Potential for Incorporating Climate-Related Risks into Transmission Network Planning

A REVIEW OF FRAMEWORKS AND RESPONSES

PREPARED FOR

AEMO

Australian Energy Market Operator

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Executive Summary

Electric transmission investments underpin electricity markets, transporting the energy from generators to distribution systems and ultimately customers. These investments are long-lived and expected to operate four to six decades into the future. Due to the longevity of transmission assets and significant capital outlays required, cost-effectiveness needs to be considered over the lifetime of the assets. The planning of cost-effective investments should take into account the projections of increasing extreme weather events over the transmission assets' lifetime, including investments necessary to mitigate adverse outcomes and the need to retrofit or otherwise upgrade the system in response to extreme weather events.

The Australian Energy Market Operator (AEMO) has asked The Brattle Group to assist in understanding how climate-related risks can be incorporated into the long-term transmission network planning for the National Electricity Market (NEM). To do so, we begin by examining how several jurisdictions in North America and one jurisdiction in Europe consider climate-related risks in their current network planning processes.

- We observe that most jurisdictions are just beginning to develop policies, frameworks and approaches to account for climate-related risks when planning of transmission networks.
- We have not identified a jurisdiction where a national policy and/or framework is setting comprehensive new standards and planning process that take into account climate-related risks when developing electricity system resilience.
- The current North American approach for setting standards to account of climate-related risks in transmission network planning is very much decentralized, with each region/state and province conducting its own transmission planning, with location-specific considerations for climate-related conditions.
- In Europe, we have found that the transmission network owner and developer in Italy conducts system planning with significant considerations for increasingly severe weather conditions, including ice loading on overhead electric wires and increasingly stronger storms.

Based on our review, we draw a distinction between a proactive approach, under which a regulator or planner develops a forward looking approach to anticipate and mitigate future climate-related risks, and a reactive approach, which is generally responsive to historical events.

Italy is developing a proactive approach to mitigating climate-related risks

In Europe, we observe that Italy's electric transmission and distribution companies have begun to develop a proactive approach to account for climate-related risks in network planning and investments. Italy's proactive approach includes developing a benefit-cost model that compares the probability-weighted value of reduced customer outages to the investment cost. Under Italy's approach the probability of customer outages is estimated using historical outage information combined with high-resolution historical meteorological data. Companies are provided with financial incentives to increase the resilience of their systems through a "shared saving" approach. Such a "shared savings" regulatory approach is intended to align the regulator's and the network owners' interests to ensure that the facilities built will enhance the system's resilience, particularly when faced with ice loading on the overhead wires, severe storms, and severe and extended high temperatures.

The North American approach has been largely reactive

In North America, the centralized reliability coordinator (the North American Reliability Corporation) does not officially set enforceable system resiliency standards with which all planners and transmission network owners must comply. Similarly, there is not a United States or Canadian entity that determines national resiliency standards. Most of the regional transmission planning processes use a planning horizon of ten years, which is likely too short to account for climate-related risks that are expected to increase over time. In general, we observe significant "system hardening" efforts that react to severe weather events. Under those circumstances, regulators and transmission owners tend to focus on making investments to increase the robustness of transmission assets to avoid future events. Those efforts are primarily region-specific, with transmission planning organizations and transmission investors beginning to develop resilience plans that account for the potential for increasing the severity of future weather-related events.

Establishing a national regulatory framework could be beneficial

Having a national policy for accounting for climate-related risks when planning for transmission networks could efficiently and effectively set standards across all transmission network system providers. A national approach recognizes the interconnected nature of transmission systems and the impact of an outage in one region on other regions. Such a national policy and framework would involve:

- **Scoping** the necessary climate-related risks assessments.
- **Assessing vulnerabilities** by gathering information about how future climate-related events could affect certain important equipment or assets
- **Forming resilience plans** by setting minimum national standards with best practices for meeting the standards

Additional observations

- Planning horizons of 10 – 15 years, common in North America and elsewhere, are unlikely to capture the climate risks that electric infrastructure is exposed to over a 40-60 year lifespan.
- Many climate risks have similar potential responses, including consideration of geographic diversity of transmission lines, increasing physical robustness of the assets, increasing monitoring and the use of sensors for early alerts for potential severe events.
- Historical reviews of climate events likely understate forward-looking climate-related risks to the power sector. Forward-looking projections of climate risk would better capture future risks. However, the availability of long-range forecasts is limited, and thus, the use of forecast may limit the regulatory acceptance of such data.
- Planning for climate resilience may overlap with other areas of resilience planning, notably cyber security. Increasing the use of advanced sensors and communication is likely to significantly increase resilience and mitigate the risks and potential damage from extreme events, including severe weather-related conditions.

Recommendations

Climate-related risks for the power sector are broad-reaching. This report is only focused on examining a few jurisdictions to understand if other system planners are engaging in climate-related risk analyses when conducting transmission network planning. Thus, the lens by which we view and consider the climate-related risks is quite limited. Our recommendations from this limited study are relatively high level, and further research will be necessary to provide a stronger recommendation about the specific planning standards and the regulatory framework necessary to support a more climate-resilient planning process. Our primary recommendations are:

- Developing a holistic review of climate vulnerabilities as well as potential resilience metrics and harmonisation of those metrics with existing regulatory requirements
- Analysing mitigation approaches to climate-related risks, such as (a) line diversity, (b) the use of new and more resilient technologies and equipment, and (c) the use of advanced monitoring and alert technologies
- Developing a common approach across AEMO, regulators, and other stakeholders on decision metrics to be applied to system planning (e.g., least regrets, average value, etc.), which should include concrete examples of potential outcomes under each approach
- Analysing the potential for a national policy for accounting for climate-related risks when planning for transmission networks, including forming resilience plans by setting minimum national standards with best practices for meeting the standards (as mentioned above)

Our secondary recommendations focus on the need to incorporate best-available data and broaden the topics considered to holistically review the impacts of climate-related risks. Specifically, we recommend:

- Using forecasted climate risk data, to the extent feasible, and relying on recent historical data when necessary

- Monitoring the evolution of climate science to understand trends in projected climate risks, the availability of high-resolution data, and advances in the underlying science

- Ensuring that the time horizon used for long-term transmission network planning would capture the potential effects over the life-time of the transmission assets

- Analysing interactions between the resilience of the electric power system with other infrastructure systems, including telecommunications, natural gas delivery systems, and water supply and delivery systems

I. Introduction, Context, and Scope of Report

Climate-related risks are expected to present challenges to the power system, particularly as temperatures rise and extreme natural events occur more frequently. Since the capital investments made today are planned to operate reliably for multiple decades into the future, severe weather events that harm the capital investments and equipment could cause significant adverse system-wide impacts and create severe financial implications for investors and customers. In Australia, recent experiences with bush fires, flooding, drought, and severe storms have highlighted the vulnerability of the power system to extreme weather. Proactively incorporating climate-related vulnerabilities into planning can mitigate adverse outcomes, mitigate the need to retrofit or otherwise upgrade the system in response to events, and contribute to a more cost-effective system going forward.

Climate-related risks will affect all parts of the power system.[1] These risks can affect generators, transmission systems, distribution networks, and customers' usage patterns. Thus, the issues that can arise from climate-related risks are broad and far-reaching. For example, hydroelectric generators may be affected by multi-year droughts, traditional thermal generators may face water shortages for plant cooling, wind turbines may need to be shuttered during extreme storms, transmission lines may face severely high temperature that require rating reductions, substations may face more severe or frequent flooding, and customers' usage could increase dramatically during long and severe heat waves, right at the same time when the power grid is under severe stress from the high temperature.

Various jurisdictions are defining climate-related risks as "extreme weather conditions," "extreme natural events," or more generally referred to as "weather-related risks." When engaged in mitigating climate-related risks, some activities are considered as "building resilience" or "system hardening." While there is diversity in the terms that various jurisdictions use, for the purpose of this report, we will use the term "climate-related risks" to include the severe conditions that are weather-related. We use this term because many electric utilities and power system planners are observing that the weather-related conditions that harm the power systems are becoming more frequent and severe.

Broadly defined, climate-related risks present system security risks and system reliability risks to the power system.

[1] In this paper we focus on physical risks to the grid. There are other types of risks related to the transition to a lower carbon system, including financial risk that entities participating in the power sector will experience. These entities include parties that own, finance, insure, or operate assets in the power sector.

System Security and System Reliability reflect the system's ability to maintain service under loss of transmission or generation elements. System security exists when the system operates within its technical limits and will likely continue to do so even in the case of a disruptive event, such as the disconnection of a major element of the system. In the context of this report, such disruptions can result from severe weather events or fires. System Reliability is a related concept which measures the power system's ability to meet customer demand in spite of generation and transmission contingencies.[2]

Resource Adequacy is a measure of whether sufficient resources, typically generation and demand-side resources, are available to meet the net consumer demand. Climate-related risks can affect resource adequacy through physical threats to the supply resources (e.g., flooding of fossil power plants or lack of water for hydroelectric power plants) or operational issues (e.g., insufficient cooling water due to drought). While Resource Adequacy is an extremely important set of system standard and criteria, with significant implications for developing an integrated view of climate impact on the reliability of the full power sector, we will not address Resource Adequacy issues in this report.

In this report, we provide an overview of system security and system reliability (specific to the transmission network) responses to climate-related risks, focusing on the questions of who is responsible for understanding and responding to climate-related risks, what risks are or should be analysed, what types of responses are being implemented, and what are the observable practices that could be useful and applicable to the Australian context. Specifically in the context of new planning standards, we consider what types of changes in design standards, redefinition of standards to account for common-mode failures (e.g., defining contingencies based on exposure to a risk type), or implementation of new technologies are being considered. While providing a high-level overview of climate risk resilience framework, we focus on four of the risks identified by the AEMO in its Appendix B of its 2018 Integrated System Plan.[3] These risks are: extreme temperature, bushfires, wind speed, and flooding.

To collect the international experiences with considerations for climate-related risks when planning the power system, we review studies conducted to date, reports produced by utilities system planners/operators, and various planning organizations. Most significantly, we conducted interviews with key subject matter experts to gain insights into their perspectives.

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2 AEMO, *Power System Requirements*, March 2018.

3 AEMO, *2018 Integrated System Plan Appendices*, 2018.

II. Regulatory and Governance Frameworks

A. North America

In general, the North America Electric Reliability Corporation (NERC) is responsible for determining reliability standards in Canada, U.S., and the northern portion of Baja California, Mexico. NERC's Reliability Issues Steering Committee (an advisory committee to the NERC Board of Trustees) identified extreme weather in its 2018 and 2019 *Reliability Risk Priorities Report*. The 2019 reports identified hurricanes, tornados, intense storms, extreme heat and drought, wild fires, flooding, and extreme cold weather as regional threats to the grid.[4] The 2019 report classifies these risks into two categories, one of continual "monitoring" and another that requires "management."[5] Monitoring indicates that the individual regions are monitoring the risk and adapting their approaches. Management indicates that the risk requires a more aggressive and immediate approach for effective foresight and mitigation.

The standards set by NERC are high-level and performance-based, which allows the individual regional planning and reliability entities to implement the standards in a region-specific manner. While this approach allows for regional adaptability, it means that North America does not have system-wide planning standards for ensuring that the bulk transmission system will be planned according to the same set of requirements or standards that account for any severe weather conditions in the future.

As a part of its long-term planning function, NERC has discussed the importance of resilience, which can certainly include the analysis of climate-related risks, although not necessarily labeled as such.[6] Specifically, NERC has set specific system standards for system planning. One of its standards, called the NERC Reliability Standard TPL-001-4, Transmission System Planning Performance Requirements, requires that system planners across North America consider "wide-area events." It appears that the wide-area events include climate-related risks that are relevant to the specific region, such as wildfire and severe weather conditions. The events to be considered also include cyber-attack or loss of natural gas pipelines.[7] However, the definition of what events should be analysed in detail and directly considered during system planning is left to each of the regional planners.

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4 The report states that while the risk of events in regions is high, the relative impact on the bulk power system (beyond regional) is low.

NERC, *2019 ERO Reliability Risk Priorities Report*, November 2019, p. 20.

5 NERC, *2019 ERO Reliability Risk Priorities Report*, November 2019.

6 *Ibid.*

7 NERC, *Standard TPL-001-4 — Transmission System Planning Performance Requirements*, November 26, 2014.

1. United States

In the United States, there is no central organization that sets enforceable standards for planning or investment responses specifically to climate-related risk. The Federal Energy Regulatory Commission (FERC) establishes general regulations for transmission planning. Through Order Nos. 890 and 1000, the FERC mandated increased cooperation across the various regions subject to FERC jurisdiction.[8] The planning of new transmission lines in the United States is carried out by a mixture of vertically integrated utilities and independent system operators (ISOs), such as the PJM Interconnection, MidContinent ISO (MISO), and the Southwest Power Pool (SPP). FERC Order No. 1000 recognized twelve planning regions, seven of which cover territories that are not part of an official ISO.[9]

After the system planners arrive at consensus or approvals for certain transmission enhancement plans and projects, the project developers of the transmission projects usually must go through various state siting and permitting processes, which typically involve either national or state siting authorities' scrutiny. The siting process typically involves an environmental review which in turn can result in changes to the proposed project routing and/or equipment. Often, during the siting process, the state authorities can request system strengthening investments or consider requests from the transmission developers to include investments that increase system resilience. For example, Florida's regulations call for strengthened transmission towers as a consequence of state-level resilience policies,[10] California regulators require utilities to plan for bush fire mitigation,[11] and Texas has required hurricane-rated transmission towers.[12]

While there is no single national regulator governing the siting and construction of interstate transmission projects, a number of standards organizations such as the American Society of Civil Engineers (ASCE) and the Institute of Electrical and Electronics Engineers (IEEE), as well as the National Electrical Safety Code (NESC), have established minimum standards for the construction of transmission towers. These standards are comparable to those used for other construction and electrical engineering projects.

Within the United States, the state of California is one of the most forward-looking on issues related to climate risks. The State of California's guiding climate resiliency policy is set by the state legislature. Following extreme wildfires in 2018 and 2019, the state legislature passed new laws to increase resilience and oversight in light of climate change-driven wildfires. These

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8 The contiguous United States has three separately-synchronized but interconnected systems.

9 Eto, J, *Planning Electric Transmission Lines: A Review of Recent Regional Transmission Plans*, Lawrence Berkeley National Laboratory, September 2016.

10 Florida Public Service Commission, *Review of Florida's Electric Utility Hurricane Preparedness and Restoration Actions 2018*, July 2018.

11 California Energy Commission, Final 2019 Integrated Energy Policy Report, February 2020.

12 Electric Reliability Council of Texas, Inc and the Public Utility Commission of Texas, Joint Comments submitted to Docket No. AD18-7-000 Grid Resilience in Regional Transmission Organizations and Independent System Operators, March 2018, p. 8.

include the 2018's Senate Bill 901, which increased the California Public Utility Commission's (CPUC's) oversight of utilities, requiring them to submit wildfire mitigation plans to the CPUC for approval.[13]

As the state regulator, the CPUC is responsible for siting and permitting of transmission lines that physically traverse California (except for those that traverse over national land, which are under a different set of national siting and permitting requirements). Through the siting and permitting process, among many other considerations, the CPUC regulator evaluates and determines whether the proposed transmission projects meet certain design and engineering criteria. As cited above, recent legislation has empowered the CPUC to enforce more stringent standards relating to wildfire mitigation by utilities and transmission line operators. The CPUC also cooperates with the California Department of Forestry and Fire Protection (CAL FIRE) and local fire departments to investigate and identify the sources of wildfires, which informs CPUC's assessment of utility compliance with wildfire mitigation measures.[14]

The California Energy Commission (CEC) also plays a critical role in the state's more general and broad climate change planning and policy development both as it relates to efforts to adopt renewable energy resources and work to increase resilience in the face of climate change-driven threats such as wildfires and extreme heat. The CEC is responsible for producing the California Climate Change Assessment, a comprehensive examination of the state's climate outlook and adaptation measures. The CEC's fourth climate assessment, published in 2018, included reports assessing wildfire and extreme heat impacts and projected future costs of recovering from and adapting to these events.[15,16]

Long-term transmission planning for the California's electricity system is the responsibility of the California Independent System Operator (CAISO). In recent years, CAISO has just started to consider the potential impacts of climate-related risks in its transmission planning activities. However, the CAISO has not yet developed a process to systematically incorporate those risks into its transmission plan that would account for possible failures due to severe storms, wildfires, flooding, and other climate change-driven events. As the CAISO begins to consider climate-related events, it also recognizes that it will need to simultaneously consider the potential physical impacts of such events on resource availability and unusual load occurrences associated with climate-related incidents.

2. Canada

Canada's federal system means that, much like in the United States, transmission planning takes place on a province-by-province level, with little input from the federal government in Ottawa. With strong connections between the provinces of Quebec, Ontario, Manitoba, and British

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13 California Energy Commission, *Final 2019 Integrated Energy Policy Report*, February 2020.

14 CPUC, "Wildfires", 2020.

15 Dale, L., et al, *Assessing the Impact of Wildfires on the California Electricity Grid*, California Energy Commission, August 2018.

16 Burillo, D., et al., *Climate Change in Los Angeles County: Grid Vulnerability to Extreme Heat*, California Energy Commission, August 2018.

Columbia with the United States grid, the individual provinces focus on both own transmission infrastructure needs and how Canadian resources can be usefully exported to the United States. Canada often export more to the United States than they do to their Canadian neighbors.[17] In Ontario and Alberta, transmission planning is the responsibility of the provinces' independent system operators: the Independent Electric System Operator (IESO), which serves Ontario, and the Alberta Electric System Operator (AESO), which serves Alberta.[18,19] In other provinces, the operators, often Crown Corporations, also owns the transmission assets and therefore are also the system planners.[20]

B. Europe

Transmission planning in Europe is a decentralised process although recent regulatory changes have moved toward a more centralised approach. National regulators and system operators still have a predominant role in transmission planning; each country decides for itself the type and structure of its system needs and has an independent regulatory system. However, there are pan-European agencies including the European Agency for the Cooperation of Energy Regulators (ACER), which is the European energy regulator, and there is a European wide planning group, the European Network Transmission System Operators, Electric (ENTSO-E).

ENTSO-E has historically created an informational Ten-Year Network Development Plan TYNDP) every two years.[21] The TYNDP is based on national investment plans, including regionally-based investment plans, but has more recently evolved to focus on a top-down approach and capture a more top-down European-Union (EU) wide view. The TYNDP identifies investment cross-border capacity requirements and possible obstacles due to, for example, authorisation procedures. The ACER issues an opinion on the TYNDP to assess how well national development plans align with the plan at the EU level. The TYNDP is not binding and each national authority has the ability to decide its national investments. However, the TYNDP is the basis for the selection of the Projects of Common Interest (PCI), projects with a significant impact in the development on the internal EU market. These projects receive preferential treatment including accelerated planning and permit granting processes.

Based on our expert interviews, we identified Italy as a jurisdiction within the European Union that is leading on issues of climate resilience. In Italy, resilience planning is guided by the Ministry for Economic Development and the Ministry of the Environment's national strategy, approved in 2017.[22] Regulation and oversight is the responsibility of the Regulatory Authority for Energy, Networks, and the Environment (ARERA), which in 2018 required distributors to

17 Baker, B. *et al.*, *Canada's Electricity Infrastructure: Building a Case for Investment*, The Conference Board of Canada, April 2011.

18 IESO, *Overview of the IESO-Administered Markets*, July 2017.

19 AESO, *AESO 2020 Long-term Transmission Plan*, January 2020.

20 Baker *et al*, 2011.

21 See https://tyndp.entsoe.eu/ for additional detail on the current TYNDP.

22 Lo Schiavo, L., Turconi, C., and Villa, F., *Regulatory Incentives for Improving the Resilience of Electricity Distribution Grids in Italy*, June 2019.

publish an annual resilience plan. A national standardization committee, the Italian Electrotechnical Committee (CEI), defines the technical specifications of equipment, which can include resilience measures.

One of the major weather-related risks to the Italian grid comes from wet snowstorms, particularly in the densely populated and highly industrialized northern provinces of Lombardy, Veneto, and Emilia-Romagna. Such snowstorms can lead to outages as accumulated snow pushes lines beyond their mechanical design limits. Terna, Italy's independent transmission owner and grid operator, is particularly concerned with such events, highlighting them in its 2020 Development Plan.[23] In addition to these wet snowstorms, Italy has seen an increase in the severity and frequency of high winds, which can also damage overhead power lines. The country has also seen increases in heat waves, with the summer of 2019 experiencing record-setting conditions. The heat waves affect both overhead transmission lines as well as underground distribution networks, as buried cables are less able to dissipate heat and face an increased risk of breakdown.

In 2018, ARERA implemented a requirement for distribution system operators to develop a "Resilience Plan" to increase the robustness of the grid and establish a benefit-cost approach to evaluate investments, and a similar model is being developed for the transmission system. The Resilience Plans include a rolling three-year plan of investments to increase the distribution system's robustness to exogenous conditions including ice sleeves on bare conductors, heat-wave induced breakages in underground cables, flooding of distribution substations, strong winds, etc.[24] The benefit-cost model compares the probability-weighted value of reduced customer outages to the investment cost, and the probability of customer outages is estimated using historical outage information and corresponding high-resolution meteorological data.[25] ARERA also implemented a financial incentive program that rewards distribution system utilities up to 20% of net benefits (resulting from avoided power interruptions) and penalizes distribution system utilities if investments are not put in place on schedule.

C. Regulatory Decision Metrics to Evaluate Climate-Related Risk Responses

Considering climate-related risks when conducting system planning will likely require using a combination of economic justification, which account for the probability of adverse outcomes and the costs associated with those potential adverse outcomes, and resilience or design standards that require the system to withstand certain operating conditions. Practically, the development of mandatory resilience or design standards frequently reflect economic trade-offs that may or may not be a part of the system planning process. When defining how to measure "resilience," a team at Sandia National Laboratory in the U.S. considered 7

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23 Terna, *2020 Piano de Sviluppo* [2020 Development Plan], 2020.

24 L. Lo Schiavo, C. Turconi, F. Villa, "Regulatory Incentives for Improving the Resilience of Electricity Distribution Grids in Italy," CIRED 25th International Conference on Electricity Distribution, Paper no. 2192, June 2019.

25 Id.

"consequence categories" and 19 metrics for resilience including critical services without power, business interruption costs, cumulative customer-hours of outages, and time to recovery.[26] These metrics, such as quantifying the critical services without power, move beyond "value of lost load" studies traditionally used in many jurisdictions. Metrics used to articulate the economics of spending more upfront to reduce future costs associated to the recovery from adverse outcomes need substantial amount of regulatory and industry support.

Further complicating the comparison of the costs and benefits of spending more upfront to increase system resilience in the long-term involves the assessment of the high degree of uncertainties around both the magnitude of the adverse effects when a failure occurs in the future and the probability of those extreme events occurring. System hardening and planning adaptation measures that account for the uncertainty related to timing and magnitude of climate-related risks include using various approaches to estimate the costs and benefits of investing to improve resilience of the grid. Below is a brief explanation of three types of planning approaches: (1) the use of expected value to quantify benefits and costs, (2) the use of a "least regrets" approach to make investment decisions, and (3) the use of "robust planning" to ensure that the worst outcomes can be managed with the least cost.[27]

> **Expected Value** (probability weighted): Investment options are evaluated based on the weighted average of multiple scenarios. This approach is intuitively appealing but more complex than first appears due to the need to define scenarios and their probabilities. In the context of climate-risk planning, this requires developing scenarios and their associated probabilities that appropriately capture the likelihood of extreme weather phenomena in individual regions, which is subject to significant uncertainty. As previously described, this approach has been adopted by the Italian regulator to provide incentives for investments to strengthen the power distribution system and currently being updated for transmission investments as well.
>
> **Least Regrets** (minimax regret): Investment options are compared based on minimizing the maximum "regret" (i.e., the performance that could have been obtained if another option been selected).[28] Consider the hypothetical example where a transmission planner is comparing two plans, Plan A and Plan B. In the example, Plan A performs better than Plan B in all scenarios except one, in which it performs very poorly. A strict least regrets approach would select Plan B, because it negates the potential for a high regret outcome, whereas Plan A performs significantly worse in this scenario, even if it performs better than Plan B on

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26 E. Vugrin, A. Castillo, and C. Silva-Monroy, *Resilience Metrics for the Electric Power System: A Performance-Based Approach*, Sandia Report SAND2017-1493, February 2017.

27 Academic researchers study each of these approaches in the context of transmission network expansion planning, typically in the context of algorithmic optimization approaches. In practice, decision metrics are more likely to be used to compare investment options.

28 Note that the terms "least regrets" has been used to indicate other approaches in different jurisdictions. For example, "least regrets" has been used to indicate individual projects that appear across multiple scenarios.

average.[29] As an example in practice, the AEMO describes a least regrets approach to planning in its Draft 2020 Integrated System Plan.[30]

Robust Planning (minimax outcome): Investment options are evaluated to minimize the costs of the potential worst-case outcome, and in practical terms, this approach would likely reflect planning for the worst-case scenario of inputs. This approach differs from the least regrets approach because the system is explicitly being planned to minimize the impacts of the worst-case outcome rather than choosing amongst plans that have been developed to perform well across several potential scenarios (least regrets).

Each of these approaches, including their advantages and disadvantages, are summarized in Table 1.

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29 There are variations on the least regrets approaching including a probability weighted least regrets approach.

30 AEMO, *Draft 2020 Integrated System Plan*, December 2019.

See also the *Draft 2020 Integrated System Plan Appendices* for additional explanation of the least regrets approach applied by AEMO.

Table 1: Summary of Advantages and Disadvantages of Decision Metrics for Climate Resilience

	Advantages	Disadvantages	Approach Observed in Practice
Expected Value (weighted probabilities)	• Allows for consideration of multiple scenarios • Allows for analysis of more and less likely outcomes	• Requires assignment of probability • Comparing the Expected Value from each scenario might reduce the insights that can be gained from examining across broad range of plausible scenarios • Probabilities of specific weather events affecting populations is computationally difficult, data is not readily available, and outcomes may be litigious	• Italian cost-benefit model for resiliency improvements • Consolidated Edison (USA) resilience framework
Least Regrets (minimax regret)	• May not require assigning probabilities to climate-risks • Provides transparency in potential outcomes	• May perform less-well "on average"	• AEMO's 2020 Draft ISP
Robust Planning (minimax outcome)	• Mitigates worst-case outcomes • Does not require assigning probabilities to outcomes	• May result in overly-conservative investments by focusing on the worst scenario, which may be unlikely to occur, but in turn leads to plans with high up-front capital costs • Requires careful definition of "worst-case"	• Not observed in review

D. General Observations

Our observation from discussions across several jurisdictions include the following:

- The central authority in North America, NERC, has been setting planning and operational criteria for decades. Severe weather-related events have been a part of the existing planning criteria to ensure electric system reliability, which includes strong system resilience. However, forward-looking estimation of how climate-related risks might affect planning and operations of the grid is currently limited at the centralized level in North America.
- System resilience has received an increasing amount of attention as the weather-related events become more frequent and severe, affecting more electric system assets and customers, thus NERC and United States state and Canadian provincial authorities recognise the interest and importance of this topic.

- Across Canada, and the United States, the transmission planning activities occur at the regional or state/provincial level. Each region, province, or state, has specific weather-related concerns, and much of those concerns are considered after experiencing severe adverse conditions and incorporated into the relevant planning organization's activities and local regulator's decision-making processes.
- There is not a concerted effort across North America to coalesce and coordinate an effort for the Canada and United States to collectively set standards and requirements for planning the power system of the future. It is unclear what types of actions are needed to place those responsibilities at the national levels.
- As responses to severe storms and fires in the last decade, some jurisdictions within the United States have dedicated efforts on developing frameworks and approaches to identify the climate-related risks, their severity, and their impact, both physically and economically. These efforts are dispersed, with jurisdictions that have experienced severe conditions and damages at the forefront of "doing something about it." Examples of these include New York City, New Orleans, and California.
- The dispersed efforts across jurisdictions to develop frameworks and approaches to identify and respond to climate risks makes it difficult to compare and contrast the efforts and practices, or their successes or likely levels of successes.
- From our observations of North America and contrasting it with how Italy is considering their climate-related risks, we believe that having a stronger and more centralized approach would be valuable, particularly to develop a national framework for ensuring resilience of the power system, considering climate-related risks. Such a framework would include developing a logical framework and process for (1) identifying the climate-related risks over an extended time horizon, possibly 30-40 years, (2) analysing the risks, including their potential physical and economic impacts, (3) monitoring the risks as more information becomes available, and (4) considerations for planning a system that meets the likely challenges and minimize the impact of the associated risks for the long term horizon, possibly 30-40 years into the future.
- A structure where a central entity sets certain planning criteria or standard to effectively address climate-related risks and ensure that all local transmission planners and developers follow certain specified processes to meet those criteria / standards would help provide coordinated response to climate-related risks. A coordinated response is advantageous because regional systems are interconnected, and planning in one region affects outcomes in other regions.

III. Categories of Climate-Related Risks and Envisioned Responses

Extreme weather events continue to increase in both frequency and intensity worldwide, posing greater risks to all aspects of the electric grid, from generation to transmission, distribution and to the customers' sites. The impacts of these events range from those that are immediately obvious, such as the destruction of infrastructure by flooding, wind, or fire, to less visible impacts such as increased transmission losses due to high temperatures. These risks and impacts are summarized in Table 2. Mitigating these risks to the electric grid will require adaptations to both physical infrastructure and the planning processes that supports the long-term investments.[31]

Table 2: Climate-Related Risks to System Security and Reliability
Specifically Focusing on Transmission Assets

Increased Temperatures	• Reduced transformer capacity • Shorter lifespan for transformers • Increased conductor sag • Increase in transmission line losses (reduced transmission capacity) • Damage to underground/buried facilities due to heat build-up • Generation capability reduction or outages could result in resource shortage
Bushfire	• Destruction of physical infrastructure • Simultaneous outage of facilities across wide area • Inability to access facilities for repair • Generation outages that could result in resource shortage
Changes in Precipitation (flooding)	• Direct damage to equipment through flooding of substations and control rooms • Direct damage to facilities resulting from mudslides • Inability to access facilities for repair • Extended generation outages that could result in resource shortage
High-Winds/Intense Storms	• Direct physical damage to transmission infrastructure • Increased risk of galloping • Increased potential for trees or other vegetation to contact conductors • Large-area generation outages that could result in resource shortage
Sea Level Rise	• Direct damage to equipment through flooding of substations and control rooms • Greater risk of storm surge and flooding following hurricanes • Corrosion resulting from salt water flooding • Inability to access facilities for repair • Generation outages that could result in resource shortage

31 Our focus is on infrastructure planning decisions, so we narrowly focus on system planning and system hardening as responses. A holistic resilience plan will necessarily consider additional responses to resist, absorb, accommodate and recover from climate risks.

Heavy Snow/Icing	• Direct physical damage to conductors and towers due to increased loading • Increased conductor sag • Increased risk of galloping • Increased potential for trees or other vegetation to contact conductors • Inability to access facilities for repair • Generation outages that could result in resource shortage

Modifying and upgrading physical infrastructure—system hardening—is one way to mitigate these threats, and is thus far the most common response. To respond to these risks, system hardening adaptations can include changes to design standards, requirements for new technology, and relocation of key pieces of infrastructure, such as flood-prone substations. While new design standards and placement of infrastructure going forward mitigates the risks for those new assets, these actions will only impact a small proportion of the infrastructure in service and extensive retrofits or rebuilds may be required to harden the system. These system hardening efforts have been rationalized using benefit-cost analyses, typically based on the avoided outages that provide value of avoided lost load. We have observed benefit cost analyses using expected benefits and costs using probability weighted scenarios of severe weather occurrence[32] and a "break-even" analysis that calculates how much unserved energy would need to be avoided to justify a program.[33] However, there does not appear to be consensus amongst regulators on a preferred approach.

Our observation from current programs is that current system hardening efforts are most frequently reactive, based on damage from past weather events. However, the experience gained and the practices from various jurisdictions can set a platform for future work on building resilience into the power system, particularly as system planners across the various jurisdictions anticipate significant future needs as a result of more frequent and more severe weather events.

Updating and adapting planning processes is a long-term response to climate-related risks and requires analysing how the system performs under normal operations as well as various outage conditions, which will need to be reconsidered in light of growing climate-related risks. This may involve the redefinition of contingencies, evaluation of failure modes which will become more common with frequent extreme weather events, and explicitly incorporating climate risks into all stages of the planning process. For example, planning will need to account for increasing "common mode failures," where multiple elements may fail or otherwise be impaired due to the same root cause, such as high winds forcing multiple transmission outages, wide-area bush fires or reduced transmission capacity due to regional heat-waves. Even if the power system has sufficient supply resources (such as power generators) at all times, planning the transmission system may also need to account for common mode generation failures such as lack of cooling water or significant reduction of hydroelectric resources during droughts or

32 For example, this approach is being developed in Italy. See Section II.B for further discussion

33 This approach was used by Public Service Electric and Gas in the United States. See case study in Section III.D for further discussion.

wind turbines shutting down during high wind storms. Such adaptation plans have been recognised as important but not yet widely planned or adopted.[34]

System hardening efforts and planning efforts are necessarily interdependent to identify the most economically efficient response to climate-related risks. System hardening reduces the likelihood of equipment outage, but retrofitting a complete transmission system could be prohibitively expensive. Instead, it may be more economically efficient to build greater redundancy into the system or identify other resilience measures to mitigate the impact of equipment outages. Alternatively, retrofitting existing system with advanced monitoring and alert systems can help reduce potential adverse impact with modest incremental investment. (See case study on monitoring below.) There may also be climate-related risks that it would be impractical or infeasible to strengthen the existing system to withstand. Incorporating climate-related risks when conducting system planning will likely require using a combination of economic justification, as discussed in Section II.C, and resilience or design standards that require the system to withstand certain operating conditions. Practically, the development of mandatory resilience or design standards frequently reflect economic trade-offs that are challenging to include into the system planning process. Thus, more broad policy or regulatory initiatives are likely to be needed so that system planners have adequate guidance to ensure that the long-term economic trade-offs can be considered when planning for the power system that will need to last through the next four to six decades.

While specific risks vary based on geography, we understand that high wind events, flooding, bush fires and high temperatures pose the greatest threat to Australia's grid. In this section, we review these most relevant risks responses that other jurisdictions have proposed or implemented.

A. Extreme Heat

Climate change has made extreme heat events—extended periods of time with unusually hot weather conditions—more frequent.[35] For the electric power sector, the high temperatures that accompany extreme heat events pose a number of challenges, many of them driven by the increased strain that operating at high temperature places on equipment. These challenges include:

- Failure of power lines due to temperature-driven sag due arising from conductor thermal expansion. This expansion can lead to contacts with trees or other objects, creating shorts that interrupt the flow of power.
- Damage to underground or buried lines and other equipment due to the increased build-up of heat.
- A shorter service life and decreased maximum capacity for transformers due to sustained operation at higher ambient air temperatures.

[34] See for example U.S. Department of Energy, *A Review of Climate Change Vulnerability Assessments: Current Practices and Lessons Learned from DOE's Partnership for Energy Sector Climate Resilience,* May 2016.

[35] U.S. Centers for Disease Control and Prevention, *Climate Change and Extreme Heat Events*, 2013.

- Greater transmission line losses due to increased electrical resistance in transmission lines. Higher temperatures raise the electrical resistance of lines, i.e., the amount of power lost in the process of transmission.

To mitigate these impacts, transmission system planners have implemented or discussed the potential use of several adaptations to both improve existing infrastructure and to improve long-term planning processes, summarized in Table 3 below. Upgrades to transformers that introduce forced air or forced oil cooling can mitigate the negative effects of high ambient air temperatures on transformer lifespans, as can the installation of additional cooling capacity in other facilities, such as substations. Replacing limiting sections of transmission line and raising transmission towers will reduce transmission sag and risks of faults to ground. By installing additional transmission capacity, operators can compensate for increased demand due to high temperatures as well as increased resistance in transmission lines. The installation of additional substations, breakaway equipment, sectionalized fuses, and smart grid devices, along with the development of microgrids, is another step that can increase resilience.

Additionally, grid operators and utilities can make a number of changes to their planning and operations procedures to improve resilience during periods of extreme heat. Increasing assumed ambient air temperatures when developing load and transmission capability projections and including extreme temperature scenarios in future grid planning will provide a greater margin should these scenarios materialise. When planning for new equipment, operators can deploy lines and other infrastructure with higher temperature tolerances and develop best operating practices for this equipment that will adequately address climate risk.

Table 3: Responses to Extreme Temperatures and Heatwaves

Hardening	• Upgrade transformers (e.g., forced-air or forced-oil cooling) • Increase or install additional transmission capacity • Replace limiting wire sections to reduce transmission sag • Raise towers to avoid sag-related contact • Install additional cooling capacity to existing facilities • Limit customers affected by outages by installing additional substations and breakaway equipment and by sectionalizes fuses; develop island-able microgrids with distributed generation • Install sensing to understand when assets are at risk and enable dynamic line ratings to ensure maximum capacity can be provided • Install smart grid devices to speed identification of faults and service restoration
Planning and Operations	• Update temperatures assumed in base case for projecting load and transmission capability • Update temperatures used to determine cyclic ratings for transformers • Include extreme temperature scenarios in future grid planning • Deploy future equipment and lines with higher design temperatures • Extend planning horizon to account for change in climate risk over time • Develop best operating practices for equipment at high temperatures

Sources: Interviews with planning experts, U.S. Department of Energy, Climate Change and the Electricity Sector: Guide for Climate Change Resilience Planning, September 2016; Con Edison, *Climate Change Vulnerability Study*, December 2019.

Technology Response: Transmission Topology Optimization to Adapt the Grid to Changing Conditions

Transmission topology optimization is a software technology that provides power flow control capability using existing transmission equipment (circuit breakers and communication systems). Topology optimization improves the overall transfer capability of the system by changing the distribution of the power flow on any individual line. For a given system, the flow distribution depends on location and levels of generation and load, and the transmission topology that connects the generators and loads. By strategically opening or closing certain circuit breakers, the technology redistributes the flow away from a constrained part of the system to other parts of the system with spare capacity. The concept of topology optimization has been used mostly as "operating guides" to address reliability concerns. However, most of these switching procedures are developed based on the operators' experience and are time-consuming to create and evaluate.

Recent developments of topology optimization software allows the system operator to systematically and automatically identify beneficial system reconfigurations, analogous to the way a GPS-based map-application quickly finds alternative routes when there is road congestion. These software technology developments have rendered topology control to be a practical solution for quickly identifying beneficial reconfiguration of the transmission grid, particularly when severe conditions on the grid place risks on the operations of certain segments or components of the transmission network.

Topology optimization can be used to direct flows away from critical transmission lines to address temporary needs, including to improve the system reliability and resilience by adapting the transmission grid to best handle extreme events. These extreme events could including decreased ratings for individual elements due to heat and physical damage resulting in outages.

For example, The Brattle Group and NewGrid (a topology optimization software technology company) evaluated the benefits of topology optimization for the Southwest Power Pool system operator in the U.S. The study used SPP system real-time snapshots selected by SPP as a representative set of complex grid conditions, including emergency conditions with ongoing outages. During these conditions, the study found that topology reconfiguration options would increase the transfer capacity of individual constraints by 26% on average.

The Texas grid operator, ERCOT, has been using topology optimization software in operations planning, including to support the review and development of its Constraint Management Plans ("CMP")—which includes a set of predefined transmission system actions executed in response to system conditions to prevent or resolve transmission security violations or to optimize the transmission system. In Texas, plans developed with topology optimization software have reduced the need to shed load to mitigate overloads caused by outages under extreme summer peak conditions, by relying on reconfigurations instead.

B. Bush Fire

In Canada in 2016, the Fort McMurray wildfire burned nearly 6,000 square kilometers of land in Alberta and neighboring Saskatchewan. The fire remains the most expensive natural disaster in Canadian history, causing CAD $3.7 billion in insured losses and a 16.4% drop in the country's exports of refined oil and gas products, many of which come from the region affected by the fires.[36] Fast-moving fires such as the Fort McMurray fire can overwhelm and destroy transmission infrastructure. This, combined with the increased carbon emissions from large-scale fires, makes mitigating such events a top priority. The risks posed by bush fires, many of which overlap with those posed by extreme heat, include:

- Multiple simultaneous outages across wide geographic areas.
- Increased transmission sag, which can result in contact with vegetation or other objects and may itself spark additional fires.
- Physical damage to towers and other infrastructure.
- Required de-energization of facilities during high-risk fire periods.
- Inability to access facilities for repair for significant periods of time.

The responses to bush fire risks, summarized in Table 4 below, include measures to improve the resilience of the existing infrastructure, many of which overlap with the system hardening measures adopted to address threats from other weather events, such as high heat and storms. Increased redundancy in transmission systems along with the installation of additional substations, breakaway equipment, sectionalizing fuses, and the development of microgrids will increase resilience in areas cut off from the wider grid by fire and other hazards.

System planners and operators can also make a number of modifications to their planning and operations processes to address long-term resilience. The siting of equipment in areas that are less prone to wildfire that take into account geographic diversity can mitigate the system-wide impact of wildfires. Requiring coated conductors on transmission lines can substantially reduce the risk of fires resulting from faults to ground in which the sparks resulting from uncoated lines coming into contact with the ground or vegetation cause fires. Likewise, enhanced vegetation management will reduce the risk of fire by removing fuel for the initial stages of a fire. Operators can also develop plans to preemptively de-energize lines when exceptionally dry conditions indicate a high risk of fires. Finally, coordination with local partners and the development of fire response plans will enable a more effective response in the event that a fire does break out.

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[36] Statistics Canada, *Fort McMurray 2016 Wildfire: Economic Impact*, 2017.

Table 4: Responses to Increasing Bush Fires and High Fire Risk Conditions

System Hardening	• Replace wood poles and support structures with stronger materials (e.g., steel or concrete) • Limit customers affected by outages by installing additional substations and breakaway equipment and by sectionalizes fuses; develop island-able microgrids with distributed generation • Install smart grid devices to speed identification of faults and service restoration • Install special protection schemes to prevent widespread cascade tripping when multiple lines trip out of service • Install sensing to understand when assets are at risk and enable dynamic line ratings to ensure maximum capacity can be provided
Planning and Operations	• Increase redundancy in transmission systems • Site equipment in areas less prone to wildfire • Require geographic diversity in siting of infrastructure to mitigate system-wide impact of large wildfires and potential need to proactively de-energize lines • Require coated conductors on transmission lines • Develop plans for proactive de-energization of transmission lines in response to raised fire risks • Develop fire response plans and tools; coordinate with local partners • Enhance vegetation management (e.g. tree trimming, forest thinning, and prescribed burning) • Develop firefighting compounds safe to use near active power lines • Extend planning horizon to account for change in climate risk over time

Sources: Interviews with planning experts augmented by the US Department of Energy, *Climate Change and the Electricity Sector: Guide for Climate Change Resilience Planning*, September 2016.

San Diego Gas and Electric: Wildfire Mitigation Plan

San Diego Gas & Electric (SDG&E) serves the south-western corner of California, with its service territory centred on the city of San Diego and Orange County and extending south to the border between Mexico and the United States. This area, like much of California, experiences seasonal wildfires. In 2018, the California legislature passed a new law (SB 901), which requires utilities to submit a wildfire mitigation plan to the California Public Utilities Commission (CPUC) annually. The law requires that a third-party evaluator review these wildfire mitigation plans, which must include steps for mitigating the risk of wildfires caused by faulty overhead lines.

Following the 2018-2019 wildfires and the enactment of these regulations, SDG&E adopted a 10-year vision for wildfire risk mitigation. This vision proposes a wide array of efforts in relation to grid design and system hardening. SDG&E also uses over 100 cameras to monitor wildfire activity.

Grid Design and System Hardening

- Continuation of overhead fire-hardening infrastructure programs
- Increased scope of strategic undergrounding
- Expansion of covered conductor installation across the system
- Enhanced Advanced Protection capabilities
- Private LTE Communication Network
- Public Safety Power Shutoff Sectionalizing (PSPS) Enhancements
- Expansion of the Generator Grant Program to mitigate PSPS impacts
- Expansion of microgrid solutions in the new Backup Power for Resilience Program
- Higher granularity in prioritizing initiatives across the grid
- Strategic grid design and localization that includes microgrid solutions and location of lines away from highest risk areas
- More redundant grid topology and greater sectionalizing capabilities
- Increased investment in ignition-preventing equipment and advanced technologies

Other SDG&E fire risk mitigation initiatives include a primarily automated risk assessment methodology specifically for fires, known as the Wildfire Risk Reduction Model (WRRM). The WRRM allows SDG&E to examine different projects for the best balance between cost and risk reduction. The model takes 30 years of high resolution weather information to generate failure rates of different assets under various simulated climate scenarios and risk mitigation efforts. These simulated failures allow SDG&E to measure long-term weather effects of failure modes on existing assets. Operationally, the system automatically processes new weather and fuel data and computes updated risk level information in support of emergency operations.

SDG&E's system hardening programs not only focus on reducing wildfire risk, but also reducing Public Safety Power Shutoff (PSPS) events. The utility will also continue to replace high-risk assets from previous hardening plans.

Case study sources and additional details provided in Appendix.

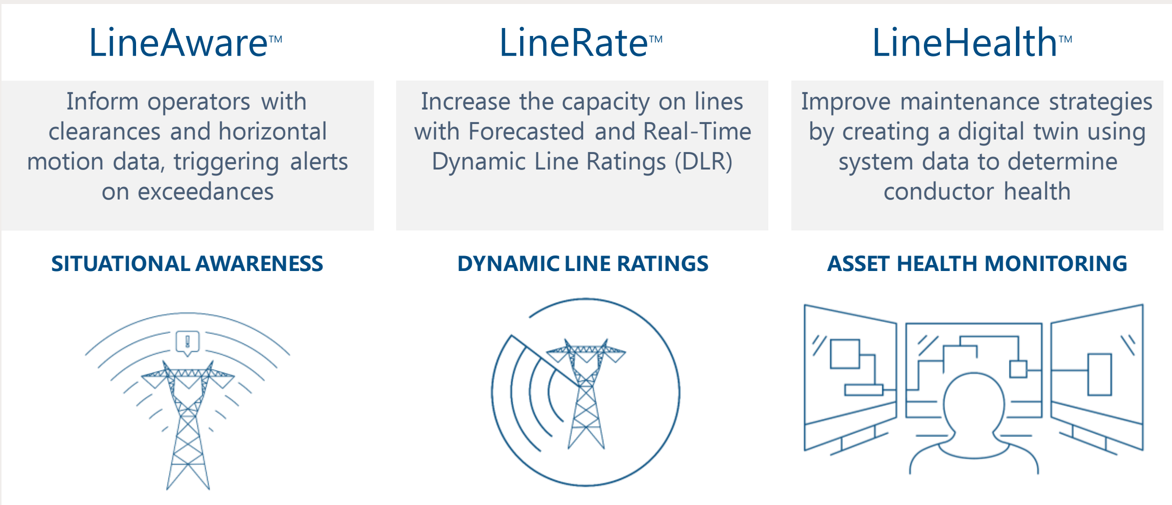
Technology Response: Overhead Power Line Sensors, Data Analytics, and Alerts

Remote sensing of transmission lines can provide operators with the ability to identify at-risk sections of transmission (and sub-transmission) lines by detecting pre-failure events such as high temperatures, line sag, line galloping, and ice accumulation. Identifying these events can be crucial to avoiding disruptions in service and diagnosing repeated problems that may indicate that a certain piece of equipment is approaching the end of its useful life. While it is possible to detect these problems with on-site, in-person inspection, the wide geographic reach of transmission systems such as those found in Australia, the United States, or Canada makes this approach impractical. Remote sensing systems help meet these needs.

Line monitoring sensors gather two types of data that they then use to determine the health of a transmission line. The first includes data on the line's electromagnetic field, which the monitoring systems use to calculate the amount of load on the line. The second is optical data, gathered through a camera, which detects line sag, galloping, icing, and other structural anomalies. One such line monitoring system, developed by LineVision, uses the combination of optical data on line sag and electromagnetic field data on load to calculate line temperature. LineVision measures temperature by using the optically measured line sag and electromagnetic data on load to calculate temperature using a known formula that relates temperature, load, and sag. Such a system come with accompanying software tools to monitor transmission capacity, provide forecasted line ratings, and alert line operators to potential faults.

Real-time line monitoring allows operators to employ dynamic line rating (DLR) on their lines. DLR uses this real-time data on actual line and atmospheric conditions to calculate whether or not lines have additional actual capacity beyond their generally more conservative static rating.

Example of Potential Benefits of Monitoring and Sensing on Overhead Power Lines (LineVision)



C. Increasing Wind Speeds

In late September 2016, violent tornadoes damaged two transmission lines in South Australia, causing a blackout across the entire state. Some areas went without power for two weeks.[37] The South Australia blackout illustrates the dangers that extreme windstorms pose to the power grid. Such events, which can include cyclones and other intense storms in addition to tornadoes, are likely to increase in both strength and frequency as a result of climate change.[38] These events present numerous issues to the power sector, including:

- Direct damage to transmission towers resulting from high wind loads.
- Damage to transmission towers and lines from debris blown into the air during a storm, including trees and other vegetation.
- Conductor galloping, in which transmission lines "swing" between poles and may contact the ground or other objects, causing a short that disrupts the flow of power.[39]

Other climate-related risks, including flooding, may accompany these increasing wind events. Our discussions with planning experts and review of climate risk planning literature identified multiple system hardening measures as well as planning and operational approaches to sustain the function of the system with increasing wind speeds, summarized in Table 5 below. These measures include the replacement of wooden structures with metal or concrete, moving critical transmission and distribution lines underground, replacement of ceramic insulators with polymer insulators, installation of smart grid devices to allow faster identification of faults and quicker service restoration, installation of monitoring devices to detect galloping and other line shifts, increased redundancy in transmission systems, and the employment of mobile transformers and substations.

Longer-term planning and operations measures include applying more stringent design criteria to account for extreme wind loading, particularly to critical infrastructure.[40] In coastal regions, locating equipment further from the water will help reduce the risk of destruction by storm surges. Likewise, more frequent vegetation management around transmission and distribution lines will reduce the likelihood that downed trees will knock out key transmission lines. Inspecting this infrastructure on a more frequent basis, combined with an increase in the dynamic monitoring of key transmission structures, will help identify infrastructure that is at risk of failure in a severe weather event. Finally, the more advanced planning, to include updated storm plans that account for more frequent hurricanes, more explicit examination of the interrelated risks of windstorms and flooding, and an extended planning horizon that accounts for the long-term effects of climate change will help to increase system resilience.

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37 AEMO, *Black System South Australia, 28 September 2016*, March 2017.

38 We understand that cyclonic rated steel towers are already used by Powerlink in Far North Queensland.

39 Oak Ridge National Laboratory, US Department of Energy, *Extreme Weather and Climate Vulnerabilities of the Electric Grid: A Summary of Environmental Sensitivity Quantification Methods*, August 2019.

40

Table 5: Responses to Increasing Winds

Increase frequency of high wind events (including intense hurricanes)	
System Hardening	• Replace wood poles and support structures with stronger materials (e.g., steel or concrete) • Underground critical transmission and distribution lines • Replace ceramic insulators with polymer • Install smart grid devices to speed identification of faults and service restoration • Install monitoring to detect galloping / other changes in conductor positioning • Increase redundancy in transmission systems • Utilize mobile transformers and substations
Planning and Operations	• Apply extreme wind loading design criteria to critical infrastructure • Site equipment further from coast • Enhance vegetation management • Update storm plans to account for higher frequency of intense hurricanes • Increase inspections of existing infrastructure • Implement dynamic monitoring of structures to detect deformation or other damage • Explicitly consider interaction with correlated risks including flooding • Extend planning horizon to account for change in climate risk over time

Sources: Interviews with planning experts augmented by the US Department of Energy, *Climate Change and the Electricity Sector: Guide for Climate Change Resilience Planning*, September 2016.

Florida Power and Light: Hurricane Response

Florida Power & Light's service area, which includes much of the Florida's Atlantic and Gulf coasts, is ground zero for hurricanes in the United States. FP&L serves some of the most densely populated areas of the state, including Miami and its surroundings, much of which lies at sea level, making it particularly susceptible to climate change-driven sea level rise and flooding and to hurricane-driven storm surges.

During the 2004 and 2005 hurricane seasons, Florida and surrounding states suffered more than USD $75.3 billion in damages from multiple major hurricanes. In response, the Florida Public Service Commission (FPSC) ordered investor-owned utilities (IOUs) to file storm hardening plans for its review every three years that include the following:

- Regular vegetation management for distribution circuits
- Auditing of agreements with telecom companies for shared use of poles
- A six-year transmission structure inspection program
- Hardening of existing transmission structures
- Development of a Geographic Information System (GIS) for transmission and distribution infrastructure
- Collection and forensic analysis of post-storm data
- Collection of outage data to compare performance of above- and below-ground lines
- Increased utility coordination with local governments
- Collaborative research on the effects of hurricane winds and storm surges
- Development of natural disaster preparedness and recovery plans

Starting in 2006, FP&L began implementing these and other resilience measures, investing more than USD $3 billion by 2018. This includes completing a full inspection of all of the utility's poles every eight years, strengthening main power lines, increased yearly vegetation clearing, installation of smart grid technology, and installing flood mitigation and monitoring equipment.

Following the 2016 and 2017 storm seasons, which were the most intense since 2004 and 2005, the FPSC reviewed the effectiveness of these measures. The review, which included input from non-utility stakeholders such as local governments and C&I buyers groups, found that the hardening measures called for by the FPSC were effective in reducing the length of outages versus the 2004-2005 storm season. The FPSC concluded that "Florida's aggressive storm hardening programs are working."

FPL Outage Rates for Facilities Impacted by Hurricane Irma

	Transmissions	Distribution feeders	Distribution Laterals
Overhead, Non-hardened	20%	82%	24%
Overhead, Hardened	16%	69%	N/A
Underground	--- [7]	18%	4%

Note: No underground section was damaged or failed causing an outage; however, the sections were out due to line termination equipment in substations.

Case study sources and additional details provided in Appendix.

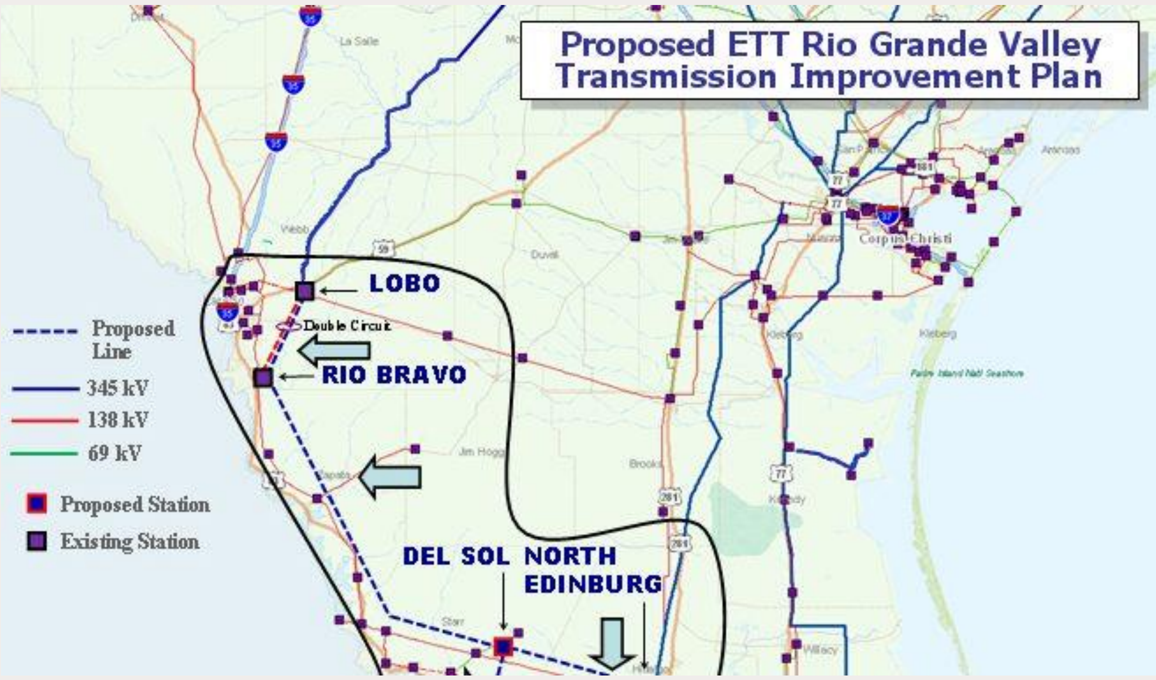
Consideration of Geographic Diversity in Texas

The coast of Texas adjacent to the Gulf of Mexico is vulnerable to the effects of severe hurricanes, and the deadliest natural disaster in United States history remains the 1900 Galveston, Texas hurricane that killed 6,000 to 8,000 people. Although neither the state, the regulator (Public Utility Commission of Texas or PUCT), nor the system operator (Electric Reliability Council of Texas or ERCOT) have explicit climate risk mitigation programs, the historical risk has been taken into account during some projects' transmission routing and infrastructure choices.

For example, in 2014, the PUCT approved a new 96 mile transmission line, called the Cross Valley Transmission Project, in southern Texas to improve system reliability. Prior to the new line's approval, the area was served by two existing lines parallel to the Gulf Coast. The proposed line added diversity, both in location/configuration of the transmission lines and access to generation supply. Sharyland Utilities, one of the developers, cited susceptibility to severe weather events as a contributing factor for the new line and provided two examples of contemporary hurricane-related rolling blackout. In its review of the project, ERCOT noted the existing infrastructure's proximity to the coast and storm-related outages.

In response to the potential for hurricane or other severe weather impacts, the layout of the transmission line was modified to provide greater system resilience. Specifically, for one portion of the line, the distance between towers was decreased to provide additional line strength.

Map of Cross Valley Transmission Project



Case study sources provided in Appendix.

D. Flooding

Changes in precipitation patterns and storm surges from cyclones can result in widespread flooding and extended electrical outages. In 2012, a hurricane and winter storm, collectively named Super Storm Sandy caused nearly USD $70 billion of damage in the United States. As a result of the storm, more than 8.5 million homes lost power due to flooding and winds, and restoration for some customers took days.[41] In New York City, underground facilities experienced outages and in one notable case, a substation experienced an explosion.[42] As Super Storm Sandy illustrates, the myriad risks posed by flooding include:

- Direct damage to equipment through flooding of substations and control rooms.
- Sustained inability to access facilities.
- Direct damage to facilities resulting from mudslides.

Responses to flooding, described below in Table 6, focus on raising equipment, preventing water inflow to existing equipment, and changing siting requirements to mitigate flooding potential. Many overlap with the mitigation measures proposed for other events as well. Flood-specific measures include enhancing water management measures such as using levees and floodwalls, installation of seawall riprap and the planting of natural barriers, and the installation of pumps behind floodwalls. Elevating or relocating critical equipment and installing waterproofing measures can also be effective in reducing outages from flooding. The replacement of wooden poles and support structures with stronger materials, increased transmission system redundancy, the installation of additional substations and breakaway equipment, and enabling microgrids and smart grid devices are other measures that will help increase resiliency both against floods as well as against other weather events.

Longer-term operational and planning measures can include siting equipment away from flood-prone areas. The installation of water level monitoring systems inside vulnerable stations will help operators identify an immediate risk of outages. Operators should also update their long-term siting and operations plan to account for sea level rise and other long-term impacts of climate change.

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41 See: https://www.eia.gov/todayinenergy/detail.php?id=8730

42 See: https://www.utilitydive.com/news/con-ed-substation-experiences-explosion-manhattan-power-restoration-could/68159/

Table 6: Responses to Increased Flooding

Increasing precipitation or heavy downpours / increasing sea level rise and storm surge	
System Hardening	• Increase redundancy in transmission systems • Enhance levees and floodwalls, install seawalls riprap, and natural barriers such as vegetation; install pumps behind floodwalls • Replace wood poles and support structures with stronger materials (e.g., steel or concrete) • Underground critical transmission and distribution lines; replace existing equipment with submersible equivalents • Limit customers affected by outages by installing additional substations and breakaway equipment and by sectionalizes fuses; develop island-able microgrids with distributed generation • Elevate or relocate critical equipment • Install waterproofing measures, such as floodgates and watertight doors, sluice gates, reinforced walls, pressure-resistant/submarine-type doors in deep basements, expansive polymer foam in conduits • Install smart grid devices to speed identification of faults and service restoration
Planning and Operations	• Locate equipment in areas less prone to flooding • Install water-level monitoring systems and communications equipment inside vulnerable stations • Update siting and operations plan to account for sea level rise • Extend planning horizon to account for change in climate risk over time

Public Service Enterprise Group: Energy Strong

Public Service Enterprise Group (PSEG) serves the central part of the State of New Jersey, with its service territory extending from the New York City suburbs in the northeast to the Philadelphia suburbs in the western part of the state. In 2012, New Jersey bore the brunt of Hurricane Sandy, which made landfall near Atlantic City and caused billions of dollars in damage to the state, including more than USD $1 billion in repair costs to power and gas lines, much of them in PSEG's service territory.

In January 2013, the New Jersey Board of Public Utilities (NJBPU) issued an order listing five categories of potential improvements that PSEG and other electric distribution utilities in the state could undertake in response to severe weather events such as Hurricane Sandy. Under the order, these potential improvements include: preparedness efforts, communications, restoration and response, post-event actions, and underlying infrastructure issues.

This order also directed PSEG and other utilities to provide a detailed cost-benefit analysis for the aforementioned resiliency improvements. In response, PSEG developed its Energy Strong Rider, which sought to fund efforts to increase the resilience of PSEG's system to future storms. The cost benefit analysis developed compared investment costs to the estimate of the value of lost load, and "break even" point was calculated such that reduction in lost load was economically equivalent to the investment costs. The analysis did not attempt to assign a probability to the potential of such an event in the future. However, using a retrospective view, an analysis was performed to demonstrate that the investments would have "paid for themselves" had they been in place during Super Storm Sandy as well as other contemporary severe weather events.

In May 2014, the NJDPU approved cost recovery for up to USD $600 million in infrastructure upgrades. This first phase of the Energy Strong program included flood mitigation and the installation of advanced communication technologies among other measures. The program entails electric station flood mitigation through the raising, relocation, or protection of 29 switching and substations damaged by storms; deployment of advanced technologies to expand system communication and data collection; and creation of system redundancies through smart switches, fuses, and adding redundancies in distribution loop designs.

In 2018, PSEG proposed a second phase to the Energy Strong program. The New Jersey Board of Public Utilities (NJBPU) approved a more limited version of the program than initially proposed in September 2019, allocating a total of USD $842 million for the second phase. Of this, USD $741 million will be spent on reliability and resiliency improvements for the utility's electric power assets.

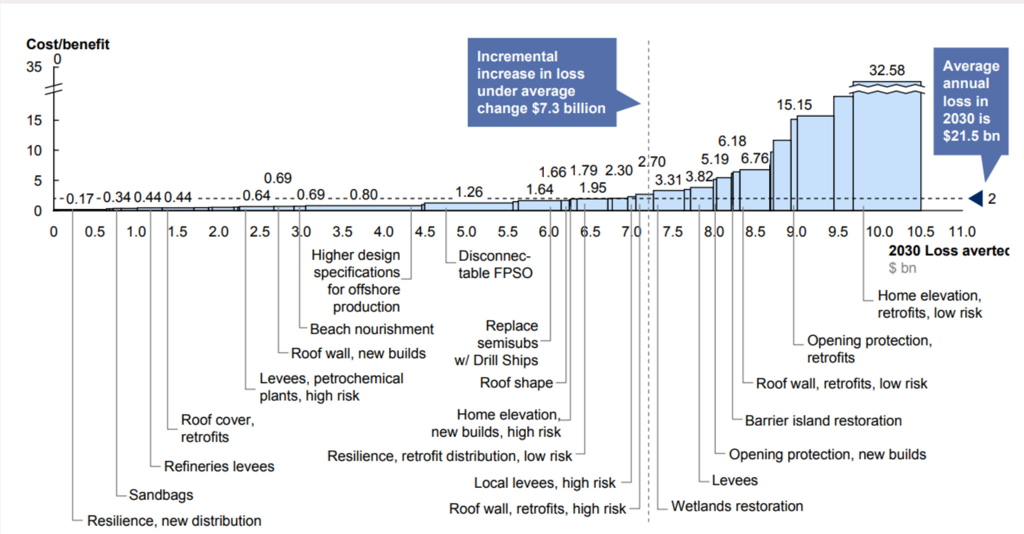
Case study sources and provided in Appendix.

Entergy: Resilient Gulf Coast

Entergy Corporation is an utility serving customers in the southeastern U.S. states of Arkansas, Mississippi, Louisiana, and Texas. Resiliency in the face of hurricanes coming from the Gulf of Mexico is a particular concern, especially given the capacity for widespread devastation demonstrated by storms such as Hurricane Harvey in 2017, which left much of the city of Houston, Texas, and surrounding areas underwater. Twelve years prior, in the neighboring state of Louisiana, Hurricane Katrina destroyed much of New Orleans in one of the biggest natural disasters in United States history.

Entergy's *Building a Resilient Energy Gulf Coast* report outlines a framework that quantifies large estimated losses due to climate and other impacts to the economics of the region and provides a list of potential measures to counter climate impacts. The report emphasizes establishing a cost-benefit analysis, with the first part of the plan detailing the magnitude of loss in the areas most at risk. The estimated potential losses involves the calculation of the magnitude of the hazard, measured as the frequency of hurricanes and levels of sea level rise; the economic value of the assets at risk from the hazard; and the vulnerability of the assets from the hazard. Entergy measured vulnerability by calculating vulnerability curves, which show the correlations between the magnitude of climate events and asset loss.

Entergy measured these resiliency strategies on a cost curve, ranking those with the lowest cost-to-benefit first and those with the highest cost-to-benefit ratio ranked last. The curve also shows the total potential of the measure to which expected loss can be reduced. These measures range from low cost/benefit strategies such as having new building codes for industries, and use of sandbags, to high cost/benefits strategies such as making levees, and pursing home elevation retrofits. The plan recommends considering the use of insurance to cover the annual expected loss that the loss mitigation strategies do not cover. Implementing these measures in an effective manner will require dedicated regional coordination across multiple jurisdictions involving a diverse range of stakeholders.



Case study sources and additional detail provided in Appendix.

IV. Research on Climate-Related Risks to System Security and Reliability

Research on the intersecting topics of power system security and reliability, resilience metrics, and climate risks span disciplines ranging from electrical engineering and mechanical engineering to atmospheric science and economics. The research conducted by laboratories and academics includes understanding how individual components react under severe weather, developing the forward-looking climate data needed by regulators and utilities to develop estimates of plans, modeling potential outages due to extreme weather, amongst others.[43] There are literatures focusing on related and complementary issues including the effects of climate change on demand forecasting,[44] resource adequacy,[45] and the impact on climate change on generation investment,[46] as well as interactions between infrastructure risks.[47]

While there is a strong research literature related to system hardening type efforts, research on the geographic dimension of climate risks is less well studied. Research focused on system reliability and failure tends to focus on the electrical topology of a system (i.e., the connections between nodes in the system and the strength of connection between those nodes) rather than the geographical topology of the system, which is an important factor with respect to climate risk. There is a smaller research body that directly addresses the need to consider geographic diversity when analyzing climate risks to the power system.[48] However, the literature on geographic diversity during transmission system planning is demonstrative of the likely impact rather than providing proactive transmission planning responses to the risks of climate change.

There is a rich academic literature on the transmission planning side focused on uncertainty that could be applied to climate risk. Specifically in an academic context, researchers have

43 For a review of recent research, see N Bhusal, M. Abdelmalak, MD Karzzuman, M. Bendrsi, "Power System Resilience: Current Practices: Challenges, and Future Directions," IEEE Access, January 29, 2020.

44 See for example M. Auffhammer, P. Baylis, and C.H. Hausman, "Climate change is projected to have severe impacts on the frequency and intensity of peak electricity demand across the United States," Proceedings of the National Academies of Science, February 2017, 114 (8) 1886-1891.

45 See for example S.W.D. Turner, N. Voisin, J. Fazio, et al. "Compound climate events transform electrical power shortfall risk in the Pacific Northwest" Nature Communications Vol 10, Article 8, 2019.

46 See for example M. Webster, P. Donohoo, and B. Palmintier, "Water-CO_2 Tradeoffs in Electricity Generation Planning," Nature Climate Change, Vol 3., 2013.

47 See for example A. Reilly, A. Samuel, and S. Guikema, "Gaming the System: Decision Making by Independent Critical Infrastructure," Decision Analysis, Vol. 12 Issue 4, December 2015.

48 See for example B. Rachunok and R. Nateghi, "The sensitivity of electric power infrastructure resilience to the special distribution of disaster impacts," Reliability Engineering and System Safety, September 2019.

explore the impact of different decision planning metrics under uncertainty (e.g., expected value versus robust optimization),[49] as well as regulatory and commodity price uncertainty (amongst others).[50] However, the fields does not appear have yet to explored or developed proactive planning approaches to account for climate risks including the trade-offs between the potential lengths of outage and recovery costs, investments in system hardening, investments to increase system redundancy, explicitly considering the benefits of geographic diversity and other approaches to building a more robust transmission infrastructure.

V. Conclusions and Recommendations

Climate-related risks are expected to present increasing risks to the power system and we anticipate that incorporation of these risks into formal planning processes will continue to grow in importance. In Australia, recent experience with bush fires, flooding, drought, and severe storms have highlighted the vulnerability of the grid to these climate risks. The investments made today will need to enhance system resiliency going forward, and this is especially true for transmission investments that are typically long lived, with lifespans of 40-60 years.

In this report, we reviewed a limited set of jurisdictional experiences focused on transmission planning adaptations for climate resilience, focusing on various regions of the United States and Italy. In Italy, the regulator is developing a forward-looking investment program, based on a benefit to cost analyses with probability-weighted scenarios of climate-related outcomes. Conversely, thus far most experience in United States jurisdictions appear to be reactive to the impact of events and performed on an ad hoc basis (not standardized by a central body), though utilities are developing climate resilience plans that we anticipate will become common in coming years.

We observe that many proposed or implemented responses to differing climate-related risks in transmission planning share common components such as changes in siting processes to provide geographic diversity in line location, increased sensing/monitoring of lines, and using stronger physical structures (e.g., more robust towers). However, these and other planning and operational approaches to allow power systems to withstand, respond to, and recover from climate risks may require significant investment and thus, should be considered in a unified framework to identify the least cost ways to mitigate vulnerabilities. Examples of frameworks from the U.S. Department of Energy and Consolidated Edison Company of New York are

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49 See for example, A. Weber, C. Gerbaulet, C. von Hirschhausen, and J. Weibezahn, "Robust Transmission Planning – An Application to the Case of Germany in 2050," 2017 14th International Conference on the European Energy Market (EEM), 2017 and P. Maghouli, S. H. Hosseini, M. O. Buygi, and M. Shahidepour, "A Scenario-Based Multi-Objective Model for Multi-Stage Transmission Expansion Planning," IEEE Transactions on Power Systems, Vol 26 Issue 1, 2011.

50 See for example, F. Munoz, B. Hobbs, J. Ho and S. Kasina, "An Engineering-Economic Approach to Transmission Planning Under Market and Regulatory Uncertainties: WECC Case Study," IEEE Transactions on Power Systems, Vol 29, Issue 1, 2013.

discussed in the Appendix. Further, the implications of climate risk affect the full ecosystem of entities that rely on and invest in the power system, and the full range of impacts across these entities should be considered in developing responses to climate risks.

While North America has not yet taken on a centralized approach to transmission planning in the face of climate-related risks, its existing structure of having a central organization setting the standards for system planning could be used and enhanced to account for those risks. Having a centralized body to set standards while regional planners and transmission developers follow those standard in future plans is an attractive way to achieve consistency in measuring risks and impacts, share best practices, and improve as more information becomes available. Such a structure could also work for Australia, as it takes on the challenge of planning an electricity system for the future accounting for increase climate-related risks.

Based on our review, we have identified a few preliminary recommendations for the AEMO to consider. These primary recommendations focus on the development of more comprehensive approach to climate resilience, including:

- Developing a holistic review of climate vulnerabilities as well as potential resilience metrics and harmonisation of those metrics with existing regulatory requirements

- Analysing mitigation approaches to climate-related risks, such as (a) line diversity, (b) the use of new and more resilient technologies and equipment, and (c) the use of advanced monitoring and alert technologies

- Developing a common approach across AEMO, regulators, and other stakeholders on decision metrics to be applied to system planning (e.g., least regrets, average value, etc.), which should include concrete examples of potential outcomes under each approach

- Analysing the potential for a national policy for accounting for climate-related risks when planning for transmission networks, including forming resilience plans by setting minimum national standards with best practices for meeting the standards (as mentioned above)

Our secondary recommendations focus on the need to incorporate best-available data and broaden the topics considered to holistically review the impacts of climate-related risks. Specifically, we recommend:

- Using forecasted climate risk data, to the extent feasible, and relying on recent historical data when necessary

- Monitoring the evolution of climate science to understand trends in projected climate risks, the availability of high-resolution data, and advances in the underlying science

- Ensuring that the time horizon used for long-term transmission network planning would capture the potential effects over the life-time of the transmission assets

- Analysing interactions between the resilience of the electric power system with other infrastructure systems, including telecommunications, natural gas delivery systems, and water supply and delivery systems

Appendix

Climate Vulnerability Assessments and Response Frameworks and System Hardening Case Studies

United States Department of Energy: Climate Resiliency Framework

States Department of Energy (U.S. DOE) developed a framework to assist utilities in planning and proactively responding to climate-related risks. This effort included the development of a framework for developing resiliency published in 2016.

In that report, the U.S. DOE developed an eight-step guide to assess the vulnerability of electric utility assets and operations at risk due to climate change and extreme weather events to help inform the utilities' resiliency plans. That framework is reproduced and shown in Figure 1 below.[51] The U.S. DOE categorizes the eight steps into four broad categories: (A) scoping, (B) assessing vulnerabilities, (C) forming resilience plans, and (D) conducting ongoing evaluation.

- **Scoping** entails developing the purpose and motivation of the climate-related risks assessments. This step involves the identification of key issues and outlining the resources and information needed to conduct the risk assessments.
- **Assessing vulnerabilities** involves gathering of necessary information to project how future climate-related events could affect certain important equipment or assets, describe the methods that can be used to estimate the likely damage that certain events may cause, including how to compute the likelihood and magnitude of economic costs of assets and operations.
- **Forming resilience plans** prioritizes the potential outcomes from the vulnerability assessment. For circumstances that are over a certain threshold, the plan would include suggestions for measures that mitigate potential impacts. The suggestioned mitigation approaches include measures that could directly reduce the probability of damage or disruption (e.g. hardening wires), or indirectly reduces impact via ex-post concerns (e.g. recovery plans or insurance).
- **Ongoing evaluation** involves continous monitoring of progress of the resilience plan, the collection of new information, feedback on implementation, and the reassessment of plans to adapt to changing circumstances.[52]

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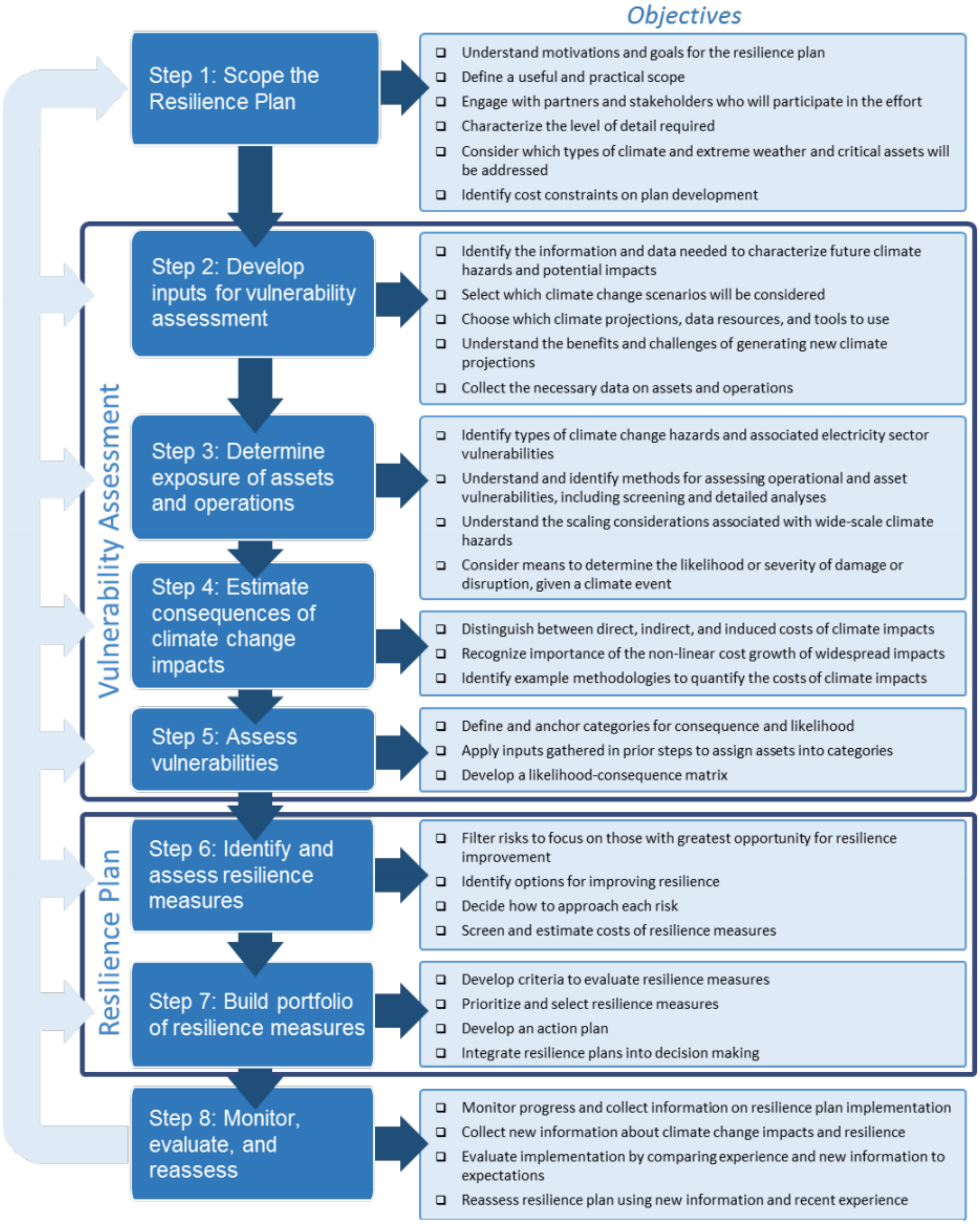
51 US Department of Energy, *Climate Change and the Electricity Sector: Guide for Climate Change Resilience Planning*, September 2016.

52 US Department of Energy, *Climate Change and the Electricity Sector: Guide for Climate Change Resilience Planning*, September 2016.

Figure 1 U.S. Department of Energy (201_) Framework for Electricity System Resilience



As part of the U.S. DOE's effort at that time, the Department worked with multiple electric utilities across the U.S. to evaluate their existing frameworks for evaluating and mitigating climate-related risks and identify gaps.

- Summarize utilities that participated
- Summarize number with forward looking plans versus responsive
- Summarize recommendations from report
- Decision Making frameworks/criteria

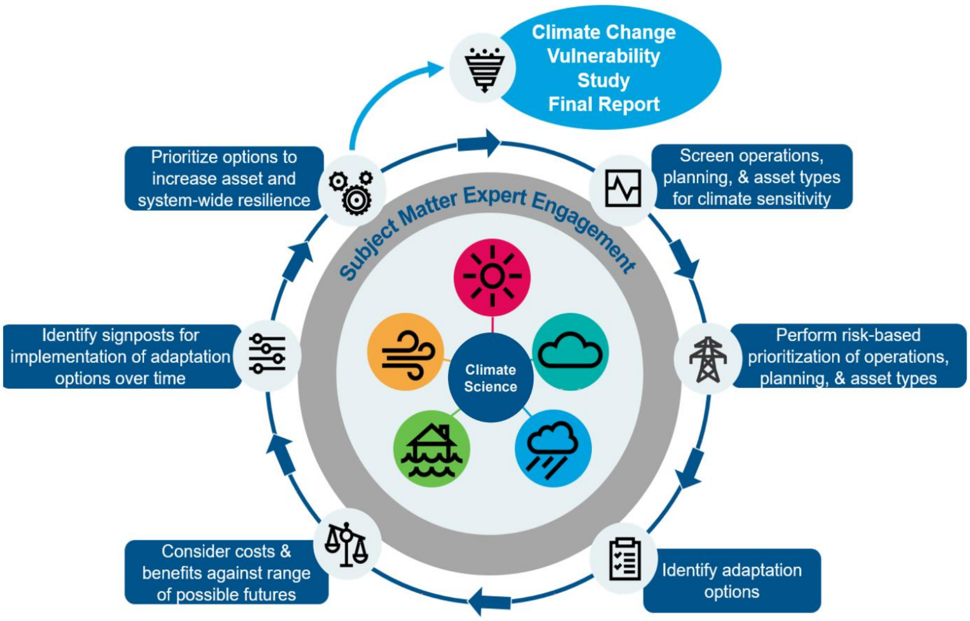
Consolidated Edison Company of New York (2019)

In the aftermath of Hurricane Sandy, Con Edison proposed USD $1 billion in storm hardening investments in its 2013 rate case. At that time, Con Edison commissioned its *Climate Change Vulnerability Study* to aid its review of design standards and development of a climate change risk mitigation plan.[53] As a part of Con Edison's its mitigation plan (published in 2019), the utility aims to meet the following three goals:[54]

- Research and develop a shared understanding of new climate science and projected extreme weather for the service territory
- Assess the risks of potential impacts of climate change on operations, planning, and physical assets
- Review a portfolio of operational, planning, and design measures, considering costs and benefits, to improve resilience to climate change.

Figure 2, which appears in Con Edison's report, illustrates the six components through which the utility will implement these goals.

Figure 2 Con Edison's Framework for Increasing Electricity System Resiliency (2019)



Con Edison used projected data to project potential risks of climate changes on its system. Based on this, the utility developed a range of scenarios for its service territory that incorporate the risks of: (i) increasing temperatures, (ii) heavier precipitation events, (iii) sea level rise, and (iv) extreme weather conditions, defined to be low-probability and high-impact phenomena including hurricanes and long-duration heat waves. Con Edison developed these scenarios based on the "best-available science" which included downscaled climate models, recent literature, and expert elicitation.[55] The utility evaluated these potential climate-related risks

53 Con Edison, *Climate Change Vulnerability Study*, December 2019, p. 1.

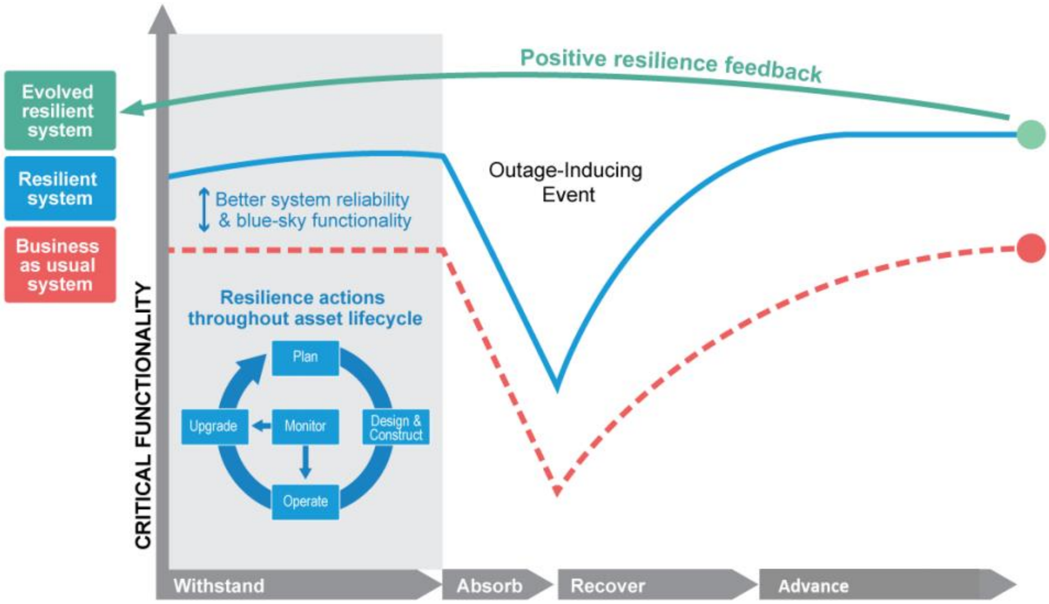
54 Con Edison, *Climate Change Vulnerability Study*, December 2019, p. 2.

55 Con Edison, *Climate Change Vulnerability Study Summary*, December 2019, p. 2.

against its existing infrastructure, design specifications, and procedures to assess its vulnerability to climate related impacts.

The study emphasized that it was not only important to evaluate adaptation strategies that focus on withstanding or avoiding impacts, it was also vital to consider adaptation strategies that allow system to absorb, reduce, and then advance further from impacts (see Figure 3).[56]

Figure 3: Con Edison's Framework for Considering Range of Reactions to Climate-related Risks[57]



Con Edison's study recommended a number of adaptive strategies to boost its system's ability to withstand, absorb, recover from, and advance beyond climate change-driven weather events.[58]

To **withstand** incidents, Con Edison plans to monitor the situation ahead of time, tracking updates in climate science, monitoring local changes in climate and differences in climate across the service territory, tracking weather related expenditures and impacts, expanding system monitoring capabilities to pre-emptively identify increasing risks. Based on this, the utility will work proactively to plan for incidents. Con Edison's study called for the utility to engage in load and volume forecasting for all commodities as well as load relief planning for the electricity system, which should include incidents that reduce resource capability with increased load due to warmer temperatures; network reliability modelling and planning to reflect more frequent and severe heat waves; long-range planning for all commodities; and working with utilities in other environments to understand how they plan and design their systems for the severe conditions that Con Edison will likely experience in the future.

Con Edison will also select an initial climate projection design pathway and allow engineers to design infrastructure in line with Con Edison's risk tolerance. The utility will also continue

56 Con Edison, *Climate Change Vulnerability Study Summary*, December 2019, p. 5.

57 Con Edison, *Climate Change Vulnerability Study Summary*, December 2019, p. 5.

58 Con Edison, *Climate Change Vulnerability Study Summary*, December 2019, pp. 8-11.

upgrading the capability of selected assets to withstand climate change (such as selective undergrounding, stronger overhead poles). Changing design standards will influence the construction of new assets but does not address the vulnerability of existing assets. Consequently, upgrading existing assets is an important aspect of adaptation plan.

To **absorb** the impact of incidents, Con Edison will update its long-term plans to account for low-probability incidents. The utility will also take concrete steps to upgrade its infrastructure, investing in energy storage, on-site generation, and energy efficiency programs to help absorb impact. Con Edison will use smart meters to implement targeted load shedding to limit the impact of extreme events on customers by limiting the likelihood of large-scale outages.

To **recover** from severe incidents, the study calls for Con Edison to plan for resilient and efficient supply chains, coordinate extreme event preparedness plans with external stakeholders in New York City, expand worker safety protocols for work during extreme heat periods, and support the creation of resilience hubs. These will be spaces that support residents and coordinate resources before, during, and after extreme weather events with continued access to energy service.

Finally, **advancing** beyond severe incidents will require Con Edison to conduct pre-planning for post-event reconstruction to ensure restoration to a better adapted, more resilient system. In the event that assets need to be replaced during recovery, the utility will have a plan already in place for selecting and procuring assets designed to be more resilient in the future to adapt to future extreme events. Finally, measuring the performance of adaptation investments during and after extreme events will inform future actions.

As conditions evolve over time, making future decisions about investment and operational strategies will require consistent tracking and monitoring. Con Edison refers to the key variables that may trigger action as "signposts." The utility has identified several broad categories of signposts: observations about climate change, climate projections, climate impacts, and policy, societal, and economic conditions.

Con Edison acknowledges that setting engineering or design standards will help identify when an action or change in action would be needed to manage climate risks. An example of a specific signpost is increased incidence of line sag or higher operation temperatures, the corresponding strategy would involve replacing limiting wire sections with higher rate wire to reduce sag during extreme heat wave events.[59]

San Diego Gas & Electric: Wildfire Mitigation Plan

San Diego Gas & Electric (SDG&E) serves the south-western corner of California, with its service territory centred on the city of San Diego and Orange County and extending south to the border between Mexico and the United States.[60] This area, like much of California, experiences seasonal wildfires. In 2018, the California legislature passed SB 901, which requires utilities to submit a wildfire mitigation plan to the California Public Utilities Commission

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[59] Con Edison, *Climate Change Vulnerability Study*, December 2019, p. 9.

[60] SDG&E, *About Us*, 2020.

(CPUC) annually. SB 901 requires that a third-party evaluator review these wildfire mitigation plans, which must include steps for mitigating the risk of wildfires caused by faulty overhead lines.[61]

Following the 2018-2019 wildfires and the enactment of these regulations, SDG&E adopted a 10-year vision for wildfire risk mitigation. This vision proposes a wide array of efforts, outlined in Table 7 in relation to grid design and system hardening.

Table 7: SDG&E 10 year vision for wildfire risk mitigation[62]

Grid Design and System Hardening
• Continuation of overhead fire-hardening infrastructure programs • Increased scope of strategic undergrounding • Expansion of covered conductor installation across the system • Enhanced Advanced Protection capabilities • Private LTE Communication Network • Public Safety Power Shutoff Sectionalizing Enhancements • Expansion of the Generator Grant Program to mitigate PSPS impacts • Expansion of microgrid solutions in the new Backup Power for Resilience Program • Higher granularity in prioritizing initiatives across the grid • Strategic grid design and localization that includes microgrid solutions and location of lines away from highest risk areas • More redundant grid topology and greater sectionalizing capabilities • Increased investment in ignition-preventing equipment and advanced technologies

Prior to the adoption of the 2020 vision, SDG&E hardened 150 miles of overhead distribution, 11 miles of underground distribution, and 10 miles of overhead transmission by 2019.[63] Other SDG&E fire risk mitigation initiatives include a primarily automated risk assessment methodology specifically for fires, known as the Wildfire Risk Reduction Model (WRRM). The WRRM allows SDG&E to examine different projects for the best balance between cost and risk reduction. It is also able to simulate and forecast the most at risk circuits during periods of high fire danger.[64] Through the incorporation of a range of inputs (see Table 8), the WRRM also provides a relative ranking of current risks. Further, the model outcomes include forecasted absolute and percentage risk reduction as a result of completions of different project hardening programs.[65]

61 SB 901, Dodd. Wildfires. September 21, 2018.

62 SDG&E, *SDG&E 2020 Wildfire Mitigation Plan*, February 7, 2020, p. 15.

63 SDG&E, *SDG&E 2020 Wildfire Mitigation Plan*, February 7, 2020, p. 39.

64 SDG&E, *SDG&E 2020 Wildfire Mitigation Plan*, February 7, 2020, p. 47.

65 SDG&E, *SDG&E 2020 Wildfire Mitigation Plan*, February 7, 2020, p. 48.

Table 8: SDG&E wildfire risk reduction model (WRRM) inputs[66]

Incorporated range of data and resulting risk factors
• Vegetation and fuels data • Weather and predictive data • Historical fire occurrence • Outage history • Equipment failures (RIRAT & FiRM data) • Fire behaviour analysis • Fire simulation modelling • SDG&E distribution network assets • Electric system conditions and characteristics • Subjective "value at risk" parameters • Risk reduction projects

SDG&E uses WRRM analysis for both planning and operating purposes at SDG&E. The model takes 30 years of high resolution weather information to generate failure rates of different assets under various simulated climate scenarios and risk mitigation efforts. These simulated failure rates allow SDG&E to measure long-term weather effects of failure modes on existing assets.[67] Operationally, the system automatically processes new weather and fuel data and computes updated risk level information in support of emergency operations.[68]

In addition, SDG&E uses its own network of weather stations to inform day to day decision making and future planning, allowing better optimization and calibration of forecasts. SDG&E also uses over 100 cameras to monitor wildfire activity.[69]

SDG&E's system hardening programs not only focus on reducing wildfire risk, but also reducing Public Safety Power Shutoff (PSPS) events.[70] SDG&E has put forth plans for its team to perform segment-by-segment analysis of the circuits that are prone to shut off events, and apply mitigation strategies to reduce the impact of shutoffs. These strategies include covered conductions, sectionalizing or reconfiguring circuits, enhanced vegetation and fuels management, backup generators and microgrid solutions. The utility will also continue to replace high-risk assets from previous hardening plans.[71]

Florida Power & Light: Tower Reinforcement

Florida Power & Light's service area, which includes much of the Florida's Atlantic and Gulf coasts, is ground zero for hurricanes in the United States. Within this, FP&L's serves some of

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66 SDG&E, *SDG&E 2020 Wildfire Mitigation Plan*, February 7, 2020, p. 48.

67 SDG&E, *SDG&E 2020 Wildfire Mitigation Plan*, February 7, 2020, p. 47.

68 SDG&E, *SDG&E 2020 Wildfire Mitigation Plan*, February 7, 2020, p. 47.

69 SDG&E, *SDG&E 2020 Wildfire Mitigation Plan*, February 7, 2020, p. 59.

70 SDG&E, *SDG&E 2020 Wildfire Mitigation Plan*, February 7, 2020, p. 65.

71 SDG&E, *SDG&E 2020 Wildfire Mitigation Plan*, February 7, 2020, p. 39.

the most densely populated areas of the state, including Miami and its surroundings.[72] This area, like much of Florida, lies at sea level, making it particularly susceptible to climate change-driven sea level rise and flooding and to hurricane-driven storm surges.

During the 2004 and 2005 hurricane seasons, Florida and surrounding states suffered more than USD $75.3 billion in damages from multiple major hurricanes.[73] In response, the Florida Public Service Commission (FPSC) ordered investor-owned utilities (IOUs) to file storm hardening plans for its review every three years that include the following:

- Regular vegetation management for distribution circuits
- Auditing of agreements with telecom companies for shared use of poles
- A six-year transmission structure inspection program
- Hardening of existing transmission structures through increased minimum design standards
- Development of a Geographic Information System (GIS) for transmission and distribution infrastructure
- Collection and forensic analysis of post-storm data
- Collection of outage data to compare performance of above- and below-ground lines
- Increased utility coordination with local governments
- Collaborative research on the effects of hurricane winds and storm surges
- Development of natural disaster preparedness and recovery plans

Starting in 2006, FP&L began implementing these and other resiliency measures, investing more than USD $3 billion by 2018. This includes completing a full inspection of all of the utility's poles every eight years, strengthening main power lines, increased yearly vegetation clearing, installation of smart grid technology, and installing flood mitigation and monitoring equipment. This last measure is based on lessons learned from the experience of utilities in the Mid-Atlantic States during Hurricane Sandy in 2012.[74] In 2018 alone, FP&L spent USD $50 million on distribution pole inspections and upgrades, USD $33 million on transmission inspections, USD $505 million on distribution hardening measures, more than USD $65 million on vegetation management, and USD $27 million on upgrading wood transmission structures.[75]

Following the 2016 and 2017 storm seasons, which were the most intense since 2004 and 2005, the FPSC reviewed the effectiveness of these measures.[76] The review, which included input

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72 Florida Power & Light, *External Affairs Service Area Map*, 2016.

73 National Hurricane Center, National Oceanic and Atmospheric Administration (NOAA), *Costliest U.S. tropical cyclones tables updated*, January, 2018.

74 Florida Power & Light, *Strengthening the energy grid to deliver reliable service*, April 2018.

75 Florida Power & Light, *Docket No.: 20190000 Florida Power & Light Company's 2019 Status/Update Report on Storm Hardening/Preparedness and Distribution Reliability*, March 1, 2019.

76 Florida Public Service Commission, *Review of Florida's Electric Utility Hurricane Preparedness and Restoration Actions 2018*, July 2018.

from non-utility stakeholders such as local governments and C&I buyers groups, found that the hardening measures called for by the FPSC were effective in reducing the length of outages versus the 2004-2005 storm season. The FPSC concluded that "Florida's aggressive storm hardening programs are working."

Consideration of Geographic Diversity in Texas

The coast of Texas adjacent to the Gulf of Mexico is vulnerable to the effects of severe hurricanes, and the deadliest natural disaster in United States history remains the 1900 Galveston, Texas hurricane that killed 6,000 to 8,000 people. Although neither the state, the PUCT, nor the system operator (Electric Reliability Council of Texas or ERCOT) have explicit climate risk mitigation programs, the historical risk has been taken into account during transmission routing and infrastructure choices.

In 2014, the PUCT approved a new 96 mile transmission line, called the Cross Valley Transmission Project, in southern Texas to relieve reliability issues. Prior to the new line's approval, the area was served by two existing lines parallel to the Gulf Coast. The proposed line added diversity, both in location/configuration of the transmission lines and access to generation supply.[77] Sharyland Utilities, one of the developers, cited susceptibility to severe weather events as a contributing factor for the new line and provided two examples of contemporary hurricane-related rolling blackout.[78] In its review of the project, ERCOT also noted the existing infrastructure's proximity to the coast and storm-related outages.[79]

In response to the potential for hurricane or other severe weather impacts, the layout of the transmission line was modified to provide greater resilience. Specifically, for one portion of the line, the distance between towers was decreased to provide additional strength.[80]

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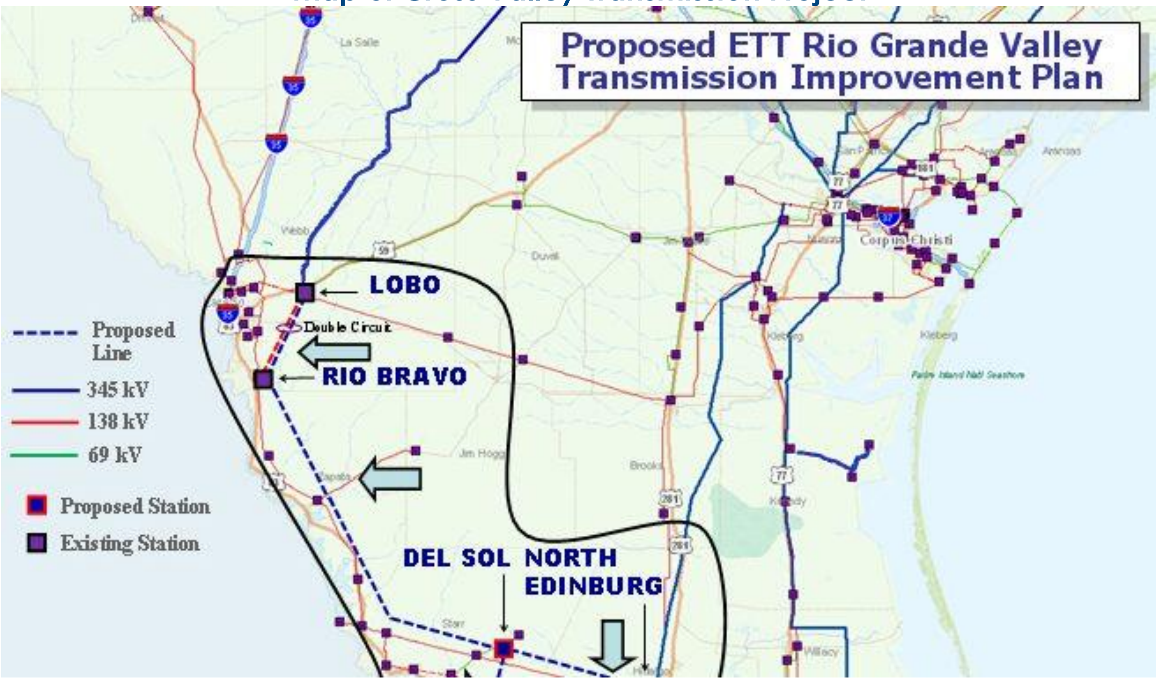
77 Direct Testimony of Mark E. Caskey on behalf of Electric Transmission Texas, LLC and Sharyland Utilities, L.P., submitted to PUC Docket No. 41606, 2013 at 6 and 14.

78 Sharyland Utilities and Brownsville Public Utilities Board, "Cross Valley Brownsville Loop Study" May 15, 2011.

79 ERCOT, *ERCOT Independent Review of the Sharland and BPUB Cross Valley Project, V 1.0*, 2011, Submitted as Attachment 6 to the Joint Application in PUC Docket No. 41606.

80 Electric Transmission Texas, "New ETT 345kV lines begin delivering power to LRGV," August 31, 2016.

Map of Cross Valley Transmission Project



Source: https://electricenergyonline.com/article/energy/category/T-D/56/594530/New-ETT-345-kV-lines-begin-delivering-power-to-LRGV.html

Public Service Enterprise Group: Flooding

Public Service Enterprise Group (PSEG) serves the central part of the State of New Jersey, with its service territory extending from the New York City suburbs in the northeast to the Philadelphia suburbs in the western part of the state.[81] In 2012, New Jersey bore the brunt of Hurricane Sandy, which made landfall near Atlantic City and caused billions of dollars in damage to the state, including more than USD $1 billion in repair costs to power and gas lines, much of them in PSEG's service territory.[82]

In January 2013, the New Jersey Board of Public Utilities (NJBPU) issued an order listing five categories of potential improvements that PSEG and other electric distribution utilities in the state could undertake in response to severe weather events such as Hurricane Sandy. Under the order, these potential improvements include:

1. Preparedness efforts
2. Communications
3. Restoration and Response
4. Post-event actions
5. Underlying infrastructure issues[83]

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81 PSEG, *Electric Divisions*, 2011.

82 Blake, E.S., et al., *Tropical Cyclone Report: Hurricane Sandy*, National Hurricane Center, February 2013.

83 NJBPU, *In the Matter of the Petition of Public Service Electric Gas Company for Approval of the Energy Strong Program: Order Approving Stipulation of Settlement* (Docket Nos. EO13020155 and GO13020156), May 2014.

This order also directed PSEG and other utilities to provide a detailed cost-benefit analysis for the aforementioned resiliency improvements. In response, PSEG developed its Energy Strong Rider, which sought to fund efforts to increase the resilience of PSEG's system to future storms. This order also directed PSEG and other utilities to provide a detailed cost-benefit analysis for the aforementioned resiliency improvements.

PSEG developed its Energy Strong Rider, which sought to fund efforts to increase the resilience of PSEG's system to future storms, and a new cost benefit analysis. The cost benefit analysis developed compared investment costs to the estimate of the value of lost load, and "break even" point was calculated such that reduction in lost load was economically equivalent to the investment costs.[84] The analysis did not attempt to assign a probability to the potential of such an event in the future. However, using a retrospective view, an analysis was performed to demonstrate that the investments would have "paid for themselves" had they been in place during Super Storm Sandy as well as other contemporary severe weather events.

In May 2014, the NJDPU approved cost recovery for up to USD $600 billion in infrastructure upgrades.[85] This first phase of the Energy Strong program included flood mitigation and the installation of advanced communication technologies among other measures. The program entails electric station flood mitigation through the raising, relocation, or protection of 29 switching and substations damaged by storms; deployment of advanced technologies to expand system communication and data collection; and creation of system redundancies through smart switches, fuses, and adding redundancies in distribution loop designs.[86]

In 2018, PSEG proposed a second phase to the Energy Strong program. The utility's proposal for Energy Strong Phase 2 called for USD $428 million in additional station hardening and raising, USD $478 million to rebuild aging outdoor stations, USD $345 million for circuit upgrades, and an additional USD $252 million for smart grid upgrades and an advanced distribution management system.[87] The New Jersey Board of Public Utilities (NJBPU) approved a more limited version of the program in September 2019, allocating a total of USD $842 million for the second phase. Of this, USD $741 million will be spent on reliability and resiliency improvements for the utility's electric power assets. Program work began in the fourth quarter of 2019 and is expected to continue through December 2023.[88]

Entergy: Hurricanes, High Winds, Flooding

Entergy Corporation is a generation and retail distribution company serving customers in the Southeastern states of Arkansas, Mississippi, Louisiana, and Texas in the United States. As such, resiliency in the face of hurricanes coming from the Gulf of Mexico is a particular concern, especially given the capacity for widespread devastation demonstrated by storms such as Hurricane Harvey in 2017, which left much of the city of Houston, Texas, and surrounding

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84 P. Fox-Penner and W.P. Zarakas, "Analysis of Benefits: PSE&G's Energy Strong Program," The Brattle Group performed on behalf of Public Service Electric & Gas, October 2013.

85 *Ibid.*

86 PSEG, *Making New Jersey Energy Strong: Phase 2*, December 2018.

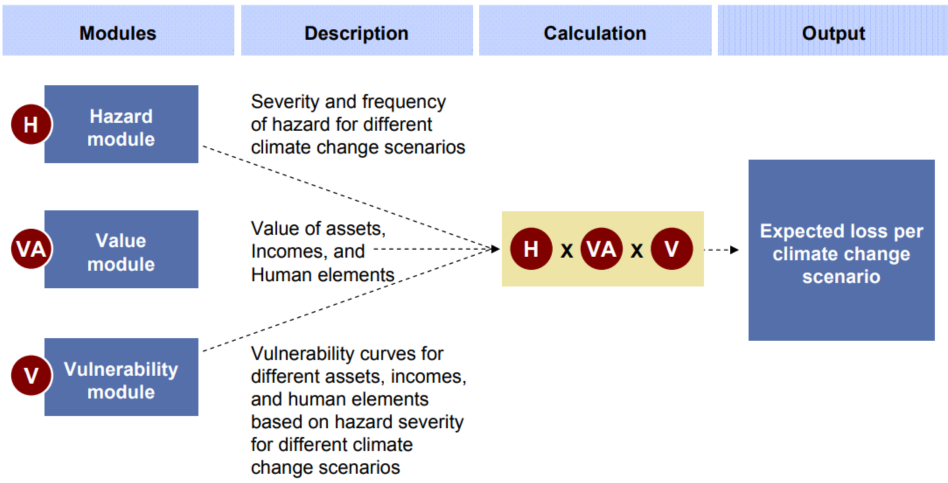
87 *Ibid.*

88 PSEG, *December 2019 PSEG Investor Update*, December 2019.

areas underwater. Twelve years prior, in the neighboring state of Louisiana, Hurricane Katrina destroyed much of New Orleans in one of the biggest natural disasters in United States history.

Entergy's *Building a Resilient Energy Gulf Coast* report outlines a framework that quantifies large estimated losses due to climate and other impacts to the economics of the region and provides a list of potential measures to counter climate impacts. The report emphasizes establishing a cost-benefit analysis, with the first part of the plan detailing the magnitude of loss in the areas most at risk. This involves the calculation of the magnitude of the hazard, measured as the frequency of hurricanes and levels of sea level rise; the economic value of the assets at risk from the hazard; and the vulnerability of the assets from the hazard. Entergy measured vulnerability by calculating vulnerability curves, which show the correlations between the magnitude of climate events and asset loss.[89]

Figure 4 Entergy Resiliency Framework



Source: Entergy, Building a Resilient Energy Gulf Coast: Executive Report

Entergy measured these resiliency strategies on a cost curve, ranking those with the lowest cost-to-benefit first and those with the highest cost-to-benefit ratio ranked last. The curve also shows the total potential of the measure to which expected loss can be reduced (see Figure 5).[90] These measures range from low cost/benefit strategies such as having new building codes for industries, and use of sandbags, to high cost/benefits strategies such as making levees, and pursing home elevation retrofits. The plan also recommends considering the use of insurance to cover the annual expected loss that the loss mitigation strategies do not cover. Implementing these measures in an effective manner will require dedicated regional coordination across multiple jurisdictions involving a diverse range of stakeholders.

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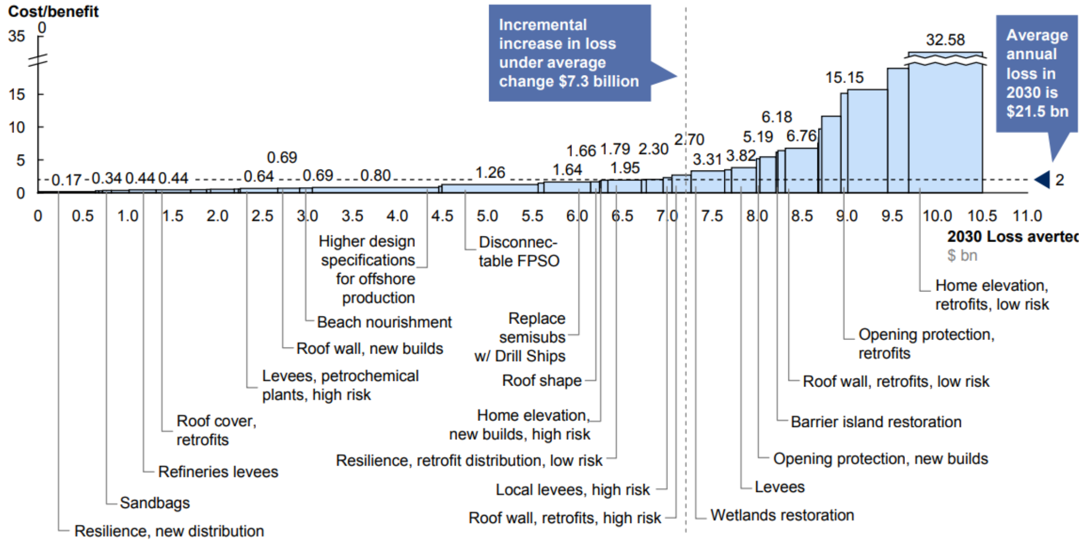
89 Entergy, *Building a Resilient Energy Gulf Coast: Executive Report*, 2010.

90 Entergy, *Building a Resilient Energy Gulf Coast: Executive Report*, 2010.

Figure 5 Cost curve of measures to avert losses from climate risk[91]



Source: Entergy, Building a Resilient Energy Gulf Coast: Executive Report

91 Entergy, *Building a Resilient Energy Gulf Coast: Executive Report*, 2010, Exhibit 5.

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