflation to 2022 dollars.

Other than for pole inspections, the costs of all resilience strategies appear to be increasing. A traditional learning curve economic model suggests that the cost to do the "same" thing that utilities have been doing since 2006 should go down. There are several reasons this may not be happening. First, utilities could be changing some of these processes in non-trivial ways without describing the nature or effect of those changes in their annual reliability reports. For example, maybe the distribution poles being replaced since 2016 are of a higher class or different material than previously deployed, despite claims that they meet the same NESC B construction standards. Alternatively, the material cost of the poles could have increased. After interviewing several utilities (detailed further in Chapter 5), there may be supply chain issues for higher-class wood poles and non-wood poles. All utilities have been considering stronger poles and have been increasing their replacement rates for higher resilience and reliability, which can lead to higher competition for the same resources. Whilst skill sets for the relevant crews are different, labor costs do not seem to be increasing much when looking at the inspection cost per transmission and distribution pole (except for 2012, when Gulf inspected far fewer poles than usual because they were ahead of schedule but still reported an inspection cost as high as the year previous)[39]. This is also true for vegetation trimming in FPL and Gulf: another labor-intensive activity where costs seem to be relatively invariant over time. However, the vegetation costs per mile seem to be increasing for the other utilities. Perhaps more extensive vegetation management procedures were introduced at these utilities in recent years; these could have been included in the total vegetation cost but not described in the annual reliability report. This could include the use of pesticides, vegetation management software, satellite imagery and LiDAR, or purchasing wider rights of ways. Some of these cost increases could also be due to increases in overhead costs: many utilities now have designated staff positions for "resilience"; increasing visibility and control of a system could also lead to an increase in the number of staff required for its oversight.

Beyond the strategies discussed above, there are other ways to harden overhead distribution. For this reason, how much extra utilities were spending (normalized over number of customers) on top of already required storm hardening initiatives was also examined. There is a section in the annual reliability reports called "other distribution storm hardening", where utilities report their targeted hardening initiatives. From 2006 to 2020, FPL hardened approximately 47% of its feeders, with the primary goal being to apply "Extreme Wind Loading" (EWL) to critical feeders and then to other vulnerable feeders. EWL refers to an NESC guideline (figure 250-2(d)) which indicates the region-specific wind gust speeds that utilities should ensure their lines and poles can withstand. FPL activities included in the cost above are installing

[39] FPL reported a one large cost value for inspection, replacement and remediation of distribution poles. This number was divided by the number of poles that were replaced and remediated to get an estimate for annual replacement cost.

switches, creating tie lines, replacing poles (with poles of different class or material), reconductoring, and adding guy wires. Duke also invested in reconductoring, switchgear replacement, transformer retrofits, and some coastline storm surge pilot projects in the early years, but it specifically did not apply EWL because it didn't think it was a cost-effective strategy. Gulf began EWL projects from 2007 to 2012, which consisted of upgrading poles, adding guy wires and meeting NESC B grade standards, but decided against continuing such projects due to cost. However, after the devasting impacts to its territory of Hurricane Michael in 2018, it reconsidered (Gulf Power Company, 2019):

> As a result of its system performance during Hurricane Michael and the associated data obtained from forensic analysis, combined with the sharing of Florida Power and Light Company's experience with its own storm hardening initiatives, Gulf is proposing to increase its future storm hardening efforts.

From 2013 to 2017, despite stating that it was not applying EWL, Gulf was still "upgrading all new construction, major projects, and maintenance work, including any work performed on critical infrastructure facilities, to bring them to Grade B construction standards." Nonetheless, it was spending virtually the same amount of money as in previous years (Figure 4.16). Gulf performed other distribution hardening activities as well, such as converting 4kV lines to 12kV lines, as well as flood and storm surge mitigation, which included "storm guying"[40], placing equipment as high as possible, using stainless steel equipment, and ensuring main feeders were far from the coast. TECO hardened vulnerable feeders by also upgrading poles and adding guying, they replaced and repaired network protectors, converted 4kV lines to 12kV lines, and began a capacitor bank inspection program. FPUC-NW hardened its system by relocating two feeders and hardening three more (details unclear). FPUC-NE did no additional hardening.

[40] Storm type down guys are additional down guys and anchors, positioned perpendicular to the path of conductors. These storm type down guys are not normally needed for support of the structure but provide support in the event of high winds. They are installed in pairs with as much anchor lead as possible and have the same requirements as any other down guy as far as insulating and grounding. (Gulf Power Company, 2013)

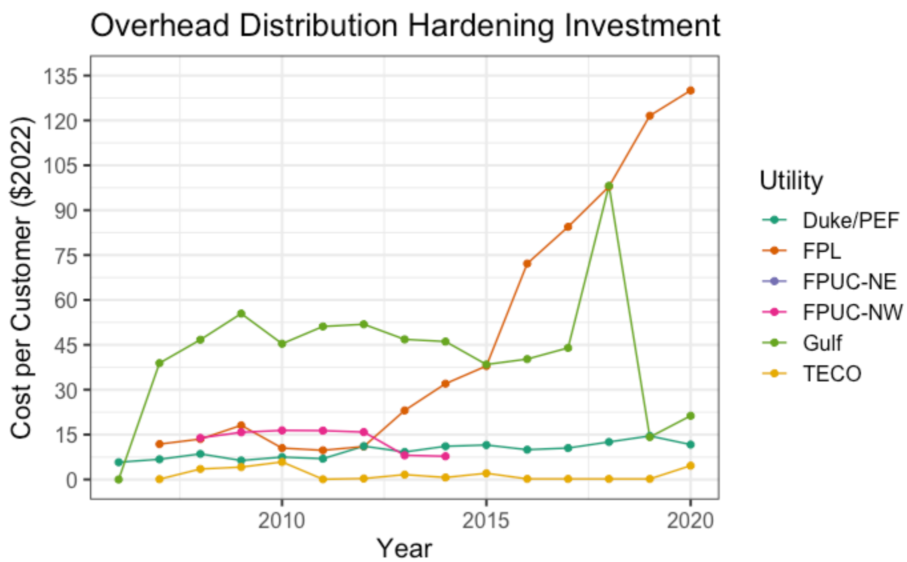

Figure 4.23. The average cost per customer for the additional distribution hardening initiatives the utilities self-selected to invest in. Costs are adjusted for inflation to 2022 dollars.

As shown in Figure 4.23, FPL has been dramatically increasing their resilience spending and Gulf has consistently been spending about twice as much per customer as the other three utilities. Some of this may be why FPL is performing, on average, better than the other utilities against excludable storm events. These values don't even include distribution automation. FPL only provides annual distribution automation budget estimates—not actual costs—in its annual reliability reports, but in 2021 they budgeted $130 million for this activity. The company already owns 80,000 automated feeder switches (Intellirupters) and fuse protectors (TripSavers) from S&C to improve the reliability of its system (S&C Electric Company, 2020). Duke in 2020 began its self-optimizing grid initiative and has invested $14 million in its inaugural year. Gulf has been spending roughly $5 million annually on distribution automation between 2010 and 2018.

Additionally, the differences in average CAIDI could reflect differences in implementation of some of the more qualitative resilience strategies. For example, FPL's system for emergency planning or its relationship with its local government could be better than the other utilities'. It's hard to determine precisely why FPL is outperforming other utilities with this data set, but it is likely some of its additional investments are playing a role, especially since FPL does not have the highest levels of undergrounding or non-wood poles.

4.3.5 Summary of Results

Table 4.7 shows how much it costs to achieve the percent change in CAIDI for the resilience investments explored. AMI is not included in Table 4.7, because no cost data are available for this strategy.

Table 4.7. Translating the results of third regression model to physical changes and cost required to achieve the respective reductions in CAIDI. (M = million, K = thousand)

2020 Values	1% increase in activity	Total cost for a 1% increase	Cost per customer for a 1% increase	% change in CAIDI
Undergrounding	Duke: 339 miles FPL: 688 miles	Duke: $88 M FPL: $405 M	Duke: $46 FPL: $79	-5.3%
Non-wood pole replacement	Duke:11,034 poles FPL: 12,343 poles TECO: 4,110 poles	Duke: $63 M FPL: $80 M TECO: $26 M	Duke: $33 FPL: $16 TECO: $32	-2.2%
Vegetation Trimming	Duke: 181 miles FPL: 125 miles FPUC-NE: 1 mile FPUC-NW: 6 miles Gulf: 59 miles TECO: 63 miles	Duke: $1488K FPL: $488K FPUC-NE: $8K FPUC-NW: $43K Gulf: $159K TECO: $624K	Duke: $0.78 FPL: $0.09 FPUC-NE: $0.46 FPUC-NW: $3.54 Gulf: $0.35 TECO: $0.77	0%

The resilience investments made by the Florida IOUs do appear to be improving the outcome of excludable tropical storm events, but the cost is significant. In 2020 alone, the average cost for storm hardening for each FPL customer was about $201, each Duke customer $93, each Gulf customer $77, each TECO customer $38, and each FPUC customer $25. In just one year (2021), the costs increased to $219 per FPL customer, $180 per Duke customer, $200 per Gulf customer, $140 per TECO customer, and $79 per FPUC customer for the year[41]. This equates to between a 2% and 8% increase in their annual electric bills, given that the average bill in Florida is $2,673 (EnergySage, 2022). TECO has estimated an additional 1% increase in customer bills annually until 2023 to cover these costs.

[41] These costs all consider the same type of investments except Duke is the only utility that still includes Distribution Pole replacement in its Storm Hardening cost instead of in the rate base as apart of O&M costs.

Without any data before 2006, it's impossible to determine from this data set how bad these storms would have been without these investments, so a direct benefit-cost analysis cannot be conducted. However, FPL did its own analysis and in its 2017 report writes:

> over an analytical study period of 30 years, the net present value of restoration cost savings per mile of hardened feeder would be approximately 45% to 70% of the cost to harden that mile of feeder for future major storm frequencies in the range of once every three to five years. It is possible that FPL could face major storms more frequently than that, as it did in the 2004-2005 hurricane seasons. If that were the case, then the net present value of restoration cost savings likely would exceed the hardening costs. It is also important to recognize that in addition to restoration cost savings, customers benefit substantially, in many direct and indirect ways, from the reduced number and duration of storm and non-storm related outages resulting from the planned hardening activities.

While it is unknown what assumptions were made in these calculations, this suggests that the costs to invest in resilience could potentially be equivalent to avoided damage costs considering the increase in storms we've seen in the last 5 years. However, this analysis only considers the costs of the hardened overhead feeders, which does not speak to benefit-cost comparison of undergrounding lines or other transmission spending for example.

FPL also argued that the "hardened feeders are providing significant day-to-day reliability benefits, as hardened feeders have performed approximately 40% better than non-hardened feeders" (Florida Power and Light, 2019a). FPL's average adjusted CAIDI from 2017 to 2021 is 9% better than its average adjusted CAIDI from 2006 to 2010. This could be partially due to these investments. Gulf improved dramatically in this period, decreasing its average adjusted CAIDI by 33%. This is where we could be seeing the benefit of their additional spending (Figure 4.23) that was not apparent in the storm CAIDI (Figures 4.10 and 4.12). Gulf also had the poorest CAIDI values of the 5 utilities in 2006 to 2010, so it was much easier to improve from that level as compared to FPL, a utility that was already highly reliable 15 years ago. TECO, which invested a lot less in storm hardening, also improved its CAIDI by 6%. There could be other reliability upgrades they are doing that were just not reported, or these CAIDI decreases could be related to features inherent to their service territory. We cannot know for sure, because adjusted CAIDI includes a wide range of outage causes. FPUC's average adjusted CAIDI has increased 4% – unsurprising considering climate change impacts and their lack of resilience investments. Finally, Duke's average adjusted CAIDI in the periods 2006-2010 compared to 2017-2021 increased by 27.5%. This could be due to outage management tracking changes introduced when Duke acquired the utility in 2013. This remains a large difference though, and could be partially explained by climate change or other weaknesses in its system.

Ultimately, it is up to Floridians to decide if these investments have been worthwhile. While the present analysis provides some of the evidence they need to make that decision, key information remains unavailable. There is evidence suggesting that these investments have been able to reduce storm CAIDI in the last 15 years. However, to continue performing at current levels of reliability, these utilities will have to spend more on the same activities and even more on others to continue to address the impacts of climate change and the uncertainty they induce.

4.4 Discussion

4.4.1 Data Discrepancies

It is perhaps not surprising that there were twenty occasions in which the various weather databases did not match – either not registering that an event happened or significant differences in the reported values of rain and windspeed. The worst example was a case in which the storm events database stated that the Alachua FAWN rain gauge measured 2.6 inches of rain in one hour for a particular event, but data downloaded from that rain gauge reported a maximum of 1.07 inches of rain in one hour at the time of the storm. Appendix F includes a description of every storm, the data used to create the database, and reports on conflicting data. Chapter 4 will highlight how two of the utilities interviewed specifically stated that they wanted better weather prediction as a resilience strategy and were starting to deploy their own sensing equipment because they had been getting such bad predictions from other weather sources.

This analysis also assumed the data in the Florida IOU annual reliability reports is correct. These reports are required by law to be submitted to the Florida PSC: lawyers approve them and there are dedicated staff within each utility producing them. In fact, in 2015, the PSC conducted an audit that stated the data being provided in the annual reliability reports is accurate (Florida Public Service Commission, 2015). In view of this, it is troubling that there are often mistakes, discrepancies, and confusing inputs. Mistakes in early years are understandable due to limitations in system visibility and asset tracking, but there are often confusing values in the 2020 report as well. Several of these have been noted previously, but of particular concern are the cost values. For instance, in 2012, Gulf inspected 1,709 poles at a cost of $1,415,988, when every other year it was costing around $2 million to inspect 20,000 poles. From 2006 to 2013, FPL reported the wood transmission structures converted to steel in both the "Transmission Hardening" and "Transmission Inspection" sections of their reliability report, because essentially the structures that failed inspections were the ones replaced with steel. It was clear they were doing this because the number of poles and cost were the same in both sections. Then, from 2014 to 2020, they reported the same number of transmission poles replaced in both sections, but at vastly different costs ($41.1 million in one section and $28.9 million in the other), which if taken at face value suggests that it costs different amounts to do the same thing. In 2020, we see the same discrepancy, but all the storm preparedness costs are added together, including "Structures/Other Equipment Inspections – Transmission Program" and "Wood Structures Hardening (replacing) – Transmission Program", which makes it seem like replacing transmission wood poles was double-counted in 2020. Email correspondence with FPL occurred in June 2021 to ask them about this discrepancy, but we were told that the information was proprietary. In TECO's 2020 Storm Protection Plan Annual Status Report, the final table that sums all hardening projects for the year (pg 63) states that transmission hardening cost $4.95 million, distribution lateral undergrounding cost $7.18 million, and distribution overhead feeder hardening cost $3.8 million. Earlier in the document, it stated that transmission hardening cost $240,002; distribution laterals cost $78,744; and distribution overhead feeder hardening cost $67,747. In the case of distribution laterals, the reporter may had forgotten to multiply by 100, but the overhead distribution and transmission hardening costs are inexplicably different. FPUC and TECO often report budget information in their 3-year storm hardening plans, but then rarely report the actual value for each item, even though they budget for each. Reporting the actual costs in the annual reliability reports had not been required until 2020 (Rule 25-0631 Storm Protection Plan Cost Recovery Clause); the previous rule only required estimated costs and a description of what was going to be implemented and why (Rule 25-6.030 Storm Protection Plan).

Because of the new ruling in 2020, the template the PSC now asks utilities to complete annually is much improved; hopefully, new and better data will result. However, the form still focuses on collecting data on processes more than outcomes. For example, the PSC collects data annually on inspections, inspection failure rates, and the numbers of poles that were remediated or replaced. These values alone don't say much about the system unless one knows something about the vintage or material distribution of all poles on the system. Similarly, knowing that EWL is happening is less helpful than knowing what percentage of the system has been designed to meet NESC B standards. Knowing the number of undergrounding or distribution automation "projects" is not helpful, if the number of miles/feet and number of devices are not reported. Such information could help the PSC compare utilities and determine progress within an individual utility, as opposed to just checking boxes to report whether something has or has not been done.

4.4.2 Rethinking excludable events

Although 136 storm events were included in this analysis, many of them probably should not be considered excludable events. A utility will either claim a tropical storm as an excludable outage event even when the impact was minimal (<35mph and <3 inches of rain), or they may attribute a different weather event to a tropical storm that happened to occur at the same time but in a different part of Florida. Sometimes these events are also extreme weather events that could warrant exclusion, but the reporting is never explicit or consistent to justify these decisions.

A troubling example involves FPUC-NW, in which Hurricane Dorian (2019) was claimed as an excludable event. Figure 4.24 shows the track of Dorian (left) and the rainfall due to Dorian (right). The red circle shows where FPUC-NW's service territory lies, which is approximately 250 miles from the eastern coast of Florida. Not only does the storm stay off the eastern coast of Florida, but the rainfall doesn't make it to Marianna, FL. The weatherspark and FAWN Marianna rain gauges confirm no rain during this time, and the Marianna Municipal Airport registered a maximum wind gust of 24.2mph. Yet, FPUC-NW still had 1090 Customer Interruptions (48 CAIDI minutes, 0.09 SAIFI, and 4.3 SAIDI minutes).

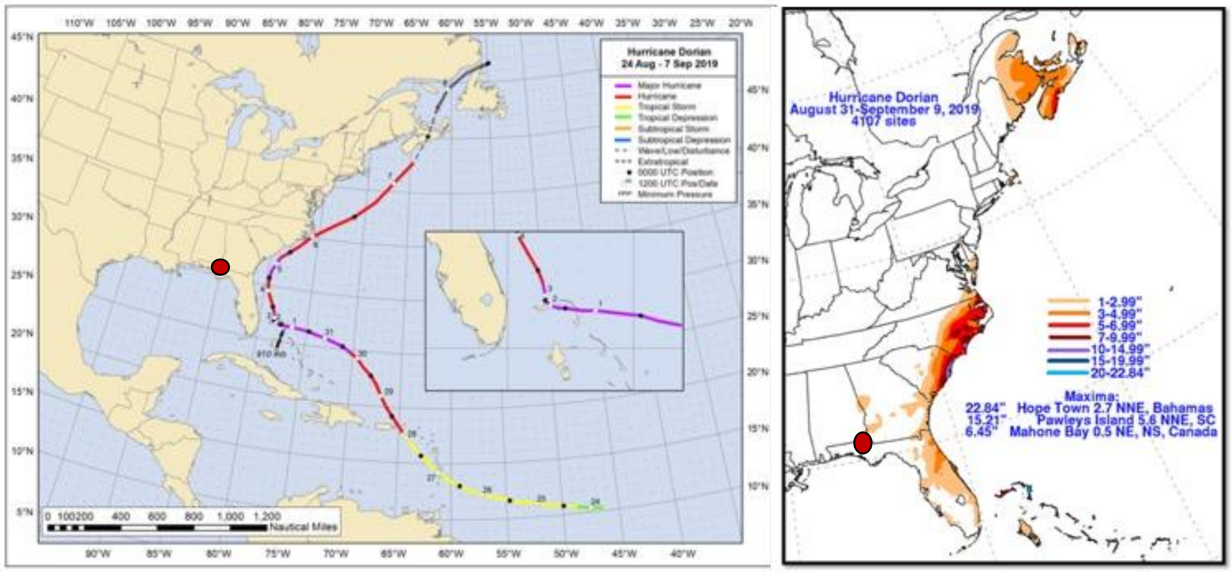

Figure 4.24. Left: the path of Hurricane Dorian (2019). Right: rainfall due to this TC. The red circle shows FPUC-NW's service territory. Both figures are from the National Hurricane Center's report on Hurricane Dorian (Figure 1 and Figure 10).

Another troubling example involves FPL and Tropical Storm Erika, which died near the Dominican Republic on August 28, as shown in Figure 4.25. Instead, from August 29 to August 31, FPL experienced "an upper level low over the lower MS River Valley continued a moist and divergent upper level southerly flow over the local area. Combined with daytime heating, scattered strong storms and heavy rainfall impacted the area." (NOAA Storm Events Database). This was not due to TS Erika, which did have remnants that affected Miami on September 2 but did not cause outages: the outages in FPL's reliability report stop on August 31. While this event produced ~50mph gusts and could perhaps be considered an excludable outage event, it was not caused by TS Erika. Additionally, in 2014 FPL reports a number of outages from May 14 to 15, and listed the cause as "Tropical Storm"-related, but there were no tropical storms anywhere in the Atlantic on those dates. Instead, there was a storm that caused heavy rainfall of 4 to 6 in. in 24 hours and peak wind gusts of 72 mph. Perhaps this should be classified as an excludable event, but that was not explicitly done, and instead was buried in hundreds of pages of outage reports. The PSC has no record of this event occurring and FPL makes no mention of it in the text of its reliability report. It was only found by reviewing the row-by-row reporting of outage events in the appendix.

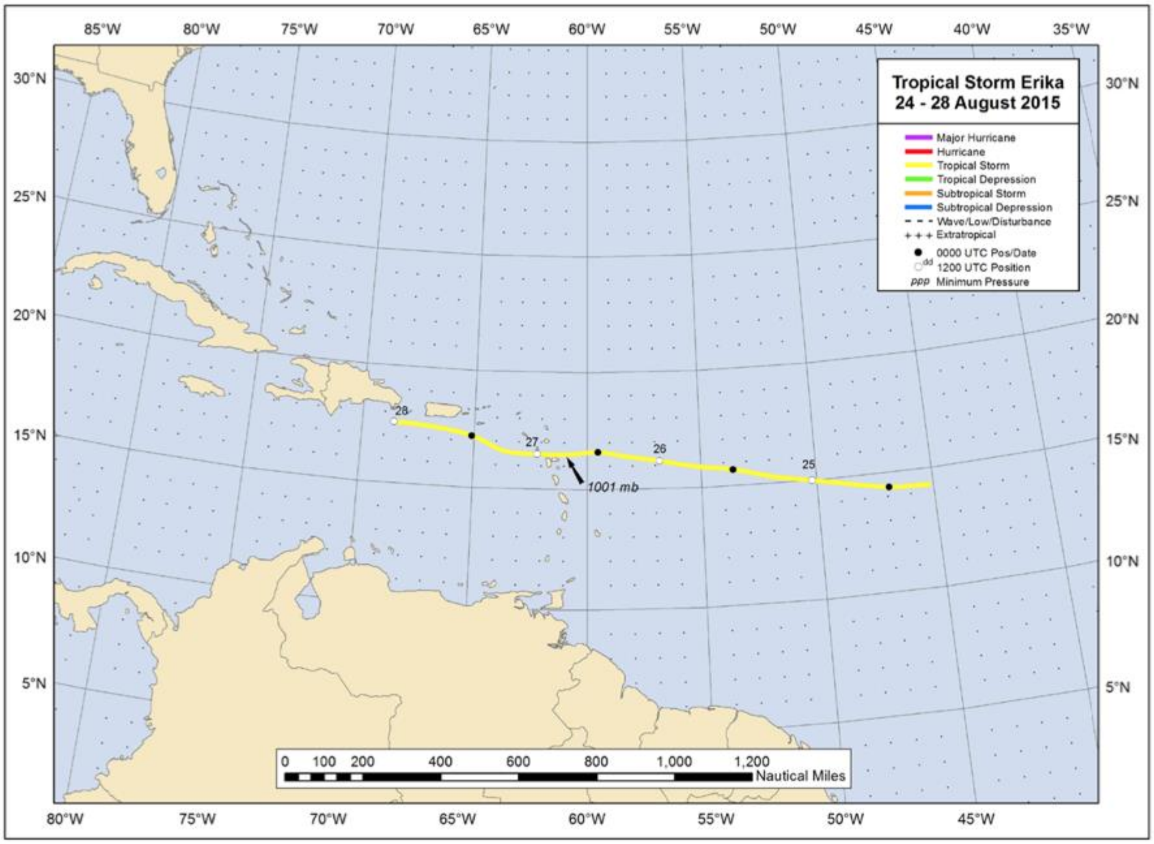

Figure 4.25: Figure 1 from Tropical Storm Erika Report (2015) published by the National Hurricane Center.

Table 4.8 Storms that arguably shouldn't be considered excludable events.

Utility	Mild Storms (<35mph gusts)	Mis-aligned storms
FPL	TS Mindy (2021)	Unnamed Tropical Storm (2014); TS Erika (2015); TS Nate (2017); TS Bertha (2020); TS Claudette (2021); TS Fred (2021)
Duke	Ts Julia (2016); TS Bonnie (2010); Hurricane Sandy (2012)	TS Gordon (2018)
Gulf	TS Karen (2013)	
FPUC-NW	TS Isaac(2012); Hurricane Dorian (2019); TS Cindy (2017); TS Alberto(2018); Hurricane Hermine (2016); TS Debbie (2012); TS Claudette (2009); Hurricane Ida (2009).	Hurricane Harvey (2017); TS Gordon (2018)

The Florida PSC should be more explicit about what constitutes an excludable event. Perhaps the severity of the storm must reach a certain level, or the number of customers who lose power and/or the duration of the event needs to exceed a certain threshold. This problem is not unique to Florida. It occurs across the US. There is no standard for defining excludable events[42]. Several approaches exist, including the Florida PSC's which was described earlier. The IEEE's standard is "a Major Event Day is any day that exceeds a daily SAIDI threshold called Tmed. Tmed is a duration statistic calculated from daily SAIDI values from the past five years." Still other utilities, for example in Texas and Louisiana, define a major event day as one in which 10% or more of all customers are without power for 24 hours or more (Warren, 2006). Pennsylvania defines a major event day as one in which 10% of customers are without power for 5 minutes or more (Pennsylvania Public Utility Commission, 2022). It is important to create and use a common definition for excludable events because whether reliability standards are met could be drastically different depending on what definition of excludable event is used. Additionally, defining excludable events (Major Event Days) also begs the question of what level of reliability we should be expecting of our utilities going forward. If extreme weather events are going to become more common, we would hope that utilities could perform better when they occur. However, if we want to be able to understand what is going on during these extreme events, we first need to determine a common definition or, at a minimum, a common cause.

4.4.3 A utility is only as resilient as the community it serves.

At the time of writing, Hurricane Ian, a Category 4 hurricane, devasted a large portion of the state of Florida. Although it is too early to know specifics, Florida is restoring power faster than Louisiana (Karlin, 2022) and, many Floridians have been able to get their powered restored within two weeks (Taylor, 2022). Fort Myers was one of the hardest hit areas, with 140+ mph winds and 15+ feet of storm surge. Fort Myers is served by FPL, and images and videos of the aftermath show a surprising number of utility poles that remained standing after the storm. While impressive, many of the homes and businesses they served, as well as the roads they line, were destroyed, as shown in Figure 4.26. Whether those poles remained intact or not clearly had little

[42] EIA collects reliability data from utilities annually in the EIA-861 form and specifically states that "Major Events are self-determined by the reporting utility." https://www.eia.gov/electricity/annual/html/epa_11_01.html

impact on these buildings' recovering access to power. In this case, the extra money customers had been paying for added hurricane resilience turned out not to be very beneficial, because though the poles were still there, the homes they serve were not and the problem of customers without power remained.

Figure 4.26. Left: Destruction from Hurricane Ian in Fort Myers, Florida with a surprising number of poles still standing. Photo by *Hilary Swift of The New York Times.* Right: Many homes in Fort Myers were destroyed. Photo by *Wilfredo Lee of Associated Press.* Photos accessed from: (Boston.com, 2022)

Of course, where and when the worst of a hurricane hits is unknown, and FPL can only harden based on highest-risk areas on their system, regardless of the "resilience" of the community itself. However, if climate adaptation is going to cost a lot of money regardless, we should be more deliberate about how we're designing our communities and how we spend money to achieve maximum benefit.

4.5 Conclusion

Increases in the frequency and severity of extreme events, exacerbated by climate change, are forcing utilities to adapt and work to make their systems more resilient. Even with this limited data, the resilience strategies implemented by the Florida IOUs seem to be improving performance against tropical storms. Undergrounding distribution lines and newer and non-wood poles have a greater impact on reducing tropical cyclone CAIDI than tree trimming or AMI. However, many of these resilience investments are very expensive, and I found no clear explanation as to why their costs are increasing. While the recent uptick in storms could indicate a more positive cost/benefit ratio, historical data suggest the avoided storm costs are not as high as the cost to invest in these resilience initiatives, making the costs higher than the benefit. To expand upon this analysis would require much better information from utilities that focuses data collection on outcomes instead of processes and employs a standardized metric for considering excludable events. For example, asking utilities to provide annual statistics on all poles that identify the distribution of vintage, material, guying, etc. provides more detail on resilience than annual inspection data. Additionally, getting more information on number and type of smart grid devices, as well as gathering data on restoration activities (number/types of emergency crews, contracts, inventory etc.) could help provide insights on other types of resilience investments. Utilities don't exist in a vacuum, and ultimately the conversation about increasing resilience should consider the broader resilience of the communities they serve.

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Chapter 5: Using Expert Judgement to Steer Future Investments in Power System Resilience

5.1 Introduction

Even after gathering insights from Florida on resilience, there is still very limited evidence regarding the effectiveness of specific strategies designed to enhance the resilience of the power system. In this chapter, the technical data accumulated in the previous chapters are supplemented with the expert judgement of utility engineers on an effort to further characterize the efficacy of resilience strategies. Utility engineers and operators have intimate knowledge of their respective systems, knowing both the problems and potential solutions. Moreover, they are in the best position to assess the impact of the broader energy transition—the penetration of electrified cars and homes, or the introduction of distributed energy resources—on the resilience of their power systems. Extracting this information in a systematic allows us to summarize the benefits, risks, and costs of implementing resilience strategies, including their effect on past and future LLD-outages.

As seen in Chapter 2, almost all studies on resilience efficacy look at one specific strategy (usually hardening) and one type of outage event. There is little to no research that considers resilience systems as a whole and tries to compare across different clusters of strategies – prevention, mitigation, and restoration – or across multiple outage scenarios. The Department of Energy's National Labs have created some resilience modelling tools that consider fuel supply and back-up generation as well as grid hardening strategies, but they all focus on a specific location and on one type of outage threat[43]. Similarly, Quanta Technology (2009) conducted a cost-benefit analysis of prevention, mitigation and restoration strategies but specifically against Hurricanes in Texas; that study is now more than a decade old. In Chapter 4, we saw that the Florida Investor-owned utilities were investing in a wide range of resilience options, but could only analyze the effectiveness of four strategies because many of the other strategies are difficult

[43] Pacific Northwest National Laboratory created the "Electrical Grid Resilience Assessment System" for Puerto Rico https://egrass.pnnl.gov. Lawrence Berkeley National Laboratory and Argonne National Laboratory partnered with CMU and Northern Arizona University to create an Alpha version of the "Framework for Overcoming Natural Threats to Islanded Energy Resilience", which employs two case studies: Guam Power Authority and Alaska Power and Telephone.

to quantify (i.e., increased coordination with local governments). This chapter seeks to fill the gap in the resilience efficacy literature by interviewing multiple utilities that experience a wide range of outage threats and asking them to directly compare *all* resilience strategies based on their effectiveness and cost, and against *all* potential outages in the next 15 years.

When the future technology landscape is uncertain with many interrelated complex elements, conducting semi-structured interviews with experts is an excellent way to distill best practices and policy recommendations as Abdulla, Hanna, Schell, Babacan, & Victor (2021) did with carbon capture sequestration and Ford, Abdulla, Morgan, & Victor (2017) did with nuclear fission. Additionally, Bruine De Bruin, Fischhoff, Brilliant, & Caruso (2006) elicited mitigation strategies from experts on a complex social-technical system: a global pandemic. Leveraging these previous studies, a semi-structured interview protocol was developed to extract information about the efficacy and cost of resilience from utility engineers themselves.

5.2 Method

5.2.1 Participants

From April 2022 to November 2022, respondents were recruited via email to participate in a study that asked utility representatives to detail current resilience investments being made by their utility as well as their judgement regarding the effectiveness of these strategies and, if they had the resources, where they would like to invest in the future. An email was sent to the National Rural Electric Cooperative Association's (NRECA) engineering research mailing list, from which 5 rural electric cooperatives (coops) were recruited, despite this mailing list reaching 2,000 coops. The rest of the utilities interviewed were approached directly as contacts were given by participants and other industry connections. A total of 16 utilities participated in the study: eight rural electric cooperatives (coops), one municipally run electric utility (muni), and seven investor-owned utilities (IOU). The participant utilities represent a reasonable sample of the climate regions in the United States, as shown in Figure 5.1. Additionally, all 16 participants held senior positions that consisted of general managers, vice presidents, C-suite employees, and head resilience or distribution system managers. Everyone had been in the industry at least 10 years, even if they had not been at their specific utility for that long. Thirteen participants had been employed by their utility for a decade or longer. Carnegie Mellon University's Institutional Review Board approved the interview protocol, under which interviewees as well as the utility they represent were to remain anonymous.

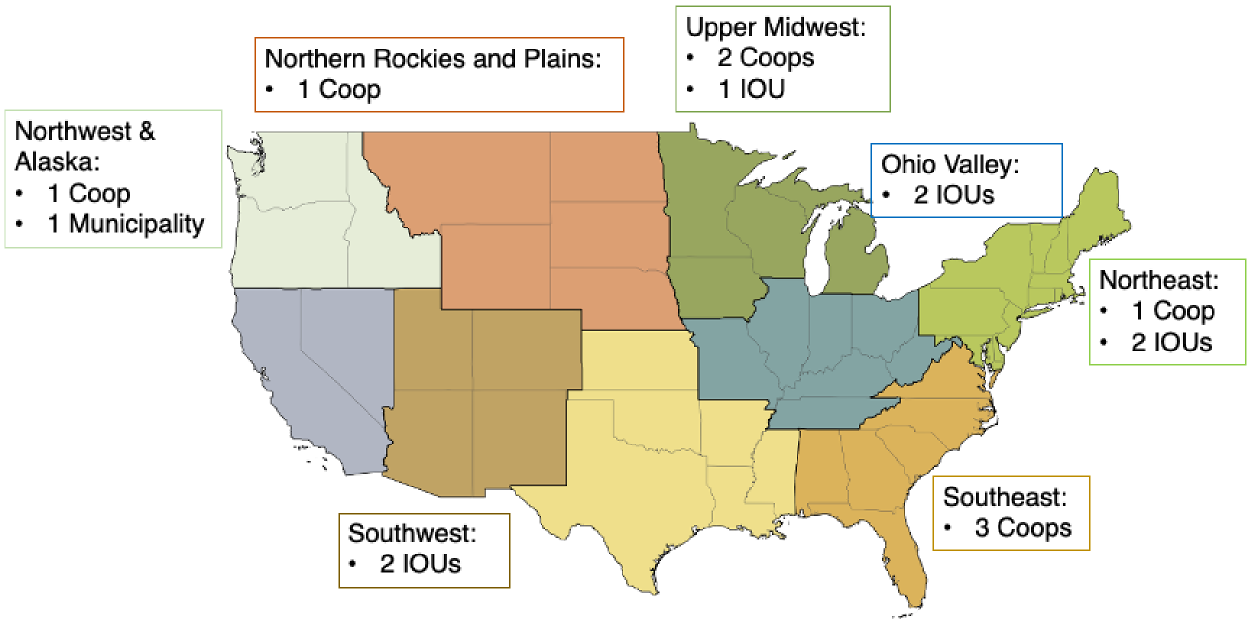

Figure 5.1. Using NOAA's nine climatically consistent regions shown on their map, this figure identifies which parts of the country the utilities represented serve. (National Centers for Environmental Information, n.d.)

Having representation from a wide range of climate areas is important, because large power outages are typically caused by climate-specific weather events (e.g., hurricanes or ice storms). Therefore, it is important to see whether resilience approaches are regionally specific. Additionally, resilience investments are expensive, and having representation from both profit-motivated and non-profit electric utilities is important for assessing resilience priorities.

5.2.2 Procedure

Respondents were first sent a series of "pre-interview questions" to inform them of the type of information we would be looking for during the interview and to ensure the person being interviewed was the most knowledgeable about each utility's distribution resilience. The pre-interview questions showed a table of potential resilience strategies, and they were asked to describe how that strategy was implemented on their system and how much they were spending on it, as shown in Table 5.1. This list also ensured that participants considered a common but wide range of strategies to be “resilience,” which was key for them to answer later interview questions about the most beneficial resilience strategies. The list of resilience strategies was derived from the resilience literature review done in Chapter 2, with an option for participants to add to the list as needed. If respondents were anchored by the resilience strategies presented in Table 5.1, then the resilience issue arising from deliberate attacks (physical or cyber) may be undervalued in this analysis. Most of the time, interviewees did not have time to answer the “pre-interview questions” before the scheduled interview, but the two-hour interview duration allowed ample time to account for this. The first third of the interview was spent asking them to detail the resilience investments their utilities had been making.

The two-hour interviews were conducted via Zoom. Participants could see the questions being asked and how their responses were being documented using the shared screen feature in Zoom. Additionally, each session was recorded in case clarification was needed when reviewing notes.

Table 5.1. Pre-Interview table sent to utilities to get a sense of current resilience investments.

Resilience strategy (please highlight or bold the ones you’ve adopted on your system)	How much of this strategy have you implemented? You can report this as an absolute number, per mile, per year, or per circuit.	How much have you spent on this strategy? You can report this $ per unit or $ per year.
Convert wood poles to steel, concrete, ductile iron, or fiber reinforced polymer.		
Change the height, class, or distance between poles.		
Increase the frequency with which you inspect and replace poles.		
Reduce the load on poles from pole-mounted equipment or third-party attachments.		
Changes to wires: e.g., heavier T-2/ACSR, quick disconnect, guy wires, vibration dampers, etc.		
Increase the frequency or change methods of vegetation management.		

Move some or all distribution circuits underground.		
Implement high-end distribution automation to automatically reconfigure existing circuits.		
Increase system visibility and the ability to rapidly reconfigure all existing distribution circuits.		
Implement distributed storage and generation throughout the distribution system.		
Maintain a higher level of pre-staged equipment.		
Relocate or reinforce vulnerable substations.		
Implement smart meters or other demand side management techniques.		
Build more redundancy into the system.		
Change or improve any operating systems, e.g., outage management, inventory management, or workforce management systems.		
Change emergency planning or coordination with other government and critical infrastructure organizations.		
Change workforce, e.g. different or more training/drills, availability of emergency crews, add/change positions, etc.		
Other:____________________		

5.2.3 Questions

This section describes the questions asked during the interview in order of appearance. The full list interview protocol, as presented to participants, is available in Appendix G.

System overview. Respondents were asked to provide basic information about their system and the position they hold in the utility. Answers received to these questions allow for comparison across utilities by normalizing results and determining biases based on position within the utility.

1. What is the title of the position you hold at your utility?

2. How long you have been employed at this utility?

3. In 2021, what was your total revenue?

4. In 2021, how many total customers were on your system?

Outage threats. Next, participants were asked to consider what events pose the greatest risk to their system over the next 15 years, in their judgment. Respondents were shown a list of possible outage threats and asked to first consider if any events could cause an outage affecting more than 10% of customers and lasting 24 hours or more in the next 15 years. Then interviewees were asked to rank these events in descending order, in terms of the risk they posed over the next 15 years.

Respondents were then asked to report on the largest outage event on their system in the past 15 years. They were asked to provide the cause of the outage, the peak number of customers without power and how long it took to restore power for all customers. Using this outage event as an anchor, participants were asked, "Assuming that there were no budget constraints, what three strategies could have been implemented on your system prior to the event that you believe would have most reduced the number of customers who lost service, or improved the speed with which you could have restored service after that event? Please describe how these upgrades would be implemented on your system to provide the most benefit?" Once strategies were determined, the respondents were asked to estimate the overnight capital cost of the strategies they identified, were they to be implemented today.

This exercise was done a second time, in which interviewees were asked to think of another outage threat, using the list complied earlier as a reference, that would require a *different* set of resilience strategies to address and then pick up to three new resilience strategies and estimate the overnight capital cost of the additional strategies.

Resilience weighting. After considering the worst outages their utility would likely face in the next 15 years, the participants identified up to six resilience strategies they would want to implement. They were next asked to rank and weight these strategies based on how well respondents thought each strategy would mitigate the consequences of <u>all</u> future outages. The ranking was used to help the respondents order the resilience strategies from most to least beneficial before asking them to assign a weight. The weights were on a scale of 0 to 100, where the resilience strategy determined to be the most impactful was given a rank of 1 and a weight of 100. Naturally, all 5 other resilience strategies had to be given weights less than 100, matching the order in which they were ranked. This method of weighting is known as direct rating in the decision sciences and it is the most reliable form of weighting because it the least cognitively taxing for the interviewee (Riabacke, Danielson, & Ekenberg, 2012).

Resilience through the Energy Transition. The final set of questions asked participants to consider what concerns they have, broadly speaking, regarding the management of the electric power grid as it transitions to a more electrified, automated, and decarbonized system. The question immediately following asked them to identify “What additional technologies, policies, or resources that are currently outside your control do you need to address any of the concerns you listed (list up to 5)?” The final question asked utility representatives to take these responses and indicate the feasibility and efficacy of these interventions on the graph shown in Figure 5.2. This plot allows for comparison of the solutions provided.

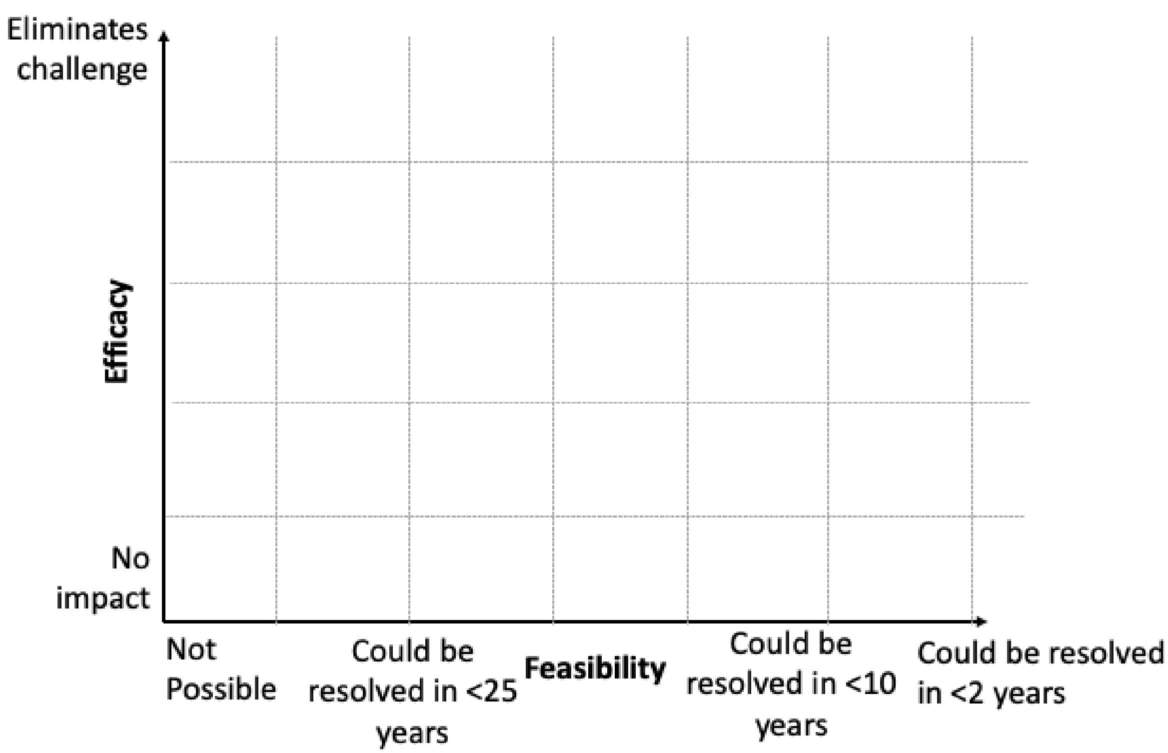

Figure 5.2. Plot that utilities were asked to fill in based on how feasible (x-axis) a solution they proposed was vs how effective (y-axis) it would be.

5.3 Results

In section 5.3.1, the various resilience strategies adopted by each utility is reviewed in detail. Readers who are primarily interested in the summary results may wish to skim these details and then skip to section 5.3.2

5.3.1 Current Resilience Investments

One of the major gaps in the resilience literature is an understanding of where utilities are currently in their resilience investments, how similar their approaches are, and how much they are paying for these investments. The following sections describe these current resilience investments and their costs, identifying commonalities across utilities as well as when they disagree. The section is divided into the resilience sub-categories listed in Table 5.1.

1) Convert to non-wood poles.

Two utilities are converting wood to steel distribution poles at a cost of $11,000/pole - one is doing this for wildfire protection and is working to convert a majority of their poles. The other has converted fewer than 1% of its poles to steel for wind protection and to increase their service life, but is only doing this in hard-to-access areas. One utility is adding fire mesh around wood poles in wildfire-prone areas. A separate utility is adding a composite fiberglass pole as every 5th pole on sub-transmission (69kV) lines, at a cost of $18,000 per pole. It was determined that it was too expensive to replace all poles with composite fiberglass, so every 5th pole is replaced to stop cascading pole breakage. According to two utilities, a wood pole costs roughly $5,000-$10,000 to replace. One utility is converting cross arms from wood to fiberglass for which they said the additional cost is negligible. All other utilities said they were not changing pole material on the distribution system, because it is not worth the cost and often logistically hard to do. However, many of the utilities with transmission lines did say they were converting wood transmission poles to steel.

2) Change the height, class, or distance between poles.

Only three utilities said there were no upgrades in this space. Seven have increased the class of their poles (wider and taller), seven have increased the height of poles, three have standardized on a shorter span between poles (no more than 250ft), and three did a combination of these pole upgrades to meet extreme wind loading criteria on targeted poles as defined in the National Electric Safety Code B construction standards. Typically, class changes are from 5 to 3, especially on single-phase lines, and these pole upgrades only cost $50 per pole. However, one utility is converting class 3 to class 1 on three-phase, another is using class 1 as a "stopper" amongst class 3 poles (a strong pole to stop cascading pole breakage), another has chosen to go exclusively with class 2, and yet another is converting from class 1 to h1 in high wind areas[44]. These higher class changes can cost $200-400 per pole. Height increases are typically to 40 or 45 feet, though one utility is adopting increases to 65-70ft poles across its distribution system. One participant mentioned that because everyone is switching to a higher-class wood pole, there are going to be supply problems in the next decade. According to this interviewee, higher pole classes require trees to grow for longer and become larger. Thus, if the class 4 and 5 poles become obsolete, everyone is going to have to wait for these trees to grow.

3) Increase the frequency with which poles are inspected and replaced.

Most utilities are on a 10-to-12-year inspection cycle for poles, and this includes sound and boring and partial excavation. They have been on these cycles for more than a decade. The improvements that have been made include one utility moving to a 5-year cycle; one utility doing more than the cycle calls for annually to more quickly upgrade failing poles; one utility doing annual visual inspections on top of regular inspections; two utilities using drones for inspection; one utility using Resistograph technology for wood density analysis; and one utility using an age-based inspection program instead of inspecting every pole in each cycle.

[44] Classes of poles are defined based on the circumference of the pole and its load-bearing capability (not height, which can vary within the same class. H5 is the strongest pole type decreasing to H1, then the numbering starts over and reverses where class 1 pole is stronger than a class 5. More information on classification can be found (Altork, 2017)

4) Reduce the load on poles from pole-mounted equipment or third-party attachments.

Utilities are generally not reducing the load on poles from attachments and instead are doing pole capacity upgrades. They can't reduce pole load because of increased broadband and fiber optic-demands on their poles. A few utilities have put the onus of loading requirements on third parties seeking to attach equipment to their poles. This involves setting standards that third parties are required to meet before attachment, but no one stated that they were doing a systematic review of current attachments.

5) Changes to conductors

The utilities interviewed had already coalesced on aluminum conductor steel reinforced (ACSR) conductors, but a few are working to upgrade to heavier wire sizes (i.e., to 1/0 or 4/0 from #6 or #8), which two utilities estimated to cost $5,000-$10,000 per mile, while another estimated $125,000 per mile for reconductoring. Replacing legacy lines is needed in general for aging infrastructure within a utility. Three utilities are also installing covered conductors, aka "tree wire", which is estimated to cost $150,000-250,000 per mile to reconductor. One utility is using spacer cables which help reduce tree-related outages. Another utility specifically stated it chose not to invest in these technologies because they increase restoration time: the extra vegetation protection takes longer to put back up and therefore doesn't provide much benefit.

6) Increase the frequency or change methods of vegetation management.

Vegetation management is a huge area of concern for utilities, and all interviewed utilities have increased vegetation management in some way over the past 5 years. Utilities typically have a tree trimming cycle under which they will trim every line on their distribution system once every set number of years. The cycles among this group of utilities are anywhere from 3 to 12 years, with most utilities trimming on a 5-to-7-year cycle. Most utilities have either increased annual trimming—decreasing the trimming cycle by 1 to 2 years—or increased their annual targeted or danger tree trimming. They have been increasing their spending on trimming from $500,000 to $4,000,000 annually, and spending between $1,000/mile and $5,000/mile annually on trimming. Three utilities have started using herbicides, with one estimating an annual cost of $250,000. Two utilities have just implemented AiDash, a vegetation management system that uses satellite imagery and analytics to target trimming, with one implementation costing $150,000/year. Two utilities use satellite imagery with in-house analytics, at a cost of $50,000/year.

7) Move some or all distribution circuits underground

Utilities have widely different approaches to undergrounding power lines. The current percentage of distribution lines underground ranges from less than 10% to 100% amongst interviewed utilities. About one third of the utilities (5) think it is not worthwhile and thus only underground when required. Two of these participants stated that underground lines have a lifetime that is half that of overhead lines (35 vs. 70 years); one participant said the time to repair underground lines is much longer than what is required for overhead lines. Several utilities noted that the cost of undergrounding could be anywhere from 2 to 5 times as much as overhead lines and agreed that single-phase radial new underground construction typically cost $150,000/mile to 200,000/mile, while three-phase cost $300,000/mile to $350,000/mile. Three utilities that served large urban areas said new installations cost just under $1 million/mile, while downtown networked undergrounding could cost up to several million dollars per mile. Several utilities noted that converting overhead lines to underground typically cost more than new installations—according to one interviewee, twice as much. Three utilities acknowledged that older underground lines on their system were starting to fail and have been difficult to repair: one said it costs $500,000/mile to repair these lines, being more expensive than new construction because the system has to remain online. To avoid this issue, two utilities from the same state said they were placing the "cable in conduit" underground going forward (i.e., directional boring: placing wires in flexible/strong conduit, and then using a drill to place the lines directly underground, without requiring traditional major construction for trenching), because once the conduit is in place, through which new lines can be pulled, it will last as long and cost virtually the same as overhead lines. Another participant pointed out that even in the case of traditional undergrounding there can be many instances, particularly on single phase radial lines, that the lifetime cost is still cheaper for undergrounding because of the avoided vegetation-related damage. Five utilities place all new construction underground and nine utilities have been slowly converting underperforming overhead lines to underground annually.

8) Increasing system control and automation

All participating utilities have a baseline supervisory control and data acquisition (SCADA) system installed, although coops seem to have installed them more recently and were actively upgrading SCADA systems: one spent $5 million over 10 years installing SCADA and now spends $35,000 annually upgrading it. Another utility estimates $700,000 over 6 years for full installation. Yet another is spending $100,000 annually on upgrades. Two utilities specifically mentioned installing more sensors and fault indicators, which can cost $200 to $500 per device—one of these utilities was using both S&C Intellirupters, which notify of a fault without overloading the system, and S&C Trip Savers, which save a fuse by having it disconnect without blowing, saving time and money in restoration. It was estimated that Trip Savers cost approximately $2,500 per device, with an additional $2,500 in labor costs to install. A large part of system control involves being able to transfer loads between feeders using switches at tie lines. The switches themselves typically cost $50,000 to $60,000 per device, while two utilities indicated that fully automated switches, which require configuration, cost in total between $150,000 and $250,000 per device. Two utilities have more or less fully implemented feeder switching, though it is manual switching that is done remotely—the system notifies them of a fault and an operator decides whether to open or close the switch. Three utilities have between 10% and 25% of the system able to automatically transfer loads; six have implemented this at a pilot testing level; and five don't do this at all (though three of those are hoping to start pilot testing in the next few years).

9) Implement distributed storage and generation throughout the distribution system.

As described in Chapter 3, one distribution system resilience strategy is having distributed generation on the system that can island during an outage. Seven utilities have one microgrid that serves a small community and is usually a pilot test for resilience. These microgrids do island during bulk power outage and typically cost between $2 and $6 million to construct. One of these utilities is currently considering a new rate design for “resilience as a service” where they would help run and maintain these microgrid communities, but customers that benefit would pay more for this added resilience. Five utilities have grid-level batteries, usually installed at a substation, that are used for peak shaving; these cannot currently island and typically cost between $300 and $2000/kWh. Three utilities have been able to encourage customers to get their own backup power (e.g., generators or batteries) through incentive programs (e.g., rebates or subsidies), and one of those utilities controls those batteries, both for peak shaving and outages. The customers of this utility only pay one third of the normal cost of the battery ($5000 to $6000). One utility has some distributed generation, but it is for decarbonization purposes: specifically, this comprises more than 20 MW of solar at a cost of $2,000/kW. Three utilities own no distributed energy resources (DERs). Many utilities aren't allowed to own generation, so some of these programs can't happen or must involve a third-party.

10) Maintain a higher level of pre-staged equipment.

Nine utilities mentioned supply chain issues with long lead times for equipment: delivery time for transformers used to be 6 to 8 weeks, but now is taking 1 to 1.5 years. Because of the long lead times, utilities are increasing their inventory to ensure they have what they need going forward, which exacerbates the issue. Additionally, one utility said there has been a 31% increase in material costs post-pandemic, so they are also having to spend more money to get the same material. About two thirds of utilities have a “storm stock” that they believe can cover 2-to-3-day-long outages. One utility has a mobile generator that can be placed at a substation and two utilities have mobile substations with an estimated capital cost of $3.5 million to serve a 2.5MW load.

11) Relocate or reinforce vulnerable substations.

Six utilities mentioned flood proofing substations; only two of those six have been using flood mitigation strategies: raised equipment, flood sensors, dutch doors, sump pumps, etc. One utility spent between $50,000 and $150,000 per substation, while the other spent between

$500,000 and $1,000,000 per substation. The other four utilities are instead relocating the substations to higher ground to avoid future flooding problems, which also had a wide range of costs depending on how far the substation must be moved and its MVA rating: small substations cost $500,000 to $1,000,000, while larger substations cost $3 to $6 million to relocate. Two utilities are wind and ice-proofing substations, one by placing them underground (which costs an addition $750,000 per substation) and one by replacing lattice box structures with tubular structures (it is spending roughly $1 million a year). One utility is seismic hardening their substations, which costs between $250,000 and $500,000, while one has EMP proofed a substation as a part of an EPRI project which cost $200,000 for that substation. Two utilities are particularly concerned with physical attacks on substations and spend $3 to $8 million per substation to counter this threat. One utility has been working on the ability to bypass a substation if it's not functional and has spent $400,000 on one substation for this feature.

12) Advanced Metering Infrastructure (AMI)

All 16 utilities have installed AMI or are in the process of doing it across all customers. They spend between $100 and $400 per meter installed; three coops have been installing meters that communicate via radio, which tends to be more expensive. Seven utilities have other demand side management programs, with five specifically using thermostat control programs. One utility has installed load control devices that cost roughly $300 per device. Three utilities noted energy efficiency programs, and while other utilities may also have similar programs, these utilities felt it was necessary to discuss for resilience, because it has had an impact on avoiding outages. Two utilities specifically mentioned that AMI has had a positive impact on the utility's ability to restore power and monitor outages.

13) Build more redundancy into the system

Being able to effectively transfer load requires circuits that are tied to other circuits connected to the same substation. This is hard to do in rural areas with single phase radial lines. Ten utilities already have looped circuits and plan to increase their numbers. Three utilities are starting to investigate whether they can create tie lines. An additional utility is planning to take this one step further by adding more substations, so feeders can have multiple substation sources. It costs over $100 million to install each substation. Utilities said that the cost to “create the tie line” which would include the switch itself (automated or motor-operated) is between $50,000 and 60,000. One utility said the cost to add one mile of backup conductor plus the switching devices costs their utility between $500,00 and $1,000,000; another said they spent roughly $180,000 per mile; a third said that it cost $100,000 per tie. One utility said they were upgrading single-phase lines into three-phase and spending roughly $200,000 annually on this strategy. Finally, one utility mentioned having a redundant source of generation connecting through one of their main substations, while another utility mentioned they are in the early stages of looking into creating redundant substations by doubling the functionality within targeted substations (i.e., installing two transformers where one is needed).

14) Change or improve operating systems

Seven utilities have recently replaced their outage management systems. They now use GIS to give them better visibility on outages, allow for better tracking of repairs and communication with customers. Four utilities are planning to do an overhaul on the outage management systems in the next few years because another system needed to be overhauled first. Two utilities purchased advanced distribution management systems, which integrate the real-time data coming from smart meters with SCADA and outage management system activities to have full system visibility. Two utilities overhauled workforce management systems and one updated their asset management. Oracle seems to be a favorite vendor and was mentioned by four different utilities. Some utilities gave cost values in terms of annual cost for maintenance and upgrades of systems, which costs between $50,000 and $250,000 annually or roughly $1 to $5 per customer annually. Other utilities reported total implementation cost which was spread over 3 to 5 years and cost between $10 and $40 per customer. One utility’s overhaul of its workforce management system ended up taking 10 years with many cost overruns: ultimately, it cost them “100s of millions of dollars”, which translates to 100s of dollars per customer.

15) Changes in emergency planning

Over the last decade, all utilities updated their emergency planning processes and participants seem to be happy with their current systems. Fifteen out of 16 utilities have dedicated personnel with pre-defined roles during emergencies (i.e., an incident command structure). Two utilities have emergency option contracts with vendors and four utilities emphasized the importance of mutual assistance, especially now that supply chains are strained. One utility is implementing a radio system for interoperability between multiple utilities during an emergency. One person said that making these changes has been the single biggest improvement in reliability in the last decade.

16) Changes in Workforce

Eight utilities brought up workforce shortage issues, particularly with line-workers. One utility doesn’t allow line-workers to return to work once they have left to work for a contractor: this is an effort at retention (contract line workers make roughly $10/hour more than employee line-workers). Another utility is training in-house staff to be line-workers. One utility said bringing tree crews and line-workers in-house saved a significant amount of money (roughly $1.2 million). Coops seem to have fewer staffing issues than IOUs. Five utilities employ contractors for emergencies - most use contractors but one utility gives retirees the option to be called upon during emergencies, while another uses specific language in its contract with union workers stating that they can be called to work in an emergency a certain number of times per year. Emergency crews can cost roughly $1 million to bring on for a specific large event. Six utilities have increased their emergency exercises in the last decade. Two utilities mentioned cyber security training, one of which has been spending $300,000 annually on it as well as new software and tools. Another utility mentioned spending roughly $10,000 per year per employee on training across the board. Two utilities invested in new training facilities that will also serve as storm management centers.

17) Other

Two utilities mentioned volt-var optimization to be able to reduce voltage serving customers if they stay within a certain frequency, which can reduce how much power each customer needs. Two utilities mentioned utility-owned weather sensors for outage prediction: these cost roughly $5,000 per sensor. Two utilities mentioned upgrading their two-way radio system for protected communication during outages: one spent $200,000 on this and the other spent $760,000. Three utilities mentioned better outage prediction modelling in general, considering the condition of assets as well as potential outage threats. One utility mentioned hardening operation center buildings against high winds and flooding, as well as ensuring backup power is onsite for multiple communication sites. This utility spent roughly $13 million on construction of new storm hardened facilities and $194,000 on seven generators added to communications sites. Another utility mentioned more community engagement activities and a few others also attempted recruitment outreach activities. Two utilities in the Northeast mentioned relocating lines to bring them across roadways for better access: this costs roughly $233,000 per mile.

In summary, the utilities interviewed have already implemented a wide variety of resilience strategies and are actively planning their next investments. However, participant utilities could on average be more resilient than the average US utility, because they self-selected to participate in the study and are concerned about grid resilience. Additionally, utilities had conflicting views on the benefits of non-wood pole material, undergrounding and tree covered conductors. Conversely, utilities agreed on the importance of tie lines for automated load transfers, higher class poles, system visibility and control in general, and emergency preparedness. Utilities have reached a level of emergency planning with which respondents are generally satisfied and it has made a big difference in the past decade. There are supply chain and workforce problems, which do not have any easy solutions and might not be resolved in the near-term.

5.3.2 Outage threats

Before examining the efficacy and costs of future resilience strategies, it is important to understand what outage threats utilities are concerned with going forward. To provide context to these future outage threats, Figure 5.3 shows the worst outage that these utilities have experienced in the last 15 years.

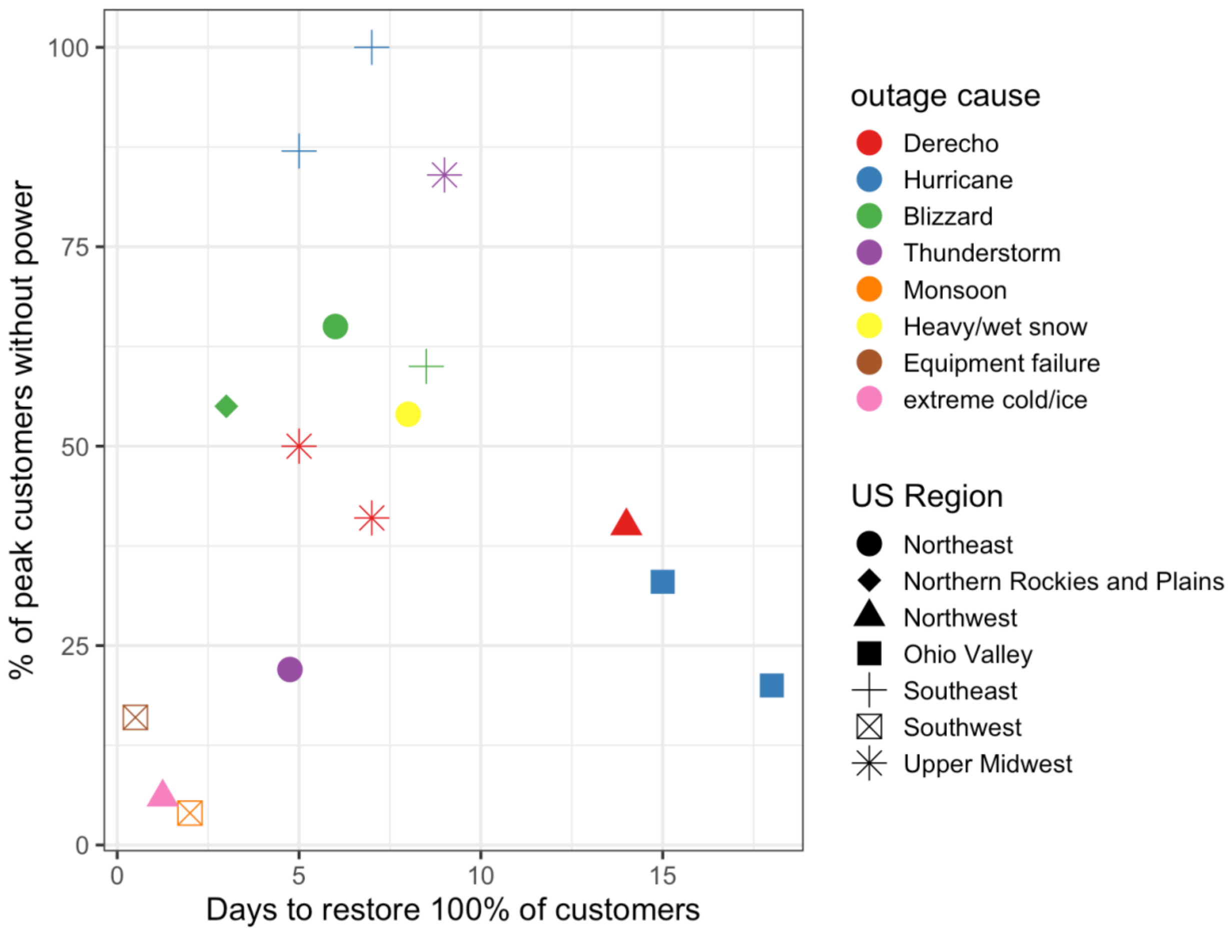

Figure 5.3. The worst outage each utility experienced in the last 15 years, categorized by outage cause and the region of each utility. The x-axis is the number of days it took to restore power to 100% of customers, and the y-axis is the peak percentage of customers who lost power during this event. High wind events and snow/ice events dominated the list of worst outages.

All but one outage cause could be sorted into one of two categories: high wind events and winter storms. High wind events were the largest category of worst outages reported (hurricanes, thunderstorms, monsoons, and derechos), and although these events can also have a lot of rainfall and cause flooding, all participants said it was the high windspeeds that were really damaging. Two utilities did have difficulty accessing lines to repair them because of flooding, but the flooding was isolated to a small portion of their system. Another respondent pointed out that their distribution system is relatively unaffected by flooding, though it can hurt generation. The next most impactful category was winter storms, where high winds caused outages, ice and freezing temperatures damaged lines and snapped tree branches, which downed lines. Additionally, heavy snow without ice can still cause trees to collapse under the weight of the snow, downing power lines. Freezing temperatures as well as snow and ice can block access to repair lines: one utility had a manhole cover freeze over. Finally, one utility did not fit into these two categories and experienced an equipment failure that caused a 12-hour outage.

It is important to note that regardless of the region of the country in which the utility is located, there are common causes for the worst outages. If there had been representation from the South or West, this might change, though extreme cold and winds remain problematic in these areas, too: especially in the south, which experienced the 2011 and 2021 freezes.

When utilities were asked to consider future outage risks (over the next 15 years), we see the same outage concerns: wind and winter storms, as shown in Figure 5.4. Thunderstorms constituted the outage threat that all but one utility thought could cause an outage to 10% of their customers for 24 hours or longer.

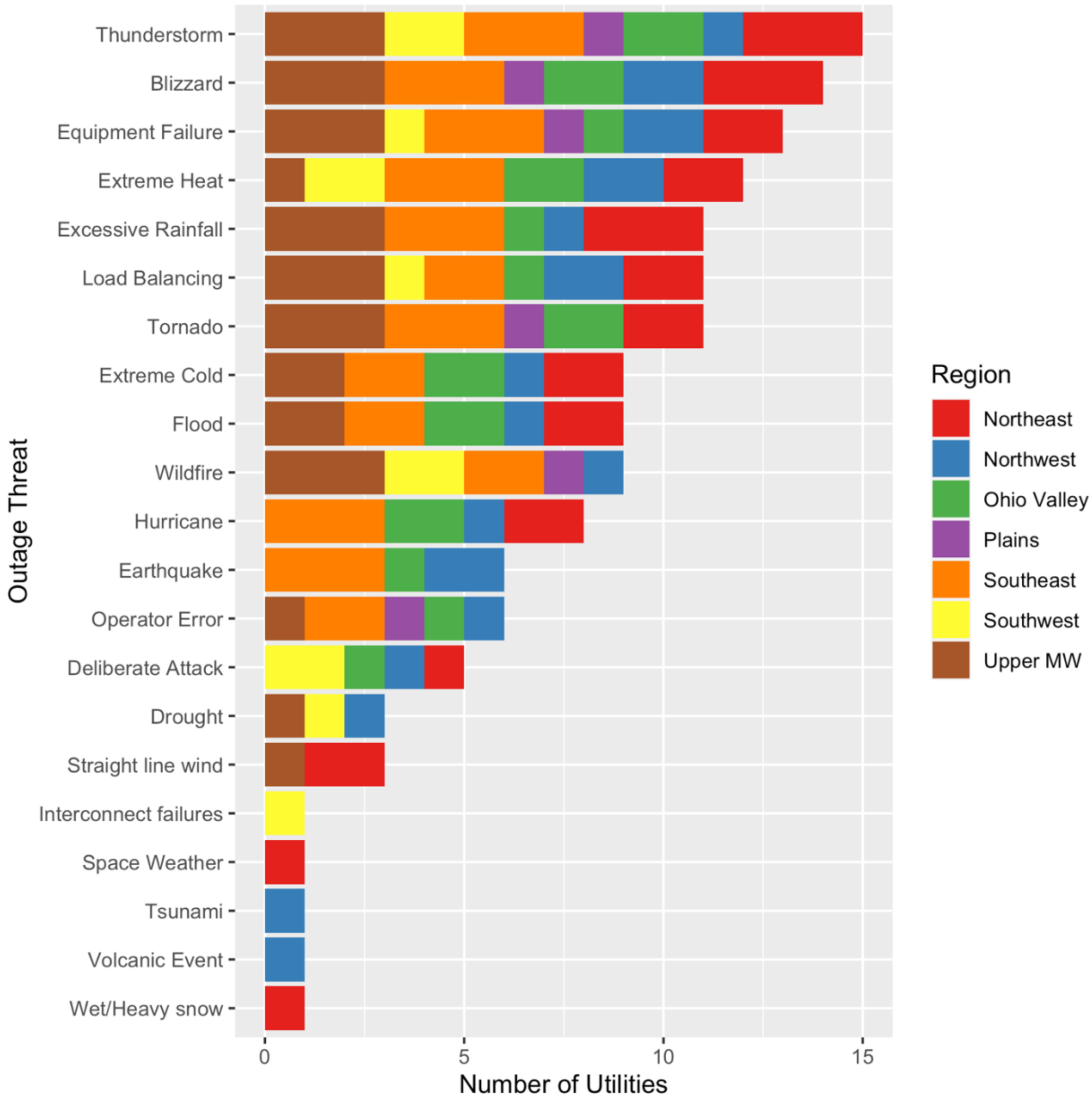

Figure 5.4. Outage threats that participants think could cause an outage with more than 10% of customers out of service for 24 hours or more in the next 15 years.

Figure 5.5 shows which outages threats were the highest-ranked, meaning utility representatives believed they would be the greatest risk in the next 15 years. We see that, for the most part, they are concerned about the types of outages they have already experienced. This could be partially due to availability bias. However, many had good reason to believe that the same types of events will continue to cause problems and could get worse due to climate change. Participants did acknowledge other threats like extreme temperatures and wildfires could cause more outages in the future than they do now due to climate change. They also acknowledged that the energy transition could cause more load balancing issues, and aging infrastructure could lead to more equipment failures. Lastly, only five out of the 16 interviewees listed deliberate attacks as a potential outage threat in the next 15 years. This result conflicts with Utility Dive's State of Electric Utility 2019 survey that showed 85% of respondents from over 500 utilities ranked cyber and/or physical attacks as "important" or "very important" (Gahran, 2019). As hypothesized in the methods section, this could be due to the design of the interview protocol which is likely to have anchored respondents on natural disaster outages, but also meant that the person being interviewed was less likely to have expertise in deliberate attacks, especially cyber-attacks.

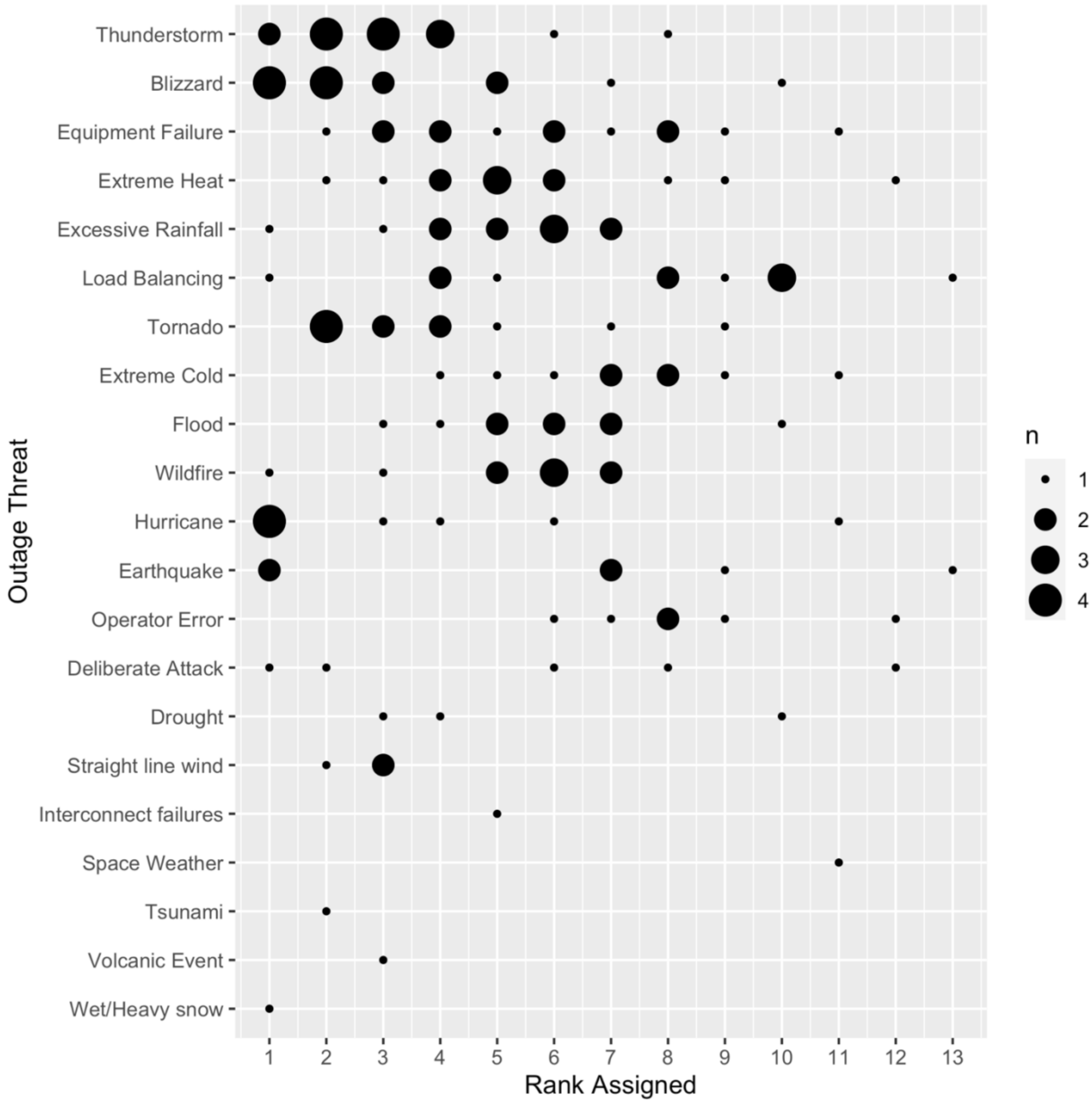

Figure 5.5. Rank assigned to each of outage threat and number of participants that gave each ranking. The bigger the circle, the larger the number of utilities that gave that specific outage cause the same ranking. A ranking of 1 means this outage threat poses the greatest risk.

In conclusion, utilities are worried about similar outage causes despite being in different parts of the country. This was confirmed when I asked participants to think of a second outage threat(s) for which they might want to employ different resilience strategies: they often had difficultly articulating a new threat. Wildfires, high winds, snow and ice are all outage threats with the same prevention method: keeping vegetation clear from power lines. Sometimes, extreme temperature was considered an issue. Addressing this involved increasing capacity. Participants were concerned in general with aging infrastructure and avoiding equipment related outages, both of which require system upgrades. Finally, some were concerned about future large outages because of decreasing dispatchable generation to serve loads.

5.3.3 Judgements on resilience effectiveness

Next, we look at the resilience investments the participants identified for protecting against the outages about which they were concerned. Using the results of the weighted resilience strategies from all 16 utilities, I categorized the responses into 11 resilience strategies as shown on the y-axis in Figures 5.6 and 5.7. Figure 5.6 shows the cumulative weighting for each resilience strategy, while Figure 5.7 shows the distribution of weightings over each resilience strategy; the size of the circle showing the number of utilities that gave each strategy a specific weight.

In almost all cases, participants mentioned strategies that were an extension of resilience investments they were already implementing. If respondents came up with new ideas, it was usually something that the utility was already thinking about but hadn't begun implementing, or something that needs higher technological readiness levels before implementation.

In Figure 5.6 the highest cumulative weight possible is 1600, which would occur if all 16 utilities gave the same strategy a weight of 100. Undergrounding lines was a clear favorite, being the only strategy to cross the halfway point of 800.

Given the split opinions on the benefit of undergrounding, it is surprising that undergrounding scored so high. Eleven participants identified undergrounding as a resilience option; the lowest weight assigned to it among those eleven was 70. One didn't mentioned undergrounding simply because 100% of their system is already underground – so 12 out of 16 participants think undergrounding is beneficial, when the cost barrier is removed. In fact, two participants, who work at utilities that only underground by customer demand or ordinance, selected undergrounding as one of the resilience strategies they would invest in if money was not a barrier. Two participants said they would underground the entire distribution system. These two participants are from the same state. However, all other nine participants wanted to target certain areas for undergrounding: three participants wanted to target radial single-phase overhead lines because they were most vulnerable and had no tie to other feeders, while being the cheapest form of undergrounding; two participants wanted to underground high vegetation areas on their system; and the remaining four participants wanted to increase their undergrounding by 10-20%. The only region that did not suggest undergrounding as a key strategy was the Southwest, likely due to the difference in vegetation type in the desert. There was no difference between coops/municipalities and IOUs in preference for undergrounding. Additionally, even the utilities that had experienced flooding-related outages still preferred to underground, stating that as long as switchgears were flood-rated and equipment pad-mounted above ground, undergrounding was highly resilient.

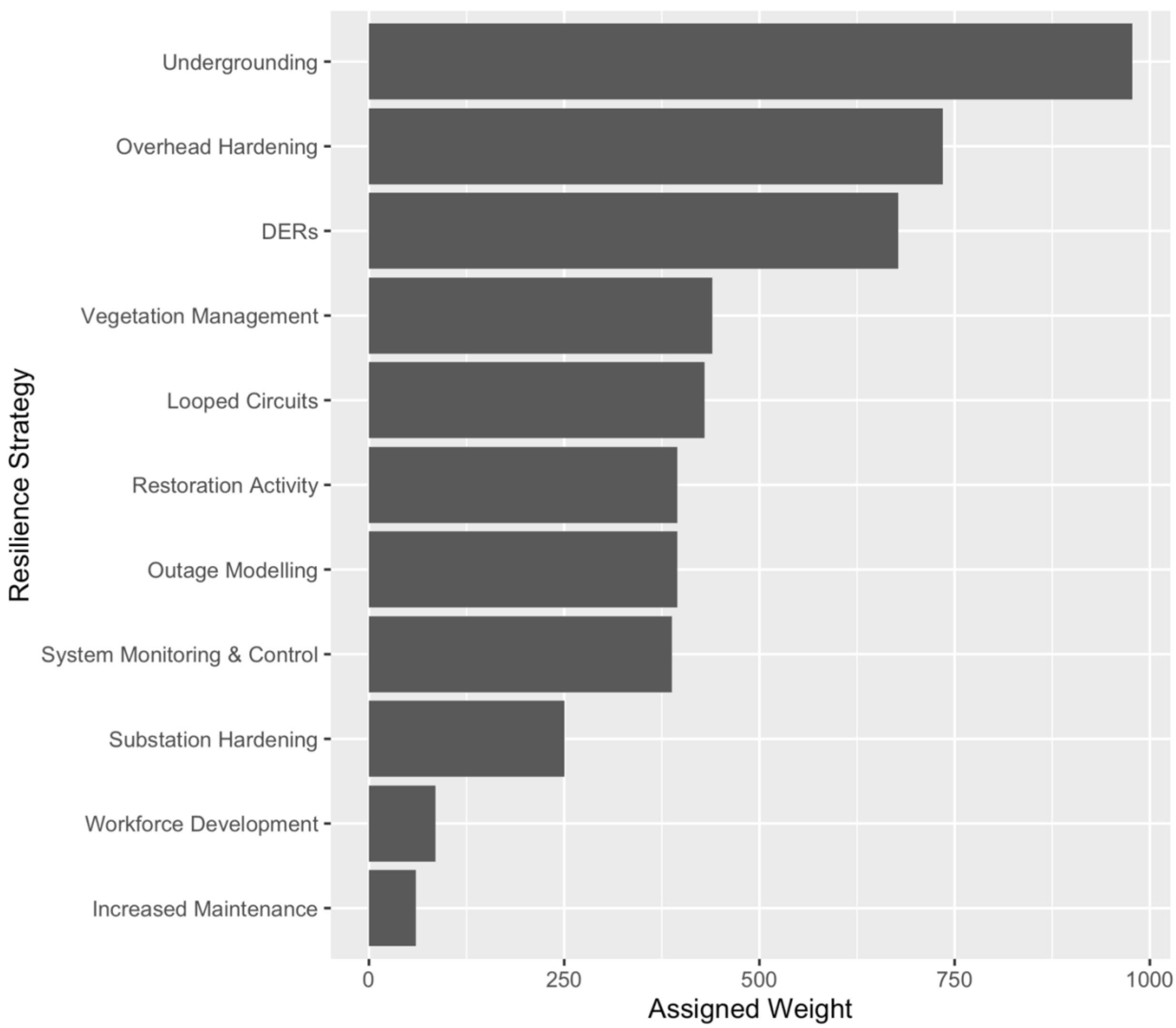

Figure 5.6. Cumulative resilience weighting of the resilience strategies identified by each utility.

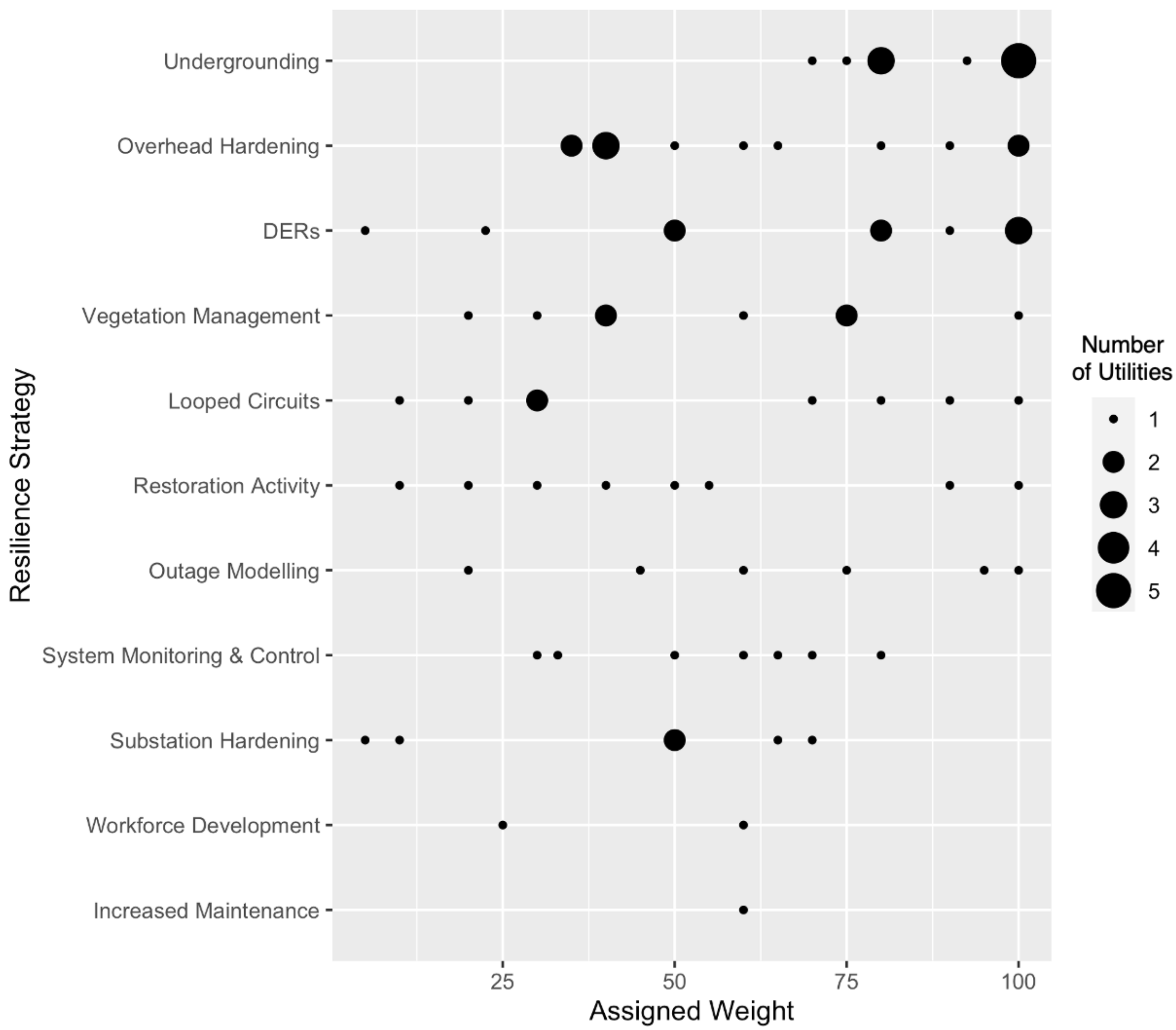

Figure 5.7. Distribution of weightings for the identified resilience strategies.

There was a wider range of opinions about the remaining strategies. This was particularly interesting in the cases of looped circuits, overhead hardening, and vegetation management, because utilities were suggesting similar implementation strategies but making very different judgements about how effective they would be. For example, utilities were suggesting the same strategies for hardening overhead power lines - converting all poles to a stronger class, stronger conductors, and covered conductors - and yet they assigned weights between 35 and 100. There was no discernable pattern in these rankings, other than two of the most anti-undergrounding participants gave a weighting of 100 for converting from class 5 to class 3 poles – the only two to give overhead hardening that score. Additionally, not included in Figures 5.6 and 5.7 were five utilities that stated they didn't need any upgrades on the lines, but that they just needed new equipment, because large parts of their system are over 50 years old. These utilities weighted changing out old lines for new on the distribution system 100 and 99, while weighting upgrades on transmission 40, 50, and 85.

On the other hand, there were several categories where participants had very different designs in mind which contributed to the wide distribution of weightings: distributed energy resources (DERs), restoration activity and substation hardening. Ten participants identified DERs as a solution; 4 of those 10 wanted to implement DERs across all or a large portion of customers, weighting this between 80 and100. Another four utilities considered battery or backup generation at substations or in a few vulnerable communities: they weighted these between 5 and 50. Finally, two utilities considered microgrids for all customers in small clusters (50-100 meters) and weighted the benefit of this strategy 90 and 100. Similarly, there was a wide variety of views about restoration strategies: three utilities mentioned increasing storm stock and working with vendors to have equipment available when ready; two utilities wanted better workforce management and communication systems for coordination of the restoration; two suggested physical equipment that could help like drones or all-terrain vehicles; and one utility wanted a mobile substation on hand. The physical equipment ranked lower than the others because it wouldn't get used very often – only during large outage events.

The 2017 report by the US National Academies on *Enhancing the Resilience of the Nation's Electricity System* defines resilience as prevention – "anticipating and preparing for disruption", mitigation – "mitigating the impacts of disruption", and restoration – "recovering from and learning after disruption"(NASEM, 2017). Figure 5.8 shows how much weight each utility put on prevention, mitigation, and restoration activities. Prevention activities stop an outage from occurring in the first place and include physical system hardening. Mitigation activities involve contingency action that can provide customers power, while the system is being repaired. Restoration involves all activity required to repair the system.

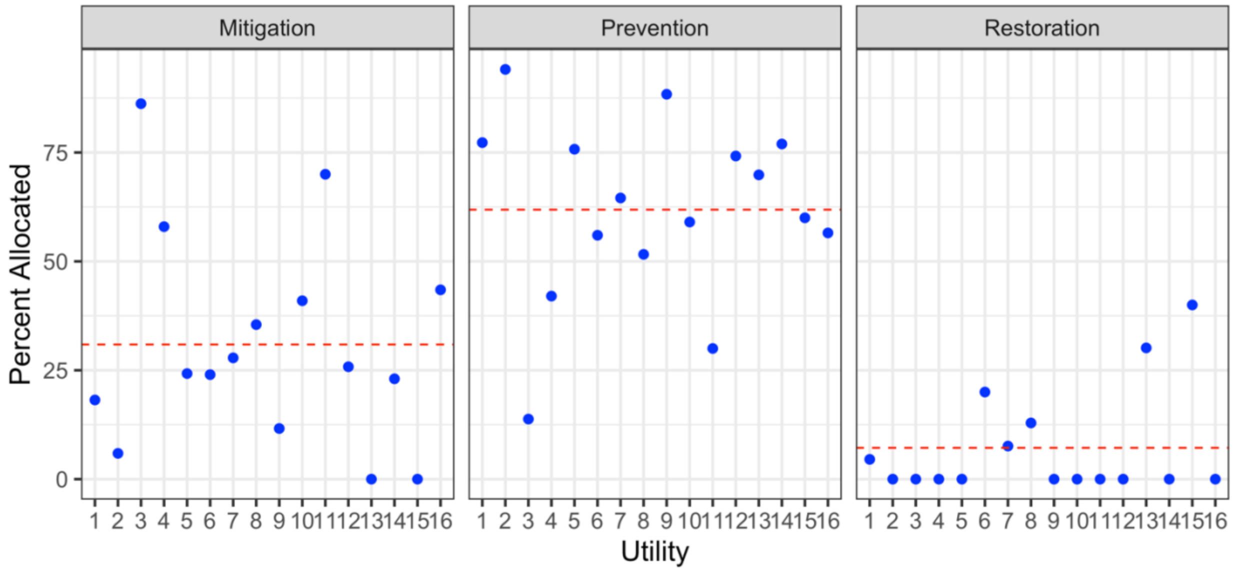

Figure 5.8. Participant weighting by resilience stages. Each blue point represents a single participant's weighting. The red dashed line represents the mean for each resilience stage.

Only six participants considered any kind of restoration activity for one of their resilience strategy goals; all six came up with one restoration activity. This is likely because participants are satisfied with their current emergency preparedness plans. They all felt they had made the necessary changes in the last decade and now have a robust process for restoring power quickly. Unsurprisingly, prevention strategies slightly outweighed mitigation strategies, because utilities have been reliability-focused for decades, but many respondents have recognized the benefit of redundancy in the form of tie lines and even redundant substations to reconfigure the system when a fault occurs and avoid as many customer interruptions as possible.

5.3.4 Judgements on resilience cost-benefit

We now consider how much it would cost to implement these ideal resilience strategies. Figure 5.9 shows the relationship between cost and efficacy of the resilience strategies proposed. To facilitate comparison between utilities of different size, cost is represented as a percentage of each utility's 2021 revenue. Additionally, respondents were asked to provide an overnight capital cost estimate, but some resilience activities they selected were annual operation and maintenance activities, such as increases in annual vegetation trimming. These costs are provided in net present value assuming a 5% discount rate over a 15-year period because participants were asked to think about outage threats 15 years into the future.

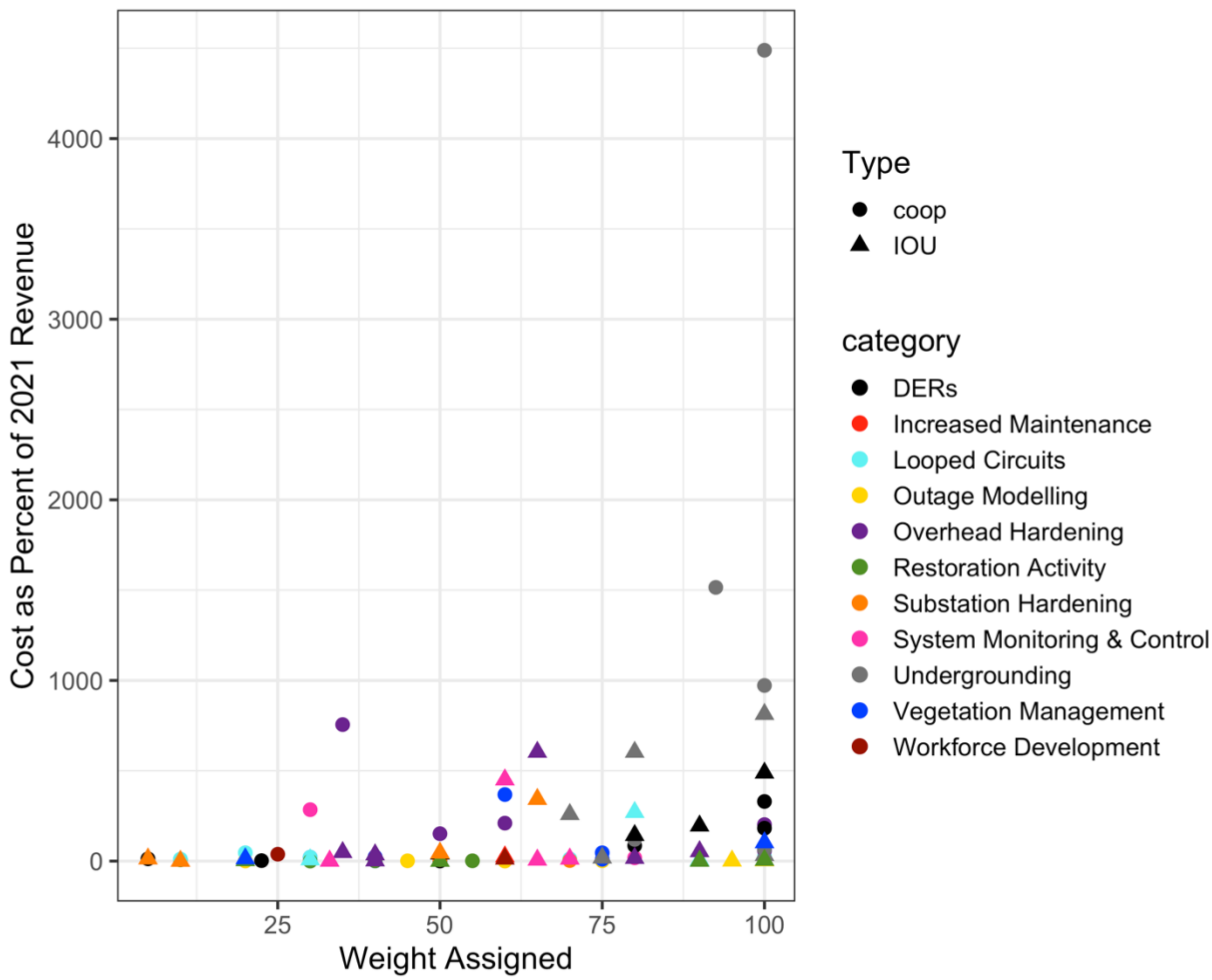

Figure 5.9. Efficacy of strategies compared to their implementation cost. The x-axis is the weight assigned to a particular strategy and the y-axis is the cost as a percentage of the 2021 revenue of that utility. Colors indicate resilience strategy type; shapes indicate utility type.

First, there is a wide range of costs across all resilience strategies. The few expensive outliers are for undergrounding. The highest four costs are undergrounding the entire distribution system or undergrounding 60% percent of the distribution system. Figure 5.10 displays strategies with costs of under 100% of the total 2021 revenue, removing the outliers in Figure 5.9.

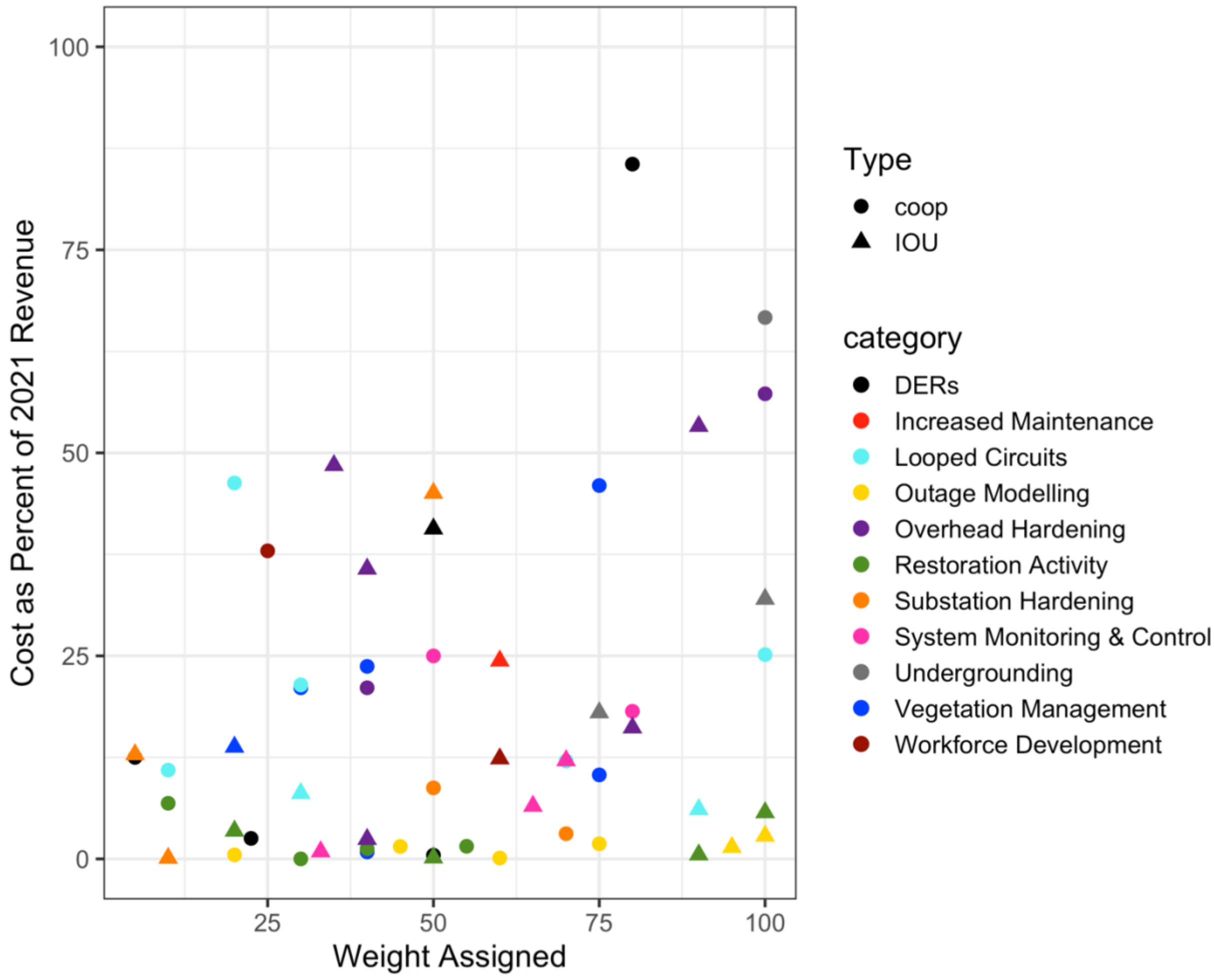

Figure 5.10. Efficacy of strategies compared to their implementation cost. The x-axis is the weight assigned to a particular strategy and the y-axis is the cost as a percentage of the 2021 revenue of that utility. Colors indicate resilience strategy type; shapes indicate utility type. *This plot only considers strategies that cost less than the 2021 revenue for each utility.*

Seventy percent of the strategies considered cost less than the total revenue each utility generated in 2021. There is still no obvious relationship between weight and cost, and all resilience strategies are represented, including undergrounding. This suggests that there exists a wide range of "ideal" resilience options that are reasonably cost-effective. Figure 5.11 further decomposes this graph by individual resilience categories.

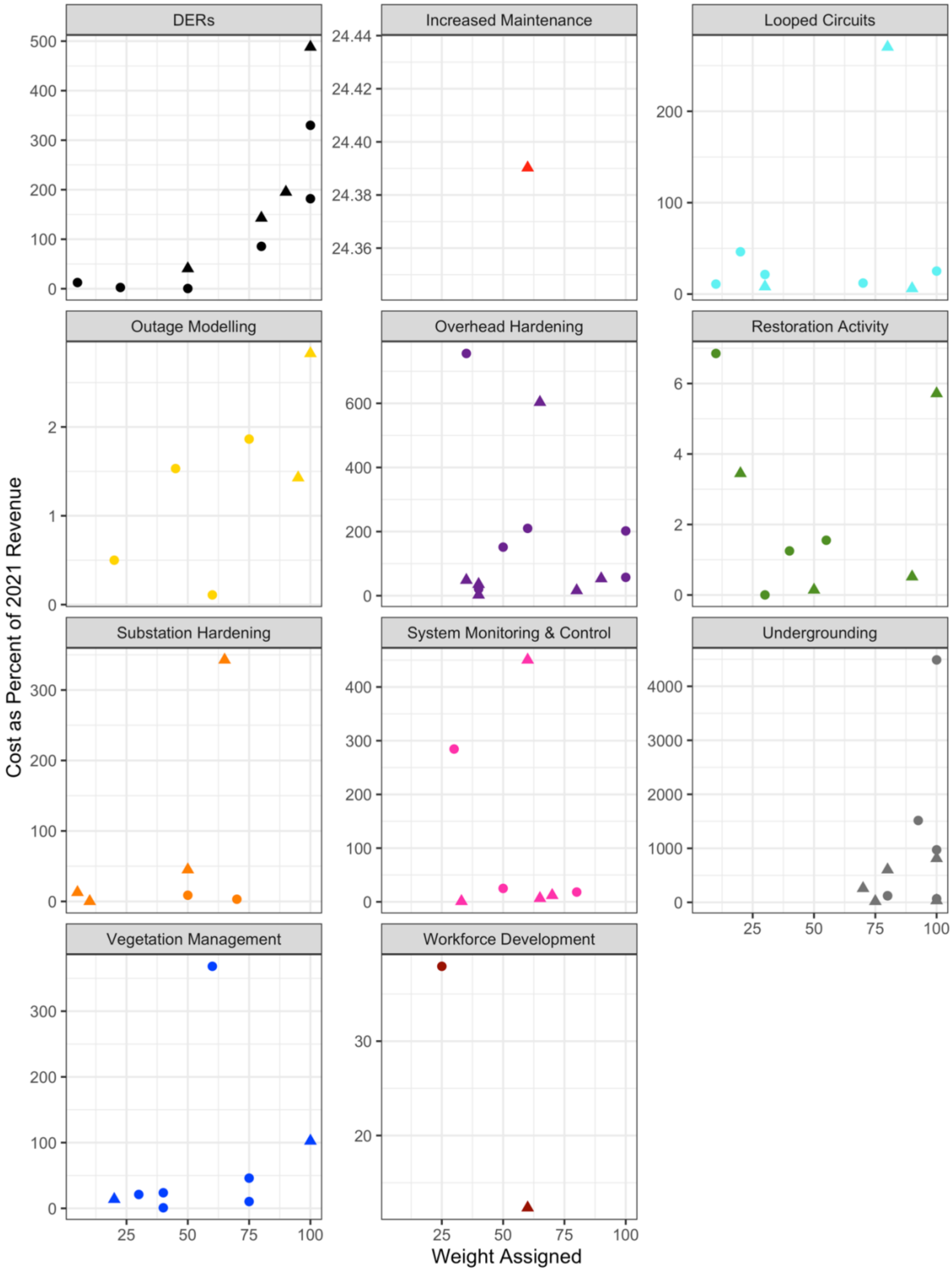

Figure 5.11. Efficacy of strategies compared to their implementation cost, separated by resilience category. The x-axis is the weight assigned to a particular strategy and the y-axis is the cost as a percentage of the 2021 revenue of that utility.

There is a wide distribution of effectiveness weightings across strategy, as shown in Figure 5.7. From Figure 5.11, there is also a wide range of cost estimates for each strategy. Part of this is due to the different implementation designs the participants described as their ideal, and these different designs were usually a function of how much the utility had *already* been able to accomplish. As stated earlier, almost every strategy identified was just “finishing” the implementation of current resilience investments, so the cost represents how much more the utility must accomplish. Therefore, there isn’t necessarily a relationship between cost and weight. The only two cases where we see a positive relationship between cost and weight is DERs and undergrounding. For the case of DERs, we are likely seeing this trend because higher-weighted DERs involve giving every or most customers some sort of battery or backup generation system, which costs more than targeted microgrids.

Despite this variation, there is still something to be learned from considering the average weight and cost. Figure 5.12 could be interpreted as the cost, on average, that is required for the utilities to achieve their own optimal level of each resilience strategy.

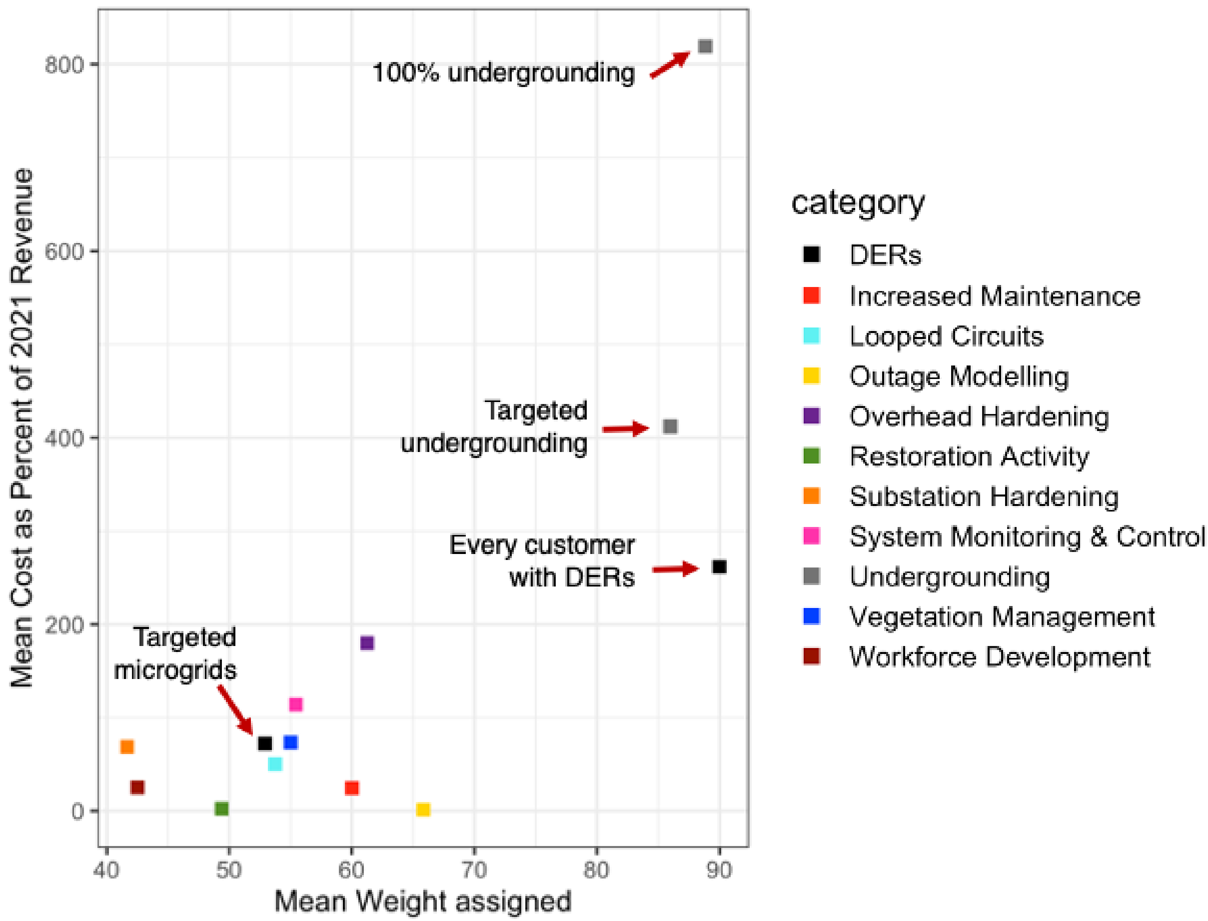

Figure 5.12. The mean weight assigned vs the mean cost as a percentage of 2021 Revenue. Undergrounding is represented twice, once with all undergrounding estimates, once with the two participants that wanted to underground everything removed. DERs is also represented twice, once with the four participants that wanted to give everyone a behind the meter DER, once with the remaining six participants who envisioned targeted microgrids on the feeder.

When considering the mean, the positive relationship between cost and weight is more defined. Undergrounding and DERs for all customers are the highest-weighted categories. Each are split into two points represented in Figure 5.12 to account for differences in ambition of interviewees for “desired” levels of resilience. However, even when removing the responses from the two participants who wanted to underground 100% of their distribution system, targeted undergrounding still has a capital cost on average four times a utility’s annual revenue. Installing DERs for all customers also costs roughly 2.5 times a utility’s annual revenue whereas targeted microgrids could be less than the annual revenue. It is important to also note here that the lowest weight assigned shown on the x-axis is 40, which means that although the remaining resilience strategies may be less impactful than DERs or undergrounding, their impact is certainly not negligible and could provide cheaper alternatives. Figure 5.13 considers the mean differences between IOUs and Coops/Municipalities.

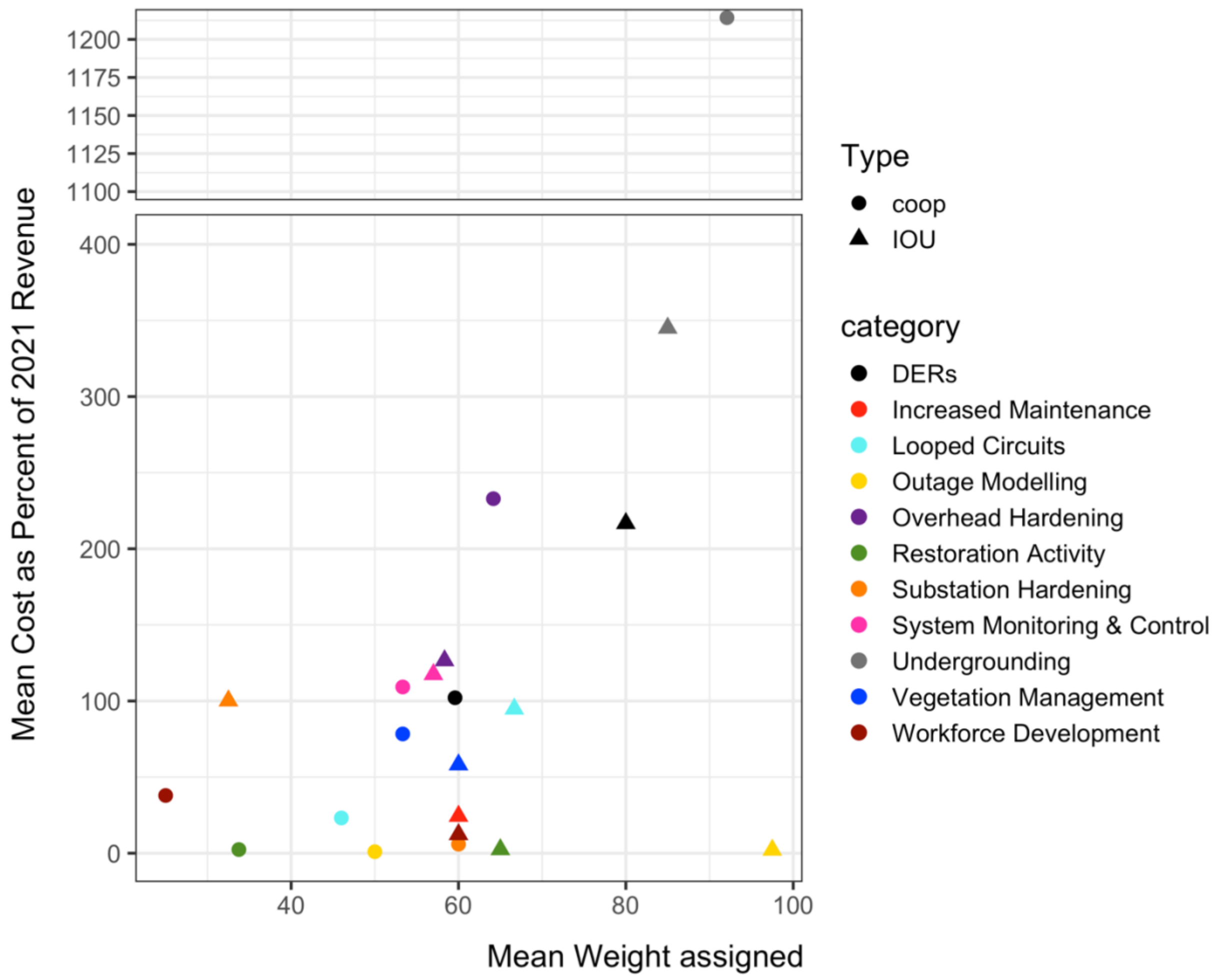

Figure 5.13. The mean weight assigned vs the mean cost as a percentage of 2021 Revenue grouped by utility type (nonprofit coop/municipality vs for profit IOU).

Costs do not differ much across utilities when it comes to mitigation and restoration activities. However, prevention strategies that require hardening lines (undergrounding, overhead hardening, vegetation management) are much more expensive for coops/municipality than IOUs, even though the two were suggesting similar implementation strategies for those resilience options. This is likely because cooperatives have much less revenue (and fewer customers), but still have large systems that must serve spread-out communities in rural parts of the US. This would imply that cooperatives will need more financial aid to reach the same level of resilience as IOUs when it comes to preventive system hardening. Additionally, three utilities (one IOU, two coops) stated that it would cost between 3.5 to 24 times their current annual revenue to update transmission lines that are over 50 years old.

Although utility experts were asked to provide overnight capital cost estimates for the resilience strategies they suggested, Figures 5.12 and 5.13 may be misleading because they do not account for the wide range of lifetimes that are associated with these strategies. For example, smart meters, although designed to last 12-15 years (Rashed Mohassel, Fung, Mohammadi, & Raahemifar, 2014), may realistically only last 5-7 years (Weaver, 2015). Conversely, utility poles and wires can last over 60 years (Braik, Salman, & Li, 2019; Salman & Li, 2016). Figure 5.14 reproduces the mean weight and cost graph, but instead of considering total capital cost (or O&M over 15 years) it provides the annualized capital cost for these resilience strategies.

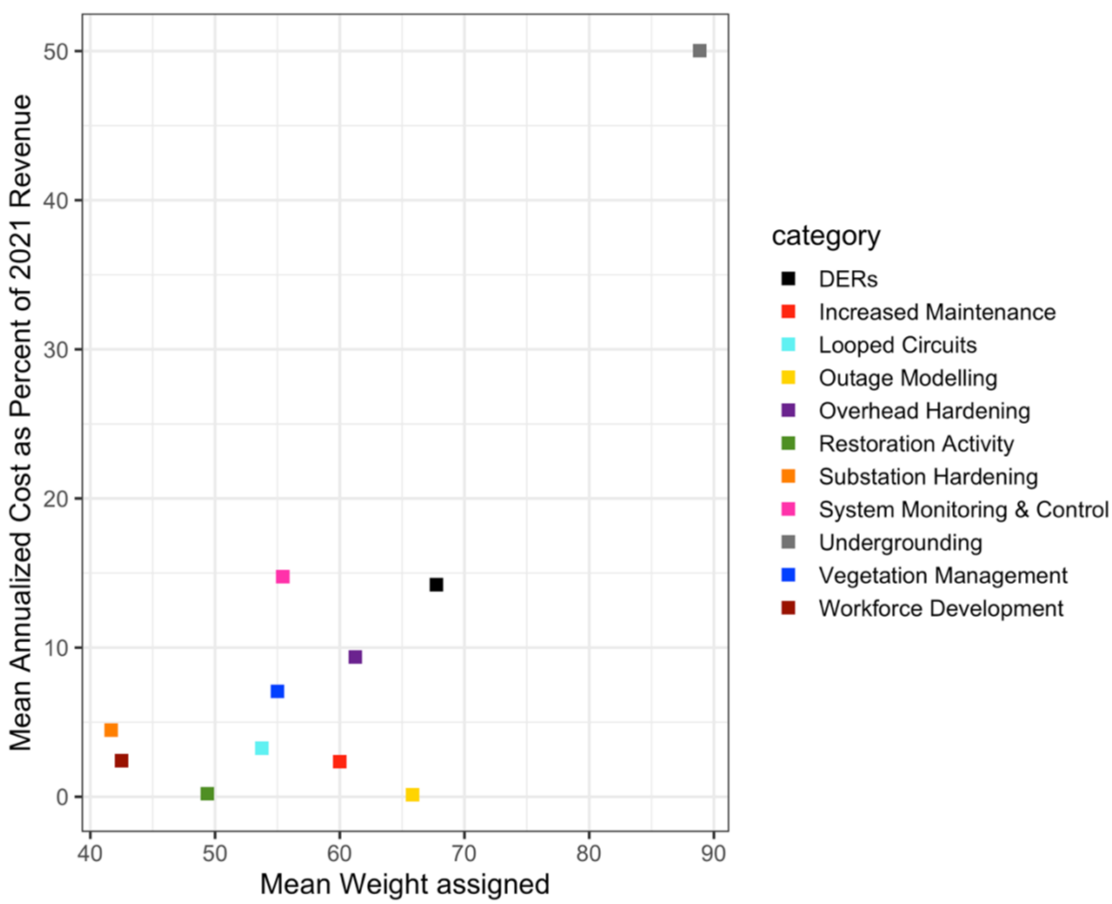

Figure 5.14. The mean weight assigned vs the mean annualized capital cost as a percentage of 2021 Revenue. This graph does *not* include O&M costs for installed new equipment.

In Figure 5.14, DERs and Undergrounding still seem to be among the more expensive and the strategy costs have not changed significantly. However, adding devices that only last 10 years for improved system monitoring and control does increase the annualized cost of smart grid technologies, potentially making them less cost-effective than initially thought. Table 5.2 shows the life expectancy assumptions made for developing annualized cost estimates.

Table 5.2 Life expectancy of resilience strategies.

Parameter	Years	Source
Battery for Microgrid	15	(EnergySage, 2019)
Underground lines	35	Interviewees
Fossil Fuel Backup Generator	25	(Authorized Services of New England, 2018)
Overhead poles and conductor	70	Interviewees
Switchgears/Transformers/Substations	30	(Electrical Technology, n.d.; Gardner, Bettler, Dolezilek, Sykes, & Zeller, n.d.; Schneider Electric USA, n.d.; Siemens USA, 2014)
Distribution Automation Devices	10	(Rashed Mohassel et al., 2014; Weaver, 2015)
Purely O&M activities (vegetation management, workforce development, software maintenance)	15	Interview protocol asks participants to consider outage threats 15 years in the future
Drones	5	~500 hours of run time, assuming 100 hours of use per year. (Droneblog, n.d.)
All-Terrain Vehicles	20	(Muskoka ATV, n.d.)

5.3.5 Energy Transition Concerns

Grid resilience must consider not only large power outages of long duration, but also adapting to a changing energy landscape. To do this, all the concerns utilities identified for managing the future grid are pulled together for comparison. Participants were asked to identify their biggest concerns in the next 15 years about managing their system and what potential solutions existed to mitigate these concerns. We often think of electrification, decarbonization and reliability separately in the literature, so I wanted to get a sense for how utility personnel thought about them all together. Figure 5.15 shows a network diagram of all the concerns and solutions they identified, as well as which solutions mitigate which problems.

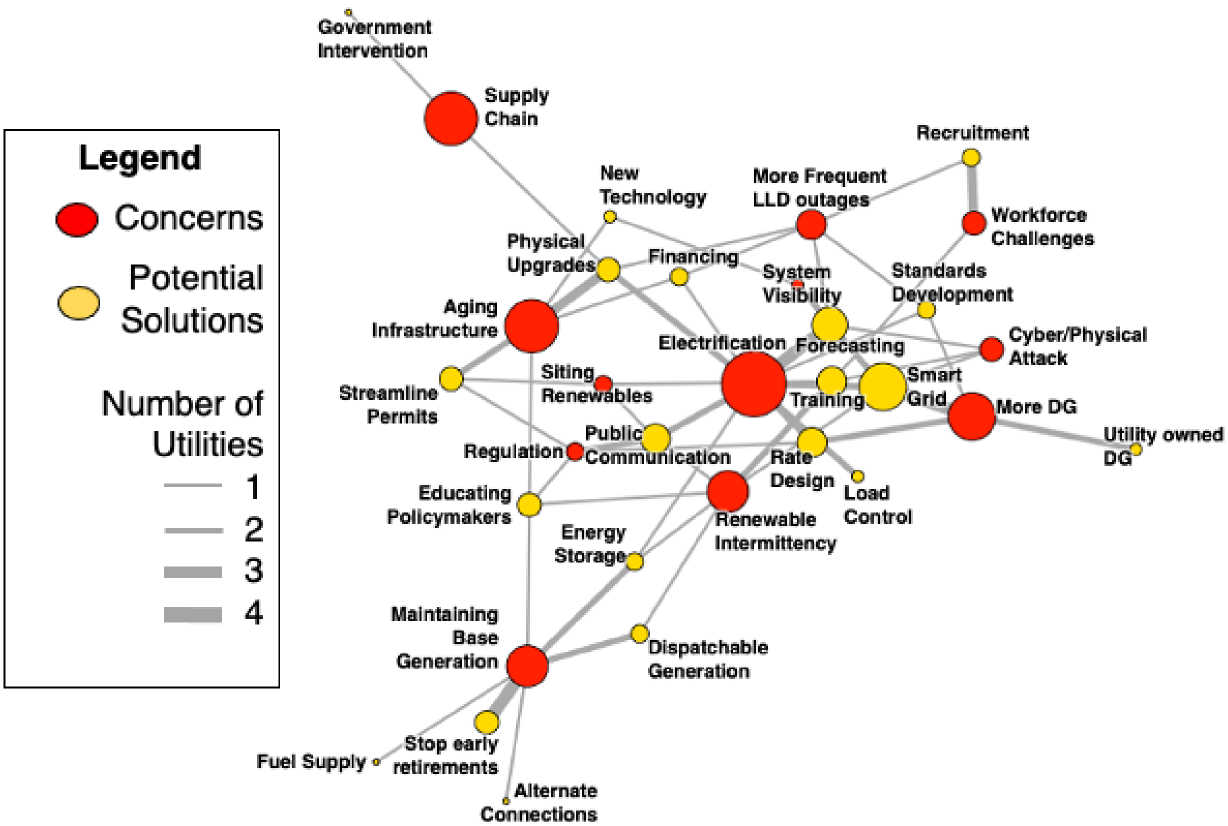

Figure 5.15. Network diagram showing the relationships between utility concerns and potential solutions to mitigate these concerns. Red circles identify concerns, with the size indicating the number of participants that noted each item as a concern. Yellow circles identify solutions, with the size indicating the number of participants that stated each item was a solution. The gray lines connecting nodes are sized based on the number of participants that identified a particular solution for the same problem.

The largest problem identified by eleven respondents was increased electrification, as it will not only increase load, which will likely result in the need for capacity upgrades, but could also make load more unpredictable. Additionally, nine participants had concerns about aging infrastructure and supply chain. Many utilities have poles and lines that are 60 to 70 years old and need to be replaced, but this replacement is very expensive. As utilities order more inventory to account for aging lines and worsening extreme events, this only exacerbates the existing supply chain crunch.

The most common solution identified (by eight participants) was implementing more system monitoring and automatic reconfiguring devices, often referred to as a “smart grid”. Four of the eight suggested that smart grid technologies could help with higher penetration of distributed energy resources; two stated it would help with system visibility and electrification; and one noted it could mitigate renewable intermittency. One person even suggested that it could be beneficial in preventing cyber-attacks. Six participants identified a need for better forecasting; four stated it was needed for increased electrification and two for outage planning and mitigation. The highest number of participants that made the same connection between a problem and a solution was four. The last largest problem-solution relationship identified was to stop early retirement of dispatchable generation to maintain capacity. Participants are concerned not only about the intermittency of renewables, but also about not having enough generation to meet load growth: many dispatchable plants are being retired too quickly without replacement.

Figure 5.16 examines tangible interventions participants identified and how feasible and effective they thought these solutions would be.

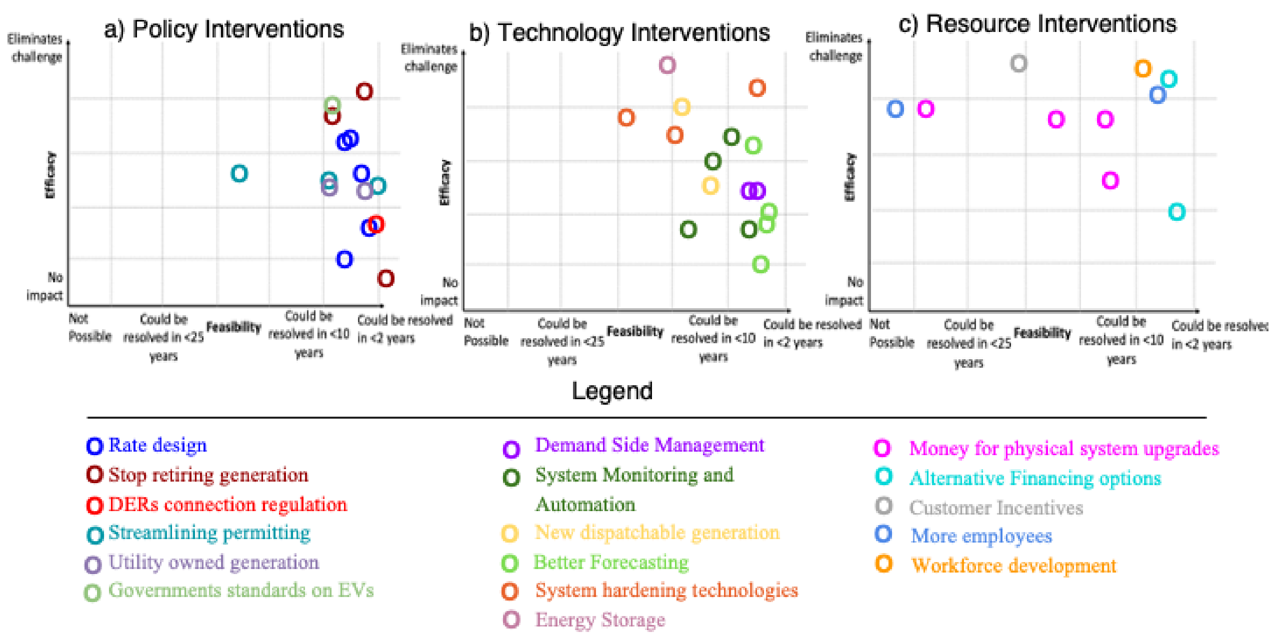

Figure 5.16. Utility-specific recommendations for a) policy, b) technology and c) resource interventions that would address some of the concerns they identified. The x-axis represents “feasibility”, measured in the number of years it would take to implement each intervention. The y-axis represents “efficacy” – the extent to which a recommendation address problems.

Generally, respondents believed that policies could be implemented quickly but have a wide range of efficacy. Given that interviewees tended to be technology-focused within their utilities, they may have underestimated the nuances and associated delays in government policymaking, with the result that some of these timelines are optimistic for policy interventions. Technology interventions tended to be more beneficial but with a wider range of estimates for "feasibility", likely due to varying technology readiness levels. However, smart grid and demand management technologies were deemed easy to implement, as were better forecasting for uncertainty of load growth and outage threats. It is likely that the feasibility estimates respondents provided for developing new forecasting models are optimistic. Resource interventions, while being generally the most effective, are also the hardest to implement. We have an aging power system that will take a lot of money to upgrade, but there are few alternatives to that.

These results suggest that creative rate design, new standards for thinking about higher DER penetration and electrification are considered "quick wins" in the policy sphere that could be resolved in the next 5 years. Although it is unlikely the US will slow down current decarbonization efforts, ensuring public and policymaker understanding of the limitations of the currently available low-carbon technologies could help manage expectations during this transitional time.

5.4 Discussion

Although utility representatives generally agreed on the resilience options available, they had differing opinions on best implementation design for their systems and therefore how effective a particular strategy would be. This is not surprising given that utilities operate in very different environments and have unique needs. However, these responses serve as baseline for understanding the range of effectiveness of each resilience strategy and allows for the first direct comparison of the average efficacy and cost of a wide range of resilience strategies; prevention, mitigation and restoration activities. However, the impact of restoration activities could be undervalued in this analysis. While participants deemed it a significant aspect of the utilities' resilience portfolios, only five participants could think of further improvements. Due to the design of the interview protocol, only restoration improvements were weighted, not emergency preparedness as a whole. The one interviewee that did consider mutual assistance and emergency planning as a whole, gave it a weight of 100. After the devasting impacts of Hurricane Ian in October 2022, the Florida utilities were able to restore power to all but the most severely hit areas within two weeks (Taylor, 2022). A large part of this success was due to the "44,000-strong army of electrical workers" (Taylor, 2022) that came from 27 different states (Wachter, 2022) to aid in the repair. These anecdotes suggest that restoration activities could have a much higher weighting than shown in Figure 5.12.

Undergrounding was rated by far the most of effective strategy but also has the largest capital cost. However, the potential cost savings from avoided outages are not included in these cost estimates, which could bring the total life-cycle cost down for undergrounding investments making it a more viable option. Participants additionally agree there is benefit in smart grid technologies incorporating both more DERs and demand response initiatives, which would continue utilities down a path of decentralizing. However, as we saw in Figure 5.14, the perceived cost savings for smart grid devices are not accurate when considering the full lifetime of these resilience investments. DERs can also add complexity to the system by requiring new advanced distribution management systems and may eventually include connections to the grid by many other third parties, all of which can also make the system more vulnerable and less resilient. Additionally, one participant cautioned that installing new devices on 60-year-old lines doesn't solve the problem; attaching new devices to old poles that will likely fail soon still causes outages. For example, three utilities estimated it would cost between $200,000-$1,000,000 per mile to update transmission lines. Considering there are roughly 700,000 circuit miles of transmission in the US (U.S. Energy Information Administration (EIA), 2018) and roughly 70% of the entire US grid is older than 25 years (Lewis, 2022), it would cost between $98-$490 billion to upgrade current transmission lines. Although the Bipartisan Infrastructure Bill – allocating $65 billion for transmission upgrades, new transmission lines and deployment of more clean energy sources (The White House, 2021) – and the Inflation Reduction Act – creating a more robust loans program for energy infrastructure investment (US Department of Energy, 2022) – are important first steps to upgrading the grid, "It's a drop in the bucket," as one participant explained. Without continued spending in this space, we may see greater challenges from aging infrastructure in the future.

Having enough baseload generation is another major concern of participants. In fact, one participant stated that the very real possibility of brown outs due to lack of dispatchable generation would become much more of a concern for customers than large weather-related outages in the coming years. Ultimately, resilience becomes more challenging in a changing energy landscape.

5.5 Conclusion

This analysis allows for the first direct comparison of the average efficacy and cost of a wide range of resilience strategies. Results showed that the distribution utilities interviewed are predominantly concerned with weather events that cause vegetation-related outages. They have already implemented a wide range of resilience strategies to enhance their systems and agree on the value of many mitigation and restoration strategies, but have more contrasting views on prevention strategies. However, when asked to consider resilience strategies without financial barriers, undergrounding power lines was the clear favorite. Utility experts also favored DERs for individual customers behind the meter, however other benefits from third-party DER managers and microgrid communities are probably not fully realized in this analysis due to utility risk aversion to new connections. Considering policy changes in rate design and creating standards to better prepare for increases in load and distributed generation can mitigate some of the challenges to system management in the near term. Conversely, aging infrastructure and supply shortages are likely to continue without any easy solutions.

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Chapter 6. Conclusion

This thesis reviewed the literature on power grid resilience investments and provided further assessment on the cost and effectiveness of distribution system resilience. Chapter 2 provided a comprehensive literature review on the cost and efficacy of resilience strategies. Chapter 3 provided a techno-economic analysis of individual vs collective contingency power deployments in residential communities during a multiple day outage. Chapter 4 conducted an exploratory data analysis on the cost and performance against tropical cyclones of the resilience investments made by Florida IOUs. Lastly, Chapter 5 compiled a comprehensive list of distribution resilience investments and asked utility engineers to compare them through a highly-structured interview.

Chapter 3 showed the cost of collective solutions could be as much as 10 to 40 times less than individual solutions (less than $2 per month per home), when considering an emergency load required for survival (~10% of average residential consumption) for 5-, 10-, and 20-day outages. However, collective solutions would require community-wide coordination, and if local distribution system lines are destroyed, only individual back-up systems could provide contingency power until those lines are repaired. Additionally, policy changes in grid operation; allowing communities to island while the bulk system is repaired is required to realize collective scenarios. Additionally, allowing distribution companies to own generation for the explicit use for resilience would make it easier to adopt collective solutions.

The analysis in Chapter 4 provides evidence suggesting that the resilience investments made by Florida IOUs have been able to reduce storm CAIDI in the last 15 years. The strong negative correlation between undergrounding and tropical storm CAIDI indicates that undergrounding has been effective at reducing outages. Increases in AMI and non-wood poles likely also reduces tropical storm CAIDI. However, to continue performing at current levels of reliability, these utilities will have to spend more on the same activities and even more on others to continue to address the impacts of climate change and the uncertainty they induce. The investments made in 2020 alone equate to between a 2% and 8% increase in an average customer's annual electric bill.

To be able to conduct similar analysis across the US and even improve upon this analysis, requires better data on resilience investments and outages. The 2020 adjustments made by the Florida PSC to IOU reporting requirements are the best example currently being used - the template is detailed and uniform across utilities. However, PUC's should consider collecting more data on outcomes instead of processes when it comes to resilience investments. For example, knowing the distribution of vintage and material of poles on a system allows for comparison as opposed to only confirming if an 8-year inspection cycle has been met. Additionally, understanding the potential benefits of resilience investments requires common definitions of outage causes and detailed reliability metrics for individual outage events.

Finally, Chapter 5 showed that distribution utilities are worried about similar outage causes despite being in different parts of the country. Wildfires, high winds, snow and ice are all outage threats with the same prevention method: keeping vegetation clear from power lines. The utilities interviewed already had high levels of resilience and reached a level of emergency planning with which respondents are generally satisfied, which has made a big difference in power restoration in the past decade. When considering resilience options without financial barriers, respondents rated undergrounding power lines by far the most of effective strategy but it also has the largest capital cost. However, the potential cost savings from avoided outages could bring the total life-cycle cost down for undergrounding investments making it a more viable option. Participants suggested creative rate design, new standards for thinking about higher DER penetration and electrification could be considered "quick wins" in the policy sphere that could be resolved in the next 5 years. Conversely, participants cited supply chain lead times, aging infrastructure, line-worker retention, and lack of dispatchable generation as major concerns in the near future with no easy solutions.

APPENDIX A: Modifying ResStock housing stock distributions

Many of the distributions of housing characteristics in ResStock are derived from the Energy Information Administration's (EIA) Residential Energy Consumption Survey (RECS). ResStock bases its housing stock data on Typical Meteorological Year 3 (TMY3)[45] locations across the U.S., which means the estimated distributions of housing characteristics apply to more populous regions than we are considering in this research. We down selected the model to the three TMY3 locations closest to the Upper Connecticut River valley: Concord, NH; Burlington, VT; and Caribou, ME. These locations are representative of the weather and climate of our hypothetical community. While we cannot validate all the housing stock distributions identified in ResStock, we did cross-validate heating fuel type, year built, and house size with census data for Grafton County, NH[46], and housing records from Enfield[47] and Hanover[48], NH. The tables below show the distributions from each source. We determined that house size and vintage were sufficiently close to the ResStock estimates to not warrant a change, but we changed the heating fuel distribution for Community 1 in ResStock to 51% oil, 32% propane, 5% electric, and 12% other fuel.

Table A1 Distribution of houses by size across data source.

House Size (ft^2)	Hanover	Enfield	ResStock
0-1499	20%	52%	27%
1500-2499	30%	41%	39%
2500-3499	30%	6%	22%
3500+	20%	1%	12%

[45] Weather data set derived from 1991-2005 as a part of NREL's National Solar Radiation Database at 1020 different locations in the U.S. Available at: https://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/tmy3/
[46] https://factfinder.census.gov/faces/nav/jsf/pages/index.xhtml
[47] https://www.axisgis.com/enfieldnh/
[48] https://www.hanovernh.org/assessing-department

Table A2 Distribution of houses by vintage across data source.

<table>
<tr><th>Year Built</th><th>Hanover</th><th>Enfield</th><th>Census</th><th>ResStock</th></tr>
<tr><td><1950</td><td>20%</td><td>20%</td><td rowspan="2">34%</td><td>27%</td></tr>
<tr><td>1950s</td><td>5%</td><td>3%</td><td>7%</td></tr>
<tr><td>1960s</td><td>10%</td><td>5%</td><td rowspan="2">21%</td><td>9%</td></tr>
<tr><td>1970s</td><td>10%</td><td>12%</td><td>16%</td></tr>
<tr><td>1980s</td><td>20%</td><td>22%</td><td rowspan="2">29%</td><td>19%</td></tr>
<tr><td>1990s</td><td>14%</td><td>16%</td><td>12%</td></tr>
<tr><td>2000s</td><td>21%</td><td>22%</td><td>17%</td><td>11%</td></tr>
</table>

Table A3 Distribution of houses by heating fuel across data source.

Heat Fuel	Hannover	Enfield	Census	ResStock	ResStock adjusted
Oil	46%	52%	50%	65%	51%
Propane Gas	46%	41%	23%	4%	32%
Electric	6%	6%	7%	2%	5%
other fuel	1%	1%	16%	15%	12%
Utility Gas			3%	14%	0

APPENDIX B: Comparing the simulated feeder to real feeders in New England

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We randomly loaded our simulated houses onto the feeder until reaching a peaking load of 3.7MW (60% of the feeder's 6.1MW capacity) at some point during the year. Doing that yielded 1,488 houses in Community 1 and 1,614 houses in Community 2 to be served by our representative residential feeder. We compared our average customer annual load distribution on the simulated feeder to the average customer load distribution from real feeders in New England, as shown in Figure B1 below. Our simulated feeder resembles other feeders in terms of mean load for an average customer, but its variance is smaller. Of course, unlike the real feeders, ours has no commercial customers, no installed distributed generation (DG), and uses average weather data while the real feeder data are 2018 loads, which include real weather. The customer type and distributed generation on each feeder is summarized in Table B1.

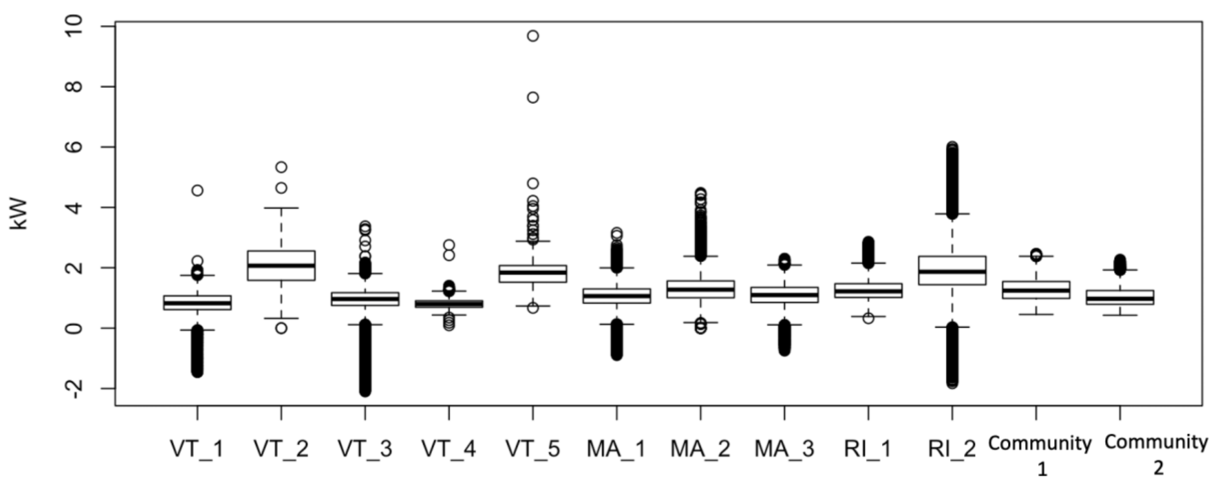

Figure B1. A comparison of our simulated distribution feeders' average customer load distribution (far right) with real feeder average customer load distributions from Vermont (VT), Massachusetts (MA), and Rhode Island (RI). Data from real feeders were derived from three utilities in the region, not identified here because we signed non-disclosure agreements. Variance in real feeders is higher in large part because they reflect real, as opposed to average, weather.

Table B1: Customer type and distributed generation nameplate capacity installed on each of the real feeders used in validation.

Feeder	Distributed Generation (MW)	Commercial Customer Count	Residential Customer Count
Vermont 1	1.9	54	695
Vermont 2	0.5	54	942
Vermont3	6.3	209	1641
Vermont 4	0.15	155	1126
Vermont 5	0.22	111	599
Massachusetts 1	5.6	202	1479
Massachusetts 2	2.6	196	1858
Massachusetts 3	10.1	379	2561
Rhode Island 1	3.3	288	3014
Rhode Island 2	7.2	215	1469

We also examined the load shape of each of the real feeders to see if our simulated feeders were capturing the load peaks correctly. Figure B2 shows a sample week from summer and winter months for the two real feeders that most closely represent our communities. Given that the simulated load is using average weather data, the simulated feeder appears to adequately capture the peaks in the load profile that are typical of this climate region and customer type. The very low values for MA_1 feeder in the summer months is due to the very high installed DG capacity, 5.6MW, which primarily consists of solar PV systems.

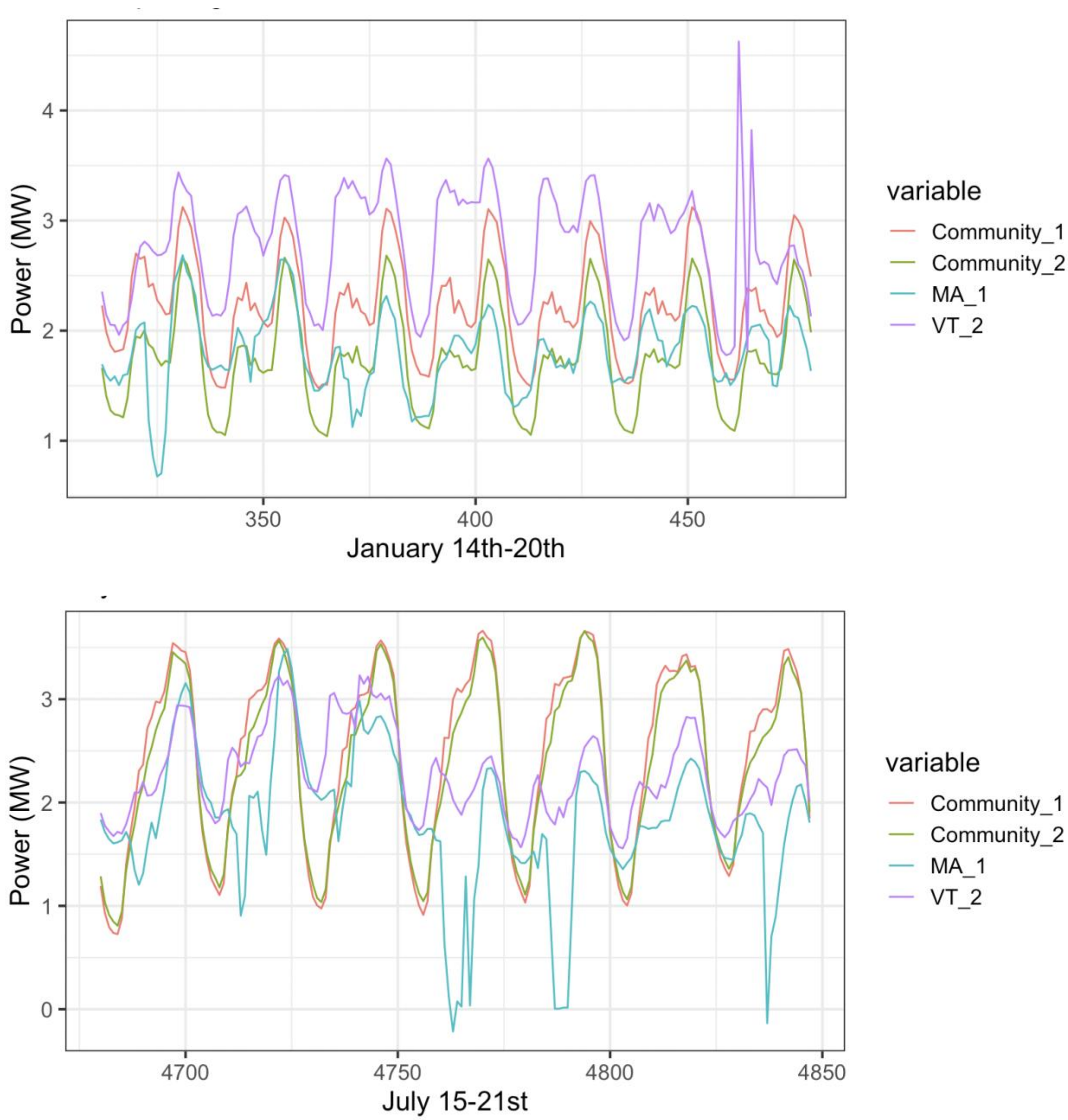

Figure B2. A comparison of Community 1 and Community 2 full feeder loads to a feeder in Massachusetts (MA_1) and in Vermont (VT_1). The simulated communities both peak at similar time intervals and power levels indicating the simulated feeders are a good representation of typical feeders in the Northeastern U.S.

APPENDIX C: Defining household emergency load profiles

C.1 Heating

In an emergency load situation, we want to heat the house sufficiently to avoid pipes freezing. To do that, we set the thermostat to 50ºF(U.S. Department of Energy, n.d.-a). Being able to predict heating load profiles is challenging due to the complex relationship between inside and outside temperature as well as design characteristics of houses that include size, number of rooms, number of occupants, insulation, and other heat emitting appliances. We assume that ResStock (in conjunction with EnergyPlus) has built a sufficiently accurate heating model, and we leverage this by changing the heating set point while holding all other housing characteristics constant to see how the heating load changes. Once we defined a relationship between changes in heating set point, we could estimate energy usage for a 50ºF setpoint using Moon and Han (2011) analysis of annual energy consumption with different heating setpoints for residential homes in Michigan.

The ResStock version used in this analysis has a fairly narrow range of allowable inputs for heating setpoint (66-70ºF). While we could not obtain a direct estimate for energy consumption at 50 degrees, we could examine how the heating load profile shapes change, by moving the heating set point up to 70ºF from the 67ºF. Below is a plot comparing power consumption by house heating type at 67ºF heating setpoint and 70ºF with all other house characteristics held constant.

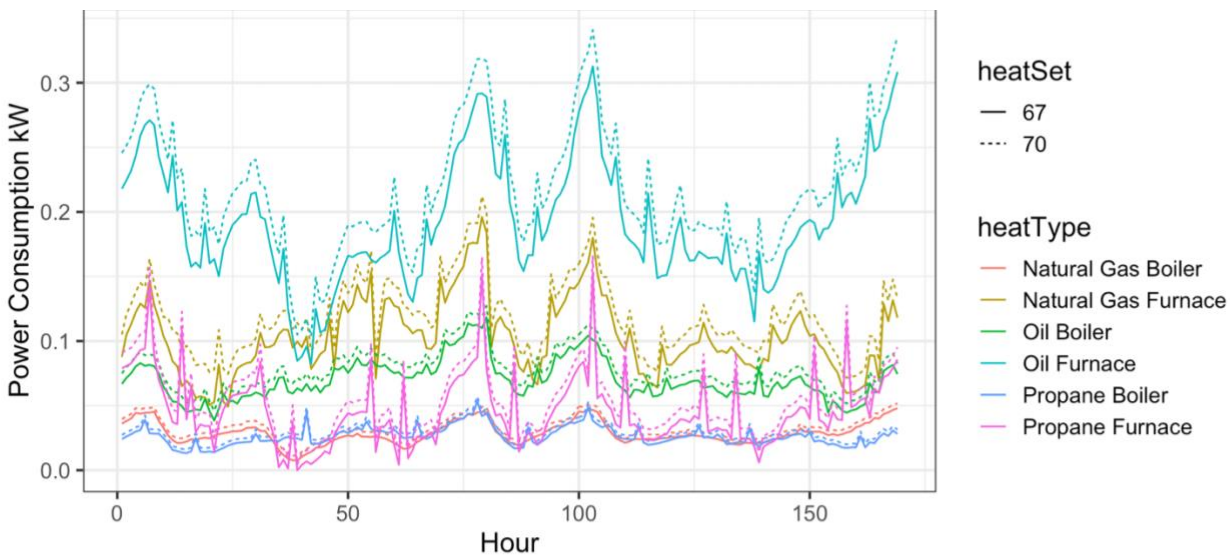

Figure C1. A comparison of heating loads at thermostat settings of 67ºF and 70ºF—by heating type—for six separate houses. All other house characteristics are held constant.

Although the values may be different, the shape of both the 67ºF profile and the 70ºF profile look almost exactly the same. To confirm this relationship, we divided the 67ºF heating load by the 70ºF heating load to see if the ratio between the heating set points was the same for every time period. The ratio between heating curves is not exactly the same but we plot the median ratio for which the two curves match in Figure C1, which is 90% of the 70ºF curve. Figure C2 shows electric heating for a single house, comparing the 67ºF heating set point to the 70ºF heating set point scaled down to 90% of its original consumption–the predicted 67ºF curve. The two lines match up for the most part, but some of the dips in power usage are slightly underpredicted.

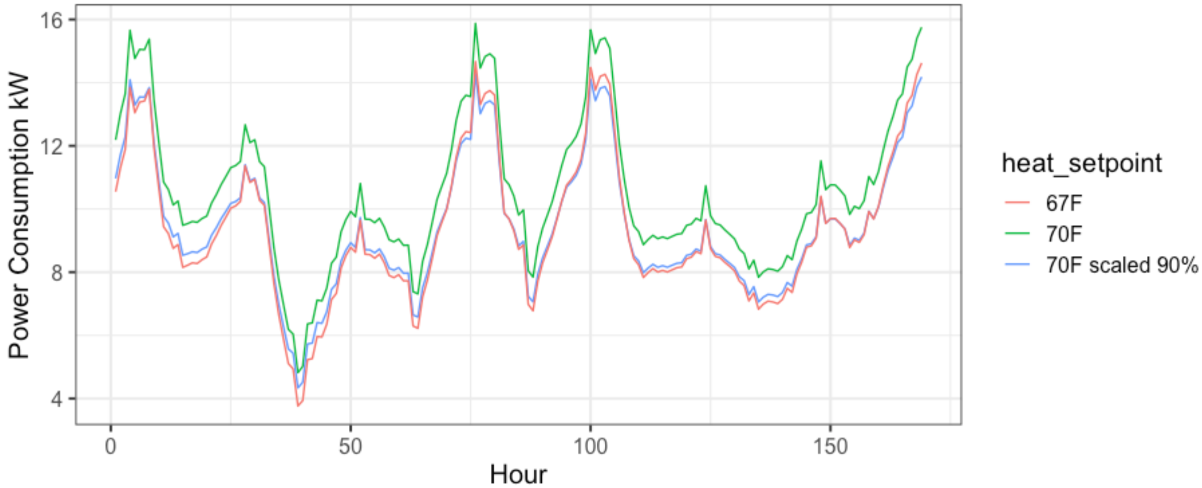

Figure C2. Using an electrically heated house we compare the relationship between ResStock's predicted energy consumption at 67ºF to scaling down the 70ºF heating profile to 90% of consumption.

To quantify this slight gap between the lower heating set point and scaled down higher heating set point, we plotted the wattage difference between the 67ºF predicted heating curve and the actual 67ºF heating curve. In the first boxplot below, Figure C3, the difference between predicted and actual is very large for electrically heated homes (± 400W), but seemingly insignificant for the other heating types. Although 400W may seem large, for a house that uses electric heating, which peaks around 10kW in the winter, a change in 400W is very small. Additionally, the percentage of houses that have electric heating in our hypothetical community is 5%, which means this difference will have no significant impact on the total feeder load.

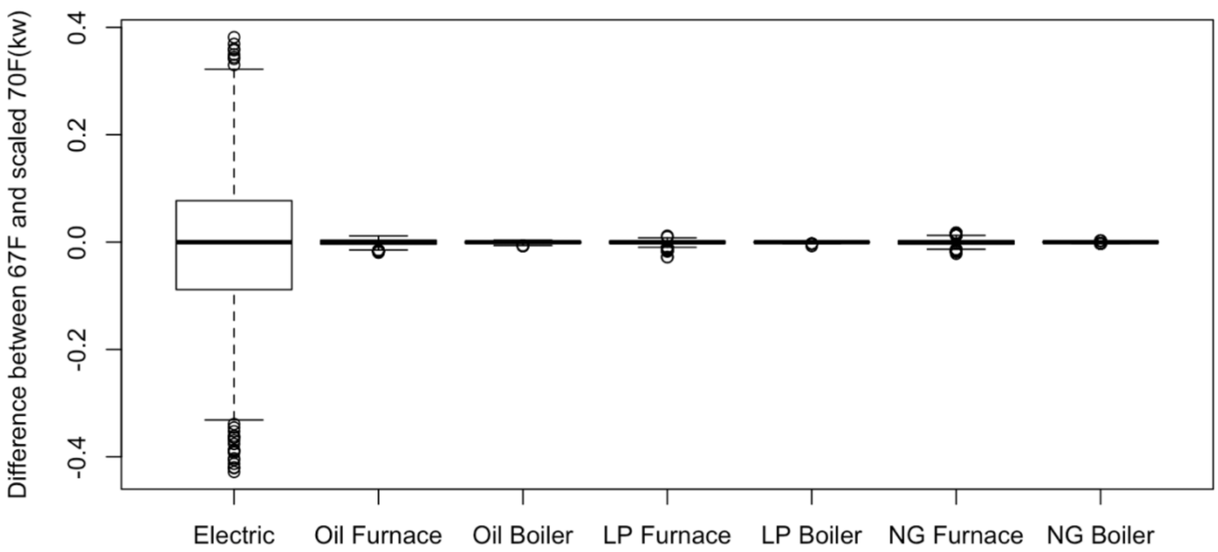

Figure C3. Box plot representing the difference in kilowatts between the actual 67ºF heating curve and predicted 67ºF heating curve (90% of the 70ºF curve) by house heating type. Each point represents the difference in hourly energy consumption in a typical year.

The second box plot below, Figure C4, removes the electric heating example to better visualize the difference in predicted vs. actual 67ºF heating load for other heating types. We see that in all of these cases the predicted load is within 20W of the actual load. This analysis implies that within the EnergyPlus modelling framework, when we hold all other house characteristics constant, changing the heating set point changes the scale of the heating load profile, but not its shape. Applying a single scalar for all time periods in the heating load profile provides a sufficiently close approximation to the actual heating profile of the same house with a lower heating setpoint. Knowing this, the next step is determining what that scalar should be.

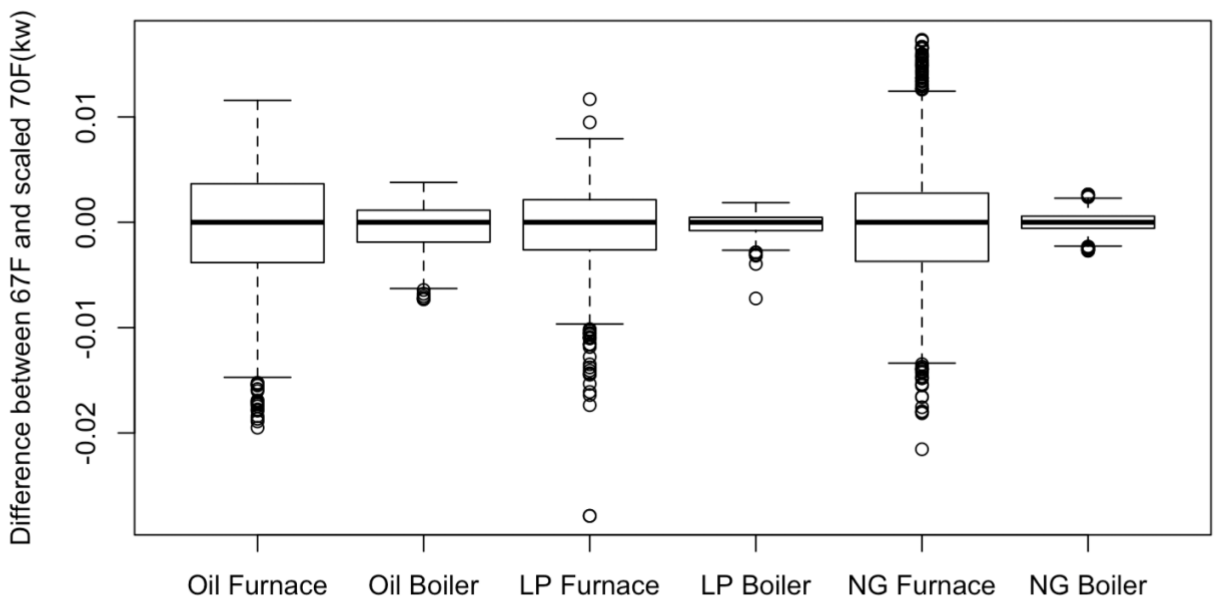

Figure C4. Box plot representing the difference in kilowatts between the actual 67ºF heating curve and predicted 67ºF heating curve (90% of the 70ºF curve) by house heating type with Electric heating removed for a better visual. Each point represents the difference in hourly energy consumption in a typical year.

Moon et. al (2011) studied the changes in annual energy consumption of a typical single-family home in Detroit, Michigan and Miami, Florida due to changes in thermostat setting. They determine that the annual energy consumption in Detroit, Michigan with a 50ºF setpoint is 17,508 kWh and a 67ºF set point is 22,071 kWh. The 50ºF setpoint energy consumption is 80% of the energy consumption at 67ºF. Given that Detroit, Michigan is in the same climate zone as New Hampshire according to PNNL's Distribution Taxonomy (Schneider et al., 2008), we assume the same relationship exists in the sample town in New Hampshire. We apply this scalar to the heating load of each individual house.

Refrigeration

We assume a refrigerator is not needed in the winter, because food could be kept outside. In warmer weather, we assume a refrigerator would need to run at its normal level and cycle to maintain its interior temperature. ResStock uses a distribution of 4 different refrigerator types based on efficiency ratings. This gives a peaking load of between 72W and 203W for an individual refrigerator depending on efficiency rating.

Minimal Lighting

We assume that the houses in this hypothetical community use efficient lighting, because being a town that values resilience, homeowners would know to install low wattage lighting. Compact fluorescent lamps (CFLs) and light-emitting diodes (LEDs) use 20W for the equivalent lumens that an incandescent light gives off at 100W(The Home Depot, n.d.). Therefore, we assume 20W per light and 6 lights maximum are on at any given time in an individual house, which gives a peak lighting load of 120W.

Charging Cellphones

We assume that communication during an emergency is a priority and being able to use cellphones at all times would be required. We assume each household would have 2 smart phones based on EIA RECS survey responses which report a median of 2 smartphones per household in very cold climate regions(Energy Information Administration (EIA), 2015). Additionally, we assume a smartphone would need to be charged once daily. An iPhone battery holds 5.45 watt hours of charge (Helman, 2013). So, if we assume each phone is charged once a day and it takes about 1-2 hours to charge each phone that would be a maximum of 10.9 watts, if one were charging both phones simultaneously. We assume a buffer for other phone types and therefore allocate 15 watts every hour of the emergency load for phone charging.

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APPENDIX D: Cost analysis assumptions

In conducting this cost analysis, we assume an implementation horizon of 25 years and consider LLD-outages of increasing severity: 5-, 10- and 20-day outages. This requires all systems to be well-maintained and supplied with enough fuel to meet the load during these three LLD-outage scenarios. We also assume that the PV + battery system is the only DG that is used for peak shaving purposes throughout the year. The cost savings associated with this operation are subtracted from the total system cost.

Our cost estimates for a residential PV + battery system are derived from an NREL study (Ardani et al., 2017) that reports a total installed cost for a 5.6kW PV + 20kWh/5kW battery system of $51,000 (2019 dollars). This estimate was validated through consultation with local New Hampshire solar companies with systems for sale that match our power generation requirements shown in Table DI. We find the average installed cost of PV systems across these New Hampshire companies to be $4.19/W (Solar Reviews, 2019). Assuming a 9.6kW PV system supplemented with a Pika Energy battery (16kWh/5.6kW) (EnergySage, 2019c) yields a total cost of $52,000 for both hardware and installation, which closely matches the NREL estimate. The range of available batteries and their associated capital costs are shown in Table DII.

Table DI: Solar installation costs from companies based near Hanover, New Hampshire (Solar Reviews, 2019).

Company	PV installed cost ($/W)
Patriot Solar Energy Inc	3.34
Revision Energy	4.01
New England Clean Energy	4.29
RGS Energy	4.68
Tesla/SolarCity reviews	5.09
Milhouse Enterprises Reviews	3.56

Snow Dragon Solar Reviews	4.39
Average	4.19

Table DII: Capital costs for batteries designed for PV storage that match our capacity requirements.

Battery	Bank Capacity (kWh)	Bank Power (kW)	Capital Cost ($)	Source
Tesla Energy Powerwall 2	14	5	6700	(EnergySage, 2019d)
LG RESU 10H	9.8	5	5880	(Solaris, n.d.)
Electriq Power PowerPod 20.2	20	5.5	8999	(EnergySage, 2019a)
Pika Energy Harbor 5*	16	5.6	12000	(EnergySage, 2019c)
Sonnen Eco 10	10	9	16750	(FreeCleanSolar.com, n.d.)
Blue Planet Energy Blue Ion 2.0	12	8	12950	(Spector, 2016)

* Pika Battery cost includes installation costs as well.

We also consider a smaller PV module installation cost—specifically, we adopt the national average of $3.7/W (Barbose & Draghouth, 2018), supplemented with a least cost battery large enough to serve our load[49]. This yields a conservative estimate of $45,000 for the entire system. As a result, the detailed NREL cost assessment described in Aradani (2017) is accepted as a good estimate for the cost of the residential PV + battery system that might be deployed in our simulated community, though we increase the size of the PV system from 5.6kW to 9.6kW to serve our load, which yields a total installed PV + battery cost of $54,000. We use NREL's SAM to predict the income that will be generated from the system's peak shaving operation throughout the year. SAM estimates that 6MWh of a household's annual load of 10MWh can be met with a

[49] A LG RESU 10H battery(Solaris, n.d.) with a conservative installation cost estimate of $2,000 (EnergySage, 2019d)

PV + battery system of that size; assuming New Hampshire electricity rates of $0.16/kwh (Electricity Local, 2019), homeowners would save approximately $1,000 a year through peak shaving operation. These cost assumptions and others which allow for the maintenance and operation of PV+ battery system are outlined in table D3.

Table D3: Cost Assumptions for PV + Battery system.

Parameter	Value	Source
PV + battery total installed cost ($)	54039	(Ardani et al., 2017)
solar panel life expectancy (years)	25	(EnergySage, 2019b)
annual panel maintenance cost ($)	211	(Fu, Feldman, & Margolis, 2018)
battery life expectancy (years)	15	(EnergySage, 2019b)
Cost to replace battery and battery inverter ($)	14795	(Ardani et al., 2017)
utility generation cost ($/kWh)	0.16	(Electricity Local, 2019)
Average household annual grid usage (kWh)	3933	(National Renewable Energy Lab (NREL), n.d.)
Average household annual load (kWh)	10117	(National Renewable Energy Lab (NREL), n.d.)

For each of the remaining DGs, we obtained cost estimates from different producers and third-party vendors. The average capital cost and fuel consumption at 50% load was determined for each system size and fuel type. Maintenance and upkeep of generators vary greatly by fuel type. If they are only used for backup, portable gasoline and propane generators require little maintenance—about $150 every 5 years[50]—but gasoline does not store for very long; it needs to be replaced every six months (Exxon and Mobil, n.d.) unless a fuel stabilizer is added in which case it can last up to 2 years(Amazon.com, n.d.). Therefore, if we want to have fuel on hand for a 5-,10-, or 20-day outage, we need to supply much gasoline that also has to be replaced every two years.[51] Similarly, diesel fuel needs to be polished every 2 years if it remains in a fuel tank, since mixing with water and oxygen can cause the fuel to become contaminated or break down (Generac Power Systems, 2010). Diesel fuel polishing requires specialized equipment and costs approximately $2/gal[52]. Propane and Natural gas do not suffer from these issues, though propane does need to be stored in a tank, which can be quite large and expensive if we are to have enough fuel on hand for a 100-150kW system during a 20-day outage (HomeGuide, 2019). Natural gas fed generators would only need access to a gas pipeline, which is a given in individual cases, but may require the installation of more lines for the collective scenarios. We assume $500 of the construction of short extra lines needed for clusters of 10 houses and $2,000 for clusters of 100 and full feeder in community 2 (HomeGuide, n.d.). Additionally, the cost of natural gas fuel itself is not included in this analysis be because it would be incurred at the time of outage. But the 10 house NG system would require $500-900 ($50-90 per household) at today's New Hampshire gas rates(Natural Gas Local, n.d.) to serve a 20-day outage; $2,300-4,700 ($23-47 per household) to serve 100 houses for a 20-day outage; and $23,000-50,000 ($14-30 per household) to serve the full feeder (1614 houses) in Community 2.

[50] Annual maintenance is estimated at about $150, but we are assuming that this system is only being run during an outage, so maintenance costs will only be incurred every 5 years. These costs typically include changing spark plugs, oil, oil filter and air filter. (Angie's List, 2018; Authorized Services of New England, 2018; Homeadvisor, 2019; Norwall PowerSystems, 2018)
[51] Although a household could use some of this gasoline in their vehicles before needing to replace it, for the purposes of this analysis, we assume that gasoline is a resilience cost.
[52] Generac Power Systems, personal communication. November 22, 2019

As with portable generators, diesel and LP/NG standby generators will not need much maintenance if they are only being run in an outage, although they do need to be started periodically to assure that they will be available when needed. Maintenance costs are dominated by labor to periodically test the system; this costs $35/kW (Ericson, Olis, & (NREL), 2019). Generac estimates that this load banking is required every 3 years for diesel systems and every 6 years for natural gas or propane systems; we use these parameters here (Generac Power Systems, 2016).

Table D4: Average capital cost ($\$10^3$) for back up generation by DG scenario[53].(Americas Generators, n.d.; Electric Generators Direct, n.d.; Northern Tool, n.d.; Norwall Power Systems, n.d.)

	Portable Gasoline/LP		**Standby Diesel**		**Standby (NG/LP)**	
Load	Community 1	Community 2	Community 1	Community 2	Community 1	Community 2
Individual	0.62	0.62				
Individual (electric heating)	0.89	0.89	3.8		3.6	
10 houses (baseline)			8.7	2.1	3.1	
10 houses (1.5 times)			12	5.6	3.5	2.0
10 houses (2 times)			14	10	4.8	2.9
100 houses (baseline)			12	17	19	15
100 houses (1.5 times)			28	16	13	19
100 houses (2 times)			26	22	28	24

[53] Feeder sized NG generator costs from personal communication with sales representative at Worldwide Power products June 10, 2020.

Feeder (baseline)		180	100		350
Feeder (1.5 times)		330	140		500
Feeder (2 times)		430	190		600

Table D5: Cost Assumptions for Portable Gasoline/LP.

Parameter	Value	Source
Maintenance cost - incurred once every 5 years ($)	150	(Angie's List, 2018; Homeadvisor, 2019)
Life expectancy (years)	25	(Authorized Services of New England, 2018)
Fuel cost ($/gal) (**LP**)	3.05	(Energy Information Administration (EIA), n.d.-b) (2019 average)
Fuel cost ($/gal) **(gasoline)**	2.63	(Energy Information Administration (EIA), n.d.-a) (October 2019)

Table D6: Cost Assumptions for Standby Diesel.

Parameter	Value	Source
Installation costs ($/kW)	150	(Generac Power Systems, 2016)
Maintenance cost - incurred once every 3 years ($/kW)	35	(Ericson et al., 2019)
Life expectancy (years)	25	(Authorized Services of New England, 2018)
Fuel Polishing ($/gal)	2	(*Generac Power Systems,*

		personal communication. November 22, 2019.)
Fuel cost ($/gal)	3.05	(Energy Information Administration (EIA), n.d.-a) (October 2019)

Table D7: Cost Assumptions for Standby Propane/Natural Gas.

Parameter	Value	Source
Installation costs ($/kW)	150	(Generac Power Systems, 2016)
Maintenance cost - incurred once every 6 years ($/kW)	35	(Ericson et al., 2019)
Life expectancy (years)	25	(Authorized Services of New England, 2018)
Cost of additional gas pipeline ($\$10^3$) (**NG only**)	0.5-2	
Purchase a tank for every non-individual application ($\$10^3$) (**LP only**)	1.5-250	(HomeGuide, 2019)
Fuel cost ($/gal) (**LP only**)	3.05	(Energy Information Administration (EIA), n.d.-b) (2019 average)

Microturbines are a relatively new technology, and the market is dominated by only a few companies. The most prominent producer in North America is Capstone; we therefore use the technical specifications and cost estimates of their C200S system. Although microturbines can technically be run on multiple fuel sources, there are minimum pressure requirements needed for the system, and the use of compressed natural gas (CNG) is not only advised, but also cheaper than other fuel sources—even if it needs to be trucked in[54]. Microturbines are designed to be modular, with smaller generators integrated together to meet a load, building redundancy into the system. One C200S microturbine has a total installed cost of $1 million, with an additional $625,000 per C200S added[55]. They require very little maintenance, with Environmental Protection Agency (EPA) estimates of approximately $8/kW/yr (Darrow, Tidball, Wang, & Hampson, 2015).

For community 2, additional costs include adding a natural gas line to the microturbine located near the substation, which we estimate cost $2000 (HomeGuide, n.d.). Additionally, the cost of natural gas fuel itself is not included in this analysis be because it would be incurred at the time of outage. For reference, using today's natural gas rates in New Hampshire (Natural Gas Local, n.d.) the microturbine would require $17,000-$28,000 worth of fuel for a 20-day outage ($11 – 17 per household).

Community one will instead have to transport and store CNG to use in the microturbine. Estimates for CNG storage are hard to find and usually exist in the context of building an alternative fuel refueling station; we assume costs of $70,000, $100,000 and $130,000 for building the infrastructure to store 5-, 10-, and 20-days' worth of fuel (Smith & Gonzales, 2014). Cost estimates for CNG trucking come from a World Bank (World Bank Group, 2015) study and are reported to be $163/gas gallon equivalent (GGE).

Table D8: Cost Assumptions for Microturbines.

Parameter	Value	Source

[54] Capstone Turbine Corporation, personal communication. October 29, 2019.
[55] Capstone Turbine Corporation, personal communication. October 29, 2019.

Capital + Installation costs per 200kw system ($)	1 million + 625,000 for every additional system	(*Capstone Turbine Corporation, personal communication. October 29, 2019*)
Maintenance cost ($/kW/year)	8	(Darrow et al., 2015)
Life expectancy (years)	25	(*Capstone Turbine Corporation, personal communication. October 29, 2019*)
Cost of additional gas pipeline ($\$10^3$) (**community 2**)	4	(HomeGuide, n.d.)
Storage Tank ($\$10^3$) **(community 1)**	70-130	(Smith & Gonzales, 2014)
Trucking ($/GGE) (**community 1)**	163	(World Bank Group, 2015)
Fuel cost ($/GGE) (**community 1)**	2.21	(U.S. Department of Energy, n.d.-b)

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APPENDIX E: Cost analysis results including cost sensitivity

Table E1. Bounds used in sensitivity analysis of the cost of various strategies. These are reported as percentages relative to a baseline point estimate derived either from the literature or from personal communication with producers or third-party vendors.

Parameter	Lower bound	Upper bound
Discount rate	0.07	0.03
Maintenance + installation cost	-50%	50%
Fuel cost	-25%	25%
PV + battery capital cost	-50%	0%
Electricity rate	-25%	25%
Transportation of CNG	-50%	50%
Storage tanks	-15%	15%
Gas lines	-15%	15%
Microturbine capital cost	-50%	0%

Table E2: Cost per household for 25 years of LLD-outage protection by contingency generation option at the *baseline load level* for individual houses in both Community 1 and 2. Values were rounded to two significant figures.

	Individual			**Individual (electric heating or well pump)**		
Baseline Generation	Lower bound ($\$10^3$)	Point ($\$10^3$)	Upper bound ($\$10^3$)	Lower bound ($\$10^3$)	Point ($\$10^3$)	Upper bound ($\$10^3$)
PV + battery	16	50	56			
portable gas 5-day	1.2	1.7	2.5	2.2	2.9	4.1
portable gas 10-day	1.7	2.5	3.6	3.2	4.5	6.4
portable gas 20-day	2.8	4.0	5.8	5.2	7.6	11
portable propane 5-day	0.84	1.1	1.5	1.1	1.3	1.7
portable propane 10-day	0.92	1.2	1.6	1.2	1.5	1.9
portable propane 20-day	1.1	1.4	1.9	1.4	1.8	2.3

standby diesel 5-day		5.0	6.5	8.3
standby diesel 10-day		5.4	7.2	9.7
standby diesel 20-day		6.1	8.8	13
standby propane 5-day		4.3	5.1	6.0
standby propane 10-day		4.4	5.2	6.2
standby propane 20-day		4.6	5.4	6.5

Table E3: Cost per household for 25 years of LLD-outage protection by contingency generation option at the *baseline load level for Community 1* for collective isolated microgrid scenarios. Values were rounded to two significant figures.

	10-House			**100-House**			**Full Feeder**		
Baseline Generation	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)
standby diesel 5-day	1.2	1.4	1.7	0.34	0.48	0.67	0.33	0.46	0.63
standby diesel 10-day	1.2	1.5	1.9	0.37	0.54	0.77	0.35	0.50	0.70
standby diesel 20-day	1.3	1.8	2.4	0.43	0.66	0.97	0.39	0.58	0.84
standby propane 5-day	0.66	0.81	0.98	0.40	0.50	0.60			
standby propane 10-day	0.68	0.83	1.0	0.48	0.59	0.71			
standby propane 20-day	0.86	1.1	1.3	0.58	0.74	0.94			
Microturbine 5-day							1.6	3.0	3.3
Microturbine 10-day							1.8	3.5	4.0
Microturbine 20-day							2.3	4.4	5.4

Table E4: Cost per household for 25 years of LLD-outage protection by contingency generation option at the *baseline load level for Community 2* for collective isolated microgrid scenarios. Values were rounded to two significant figures.

	10-House			100-House			Full Feeder		
Baseline Generation	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)
standby diesel 5-day	0.41	0.54	0.70	0.36	0.47	0.61	0.22	0.29	0.39
standby diesel 10-day	0.45	0.61	0.83	0.38	0.52	0.69	0.23	0.31	0.44
standby diesel 20-day	0.52	0.75	1.1	0.43	0.61	0.87	0.25	0.35	0.52
standby NG 5-day	0.43	0.52	0.63	0.31	0.37	0.44	0.35	0.39	0.43
standby NG 10-day	0.43	0.52	0.63	0.31	0.37	0.44	0.35	0.39	0.43
standby NG 20-day	0.43	0.52	0.63	0.31	0.37	0.44	0.35	0.39	0.43
Microturbine 5-day							0.88	1.7	1.7
Microturbine 10-day							0.88	1.7	1.7
Microturbine 20-day							0.88	1.7	1.7

Table E5: Cost per household for 25 years of LLD-outage protection by contingency generation option at the *150% baseline load level for Community 1* for collective isolated microgrid scenarios. Values were rounded to two significant figures.

	10-House			100-House			Full Feeder		
150% Baseline Generation	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)
standby diesel 5-day	1.6	1.9	2.3	0.56	0.78	1.1	0.50	0.70	0.97
standby diesel 10-day	1.6	2.1	2.6	0.68	1.0	1.5	0.53	0.77	1.1
standby diesel 20-day	1.8	2.4	3.2	0.76	1.2	1.8	0.59	0.91	1.3
standby propane 5-day	0.75	0.94	1.2	0.38	0.51	0.66			

standby propane 10-day	0.78	0.99	1.2	0.46	0.61	0.78			
standby propane 20-day	0.98	1.2	1.5	0.57	0.71	0.85			
Microturbine 5-day							2.5	4.1	4.5
Microturbine 10-day							2.9	4.8	5.6
Microturbine 20-day							3.5	6.1	7.5

Table E6: Cost per household for 25 years of LLD-outage protection by contingency generation option at the *150% baseline load level for Community 2* for collective isolated microgrid scenarios. Values were rounded to two significant figures.

	10-House			**100-House**			**Full Feeder**		
150% Baseline Generation	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)
standby diesel 5-day	0.80	0.96	1.2	0.38	0.52	0.70	0.27	0.36	0.49
standby diesel 10-day	0.84	1.1	1.3	0.45	0.69	1.0	0.28	0.39	0.54
standby diesel 20-day	0.93	1.2	1.6	0.52	0.82	1.2	0.31	0.46	0.65
standby NG 5-day	0.43	0.52	0.63	0.37	0.44	0.53	0.46	0.51	0.58
standby NG 10-day	0.43	0.52	0.63	0.37	0.44	0.53	0.46	0.51	0.58
standby NG 20-day	0.43	0.52	0.63	0.37	0.44	0.53	0.46	0.51	0.58
Microturbine 5-day							1.1	2.1	2.1
Microturbine 10-day							1.1	2.1	2.1
Microturbine 20-day							1.1	2.1	2.1

Table E7: Cost per household for 25 years of LLD-outage protection by contingency generation option at the *200% baseline load level for Community 1* for collective isolated microgrid scenarios. Values were rounded to two significant figures.

	10-House			100-House			Full Feeder		
200% Baseline Generation	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)
standby diesel 5-day	1.9	2.3	2.9	0.59	0.86	1.2	0.62	0.89	1.2
standby diesel 10-day	2.0	2.5	3.2	0.63	0.95	1.4	0.66	0.98	1.4
standby diesel 20-day	2.1	2.9	3.9	0.72	1.2	1.7	0.75	1.2	1.7
standby propane 5-day	0.96	1.2	1.6	0.63	0.81	1.0			
standby propane 10-day	1.1	1.4	1.8	0.73	0.92	1.2			
standby propane 20-day	1.9	2.4	2.9	0.81	1.0	1.3			
Microturbine 5-day							4.0	5.7	6.3
Microturbine 10-day							4.5	6.7	7.7
Microturbine 20-day							5.4	8.5	11

Table E8: Cost per household for 25 years of LLD-outage protection by contingency generation option at the *200% baseline load level for Community 2* for collective isolated microgrid

	10-House			100-House			Full Feeder		
200% Baseline Generation	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)	lower ($\$10^3$)	point ($\$10^3$)	upper ($\$10^3$)
standby diesel 5-day	1.3	1.5	1.8	0.47	0.64	0.87	0.32	0.44	0.60
standby diesel 10-day	1.4	1.6	2.0	0.50	0.72	1.0	0.34	0.48	0.67
standby diesel 20-day	1.5	1.9	2.4	0.58	0.87	1.3	0.38	0.56	0.80
standby NG 5-day	0.53	0.65	0.79	0.44	0.54	0.65	0.54	0.60	0.70

standby NG 10-day	0.53	0.65	0.79	0.44	0.54	0.65	0.54	0.60	0.70
standby NG 20-day	0.53	0.65	0.79	0.44	0.54	0.65	0.54	0.60	0.70
Microturbine 5-day							1.3	2.5	2.6
Microturbine 10-day							1.3	2.5	2.6
Microturbine 20-day							1.3	2.5	2.6

Appendix F: **Tropical Storm Data Collection Details**

The area of impact and relevant weather data for each storm was found using the names and dates of the storms provided by the utility and searching both NOAA National Hurricane Center's TC Reports[56] and NOAA's Storm Events Database[57]. When these databases were missing information about a particular service territory, multiple sources were used to supplement. Among these are NOAA tides gauges[58] to estimate storm surge; the rain gauges from the University of Florida's Florida Automated Weather Network (FAWN) to estimate rainfall and storm duration[59]; the rain gauges from the Florida Data Climate Center at Florida State University[60]; the rain gauges from the South Florida Water Management government organization[61]; and historical wind and precipitation data from weatherspark.com. The latter source gets its weather data from NASA's MERRA-2 database[62]. MERRA-2 provides weather data at a 50km grid resolution and predominately collects data from airports. Using these databases, estimates for maximum 3-second wind gust at NOAA's standard 10m measurement height (in mph), storm surge (in ft), total rainfall (in inches), duration of rainfall (using as an indicator for "total storm" duration) and area of impact for each utility were collected. This appendix details the situations for each storm when the NOAA Tropical Cyclone or NOAA Storm Events Databases were not used and when there was conflicting information.

March 2007 Gulf Emergency Operations Center (EOC) Activation. Gulf states in their annual reliability report there was an Emergency Operations Center Activation for a March 1-2 storm in Escambia County. NOAA Storm Database has nothing on this storm in Escambia County. This particular thunderstorm impacted Duke and FPL significantly more than any other Gulf County. Still reporting the information available for the 3 other gulf counties. Using NOAA's historical tide gauge information for Panama City, "8729108 Panama City, FL", storm surge is estimated at 1.52ft. Additionally, the two locations of thunderstorms were in Walton and Holmes Counties and the only rain gauge near there with data from 2007 is the Bob Sikes Airport from weathersparks.com, which reported 2.17inches of total rain, also was also used to estimate most rainfall in an hour and total rain duration.

TS Barry 2007. Using NOAA's historical tide gauge information for "8726607 Old Port Tampa, FL" the estimated storm surge at the time of the incident is 2.03ft for TECO, and 1.672ft at the

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[56] https://www.nhc.noaa.gov/data/
[57] https://www.ncdc.noaa.gov/stormevents/
[58] When the tropical cyclone reports did not report storm surge values, storm surge was estimated it by checking the tide gauges associated with each utility during the time of the storm and seeing the difference between Mean Lower Low Water predicted and actual Mean Lower Low Water levels. MEAN Lower Low water (https://tidesandcurrents.noaa.gov/datum_options.html)
[59] https://fawn.ifas.ufl.edu
[60] https://climatecenter.fsu.edu/climate-data-access-tools/downloadable-data.
[61] https://www.sfwmd.gov/weather-radar/rainfall-historical/daily
[62] https://gmao.gsfc.nasa.gov/reanalysis/MERRA-2/

“726384 Port Manatee, FL” tide gauge for FPL. Used Dover FAWN rain gauge to estimate rain duration for TECO. For FPL - None of the weatherspark gauges near Flagler beach show significant rainfall. However, the Southern Florida Water Management gauges near palm beach have a total of 5.51 inches of rain over 11 hours with a peak of 2.05 inches in an hour which tracks with what the storm database estimated for the storm. For Duke most rainfall fell in Pasco County in Holiday, rain gauges near there showing ~3 inches.

TS Fay 2008. Tampa Bay was relatively protected from the storm, but other parts of Polk County got 6-14 inches of rain but TECO did not list TS Fay as an excludable event, even though every other utility did. Although the Storm Events Database records weather for Nassau County there isn’t any detail information on the weather for the county/Fernandina Beach. Weatherspark.com has historical weather data for Jacksonville Airport so I can estimate wind gust at 57 mph. Additionally the Florida Climate Center at Florida State University has daily precipitation values for Fernandina Beach specifically[63]. Using those to total estimate rainfall. Used weatherspark Jacksonville airport to determine how many hours of just rain over that time period and assume Ferninadina would have been the same. “8729108 Panama City, FL” tide gauge showed 0.2ft storm surge for Gulf and 8727520 Cedar Key, FL tide gauge showed 2.65ft storm surge for Duke, 3.05 storm surge for 8720030 Fernandina Beach, FL (FPUC-NE). According to the storm events database the most rain to fall on Gulf was in Jay and Milton with about 3 inches. However, after checking the Jay FAWN station and the Milton Whiting Field weathersparks station it looks like under 1 inch at those locations. It would appear Panama City got the most rain being closest to the big bend at 1.19inches total with a duration of 17 hours of rainfall. Although Brevard county had the most rain, none of the weatherspark stations near there were recording rainfall so used the South Florida Water Management daily finder[64] and found the largest rainfall at 15.27 in Palm Beach County with maximum in one hour at 2.59 over 49 hours of rainfall. Not a lot of rain gauges in the Big Bend (Duke) but Madison county experienced quite a bit of rain (up to 16inches) with flooding in low lying areas, Monticello FAWN station is in Madison and recorded 13.88 inches of rain over 40 hours with 1.6 as the most in one hour. Used weatherspark Marianna airport to estimate windspeed in Marianna for FPUC-NW.

Hurricane Ike/Gustav 2008. Duke and Gulf both experienced some large surf due to Gustav and Ike which were back to back storms (9/1 and 9/10). However, Duke only listed Ike as an excludible event and Gulf only listed Gustav, even though both storms seem about the same severity for both utilities. In fact, the Duke coastal areas had about a million dollars worth of damage with Gustav but Ike has none. Gulf also had $1 million in property damage with Ike but only $500,000 with Gustav. Additionally, Hurricane Ike affected FPL but they did not list it as an excludable event. I’m assuming the duration in Gulf is the same for FPUC-NW because they are next to each other and there is only a 1-minute tornado reported for FPUC-NW in the storm

[63] https://climatecenter.fsu.edu/climate-data-access-tools/downloadable-data
[64] https://www.sfwmd.gov/weather-radar/rainfall-historical/daily

events database. The most rainfall for Gulf reported in Destin, Checked weathersparks Destin Executive airport weather stations for rainfall duration (7 hours).

Hurricane Ida 2009. "The cyclone dissipated over the Florida Panhandle at 1200 UTC 11 November. Ida's remnants contributed to the formation of a separate, strong extratropical low that affected the U.S. east coast during the following few days." Although the extra-tropical portion of the storm likely passed over FPUC-NW. There is not a lot of information in the storms event database, however the Marianna FAWN Rain Gauge provided rainfall data and the Marianna Airport station on weathersparks provided windspeed data. Additionally, a weather.gov map of Ida indicates the windspeeds would have been below 35mph and rainfall 3 inches or less (US Department of Commerce, n.d.-a). Used 8728690 Apalachicola, FL tide gauge to estimate Duke storm surge (2.971ft) and 8729108 Panama City, FL tide gauge to estimate Gulf's storm surge (2.6 ft). Maximum total rainfall was in Gulf's territory at Bob Sike's airport on weathersparks. Although the NOAA Storm Events Database reported coastal flooding, there was less rain on the coast so it may have been due more to storm surge or a combination of both. For Duke's territory Apalachicola weatherspark station indicated 1.42 inches in 17 hours with 0.32 in one hour.

FPL EOC 2009. Used "8720218 Mayport (Bar Pilots Dock), FL" tide gauge to determine storm surge during this time (1.9 ft). This storm happened in the middle/north part of the Florida eastern coast. Daytona beach airport on weathersparks recorded 20.31inches over 5 days (81 hours of rain).

2009 FPUC-NW flooding – Very bad storm with lots of flooding in north florida and south Georgia. Used FSU climate summary data to estimate 12 inches of rainfall (Florida Climate Center, n.d.) and used FAWN Marianna station to estimate duration (total rainfall was lower at the station but assuming FSU is correct).

TS Claudette 2009. FAWN Marianna Rain gauge only shows 0.16 inches of rain fell in 2 hours. The Marianna Airport station on weathersparks provided windspeed data. Largest rainfall was in Milligan, Florida which is in Gulf territory according to Storm Events database. Closest rain gauge is in Duke Field on weathersparks.com which shows a duration of rainfall of 10 hours (Duke field's total rainfall was 3.11in). For Duke, used weatherspark Apalachicola gauge to estimate duration of rainfall. Apalachicola experienced about 4 inches of rain for TS Claudette, no flooding was reported. However, there was 2 inches of rain the previous day but both Duke and storm events database indicate storm started on 16th not 15th so did not include that rain.

TS Bonnie 2010. Duke claimed this as an excludable event, but I can only find one instance of thunderstorms in Pinellas county on the Storm Events database: "Numerous thunderstorms developed across the area in the warm and moist environment behind Tropical Storm Bonnie. An individual was struck by lightning from one of these storms." No weather variables were reported in the Tropical cyclone report or storm events database. Duke claims outages from July 23-25 and that there were sustained windspeeds of 30-40mph, but I just see a gust in St Petersburgh airport of 32.2mph and a total of 1.45in of rain in 7 hours using weatherspark. Used 8726520 St. Petersburg NOAA tide gauge to estimate storm surge during that time as well. Conversely, Gulf's service territory recorded 60 mph wind gusts and $17000 in property damage but Gulf did NOT claim TS Bonnie as an excludable event. Minimal effects on Miami-Dade county reported in the NOAA storm events database, so I used South Florida Water Management gauge for Miami-Dade county to record 2.09 inches over 7 hours.

TS Nicole 2010. Using Monroe County duration to estimate storm duration for FPL, because otherwise there is only one entry in the storm events database that implies a single minute of duration. 0.56ft storm surge estimated using "8723214 Virginia Key, Biscayne Bay, FL" tidal gauge for FPL. Minimal effects on Miami-Dade county so use south Florida water management gauge in Miami-Dade county that had 6.92inches over 27 hours.

Hurricane Irene 2011. Looking at rain map Figure 7 in Tropical Cyclone Report, I am assuming 1 inch of rain for FPL. Storm hit the Flagler beach to Jacksonville area, not a lot of rain because it was actually off the coast. Northeast Florida Regional Airport (weatherspark) got the most rain at 1.58inches in 6 hours.

TECO Thunderstorm 2011 - 2.1ft storm surge estimated using "8726607 Old Port Tampa, FL" tidal gauge. There was no rainfall reported in the Storm events database but of the available TECO rain Gauges the MacDill Air Force base reported the highest of 4.93 inches (weathersparks). Used FAWN Dover rain gauge to estimate duration.

TS Lee 2011. 2.23 ft storm surge estimated using "8728690 Apalachicola, FL" tidal gauge. According to NOAA Storm Events Database there was a pretty wide effect in Duke territory, with some flooding near Tallahasee which I can't really find any rain data on and some in Franklin county due to storm surge but also a little rain. Used Apalachicola weatherspark station to estimate duration. For Gulf, it was reported in the storm events database there was 2-3ft of water over roadways was in Crestview Fl, which the Bob Sikes Airport (weathersparks) is also in. So used this station to estimate duration.

FPUC-NE EOC 2011. Used "8720030 Fernandina Beach, FL" tide gauge to determine tide levels during this time (0 ft). For whatever reason the NOAA and the Florida Climate Center have no data from 2011 at Fernandina Beach weather stations so I can't confirm the events listed in the Storm Events Database. "An unstable airmass coupled with active sea breezes produced scattered severe storms across the forecast area during the late afternoon and early evening hours. The park ranger at Fort Clinch state park reported standing water of 1 foot on the roads.

Fire trucks had difficulty maneuvering the roads to respond to lightning damage calls. NWS radar estimated 8 to 10 inches across Fernandina." Jacksonville International Airport which is ~20 miles inland from Fernandina Beach only experienced 0.36in for the entire day of September 26. Similarly, Jacksonville Beach, which is also along the coast about ~35-40 miles south as the crow flies, rain gauge also indicated only 0.26 inches of rain (which is close to McCormick road Jacksonville which the Storm Events Database states had trees blown down over). Although more than that clearly hit Fernandina Beach, 8-10 inches seems a little high…. Based on this information I am just guessing that 8 inches fell over 5 hours in Fernandina.

Gulf EOC Flooding 2012. Used the 8729840 Pensacola, FL tide gauge to estimate storm surge, 1.02 ft. Used Pensacola International Airport (which had the highest flooding in the storm events database) from weathersparks to estimate duration and total rainfall (20.47in). The storm events database estimated up to 48 inches of rain in Escambia county using radar. But the rain gauges near Escambia (Jay FAWN station) registered around 10 inches, with Pensacola registering the highest in all of Gulf's territory. Assuming the actual rain gauge data is correct over the storm events estimate.

TS Isaac 2012. FPUC-NW claimed TS Isaac 2012 as an excludable event but it seems they just experienced "outer remnants of Hurricane Isaac spawned a couple of funnel clouds and tornadoes". So, this may be more of a just a tornado outage. Using Marianna FAWN Rain Gauge, we get an estimate of 1.81in of rainfall and 11 hours of duration. I estimated windspeed using the Marianna Airport station on weathersparks. Tropical cyclone report registered 2.7in for Tampa, and Use Dover FAWN station to estimate duration for TECO. Used Destin executive airport (weatherspark) station for rain duration estimate in Gulf. For FPL much of northeast Florida experienced flooding in Duval, Clay and Suwannee counties. Live Oak FAWN rain gauge actually reported more rain that was reported in the Tropical Cyclone report at 20.12 inches, so used this station to estimate duration but assumed Troprical cyclone report was correct for total rainfall. Longest duration of storm was in south Florida, so used the South Florida water management rain gauges and 28 hours of rainfall on Okeechobee for FPL. Rainfall and flooding in Osceola and highland counties for Duke. Lake Alfred FAWN station closest was the closest and used to estimate duration (17 hours).

Hurricane Sandy 2012. Duke claimed Hurricane Sandy 2012 as an excludable event. Hurricane Sandy moved up the Atlantic, offshore and parallel to the eastern coast of Florida. Duke doesn't serve any eastern coastal areas of Florida. From the storm events database the only 2 counties that both Duke and FPL serve seemed to have been affected by the storm were Flagler and Brevard but the description of the events described wind/storm tide along the coast of these counties. The tropical cyclone report does indicate that the Orlando area was impacted which is theoretically in Duke's territory, although a quick google search shows that the Orlando area electricity may be run by a municipal organization. But because I don't know for sure and of course weather data is limited I'm going to use Orlando data for Duke in this situation. FPL had the most rain in Daytona Beach according to tropical cyclone report at 4.3 in. Daytona airport (weatherspark) was closest but only measured 1.5inches, but used this anyways to estimate a duration of 8 hours.

TS Beryl 2012. "The remnants of Tropical Storm Beryl affected the southeast big bend of Florida with very heavy rainfall, in excess of 12 inches in some areas. However, due to the ongoing extreme drought across the area, no flooding of significance was reported" (Storm Events Database). Using Naval Station Mayport as estimate for rain and duration for FPUC-NE (weathersparks.com). Duke storm surge estimated with "8727520 Cedar Key, FL" NOAA tidal gauge at 1.59 feet. Wellborn in Suwannee according to the Storm Events Database measured 15 inches of rain, but the FAWN Live Oak rain gauge only measured a little under 5 and that is 11 miles from Wellborn. Similarly, Jacksonville experienced flooding but all the Jacksonville rain gauges only measure about 5 inches of rain so not sure what was happening there. Used the Live Oak station to estimate duration of rainfall for FPL. Minimal rain gauges in this part florida (big bend) so the highest I found was Ocala international airport in Marion county which did experience thunderstorms and flooding at 3.23in of rainfall for Duke. However, I used the FAWN Citra rain gauge to estimate duration (citrus county also flooded) because it more correctly matches the duration in the storm events database so I trust it more.

TS Debby 2012. FPUC-NE did not report this as an outage but there is NOAA data for storm tide and wind speeds affecting Fernandina Beach. Used the wind information in the tropical cyclone report for Marianna (FPUC-NW) although the NOAA storm events database doesn't register anything for Marianna. Also using Marianna FAWN rain gauge to estimate rainfall and duration. Gulf storm surge estimated with "8729108 Panama City, FL" at 1.63 feet. Tampa International Airport on weatherspark.com highest rainfall was 9.31 for TECO, but assumed storm events database was correct instead with 11.91in of rainfall near Citrus Park. Use FAWN Dover for duration because its easier and duration is pretty standard in areas near each other.

FPL 2013 EOC activation. "Thunderstorms developed a pre-frontal squall line and developed two prominent bow echoes. The bow echoes raced east at 55-60 mph from the central Florida interior and persisted to the Brevard County coast. Significant straight-line wind damage occurred along two long swaths, from southwest Lake County to Cocoa, and from Orlando to Cape Canaveral. Winds were measured up to 86 mph at two observing sites in Orange County. Much the surrounding areas of Lake, Orange, and Brevard Counties (as well as adjacent portions of Seminole and Osceola Counties) experienced minor wind damage. A woman was injured in Cocoa when a tree fell on the Florida room that she was entering from outdoors. Damage estimates totaled over $3M, of which $2M was from the collapse of a storage warehouse under construction in Orlando. The remainder of the cost estimate was a result of falling trees and mainly minor structural damage." Duke, FPUC-NW and Gulf also experienced the thunderstorms and large hail but did not report this event. However, it seems the extremely high wind speeds were mostly contained to FPL's territory and likely the predominant outage cause. Estimated storm surge using "8721604 Trident Pier, Port Canaveral, FL" tide gauge at 1.19 ft. Live Oak FAWN station had closest rainfall measurement compared to storm events database (4.52) and measured total rainfall of 3.97 over a duration of 17 hours.

Gulf 2013 Flash flooding. "A very anomalous pattern set up across the U.S. in early July featuring a persistent upper level trough over and just west of the Mississippi Valley and a downstream ridge off the Mid Atlantic Coast. This brought deep layer moist tropical air into the Southeast for several consecutive days resulting in torrential rains, flash flooding and river flooding. While several episodes of severe weather also occurred during this period, the heavy rain and accompanying flooding were the primary impacts. Between 10 and 20 inches of rain fell in a three day period between July 2-4, and serious flooding occurred across portions of the Florida Panhandle with Walton, Holmes, and Washington counties declared federal disaster areas. Damage estimates include $11 million for Walton county, $18.7 million for Washington County (including $3.7 million for the town of Vernon alone), $8.5 million for Holmes county, and $1 million for Bay county. Most of the damage was due to roads and bridges, but some structures were also affected." 8729108 Panama City, FL tide gauge showed 1.46ft storm surge for Gulf. Rain Gauge with the most rainfall was Northwest Florida beaches airport in Panama city (weathersparks.com) with 11.5 inches over 43 hours of rainfall, but assumed 20 inches for rainfall in the analysis.

TS Andrea 2013. It likely that FPUC-NE experienced an EF01 Tornado that may have resulted from TS Andrea, "A few tornadoes were spawned along the Duval and Nassau county Atlantic coasts...with gusty tropical storm force winds and locally heavy rainfall over inland areas." Using 8720030 Fernandina Beach, FL tide gauge for FPUC-NE (7.17ft). Using a weather.gov rain map (US Department of Commerce, n.d.-b), estimating 1.5 inch for FPUC-NE. Using Florida Climate Center Rain Gauge for Fernandina beach total rainfall was 3.9inches. Based on the path of the storm, it looks like Jacksonville International Airport would have experienced the most close rainfall, used weathersparks.com to determine rainfall duration. For TECO used Dover FAWN station for rainfall duration. Dover rainfall is within 2 inches of total measured near Lutz in the storm events database. According to storm events database about 13 inches of rain fell in Miami beach on 6/7 and they cite the south Florida water management rain gauges, well looking at these rain gauges I don't see any rainfall greater than 3 inches on that day. Similarly, the weatherspark Miami international airport also only registered about 2 inches of rain. I used the weatherspark location to estimate duration and still assumed the events database was correct with rainfall. The Storm Events Database also implied heavy rain in Pinellas through Levy counties for Duke, but the most I could find was measured at St. Petersburg airport on weatherspark with 3.4 inches over 16 hours. Still assumed storm events databse was correct with 6.17 in.

TS Karen 2013. I can find 0 weather information for Gulf's service territory for this tropical storm. (not even light rain or thunderstorm). In fact the tropical cyclone report specifically states" Given the weakening trend on 4 October, the hurricane watch was discontinued at 2100 UTC 5 October. All remaining tropical storm warnings were discontinued early on 6 October when Karen was downgraded to a tropical depression. No tropical-storm-force winds occurred along the northern Gulf coast." Using rainmap for storm it would appear bay county would have been hit the worse, so I use Tyndall AFB weathersparks to estimate wind, rainfall and duration. Used 8729210 Panama City Beach NOAA tidal gauge to estimate storm surge. Also since the storm events database didn't have anything on this, I'm estimate that this impacted Bay, Washington, and Walton counties based on a NOAA rain map[65]

EOC 2014 FPL. Heavy rainfall in under 24 hours (most within 6 hours) + straight line wind event. Estimated storm surge using "8723214 Virginia Key, Biscayne Bay, FL" tide gauge at 0.97 ft. South Florida water management does not record the same high values only about 4.5 inches in palm beach and martin/st-Lucie counties. Going to assume storm events database is correct and that 22.21 inches fell in 6 hours which we can use to estimate total and duration.

Hurricane Arthur 2014. Had pretty minimal impact on Florida. Duke and FPL's territory had thunderstorms in the days following hurricane Arthur (while it moved up the east coast) there is a chance they included these storms under the umbrella of "hurricane Arthur". Additionally, Fernandina had some storm surge but FPUC-NE didn't report it. Putnam and St John's counties were affected, only one rain gauge along the coast on weatherspark.com at the Northeast Florida Regional Airport in St John's and the Putnam Hall FAWN rain gauge. The Putnam one had more rain so used that for total and duration. Using 8727520 Cedar Key, FL tide gauge to estimate storm surge (0.63ft). Wakulla county had a lot of power outages due to wind and there was some heavy rain in hamilton county with 4 inches in 2 hours, confirmed with live oak, and Apalachicola rain gauges that rainfall was really just for 4 hours and use storm events database for rate which said 4 in 2 so 2/hour.

EOC 2014 Gulf. "Central and southern Escambia county experienced historic flooding the night of April 29th into the early morning of April 30th. Nearly 2 feet of rain fell across portions of southern Escambia County. Pensacola International Airport recorded a storm total of 20.47 inches." Rain Gauge with the most rainfall recorded was Hurlburt air field (weathersparks.com) with 12.27 inches and fastest rainfall in one hour was at DeFuniak Springs 3.83in and 21 hours of rainfall. Found nothing close to 20 or even 48inches, including at the weathersparks Pensacola international airport. I split the difference and assumed 20.47 was the highest amount of rainfall and used 8729108 Panama City, FL tide gauge to estimate storm surge for Gulf (1.318ft).

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[65] https://www.wpc.ncep.noaa.gov/tropical/rain/karen2013filledrainwhite.gif

The 2014 FPL "unnamed TS" was actually not a TS but FPL labelled it as such in their CMI/CI data: "A pre-frontal squall in and mesolow tracked across southeast Georgia and northeast Florida in several waters of convection through the day. High instability was present, with upper level forcing in place ahead of a long wave trough. The tornado was a associated with the core of a mesolow that tracked ENE inland from the Gulf Coast and over Columbia county and NE over Charlton County. Very heavy rainfall of 4-6 inches occurred over 24 hours with hourly rainfall rates of 2-3 inches in some locations." However, looking at the FAWN rain gauges the Storm Events database referenced (Alachua and Live Oak) do not match what they say happened! There was 1.07 inches of rainfall in Alachua in an hour not 2.6 like the storm events database said and the total in Alachua was 2.23in and in Live Oak was 3.18in. Since Live Oak was greater split the difference in duration (13 hours in Alachua and 19 hours of rainfall in Live Oak so 16). Estimated storm surge using "8721604 Trident Pier, Port Canaveral, FL" tide gauge at 0.44 ft.

2015 Duke EOC flooding. "A weak area of low pressure developed along a stationary frontal boundary across north Florida. This allowed for waves of showers and thunderstorms to move across the area for a few days causing flooding throughout much of the Tampa Bay area. The heaviest rain fall on the morning of the 3rd with some portions of Hillsborough, Pinellas and Pasco Counties receiving 6 to 8 of rain. This event was exacerbated from the flooding and saturated soils from multiple heavy rain events that occurred on August 1 and again during the last week of July." No wind gust values were given in storm events database but use St. Petersburg airport weatherspark station which measured 41.4mph gusts also used this station to confirm 6-hour duration of rainfall. Estimated storm surge using "8726724 Clearwater Beach, FL" tide gauge at 1.256 ft.

TS Erika 2015 didn't really hit Florida other than "The remnants of T.S. Erika crossed the forecast area from the Gulf region through the day. High moisture combined with forcing and weak onshore convergence around the remnant low brought waves of heavy rainfall and isolated strong storms." Estimated storm surge using "8720218 Mayport (Bar Pilots Dock), FL" tide gauge is 0.15 ft. Except this narrative was for 9/2 and FPL only reported outages for Erika from 8/28-8/31 which means they were referring to the other storms that happened during this time. The actual storm event was "An upper level low over the lower MS River Valley continued a moist and divergent upper level southerly flow over the local area. Combined with daytime heating, scattered strong storms and heavy rainfall impacted the area." Additionally the extreme amount of rain reported in Alachua does not match the Alachua FAWN rain Gauge and also not seeing this in the northeast Florida airport in St John's county or in Daytona beach (closest rain gauge to Flagler). But pretty much the storm events database has what we need.

Gulf EOC 2016 back to back thunderstorms in February. It looks like some of Duke's service territory was also impacted by the Feb 15 thunderstorms but they did not make this an excludable event. Overall the only reason both of these events seem to be excluded is because of 2 big tornadoes. Feb 15 thunderstorms: "A strong upper level trough and cold pushed through the region during the evening of February 15th. Ahead of it, a squall line progressed across the area with reports of damaging wind gusts, mainly in the form of trees and power lines blowing down." There was an EF03 tornado that caused $5million in damage Feb 15. Feb 23 thunderstorms: "A unusually strong storm system produced a highly favorable setup for severe thunderstorms and tornadoes. The highest impact across the Florida Panhandle was from a strong tornado that impacted the Pensacola metro. Some flooding was also experienced." Another EF03 tornado that caused $22 million in damage on Feb 23. For Rainfall for these events: Feb 23 DeFuniak Springs experienced flooding according to storm events database and the FAWN DeFuniak Springs rain gauge reports 4.23 in of rain and 4 hour duration. The Feb 15 event Northwest beaches Florida airport in Panama city had the most rainfall at 1.71in over 7 hours (weathersparks.com). Using the 8729210 Panama City Beach, FL Tide Gauge to estimate storm surge for both storms.

Hurricane Hermine 2016 – No Storm database records for FPUC-NW. Used 8720030 Fernandina Beach, FL tide gauge to estimate storm surge for FPUC-NE. Marianna FAWN gauge for duration and rainfall and the Marianna Airport station on weathersparks provided windspeed data. For FPUC-NE using Florida Climate Center Rain Gauge for Fernandina beach total rainfall was 1.47inches. Based on the path of the storm, it looks like Jacksonville Beach would have experienced the most close rainfall except in reality Jacksonville airport actually totaled values closer to Fernandina and had rain on 9/3 which Jacksonville Beach did not, so used Airport (weathersparks.com) instead to determine rainfall duration. FPL had flooding in Sarasota and Manatee counties and the storm events database indicated 9.82 inches of flooding was the max in Manatee but the weathersparks for the Bradenton-Sarasota international airport tracked 10.39 inches over 33 hours. Hermine hit Duke's territory pretty hard particularly Pinellas county. Used St Petersburg-clearwater airport (weatherspark) to estimate duration of rainfall over the 3 days = 37 hours.

Hurricane Matthew 2016. The Florida Climate Center Fernandina beach rain gauge has errors for hurricane Matthew, but looking at the storm track and rain map, Jacksonville Beach likely had similar rainfall. The Florida Climate Data Center Jacksonville Beach rain gauge reports 7.71 inches from 10/6-10/8. However, for hourly estimates the Jacksonville beach stations on weathersparks are inaccurate so using the Jacksonville airport to estimate rain duration and most rain in one hour. Heavy rain and Flooding in Volusia and Brevard counties with tropical cyclone report measuring 17.01 at cape canavaral. The weatherspark radar on cape canavaral confirms estimates at 16.64inches but does not breakdown hour by hour, closest station is Melbourne International airport which had significantly less rain (3.46)but used to estimate duration and total in an hour was only 0.70in. Used 8727520 Cedar Key, FL tide gauge to estimate Duke storm surge (0 ft). Matthew didn't really have a lot of rainfall in Duke's territory but the most was in Lake/Seminole counties, used Umatilla FAWN rain gauge to estimate duration because total was 3.81in and highest rainfall recorded by storm events database was 4.65in.

TS Colin 2016. Some inconsistencies in the NHC report and the storm events database around storm tide and rainfall, I'm assuming the storm events database is correct and only use NHC report when I'm missing information. Fernandina had a pretty high storm tide but FPUC-NE did not report this has an excludable outage event. The FPL weather stations I have access to don't really experience the most rainfall. Used weatherspark Sarasota-Bradenton to estimate duration because that was close to where the most rainfall hit. Heaviest rain in Levy and Leon counties for Duke, which is interesting because they aren't near each other and flash flooding was technically only tracked in Leon county, but the Bronson FAWN station near Levy county recorded the most rain at 8.28in for 18 hours.

TS Julia 2016. For Duke In the storm events database the only weather event reported was a funnel cloud in Lake county. Duke does serve some of the inland portions of Volusia and Brevard counties which may have been impacted by TS Julia: "A tropical disturbance, with a well-defined surface circulation, moved onshore near Vero Beach during the early morning hours, then lifted northward along the coast to Volusia County (and beyond) through the evening. By late evening, the system was upgraded to Tropical Storm Julia, as it approached Jacksonville. A rainband associated with the system spawned an EF-0 tornado in southern Brevard County during the early afternoon, resulting in damage to a few residences. Other passing rainbands, produced strong wind gusts along the coast of Brevard and Volusia Counties, one of which resulted in damage to a home in Edgewater. A funnel cloud was also sighted in Lake County." Duke claimed that it experienced outages on 9/14 and hit 35mph winds. I instead found <1 inch of rain in Lake, orange and inland Volusia counties with a max of 25mph at Orlando international airport (weatherspark). Using Naval air station Mayport rainfall to estimate FPUC-NE rainfall and Jacksonville airport for rainfall duration (weatherspark). For FPL Craig municipal airport (weatherspark) at 1.96inches of rain over 11 hours which was closest to the highest amount recorded.

FPUC-NW EOC 2017 . There were a set of 2 bad thunderstorms that FPUC-NW reported as EOC activation events – one in January (1/21-1/21) and one in February (2/7). Used the "Florida automated Weather Network" rain gauge in Marianna from the University of Florida to determine rainfall, rainfall rate and duration.

Hurricane Harvey 2017. FPUC-NW basically experienced a normal thunderstorm at the same time as Hurricane Harvey, but I'll include it because we have enough data for it. The storms event data base states for Jackson County " Scattered afternoon thunderstorms developed in a typical summer environment with a few becoming marginally severe with impacts to trees and power lines." And makes no mention of Hurricane Harvey. Additionally estimate duration to a few hours because the start and end time are the same. Storm events database estimated 50kts but the Marianna weathersparks shows only 25mph assuming weathersparks is correct. Using Marianna FAWN station for rainfall and duration.

Hurricane Irma. compound effect of bad weather after bad weather: “Prior to Irma's arrival, a local nor'eastern developed 3 days prior, with strong onshore flow pumping water into the St. Johns River basin. Elevated water levels of 1-2 ft above normal tidal departure were already ongoing for several tidal cycles before Irma's surge and rainfall. The nor'easter also brought localized heavy rainfall bands, with some areas near the coast realizing 4-6 inches in 24 hrs the days prior to Irma. In addition, precursor conditions to the nor'easter included an above average rainfall across the region during the summer months. Major, historic river flooding was forecast along Black Creek and the Sante Fe a week prior to Irma. Realized river values along the St. Johns surpassed prior record levels set by Hurricane Dora in 1964, during low tide the morning of Sept. 11th. The St. Johns River basin continued to rise with the combination of trapped tides due to the nor'easter, astronomically high tides heading into the spring tide season, storm surge of up to 5 ft in some areas, fresh water rainfall of 7-11 inches, and strong southerly winds pushing the water across the basin on the east side of Irma. Historic river flooding occurred across much of NE Florida Sept 11th through the following week as water levels were slow to funnel out of the St. Johns basin. Coastal infrastructure that was already weakened about 1 year ago due to Hurricane Matthew suffered the most damage from Irma's storm surge.” By the time Irma passed over FPUC-NW and Gulf it had dropped to a TS so there is very little data. Used Marianna FAWN station for rainfall and windspeed data from weatherspark Marianna airport for FPUC-NW. FCDC Fernandina Beach rain gauge confirmed tropical cyclone report of 12.7 inches of rainfall (well 12.63), and 12 inches of that all fell on 9/11.Based on Storm track using Mayport(/Jacksonville beach) in weathersparks.com to estimated rainfall duration. Storm Events database says ~16 inches fell in Tampa, but weathersparks data for 5 Tampa locations + Dover FAWN station showed about 5 inches (which does match storm events database which stated: “Rainfall was generally around 5 inches or greater, with the highest rain total being 16.18 inches at the CWOP site D3252 in Tampa.” So still assuming the correct max of 16.18. Most rain in Gulf was recorded at Bob Sikes Airport on weathersparks. Most rainfall in FPL was at Fort Pierce in St Lucie reported by tropical cyclone report at around ~20inches. The south florida water management gauges were not recording all day so they can’t be used for Irma. Weathersparks St Lucie county airport recorded 15.38 inches of rain in 38 hours. The highest recorded rainfall according to the storm events database in Duke’s territory was in Citrus county at 18.45 inches, however the rain gauges in that area I was able to find were only registering ~8inches. There was widespread flooding, but flash flooding occurred in Alachua county, the Alachua FAWN rain gauge registered 12.22 inches, so I used duration of rain 40 hours for Duke.

Hurricane Nate 2017. I can find no evidence that this hurricane hit FPL’s territory. In their reliability report FPL claims they had many outages on 10/8/17 due to hurricane Nate. Not only did hurricane Nate not hit FPL's territory, there is not a SINGLE reported weather event in FPL's territory on that date. There, however is some coastal flooding in FPL's territory 10/4/17-10/7/17. So I'm going to assume someone messed up on the dates and the outages are due to these flooding events because FPL says in their report about this storm "40 mph peak rainfall 9 inches 2-4 ft inundation" which mostly match the coastal flooding events. It seems like this was really just from tides and coastal flooding and not rainfall because the weatherspark stations with the most rainfall I can find is palm county international airport with 3.2 inches of rainfall, used this to estimate rainfall duration. Used 8723214 Virginia Key, Biscayne bay NOAA tidal gauge to estimate storm surge at 1.79ft. Gulf rainfall reported in Gulf Breeze (near Destin) as 9.93 in by NHC tropical cyclone report. However, the storm events database reports flooding instead in Okaloosa near Bob Sikes Airport and that is the rain gauge with the most total rainfall in the area at 6.16in I can find. Using this for rainfall duration (weathersparks.com).

TS Cindy 2017. Used the Marianna FAWN Rain Gauge to estimated duration and rainfall. Used Marianna Airport station on weatherspark to estimate windspeed for FPUC-NW. According to the storm events database, Whiting Field in Milton (Gulf's territory) got 9.46 inches of rainfall but the weathersparks record at that station is only 6.27 inches in total. Additionally, the tropical cyclone report records 10.68 inches in Navarre, Hurlburt Field which is pretty close to Whiting Field and only registered about 2 inches of rain. Jay FAWN rain gauge which is in northern Escambia which is likely to have a lot of rain also only recorded 6.28 inches of rainfall. Rainfall duration for Gulf comes from Whiting Field air station (weathersparks.com).

TS Emily 2017. –Used South Florida Water Management gauges to find most rainfall near Naples, with 6.51inches total over 27 hours. Duke damage was mainly just Pinellas county, used Albert Whitted weatherspark gauge to estimate rainfall duration.

TS Phillipe 2017. Used 8723214 Virginia Key, Biscayne Bay, FL tidal gauge to estimate storm surge which was 0.56 ft for FPL. Flooding and heavy rain in Broward and palm beach counties. 15-min south florida water management doesn't capture this accurately even though it tracks the day total correctly. Used weathersparks palm beach international airport for duration 16 hours for FPL.

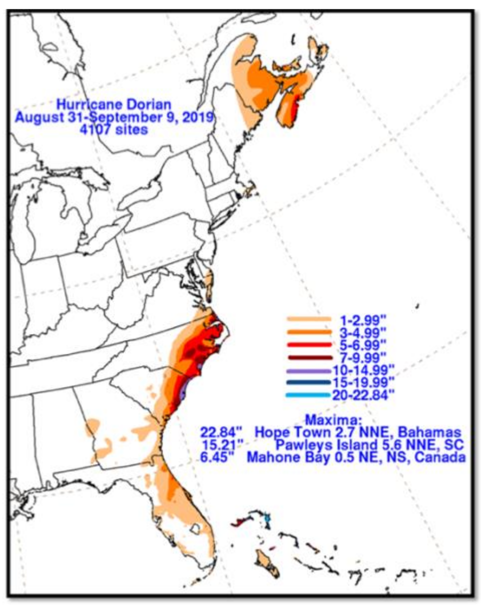
Hurricane Michael 2018. Didn't really hit FPL's territory, "The high October astronomical tides, King tides, in combination with the strong winds and minor surge from Hurricane Michael in the Gulf of Mexico brought a couple days of minor saltwater flooding along both the Atlantic and Gulf coasts of South Florida." Used Naples 8725110 Naples, Gulf of Mexico, FL to estimate storm surge at 1.685 ft for FPL. The weathersparks stations seem to have failed to record all the rain during this time, because it will list heavy rain but then not list an amount for several hours. Because the eye of the storm passed over Tyndall AFB used this for rain duration (12 hours) for Gulf even though it's technically in Duke's territory it is right on the cusp. Very little rainfall in

FPLs territory with a little over 1 inch measured by tropical cyclone report in Mayport. Used Jacksonville Naval Air station to estimate duration- 7 hours. Highest rainfall for duke was in Hosford Fl, Quincy FAWN rain gauge is the closest (20 miles) and registered about 1 inch less rain than storm events database, used this to estimate rain duration.

TS Alberto 2018. Storm events database indicated FPUC-NW did get hit by Alberto but provides no specific wind/rain values and neither does the NHC report. Use Marianna Rain gauge to estimate rainfall and duration, used Marianna airport on weatherspark to estimate windspeed for FPUC-NW. In general, the storm events database was rather sparse on TS Alberto, all numbers come from the cyclone report. There was an observation of 70 mph gust in FPL territory in the storms event database but it seemed contradictory to the much lower estimates in the cyclone report that I decided to trust the cyclone report. Highest rainfall recorded in Niceville by NHC. Destin is close and destine-Fort Walton beach (weathersparks.com) has rainfall of 3.44inches over 14 hours for Gulf. TS Alberto had the most rainfall near Lake Okeechobee in FPL's territory. South Florida WM gauges not registering this 11.8 inches. Weatherspark Okeechobee international airport closer with 5.52inches over 7 days (30 hours in those days). For Duke, Gadson County registered the most rainfall in storm events databased. The highest rainfall I could find was in Monticello FAWN station around 4.4 inches with 35 hours of rainfall for Duke.

TS Gordon 2018. The outer band of the tropical cyclone just barely passed through Duke's service territory. There seems to be thunderstorms at the same time which could be caused by Gordon but the storm events database doesn't specifically say its related to the TS (which they usually do). Storm events database also doesn't recognize Gordon for FPUC-NW but does log the "scattered thunderstorms". Because of this thunderstorm discrepancy, the storm events database estimates wind gusts for Duke at 50kts and FPUC-NW at 55 kts but none of the other more directly hit parts of Florida got above 53 kts and that was Pensacola, which is very far from FPUC-NW and Duke territory. I instead use estimates for wind speeds in Duke's territory from the tropical cyclone report are lower (43 kts wind gust) and there are no estimates for any place near FPUC-NW. So instead use the Marianna airport wind estimate from weatherspark at 38mph. Additionally I estimate that FPUC-NW experienced under 4 inches of rain based on the weather station readings from the closest points which are little over 4 inches but about 60 miles away. Highest rainfall reported by tropical cyclone report was 12.73 inches in Gulf's territory. Of the rain gauges available to me highest was at Pensacola international airport (weathersparks) at 11.46inch total over 26 hours. FPL mainly had heavy rainfall in Homestead and Miami. Used homestead air force base (weatherspark) to estimate duration of rainfall. Apalachicola had the most rainfall in duke territory used the weatherspark gauge to estimate duration and most in one hour.

Hurricane Dorian 2019. FPL was hit by the hurricane but we don't have CMI & CI values for it so its not included. It does appear that a small amount of Duke's service territory was hit by the hurricane, but all the impact occurred inland from the east coast, and there just isn't any storm values for the these inland areas and FPL owns the entire eastern coast of Florida. Additionally the wind impact to Duke's territory is minimal with "minimal tropical storm force" and in some cases "below tropical storm force". So for this reason I have to estimate Duke's impact using weatherspark Orlando international airport values for rainfall, duration and wind gust. Additionally, it is surprising FPUC-NW included this as a storm giving it formed off the east coast of florida and the FAWN Marianna Rain Gauge showed no rain occurred and weatherspark Marianna municipal airport station recorded highest gust of 24.2mph. Because there was no rain, to estimate storm duration I just estimated the hours where the windspeed was over 20 mph, which was 5 hours. See picture below: FPUC-NE rain estimated with rainmap =1 in of rain. FCDC rain gauge for Fernandina beach reported 0.45in on 9/4, but error for 9/3 and 9/5. Looking at the storm track map, Hurricane Dorian would have affected Fernandina into the early hours of 9/5 and I do not have that rain data (so this is probably an underestimate) Starting in 2019, weathersparks.com has rain data for Fernandina Beach Municipal Airport, using that to estimate rainfall duration and most in one hour, this data may also be somewhat inaccurate because it shows only 0.09 inches of rain in 24 hours. (use the ratio of .09 to 0.45 to estimated total rainfall in an hour).

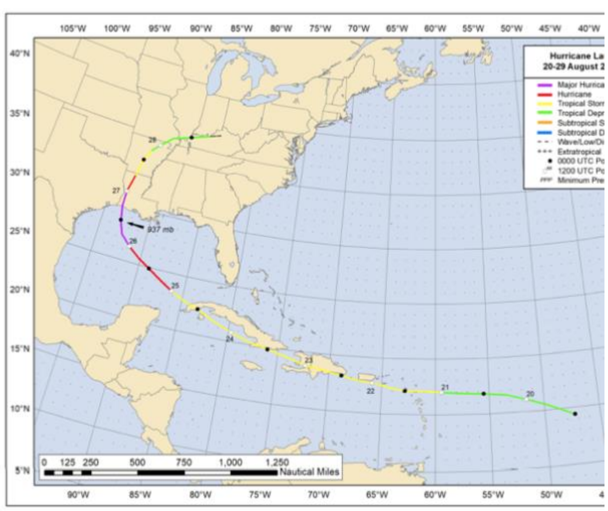


Hurricane Barry 2019. The storm events database has no record of Hurricane Barry for Gulf's service territory however a rip current does occur in Bay and Walton counties on July 14. Conversely, the Tropical Cyclone Report on Hurricane Barry definitely has data on wind and storm tide for Gulf's service territory. Additionally, using a national weather service rain map (US Department of Commerce, NOAA, n.d.) I use to estimate about 4 inches of rainfall in Gulf's territory. Weathersparks Northwest Florida Beaches Airport tracked 1.54 inches of rain over 12 hours.

TS Nestor 2019. Estimated Gulf's rainfall using Northwest Beaches Florida Airport station on weathersparks.com with 1.13in of rain over 20 hours. FPL was affected by TS Nestor but because there are no individual values for CMI/CI it's not included. Highest rain values for the rain gauges in TECO come from the FAWN Dover gauge with 4.82 inches total in 16 hours. Rain mainly hit Pinellas County with storm total of 7.7 in Baskin, Pinellas county. However, when looking at weatherspark St petersburg-clearwater airport (only 9 miles away) it registered 3.24 inches total. Still used this to estimate duration of rain, but assume storm events database is correct with the 7.7.

Hurricane Isaias 2020. Crazy that only 2.6 inches of rain can flood Miami "Rainfall flooding impacts were minor across South Florida with 2 to 2.6 inches measured mainly across Miami-Dade and Broward counties. Almost 3,000 customers lost power during the event, almost all of them in Palm Beach County." Broward and Miami-Dade counties with most rainfall, on weatherspark fort Lauderdale reported the most at 1.94in, used this to estimate rainfall duration of 12 hours for FPL. General note, the south Florida water management gauges don't handle hourly well and it hasn't been accurate for many of the storms passed 2015/2016.

Hurricane Laura 2020. FPL reported this as an excludable event, "A low pressure system moving across the tropical Atlantic into the Bahamas formed into Tropical Storm Laura near Puerto Rico and Hispaniola. As Laura continued across the northern Caribbean Sea, making landfall along southern Cuba, the outer rain bands extended across the South Florida bringing minor impacts. Tropical Storm force wind gusts reached across Miami-Dade, a few strong enough to become severe gusts." Looking at the rain map and the description assuming <1 inch of rain so 0.5 in from the Tropical Cyclone report. Tide Gauge 8723214 Virginia Key, Biscayne Bay, FL used to estimate storm surge in Miami (0.83ft).



Hurricane Sally 2020. There are no wind speed readings for FPUC-NW but it did experience TS force winds. Storm database estimated 50 kts gust but those estimates have seemed more unreliable, and instead assumed 34.5mph from Marianna airport weatherspark reading is correct. According to tropical cyclone report, most rain fell one mile from Pensacola Naval Air station at 24.88in. That station and the Pensacola airport station seemed to have difficulty recording rain values on weathersparks even though heavy rain is acknowledged to have happened. So closest station with the most rainfall is Hurlburt Field with 14.82 inches over 34 hours for Gulf's territory. Sally hit Collier and Miami counties with moderate flooding, most recorded was in collier with 8.7 inches in storm events database. Naples municipal airport on weatherspark recorded 5.06 inches, which was used to estimate duration for FPL.

Hurricane Zeta 2020. There was flooding due to the tropical depression that became Hurricane Zeta in FPL's territory but no reported outages or they at least didn't include it as an excludable event. There is no record of FPUC-NW being hit in the storm events data base experienced. Using the FAWN Marianna rain gauge to estimate rainfall and duration for FPUC-NW and windspeed from Marianna airport weatherspark station. Some "tropical storm force winds" hit Escambia, Santa Rose and Okaloosa counties in Gulf's territory. Closest rain gauge to Berrydale where the Tropical Cyclone Report indicated most rain in Florida fell at 1.4in is Jay, which had 1.19in total. Therefore using Jay FAWN rain gauge to estimate duration (10 hours) in Gulf.

Hurricane Eta. tropical cyclone report indicated most rainfall in Broward county 20.74 inches. Closest I could find was the FAWN Fort Lauderdale rain gauge with 10.17 inches over 44 hours of rainfall to record duration for FPL. For Duke, Flooding just in Pinellas county, pretty bad flooding, unclear if due to rainfall, storm surge or both, but St Petersburg-clearwater airport tracked the most with 6.03inches over 20 hours to record duration for Duke.

TS Arthur 2020. Up to 0.88 inch hail not captured. Tide Gauge 8723214 Virginia Key, Biscayne Bay, FL used to estimate storm surge in Miami at 0.66 ft for FPL. Boynton beach got the most rain with 7.37 inches, closest rain gauge on weatherspark was pompano Beach airport that measured 5.3inches and 27 hours of rain which was used to estimate FPL duration.

TS Bertha 2020. Before Bertha became a tropical storm and it was a tropical depression there was some gusts and hail that hit palm beach county. There were also thunderstorms in St John, St Lucie, Duval, Clay and Volusia counties on the same days as TS Bertha but the storm database does not attribute this to TS Bertha. However, FPL probably does because there was a downed power line in St John's county. Also the Tropical cyclone report does indicate some of Florida was hit with 15 inches of rain by the "precursor disturbance of Bertha" which was assumed to be the highest rainfall in FPL. Used Miami international airport weatherspark station found 14.31 inches over 3 days (36 hours) which was used to estimate duration for FPL. Additionally, 8720218 Mayport (Bar Pilots Dock), FL used to estimate storm surge in Miami at 1.309 ft for FPL.

TS Cristobal 2020. Seems that Duke's territory was also impacted by this TS but they didn't report it. The National Hurricane Center's tropical cyclone report had information for gulf's territory but almost nothing on FPL's territory where the reverse was true in the storm events database. Additionally, the highest wind speed was a straight line wind event in Daytona (FPL) which was caused because "Conditions became favorable for severe weather in central Florida due to enhanced winds aloft on the far eastern periphery of Tropical Storm Cristobal which was moving north over the central Gulf of Mexico." So The Tropical cyclone report didn't really consider this a part of TS Cristobal yet there seemed to be follow on effect that FPL counted (but Duke did not…). FPL reports 13.03 inches in Suwanne county, so used Live Oaks FAWN rain gauge to estimate duration. Additionally, 8721604 Trident Pier, Port Canaveral, FL used to estimate storm surge in Miami at 0.713 ft for FPL. Most rain in Gulf's territory was at Destin according to tropical cyclone report. Weathersparks Destin Exec airport confirmed this and had rainfall over 26 hours.

Hurricane Elsa 2021. Used weathersparks rain data for Fernandina beach Municipal airport to estimate rainfall and duration for FPUC-NE. Additionally, 8726607 Old Port Tampa, FL used to estimate storm surge in TECO at 2.061 ft. And 8720030 Fernandina Beach, FL used to estimate storm surge in FPUC-NE at 1.023 ft. Looking at Rain gauges in TECO, FAWN Dover rain gauge had the highest rainfall at 4.97in with duration at 18 hours. FPL's southwestern territory was affected with the most rain in Charlotte county. Used Punta Gorda Airport on weatherspark to estimate duration (23).

Hurricane Ida 2021. Hurricane Ida only passed through the Florida panhandle (hitting Gulf power) but FPL lists this as an excludable event because thunderstorms formed as a result from Ida forming: "The combination of high pressure sinking southward and Tropical Depression Ida moving across the NE United States allowed for a mid-level trough and deep moisture to sink southward across the region. This prompted light S to SW flow, which pushed the Gulf Sea Breeze inland and towards the east coast while the Atlantic Sea Breeze pinned along the east coast. With adequate moisture and shear, strong storms developed, especially in areas where the sea breezes collided. Heavy rain and flooding were the main hazards." Mostly just Miami was impacted, with estimated 3 inches of rain. Used Miami International airport to estimate rain duration: 3 hours. To estimate storm surge in FPL used "8723214 Virginia Key, Biscayne Bay, FL" tidal gauge (0.38 ft). Additionally in Gulf's territory "High surf of at least ten feet resulted in significant flooding and sand on coastal roadways along the Gulf Islands National Seashore. Portions of the road and access areas were closed for an extended period of time." Ida hit most of the pan handle, highest rainfall was in corner of northwest Florida, checked all rain gauges and Destin Exec airport had the most in one hour so used this location to estimate rainfall duration. It is surprising that FPUC-NW didn't report anything given Marianna got ~ 5 inches of rain and about 33 mph winds.

TS Claudette 2021. Did not hit FPL's service territory, instead they had unrelated thunderstorms at the same time which they are attributing to TS Claudette: "An unusually strong summertime cold front extended from New England southward through the southern Appalachians and entering the northwestern Gulf of Mexico. Aloft, the axis of Atlantic surface ridging remained stretched across south FL while a potent trough across the Great Lakes region was drove a broad longwave trough|across the eastern third of the nation. The added forcing from these features combined with high moisture and instability with speed shear triggered a few strong to pulse severe storms across the local area in the afternoon." Used tidal gauge at Port Canaveral to estimate storm surge (0.471 ft) for FPL. Confirmed rainfall duration was only 5 hours in FPL's territory using live oaks FAWN. Pensacola regional airport had the most rainfall, rain gauge closest with most/fastest rain was Pensacola international airport (weathersparks.com) total at 5.35inches over 22 hours for Gulf's territory.

TS Fred 2021 – The impact on FPL's territory was a "Deep tropical moisture ahead of Tropical Storm Fred moved across Martin County on August 13, 2021" which dumped 7.91 inches of rain. However, several other counties in FPL also experienced thunderstorms and heavy rainfall, which they likely also attributed to TS Fred. The storm database estimates up to 40kts wind gusts. Used tidal gauge at Mayport to estimate storm surge (0.586 ft) for FPL. Fred dropped a lot of rainfall in Washington and Bay counties for Gulf, but there not a lot of rain gauges there. USED Tyndall AFB (weatherspark), which is technically in Duke's territory but right on the cusp to estimate rainfall duration in Gulf's territory and in Duke's territory (14 hours).

TS Mindy 2021. there was some flooding in St John's County (FPL territory) due to "A tropical low was approaching the FL panhandle from the Gulf of Mexico with deep tropical moisture on the east side of the system overspreading the local forecast area under SSW flow. Showers and storms developed west to east through the day with storm enhancement toward the I-95 corridor and east coast where an east coast sea breeze drifted inland." Used the Northeast Regional Airport weatherspark station in St. John's county to estimate windspeed, rainfall and duration. Additionally, used Mayport NOAA tidal gauge to estimate storm surge at 0ft for FPL. There are some flash floods in Bay county in Gulf's territory due to TS Mindy but no rainfall or windspeed data was provided so I am instead assuming windspeed is the same as at Tyndall AFB. Used the Panama City Tide Gauge to estimate storm surge at 0.723 ft Storm events database indicates flooding in Bay county and near Lynn Haven which is close to the Northwest beaches Florida airport (weatherspark) using that to estimate total rainfall (2.24inches) over 15 hours for Gulf's territory. The most amount of rain was in Citrus County at 5.16 inches but the storm events database indicates flooding in Leon County near Tallahasse. So used the weatherspark Tallahasse site to find duration, compared to crystal river airport in Citrus county.

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Appendix G: Interview Protocol

1. What is the title of the position you hold at your utility?
2. How long you have been employed at this utility?
3. In 2021, what was your total revenue?
4. In 2021, how many total customers were on your system?

5. Looking at the below list of resilience strategies please highlight strategies that have **already been adopted** on your system, identify the extent to which they have been implemented, and indicate how much have you spent on them.

Resilience strategy (please highlight or bold the ones you've adopted on your system)	How much of this strategy have you implemented? You can report this as an absolute number, per mile, per year, or per circuit.	How much have you spent on this strategy? You can report this $ per unit or $ per year.
Convert wood poles to steel, concrete, ductile iron, or fiber reinforced polymer.		
Change the height, class, or distance between poles.		
Increase the frequency with which you inspect and replace poles.		
Reduce the load on poles from pole-mounted equipment or third-party attachments.		
Changes to wires: e.g., heavier T-2/ACSR, quick disconnect, guy wires, vibration dampers, etc.		
Increase the frequency or change methods of vegetation management.		
Move some or all distribution circuits underground.		
Implement high-end distribution automation to automatically reconfigure existing circuits.		
Increase system visibility and the ability to rapidly reconfigure all existing distribution circuits.		
Implement distributed storage and generation throughout the distribution system.		
Maintain a higher level of pre-staged equipment.		

Relocate or reinforce vulnerable substations.		
Implement smart meters or other demand side management techniques.		
Build more redundancy into the system.		
Change or improve any operating systems, e.g., outage management, inventory management, or workforce management systems.		
Change emergency planning or coordination with other government and critical infrastructure organizations.		
Change workforce, e.g. different or more training/drills, availability of emergency crews, add/change positions, etc.		
Other:____________________		

6. Please complete the table below to indicate what events do you believe could pose risks to your system. Then please rank them from greatest to least risk posed to your system.

Event that could cause disruption to your system.	**Check all that you believe could cause an outage with more than 10% of customers out of service for 24 hours or more in the next 15 years.***	**Please rank order *only* the events that you stated pose a risk to your system. (1=greatest risk; 2= next greatest; etc.)**
Drought/water shortage		
Earthquake		
Flood/storm surge		
Hurricane/tropical storm		
Ice storm/Blizzard		
Tornadoes		
Space weather		
Tsunami		
Volcanic event		

Wildfire		
Thunderstorms		
Extreme heat		
Extreme cold		
Excessive rainfall		
Operator Error		
Equipment Failure		
Load Balancing		
Other __________ ?		

** ≥1% chance of impacting your system in the next 15 years.

Now, let's consider the most serious outage event that your system has **already** experienced in the last 15 years.

8. Please give us a general description of what caused this event, what time of year was it, how long did it last, how and when did customers lose power, and what challenges did you face in responding and restoring power?

8. Assuming that there were no budget constraints, what <u>three</u> strategies could have been implemented on your system **prior** to the event that you believe would have most reduced the number of customers who lost service, or improved the speed with which you could have restored service after the specific event you just described in question 7? Please describe how these upgrades would be implemented on your system to provide the most benefit?

Strategy 1 ____

Strategy 2 ____

Strategy 3 ____

9. If these three strategies were to be implemented on your system <u>today</u> exactly as described in question 8, please estimate the overnight capital cost of *each* of these investments?

Strategy 1 ____

Strategy 2 ____

Strategy 3 ____

10. Now consider the outage threats you identified in question 6. Which outage threat are you most concerned about that would require a *different* approach to addressing? Assuming that there were **no budget constraints**, what <u>three</u> strategies could be implemented on your system prior to

this event that you believe could reduce the number of customers who lose service, or improve the speed with which you could restore service after this second outage event? Please describe how these upgrades would be implemented on your system to provide the most benefit?

Strategy 1 ____

Strategy 2 ____

Strategy 3 ____

11. If these three strategies were to be implemented on your system today exactly as described in question 10, please estimate the overnight capital cost of these investments?

Strategy 1 ____

Strategy 2 ____

Strategy 3 ____

12. We have now considered the two largest outage threats to your system for the next 15 years and identified a total of 6 resilience strategies to mitigate these threats. If these strategies were to be implemented on your system exactly as you described, can you rank and weight them based on how well each strategy would mitigate the consequences of <u>all future outages</u>? (Rank 1 = 100 weighting = most impactful). *Slide 10 shows the below table which will be filled in by interviewer as respondent(s) talk. Provide an example if having difficulty understanding.*

Rank	**Strategy**	**Weight (Rank 1 = 100)**
1		**100**
2		
3		
4		
5		

6		

13. When considering resilience investment in the context of large power outages of long duration, how do you think funds should be allocated across prevention, mitigation and restoration activities? Please identify what percentage of your resilience budget you would allocate to each.

Prevention		Mitigation		Restoration		Resilience Budget
_____ %	+	_____ %	+	_____ %	=	100 %

14. So far, we've been discussing resilience in the context of historical power outages, but as changes to the grid (e.g., electrification, automation, decarbonization) make balancing the system more challenging, keeping the system operating may require additional modifications. In the next 15 years, what concerns you most about managing your system?

15. What additional technologies, policies, or resources that are currently outside your control do you need to address any of the concerns you listed? (list up to 5). Please identify what concerns they will specifically address.

16. In the diagram below, please indicate the feasibility and efficacy of implementing each of the additional needs identified in question 15. Use a different color x for each strategy.