

Prioritization & Valuation Methodology Report

CLIENT: Grid Deployment Office (GDO)

PROJECT: Grid Resilience Analysis and Climate Change Impacts (GRACI)

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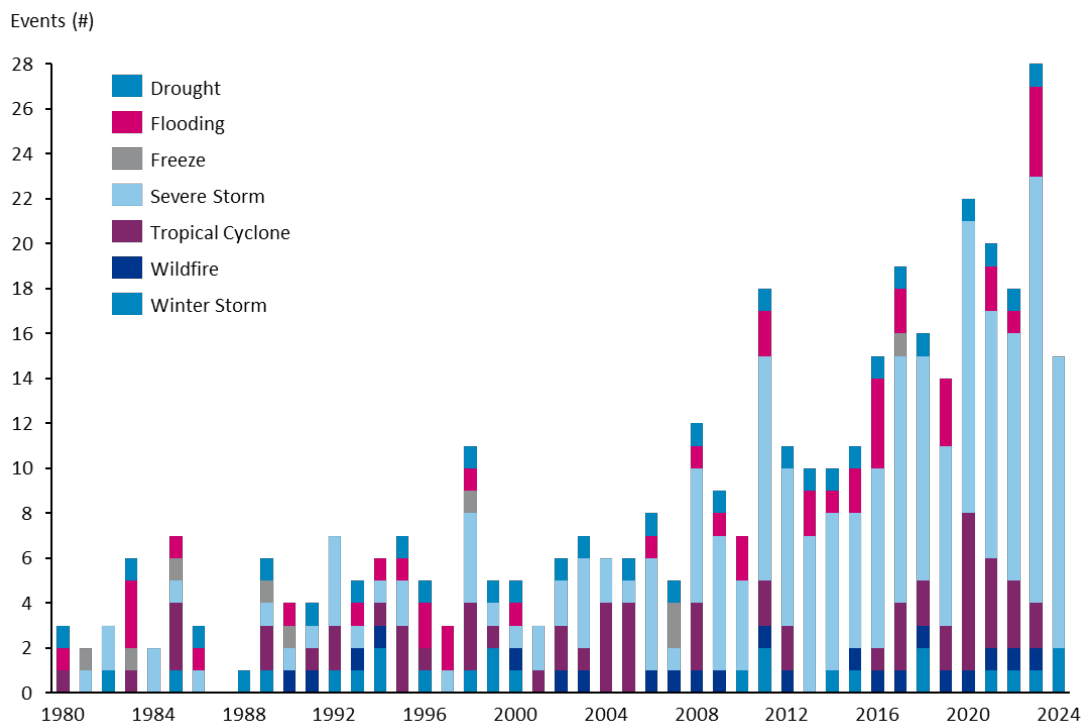
Contents

1	Imperative of Grid Resilience	4
1.1	Investment Challenges	7
1.2	Overview of 40101(d)	8
2	Asset Resilience Framework.....	9
2.1	Extreme Weather Projections	10
2.2	Exposure	14
2.3	Risk.....	18
2.4	Adaptation.....	20
2.5	Prioritization	23
3	Implementation	27
3.1	Collaborating with Utilities.....	27
3.2	Asset Resilience Framework Implementation.....	27
3.3	Available Resources.....	28
4	Conclusion.....	29
5	Works Cited.....	30

1 Imperative of Grid Resilience

The United States' electricity grid faces an array of extreme weather hazards that pose substantial and growing risks to the reliability and security of its physical infrastructure. Extreme weather events have a physical impact on all electricity assets (generation, transmission, and distribution) and catalyze volatile swings in wholesale energy markets. Recent historical data highlights the increasing frequency and severity of weather-related disruptions to grid operations. In 2022 alone, the United States experienced 27 separate weather events that each caused over \$1 billion dollars in damage, with winter storms and freeze events alone accounting for an estimated \$141.6 billion in costs since 1980.¹ Given that, electric utility customers experienced an average of over five hours of cumulative power interruptions in 2022, with over half of that attributed to days with poor weather according to the Energy Information Administration (EIA).²

1980-2024 United States Billion-Dollar Disaster Year-to-Date Event Cost (CPI-Adjusted)³



¹ NCEI. 2025. U.S. Billion-Dollar Weather and Climate Disasters. 21 January. doi:10.25921/stkw-7w73.

² Gorski, Alex. 2024. Today in Energy. 25 January. <https://www.eia.gov/todayinenergy/detail.php?id=61303>.

³ NCEI. 2025. U.S. Billion-Dollar Weather and Climate Disasters. 21 January. doi:10.25921/stkw-7w73.

The frequency, severity, and diversity of extreme weather events are growing. With each year, “once in a lifetime” billion-dollar weather events become more common, bringing increasingly devastating impacts on infrastructure and communities. For example, the 2019-2020 Australian bushfire season was unprecedented in its scale and destruction. In 2021, Winter Storm Uri left behind an estimated \$195 billion of damage in Texas. The 2023 summer heatwave in the UK defied forecasts and broke temperature records.

Recent Significant Weather Events and Their Impact on the US Electricity Grid⁴

Event	Description	Energy Markets & Infrastructure Impacts
Winter Storm Elliot	Historic Winter Storm Elliot brought a powerful Arctic front that swept across the Midwest and eastern seaboard, bringing heavy rain, snow, ice and high winds that sent temperatures plummeting.	A record-setting 90.5 GW, or 13% of the generating capacity in the Eastern Interconnection either failed to run or operate at full capacity. More than a million customers, from Texas to Maine, were left without power. ⁵
PNW Heat Dome	Western drought persisted throughout 2021, expanding and intensifying across many states. A historic heat wave developed for many days across the Pacific Northwest, shattering numerous all-time high temperature records across the region.	Thousands of customers faced blackouts during the heat wave due to lack of heat-resistant investments in grid infrastructure. Low water levels forced the 700 MW hydroelectric power plant at Lake Oroville, CA to shut down for the first time since its opening in 1967. ⁶
LA Wildfires	January 2025 wildfires in Los Angeles burned over 40,000 acres of land and destroyed thousands of buildings and structures, with total property	The fires caused power outages for hundreds of thousands of people due to transmission and distribution infrastructure being shut down for safety. Utilities Southern California

⁴ NCEI. 2025. U.S. Billion-Dollar Weather and Climate Disasters. 21 January. doi:10.25921/stkw-7w73.

⁵ Howland, Ethan. 2023. “Record 13% of Eastern Interconnect capacity failed in Winter Storm Elliott: FERC, NERC.” Utility Dive. 22 September. <https://www.utilitydive.com/news/winter-storm-elliott-ferc-nerc-report-power-plant-outages/694451/>.

⁶ Geranios, Nicholas K., and Andrew Selsky. 2021. “Blackouts in US Northwest due to heat wave, deaths reported.” Associated Press (AP). 29 June. <https://apnews.com/article/climate-change-government-and-politics-business-environment-and-nature-6a66be20ed86ad18ed131156c9f7a517>.

	damages estimated between \$28.0 billion and \$53.8 billion. ⁷	Edison and LADWP were criticized and investigated regarding their infrastructure's insufficient resilience and potential contribution to the wildfires. ⁸
Hurricane Helene	Category 4 Hurricane Helene's most severe impacts were from historic rainfall (up to 30+ inches) and flooding across western North Carolina, which eclipsed the region's previous worst flood in 1916. Landslides and historic levels of flooding inundated homes, businesses, and hospitals, and damaged thousands of roads, highways and bridges.	Helene caused over 4.7 million power outages across the southeastern United States. Grid infrastructure suffered catastrophic damage. For example, Georgia Transmission estimated over 100 high-voltage transmission lines and over 60 substations were put out of service. ⁹
Hurricane Beryl	Hurricane Beryl was the earliest Category 5 hurricane and the second Category 5 on record during the month of July in the Atlantic Ocean. Beryl made landfall in Texas as a Category 1 and produced more than 50 tornadoes across Texas, Louisiana, and Arkansas.	More than 2.6 million Texas power customers went without electricity for days in the summer heat. The Houston area's electric utility, CenterPoint Energy, suffered about \$1.3 billion worth of damage to its infrastructure. The Public Utility Commission of Texas launched an inquiry into how CenterPoint Energy prepared for severe weather and responded to the outages. ¹⁰

⁷ Horton, Matt, Shannon M. Sedgwick, Justin Adams, Dan Wei, and Matthew Skyberg. 2025. Impact of 2025 Los Angeles Wildfires and Comparative Study. Los Angeles, CA: LAEDC Institute for Applied Economics. <https://laedc.org/research/reports/impact-of-2025-los-angeles-wildfires-and-comparative-study/>.

⁸ Strupp, Julie. 2025. "LA fires damage power, sewer and water infrastructure." Construction Dive. 14 January. <https://www.constructiondive.com/news/la-wildfire-damage-infrastructure/737305/>.

⁹ Micek, Kassia, Corey Paul, J Robinson, and Ronnie Turner. 2024. "Hurricane Helene causes over 4.7 million power outages across Southeast US." S&P Global Commodity Insights. 27 September. <https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/092724-hurricane-helene-causes-over-47-million-power-outages-across-southeast-us>.

¹⁰ Martinez, Alejandra, and Emily Foxhall. 2024. "Public Utility Commission releases investigative report on CenterPoint Energy's Hurricane Beryl response." Texas Tribune. 25 July. <https://www.texastribune.org/2024/07/25/texas-power-grid-puc-centerpoint-hurricane-beryl/>.

While devastating events like these have proven to be more likely over recent history, they can be perceived as low frequency given anecdotal bias and relatively low historical statistical likelihood. As such, it is easy for asset owners to dismiss weather-related destruction as a remote possibility that can be dealt with in the future. However, even if the odds of a disaster are small on an annualized basis, they still pose a significant risk that asset owners and investors must account for given the multi-decade useful lives of infrastructure assets.

For example, a 1 in 100-year weather event has a 35% chance of occurring at least once over a fifty-year asset lifetime. This means that if a distribution utility's pole design standard is set based on historic wind speeds, there is a 1/3 chance that the asset will fail before the end of its useful life. However, this assumes that the frequency and severity of those extreme events are static. Meteorologists expect that the frequency and severity of extreme events will continue to grow on average, meaning that this 35% chance of failure likely understates the true cumulative risk.

Underestimating lifetime risk can lead to premature asset replacement, which is extremely costly for electric utility customers who ultimately bear the expenses to secure the same asset multiple times. To prevent this, utilities must make investment choices with a view that is at least as long as the useful lives of their assets, despite only having multi-year planning horizons. Utilities should act now to understand the extreme weather risks their assets face so they can make well-informed actions to ensure reliability, lowering costs for customers in the long term.

1.1 Investment Challenges

The reliability of the energy system requires its infrastructure to be resilient against weather. **Resilience** is defined by the Federal Energy Management Program as “the ability to anticipate, prepare for, and adapt to changing conditions and to withstand, respond to, and recover rapidly from disruptions through adaptable and holistic planning and technical solutions. Highly resilient systems prevent disruption or reduce the magnitude or duration of disruptive events caused by hazards”¹¹. The risk of outage due to extreme weather events is therefore called “resilience risk.” This risk demands utilities to proactively invest in adaptation to prevent premature asset failures, customer outages, and wildfire ignitions.

Funding for resilience investments, however, is constrained by customer affordability. As a result, utilities need a framework to quantify resilience risk and guide their investment decision-making against other competing asset needs. For example, a utility may need to decide between undergrounding a feeder to protect against extreme winds or elevating a substation to protect against flooding. In another scenario, a utility may need to decide between upgrading either a low-reliability feeder that serves few customers or upgrading a medium-reliability feeder that serves many customers. Without explicit quantification of risk in dollars, utilities are unable to determine the cost-effectiveness of investments

¹¹ Federal Energy Management Program. n.d. “Technical Resilience Navigator.” Pacific Northwest National Laboratory. <https://trn.pnnl.gov/>.

and subsequently determine which investments to prioritize using available funding. Further, as utilities must make investment decisions at the asset-level, the risk forecast should also be at the asset-level for aggregation into projects and programs later on in the process.

The optimal allocation of the budget maximizes avoided dollars of risk per dollar of investment. This paper details Baringa's methodology to forecast asset-level dollars of resilience risk, to value adaptation investments to address those risks, and to inform the prioritization an investment portfolio.

1.2 Overview of 40101(d)

The Infrastructure Investment and Jobs Act (IIJA), Section 40101(d): Preventing Outages and Enhancing the Resilience of the Electric Grid Formula Grants to States and Indian Tribes, provides funding to states and Indian Tribes to enhance grid resilience.¹² Managed by the U.S. Department of Energy's Grid Deployment Office (GDO), the program aims to strengthen and modernize America's power grid against wildfires, extreme weather, and other natural disasters.¹³

Regional stakeholders like State Energy Offices (SEOs) are responsible for awarding these funds to eligible projects, prioritizing efforts that generate the greatest benefit by providing affordable and reliable energy. Eligible projects span a wide range of resilience measures, including weatherization technologies, fire-resistant systems, monitoring and control technologies, undergrounding of electrical equipment, utility pole management, relocation of power lines, vegetation management, distributed energy resources (microgrids, battery storage), adaptive protection, advanced modelling, and hardening of power lines, facilities, and substations.

Funding is distributed over five years based on a formula that considers factors such as population size, land area, and the probability and severity of disruptive events.¹⁴ To date, tens of millions of dollars have been awarded to dozens of projects by various state energy offices nationwide.

As Phase 4 of Grid Resilience Analysis and Climate Change Impacts (GRACI), a technical assistance program funded by the GDO Baringa has produced this report to outline its Asset Resilience framework for prioritizing and valuing resilience investments. In the following sections, Baringa will explain how this approach will help SEOs and utilities understand best how to forecast the resilience risk in dollars, justify resilience investments, and understand best practices in resilience planning

¹² Delaware DNREC. n.d. 40101(d) Grid Resilience Grant Program. <https://dnrec.delaware.gov/climate-coastal-energy/energy-office/bil/40101d/>.

¹³ NETL. n.d. "Grid Resilience State and Tribal Formula Grant." DOE National Energy Technology Laboratory. <https://netl.doe.gov/ijahub/grid-resilience/formula-grants>.

¹⁴ Delaware DNREC. n.d. 40101(d) Grid Resilience Grant Program. <https://dnrec.delaware.gov/climate-coastal-energy/energy-office/bil/40101d/>.

2 Asset Resilience Framework

This report outlines Baringa’s Asset Resilience framework for forecasting resilience risk in order to inform asset investment valuation and prioritize portfolios. Its purpose is not to prescribe specific adaptation strategies for any jurisdiction or hazard, but rather to give decision makers a framework to evaluate the effectiveness of different investments given a utility’s exposure to specific types of extreme weather.

Additionally, this framework includes methodology that does not require large amounts of data, to ensure accessibility to smaller utilities and cooperatives which may not have the resources to carry out complex resilience analysis. This lower-complexity methodology utilizes basic data on asset classes and locations to quantify risk, while still providing significant insights to inform investment decisions.

State Energy Offices can distribute this framework to utilities to inform their resilience investment planning and to substantiate their applications for 40101(d) funding. Capital plans which adopt this framework will give utility boards and regulators confidence that spending is being allocated efficiently and is worth approving.

Baringa’s framework includes five core principles:

Extreme Weather Projections	Extreme weather projections are necessary to forecast asset exposure to weather hazards. Historical trends in weather data cannot predict anomalous weather events which are continually changing in frequency and severity, especially when there is an insufficient historic period to accurately capture tail risk events. Typical hazards to grid assets may include wind, flood, heat, cold, and wildfire which can respectively cause each asset class to experience failure through an array of potential failure modes.
Exposure	Exposure forecasts the probability of failure (%) for each asset conditioned on the expected extreme weather projections over the remaining useful life of the asset. Failure likelihood can be based on failure thresholds from asset design standards or fragility curves that assess which determine failure likelihood given an extreme weather condition. Fragility curves are often based on age and can incorporate other factors such as asset condition.

Risk	Risk is the expected cost of failure to the utility and customers. Risk is forecast by multiplying the probability of asset failure times the cost of asset failure, including both utility costs and customer costs related to the value of lost load (VOLL). This risk is called pre-investment risk, as it is the risk present before any investment action is taken to abate it.
Adaptation	Adaptation defines the investment actions a utility may take to address pre-investment risk. Investment can be evaluated based on the difference between pre-investment risk and post-investment risk, indicating the benefits of making the investment. An unconstrained portfolio of asset investments is defined across asset classes and hazard to address system risk.
Prioritization	Prioritization of investments is based on respective benefit-cost ratio (BCR), or net present value (NPV). Ranking investment actions in the portfolio by their effectiveness informs the investment plan sequence. Financial and resource constraints can then be applied to determine which investments are made each year.

The following sections provide utilities and decision makers with a roadmap for understanding and implementing the Asset Resilience framework. The following sections expand on the principles found in the above table and include concrete steps for utilities to incorporate into their planning practices.

2.1 Extreme Weather Projections

To implement this framework, asset owners must first overlay downscaled climate projections onto their assets. This exercise illustrates how extreme weather might currently affect specific assets, and how it is expected to change in the future. Extreme weather projections are the outputs of models that probabilistically forecast the characteristics of future weather occurrences over time and geographic area.

The following table illustrates the types of hazard metrics from climate projections that can indicate weather's potential risk for assets:

Hazard	Example Hazard Metric
Flood 	Depth of water from storm surge, sea-level rise, pluvial flooding, fluvial flooding
Wind 	Maximum speed 1-min sustained and 3-sec gust wind speeds
Rain 	Daily total rain, maximum volume
Fire 	Number of wildfires expected in 1km ² per 1,000 years
Heat 	• Days per year above threshold • Cooling degree days • 3-day heat waves with lows above a thresholds • Monthly high temperatures • Annual maximum temperature
Cold 	• Days per year below threshold • Heating degree days • 3-day cold waves with highs below a threshold • Monthly low temperatures • Annual minimum temperature
Drought 	• Annual average local water stress levels • Months per year with low Standardized Precipitation Evapotranspiration Index (SPEI)
Storm 	• Days per year with risk of large hail • Days per year with risk of severe thunderstorms

Traditional methods of resilience analysis utilize historical data to predict future impacts on assets from weather. Under a static climate, this method could produce reasonable outcomes; however, given the non-stationary nature of Earth's climate, utilities cannot rely on historical evidence alone to accurately predict the impacts of extreme weather over the future of assets' multi-decade lifetimes.

Tail risk events such as those that occur once every 100 years cause the most devastating damage and are therefore the most crucial to be captured in predictions. The lookback windows of historical datasets are often insufficient to capture the occurrences of these anomalous weather events across a utility's service area, especially as their frequency and severity are changing over time. Planners must understand how critical climate variables will change in the future to invest in ways that future-proof their systems and achieve fewer failures, fewer outages, and overall lower costs to customers.

The Differences Between GCMs and Downscaling

Global Climate Models (GCMs) are sophisticated models which simulate Earth's future climate on a global scale and provide long-term forecasts under different future scenarios, known as shared socioeconomic pathway (SSP) scenarios. GCMs differ from one another due to varying initial assumptions, parameters, and resolution, leading to a range of projections. Since a variety of GCMs exist, it's possible to determine future boundary conditions, or the range of expected climate impacts from each scenario.

GCMs produce very coarse climate projections (typically gridded outputs on cells that are 100km²) which obscure local variation. Coarse GCM outputs alone are insufficient for the resilience analysis use case, as utilities need granular climate predictions to understand what conditions impact each asset on their system rather than at the global level. Certain hazards such as heat and flood exhibit significant local variation due to topology and the built environment, which must be captured to understand asset-level impacts. GCM projections can be further refined through downscaling to capture crucial local variation.

Example: GCM (54 x 54km) vs. Downscaled (9 x 9km) Resolution



Downscaling refers to a set of methods used to improve the spatial and temporal resolution of information from GCMs. This refines GCM outputs to better characterize the local variability in weather

conditions and makes it possible to more precisely capture how projected impacts will affect individual assets.

While traditional methods of downscaling are statistical and dynamical, modern approaches of downscaling leverage machine learning to handle large complex datasets. It is important to note that downscaling can sometimes inherit or add uncertainty or new biases to GCM-based projections that must be corrected later.

	Global Climate Model (GCM)	Downscaling
Definition	Models that simulate Earth's climate under different GHG emission scenarios	Statistical or physics-based methods used to improve the spatial and temporal resolution of GCM outputs
Strength	Inclusion of multiple variables produces a wide range of climate projections and boundary conditions	Refines GCM outputs typically to cells of 10 x 10 km, to capture local variability
Limitation	Insufficient for asset-level insights, produce very coarse climate projections: outputs on 100km x 100km grid cells	Downscaling includes uncertainty or new biases to GCM-based projections that must be corrected

Probability

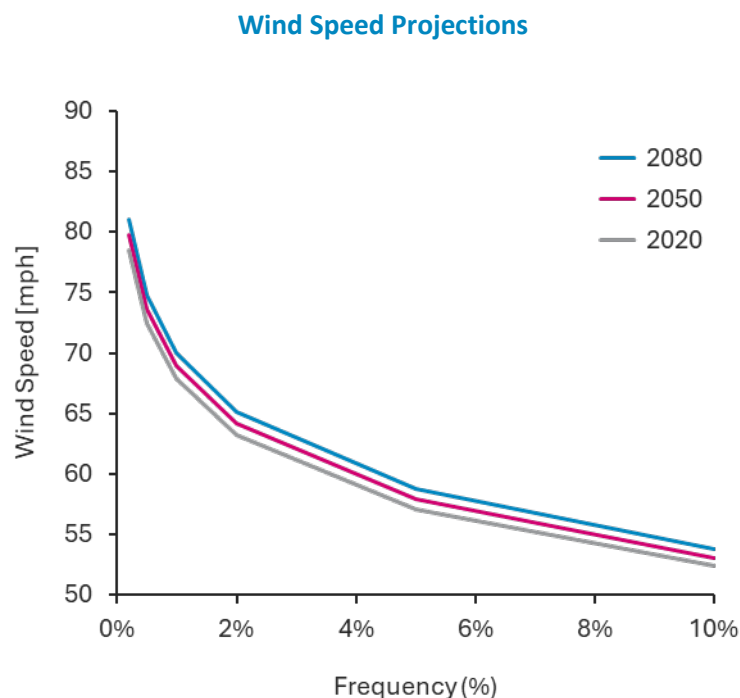
A key component of climate projections is the usage of probability. Climate models leverage probabilistic analysis to determine the frequency and intensity of future weather events. The frequency of a weather event of a given level of severity can be defined in terms of its return period, which is the expected average length of time between occurrences of the event.

Return Period	Annual Average Probability of Occurrence	Example Severity
25-year flood	$1/25 = 4\%$	>2 feet flood depth
50-year flood	$1/50 = 2\%$	>6 feet flood depth
100-year flood	$1/100 = 1\%$	>10 feet flood depth

Modeling projections in terms of probability is essential to deriving future risk. Rather than simply arriving at static, deterministic values for climate metrics under a few defined scenarios, probabilities represent the entire distribution of outcomes simultaneously. This enables the asset owner to invest against the most cost-effective level of risk against the expected probability distribution of event severities.

Using these probabilities, utilities can build climate curves which represent the relationship between severity and frequency of weather hazards. Generally, as the severity of a particular hazard increases, its probability of occurrence decreases. The example line chart below illustrates this relationship between wind speed and the annual probability of occurrence. This relationship changes over time as pertinent characteristics of Earth's climate develop. As shown on the chart, the probability of occurrence of a given wind speed increases in the future. This is visually represented by curves corresponding to later years shifting upwards relative to those corresponding to earlier years.

Using a chart like this can allow the utility to see how the hazard's frequency and severity are expected to change. In the example below, there is a modest increase in both frequency and severity indicating that extreme events are expected to occur more often with a higher degree of severity.



2.2 Exposure

Downscaled climate projections should be overlaid onto the utility's assets in a spatially representative way that reflects the spatial variability of the hazards of interest. For example, wind tends to not exhibit significant spatial variability within 5km, so it may only be necessary to project asset impacts for every 5km along a distribution line. Flooding, however, is highly spatially dependent. Assets at the top of a hill compared to those at the bottom of a valley will experience entirely different flooding exposures. In this case, the closer the climate projection point is to the asset's actual location, the better the asset-specific impact can be forecast.

Once climate projections are overlaid onto assets, utilities can quantify asset exposure. Exposure is the probability of asset failure due to future extreme weather events. Assets can fail in a variety of ways, with each mode of failure corresponding to a specific interaction between equipment and extreme weather. In other words, a failure mode defines how an asset will fail given the occurrence of an extreme weather condition (e.g., thermal derating due to high temperature, pole failure due to severe wind, etc.).

Below are examples of failure modes for solar panels under exposure to different hazards. Utilities should work closely with their engineers and asset planners to define failure modes by asset class and hazard.

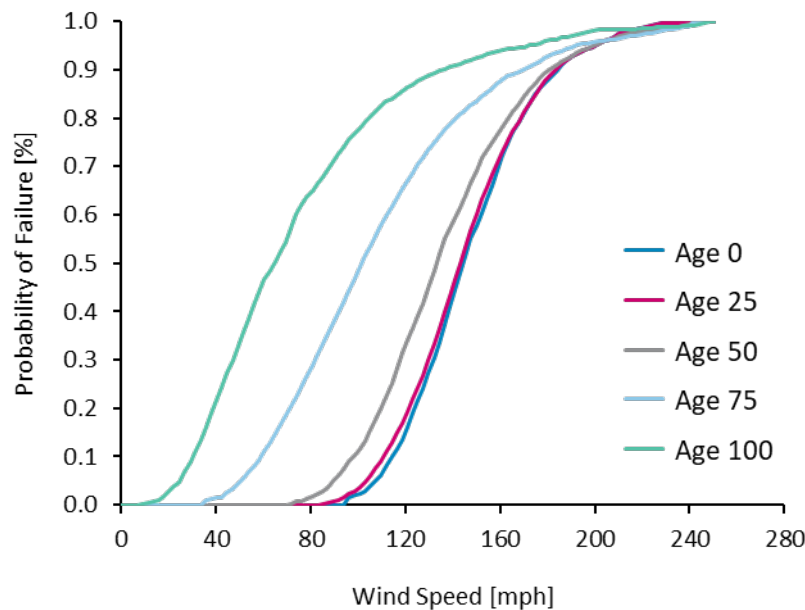
Flood 	Submergence of solar panels can cause electrical short circuits, while water ingress may damage electrical components, and support structures may erode or become unstable	Heat 	Increased temperatures can reduce the efficiency of solar panels, cause overheating in inverters or other electrical components, and lead to material degradation, decreasing overall lifespan
Wind 	High-speed winds can lead to structural damage of panels or support structures, potential displacement or detachment of panels, and wear on moving parts like tracking systems, resulting in malfunction	Cold 	Freezing temperatures can impact the functionality of electronic components, cause ice buildup on panels which reduces efficiency, and lead to structural damage due to material expansion and contraction
Rain 	Water seepage might cause electrical malfunctions or corrosion in wiring, potential short-circuiting of electrical components, affecting panel efficiency	Drought 	scarcity might hinder cleaning processes and reduce output, and dry conditions increase dust and debris. Accumulation on panels can reduce efficiency and increase fire risk
Fire 	Flames can directly damage panels and support structures. High temperatures might cause electrical system damage or short circuits. Smoke and ash accumulation can impact panel efficiency	Storm 	Lightning can strike assets and cause voltage that exceeds the basic insulation level, leading to backflashover. Elevated voltage can surge through conductors and cables to impact other connected assets as well

Modeling Failure Thresholds

Exposure estimates the likelihood of an extreme weather event exceeding an asset's failure threshold. Failure thresholds represent the level of hazard severity which causes an asset to fail, quantifying the relationship between hazards and failure for every possible failure mode. There are several methodologies that can be used to model asset failure thresholds, with positive and negative trade-offs between them. The simplest methodology to model failure assumes static thresholds that do not change over time, whereas multivariable models can range in complexity and incorporate different factors to derive a fragility curve that represents a variable failure threshold.

Methodology	Assets (granularity)	Weather hazards (granularity)	Determining Variables
Static Threshold Modeling	General class of assets industry-wide, assumes no deterioration over time	General weather hazards that impact assets industry-wide	Weather severity ; this simplification assumes that asset age does not affect failure thresholds, all else equal
Fragility Curve, time-dependent threshold	General class of assets industry-wide, assumes uniform deterioration across all assets in class	General weather hazards that impact assets industry-wide	Weather severity and asset age ; assumes that assets become more fragile with age, all else equal, so failure thresholds decline over time
Fragility Curve, machine learning-based threshold	Model is trained on utility-owned asset-level data to output asset-level fragility curves	Model is trained on local weather hazard projections	Weather severity, asset age, condition & maintenance history , other technical, physical & environmental factors; assumes that age and various other factors each affect fragility, all else equal

Fragility Curves, Time-dependent Thresholds



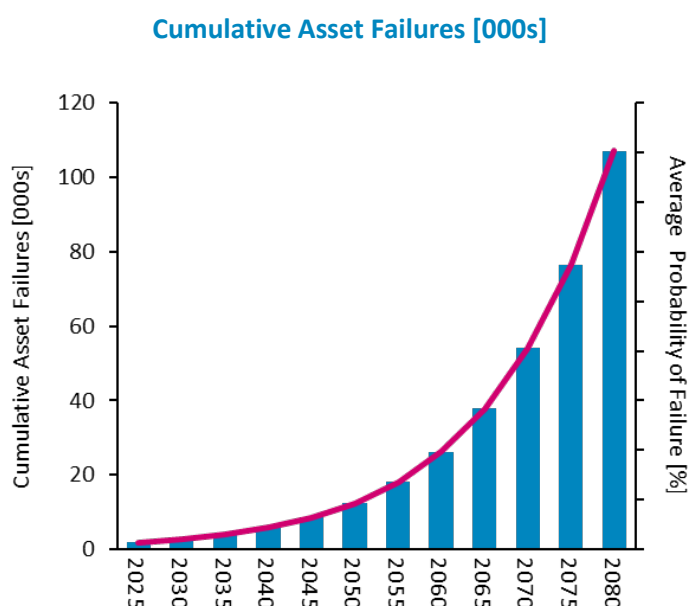
When considering important variables to derive fragility curves, asset owners should select factors that are able to be augmented through resilience actions. The values of these variables should be manipulated in the modeling process to reflect the asset attributes changed by reinforcements and upgrades. This allows for the calculation and comparison of pre- and post-investment levels of asset exposure to weather.

Methodologies to Derive Fragility Curves

	Empirical	Physics-Based	Hybrid
Definition	Derived empirically from utility-specific asset data	Derived based on simulated structural mechanics	Adjust physics-based curves according to asset attributes
Strength	Utility-specific, more precise	Does not require utility-specific data, lower effort	Combines utility of empirical & physics-based approaches
Limitation	Higher effort	Not utility-specific, less precise	Moderate effort

Cumulative Failures

Once failure thresholds are determined, they can be overlaid with projected probability distribution of weather conditions to determine the expected cumulative number of asset failures over time. The cumulative number of failures is equal to the sum of the annual failure probabilities across all assets conditioned on the weather projections and their corresponding failure thresholds.



Data Limitations

Comprehensive data management practices support exposure modeling but might not be currently widespread within US utility operations. While this framework can be implemented with limited data, such as asset class and GPS coordinates, the key to enhancing the accuracy of the modeling is by incorporating high fidelity and complete asset data. Best practices include compiling outages records inclusive of specific equipment failure and cause code information, keeping asset condition and maintenance records up-to-date, and employing digitized asset management systems. Utilities that do not have access to this level of data quality can instead implement static threshold modeling which is independent of endogenous asset condition.

2.3 Risk

The previous step instructs utilities how to derive the probability of failure over the lifetime of an asset. Utilities are next tasked with converting asset exposure into dollars of asset risk, which is defined as the expected cost to asset owners to maintain or restore an asset in the face of failure or damage. To calculate the expected cost of failure for a particular asset in a year, failure probabilities are multiplied by the associated costs of that failure, such as downtime costs, repair or replacement costs, and ignition costs. Utilities often maintain databases of asset-level data that can be used to estimate costs at risk for

transmission and distribution system failures. The following table expands on how these costs accrue to assets:

Costs of Failure

Ignition Costs	• Utility-caused wildfire ignition • Costs of acres burned, buildings damaged, and possibly the loss of human life
Downtime Costs	• Costs to the asset owner and customers for the duration of business interruptions (i.e Value of Lost Load)
Replacement Costs	• Asset failure may necessitate entire replacement • Cost to return to normal operation, either with a similar replacement or with a more resilient asset
Repair Costs	• Some assets can withstand significant stress from extreme weather but require only repairs with minimal to no downtime • Costs to bring the asset back to normal operations without full replacement

Costs of failure can be categorized as direct or indirect; with direct costs explicitly borne by utilities, and indirect costs impacting customers. Direct costs include asset repair or replacement depending on the extent of damage, the process of restoring normal operations and service, and costs of downtime. Indirect costs of failure stem from the value of lost load (VOLL), which is the value to customers of undelivered electricity in \$/kWh¹⁵ or equivalently, the costs saved by improving reliability to reduce customer outages. It represents the societal cost associated with disruptions, and includes the following:

- Higher marginal cost of backup power generation
- Loss of sales and worktime during interruptions to business operations
- Spoilage of unrefrigerated perishable goods, and human injury or death
- Costs to restore grid operation
- Resultant investment uncertainty

Total VOLL varies by customer type with the outage of commercial & industrial customers is much more costly than the outage of residential customers, on a per-customer basis. This means that one low-risk

¹⁵ Weimar, Mark R. 2022. Framework for Quantitative Evaluation of Resilience Solutions: An Approach to Determine the Value of Resilience for a Particular Site. Richland, WA: Pacific Northwest National Laboratory.

industrial customer could incur greater risk for a utility than several high-risk residential customers, in terms of VOLL.

Example Value of Lost Load Figures

Load scope	Example \$/kWh	Example \$/customer
Residential	\$17/kWh	\$200/customer
Commercial & Industrial	\$380/kWh	\$60,000/customer

A helpful tool to calculate the societal cost of an outage is the Interruption Cost Estimate (ICE) Calculator¹⁶. This is an online tool by Lawrence Berkeley National Labs that estimates interruption costs and/or the benefits associated with reliability improvements.

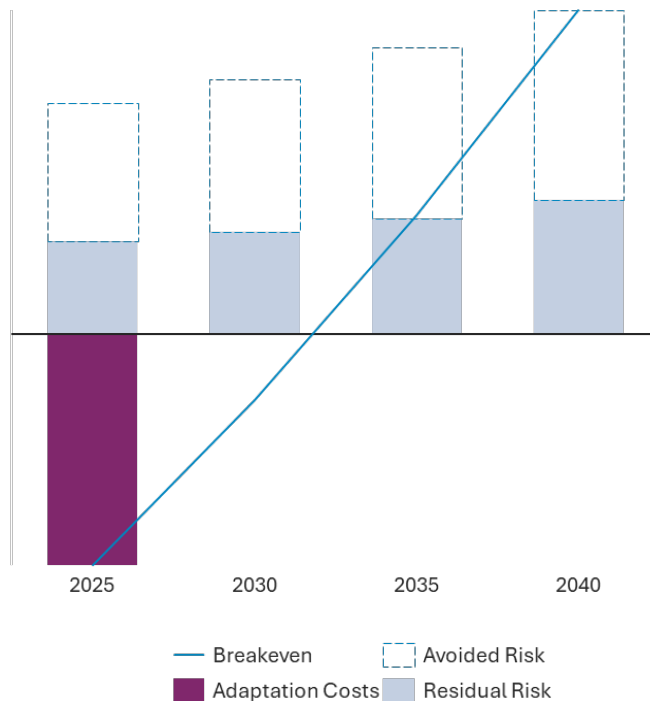
There are also benefits to improving grid infrastructure resilience which are not easily quantifiable but are nonetheless valuable to society. These include protecting cultural and historical assets, aesthetics, improved relations among the local community, and alignment with sustainability & environmental management standards. While these are challenging to include into the cost benefit analysis, other benefits can be evaluated qualitatively in support of the financial outlook of a potential investment.

2.4 Adaptation

Utilities have at their disposal a myriad of solutions to reduce or eliminate resilience risk. Referred to as adaptations, these investments vary both in the extent to which they address risk and their cost of deployment. While the majority of adaptations are capital in nature, such as undergrounding a line or upgrading pole class, some can be operational. Investments in vegetation management and standardized, digitized inspection programs are important operations-based aspects of a robust resilience program, which decrease the probability of wind and wildfire related failures. Baringa's Asset Resilience framework helps utilities understand how to choose the optimal adaptation among a portfolio of potential options.

¹⁶ Lawrence Berkeley National Laboratory. 2025. Interruption Cost Estimate (ICE) Calculator. 2.0. Berkeley, CA, 23 August. <https://icecalculator.com/>.

Net Present Value of Resilience Investment



To select the most appropriate and cost-effective adaptive action, utilities must model the effects of a portfolio of options to determine how they impact the new risk profile of certain assets. Given that expected cost is calculated as the probability of asset failure multiplied by the cost of asset failure, adaptation actions can address either one of these risk components. An adaptive action that would reduce the probability of failure could include elevating a substation that is exposed to high flood risk, thus reducing the likelihood of critical equipment becoming inundated during an event. An adaptive action that would reduce the cost of failure could include a grid network design that implements meshing and redundancy so that fewer customers are affected if a given substation is compromised.

Utilities should build a portfolio of possible investments that reduce or eliminate risks comprehensively across their system. To optimally select the most cost-effective investments, utilities should quantify the benefits of each and compare against one another. The benefits realized from a resilience investment can be quantified as the difference between post-investment risk to the pre-investment risk, expressed either as Net Present Value (NPV) or Benefit Cost Ratio (BCR). To calculate post-investment risks, asset owners should rerun their risk model with adjustments made to either the probability of failure or the cost of failure. Each investment has a unique effect on these variables and should be quantified in collaboration with the subject matter experts (SMEs) and engineers who are most familiar with implementing these adaptations.

Calculating Net Present Value (NPV) & Benefit-Cost Ratio

Additionally, it is critical to consider risks and costs cumulatively across the entire useful lifetime of the asset, rather than just incrementally for each year. Lifetime risk represents the expected cost of failure given the asset will experience at least one design standard exceeding event over its remaining useful life. Calculating lifetime risk enables comparison of costs for assets with different risk profiles and retirement years.

One methodology to compare cost-effectiveness of investments that reduces lifetime risk is by calculating the Net Present Value of each investment. The formula is as follows:

$$NPV = \text{discounted lifetime benefit} - \text{cost} = (\text{pre investment risk} - \text{post investment risk}) - \text{cost}$$

Future dollar values are discounted by the expected inflation rate to determine their present value. A positive Net Present Value indicates that the benefits realized over an asset's lifetime after an investment are greater than the cost of the investment, meaning the investment is cost-effective.

A simpler alternative financial metric to indicate the cost-effectiveness of an investment is the Benefit Cost Ratio (BCR), calculated as the ratio of risk reduction benefits realized from an investment to the cost of the investment over the asset lifetime. BCR does not include discounting by the inflation rate.

$$\text{Benefit to Cost Ratio} = \sum_{t=1}^{\text{asset end of life}} \frac{\text{pre investment risk} - \text{post investment risk}}{\text{investment costs}}$$

By converting risk into dollars and deriving NPV or BCR for investments, utilities are equipped with a common value framework to compare different resilience investments. Returning to an earlier example cited in this paper, by calculating NPV, a utility could determine whether it would be more cost-effective to allocate capital towards upgrading one of two feeders:

- **Feeder A:** a feeder with a low customer count but a high probability of failure
- **Feeder B:** a feeder with high customer count with a low probability of failure

Quantifying exposure in dollars is the only way to compare the absolute risk that each location faces and the subsequent risk reduction benefits to be realized from potential investments. For an illustrative example, please find the graphic below which visualizes a benefit comparison to identify the highest risk conductors.

Pre-Investment & Post-Investment Risks for Conductor Material Modifiers



Cond. #	Pre-Investment	Post-investment	Risk benefit realized, 2025
Cond. #1	0.008	0.006	\$70 \$21
Cond. #2	0.002	0.000	\$21 \$11
Cond. #3	0.04	0.02	\$523 \$181
Cond. #4	0.03	0.01	\$260 \$83

Baringa's cost-benefit framework explicitly uses BCR as a simpler metric to indicate cost-effectiveness, but it is essentially interchangeable with NPV for the purpose that it serves. Utilities which implement this framework can leverage whichever metric is preferred.

2.5 Prioritization

Bounded by a finite capital budget, asset owners can only choose a select number of adaptations in which to invest. By yielding a single NPV for each potential adaptation, Baringa's Asset Resilience framework equips utilities with a metric that is comparable across investments. A given portfolio of notional adaptations can be ordered by highest NPV, ensuring that the utility is first executing those projects with the highest value. Thus, resilience plans are then filled with investments that buy down the most risk for the least amount of dollars. Utilities can continue through the prioritized list until their resilience budget is exhausted.

Ultimately, this approach can be applied not only to resilience plans, but to utility capital plans more broadly. It is important for utilities to view resilience not as a separate ad hoc need, but as fundamental to the capital planning process. This means that resilience risk should be quantified alongside other types of asset risks and resilience investments should be integrated into standard capital plans.

Incorporating Other Types of Asset Risk

Resilience risk is only one of multiple types of risks that face utility assets. In addition to extreme weather, utility assets are prone to damaging capacity violations and other, non-weather driven failures such as those due to age and condition or human interaction. The Baringa Asset Resilience framework denominates these additional risks as **capacity risk** and **reliability risk** respectively.

Capacity Risk 	Capacity risk is the expected cost of failure or damage due to capacity or voltage violations
Resilience Risk 	Resilience risk is the expected cost of failure or damage due to weather hazards
Reliability Risk 	Reliability risk is the expected cost of failure or damage due to condition-adjusted age

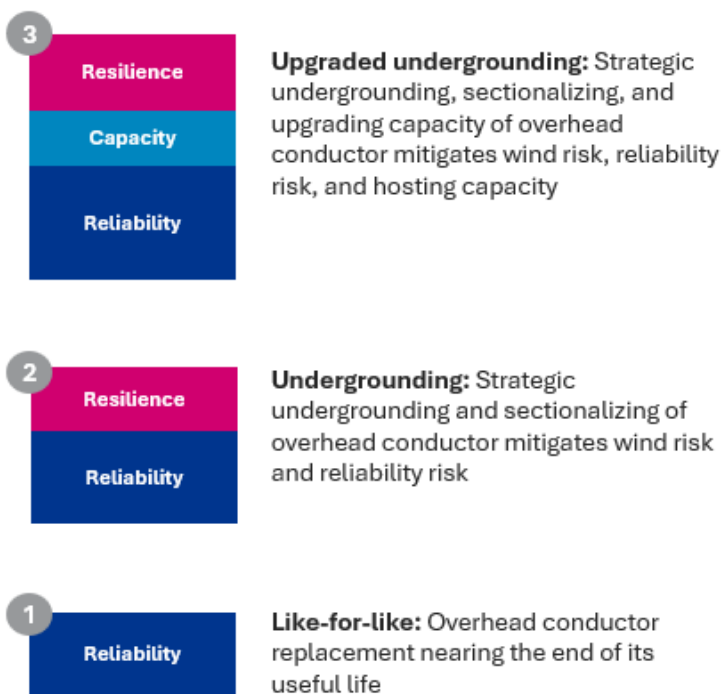
Utility planning should not inherently prioritize one risk type over another. Each asset across a system is unique, accruing a different risk profile given a variety of factors such as exposure to weather, age and condition, peak load, customer density, etc. While this framework does not explicitly provide

instructions for deriving types of risk that are not resilience, the underlying principles remain; both capacity and reliability risk should be quantified in dollars such that all risk types can be evaluated in aggregate, providing an accurate picture of the totality of physical risk posed to an individual asset. This concept, known as Integrated System Planning (ISP), enables a utility to integrate planning across asset needs. Integrated System Planning will be discussed in more detail in the following section.

Adaptations that are intended to eliminate resilience risk can also provide an opportunity to address other types of risk. Oftentimes, the adaptation itself can reduce multiple risks simultaneously. For example, undergrounding a line will reduce the risk posed to conductors from extreme weather exposure, thus eliminating resilience risk. In this scenario, the old overhead conductors will be replaced with a new undergrounded conductor, also eliminating the reliability risk on the feeder from the aging old assets. The utility can improve the business case for this length of undergrounding by quantifying both resilience and reliability risk which would accurately represent the risk to the overhead conductors.

In other cases, addressing alternative risks through additional upgrades while undergoing a resilience investment can be extremely cost effective. For example, executing two capital investments simultaneously can save utility funds through reducing time on staging crews, procuring parts, and preventing early replacement of assets to handle these imminent issues in the future. In the previous undergrounding example, the utility could also upgrade the capacity of the undergrounded line to address the increased forecasted load that will materialize on the feeder in the future. Upgrading the line now prevents the utility from having to dig it up later to serve the new load, thus avoiding premature replacement and consolidating crews into a single project. Utilities can strategically buy down multiple types of risk with the same investment by quantifying all types of risks for assets.

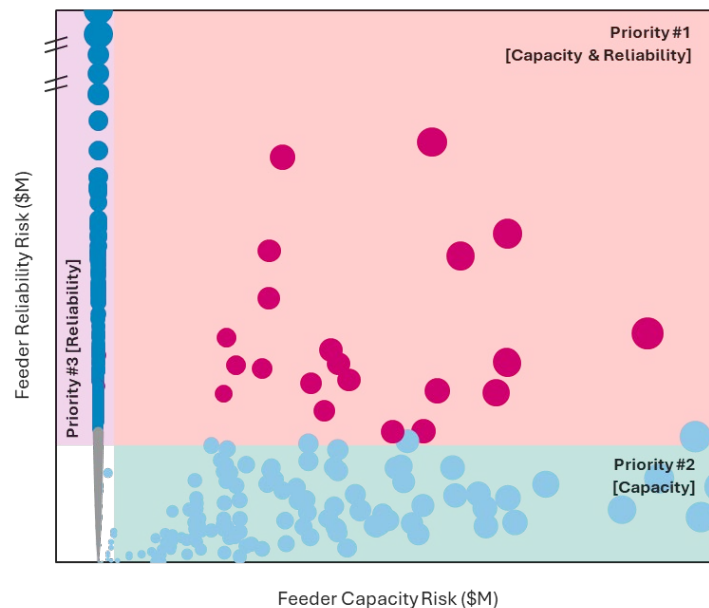
Stacking Risks Example: Undergrounding



Despite these benefits, utilities do not always consider multiple types of risk when planning their projects. Utilities typically prioritize addressing capacity risk non-discretionarily, as it constrains their ability to serve load. This naturally leads to utilities forgoing investments in feeders with reliability and resilience risk to focus on capacity issues, even when the former risks are more significant. The scatter plot below illustrates this concept. Feeders shown in the graphic with very low reliability and pressing capacity risk are labeled Priority Group 1 for utilities and will see investment. In many planning cases, utilities choose feeders that are capacity constrained, regardless of the full capacity risk as Priority

Group 2, shown in the green area in the scatter plot. Prioritizing Group 2 as non-discretionary over Group 3 may defer higher risk feeders. In this case, the greater the lack of coincidence of reliability and capacity risk, the greater the potential deferral of higher risk feeders to address capacity violations. This common example reinforces the need for utilities to quantify all asset risk types during their risk assessments.

Risk Concentration on Feeders



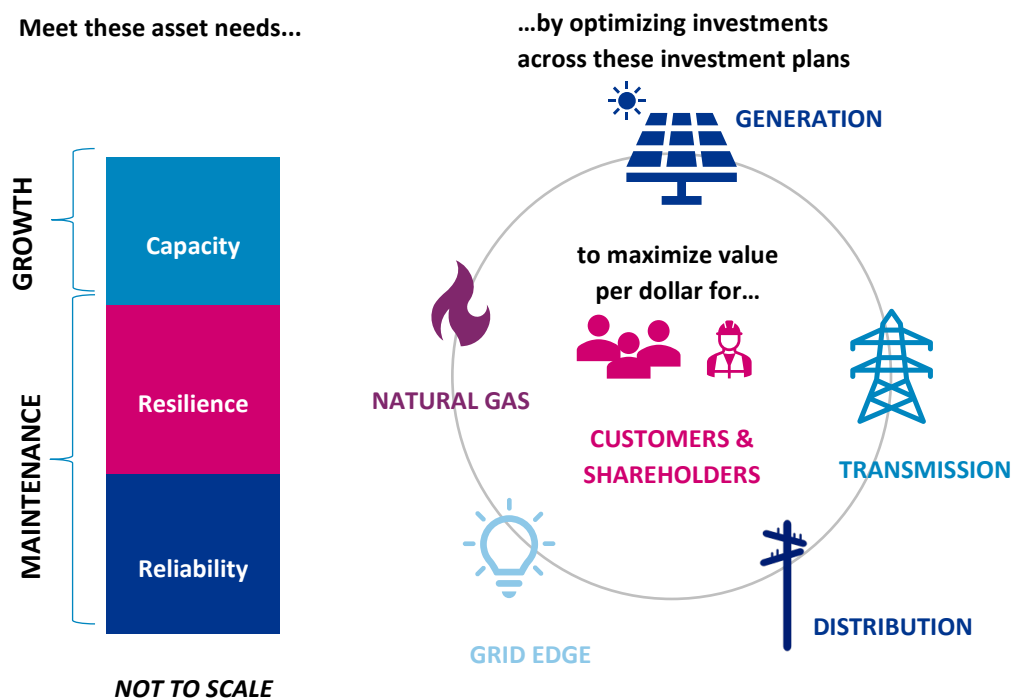
[Marker size is proportional to asset capacity]

Integrated System Planning (ISP)

In addition to addressing multiple asset needs in the same planning process, utilities can expand their risk assessments and solution optimization to include other parts of the utility value chain as well. In the most comprehensive case, utilities could evaluate resilience risk across their generation, transmission, distribution systems, creating one optimized plan that considers how the effects of extreme weather and the benefits of each solution impact the risk to all assets on the system. This concept is known as **Integrated System Planning (ISP)**, and refers to a comprehensive, coordinated, approach to planning the entire electric system. Utilities can employ ISP to strategize their investments to reduce redundancy in capital projects and ensure that the highest risk areas on the system are being addressed first.

Integrated System Planning integrates across two dimensions: 1) the needs of the assets (discussed in the previous section), and 2) the planning functions, which include generation, transmission, distribution, and in some cases, grid edge and natural gas.

Conceptualizing Integrated System Planning (ISP)



An easy example to illustrate how a utility can integrate across asset needs is through assessing the impact of extreme heat on the system. For distribution assets specifically, extreme heat causes failure of transformers and thermal derating of capacity. This hazard affects both the resilience and capacity of the system. By forecasting the elevations in temperature and its effects on increased cooling load, a utility can specify a new transformer that will be hardened to expected heat waves and will still have enough capacity to address the new cooling load despite the potential derates. This investment in a new transformer addresses the coincident capacity and resilience risk posed by extreme heat.

In most utility applications of ISP, it refers to the integration of planning functions. A common example of this can be utility investment in Distributed Energy Resources (DERs). By investing in FTM or BTM DERs on the distribution network, utilities can address load concerns onsite or at least close by. These assets defer investment in the additional poles and wires needs on the distribution and transmission system to serve capacity as well as defers the generation capacity from bulk generation resources. Alternatively, if planning functions are siloed and do not consider the interconnected effects of DERs on transmission and generation, planners may erroneously move forward with redundant and unnecessary investments. Integrating assessments in this way saves ratepayers money and oftentimes improves the reliability and resilience of the system through coordinated and creative adaptations.

3 Implementation

3.1 Collaborating with Utilities

State Energy Offices should firstly seek interest and support from utilities for implementing this risk analysis framework. Leveraging existing collaborative relationships with utilities, SEOs can engage in outreach and education in the form of webinars, workshops, and consortiums. This will serve to educate utilities on the benefits of failure modeling and socialize the Asset Resilience framework's principles, improving their ability to allocate capital and build applications for further funding opportunities.

Additionally, SEOs can work with public utility commissions (PUCs) to enact requirements for utilities to perform risk analysis and quantified resilience planning. In the West, this could take shape through enhancing and expanding the already effective Wildfire Mitigation Plan (WMP) requirements to include risk assessments for other critical hazards as well.

While SEOs and regional regulators hold the funding and authority to make investment decisions pertaining to the grid, the utilities own the grid assets and hold the proprietary asset-level data needed to inform such decisions.

3.2 Asset Resilience Framework Implementation

Asset Resilience implementations can take various paths, depending on things like utility resource constraints, location and size, ownership structure, asset types, and data availability. Not all utilities have sufficient resources and funding to immediately perform a risk assessment.

As discussed in the Exposure section, silos in data ownership between utilities and SEOs can pose a significant hurdle to investment planning. Utilities can then share their data and insights with SEOs and regulators to better inform investment decisions. However, the quality and fidelity of asset management systems vary. Additionally, smaller utilities like cooperatives and municipalities, might be personnel constrained and require outside support to help them undertake this analysis.

To help with these implementation challenges, it is important to note that the cost of analysis scales volumetrically. This is due to the pricing structure of climate projections, allowing for a better price per point as the volume increases. Therefore, it can be more cost-effective for small utilities to perform analysis in a coalition with a larger amount of shared data. Additionally, several regulatory and research entities have created publicly available meteorological data inventories to remedy data inaccessibility, such as [EPRI](https://apps.epri.com/climate-data-inventory/en/).¹⁷

¹⁷ EPRI. 2024. "Climate Data Inventory." Electric Power Research Institute. 3002028492. Palo Alto, CA, 28 March. <https://apps.epri.com/climate-data-inventory/en/>.

3.3 Available Resources

Utilities lacking the resources to perform advanced analysis can start by leveraging pre-existing resources to inform their resilience planning. Below are publicly available reports and tools for asset owners to consult prior to engaging in a proper asset-level risk assessment:

Organization	Resource Name	Resource Description	Applicable Geographies
	Grid Resilience Reports (GRR) <i>(link to public landing page in progress)</i>	Analyzes the impact of future extreme weather on generation, transmission, and distribution infrastructure. Reports highlight problem areas and suggest potential adaptations to explore for risk abatement.	WECC states <i>(please request for additional states)</i>
	State of the Grid Reports (SOGR) <i>(link to public landing page in progress)</i>	Explores the relationship between historical outages, ignitions, extreme weather, and utility capital spend. Identifies the most impactful historical hazards on county outage rates and evaluates the alignment of utility spend to this risk.	WECC states <i>(please request for additional states)</i>
	<u>TASTI-GRID</u>	An interactive tool that enables users to explore historical electric outage data to better understand the state of the grid and inform grid resilience investments.	50 states
	<u>ClimRR</u>	Provides data about future conditions and environmental extremes to help us better plan and adapt for the future. Using one of the world's largest supercomputers, ClimRR datasets provide among the most comprehensive, free dynamically downscaled projections for the United States.	50 states

Baringa will be developing a landing page to host the outputs of the GRACI program, inclusive of reports, webinars, and analysis. Please reach out to the Baringa team if there is interest in producing these reports for your state.

4 Conclusion

Electric utilities must act now to invest in the resilience of their assets in the face of extreme weather hazards that pose substantial and growing risks to the grid's security and reliability. Extreme weather events catalyze volatile swings in wholesale energy markets as they physically impact on all utility assets (generation, transmission, and distribution) through asset failures, outages, and wildfire ignitions. Even if the odds of a disaster are small on an annualized basis, they still pose a risk that asset owners and investors must account for, given the multi-decade useful lives of infrastructure assets. Underestimating lifetime risk can lead to premature asset replacement, which is extremely costly for customers who end up paying for the same asset multiple times.

Funding for investments that address such resilience risk is bound by customer affordability. Therefore, utilities must determine the optimal allocation of the budget that maximizes avoided cost of failure per dollar of investment, which requires a framework that quantifies resilience risk to guide investment decision-making against other competing asset needs. Baringa's Asset Resilience Framework enables utilities to forecast asset-level dollars of resilience risk, to value investments to address those risks, and to prioritize investment portfolios.

The Infrastructure Investment and Jobs Act (IIJA), Section 40101(d) funding allotted to State Energy Offices (SEOs) to modernize America's power grid against wildfires and extreme weather can be awarded to utilities seeking to make resilience investments. Baringa's Asset Resilience Framework can help SEOs understand best practices in resilience planning and educate utilities on how to forecast dollars of resilience risk to justify the investments they propose. SEOs can distribute this framework to utilities to inform their resilience planning and substantiate their applications for 40101(d) funding. Capital plans which adopt this framework can give utility boards and regulators confidence that spending is being allocated efficiently and is worth approving. Additionally, this framework includes methodology that does not require large amounts of data, to ensure accessibility to smaller utilities and cooperatives which may not have the resources to carry out complex resilience analysis. **It is critical that utilities perform quantified risk analysis to ensure the most effective resilience upgrades receive 40101(d) funding from SEOs to deliver the greatest risk-reduction benefits to utilities and their customers.**

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