A Customer-focused Framework for Electric System Resilience

ALISON SILVERSTEIN | ALISON SILVERSTEIN CONSULTING
ROB GRAMLICH | GRID STRATEGIES LLC
MICHAEL GOGGIN | GRID STRATEGIES LLC

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Executive Summary

Although America's power grid is very reliable, resilience is in the news for two reasons. Recent hurricanes, winter storms, and other extreme weather events have violently awoken customers to the realities of major, extended power outages by damaging transmission and distribution (T&D) assets. At the same time, concerns over the changing generation fuel mix have led to claims that retirements of uneconomic coal and nuclear plants threaten grid reliability and resilience.

Customers pay the ultimate price for power outages, whether through their electric bills or their own personal losses and expenditures. Increasing numbers of bad weather events have led many customers to expect that more outages will happen. We cannot prevent and mitigate all the hazards and threats that cause outages, and we can mitigate some but not all of their consequences. So which risks should we take, what level of resilience and mitigation cost are we willing to bear, and how should we choose among resilience measures? This paper cannot answer the risk question, but it does offer a path for assessing and selecting resilience regulatory policy options.

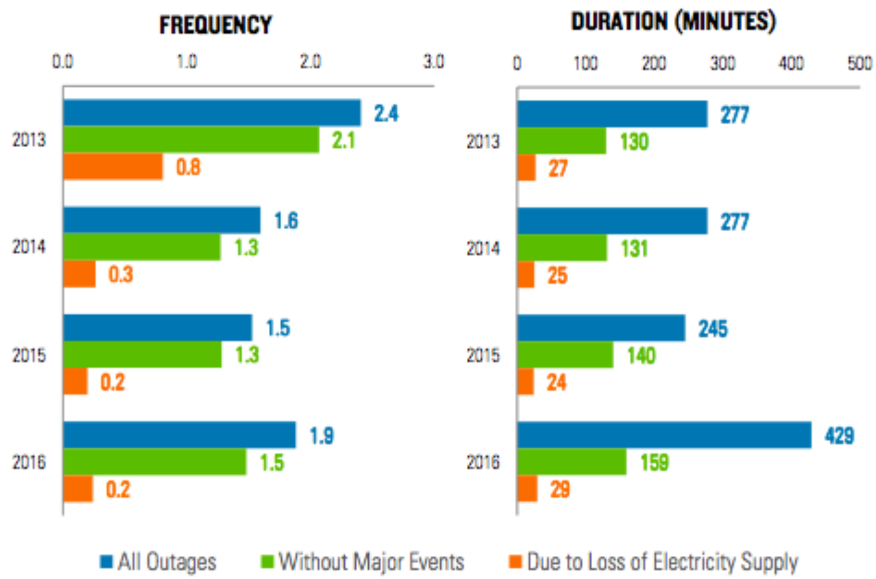
Power system reliability and resilience are deeply intertwined -- reliability covers those long-term and operational steps that reduce the probability of power interruptions and prevent loss of customer load, while resilience measures reduce damage from outages and hasten restoration and recovery to shorten outage durations. Many reliability measures improve resilience and the same utilities and system operators that are responsible for providing reliability also provide resilience. In practice, bulk power system actors have been performing both reliability and resilience under the umbrella of "reliability," and the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) have been regulating both reliability and resilience under that same umbrella.

Although many discussions of reliability and resilience focus on the bulk power system, this study recommends use of a much broader framework and metrics that are focused on customers' experiences, rather than the grid alone. In a customer-centric framework, the power system should be viewed end-to-end, spanning from the customer premises (including customer-sited energy efficiency and distributed generation and storage) through distribution and transmission up to power generation and fuel supply. Power system resilience should be measured from the end user's perspective – how many outages happen (frequency), the number of customers affected by an outage (scale), and the length of time before interrupted service can be restored (duration). And since long outages do occur, we should also consider customer survivability as an important element of resilience preparations.

The power system faces a wide variety of natural hazards and intentional threats. Natural hazards such as hurricanes and ice storms cause extensive and costly damage to electric distribution and transmission, causing multi-day outages for large numbers of customers. The number and magnitude of storm and other major natural hazards have increased significantly over the past fifteen years, so these are high impact and growing probability threats. The power system can also be harmed by geomagnetic disturbances (GMD) from solar weather and electromagnetic pulses, and by cyber and physical attack.

Based on historic events, however, the vast majority of outage events arise at the distribution and transmission levels from weather events. The Rhodium Group finds that the bulk of outage events are due to routine causes (local storms, vegetation, squirrels, equipment problems), and the Department of Energy reported that 90% of electric power interruptions arise on the distribution system, mostly weather-related. But high-impact, low-frequency events such as hurricanes and winter storms cause about half of customer outage-minutes, as shown in Figure ES-1. At the other end of the probability and causal spectrum, Rhodium determined that less than 0.1% of customer outage-hours were caused by generation shortfalls or fuel supply over the 2012-2016 period.

Figure ES-1 – Customer electric outage frequency is dominated by routine rather than major events
(Source: Marsters et al. (2017))



Source: Rhodium Group analysis, EIA. Note: Loss of supply during major events is included in loss of electricity supply.

These and other sources confirm several broad conclusions about electric service interruptions:

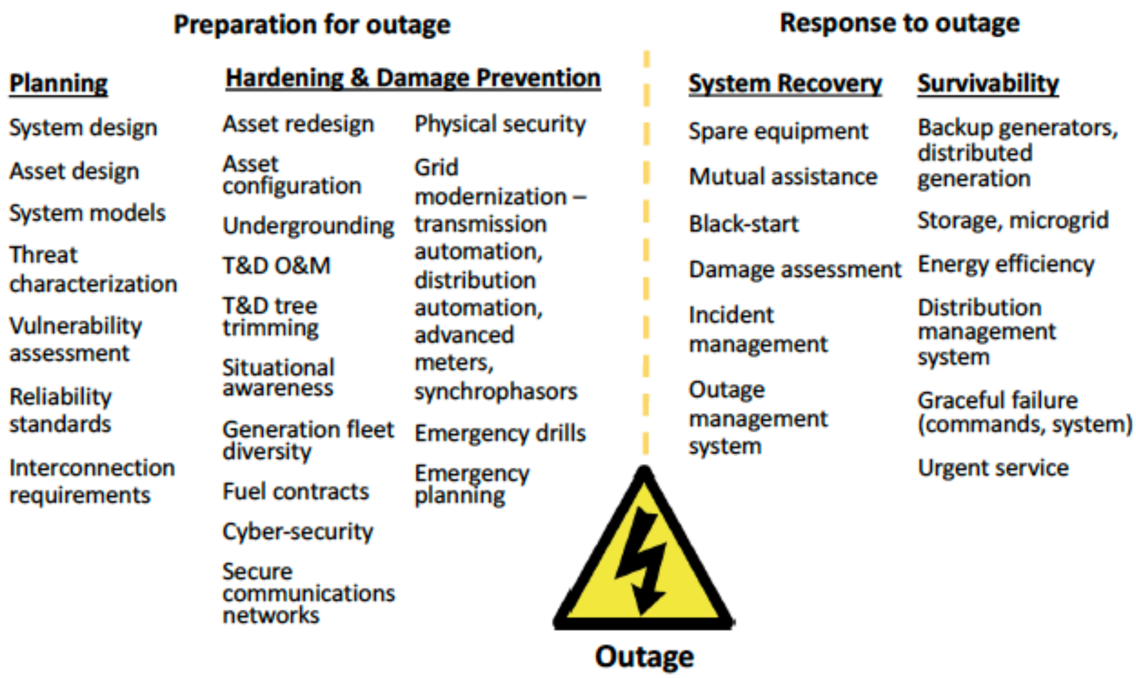
- Over 90% of outages (frequency) occur due to distribution-level problems,
- Typically no more than 10% of all power outages (frequency) are due to major events.
- About half of outage durations are due to high-impact major events, and,
- Adverse weather is the primary cause of both outage frequency and duration.

Most outage events and threats have common consequences -- they damage distribution and transmission assets, causing customers to lose electric service. A proactive approach to reliability and resilience would take an all-hazards approach and focus on how to address and mitigate these common consequences, managing risk by taking measures that mitigate against as many threats as possible.

The number of natural disaster-caused outages is high and growing. Threats such as hurricanes and GMD are impossible to eliminate and are infeasible or extraordinarily costly to protect against, so it is impossible to drive power system risk to zero. Therefore, the best strategy is to figure out how to reduce the magnitude and duration of damage caused by an outage, help customers and society better survive an extended outage, and try to recover from it as quickly as possible.

There is a wide array of measures available to maintain and improve power system reliability and resilience, as shown in Figure ES-2. Most of these measures are threat-agnostic; they protect and improve reliability and resilience – from the customer's perspective, not just for the grid -- against many threats, rather than being threat-specific. These measures are already being applied at every level of the power system, by customers, transmission & distribution asset owners, generators and grid operators. Many are routine responsibilities and good utility practice (e.g., utility system design, tree trimming, following the North American Electric Reliability Corporation (NERC) reliability standards, and emergency planning) and some are voluntary practices (such as customer investments in energy efficiency and backup power sources).

Figure ES-2 – Measures to improve power system reliability and resilience



These measures represent significant efforts to protect vital power system assets and human health and safety. But from the customers' perspective, keeping the lights on and shortening outages also requires extensive action by distribution system providers and end users, under regulatory direction of state regulators and local decision-makers.

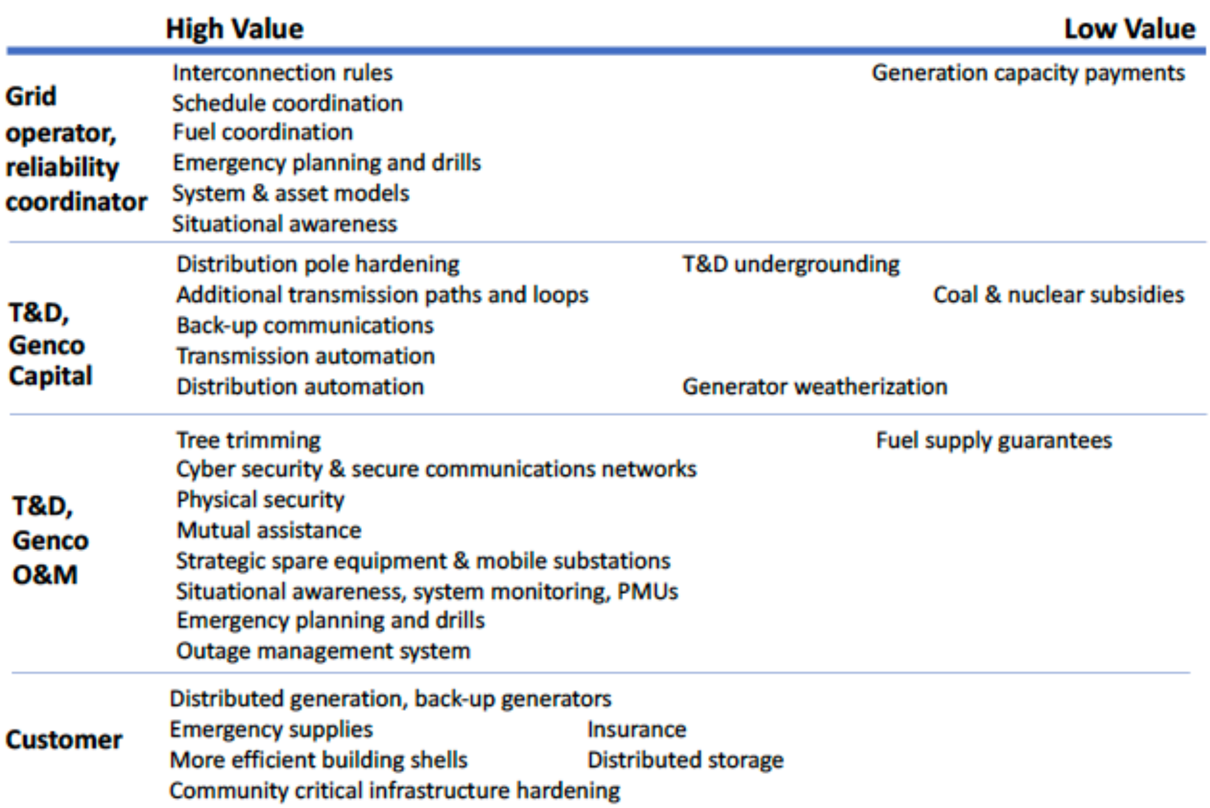
America's resources are not unlimited. We need a way for policy-makers and industry executives to assess and compare the effectiveness and cost-effectiveness of various resilience options. Those comparisons should be customer-centric rather than grid-centric.

The best way to assess the cost-effectiveness of a reliability or resilience measure, and compare between measures, is to estimate its impact on the probability of outage frequency, magnitude and duration, and upon customer survivability. A constructive resilience analysis process will define resilience goals, articulate system and resilience metrics, characterize threats and their probabilities and consequences, and evaluate the effectiveness of alternative resilience measures for avoiding or mitigating the threats. Regulators and stakeholders should ask how each remedy (individually and in suites of solutions) might reduce the frequency, magnitude and duration of customer outages relative to the entire scope of customer outages, not just those resulting from generation- or transmission-level causes. This analysis should be both threat-agnostic and jurisdiction-agnostic – many of the best solutions to maintain and enhance resilience lie beyond the limits of the bulk power system and federal jurisdiction.[1]

Figure ES-3 shows the authors' assessment of the value of various reliability and resilience measures, assessed according to their impact on total customer outage frequency and duration. Note that the most cost-effective measures address distribution system improvements (since that is where most outages occur) and customer protection efforts.

Figure ES-3 – Relative values of measures to improve resilience

(Subjective assessment based on cost per impact on outage reduction and customer survivability)



Many of the measures that offer the highest value for reliability and resilience delivery address the provision, operation and maintenance of distribution and transmission assets, because those are the power system elements that are most frequently damaged by routine events and severe weather. Most of these T&D measures are effective against a wide range of threats and deliver multiple benefits – for instance, an inventory of critical spare equipment can be used to deal with a variety of damages and causes, emergency planning and exercises improve response effectiveness against many types of disasters, and transmission automation or situational awareness can be used to improve system efficiency and resource integration. Similarly, measures that protect customer survivability, such as more energy efficient building shells and distributed generation with smart inverters (to keep providing

[1] FERC has regulatory jurisdiction over the bulk electric system, which consists of generation, transmission and wholesale power markets, and interstate natural gas pipelines.

energy to the host after the surrounding grid is out of service), help customers under many adverse threats and offer multiple benefits (such as customer bill savings and comfort).

Generation and fuel supply shortages rarely cause customer outages, and when they do it is almost always due to an extreme weather event or operational failure that may also affect T&D assets. No single unit or type of generation is critical or resilient in itself. Grid operators have always relied on a portfolio of resources performing diverse roles to meet the range of reliability services needed; over the past decade, those portfolios have expanded to include distributed resources such as demand response and distributed generation. Many alternate portfolios of supply- and demand-side resources can provide reliable power delivery.

To ensure that electricity markets operate efficiently and support reliability, reliability services should be defined in functional, technology-neutral terms based on actual system needs, rather than in terms of the characteristics or attributes of resources that historically provided those services.

The combination of a generation fleet and robust transmission system, with customer-side demand response and distributed generation assets, generally offsets the outage risk from losing individual plants or fuel sources. Because the marginal benefit for customers of protecting generation is quite low (particularly when reserve margins are high), generation-related solutions are generally not the most cost-effective means of reducing customer outages on power systems today. There is no evident need to compensate generators or other assets for bulk power system resilience beyond the engineering-based reliability services already being procured.

The authors encourage others to undertake the data collection and analysis required to assess reliability and resilience measures at all power system levels using the customer-centric analytical approach described above. Since most outages occur due to problems at the distribution level and long-duration outages are caused primarily by severe weather events, it logically follows that measures that strengthen distribution and hasten recovery would be highly cost-effective. In contrast, measures to make generation more resilient are likely to have little impact on outage frequency, duration or magnitude or on customer survivability.

Federal and state regulators do not coordinate the financial obligations they place upon the electric providers and actors which they regulate. Electric utilities and customers must deal with the consequences and costs of rules and decisions intended to foster reliability and resilience, including well-intended policies that crowd out or preclude more useful and impactful investments and actions. There is a great risk that if regulators and stakeholders do not conduct the type of analyses suggested here to inform and coordinate resilience investments, we will end up committing significant amounts of money and effort to improve resilience, yet have little constructive impact on the probabilities or actual levels of future customer outages.

Section 1 | Resilience and Power Systems

1.1 Introduction and background

New conversations about power system resilience, whether it is different from reliability, and how it should be measured and delivered, began on April 14, 2017 with the issuance of a memo from Department of Energy (DOE) Secretary Rick Perry.[2] That memo directed DOE staff to conduct a study on the reasons why "baseload power plants" were retiring across America, and what impact these retirements would have on grid resilience, reliability and affordability. His memo also asked whether electric power markets are adequately compensating the attributes that strengthen grid resilience.

In response, on August 24, 2017 DOE released the "Staff Report to the Secretary on Electric Markets and Reliability."[3] That report found that while cumulative power plant retirements have been significant, the bulk power system remains reliable. But the study pointed to recent severe weather events and the range of highly disruptive, low-probability events as demonstrating the need to improve system resilience. Due to the framing of the Secretary's memo, the Study defined resilience principally in the context of generation resources, with particular attention to fuel diversity and "fuel assurance."

On September 28, 2017, Secretary Perry sent the Federal Energy Regulatory Commission (FERC) the proposed "Grid Resiliency Pricing Rule,"[4] which proposed that FERC create mechanisms to provide mechanisms for merchant coal and nuclear plants to recover their "fully allocated costs" in "Commission-approved independent system operators or regional transmission organizations with energy and capacity markets." The cover letter explained that, "the resiliency of the electric grid is threatened by the premature retirements of … fuel-secure traditional baseload resources,"[5] and this profit guarantee mechanism is necessary to protect people from the threat of energy outages resulting from the loss of such capacity. The letter further asserted that organized power markets have under-valued grid reliability and resilience attributes and should be modified accordingly.

On January 8, 2018, FERC issued an Order unanimously denying DOE's proposed rule.[6] FERC found "the extensive comments submitted by the RTOs/ISOs do not point to any past or planned generator retirements that may be a threat to grid resilience."[7] FERC thanked the Secretary for reinforcing, "the resilience of the bulk power system as an important issue that warrants further attention,"[8] and opened a docket for the present inquiry.[9]

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[2] DOE Secretary Perry (2017a).

[3] DOE (2017b).

[4] DOE (2017c).

[5] DOE Secretary Perry (2017b).

[6] FERC (2018), Order 162 FERC ¶61,012.

[7] FERC (2018), paragraph 15.

[8] Ibid., paragraph 1.

[9] FERC Docket No. AD18-7-000.

1.2 The relationship between resilience and reliability

FERC's Order offers an "understanding" of resilience to mean, "[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."[10] The Order recognizes that resilience:

> *… could encompass a range of attributes, characteristics, and services that allow the grid to withstand, adapt to, and recover from both naturally occurring and man-made disruptive events. At the most basic level, ensuring resilience requires that we both (1) determine which risks to the grid we are going to protect against, and (2) identify the steps, if any, needed to ensure those risks are addressed.*[11]

FERC's Order notes that it has taken many actions over the years to address reliability and other issues to ensure the uninterrupted supply of electricity in the face of fuel disruptions or extreme weather threats," and other high-impact threats such as cyber-security, physical security and geomagnetic disturbances.[12] FERC's Order and proposed definition raises the question of how resilience relates to reliability and whether it is a subset of reliability or a different yet related issue. Commissioner LaFleur's concurrence observes, "[i]n my view, resilience -- the ability to withstand or recover from disruptive events and keep serving customers – is unquestionably an element of reliability."[13] In other words, FERC's authority over reliability appears to cover resilience on the bulk power system.

Commissioner LaFleur is correct. NERC has defined reliability to include post-outage recovery and restoration as well as outage avoidance.[14] NERC defines reliability as the ability of the electric system to supply power at all times and withstand sudden disturbances[15] – as so defined, reliability activities are those that attempt to prevent a grid outage. In contrast, FERC's definition of resilience acknowledges

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[10] FERC (2018), paragraph 23.

[11] Ibid., paragraph 24.

[12] Ibid., paragraph 12.

[13] FERC (2018) LaFleur Concurrence, p.1. FERC has authorized jurisdiction over reliability by the Federal Power Act (16 U.S. Code, Chapter 12, Subchapter II, §824o), which defines the term, "reliable operation," to mean, "operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

[14] NERC (2013b).

[15] NERC broadly defines a reliable bulk power system as "one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the amount of available electricity." It divides reliability between resource adequacy ("having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all the time," recognizing scheduled and reasonably expected unscheduled outages of equipment) and security or operating reliability (the ability of the bulk power system to withstand sudden disturbances to system stability and the unanticipated loss of system elements due to natural causes and physical or cyber-attacks). (NERC (2013a) and NERC letter (2017)).

Both the long- and short-term meanings of reliability, traditionally divided between system planning and system operating timescales respectively, have become complicated because the nature of both supply and demand have changed – now that electric demand is manageable rather than fixed (because customers can use demand response and distributed generation to alter demand in real time), supply-side resources on the bulk power system are no longer the only way to meet customer demand and "resource adequacy" takes on new meaning.

that its aim is reducing the damage from, surviving and recovering from disruptive events on the grid – i.e., resilience aims to make outages less probable, severe, long and damaging.[16]

Functionally speaking, most reliability and resilience activities are performed by the same entities (T&D owners and grid operators). Resilience and reliability have common elements including system planning, maintaining real-time operational security to prevent system disturbances, threat identification, and risk management. Many bulk power reliability measures can reduce the consequence as well as probability of outages and therefore reduce the need for executing recovery and survival measures afterwards. In practice, therefore, bulk power system actors have been performing both reliability and resilience under the umbrella of "reliability," and FERC and NERC have been regulating both reliability and resilience under that same umbrella.

Reducing the frequency, duration and impact of outages for end-use customers also requires extensive action by distribution system providers and end-users, and implicates decisions jurisdictional to state regulators as well as FERC.

Table 1 shows many of the internal and external threats that cause power system outages. Most of the events that cause outages have the same ultimate effects to the power system – they damage power system equipment and cut off service to some customers. The difference in impact is often a matter of scale -- how many pieces of equipment are damaged, whether it harms distribution, transmission and/or generation, over how large a scale, affecting how many customers, and for how long. Because so many of these threats have common consequences, sound reliability and resilience management requires planning and acting on an all-hazards basis, managing risk by taking measures that mitigate against as many threats as possible.

[16] The National Academy of Sciences study, *Enhancing the Resilience of the Nation's Electricity System*, finds that, "Resilience is not the same as reliability. While minimizing the likelihood of large-area, long-duration outages is important, a resilient system is one that acknowledges that such outages can occur, prepares to deal with them, minimizes their impact when they occur, is able to restore service quickly, and draws lessons from the experience to improve performance in the future." (NAS (2017), p. 10).

Table 1 – Threats, hazards and vulnerabilities of the electric infrastructure

(Source: Argonne National Laboratory (2016), Table E.1, p. xiv)

Natural Hazards		Direct Intentional Threats		Other Threats, Hazards, and Vulnerabilities	
	Ice, snow, and extreme cold weather		Physical attacks		Geomagnetic and electromagnetic pulses
	Thunderstorms, tornadoes, and hurricane-force winds		Cyber attacks		Aging infrastructure
	Storm surge, flooding, and increased precipitation		---		Capacity constraints
	Increasing temperature and extreme hot weather		---		Workforce turnover and loss of institutional knowledge
	Earthquakes		---		Human error
	---		---		Dependencies and supply chain interruptions

1.3 Resilience for all hazards or high-impact, low-frequency events?

Most of the Independent System Operators' (ISOs) and Regional Organizations' (RTOs) submissions in the FERC Resilience Docket (AD18-7) interpret the resilience threat from "disruptive events" as arising from high-impact, low-frequency (HILF) events such as earthquakes, attack, extreme weather or geomagnetic disturbances. HILF outages are significant events: Hurricane Sandy knocked out power to 8.5 million customers in all 2012;[17] Hurricane Matthew caused 2.5 million customers to lose power in October 2016;[18] and the January 2016 snow and ice storm affected 14 states and over a million customers lost power.[19] Most major disruptive events such as hurricanes, ice storms and floods cause extensive damage to distribution facilities as well as transmission and generation assets.

RTOs and ISOs focus on HILF events because such events can damage the bulk power system, and cause very large outages by harming distribution as well as transmission (and some generation) assets. But this focus obscures the fact that grid operators and asset owners are already taking many steps to ensure resilience against all hazards, addressing both routine and extreme events. Their actions to protect against routine problems such as equipment mis-operations, lightning strikes and routine tree contacts improve the grid's resilience against extreme events.

Consistent with Commissioner LaFleur's view that resilience is an element of reliability, grid operators manage the grid with the reliability goal of "keeping the lights on" and view resilience as part of their

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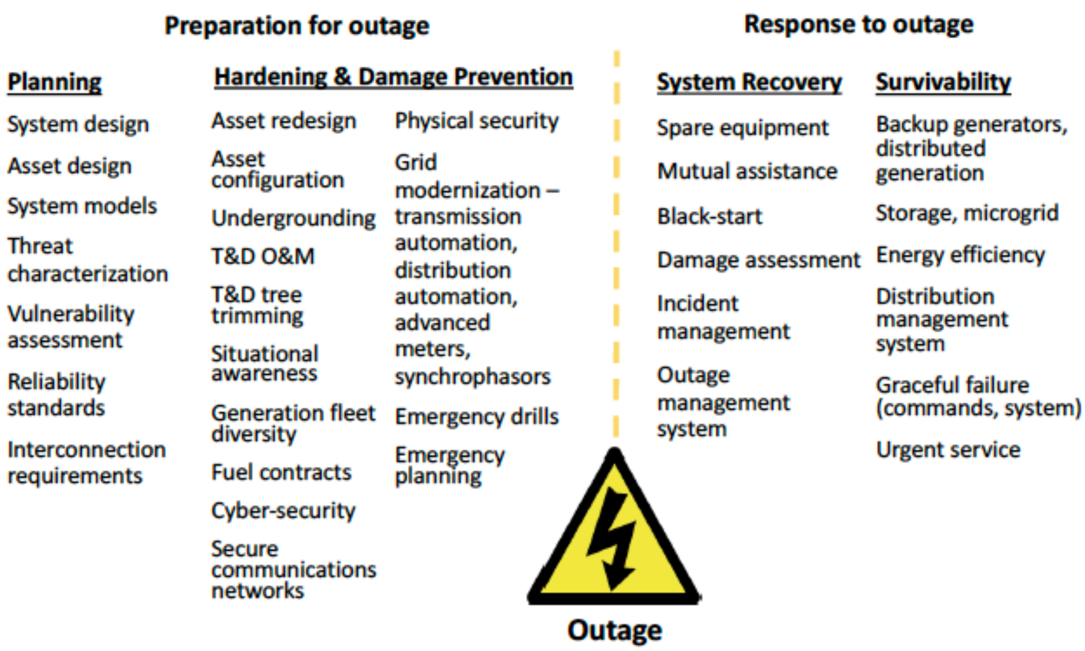
[17] DOE EIA (2012).

[18] DOE EIA (2016c).

[19] DOE EIA (2016a).

existing responsibility.[20] These efforts work -- measures undertaken in the name of reliability actively improve resilience, as shown in Figure 1. Reliability measures such as reserve margin requirements, system planning and modeling requirements, and regional coordination and scheduling, also enhance resilience by helping to absorb and adapt to a sudden disturbance on the grid and thereby reduce the probability and magnitude of an outage. NERC has catalogued how its reliability requirements and other activities address resilience, explaining that its mandatory standards make the system robust against a range of threats and require operators to plan to respond to events, while other activities provide the coordination and situational awareness to recover from events.[21] For example, voltage and frequency disturbance ride-through requirements reduce vulnerability to a number of operational threats, while system restoration plans and black-start capability are key elements of system restoration.

Figure 1 – Measures to address reliability and resilience



Note that the reliability and resilience measures listed above are threat-agnostic – each addresses a practice or solution that strengthens the power system against a variety of threats and failure modes, rather than trying to address and prevent against a single, specific threat. A well-chosen suite of multi-hazard, multi-benefit measures makes it less necessary to assume that every threat will occur, and less necessary to design specific measures to protect against every individual threat or risk. It also recognizes the reality that we cannot eliminate every risk nor ensure that the grid can operate through any risk -- some threats are impossible to avoid (such as hurricanes), or too costly to mitigate (such as a near-by replacement unit for every unique high-voltage transformer).

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[20] See, for instance, ERCOT & PUCT (2018), p. 2, filed in FERC AD18-7. Also, NERC's definition of "Adequate Level of Reliability" includes both avoidance of those grid events that could cause a blackout or grid collapse and restoration of the bulk power system after widespread outages. (NERC (2013b), p. 2)

[21] NERC (2018a), pages 58-65.

1.4 Conclusions

Power system reliability and resilience are closely interrelated. Reliability principally aims to do those things that prevent uncontrolled loss of customer load, while resilience aims to reduce the probability of power interruptions, reduce damage from outages, and hasten restoration and recovery to shorten outage durations. FERC's authority over reliability includes resilience of the bulk power system. But from the customers' perspective, keeping the lights on and shortening outages also requires extensive action by distribution system providers and end users, under the regulatory direction of state regulators and local decision-makers.

The power system spans the functional stretch from customer premises (including customer-sited energy efficiency and distributed generation and storage) through distribution and transmission up to power generation and fuel supply. That system faces many threats. Most of these threats have common consequences – damage to distribution and transmission, causing customers to lose electric service – so sound reliability and resilience management requires planning and acting on an all-hazards basis, managing risk by taking measures that mitigate against as many threats as possible.

From a customer-centric perspective, the most cost-effective measures to advance reliability and resilience are those that are effective against multiple threats and offer multiple benefits in addition to their merits for reliability and resilience. Such high-value measures include those that reduce distribution-level outages (e.g., tree-trimming and distribution automation systems), improve outage recoverability (e.g., emergency management drills, outage management systems, critical spares and mutual assistance programs), and improve customer survivability (e.g., energy efficient building shells, emergency supplies and distributed generation and storage with smart inverters).

Section 2 | Bad Weather and Distribution Cause Most Customer Outages

We do not build electric generation or transmission for their own sakes. Every element of the end-to-end power system -- generation, fuel transportation systems, transmission, distribution, distributed generation and storage, end use devices and energy efficiency measures – exists to provide energy services for end-use customers. For that reason, power system resilience should be measured from the end user's perspective – how many outages happen (frequency), the number of customers affected by an outage (scale), and the length of time before interrupted service can be restored (duration).

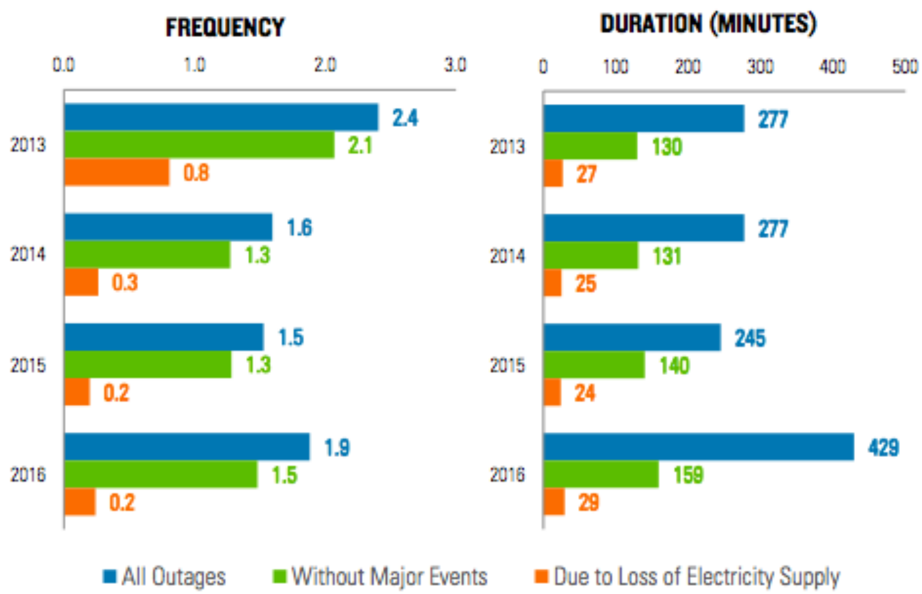
This section reviews the causes and consequences of customer outages across the entire power system -- not just on the bulk power system -- and then looks at the cost of those outages to customers and society. This examination shows that the vast majority of outages across the power system are caused by weather events rather than generation-level failures (including fuel supply failures). Furthermore, most outages caused by natural events harm electric T&D assets in common ways, leading to the conclusion that the most practical way to improve resilience and reliability is to address T&D and grid operations rather than generation and fuel issues.

2.1 Customer outage frequency is dominated by routine events and weather

Many analyses have established that the bulk of power service interruptions arise from routine causes at the distribution level, rather than from major events. This is illustrated in Figure 2, in which the Rhodium Group uses utility-submitted data[22] to count the average number of customer outages and duration for the period 2013-2016. It shows that the bulk of customer outage events occur from routine causes (shown as the green bars, due to such causes as squirrels on distribution lines, distribution operations, and normal weather events such as local storms knocking tree limbs into lines) rather than major events (such as hurricanes, floods or earthquakes). In contrast to outage frequency, in most years about half of actual average customer outage minutes (outage duration) are due to routine events, and half to major events.[23]

Figure 2 – U.S. average customer electric outage frequency is dominated by routine rather than major events

(Source: Marsters et al. (2017))



Source: Rhodium Group analysis, EIA. Note: Loss of supply during major events is included in loss of electricity supply.

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22 This Rhodium analysis (Marsters et al. (2017)) draws on utility data submitted through the Energy Information Administration (EIA) Form 861. Most other outage analyses rely on data on the cause, duration and magnitude (customer count and MW) submitted by utilities using Form OE-417. Utility reporting criteria appear to be inconsistent; and analyses such as those discussed here vary. Therefore, the reader should view the outage information discussed here as ballpark estimates, rather than as precise statements about outage frequency and duration.

23 DOE's EIA forms define a major disturbance or event as one that causes the loss of electric service to more than 50,000 customers for one hour or more. DOE does not offer clear definitions or distinctions for "severe weather (thunderstorms, ice storms, etc.)," or "natural disasters (hurricanes, floods, tornadoes, solar activity, etc.)". Utilities are supposed to report outages that last longer than 5 minutes. EIA reports that, "utilities … that reported their outage information to EIA collectively made up only 34% of all utilities but accounted for about 91% of electricity sales," (EIA (2018)), which means that additional small outages occurred that are not counted in these data.

Rhodium finds that averaged over the four years 2013-2016, only 8.6% of outage minutes are due to "loss of electricity supply" to the distribution utility (the orange bars above), which reflects those caused by transmission failures, generation failures, fuel emergencies, generation shortfalls and weather impacts to transmission and generation assets.[24] The other 91.4% of outage minutes are due to events affecting the distribution system itself.

Other analyses support the conclusions that most electric outages occur due to disruptions at the distribution level, and that most are caused by weather (whether local or extreme weather events):

- For the year 2016, EIA reports that customers experienced an average of 1.3 interruptions and went without power for four hours during the year. Excluding major events, the average U.S. electricity customer "was without power for 112 minutes and experienced one outage. When major events are included, the numbers increase by 138 minutes without power and 0.3 outage occurrences to a total of 250 minutes and 1.3 outages."[25] That means that most of the customer outage events occurred from relatively routine, local causes, even though major events caused the majority of outage minutes.[26]
- LaCommare, Larsen & Eto report that over 2000 through 2012, over the course of any year, major events "typically account for no more than 10% of all power outages."[27]
- The Executive Office of the President reported that, "[s]evere weather is the leading cause of power outages in the United States."[28]
- An analysis of transmission-based outages found that of the 32,000 automatic transmission element outages recorded in the NERC Transmission Availability Data System, over 2008 through 2014, the dominant causes of transmission element outages were lightning strikes, failed AC substation equipment, and "Other".[29]
- Larsen, Sweeney and colleagues conducted statistical review of publicly available outage and related data from 2000 through 2012 and found the top causes of outage frequency and duration have been weather (15%) and local causes including vegetation (24% -- vegetation causes an outage when bad weather causes tree-to-line contacts), equipment failures (24%) and wildlife (11%).[30]
- The Union of Concerned Scientists found that the number of electric disturbances between 2000 and 2014 has been dominated by those caused by adverse weather events, both local (small-scale) and severe (major weather events). (See Figure 3)

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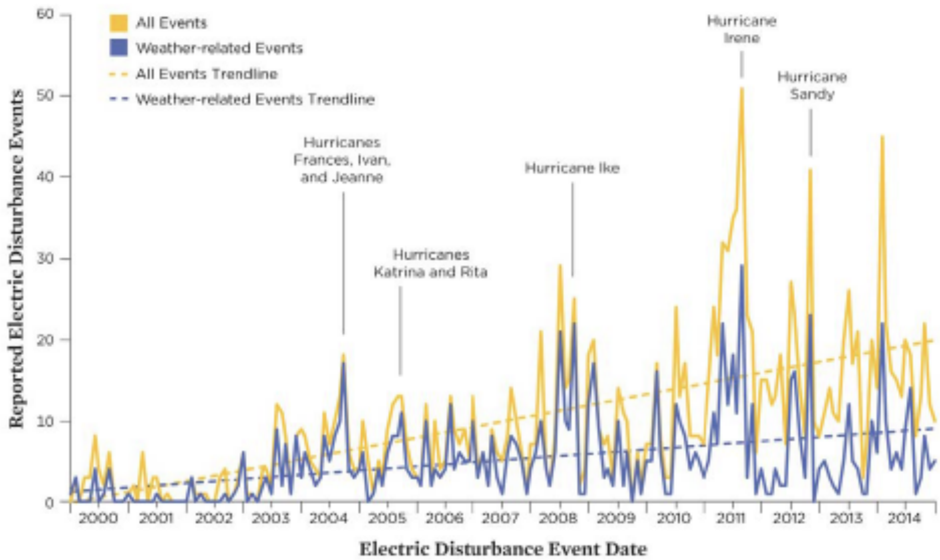
[24] Marsters et al. (2017).
[25] EIA (2018).
[26] DOE EIA (2018).
[27] LaCommare, Larsen & Eto (2015).
[28] Executive office of the President (2013), p. 3.
[29] Schaller and Ekisheva (2016).
[30] Larsen, Sweeney et al. (2014), Figures 1 & 2.

Figure 3 – Reported electric disturbance events are dominated by weather causes
(Source: Union of Concerned Scientists (2015))



2.2 Customer outage durations are driven by distribution-level problems and extreme weather events

Short outages are irritating and inconvenient, but longer outages impose much greater costs and hazards for customers and society as a whole.[31] The U.S. Department of Energy's Quadrennial Energy Review[32] (QER) reports that the average U.S. power customer experienced 198 minutes of "electric power unavailability" in 2016. DOE reports that these outages:

> *… disproportionately stem from disruptions on the distribution system (over) 90 percent of electric power interruptions), both in terms of the duration and frequency of outages, which are largely due to weather-related events. Damage to the transmission system, while infrequent, can result in more widespread major power outages that affect large numbers of customers with significant economic consequences.*[33]

Reinforcing the impact of extreme weather events on outage duration, Figure 4 shows the distributions of customers without power over time for fifteen major storms occurring between 2004 and 2013, in terms of the fraction of customers without power as a percentage of the peak number of customers

[31] When the common service quality metrics of SAIFI (System Average Interruption Frequency Index) and SAIDI (System Average Interruption Duration Index) are calculated, major outage events dominate the SAIDI calculation because the high number of customers out for a lengthy time period swamps the number of outage-minutes for small groups of customers out of service for brief periods from numerous small outages. But because long outages are much more socially and economically costly than short outages, small increases in SAIFI and SAIFI averages mask the grave importance and cost of major events.

[32] U.S. DOE QER (2017a), p. 4-5. Other than the timing difference between development of these QER outage estimates in 2017 and the EIA estimate cited earlier (published in 2018), the authors are not aware of the reasons why these two DOE average outage duration estimates differ by over an hour. More broadly, this points to the challenge of finding consistent data and analytical methods for understanding U.S. customer outages.

[33] DOE QER (2017a), p. 4-5.

without power, over the course of the outage event.[34] Figure 5 shows the widespread impact of a single hurricane, which caused outages that spanned five states over eight days.

Figure 4 – Number of customers out of power over the course of major weather outage events, 2004-2013

(Source: Executive Office of the President (2013). For comparison purposes, the duration of every outage is normalized to 1.0 (horizontal axis) and the number of customers out of service at any point in time is calculated relative to total customers out at the peak of the outage (vertical axis).)

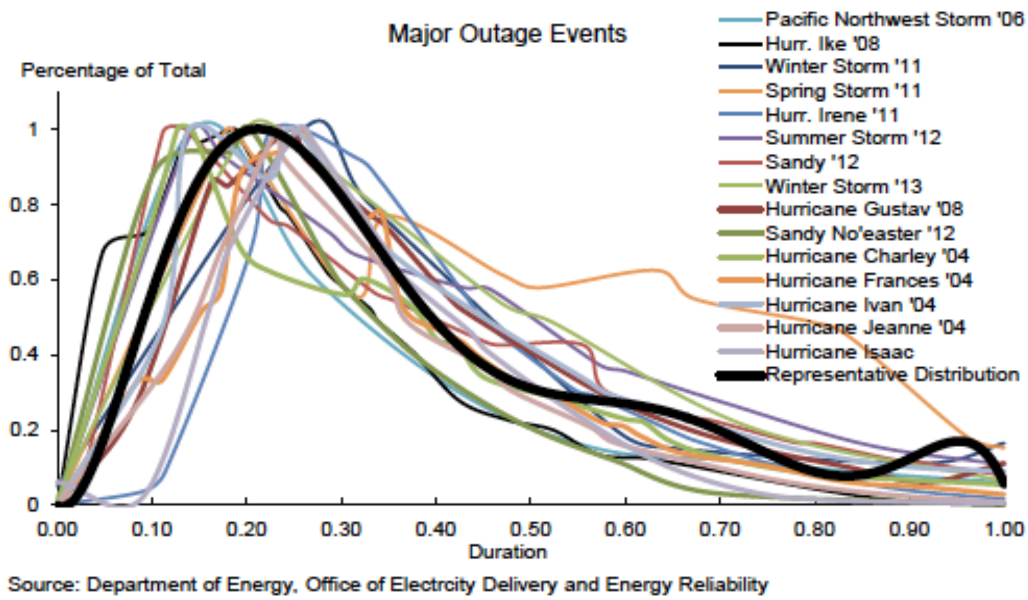
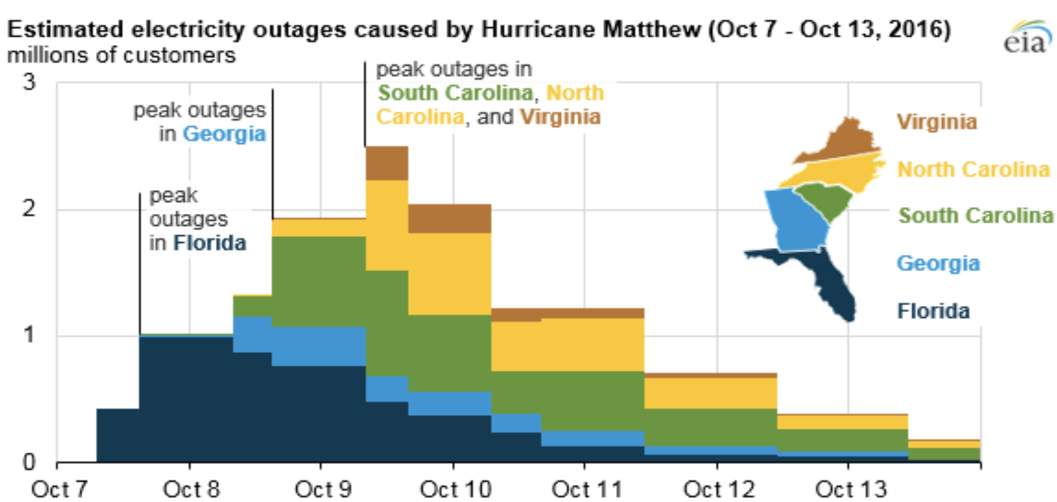


Figure 5 – Estimated electricity outages caused over eight days by Hurricane Matthew, 2016

(Source: EIA (2016c))



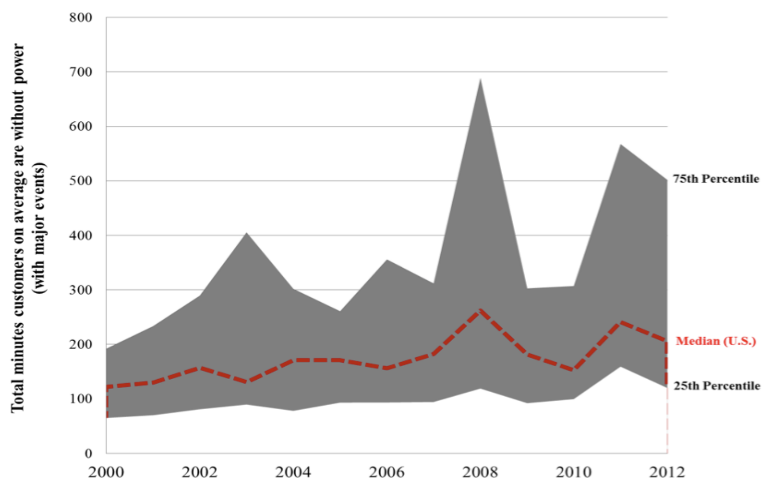
[34] Executive Office of the President (2013), p. 20.

Analysis drawing from earlier Lawrence Berkeley National Laboratory (LBNL) work on distribution system outages[35] found that distribution system failures account for more than 100 times more customer outage hours than generation shortfalls. That analysis concluded, "[d]istribution system outages appear to impose roughly two orders of magnitude more minutes of outage on customers than does resource adequacy under the 1-in-10 criterion — *i.e.,* 146 compared to 1.2 minutes a year."[36]

The LaCommare team found the severe weather factors affecting frequency and duration of power interruptions include abnormally high wind speeds, precipitation, an abnormally high number of lightning strikes per number of customers per line mile, and an abnormally high number of cooling degree days. That analysis found that with major events included, the total number of outage minutes is increasing over time, as shown in Figure 6.[37] This study also found that there is no consistent link between reliability and increased spending on utility T&D O&M expenditures, which would be expected to improve reliability.

Figure 6 – Increasing customer outage durations over time

(Source: LaCommare et al. (2015). Total minutes of customer power interruptions, including outages due to major events)



Larsen found that, "Increasingly severe weather events are linked to a 5% to 10% increase in the total number of minutes customers are without power each year."[38]

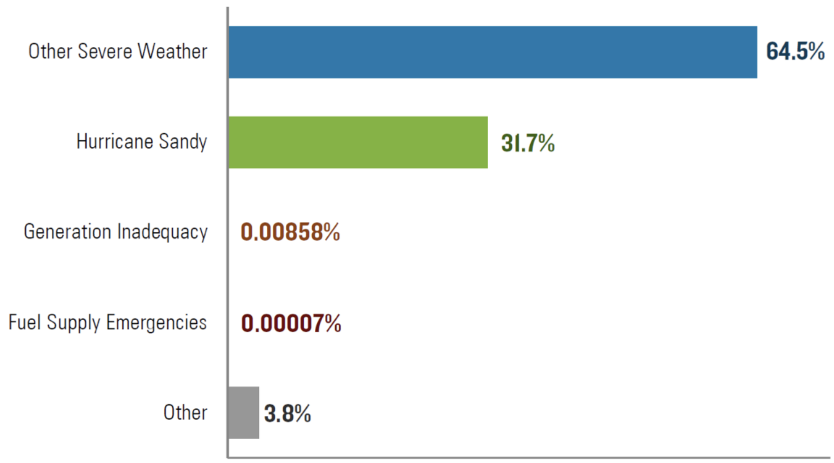
2.3 Generation shortfalls cause a tiny share of customer outages and long outages

The Rhodium Group used another EIA dataset to look at the causes of electricity disturbances in the U.S. for the period 2012 through 2016, as shown in Figure 7. This analysis concluded that of 3.4 billion customer outage hours that occurred between 2012 and 2016 due to major electric disturbances, fewer than 0.01% of customer outage-hours were caused by either insufficient generation or generator fuel supply problems and 96% were due to severe weather (Hurricane Sandy and other severe weather

35 Eto & LaCommare (2008), p. 15.
36 Wilson (2010).
37 LaCommare et al. (2015).
38 Stanford University (2015).

events).[39] Reanalysis of the same dataset for 2003 through 2017 reveals that: generation shortfalls caused only 0.2% of all customer outage-hours (including 0.0002% from fuel supply problems); T&D problems NOT related to weather caused only 5.7% of outage-hours; and weather problems caused the other 94% of outage-hours.[40]

Figure 7 – Cause of major electricity outages by customer-hours disrupted in the U.S., 2012-2016
Source: Marsters et al. (2017)

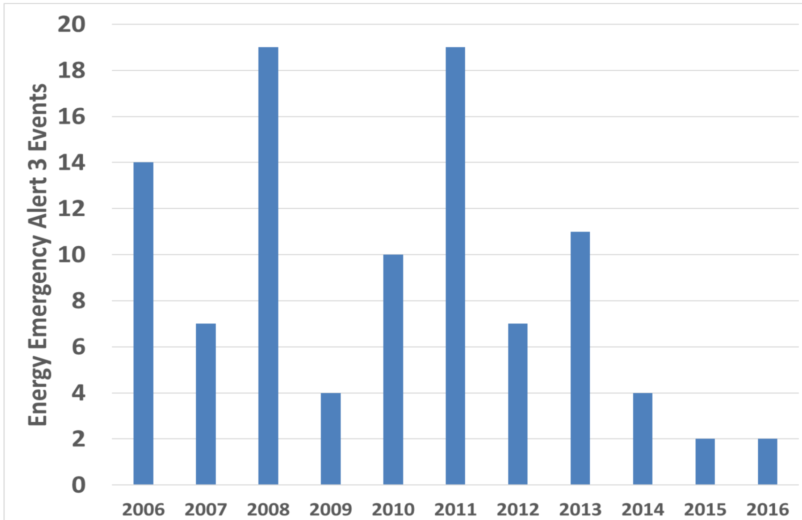


NERC tracks data that help indicate the frequency of outages resulting from generation shortfalls. Energy Emergency Alerts are issued when generation supply is inadequate to meet demand and firm load must be shed. The number of such events has trended strongly downward over the last 5 years from an already low level, as shown in Figure 8 – this suggests that the industry's decade-long efforts through rules and markets to improve generation availability and reliability have been effective.

[39] Houser, Larsen & Marsters (2017), using Form OE-417 data.

[40] Goggin analysis of Form OE-417 data. If the analysis started in 2004 (excluding the impact of the transmission-caused 2003 Northeast Blackout), 98.58% of outage hours over the 2004-2017 period were caused by weather and other natural events, while 1.07% were caused by non-weather transmission and distribution failures.

Figure 8 -- Generation shortfall events, based on Energy Emergency Alerts
(Source: NERC (undated-b))



At the generation level there is significant resource redundancy, maintained through planning and operating reserve margins, to provide both reliability and resilience – particularly as supplemented with transmission and demand response. This resource redundancy makes each individual generation plant or type of generation resource less critical. Resource adequacy planning takes full account of the functional capabilities that supply- and demand-side resources can provide, such as availability, flexibility and other essential reliability services.

Appendix A lists the 27 major blackouts occurring in the U.S. since 2002. Of this group, only four were due to non-weather problems – three started on the transmission system (the 2003 Northeast Blackout, the 2008 Turkey Point blackout, the 2011 Southwest Blackout) and one from a power plant fire (Puerto Rico 2016). Only the ERCOT 2011 rolling blackouts were related to a generation shortfall (most due to inadequate equipment weatherization for extremely cold weather).[41] It should also be noted that, due to their larger size and geographic diversity, the Eastern and Western Interconnections (which are subject to FERC jurisdiction) tend to be more resistant to generation shortfalls than ERCOT.

2.4 Power outage costs

Electricity is essential for the smooth operation of American society and economy, and the costs of doing without it are high. The 2013 study, "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages," estimates that between 2002 and 2013:

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[41] As described in the FERC-NERC investigation report, a five-day stretch of extremely cold weather caused the loss (outage, derate or failure to start) of 210 individual generating units within ERCOT, leading to controlled load-shedding of 4,000 MW affecting 3.2 million customers. Local transmission constraints and loss of local generation caused load shedding for another 180,000 customers in South Texas. Outside ERCOT, El Paso Electric lost 646 MW of local generation, and two Arizona utilities load 1,050 MW of generation. Some of these losses were due to frozen generation equipment and others were due to the loss of gas supply due in part to frozen pipeline equipment. But for this lack of weatherization, less equipment would have failed. See https://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf.

Weather-related outages are estimated to have cost the U.S. economy an inflation-adjusted annual average of $18 billion to $33 billion. Annual costs fluctuate significantly and are greatest in the years of major storms such as Hurricane Ike in 2008, a year in which cost estimates range from $40 billion to $75 billion…. The costs of outages take various forms including lost output and wages, spoiled inventory, delayed production, inconvenience and damage to the electric grid.[42]

Table 2 estimates the cost per outage event (the cost for one customer for one interruption of the indicated duration), cost per average kW of interrupted service (normalized by demand), and cost per unserved kWh. These costs are based on review of many utility interruption cost estimates and econometric analysis of outage data. The study concludes that outage costs are highest for medium and large commercial & industrial (C&I) customers, but on a per kW basis, small C&I customers place the highest value on a power service interruption. Residential customers (individually) experience lower costs from a power interruption – but there are many more residential customers so cumulative outage costs for the residential class are high. Customer interruption costs vary by season and time of day, following expected patterns of each customer group's electric usage and activities.

Table 2 – Estimated interruption cost by event, average kW and unserved kWh (US 2013$) by interruption duration and customer class

(Source: Sullivan et al. (2015), Table ES-1)

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Medium and Large C&I (Over 50,000 Annual kWh)						
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per Average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per Unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7
Small C&I (Under 50,000 Annual kWh)						
Cost per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0
Residential						
Cost per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

Table 2 shows that outage costs increase as outage duration increases.[43] The analysts caution that these estimates are more accurate for shorter-duration outages (under 24 hours), and that the estimates do not reflect the significant indirect spillover effects of an outage on the wider economy.[44] These data

[42] Executive Office of the President (2013), p. 3.

[43] As will be discussed below, the number of major event outages has been increasing over the past decades and appears likely to continue on that trend.

[44] Sullivan et al. (2015), p. xiv.

and findings were used to update DOE's Interruption Cost Estimate (ICE) calculator, which is available for electric reliability planners and others to use to estimate outage costs.[45]

Many analysts agree that the per-customer economic costs of long, large outages are far greater than the costs of short outages, and that those larger costs have not yet been well reported or well estimated.[46] Updated work on the annual cost of longer electric power interruptions estimates that for 2015, the nation-wide cost of sustained outages totaled $59 billion (28% for industrial customers, 70% for commercial customers, and 2% to residential customers).[47] Many recent severe, extended outages such as the on-going Puerto Rico tragedy indicate that Value of Lost Load estimates such as those in Table 2 above greatly under-estimate the full cost or burden that extended outages place upon affected electric customers.

Public safety concerns arise for residential customers affected by long duration outages, particularly in conditions of intense cold or heat or if access to clean water is impaired. The on-going, widespread, multi-month power outages across Puerto Rico from Hurricane Maria will set new records for the costs and impacts of American power failures. Beyond the economic costs, extended power outages can lead to human deaths – the current months-long power outage in Puerto Rico due to Hurricane Maria is reported to have caused at least 1,085 deaths between September and December 2017, from causes including the inability to power home dialysis and respiratory machines, inability to contact emergency services due to lack of cell phone power or tower service,[48] and poisoning due to lack of power for food and medicine refrigeration, clean water and sewers. On a more modest scale, a recent review of the August 14, 2003 Northeast blackout attributes approximately 90 excess deaths in New York City alone.[49]

2.5 Conclusions

The data above show clearly that the vast majority of outage events (outage frequency) arise at the distribution level from routine bad weather and other events. HILF events such as hurricanes and winter storms cause the bulk of customer outage-minutes (outage duration) by damaging distribution and some transmission assets. The fact that so few outages have been due to problems at the bulk power system level may well demonstrate the effectiveness of the efforts by NERC, FERC and the industry to improve reliability and resilience efforts over the past decade.

It follows that scarce resources and attention to reliability and resilience can best be focused on those solutions (such as tree-trimming to reduce weather-related damages to both distribution and

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[45] LBNL ICE Calculator.

[46] Keogh and Cody, writing for NARUC, observed that about half of reporting utilities exclude major event impacts from their SAIDI and SAIFI reporting because, "Large scale events warp the math because restoration costs are so high, and because they are likely to inflict longer-term service interruptions. In catastrophic situations the value to ratepayers for surviving the event without losing service is especially high." They hypothesize that the value of lost electric services increases exponentially rather than arithmetically over time, because as the outage extends after days and weeks without power "modern life becomes impossible." (Keogh & Cody (2013), p. 10.

[47] Eto (2017), p. 12.

[48] Santos-Lozado (2018).

[49] Anderson & Bell (2012), p. 189-193. Causes of blackout-associated deaths included carbon monoxide poisoning (from inadequately vented back-up generators), heart attacks from exertion of evacuating tall buildings, lack of access to food sources and prescription medicines, inability to use electric-operated home medical equipment, slow ambulance response to emergency events, heat complications, and higher localized air pollution.

transmission) that are most effective and cost-effective at reducing outage frequency, duration and magnitude. Jurisdictional limits between FERC and states should not limit recognition that some of the best solutions to maintain and enhance resilience lie outside the bulk power system.

Section 3 | There are Many Threats to the Power System

Planners must account for many threats that can affect the power system. Resilience assessment needs to identify that large set of hazards and threats relevant to each region and system, then recognize the common range, magnitude and potential consequences of those threats. This section reviews the various categories of significant threats to the power system. This analysis indicates that the electricity distribution and transmission systems are among the most vulnerable to almost all major threats, confirming the finding in preceding and subsequent sections that those systems should be the primary focus of efforts to improve resilience.

3.1 Power system resilience should address a variety of threats

Although the bulk of customer outages occur at the distribution level, both distribution and transmission are vulnerable. Damage to multiple transmission facilities can cause much larger outages, even though there is often a high level of redundancy between transmission facilities and between transmission and generation. From a customer-centric viewpoint, it is worthwhile to invest in reliability and resilience measures for both transmission and distribution because such measures have meaningful impact and benefits for a reasonable cost.

Table 3 lists a number of major events known to harm the power system and shows which parts of the system each type of threat can harm. Electricity distribution and transmission wires and substations are vulnerable to almost every type of threat, confirming that those systems should be a priority for efforts to improve resilience. Recognition of the common consequences that cross numerous threats is the first step in developing a constructive, cost-effective set of measures directed at common consequences rather than only at specific threats.

Table 3 – DOE's assessment of current threats and risks to the power system
(Source: DOE QER (2017) Figure 4-8, p.4-26)

Threat	Intensity	Electricity Transmission	Electricity Generation	Electricity Substations	Electricity Distribution (above)	Electricity Distribution (below)	Storage
		System Components					
		Assessment of Risk & Resilience					
Natural/Environmental Threats							
Hurricane	Low (<Category 3)	● (Moderate)	●	● (Moderate)	● (High)	●	◑ (Moderate)
	High (>Category 3)	◑ (High)	● (Moderate)	● (Moderate)	◑ (High)	● (Moderate)	◑ (Moderate)
Drought	Low (PDSI>-3)	●	●	●	●	●	●
	High (PDSI<-3)	●	◑ (Moderate)	●	●	●	◑ (Moderate)
Winter Storms/Ice/ Snow	High (PDSI<-3)	● (Moderate)	●	●	● (Moderate)	●	●
	Low (Minor icing/snow)	● (High)	●	● (Moderate)	● (High)	●	●
Extreme Heat/Heat Wave		●	◑ (Moderate)	● (Moderate)	●	●	●
Flood	Low (<1:10 year ARI)	●	●	●	●	● (Moderate)	●
	High (>1:100 year ARI)	● (Moderate)	◑ (Moderate)	◑ (Moderate)	◑ (Moderate)	● (Moderate)	● (Moderate)
Wildfire	Low (>Type III IMT)	●	● (Moderate)	●	●	●	●
	High (Type I IMT)	● (Moderate)	●	● (Moderate)	● (Moderate)	●	● (Moderate)
Sea-Level Rise		●	● (Moderate)	●	●	●	●
Earthquake	Low (<5.0)	●	● (Moderate)	● (Moderate)	● (Moderate)	● (Moderate)	● (Moderate)
	High (>7.0)	● (Moderate)	● (High)	● (High)	● (Moderate)	● (High)	● (High)
Geo-magnetic	Low (G1-G2)	●	●	●	●	●	●
	High (G5)	○	◑ (Moderate)	○ (High)	◑	○	◑ (Moderate)
Wildlife/Vegetation		●	●	●	●	●	●

Levels of Risk

- ○ Low
- ● (orange) High
- ● (yellow) Moderate
- ○ Unknown

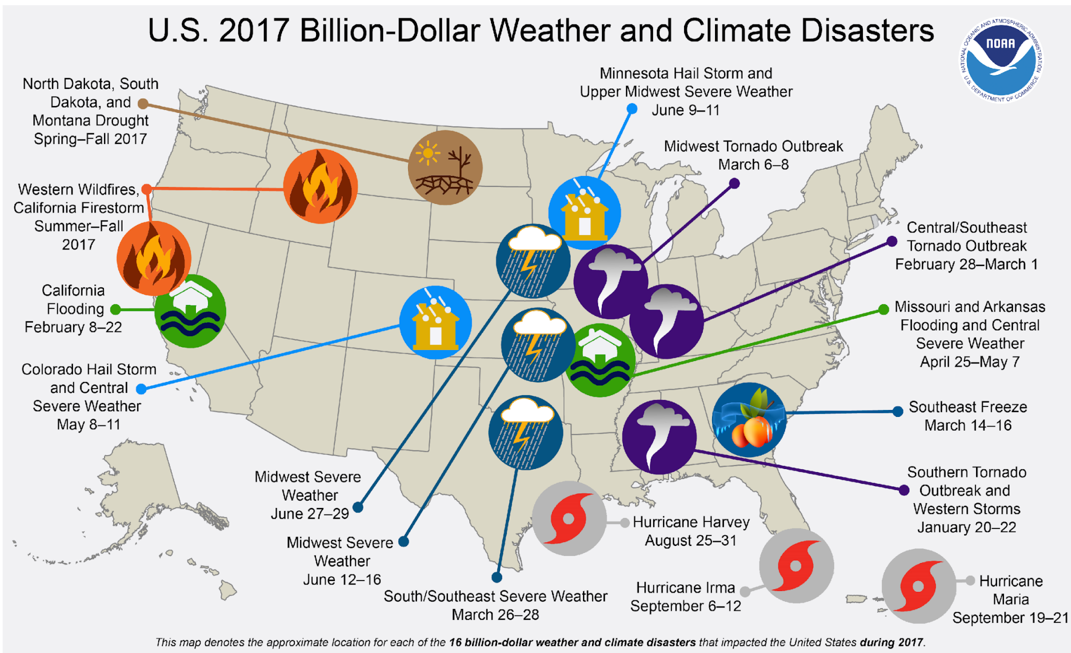
Current Status of Risk Management Practice

- ○ Nascent: critical vulnerabilities exist
- ◑ Established, but opportunities for improvement remain
- ● Well-established and robust

Figure 9 shows the 16 diverse weather and climate "disaster events with losses exceeding $1 billion each" in 2017.[50, 51] In addition to the 362 deaths and significant economic losses directly due to these events, most of these events harmed some electric system infrastructure and caused service disruptions. The cumulative cost of these events exceeded $350 billion. All of these types of severe weather are included in DOE's listing of threats and risks[52] to the power system (Table 3 above).

Figure 9 – Many diverse weather disasters hit the U.S. in 2017

(Source: U.S. NOAA NCEI (2018a))



As Figure 10 indicates, different geographic regions face differing levels of threat likelihood and risk from different types of severe natural hazards. Table 4 offers more detail, summarizing the infrastructure exposure of different U.S. regions to current and future (projected to the year 2100) natural hazards. While this table reviews all dominant infrastructures (not just electricity and fuels), all of the hazards listed can do grave damage to power system infrastructures.[53]

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[50] The U.S. National Oceanic and Atmospheric Administration's (NOAA) NCEI (2018a).

[51] NOAA's National Center for Environmental Information (NCEI) does not provide a clear definition of "extreme weather" but refers frequently to "weather disasters" such as firestorms, torrential rains, flooding and hurricanes. See, for instance, https://www.ncdc.noaa.gov/monitoring-content/billions/docs/lott-and-ross-2003.pdf. NOAA also refers to "severe weather," defined as, "a destructive storm or weather" such as "thunderstorms, hail storms and tornadoes, … and more widespread events as such as tropical systems, blizzards, nor'easters, and derechos.") https://www.ncdc.noaa.gov/data-access/severe-weather)

[52] The DOE QER broadly uses "threat" and "hazard" as things that could disrupt or impact the system; a hazard is associated with natural events while a threat is associated with human-initiated action. A "vulnerability" is a point of weakness in the system that has higher susceptibility or probability of harm from adverse events. "Risk" is the combination of potential damage from the threat event happening times the likelihood that it happens. (Source: Finster, Phillips & Wallace (2016), at p. xiii.)

[53] Willis, Narayanan, et al. (2016), p. 18.

Figure 10 – Regional vulnerabilities to tornado and hurricane tracks, wildfires, earthquakes and coastal inundation

(Source: U.S. DOE QER (2015), p. 2-5)

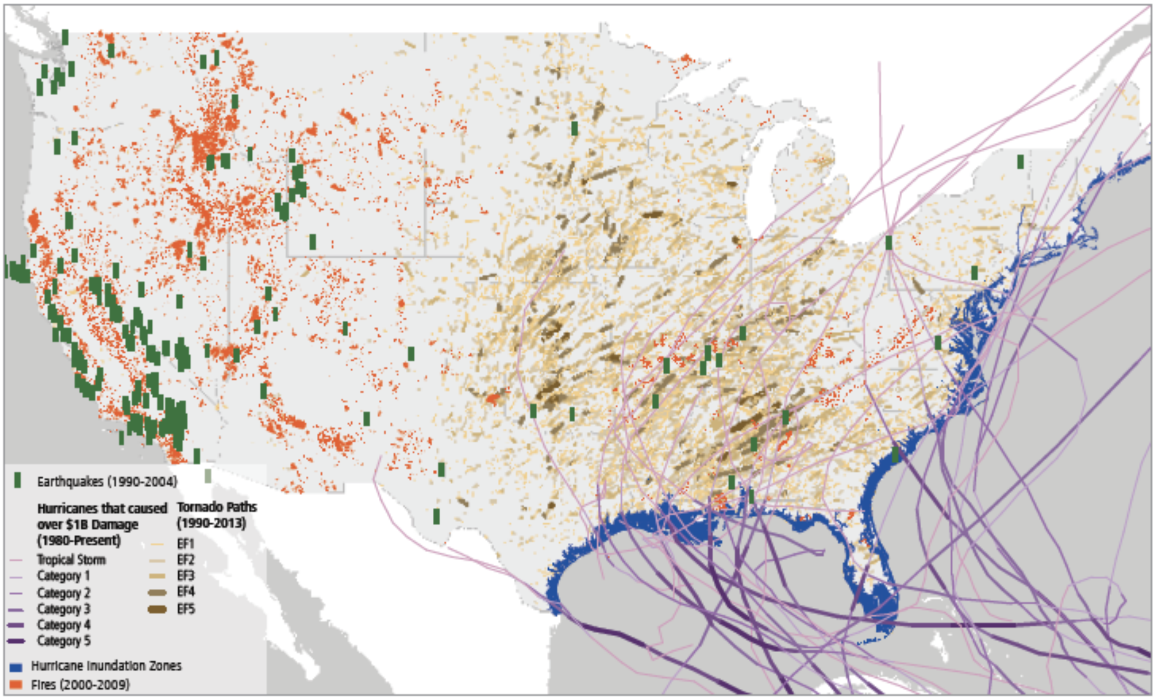


Table 4 – Current and potential (through the year 2100) weather hazards to critical physical infrastructures, by region

(Source: Willis, Narayanan et al. (2016) p.18)

Region	Predominant Infrastructure	Hazards Present	Potential for Climate Effects
California	All infrastructure sectors	Seismic, tidal flooding, riverine flooding, meteorological drought (dryness) and wildfire	Coastal flooding, drought, wildfire, and extreme temperature
Pacific Northwest	Electric power and transmission; river, interstate, and rail transportation; chemical; water	Seismic, tsunami, riverine flooding, ice storms, and meteorological drought (dryness)	Meteorological drought (dryness), wildfire and coastal flooding
Upper Mississippi River	Water, energy, transport, chemical, and nuclear	Riverine flooding, tornadoes, ice storms and meteorological drought (dryness)	Meteorological drought (dryness); exposed region extends into Illinois and Mississippi River
New Madrid Fault Zone	Rail, river, and interstate transport; power generation and transmission, gas and oil pipelines, and chemical	Seismic, ice storms, tornadoes, landslides, riverine flooding, meteorological drought (dryness), wildfires	Meteorological drought (dryness) and wildfire
Oklahoma	Interstates, rail, energy, chemical, and water	Ice storms, tornadoes, seismic, extreme temperature, riverine flooding, meteorological drought (dryness), and wildfire	Meteorological drought (dryness), wildfire and extreme temperature
Mid-Atlantic coast	Transport, electric power generation and transmission, nuclear power, pipelines, refineries, chemicals, dams, and water	Ice storms, hurricane winds, riverine flooding, tidal flooding, and storm surge	Coastal flooding

3.2 Extreme weather hazards are getting worse over time

Most grid-threatening natural hazards are increasing in both severity and frequency, and projections indicate that they will continue to get worse, as discussed below. Larsen et al. found that, "[r]eliability events are increasing and lasting longer – when major events are included in the performance metric calculation. …[T]he frequency and duration of reliability events has increased ~2% and ~8%, respectively, each year since 2000.[54] The LaCommare team reports that the number of customer outage minutes has been increasing significantly over time due to more severe weather events. [55]

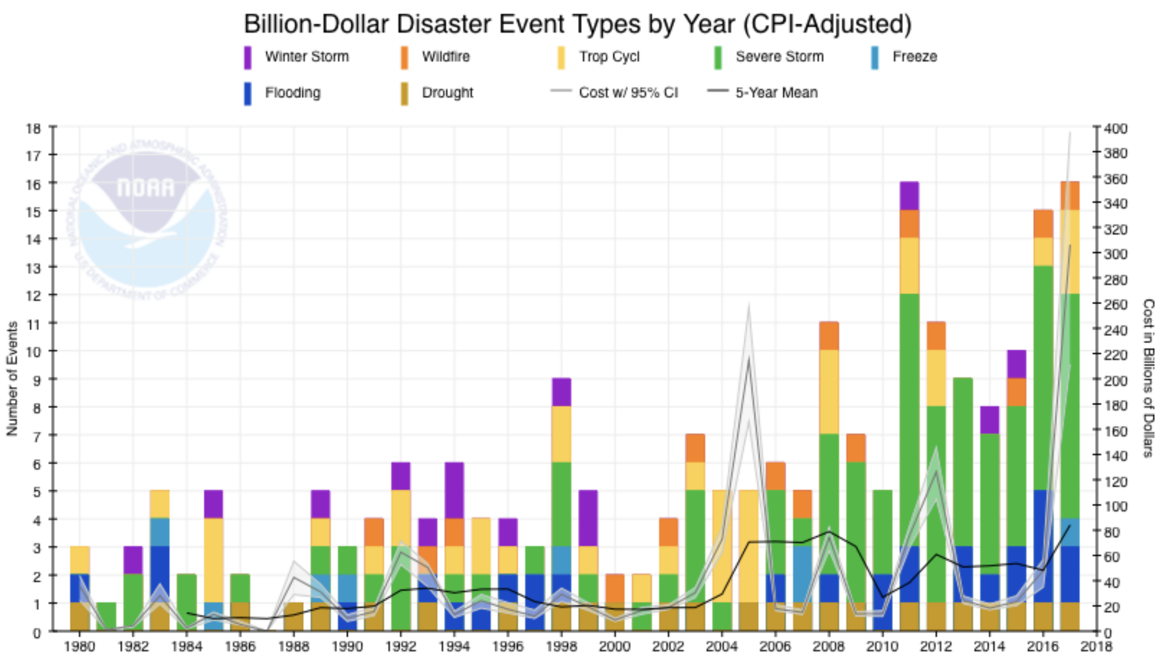
NOAA records show how the frequency, severity and societal cost impact of extreme weather events across the United States are increasing over the past four decades. Figure 11 shows that the frequency

[54] Larsen, Sweeney et al. (2014), p. 29.

[55] LaCommare, Larsen & Eto (2015).

and cost (inflation-adjusted) of severe, high-cost weather events has increased markedly over time, with a particularly noticeable growth in severe storms, flooding, and wildfires.[56]

Figure 11 – Major disaster events in the United States are getting worse over time
(Source: U.S. NOAA NCEI (2018a))



These extreme weather events can cause major power system failures, and all are expected to continue increasing in frequency and magnitude. The *2017 National Climate Assessment* projects that due to global warming, the U.S. will see increasing frequency and intensity of extreme heat and heavy precipitation events, including floods, droughts and severe storms. It also projects more large forest fires across the western U.S. and Alaska due to the warming climate and changes in ecosystems.

> Heatwaves have become more frequent in the United States since the 1960s, while extreme cold temperatures and cold waves are less frequent. Recent record-setting hot years are projected to become common in the near future for the United States, as annual temperatures continue to rise. … [O]ver the next few decades (2021-2050), annual average temperatures are expected to rise by about 2.5°F for the United States, relative to the recent past (average for 1976-2005), under all plausible future climate scenarios.[57]

Global mean sea level rise – already up 7 to 8 inches since 1900 -- is very likely to rise another 6 to 14 inches by 2050 (higher in the U.S. Northeast and western Gulf of Mexico, lower in the Pacific Northwest and Alaska).[58] A new report from the National Oceanic and Atmospheric Administration warns that expected high tide flooding events will increase significantly – <u>as much as every other day</u> by the year

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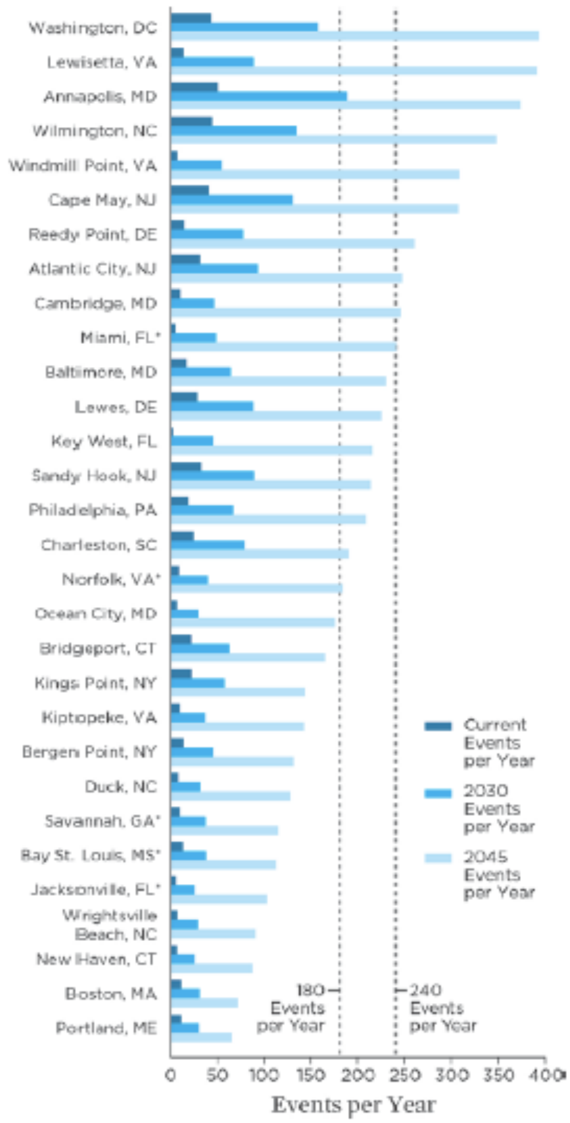
[56] U.S. NOAA NCEI (2018a).
[57] Wuebbles, Fahey, Hibbard, <u>et al</u>. (2017), pp. 12-34.
[58] U.S. NOAA NCEI (2018a).

2100 – within the Northeast and Southeast Atlantic, the Eastern and Western Gulf coast, and the Pacific Islands;[59] storm flooding will be commensurately worse in terms of magnitude and frequency. Hurricane Sandy and other recent events have shown the vulnerability of power system assets, like substations, to coastal flooding. Substations and power plants serving over a quarter of the U.S. population are located in coastal areas that are highly vulnerable to storm- and wind-associated tidal flooding. Figure 12 shows a dramatic increase in the number of current and projected tidal flooding events in many coastal cities between now and 2045.[60]

Figure 12 – Tidal flooding events by city today, and projected to 2030 and 2045

(Source: McNamara et al. (2015))



A new study of freshwater flooding risk in the U.S. found that the risk of flooding has been underestimated, because the Federal Emergency Management Agency's (FEMA) flood zone maps are based on old maps of varying quality. This new study uses more up to date spatial and data analysis

59 U.S. NOAA (2018).

60 McNamara et al. (2015).

techniques and population data and concludes that 41 million Americans are exposed to severe rainfall-based flooding risk -- 2.6 to 3.1 times higher than the numbers based on the FEMA maps. The study notes that this reflects recent weather conditions and does not account for the increased rainfall and flooding projected due to climate change-exacerbated extreme weather. [61]

Climate change is altering the probability and impact severity of many bulk power system hazards. It will require changes to electric reliability and resilience planning tools and measures. Today, few utilities are designing their current or hardened transmission and distribution poles and wires for more extensive and severe flooding, higher winds, more extensive ice storms, or longer, hotter heat waves and forest fires. Current electricity demand models are just beginning to adjust to the continuing rise in peak temperatures and loads and may not be forecasting those accurately if severe heat and drought patterns occur as projected. All of these events will increase the risks and threats to utility field crews and to electricity end-users and increase the costs and consequences of power outages to individuals and society as a whole.

3.3 Physical security attacks to the grid are a continuing threat

Figure 13 shows the sequence of actual outages caused by intentional acts against physical assets, including theft, vandalism and attacks, on domestic bulk power system assets over the period October 2013 through September 2014. Events such as these are not widely publicized, but they do not appear to be slowing down. ICF reports that many of these specific incidents caused relatively minimal damage and outages, but that does not mean that better informed, more motivated malicious attackers could not produce more consequential damages.[62]

[61] Schlesinger (2018), and Wing, Bates et al. (2018).

[62] Many more physical attacks and grid vulnerabilities are described in the ICF report prepared for the DOE QER, "Electric Grid Security and Resilience: Establishing a Baseline for Adversarial Threats," at ICF (2016).

Figure 13 – Significant physical security incidents and outages, 2013-2014
(Source: U.S. DHS (2015), p. 15)

3.4 GMD, EMP and cyber HILF events

FERC and industry members are conducting analysis and planning to address HILF events such as geomagnetic disturbances (GMD), electromagnetic pulse (EMP)attacks, and large-scale cyber-attacks. These efforts include initiatives by FERC, NERC, the Electric Power Research Institute (EPRI), DOE and the U.S. Department of Homeland Security (DHS) to characterize and determine the potential impacts of GMD and EMP on electric infrastructure assets, extensive cyber-security research and reporting, and aggressive reliability standards adoption including evolving Critical Infrastructure Protection (CIP) Standards.[63]

Over the last century, several large geomagnetic storms have caused large-scale power system outages (mostly on power systems at higher latitudes due to their greater exposure to solar weather). Industry planners are well aware of the 1989 geomagnetic storm that triggered protective relays and collapsed Hydro-Quebec's transmission system, leaving six million people without power for nine hours, and the Carrington geomagnetic event in 1859, estimated to have been about three times stronger than the 1989 event. Even small GMD events have the potential to cause significant disruption to the U.S. power system. For example, the Tennessee Valley Authority (TVA) reports that:

> Although the TVA service area is relatively southerly, solar storms or geomagnetic disturbances (GMD) in 2000 and 2003 caused harmonics, leading to nuisance trips of 161-kV capacitor banks…. Since January 2015, there have been 10 GMD storms noted

[63] See, for instance, the list of FERC orders on cyber-security at FERC Cyber & Grid Security home page, DOE research initiatives at its Cyber Security for Critical Energy Infrastructure home page, and the NERC CIP standards at NERC (2018b).

as K5 through K8 events on the EPRI Sunburst system; the maximum GIC measured in 500-kV transformer neutrals at TVA has been less than 17 A. TVA's entire fleet of 500-kV transformers has been analyzed for GIC-caused VAR and thermal response.[64]

Work continues at EPRI, NERC, FERC, DHS and elsewhere to identify the appropriate technical and operational measures to address this hazard cost-effectively.

Electromagnetic pulse attacks can harm most electricity-using equipment, not just the power generation and delivery system. EMPs could be delivered by the detonation of a nuclear weapon at extremely high altitude above the United States and may be more difficult to protect against. Such an attack could only be launched by a small number of state actors with sophisticated nuclear weapons and intercontinental ballistic missile technology. As a result, responsibility for preparing for and deterring such an attack has been given to the U.S. military rather than NERC and FERC.

Cyber-security threats to the power system are also significant and increasing. A 2016 Idaho National Laboratory analysis reported that:

> The likelihood for cyber-attacks against utilities is increasing in frequency and severity of attacks. The 2015 Global State of Information Security Survey reported that power companies and utilities around the world expressed a six-fold increase in the number of detected cyber incidents over the previous year. The number of energy sector incidents reported to ICS-CERT is significant each year, with 79 incidents (the most reported incidents per sector) in 2014, and 46 incidents (the second most reported incidents per sector) in 2015.[65]

Since that report, the level and severity of publicly admitted cyber-attacks on power systems have increased markedly (or been more widely acknowledged). TVA illustrates the magnitude of the cyber challenge:

> In 2016, almost 14 billion events were visible against TVA operating technology, of which 491 million were classified as potential security events and more than 54,000 required additional actions. Responses include defense in depth, NERC CIP, NIST/FISMA, and NRC standards, continuous monitoring, security vulnerability scans, equipment review audits, assessments, participation in E-ISAC, and in-house and industry-wide incidence response drills.[66]

Experts have cause for alarm based on incidents including two malware campaigns against energy sector targets in 2013-14, the cyber-attack that took down the Ukrainian grid in 2015-16,[67] and recent reports that Russia-linked hackers are infiltrating the U.S. grid.[68] The Federal Bureau of Investigation (FBI) and DHS report that Russian hackers have used phishing and other techniques to download malicious code into the target systems, captured users' credentials for later malicious use, and created local accounts

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[64] Cemp & Grant (2018).
[65] Idaho National Laboratory (2016), p. 2.
[66] Cemp & Grant (2018).
[67] See, e.g., the SANS Institute (2016) and Dunietz (2017).
[68] U.S.-CERT Alert (2018).

for later system access.[69] These attacks have targeted business computing, IT networks, SCADA and control systems of power plants and other critical assets, which "could be manipulated to cause equipment failure or blackouts." [70]

At the same time, there are more ways for attackers to access and harm the power system. These rise from the proliferation of two-way communications linking and automating elements and actors across the power system, as well as the growth of accessible intelligent devices, Supervisory Control and Data Acquisition (SCADA) and industrial control systems running so many of the interconnected devices. Despite the use of cyber-security measures across much of the bulk power system, much of the energy system overall remains accessible and vulnerable to cyber-attack.[71]

DOE Secretary Rick Perry told a congressional subcommittee on March 15, 2018, that he's not confident the grid is secure from cyber-intrusions, which are "literally happening hundreds of thousands of times a day. … The warfare that goes on in the cyberspace is real, it's serious…."[72] Analysts report that China, Russia, North Korea and other nations "likely have the capability to shut down the U.S. power grid,"[73] potentially causing power outages across large portions of the grid for days or weeks.

Utilities and the government are exploring mutual cyber-assistance measures to protect against and respond to cyber-attack; it appears that the current level of cyber-security measures have been ineffective against the newly reported Russian intrusions. If a malicious cyber-attack successfully moves from intrusion to a formal effort to harm generators and cause blackouts, it could take some time for an industry-wide effort to rebuild the IT communication and controls networks. In such a case, customer-level measures such as energy efficiency and cyber-islanded distributed generation would help customers survive an extended outage.

3.5 Generation and fuel supply are not significant threats

As Section 2 showed, most outages and extended blackouts have been due to weather events harming the transmission and distribution systems, while generation failures have to date accounted for an extremely small share of customer outages. Going forward, utilities and grid operators will assess risks from various scenarios including those with continued retirements of traditional generating sources. As the ISOs and RTOs reported to FERC, most see no current, serious generation or fuel supply risks to bulk power system resilience in most U.S. regions. In the generation sector, since no single source or technology is essential, there are plenty of options to achieve reliability even as generators retire.

To assess generation and fuel security threats, it is important to distinguish system reliability or resilience from plant- or technology-specific reliability or resilience. Power systems utilize a portfolio of resources such that the loss of any one unit can be covered by activating others which are held in reserve. Thus no individual unit or technology is critical, and it is not meaningful to assign a level of "reliability" or "resilience" to a generating unit or a type of generating technology. Rather, all power systems perform system-wide analyses to make sure they have enough *aggregate* energy and reliability services. The metric of generation adequacy is the reserve margin. Reserve margins are set based on

[69] U.S.-CERT Alert (2018).
[70] St. John (2018).
[71] See, for instance, Campbell (2016) testimony.
[72] Ibid.
[73] Knake (2017).

the probability of outages from different causes including fuel availability. Resource adequacy mechanisms exist in both restructured and traditionally regulated areas; there is no aspect of resilience that changes resource adequacy standards and guidelines (although considerations of resilience cost-effectiveness, as discussed in Section 5 below, invite new discussion of resource adequacy levels).

There is little current basis for finding that generation supply -- as a generic issue -- is a serious threat to power system resilience. DOE's August 2017 Staff Report on grid reliability, drawing on NERC analysis, concluded that, "all regions have reserve margins above resource adequacy targets."[74] Four RTOs and ISOs reported to FERC that they do not have a generation supply (resource adequacy) or a resilience problem associated with their generation resources. (The other three RTOs and ISOs (CAISO, ISO-NE, and PJM) are discussed below).[75] Some regions have very little to no coal or nuclear power left and other resources provide needed energy and reliability services. All regions have some demand response capability and growing levels of distributed generation affecting some portion of real-time demand. And every region is improving its load and renewable generation forecasting capabilities, which enables more accurate generation scheduling and reduces the likelihood of real-time generation shortfalls due to forecast error rather than generation shortcomings.

Fuel security is normally assumed in resource adequacy and planning reserve margin calculations. However, as reliance on natural gas has increased, at least two RTOs (PJM and ISO-NE) have raised concerns about gas supply under periods of high gas usage or the loss of a large gas pipeline.[76] While it is helpful to assess fuel security under all potential circumstances, the experiences described below have revealed primarily market design flaws that have caused or exacerbated physical fuel supply problems.[77]

No single resource or technology is essential because all of the needed energy and reliability services can be provided by a wide range of technology combinations, including combinations that include no nuclear, no coal, no gas, or no renewable sources. Figure 14 below shows capabilities from various technologies to provide the three main types of essential reliability services defined by NERC.[78] An expanded version of the table in Appendix B includes textual explanations and hyperlinked citations for each cell. Each of these resources have capabilities to provide some of the needed services, but none

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[74] U.S. DOE (2017c).

[75] Submissions to FERC by SPP, NYISO, MISO, and ERCOT, March 9, 2018, FERC Docket No. AD18-7.

[76] Events such as the loss of a natural gas pipeline that can affect production from multiple power plants are called a "common failure mode." Other common failure modes that can compromise electric generation include railroad delivery problems for coal plants, extended heat and drought affecting plant cooling water, earthquake or storm surge damaging multiple substations, or a large hurricane shutting down multiple nuclear plants (under Nuclear Regulatory Commission rules), or a communications network failure.

[77] A recent report by the National Energy Technology Laboratory argues that coal plants demonstrated their resilience by operating at much higher levels of output during the Bomb Cyclone event than they did during the earlier part of December 2017. However, this higher level of utilization primarily indicates that coal plants had large amounts of idle capacity in the earlier December period because the coal generation was uneconomic relative to gas and other energy sources. The report also incorrectly alleges renewable energy output was low during the Bomb Cyclone event, even though grid operator data confirm it was well above average across the Northeast.

[78] Based on NERC (2016). Elements in this table reflect the capabilities of the most modern generation and automated demand response offerings commercially available today; not all of the equipment currently deployed across the grid are able to provide these reliability services on demand without controller, inverter or other modifications.

can cost-effectively provide all essential reliability services and none are unique in their ability to provide any one service.

Figure 14 – Reliability services by energy resource

(Assessments below reflect the most modern equipment capabilities being installed in the U.S. today particularly for inverter-connected resources; not all installed resources have the same capabilities)

Reliability Service	Wind	Solar PV	Demand Response	Battery Storage	Gas	Coal	Nuclear
Voltage support Key: Green is positive, yellow is medium, and red indicates that in most cases the resource does not provide that service.							
Reactive power and voltage control							
Voltage and frequency disturbance ride-through							
Frequency support Note: For the following reliability services, yellow means the resource can provide the service, but during many hours it may not be the most economic choice to do so.							
Fast frequency stabilization following a disturbance (through primary frequency response and inertial response)							
Ramping and balancing							
Frequency regulation							
Dispatchability / Flexibility / Ramping							
Peak energy, winter (color reflects risk of common mode unavailability reducing fleetwide output below accredited capacity value)							
Peak energy, summer (color reflects risk of common mode unavailability reducing fleetwide output below accredited capacity value)							

Since no resource or class of resources is uniquely capable of providing a specific reliability service, power systems can be run reliably if a particular generator or class of generators retire. One cannot assume, however, that any type of resource replacement or combination will provide all the services that are needed, so it is prudent to do scenario and engineering assessments of the options.

New England region

Among the RTO/ISO comments, ISO-NE raises the most significant fuel-security concerns. The grid operator is concerned about supply adequacy in coming years during winter peaks with extended extreme cold weather events, when natural gas has import constraints and competing uses within the region.

ISO-New England has performed a series of post-hoc analyses, mostly focusing on its increasing gas dependence and constrained gas delivery system.[79] ISO New England's review of the "Bomb Cyclone" event in the winter of 2017-18 revealed that the power system was able to maintain reliability despite

[79] ISO New England (2018d), van Welie (2018).

two weeks of sustained extreme cold and long-standing gas pipeline constraints, largely because dual-fuel generators were able to switch to oil and LNG when spot gas prices spiked. ISO-NE's event analyses found market design flaws – in particular, that it was rewarding generators with capacity payments that did not incent or assure that the generators would perform when needed -- but did not find major fuel supply shortages given LNG availability. The report noted that some units began to run low on oil supplies due to the unusually long duration of the event and weather-related challenges in delivering oil.

Exelon, the owner of several natural gas-fired power plants in New England, recently indicated its desire to shut down four units. Decisions on retirements need to be made in the near term. In response, ISO-New England has used its existing reliability analysis processes to determine that it should designate two units (1,600 MW) of the natural gas-fired Mystic Power Station for Reliability Agreements, saying the units' retirement could put electric reliability at risk.[80] The grid operator fears that retirement of these two units could pose, "an unacceptable fuel security risk to the region during the winter months," when natural gas is diverted from electric generation to home heating.

ISO-NE also performed a study of long-term fuel security. This analysis tested alternative resource portfolios against a variety of grid threats.[81] It concluded that the region's growing dependence on natural gas-fueled generation, without additional pipeline or LNG delivery capability, could pose a threat to system reliability and resilience under extreme cold weather and storm conditions in the year 2025. The ISO-NE study was recently updated with a base case that incorporates updated assumptions and it shows more portfolios with no lost load even with high levels of renewables, natural gas, and energy efficiency.[82] Several scenarios that included high levels of renewables are projected to deliver high reliability and some with and without renewables were reliable with high retirements. The study also found that LNG was a viable option for gas supply if appropriate contracting terms are resolved.

Studies and corrections of New England's fuel supply and generation reliability issues are continuing in the ISO-NE stakeholder process. Despite the threat of additional power plant retirements, these studies may find several alternative ways to address these challenges effectively with a variety of resource portfolios.

PJM region

PJM's concerns reflect the stressed conditions experienced in the 2014 "Polar Vortex" event and the winter 2017-18 "Bomb Cyclone." But in PJM's report on the January 2018 Bomb Cyclone, the RTO concluded that, "the PJM footprint is diverse and strong and remains reliable," and, "even during peak demand, PJM had excess reserves and capacity."[83] PJM's 2017 reliability report found that a number of scenarios with greatly reduced coal and nuclear capacity should remain reliable and resilient.[84]

During the Polar Vortex event of 2014, PJM's generation reserves were low, but its ultimate operational problem was not total supply nor access to fuel, but rather an unusually large number of generation failures. PJM CEO Andrew Ott stated, "even at the height of the Polar Vortex, we were not facing imminent blackouts. However, the performance of the generation fleet was not where it needed to be

[80] ISO-NE (2018c).
[81] ISO-NE (2018a).
[82] ISO-NE (2018e).
[83] PJM (2018), p. 1.
[84] PJM (2017).

at that time to meet system conditions. We saw a significant number of plant outages across the board from generation of all types."[85] At its peak, 40,200 MW of PJM's generation capacity was unable to operate, or 20% of the total capacity on the system.[86] These outages were largely attributed to the market design flaw of paying for capacity that did not actually deliver energy when needed.

After that event, PJM made several rule changes including a "Capacity Performance" requirement, which collectively have improved supply performance. In the December 2017-January 2018 Bomb Cyclone, PJM reported outages of only 22,906 MW, or 11% of total capacity. Thus, the improved incentives for plant operation cut generation operational outages almost in half.[87] Table 5 compares the performance of PJM generation for the 2014 Polar Vortex and 2018 Bomb Cyclone events in terms of outage rates per generation type for each event. It shows how much outage rates have improved, as well as the outage rate differences between fuel types.

Table 5 – Comparison of PJM generation forced outage rates by resource type during Polar Vortex and Bomb Cyclone

(Source: PJM (2018), Figs. 13 & 14)

	Polar Vortex January 7, 2014	**Bomb Cyclone January 2018**	
Generation type	**Outage rate %**	**Outage rate %, January 3**	**Outage rate %, January 7**
Natural gas	35.5%	8.1%	20.7%
Coal	18.1%	12.4%	10.7%
Other	13.9%	5.0%	5.5%
Total	**22.0%**	**8.8%**	**12.9%**

Looking forward, PJM has assessed fuel security through a study of resource portfolio options. While the report found some scenarios that did not provide all of the energy and reliability services needed, many portfolios did. A number of portfolios that were very reliable and resilient had significant retirements of coal and nuclear plants. Some of the most reliable had very high natural gas penetrations, or very high renewable penetration -- dozens of times higher than current levels[88] -- or various fuel and technology combinations. The report concluded that, "PJM could maintain reliability with unprecedented levels of wind and solar resources, assuming a portfolio of other resources that provides a sufficient amount of reliability services."[89]

In evaluating resilience of possible future portfolios, it is important to use updated information about renewable and distributed resources. The PJM study was focused on historical performance rather than current and future capability, so it under-estimated the reliability contributions of renewable sources in several ways. For example, because PJM's assessment of reactive power contribution is based on historical data, it does not account for the increased reactive capability required of new wind and solar plants under a 2016 FERC order. Similarly, the study notes that renewable resources are seldom called

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[85] Ott (2018), p. 3.
[86] Ibid., p. 4.
[87] Ott (2018), p. 5.
[88] The numbers reported in the study are "unforced capacity," so nameplate capacity is much higher than shown.
[89] PJM (2017), p. 5.

on to provide frequency regulation today, though renewables have excellent capability to regulate frequency and are expected to increasingly provide this service as their penetration increases.[90] Overall, policy makers and the industry can use forward-looking portfolio analyses of energy and reliability service requirements under different stressors to understand supply system resilience needs and how to meet them in a variety of cost-effective ways.

California region

The California ISO studied resource portfolios and found scenarios that, "showed potential shortfalls in load-following and reserves, with capacity insufficiencies occurring in the early evening after sunset, based on 1,000-2,000 MW of retirements in the latest sensitivity analyses."[91] CAISO is working on a set of market design changes to encourage energy and ramping resources at these times. CAISO emphasizes this issue is being studied for reliability and there is not a need for a separate resilience guideline or standard.

3.6 Conclusions about power system threats

The power system faces a wide variety of natural hazards and intentional threats. Natural hazards such as hurricanes and ice storms cause extensive and costly damage to electric distribution and transmission in particular, causing multi-day outages for large numbers of customers. The number and magnitude of storm and other major natural hazards have increased significantly over the past fifteen years, so these are high impact threats that are becoming more probable in the years ahead.

The power system can also be harmed by geomagnetic disturbances from solar weather and electromagnetic pulses, and by cyber and physical attack. In contrast to weather hazards that physically break great swathes of power system equipment, these events could shut equipment down without extensive physical damage (although extreme levels of electromagnetic or clever cyber-attacks could physically harm some individual assets). It is difficult to estimate the probabilities of these various threats.

On the other hand, concerns about the importance of the outage threats from physical generation and generic threat of fuel supply problems are misplaced. No single unit or type of generation is critical in itself, and the combination of a generation fleet and robust transmission system, in combination with customer-side demand response and distributed generation, generally offset the outage risk from losing individual plants or fuel sources. The recent experiences of PJM and ISO-NE suggest that much of their winter supply event problems stemmed from inappropriate definitions of and requirements for capacity products, which did not incent needed resources to be available when actually needed.

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[90] Xcel Energy already uses wind plants to provide frequency regulation service (per Milligan et al (2015)) and CAISO has found solar plants can do so as well (per CAISO, NREL, First Solar).

[91] CAISO (2018), page 36.

Section 4 | Reviewing and Selecting Resilience Protections

Previous sections have established that most customer outages originate from failures on the low-voltage electricity distribution system, which is regulated by state public utility commissions rather than FERC. Since FERC's statutory responsibility is the bulk power system (BPS), in its January 2018 Order the agency appropriately directed its assessment and questions to exploring the events that threaten BPS reliability and resilience, what attributes of the system contribute to resilience, and how should we prepare for and mitigate those threats.

But the whole point of operating a power system is to serve end-use customers, and the point of a reliable, resilient power system is to preserve service and minimize outages to those customers. Therefore it is necessary to look at the entire power system and all of its components, from generators and transmission through distribution, customers and their distributed generation and energy uses, to properly evaluate the risks to reliable, resilient power delivery. The same end-to-end power system perspective is needed to evaluate the effectiveness and cost-effectiveness of proposed solutions to electric resilience. Section 2 established that most outages and customer outage-minutes occur due to failures of the distribution system rather than to generation, and that most of those outages are due to bad weather. Section 3 reviewed the range of power system threats and showed that the weather, cyber and physical threats have been increasing and these trends are projected to continue.

This section looks at the measures that power system actors are using to address reliability and resilience in the customer, distribution system, transmission system, and generation supply levels. Many of the measures that can best improve reliability and resilience for end-use customers lie far outside FERC's jurisdiction over the bulk power system.

4.1 Many measures improve resilience

A wide array of measures and practices are valuable for reducing the risk of power interruptions for end-use customers, and for speeding service restoration and diminishing customer and societal harm after an outage occurs. Table 6 shows the Argonne National Lab's description and summary of the primary types of resilience measures for the power grid. This table omits important cyber-security measures (hardening and prevention) and the many measures that can be implemented at the end-use customer level (energy efficiency, back-up generation, and distributed renewables and storage). It also omits measures that could protect against GMD and EMP (although the effectiveness of such measures is not yet fully understood).

Table 6 – Electric utility resilience measures and options
(Source: Argonne National Lab (2016), Table E2)

Table E.2 Electric Utility Resilience Enhancement Options

Resilience Enhancement Options	Definition	Example
Hardening	Physical changes that improve the durability and stability of specific pieces of infrastructure	Raising and sealing water-sensitive equipment
Security measures	Measures that detect and deter intrusions, attacks, and/or the effects of manmade disasters	In-depth security checks on all employees, badged entry and limited access areas, and surveillance and monitoring
Maintenance and general readiness	Routine efforts to minimize or prevent outages	Vegetation management and regular inspection and replacement of worn-out components
Modernization, control enhancements, and smart-grid technology	Technology and materials enhancements to create a more flexible and efficient grid	Integration of smart-grid technologies, such as smart meters and phasor measurement units
Diversified and integrated grid	Transitioning of the grid from a centralized system to a decentralized generation and distribution system	Integration of distributed generation sources, such as renewable energy sources and establishment of microgrids
Redundancy, backup equipment, and inventory management	Measures to prepare for potential disruptions to service	Maintenance of spare equipment inventory, priority agreements with suppliers, and maintenance of a supply of backup generators
Mutual aid programs	Agreements that encourage entities to plan ahead and put in place mechanisms to acquire emergency assistance during or after a disaster	Agreements between utilities to send aid or support after a disaster
Succession training, knowledge transfer, and workforce development	Planning for transfer of knowledge and skills from a large retiring workforce, to a smaller, younger workforce	Proactive efforts to create training and cross-training programs and succession plans
Business continuity and emergency action planning	A formal plan that addresses actions and procedures to maintain operations preceding an event	Components including employee awareness, training, and exercising
Models	Mathematical constructs that provide information on performance and/or disruptions to aide in decisionmaking	Probabilistic risk models to assist in predicting outage impacts after an event

Some of these resilience activities are performed by asset owners and customers, others by reliability coordinators. Other activities are cross-cutting, with responsibility for matters such as emergency planning and drills, cyber-security and physical security standards, and coordination and learning efforts (such as the Electricity Information Sharing and Analysis Center (ES-ISAC), North American Transmission Forum, and EPRI) shared across many actors. Some resilience measures are regulated at the federal or state level, but many customer options are unregulated.

4.2 Customer reliability and resilience options

Any outage that harms the grid affects customers. Customers have a variety of ways to prepare for the effects of outages, but their ability to do so depends keenly on whether they can afford to make outage mitigation investments or must wait and bear the outage and its costs (to business, health, possessions and convenience) with little or no protection.

Before Hurricane Sandy in 2012, few customers had backup generation or energy storage systems. Years ago, Carnegie Mellon estimated that there were about 12 million backup generators in the U.S. with over 200 GW of generating capacity;[92] another estimate placed about 1,320 MW of backup capacity in New York City and another 500 MW in Long Island, intended to operate only when the grid failed.[93]

Since the multi-week outages following Hurricane Sandy and subsequent hurricanes, many people have come to expect HILF weather events as quasi-routine and unavoidable. These recurring extreme weather disasters have motivated many customers to rethink the costs and benefits of storm survivability, including both waterproofing (as by relocating key equipment to higher levels) and developing backup power supplies. More and more customers have been taking independent action to improve their ability to survive extended outages comfortably. A few examples:

- After "two hurricanes in two years," a condominium complex built in the Chelsea section of New York City in 2014 includes, "a 'waterproof concrete superstructure' from the basement to the second floor that has 13-foot floodgates; waterproofed rooms with submarine-style doors to protect mechanical and electrical systems and a generator and a pumping system run on natural gas."[94] Many Class A office buildings have backup generation.[95]
- Eighty percent of national critical infrastructure (as identified by the Department of Homeland Security) have an outage mitigation system in place, including alternate generation or back-up power supplies. Most critical banking and hospital facilities have alternative or backup power. Of the facilities with internal backup generation, all can meet between 40% to 100% of peak facility demand, including wastewater treatment plants and electric generators.[96]
- New York State is funding $12 million for installation of permanent emergency generators at retail gas stations across down-state New York to ensure that they can function after major storms and emergencies.[97]
- After Hurricane Sandy in 2011, residential customers nationwide began buying home generators, leading to sustained growth in both portable and permanent generator sales. Manufacturer Generac Holdings estimated in 2012 that only 1.25 million homes already had permanent generators, with a potential market of 50 million homes. [98]
- Tesla and National Grid recently won a $1.25 million grant from the Massachusetts Clean Energy Center to install Powerwall batteries in 500 homes on the island of Nantucket.[99]
- System recovery effort installations and proposals for Puerto Rico include installation of distributed battery systems (as at hospitals), possibly microgrids at customer sites such as water and wastewater treatment plants, and more distributed solar PV.[100]

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[92] Zheng (undated).
[93] Gilmore & Lave (undated).
[94] Satow (2013).
[95] Leighton (2013).
[96] Phillips (2016), p. xi.
[97] New York State press release (2016).
[98] Tita (2012), on Generac's pre-PV maturity market opportunity estimate. See also DOE's guidance on backup generator selection for homeowners to deal with power outages, at https://www.energy.gov/oe/community-guidelines-energy-emergencies/using-backup-generators-choosing-right-backup-generator-0.
[99] Chesto (2018).
[100] Walton (2017) and NYPA (2017).

- The U.S. Department of Defense has been installing extensive solar PV on many military bases and a growing number of microgrids on bases to assure resilient power in the event of an attack or failure of the local grid.[101]
- Companies like Sonnen and Tesla are selling residential battery storage systems for islanded backup power, solar-tied storage and off-grid uses.

Each example above represents a significant investment of time and money that customers believe is necessary to reduce the risk of personal and property harm from increases in real and threatened outages.[102]

Customer energy efficiency is also valuable to enhance individual and community outage survivability and recovery. Energy-efficient buildings and high-performance appliances (particularly refrigerators) let customers shelter in place longer and help vulnerable populations (like the poor, sick and elderly) protect their food and medicines longer. High-performance building shells can make an extended blackout in extreme heat or cold conditions more survivable, and uncomfortable rather than life-threatening. [103]

Customers of all types also invest in insurance and in site-specific protection measures including emergency supplies (lighting, uninterruptible power supplies for phones and computers, food, and security) and emergency shut-down procedures for key business and industrial processes. Customers with older solar PV systems are beginning to replace old non-islanding inverters (that shut off PV production when the grid shut down) with new smart islanding inverters that can provide power to the host site when the grid is blacked out.

Many communities are investing in similar strategies, trying to storm-proof and protect critical community assets to improve their ability to provide continuing critical services and shelter for their residents if a disaster occurs.

Current Value of Lost Load studies do not recognize and reflect the full cost of the various measures that customers undertake, as personal resilience efforts, to make expected outages more bearable.

While high-income, critical use and governmental end-users can afford more reliability and resilience protections (whether self-funded, tax-funded, or otherwise subsidized), many customers have no option but to suffer through an outage. As discussed previously, the costs of a lengthy outage can be very high. Insurance (and sometime litigation) may compensate for some of those costs.

In the specific case of system-wide generation shortfalls or localized shortfalls caused by a loss of transmission infrastructure, utilities implement rolling outages (also called rotating blackouts) – controlled, temporary interruptions of electric service that are moved from feeder to feeder, neighborhood to neighborhood sequentially to drop enough load to avoid a cascading outage. These outages are generally assigned to feeders that serve residential and small businesses and exclude those feeders that serve critical need customers such as hospitals and emergency services.

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[101] See, e.g., Gardner (2017), Navigant (2017), Castillo, Johnston (2017).
[102] See Ribeiro, Mackres et al. (2015).
[103] See Leigh, Kleinberg, et al., (2014).

Consider again the generation-based reliability target, "1 in 10 Loss of Load Probability" – the idea that the power system should have sufficient generation and reserves that there should be less than one event over a ten-year period when there is insufficient generation to meet load. This criterion was developed in an age when the grid had relatively inflexible supply and demand, utilities couldn't protect specific feeders, and customers had few backup power options. But today, many customers have ways to self-provide resilience, including generation behind the meter; customers can offer demand response as a supply option for greater flexibility; and utilities can manage the grid to protect critical care customers – so there is little rationale for placing all the reliability burden on generation alone. Customers who value reliability highly are the most likely to have taken those steps, so the value of lost load for the remaining customers who would be affected by an outage may be lower than previous estimates. With so many flexibility factors available today, it is time to reexamine whether the 1 in 10 LOLP remains justifiable, and whether the funds used to provide the last increments of generation for a "1 in 10 LOLP" goal might be better spent on other reliability and resilience measures.

4.3 Distribution-level reliability and resilience options

Since the predominant cause of outages and customer outage-minutes occurs from distribution-level events and damages, state regulators need to think about how distribution systems can be made more resilient. This is even more pressing given the implications of long-term extreme weather trends and sea level rise for the customers and assets at risk.[104]

Distribution system resilience options (subject to regionally appropriate threats) include:

- Component upgrades, hardening and adaptation
    - Reinforced concrete towers in wind-threatened regions
    - Line coatings to prevent ice build-up in ice storm-threatened regions
    - Locating or moving substations away from flood-threatened locations
    - Dead-end structures to keep them upright and prevent sequential (domino) collapse
    - Additional circuits and loops to avoid impacts from the loss of a radial connection, and make critical facilities less critical
    - Selective undergrounding of critical lines
- Vegetation management
- Training and exercises to practice responses to credible threats
- Energy efficiency programs (better building shells, better refrigerators) to reduce loads and help customers survive long-term outages
- Use of distributed generation and storage to reduce dependence on particularly vulnerable lines and protect critical customers and loads
- Distribution planning, construction and hardening (based on what is appropriate for the regional risk factors and the system design, e.g. don't underground distribution infrastructure in areas with high or growing sea level rise and flooding risk and lower weather risk to above-ground infrastructure)
- Grid modernization, T&D automation and smart meters, to collect grid condition quickly and analyze and act on it more quickly, precisely and effectively
- O&M spending for T&D, including preventive and condition-based maintenance and vegetation management

[104] See Keogh & Cody (2013).

- Spare equipment programs such as Spare Transformer Equipment Program[105] and Grid Assurance[106]
- Mutual assistance alliances with other utilities[107]
- Outage management system
- Priority or critical customer lists to limit the scope of rolling blackouts and prioritize system restoration
- Expanded weather forecasting and modeling using a wide network of utility-owned weather stations[108]
- Use of demand response, automated load-shedding and interruptible rates for fast frequency response and capacity provision.

Most of these measures are standard practice for distribution utilities and should qualify for regulated cost recovery as rate-based capital or O&M expenditures.

In one example of how a distribution utility is addressing a growing grid hazard, PG&E recently announced a new plan to address wildfires and other climate-driven extreme weather, which California now views as "the new normal." PG&E's new plan includes wildfire prevention measures including monitoring wildfire risks, coordinating response efforts with first responders, and increasing utility firefighting resources. New safety measures include, "new standards to keep trees away from power lines, refining protocols for proactively turning off electric power lines [at times of imminent fire risk] and expanding PG&E's practice of disabling line reclosers and circuit breakers in high fire-risk areas during fire season."[109] Grid hardening efforts will include grid modernization and more community microgrids for islanded operation after a disaster. Given the threat of litigation over wildfire damages, PG&E is asking California legislators and regulators for "clearer standards for work it must complete to mitigate the possibility of fires and avoid negligent behavior."[110]

4.4 Transmission-level reliability and resilience options

Customer outages from transmission system problems are rare, but when they occur they tend to be widespread and can be long-lasting. Reliability and resilience are supported through planned redundancy such that the loss of one line or piece of equipment, however large, does not cause loss of load. Another strategy is building in a cushion for extreme situations in the form of emergency ratings which allow more power to flow over assets for a short period of time in the event of a disturbance. Grid operators schedule line maintenance with reliability considerations in mind.

Resilience planning for transmission should consider a range of plausible threats with near-simultaneous outages across many elements of the system. The primary goal of such planning should not be to prevent any loss of load, which for many HILF events is not achievable at a reasonable cost, but rather minimizing the extent of any disruptions and quickly restoring any outages. PG&E's plan to reduce equipment damage and facilitate firefighting with strategic cuts to customer loads is an example of this approach.

[105] See EEI (undated).
[106] See AEP (2016).
[107] See EEI (2016).
[108] Walton (2018).
[109] Ibid.
[110] Luna (2018).

TVA has created a matrix of threats to its transmission system and identified solutions to harden against, detect, and recover from each.[111] TVA has implemented those solutions, including procuring spare equipment and mobile transformers that enable the utility to respond to many different hazards and events.

System planning

A first step to planning is the scenario assessment process. For example, MISO's annual process "evaluates approximately 6,500 extreme events impacting loss of multiple facilities on the transmission grid."[112] MISO's extreme event analysis includes reviewing the following potential bulk power system outcomes that could result from a variety of threats:

- Loss of all circuits on a multi-circuit right-of-way
- Loss of three or more circuits on a common transmission tower
- Loss of all facilities at a switching station or a load service substation
- Loss of all generating units at a multiple unit generating station
- Loss of all generating units at two independent generating stations
- Loss of gas pipeline segments and all generation served by the pipeline.[113]

A reliability and resilience review examines such bulk power asset losses for their impact on a number of operational parameters, such as these listed by PJM:

> [T]ransmission design (robust and electrically dense versus sparse networks), proximity of generation to load centers, geographic dispersity of load and generation resources, margins on BES facility thermal and voltage limit loadings (i.e., the difference between normal flow and emergency capability), generator megawatt and megavar reserves, dynamic megavar reserves on transmission elements, level and availability of resource reliability attributes, the effectiveness of the system restoration plan including the proximity of Black Start Units to the next tier of Critical Restoration Units, the fuel security of both Black Start Units and Critical Restoration Units, and the redundancy of cranking paths used in restoration.[114]

Planning criteria should be reviewed with resilience in mind. The standard "n-1" criterion that guides protection against the largest single contingency may not be enough when multiple contingencies could happen at once, such as through an intentional attack. Thus "n-k" contingencies are being discussed in some regions. Considering multiple contingencies may require new analytical tools. Some planners are transitioning from deterministic planning based on several discrete scenarios to probabilistic analysis that examines a very large number of possible futures.

Transmission planners are also reviewing the types of contingencies considered in their studies. As some regions become more gas-dependent, planners are considering whether the loss of critical parts of fuel supply infrastructure (such as gas pipelines or coal-bearing railroads) should be treated as a single

[111] Clem & Grant (2018).
[112] MISO (2018), p. 4.
[113] MISO (2018), p. 18.
[114] PJM (2018b), p. 43. PJM is considering how and whether to incorporate resilience as a stand-alone driver of new transmission.

contingency or evaluated as a potential common mode failure (as opposed to treating every generator affected by the fuel supply as an independent asset). However, these fuel delivery contingencies develop more slowly than the instantaneous electrical contingencies that grid planners typically account for, providing operators with more options for addressing them in real-time. As a result, there is a argument that fuel contingencies should not be evaluated in the traditional n-1 electrical contingency planning and operating framework.

The standards that apply to Transmission Planners and Planning Coordinators may need review. NERC's "Transmission System Planning Performance Requirements" standard TPL-001-4 was intended to, "[e]stablish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies."[115] The standard provides guidance on assumptions and methods of planning studies. It does not include a requirement to mitigate load loss resulting from events classified as extreme events.[116] NERC and FERC should examine this and other reliability-based planning standards to ensure that mitigation of the consequences of extreme events are properly considered in transmission planning.

It is important to account for all of the values and benefits of a given set of facilities, since the system ends up being used for so many purposes.[117] MISO "uses its value-based planning approach to proactively identify infrastructure that is valuable under a number of long-term future scenarios."[118] Planners should account for uncertainty and attempt to identify "no regrets" infrastructure that is valuable across a range of possible events and scenarios. They should also include consideration of how demand-side resources such as demand response, energy storage, customer-owned generation and other non-wires, non-central generation options could be used to complement, mitigate or complicate bulk power system assets and scenarios.

Transmission operations

Once a system is planned and built, transmission operators need to operate the grid they have. Reliability is central to every operating action and system in place, including aggressive efforts to manage cyber-security.

MISO emphasizes inter-regional congestion management improvements that would support resilience.[119] Large regional RTOs and ISOs improve power flow compared to the balkanized system that preceded them, but there are still many seams issues between them, especially given some complex configurations between RTOs.

Better monitoring and control systems can improve reliability during extreme events by improving situational awareness and analytical support for operations. Grid monitoring is improving beyond SCADA, as reductions in the cost of synchrophasor technology enable better grid condition data collection and analysis. Improved measurement of power flows improves reliability by avoiding unintentional overloading of equipment, reduces costs by allowing higher utilization of equipment, and

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[115] NERC Transmission System Planning Performance Requirements, standard TPL-001-4.
[116] MISO (2018), p. 19.
[117] Pfeifenberger & Chang (2016).
[118] MISO (2018), pp. 15-16.
[119] MISO (2018), p. 45.

also benefits reliability and resiliency by increasing situational awareness. Such tools can also improve reliability and resilience by allowing better understanding and modeling of power system behavior. As MISO attests, "[s]ystem awareness tools such as synchrophasor information has been beneficial in understanding the dynamic and transient behavior of the bulk power system" with better modeling and performance analysis."[120] The lack of situational awareness has been a significant contributing factor in many real-world blackouts.[121]

Operators must also consider how to continue operating systems without real-time electronic communications, monitoring and control systems if those systems are knocked out by a disruption such as GMD. The North American Transmission Forum is working on this challenge.

Utilities and grid operators already practice many other activities to support reliability and resilience. Every region has emergency and crisis-management plans that include system restoration plans, disaster recovery plans, black-start plans, and other measures to ensure that they can recover from a significant event.[122] Many transmission owners have joined mutual assistance programs and spare equipment alliances for assets such as critical transformers.

Event simulation and training prepare human resources and systems for high-impact events and identify potential flaws and weaknesses for improvement. Many utilities participate in NERC's annual GridEx drills, which simulate cyber and physical threats to practice response and recovery plans and prepare communications protocols.[123] FERC and state commissions can assist by ensuring sufficient participation and execution of simulations and training programs.

4.5 Generation-level reliability and resilience options

As discussed in Section 3, there is not a demonstrated generation or fuel supply problem (other than in New England) requiring attention, and reliability standards already account for generator services needed by the system. It is important to recognize that reliability and resilience in the generation sector are system concepts, not a generator-specific or generation technology-specific concept. The system need, whether for routine disturbances such as a plant mechanical failure or a HILF event, is to ensure that under all circumstances sufficient generation and other resources are collectively available to serve load.

After events such as the 2011 freeze event in the Southwest and the 2014 Polar Vortex in PJM, NERC and generators took steps to improve performance in severe cold weather. Whether driven by markets or regulations, individual generators can act to increase the probability of producing electricity in times of system stress. Those measures include:

- Weatherization for extreme cold and extreme heat conditions
- Modifying cooling methods to use water more efficiently and avoid closure due to water scarcity (extreme drought) or over-warm cooling water (extreme heat)
- Develop better plant models and monitoring to better identify operational patterns and manage plant O&M fuel effectively

[120] Ibid., p.31.
[121] FERC and NERC (2012).
[122] See MISO (2018), p. 19.
[123] NERC (2017).

- Develop alternate fuel sources (including a potential back-up fuel source) and even firm fuel procurement to improve fuel assurance under system stress conditions
- Better staff training, drills and operating procedures (potentially including staff dependents as well) to assure workforce availability and protection under system stress conditions.

4.6 RTO, ISO and reliability coordinator reliability and resilience options

RTOs, ISOs and other reliability coordinators are using many measures to advance bulk power system resilience. At the operational level, such measures include:

- Improving wide-area situational awareness, as with better data collection inside and beyond the grid operator's formal boundaries and better data sources such as synchrophasor monitoring
- Gas-electric coordination and scheduling
- HILF event analysis, preparation and planning
- Emergency procedures and crisis management plans
- Emergency simulations and drills.

All of these functions, like other regional coordinator activities, are responsibilities that come with the job of grid management. These activities are funded ultimately by payments from end-use customers. These activities deliver substantive reliability and resilience benefits without requiring market subsidies or redesign.

Where reliability issues arise within a region, they tend to reflect a specific problem such as local voltage stability or an extended equipment outage, rather than a broad, generic problem. Often such issues can be handled using other assets and dispatch patterns. In regions with ISO- or RTO-operated markets, there are also short-term backstop mechanisms such as Reliability Must-Run Agreements for use in cases where individual generators may be needed for reliability for a season or two.

Resource adequacy

All regions except ERCOT have planning reserve margins -- long-term planning requirements to ensure that supply and demand resources equal or exceed forecast load plus a reserve margin. That is the principal tool to ensure reliability and resilience related to generation supply on the planning timescale. Some of the reserve margins are overseen by state regulators with vertically integrated utilities, some by state regulators with restructured markets, and some through federally enforced capacity obligations (PJM, NYISO, ISO-NE).

Common mode failures – a single problem that can affect multiple generators – are receiving increased attention. Recent common mode failures include the loss of a gas compressor station or pipeline, or the loss of multiple coal and nuclear generators due to frozen equipment or cooling water constraints. Until recently, the loss of any single generator has been considered to be statistically independent – but if multiple plants are subject to such a "common mode failure," this assumed independence overstates reliability. Common mode failures can be addressed through scenario analysis and by reducing the capacity credit given to generators according to their combined probability of being available.

Further fleet performance analysis is needed (in supply- and demand-side resources, fuels and capabilities as they affect ability to deliver energy and essential reliability service delivery when needed), with modeling and testing against many threat scenarios. Effective Load Carrying Capability calculations for renewable resources already account for correlations among different plants' outputs due to meteorological patterns, and similar methods could be employed for correlations in conventional resources' output.

Markets

The basic mechanisms of competitive centralized and bilateral electric markets are already doing a good job at delivering reliability. Well-designed markets have economic incentives that reward performance in providing needed services. The standard Security-Constrained Economic Dispatch (SCED) system accounts for transmission and generation constraints, and continuously re-dispatches generation to serve load at all times and places. The inherent flexibility in that system can address many disturbances automatically.

Well-designed markets will support reliability and resilience by attracting resources at the right time and place, over the short- and long-run. If prices are predictably high when scarce conditions occur, generators can be expected to purchase firm fuel supply, develop dual fuel supply capability where allowed, and improve plant weatherization. Well-designed markets include transparent prices for energy and reliability services at each time and place, with efficient optimization to sort resources into their best use, and with open participation from all resources that can potentially contribute.

Out-of-market payments such as Reliability Must-Run (RMR) agreements or cost-based compensation to specific units reduce market and price transparency. They do not attract the desired behavior from all potential sources of a service.[124] Rather, they pre-judge which resources are able to provide a service and pay only those resources without assuring that the needed service will be provided. RMR agreements are necessary only when there is a single source of supply such as for reactive power at a given location before transmission, load, or other generation options can serve a defined need. In regions that rely on markets, subsidizing a few resources for specific services prevents other sources from offering their services, thus reducing reliability and resilience. To partially address this problem, any RMR agreement should be bid out to see whether other suppliers can deliver the identified system need.

Generation diversity has been claimed as necessary to attain generation resilience, but it is an imprecise objective, only indirectly tied to reliability and resilience. Economics dictates the generation fleet's fuel mix, but well-designed markets allow each resource to play its best role, including storage and demand-side resources such as energy efficiency, distributed generation and demand response. Because no resource excels, either economically or technically, at providing all needed services at all times, the power system obtains needed services through a division of labor among different, pooled resources connected to a well-designed transmission grid. For example, coal and nuclear plants do not excel at providing many essential reliability services, such as flexibility, frequency regulation and response, and disturbance ride-through. We do not need every resource to provide every reliability service at all times – we only need aggregate supply from a portfolio of available resources.

Reliability products should be based on engineering needs. NERC recently defined the "Essential Reliability Services" (ERS) needed for system reliability. These ERS include frequency support, voltage support, and flexibility/ramping.[125] There is no obvious service for resilience that is not already covered

[124] Giberson (2017).
[125] NERC (2016).

by the wholesale power market energy and reliability services; market products should not be defined in terms of characteristics of supply such as “on-site fuel,” “baseload,” or “high capacity factor” because no technical justification exists for such products.

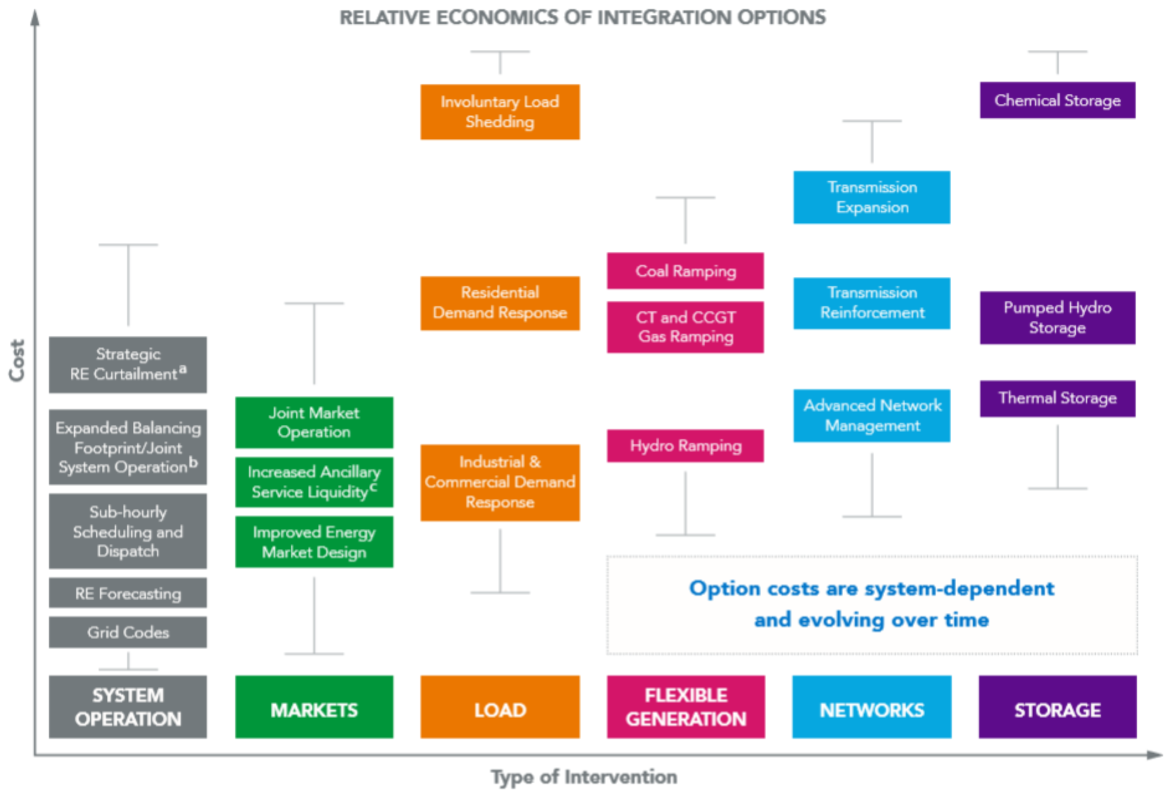
Markets should compensate delivered services and avoid or reduce compensation for “attributes” or “capacity.” Attributes are not the same as products or services. DOE Secretary Perry’s proposed rule defined a generator’s on-site fuel as an attribute to be compensated, arguing that, “[o]rganized markets do not necessarily pay generators for all the attributes that they provide to the grid, including resiliency.”[126] The proposed rule essentially defined on-site fuel as an end unto itself, rather than one potential means to providing customers with something of value, such as energy, frequency support, or voltage support. Supply characteristics may help some resources provide a service or product, but they are not the product or service per se. Compensating for raw capacity has been shown to lead to poor incentives to actually deliver services in New England and PJM, as explained in Section 3.5.

Markets will support reliability and resilience better if they compensate flexibility appropriately. Most power systems have increasing need for energy increases and decreases that can be delivered on short notice. NERC’s term “ramping/flexibility” is a suitable product definition describing these capabilities. The National Renewable Energy Laboratory (NREL) illustrated the flexibility/ramping options with its “flexibility supply curve” shown in Figure 15 below.[127, 128]

[126] U.S. DOE (2017b), p. 3.
[127] Cochran, et al. (2014), p. 11., and Milligan, Frew, Zhou et al. (2015).
[128] A new analysis from the Massachusetts Institute of Technology and Argonne National Laboratory suggests that it is both feasible and valuable for nuclear generators to operate in a more flexible and dynamic mode, to be more responsive to market and regulation needs. However, that paper does not estimate the capital costs of modifying the generator equipment and O&M costs needed to enable such operational flexibility, so it is not clear whether such changes are an economically realistic option. See Jenkins et al. (2018).

Figure 15 – NREL flexibility supply curve

(Source: Cochran et al. (2014))



A number of market design features reward flexibility, including:

- Transparent spot energy markets;
- Fast dispatch intervals, such as every 5 minutes;
- Regional market integration, to allow flexible resources in one area to serve a need in another area;
- Scarcity pricing to appropriately reward demand management and price-responsive demand;
- Co-optimized energy and operating reserves markets with an operating reserve demand curve;
- Markets for primary frequency response service, with a premium for fast and accurate response;
- Optimization and participation of Demand Management and other Distributed Energy Resources, either directly participating or indirectly through a Transmission-Distribution interface;
- Transparent prices with minimal side payments;
- Multi-settlement to provide predictability hours in advance of need.

Finally, markets best support reliability and resilience when they allow all sources to contribute, including distributed energy resources (DER) – distributed generation, demand response and distributed storage. These distributed resources can provide significant support to the reliability and resilience of the bulk power system (including through resource adequacy and speed of operation). Some systems (including California and Hawaii) have reached ten percent of resources behind the meter. Distributed storage systems in particular offer a great source of flexibility for grid operators, if they can be accessed and used in constructive ways. Access could be direct, through metering and control between the DER and the bulk power grid operator, or indirect, through a grid architecture that allows interaction at the transmission-distribution interface. Either way would harness the responsiveness of distributed resources to grow resource adequacy and help respond to any shortfall or imbalance on the bulk power system.[129]

Standards

Along with planning and market solutions, RTOs/ISOs and reliability coordinators use technical standards to support system reliability and resilience. These can generally be enforced through interconnection agreements or market rules and are most appropriate for system needs that cannot be effectively met through a market. Examples include:

- Disturbance ride-through capability standards;
- Frequency response capability standards;
- Reactive power requirements;
- SCADA connectivity;
- Providing high-resolution performance data for asset monitoring and model verification.

Interconnection requirements and standards should be applied in a non-discriminatory way across all bulk power system-connected generation sources.[130]

4.7 Conclusions

The resilience measures reviewed above are available to, and practiced by, actors at every level of the end-to-end power system. These measures include the wide array of activities and investments that utilities undertake to make their systems more reliable and resilient. They also cover a large and costly set of investments that customers make because they assume that utility efforts, no matter how well-intentioned and effective, cannot fully protect the customers from extended power outages.

The National Academies of Science electric system resilience study warns:

> In principle, an infinite amount of money could be spent hardening and upgrading the system with costs passed on to ratepayers or taken from shareholder returns. However, utilities and their regulators (or boards) are typically conservative in these investments. All mitigation strategies have cost-performance trade-offs, and it may be difficult to estimate the actual reduction in risk or improvement in resilience associated with a specific action. In most cases, an electricity system that is designed, constructed, and operated solely on the basis of economic efficiency to meet standard reliability criteria will not be sufficiently resilient. If some comprehensive quantitative metric of resilience

[129] Kristov (2017).

[130] In a violation of this principle, the voltage and frequency ride-through standards applied to wind generators under FERC Order 661A are more stringent than those for other generators. The ability of all resources to ride-through grid disturbances is critical for power system reliability and resilience, so if the Commission would like to address generation resilience it could expand the Order 661A standard to other generators.

becomes available, it should be combined with reliability metrics to select a socially optimal level of investment.

This warning points to the need to assess and prioritize among all power system resilience measures. Such prioritization should improve the system's collective reliability and resilience effectiveness subject to societal resource allocations, not just bulk power system costs and benefits. It should also promote an appropriate balance between funds spent to improve reliability and resilience at the distribution and customer level, versus those spent on generation and transmission. This is the topic of Section 5.

Section 5 | Evaluating and comparing resilience performance effectiveness and cost- effectiveness

Section 4 reviewed the wide set of tools and measures that customers, power system actors and policymakers can use to improve power system reliability and resilience and reduce the impacts of outages upon electricity consumers. Ideally customers' dollars would be allocated to the highest impact activities until incremental spending on any activity provides equal marginal benefit, as opposed to spending excessive resources in one area for little additional benefit while higher value actions are left unaddressed. The challenge is to evaluate the marginal impacts of these various solutions for reducing both the number of outages and the number of customer outage-minutes, such that each action makes a meaningful contribution to customer resilience. Federal and state regulators should ask how each solution (individually and in suites of solutions) might reduce the frequency, magnitude and duration of customer outages relative to the entire scope of customer outages, not just those resulting from generation- or transmission-level causes.[131]

As Sections 2 and 3 established, many outages happen – most arising from bad weather affecting distribution systems, and some noticeably large events arising from the combination of extreme events harming distribution, transmission and some generation assets. Customers ultimately pay the price for these outages, whether through their electric rates or their own personal losses and expenditures, and most customers have come to expect that more outages will happen. The question therefore arises, if we cannot prevent and mitigate all the hazards and threats that cause outages, and can mitigate some but not all of their consequences, which risks should we take, what level of resilience and mitigation cost are we willing to bear, and how should we choose between resilience measures? This paper cannot answer the risk question, but it does offer a path for assessing and selecting resilience options.

[131] All of the asset owners and policy makers with responsibility over the grid should be careful not to allow confirmation bias or the availability heuristic to narrow or constrain consideration of valid resilience-improving options that might help and protect customers and communities. Confirmation bias is the human tendency to favor information and options that lie within and confirm our existing knowledge and beliefs, and to ignore or dismiss ideas and options that lie outside our current knowledge and comfort range. The availability heuristic drives people to overestimate the importance of information that is available to them, and ignore the possibility that other, yet-unrecognized factors might be equally or more important. In the case of a federal regulator or NERC, confirmation bias and the availability heuristic might lead them to assume that because their scope of responsibility is bulk power system reliability: 1) they need to protect the system rather than the end-user; 2) the only outages that matter are those arising on the bulk power system; 3) the only resilience measures that matter are those relevant to the bulk power system; and, 4) the way to measure effectiveness is in terms of power system characteristics rather than customer and community impacts.

Since the vast majority of customer outages result from outages on the distribution system and to a lesser extent the transmission system, many effective and cost-effective ways to reduce outages and improve resilience start at the distribution and transmission levels. Grid managers cannot prevent lightning strikes or storms, but they can act to reduce the likelihood that a lightning strike or falling tree limbs can take out a transmission or distribution line. In contrast, generation supply shortages rarely cause customer outages, and when they do it is almost always due to an extreme weather event or operational failure that also affects the transmission and distribution systems. Because the marginal benefit for customers of protecting generation is quite low when reserve margins are healthy, generation-related solutions are typically not the most cost-effective means of reducing customer outages on power systems today.

Regulators and grid actors can find efficiencies by taking an all-hazards perspective, recognizing that most effective measures protect power system assets and processes rather than trying to mitigate against a specific threat. This approach eases the challenge of estimating the frequency and impact of specific HILF events with difficult-to-quantify probabilities of occurrence.

5.1 A resilience measure evaluation process

A constructive resilience analysis process will define resilience goals, articulate system and resilience metrics, characterize threats and their probabilities and consequences, and evaluate the effectiveness of alternative resilience measures for avoiding or mitigating the threats.[132] Such a process should ensure that the resilience metrics and analyses of threats and mitigation measures recognize impacts on the electricity end user, not just upon the physical elements of the power system**.**

Given the diverse causes for power outages and the widening set of threats across the power system, industry leaders should look for portfolios of solutions that address multiple hazards, rather than expecting that one or two magic bullets will solve all resilience and reliability problems. It is critical to evaluate portfolios of complementary resilience-improving measures that can deliver significant probability reductions in outage scale, frequency and duration for different customer classes in a collectively cost-effective manner.

The following questions should be considered in evaluating individual resilience and reliability measures, and then in building a risk-based portfolio of resilience solutions to deal with a set of outage threats with intelligently constructed scenarios and probabilities of outage cause, frequency, duration and scale:

- The measure's efficacy in reducing outage probabilities, frequency, scale and duration for different customer groups
- What part of the power system it affects (distribution, transmission, generation)
- What stage of the reliability-resilience spectrum it affects (e.g., long-term planning, operations, restoration and recovery, customer survival)
- What are the costs of the measure and how would the necessary resources be procured?
- If it is controllable, who controls it?
- How many types of outage causes or consequences the measure can mitigate
- Does the measure have any significant vulnerabilities?

[132] The resilience analysis process laid out by the Sandia National Laboratory, in Watson, Guttromson et al. (2015), is a useful starting point for this task.

- Is this measure already being performed under current practices, standards or regulatory requirements?
- Given the impact of the measure upon multiple threats, how cost-effective is the measure in terms of dollar cost per reduction in frequency of outages and customer outage-minutes (or change in SAIDI)?
- Is there a better way to protect customers against outages than this measure? (For instance, could customers survive a large outage better with an investment in more energy-efficient buildings than in more transmission automation or coal-fired generation? Could a non-wires measure such as distributed generation and storage protect customers better than a new transmission line or generator?)
- Given that many customers are already taking precautions to protect themselves against outages, does the measure deliver a substantive incremental reduction in the risk or duration of outage-minutes, or a meaningful improvement in survivability, that customers aren't already positioned to bear?[133]

Quantifying the impact of a solution for reducing customer outages, particularly for transmission and distribution system solutions, depends on regional risk factors and will be highly system-specific. For example, undergrounding may be effective for a system that is frequently exposed to high winds or ice storms, but would be ill-advised for areas that are prone to flooding and storm surge.

In many cases, precise calculations of benefits may not be feasible. First, the probability of many threats is uncertain, particularly for HILF events and weather-related events that are increasing in frequency due to climate change. In addition, many solutions for improving resilience have multiple benefits, many of which cannot be precisely quantified -- for example, energy efficiency and transmission can reduce emissions and energy costs as well as reduce customer vulnerability to outages,[134] while undergrounding distribution lines may improve community aesthetics as well as reduce vulnerability to high winds, ice and tree contacts. Similarly, investments in generating capacity, energy storage, and demand response resources increase supply capacity reserve margins while providing energy, flexibility, T&D investment deferral, and other ancillary services. Careful resilience analysis will not assign the full cost of a multi-benefit measure to the resilience benefit alone, but adjust the measure cost down to reflect the value of these other benefits.

At the portfolio level:

- Can you construct a portfolio of diverse resilience solutions that effectively reduce risk and protect the power system and customers against a wide variety of threats?
- Does addition of a specific measure to a resilience portfolio make the overall suite of measures more effective at reducing the probability of outages and their impacts on customers?
- Does the portfolio of measures have any significant common vulnerabilities?
- Does the portfolio of measures have any significant customer equity implications? (For instance, if we expect customers to bear the incremental costs of their own protection, and the losses

[133] This was an easier question to ask and answer before the Hurricane Maria destroyed Puerto Rico's grid and redefined our collective expectations about the magnitude of a disastrous, widespread electric outage, and how an electric system could or should be restored and redesigned to better protect customers and essential services from such disasters.
[134] For example, SPP documented the multiple benefits of transmission, including reliability benefits like reduced loss of load probability, in SPP (2016), p. 29.

from any outages they can't protect themselves from, then major outages will have a disproportionately large impact on lower-income customers who can't buy backup generators and energy-efficient housing).

- How are the overall costs of the portfolio allocated? Which costs are already being incurred (e.g., cyber-security and emergency drills), which get absorbed into utility retail customer charges (e.g., basic levels of distribution upgrades, energy efficiency programs and tree-trimming), which would be allocated to generators to be added into utility rates or competitive market bids (weatherization or model development), and which could be spread across all customers in a region (such as power plant RMR payments) or taxpayers (such as community emergency shelters)?
- If all the portfolio measures work as anticipated, what outage risks and consequences would remain for customers and for the power system? Are those consequences unavoidable or extraordinarily costly to mitigate further?

5.2 Use outage frequency, duration, magnitude and costs as the bases for comparing resilience options

It is possible to identify reliability and resilience investment costs and O&M costs, but it is harder to identify and monetize the benefits of those investments to customers, the utility and society as a whole.[135] Regulators would like to identify specific investments for reliability and resilience (installation and capital costs, financing cost and O&M costs) and to link those to impact on number of outage events and reductions in restoration time using SAIDI and SAIFI.[136] But regulators have a hard time estimating the value of those benefits to customers.[137]

Customer outage frequencies, durations, magnitudes and their costs to customers should be a starting point for assessing and comparing between resilience solutions, and for building portfolios of net-beneficial solutions. It is important to accurately account for the impact of a solution on both the frequency and duration of customer outages (for instance, two short outages totaling 50,000 outage minutes might impose less total customer cost than a single outage of the same total duration), and properly distinguish the impact of distribution-system solutions on different customer classes (for example, small commercial and industrial customers experience far higher outage costs than other types of customers).[138] Tools such as LBNL's outage calculator[139] incorporate that data and provide useful input into the analytic process for finding the best solutions for reducing customer outages.

The benefit-cost ratio of different solutions may be highly dependent on the topology of the transmission and distribution systems. For example, undergrounding will be much more cost-effective in a dense urban center than in a rural area with few customers per mile of line. A branching distribution network with a few critical primary lines is more likely to find hardening those lines to be cost-effective than a looped system with redundancy that reduces the risk from the loss of primary lines. Because of these system differences, generalized data that can be used to assess the effectiveness of transmission and distribution system solutions for reducing outages across different systems are typically not available.

[135] LaCommare, Larsen & Eto (2017), p. 4.
[136] Ibid., pp. 2-3.
[137] Ibid.
[138] Sullivan, Schellenberg & Blundell (2015).
[139] LBNL ICE Calculator.

Five analyses of reliability and resilience investments implement parts of the analytical approach outlined above and merit review:

- **"NARUC and MDPSC Cost-Benefit Analysis of Various Electric Reliability Improvement Projects from the End Users' Perspective,"** Analysis Summary, November 15, 2013, by Mark Burlingame & Patty Walton.[140] It quantified the costs to customers of extended outages and reviewed the mitigating measures to avoid outages, reduce outage duration, and restore power. The study concluded that a number of mitigation measures were well-justified by the utility cost reductions and customer benefits gained, but that further data collection is needed.
- **"Formal Case No. 1116, In the Matter of the Application for Approval of Triennial Underground Infrastructure Improvement Projects Plan, Order No. 17697,"** DC Public Service Commission, November 12, 2014.[141] This analysis examined the prudency of Pepco's undergrounding proposal (undergrounding being a frequent and costly proposed remedy to improve urban distribution system reliability). It scrutinizes the undergrounding costs and tradeoffs with respect to continuing activities such as tree-trimming and pole inspection. There is limited discussion of the potential impacts of the project upon customer outages, although it does acknowledge that by undergrounding these specific 6% of feeders through this project, it should account for 31.6% of customer interruptions and 35.9% of customer outage-minutes.[142] The PSC uses Value of Service methods to calculate benefits from the project.
- **"Valuing the Resilience Provided by Solar and Battery Energy Storage Systems,"** NREL and Clean Energy Group, January 2018.[143] This paper summarizes a more detailed study that walks through the elements of project cost estimation and benefits estimation. It considers the impact of resilience – particularly, how many hours that a given PV and storage system can power critical loads during an outage – on project sizing and shows how assumptions about the value of resilience can affect the ultimate project economics.
- **"Have Mandatory Standards Improved Reliability? Evidence, findings and raison d'etre,"** by Stephen Huntoon, *Fortnightly Magazine*, January 2015.[144] This article scrutinizes the assertion that NERC's reliability standards have improved reliability by reducing the number of non-weather-related significant outages due to transmission-related events. Huntoon assumes an average firm load loss per outage and average outage duration and applies the FERC-accepted Value of Lost Load dollar value to determine the annual value of the avoided load loss. This figure turns out to be very small compared to the annual budget for statutory functions for NERC and its Regional Entities, leading the author to conclude that because mandatory reliability standards are developed absent cost-benefit analysis, we are paying too much for them because the bulk of outages remain outside the influence of those standards.
- **"Evaluation of the DOE's Proposed Grid Resiliency Pricing Rule,"** by Brattle Group's Metin Celebi et al., October 23, 2017.[145] Section III of this analysis lays out the process and assumptions required to estimate the payments proposed under the proposed rule. Additional details and assumptions are provided in Appendix B of the Brattle analysis.

[140] Watson & Burlingame (2013).
[141] DC PSC Order No.17697 (2014).
[142] DC PSC Order No. 17697 (2014), p.86.
[143] McLaren & Mullendore (2018).
[144] Huntoon (2015).
[145] Celebi & Chang et al. (2017).

Regulators, utility executives, and other decision makers have enough information about the causes and consequences of power system outages to think about how to allocate resilience resources across all levels of the system, rather than only looking at the levels within their own jurisdictions. The regional and distribution system-specific nature of resilience argues for a greater focus on state regulators and distribution utilities in identifying relevant risk factors and appropriate solutions for their systems, and less effort by FERC and ISOs to view wholesale generation markets as the primary solution for improving resilience.

FERC and state commissions should work with the Department of Energy to explore how to formalize some of the analytical questions suggested here and consider how to coordinate these analyses across jurisdictions and power system levels. Although jurisdictional issues prevent a single entity from directing investments across the distribution, transmission, and generation sectors, using common impact measures and benefit-cost metrics across all levels and sectors should reveal to all parties which investments are cost-effective.

5.3 Suites of threat-agnostic measures tend to have greater cost-effectiveness

Because most customer outages and outage-minutes are due to weather-related and distribution-level events and damage, few of the resilience measures targeted to generation or transmission will reduce the impact of a hurricane or flood upon customer outage-minutes. But tree-trimming and appropriately designed distribution pole hardening could have a strong outage prevention impact by addressing and mitigating the damages caused by a number of hazards. Measures that are "threat-agnostic," providing system-wide resilience against a wide range of known and unpredictable threats, may be much more cost-effective than measures that only address a single threat.[146]

Grid monitoring, transmission automation and mutual assistance programs are good examples of effective multi-hazard solutions. Several utilities that have invested in grid modernization methods including extensive advanced metering, outage management and distribution automation systems, report that they used these systems to significantly speed service restoration for many customers. A good example is Florida Power & Light, as explained by CEO Eric Silagy:

> Since 2006, Florida Power & Light Company has invested more than $3 billion to build a stronger, smarter, and more resilient energy grid. We have strengthened transmission lines, replaced poles, and cleared vegetation from more than 150,000 miles of power lines. We've also invested in smart grid technology, including nearly 5 million smart meters and more than 83,000 intelligent devices like automated feeder switches.
>
> [Hurricane] Irma [2017] was our first major test since Hurricane Wilma in 2005, and our investments were invaluable. Fewer than half as many substations were affected, and those that were impacted came back online more quickly. We lost substantially fewer poles, and automated switching helped to avoid nearly 600,000 customer interruptions. Irma was a larger and stronger storm than Wilma – knocking out power to more than 90 percent of our customers – but all of our impacted customers were restored within 10 days, compared with 18 days following Wilma.[147]

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[146] See Preston, Backhaus et al. (2016).
[147] Silagy (2018), p. 26. 2018, p. 26.

Similarly, CenterPoint reports that its distribution automation investments allowed them to avoid almost 41 million outage minutes following Hurricane Harvey and associated flooding in Houston in August 2017. CenterPoint's advanced meters executed 45,000 operational orders remotely at 97% performance accuracy, increasing restoration efficiency and speed. Even with these advantages, CenterPoint had 1.2 million electric customers affected and 755 million total minutes of customer outages over 10 days.[148]

Mutual assistance programs are particularly effective for major event outage restoration and recovery. For Hurricane Harvey, CenterPoint used 2,200 employees and 1,500 contractors and mutual assistance personnel from 7 states.[149]

TVA's resiliency planning analyzed spare equipment needs under a variety of threat and hazard scenario. The transmission provider now uses a small set of approved standard transformer designs with a high degree of interchangeability, and also stocks spare bushings and components for these standard units. This inventory of spare equipment will serve the system in the face of threats that include flooding, tornados, physical attack, earthquakes, GMD and more.[150]

5.4 Generation resilience solutions tend to be less impactful for customer resilience than T&D and operations measures

Since so few power outages experienced by customers are caused by generation or fuel shortages, generation investment is unlikely to be a cost-effective way to reduce customer outages relative to transmission and distribution system measures.

In planning to reduce even further the number of customer outages that could result from a generation supply shortfall, grid operators use transmission expansion and more coordinated grid operations to import supply from other regions. Transmission imports are often more cost-effective solutions than adding new generation. An Xcel Colorado analysis found that 200 MW of transmission ties with neighboring Balancing Authorities enabled a reserve margin reduction from 19.2% to 16.3% while meeting the same standard for LOLP.[151] Similarly, SPP found that the transmission upgrades it has built provide $1.354 billion in net present value benefits by reducing the region's LOLP and reserve margin needs.[152] MISO and PJM have each found that the reduction in reserve margin needs enabled by the geographic diversity of supply and demand across their large footprints is the single largest benefit they provide, worth over $1 billion per year in PJM and $2 billion per year in MISO.[153]

Transmission is particularly valuable for mitigating outages broadly, and for mitigating supply shortages caused by extreme events. Because weather and other extreme events tend to be geographically limited in scope, one region rarely experiences its extreme supply shortfall at the same time as all neighboring regions. For example, during the Bomb Cyclone event in early January 2018, the low temperature anomaly was far worse in eastern PJM than in western PJM, causing wholesale electricity prices in eastern PJM to be consistently hundreds of dollars per MWh higher than in western PJM.

[148] Greenley (2018).
[149] Ibid., p.10.
[150] Clem & Grant (2018).
[151] Xcel (2011), p. 2-9.
[152] SPP (2016).
[153] PJM Value Proposition, MISO Value Proposition.

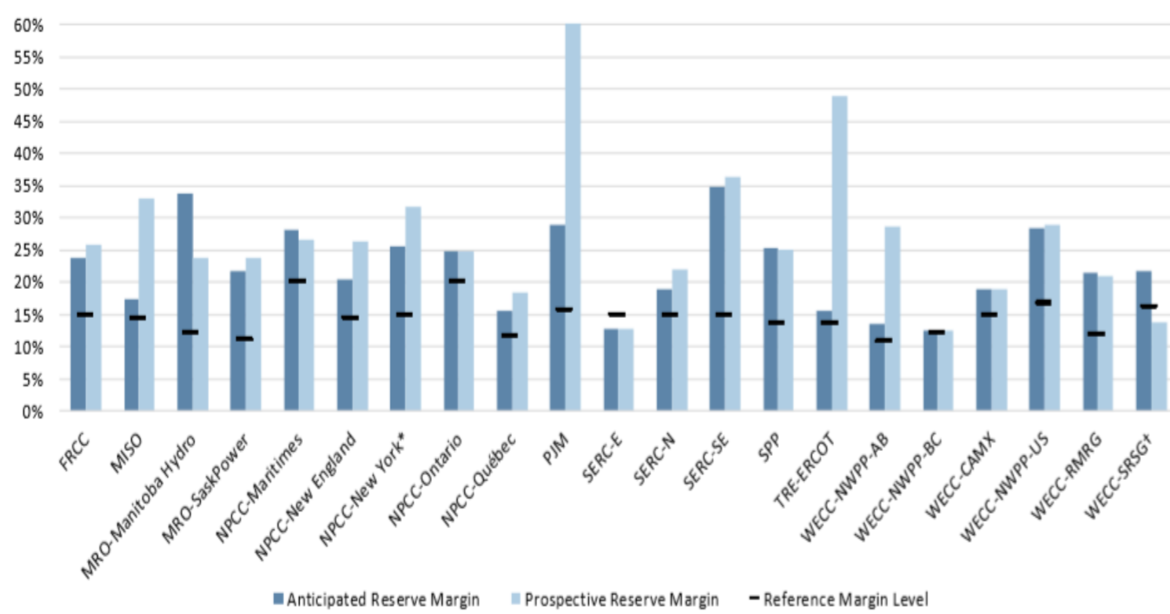
Greater west-to-east transmission capacity in PJM would have saved PJM consumers hundreds of millions of dollars during that event alone. The next extreme event might more strongly affect western PJM, causing greater demand and price spikes and generator unavailability there than in eastern PJM, so over time transmission expansion tends to benefit all in the footprint. However, scarcity-based price spikes associated with extreme events tend to be short-lived; it may be more cost-effective to bear high prices over the short term (moderated by demand response) than to invest in costly transmission or generation solutions.

Assessment of potential generation-related resilience solutions must consider current reserve margin levels. Reserve margin is a system planning measure of the amount of supply- and demand-side capacity a grid operator has in excess of its expected peak demand. The marginal value of additional generating capacity often drops off dramatically at higher reserve margins.

NERC's "2017 Long-Term Reliability Assessment,"[154] shows that nearly all regions are expected to have more than adequate supplies of generating capacity through 2022 as generating capacity additions continue to outpace retirements and load growth. (See Figure 16) This surplus is shown below as the excess of the "anticipated reserve margin" over the "reference margin level." When potential generation additions are accounted for to calculate the "prospective reserve margin," the capacity surplus grows further, as shown below. Given transmission between regions, the calculation of planning reserve margins for most regions and sub-regions becomes an artificial statistic.

Figure 16: Planning Reserve Margins by Region

(Source: NERC (2017), Fig. 3)

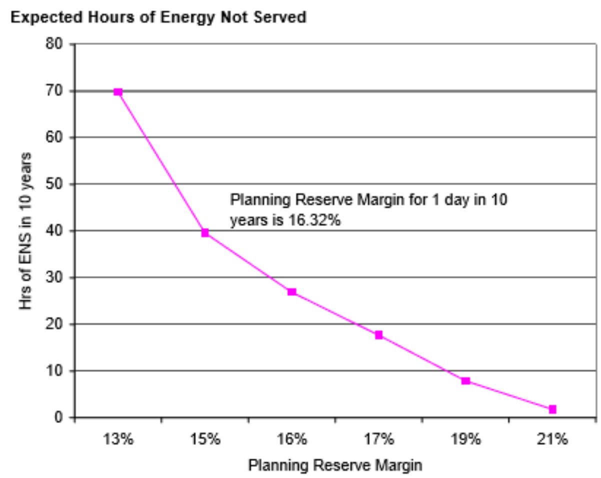


[154] NERC (2017c).

The marginal value of incremental generation capacity for reducing customer outages (as measured by loss of load probability) falls significantly when reserve margins are already high. This is illustrated in Figure 17, where the marginal value of new capacity nears zero once the reserve margin exceeds 20%.

Figure 17 – Loss of Load Probability versus reserve margin for Xcel's Colorado power system

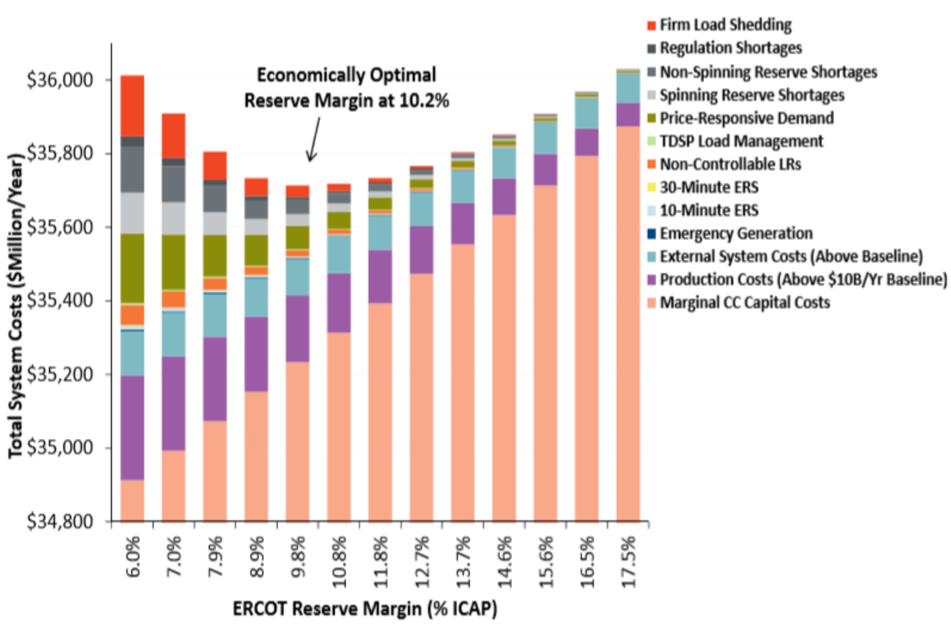
(Source: Xcel Energy (2011), p. A-1)



The Brattle Group conducted a similar analysis for ERCOT and calculated the cost tradeoff for consumers of holding reserve capacity. Brattle found that ERCOT's optimal reserve margin was around 10%. (See Figure 18) Above a 10% reserve margin, the cost of extra generating capacity outweighs the benefits of reduced risk of shedding firm load and lower costs for operating reserves and production costs.

Figure 18 – Total system costs versus reserve margin

(Source: Newell (2014), Figure ES-1)



Economic analysis presented in *Public Utilities Fortnightly* argues that under reasonable assumptions about the value of lost load for customers, the widely-used "1 in 10" Loss of Load Probability standard for the acceptable frequency of outages is about 10 times more stringent than the level of capacity investment that optimally benefits customers.[155] That article goes further to argue that, accounting for the fact that a typical rolling blackout only affects about 10 percent of the customers, the 1 day in 10 years metric is about 100 times too conservative. In competitive wholesale markets, more of the risks and costs of maintaining excess levels of generation (and other resources) fall on asset owners and shareholders and less falls on captive end-use customers – but it may be useful for state and federal regulators and policy advocates to think about whether and how to update current power system planning standards.

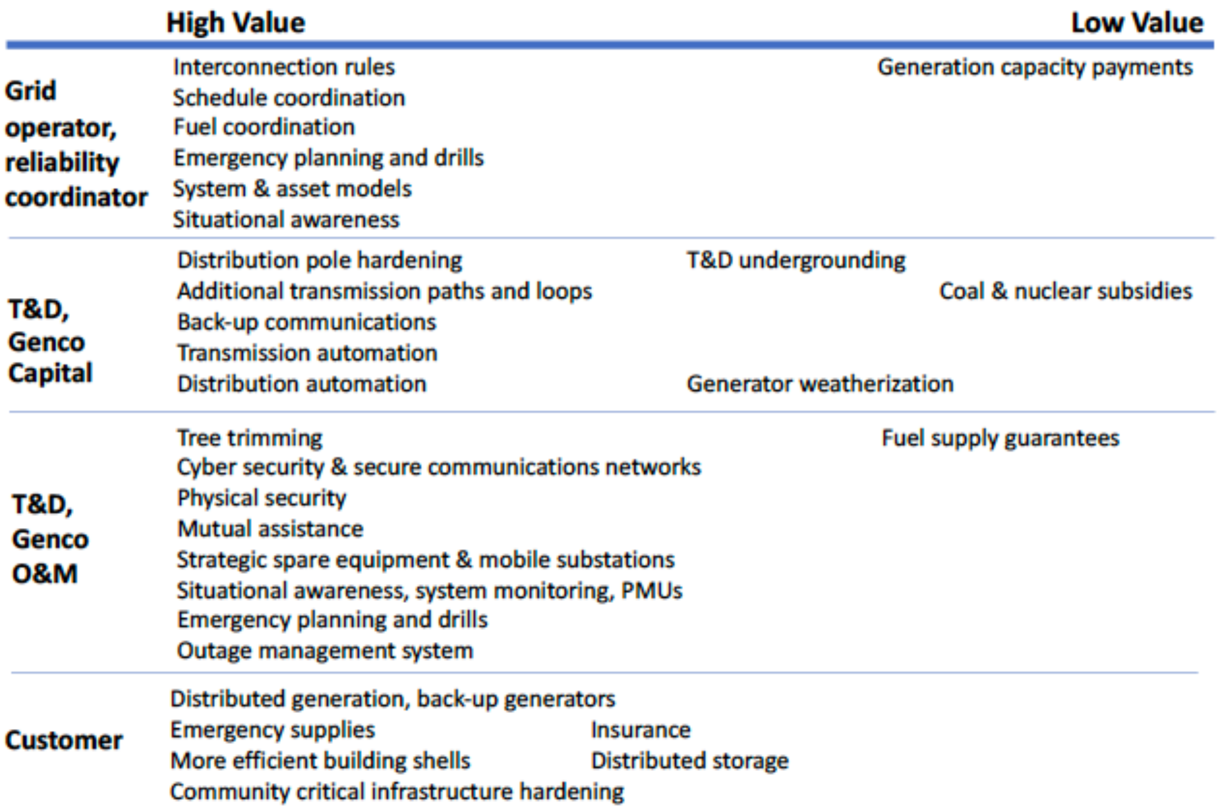
Raw capacity (MW) alone is no longer as valuable as it used to be. As discussed in the previous section, today we need supply and demand resources that can deliver flexible services such as fast frequency response, fast ramping speed and voltage support, and do so reliably when they are needed. Price-responsive demand can play a key role in enabling customers to express their true value of lost load. This is widely used in New England, where customers can reduce demand or disconnect entirely in exchange for a payment that reflects their willingness to curtail. In ERCOT, large customers receive extra payments for participating in the Load Acting as a Resource program, to automatically shed some portion of site load to provide fast frequency response. Such programs reduce the need for additional generating capacity that costs more than these marginal customers are willing to accept for curtailing their energy use.

5.5 Conclusions about relative value of resilience measures

Summarizing the ideas discussed in this section, Figure 19 offers the authors' ballpark representation of how the resilience and reliability options discussed in Section 4 might rank in terms of relative value per outage avoided and customer survivability improved.

[155] Wilson (2010).

Figure 19 – Relative values of various resilience measures, compared on a $/customer outage impact basis



The authors encourage others to undertake the data collection and analysis required to assess reliability and resilience measures at all power system levels using the customer-centric analytical approach described above. Since most outages occur due to problems at the distribution level and long-duration outages are caused primarily by severe weather events, it logically follows that measures that strengthen distribution and hasten recovery would be highly cost-effective. In contrast, measures to make generation more resilient are likely to have little impact on outage frequency, duration or magnitude or on customer survivability.

Federal and state regulators do not coordinate the financial obligations they place upon the electric providers and actors which they regulate. Electric utilities and customers must deal with the consequences and costs of rules and rulings intended to protect them in the name of reliability and resilience, even when these well-intended policies crowd out or preclude more useful and impactful investments and actions. There is a great risk that if regulators and stakeholders do not conduct the type of analyses suggested here, we will end up committing significant amounts of money and effort to improve resilience, yet have little constructive impact on the probabilities or actual levels of future customer outages.

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Appendix A -- Major North American Blackouts Since 2001

(based on DOE OE-417 data and public reports)

Year	Location	Customers affected (million)	Time until most power restored	Cause
2002 – January 30	OK	1.9	1 week	Ice storm
2003 – August 14	Northeast US & Ontario	55	1 week	Transmission in Ohio
2003 – September 19	VA, NC	1.8	12 days	Hurricane Isabel
2004 – August 13	FL	1.2	10 days	Hurricane Charley
2004 – September 4	FL	2.8	10 days	Hurricane Frances
2004 – September 25	FL	3.4	10 days	Hurricane Jeanne
2005 – August 29	FL, LA, MS, AL, TN, AR, KY	2.6	2 weeks	Hurricane Katrina
2005 – October 23	FL	3.2	1 week	Hurricane Wilma
2005 – December 31	CA	1.7	1 week	Severe storms
2006 – July 19	MO, IL	2.5	12 days	Thunderstorms
2008 – January 4	CA	2.6	11 days	Winter storm
2008 – February 26	FL	4	1 day	Transmission at Turkey Point plant
2008 – September 13	TX	2.5	3 weeks	Hurricane Ike
2010 – January 18	CA	1.7	10 days	Severe storms
2011 – February 2	TX	1	1 day rolling outages	Cold weather & generation failures
2011 - April 27	AL	1.2	1 week	Storm, tornado
2011 – August 27-28	NC, VA	1	2 days	Hurricane Irene
2011 – September 8-9	AZ, CA, northern Mexico	2	2 days	Transmission in AZ
2011 - late October	ME, CT, MA, NH, RI	1.4	9 days	Snowstorm
2012 – June 29	IA, IL, IN, OH, WV, PA, MD, NJ, VA, DE, NC, KY, DC	6	4 days	Thunderstorms, wind storms, derecho,
2012 – October 29	NY, NJ, CT, MA, MD, DE, WV, OH, PA, NH, RI, VT	8	10 days	Hurricane Sandy
2016 – September 21	Puerto Rico	3.5	3 days	Power plant fire
2016 – October 6	FL	1.2	3 days	Hurricane Matthew
2017 – March 8	MI	1	2 days	Wind storm
2017 – August 26	TX	1.1	2 weeks	Hurricane Harvey
2017 – September 10	FL, GA, SC, Puerto Rico	4.5	1 week	Hurricane Irma
2017 – September 20	Puerto Rico & islands	3.5	8+ months	Hurricane Maria

Appendix B – Reliability Services Capabilities for Major Energy Sources

(references at embedded links)

Reliability service	Wind	Solar PV	Demand Response	Battery Storage	Gas	Coal	Nuclear
Voltage support: Reactive power and voltage control	Provides, and can provide while not generating by using power electronics.	Provides, and can provide while not generating by using power electronics.	Could provide, though this would require detailed knowledge of distribution system state and dispatch	Power electronics provide fast and accurate response	Must be generating to provide	Must be generating to provide	Must be generating to provide
Voltage support: Voltage and frequency disturbance ride-through (also important for frequency support)	Voltage and frequency ride-through capabilities due to power electronics isolating generator from grid disturbances. Wind meets more rigorous ride-through requirement (FERC Order 661A) than other generators.	Can thanks to power electronics, but standards have prevented use of capability	NA	Power electronics isolate battery from grid disturbances	Generators often taken offline by grid disturbances.	Generators and essential plant equipment, like pumps and conveyor belts, often taken offline by grid disturbances.	Generators and essential plant equipment, like pumps, often taken offline by grid disturbances.
Frequency support: Frequency stabilization following a disturbance (through primary frequency response and inertial response to disturbances)	Wind regularly provides fast and accurate PFR in ERCOT today. Can be economic to provide upward response if curtailed. Can provide fast power injection (synthetic inertia) if economic to do so.	Can provide downward frequency response today, can provide upward frequency response and fast power injection if curtailed.	Load resources currently provide this in ERCOT through autonomous controls when frequency drops below a certain point	Power electronics provide very fast and accurate power injection following a disturbance	Only 10% of conventional generators provide sustained primary frequency response	Only 10% of conventional generators provide sustained primary frequency response	Nuclear plants are exempted from providing frequency response, but they do provide inertia.

Ramping and balancing: Frequency regulation	Fast and accurate response. Can provide but often costly, particularly for upward response. Provides on Xcel's system.	Fast and accurate response. Can provide but often costly, particularly for upward response.	Autonomous loads like water heaters can provide, though the cost of disruption may be too great for other DR	Very fast and accurate response	Must be generating to provide	MISO data show a large share of coal plants provide inaccurate regulation response	Does not provide
Ramping and balancing: Dispatchability / Flexibility / Ramping	Fast and accurate response. Can but often costly, particularly for upward response. Provides on Xcel's system.	Fast and accurate response. Can provide but often costly, particularly for upward response.	Many forms of DR are likely to be energy limited or too expensive for longer duration deployment	Many types of batteries will be energy limited for longer-duration events, particularly if state of charge is not optimal going into event	Most gas generators are operated flexibly	Many coal plants have limited flexibility, with slow ramp rates, high minimum generation levels, and lengthy start-up and shut down periods	Almost never provides
Ramping and balancing: Peak energy, winter (color reflects risk of common mode unavailability reducing fleetwide output below accredited capacity value)	Wind plants typically have high output during periods of extreme cold, as seen in ERCOT in 2011 and much of the country in 2014.	Solar plants have lower output during the winter.	Many DR programs are not currently designed for winter peak demand reduction	Good, though will be energy limited for longer-duration events	High gas demand can cause low gas system pressure, fuel shortages. Can be mitigated with dual fuel capability or firm pipeline contracts.	Many coal plants failed due to cold in ERCOT in February 2011, polar vortex event in 2014, and other events.	Some failures due to extreme cold.
Ramping and balancing: Peak energy, summer (color reflects risk of common mode unavailability reducing fleetwide output below accredited capacity value)	In many regions wind output is lower during hot summer days, though that is accounted for when calculating wind's capacity value. In some regions, like coastal areas or mountain passes, wind output is higher on hot summer days.	Solar plants typically have high output on hot summer days, though solar output has typically declined by the early evening peak demand period.	Many forms of DR are used for summer peak load reduction today, including air conditioning curtailment	Good, though will be energy limited for longer-duration events	Gas generators experience large output de-rates when air temperatures are high.	Coal plants experience de-rates when cooling water temperatures are high.	Nuclear plants experience de-rates when cooling water temperatures are high.