

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

<b>Grid Resilience in</b>	)	
<b>Regional Transmission Organizations and</b>	)	
<b>Independent System Operators</b>	)	<b>Docket No. AD18-7-000</b>

**COMMENTS OF PUBLIC INTEREST ORGANIZATIONS**

The undersigned Public Interest Organizations<sup>1</sup> thank the Federal Energy Regulatory Commission (Commission or FERC) for the opportunity to respond to the comments filed by the Regional Transmission Organizations and Independent System Operators (RTOs/ISOs) on grid resilience of the bulk power system (BPS).<sup>2</sup> While discussed in depth below, we respectfully offer the following key points.

**I. SUMMARY OF COMMENTS**

*First*, the RTOs’/ISOs’ comments support a finding that there is wide variation in how to define “resilience” as applied to the BPS and how it differs from “reliability.” We agree with Commissioner LaFleur’s concurrence in the Commission’s January 8, 2018 order: for purposes of the Commission’s regulatory authority over the BPS, resilience “is unquestionably an element of reliability.”<sup>3</sup> As such, resilience issues can be addressed most effectively via a reliability lens.

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<sup>1</sup> The Public Interest Organizations are Sustainable FERC Project, Natural Resources Defense Council, Acadia Center, American Wind Energy Association, Clean Wisconsin, Conservation Law Foundation, Earthjustice, Environmental Defense Fund, Environmental Law & Policy Center, Fresh Energy, NW Energy Coalition, Sierra Club, Southern Renewable Energy Association, Union of Concerned Scientists, Vote Solar, Western Grid Group, and Wind on the Wires.

<sup>2</sup> *Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,012, at PP 18-19 (2018), Docket Nos. RM18-1 and AD18-7; *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61,256, at P 3 (2018), Docket No. AD18-7.

<sup>3</sup> 162 FERC ¶ 61,012, at 1 (Commissioner LaFleur, concurring).

**Second**, the RTOs’/ISOs’ comments support that the grid is resilient and reliable. All seven<sup>4</sup> RTOs/ISOs agree that the BPS is resilient and reliable today. Five RTOs/ISOs raised no BPS resilience concerns whatsoever.<sup>5</sup> This is not surprising given the robust mechanisms already in place to address resilience concerns, albeit often in the name of reliability. These include the Commission’s existing market-based framework for supporting reliable BPS operation, existing North American Electric Reliability Corporation (NERC) reliability mandates, and resilience measures initiated at the RTO/ISO level. For example, as stated by NERC in its comments in the instant docket, a BPS that meets NERC’s “adequate level of reliability”<sup>6</sup> standard is resilient.<sup>7</sup> As such, the Commission should resist imposing top-down remedies without an identified concern, as imposing requirements without a determination of need would simply result in higher customer bills—without any identified benefit.<sup>8</sup>

The RTOs’/ISOs’ comments also support that the resilience needs of each RTO/ISO are region-specific and benefit from local stakeholder engagement. The RTOs/ISOs need the

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<sup>4</sup> The six FERC-jurisdictional RTOs/ISOs plus the Electric Reliability Council of Texas (ERCOT). For the purposes of these comments, ERCOT is included within the term “RTOs/ISOs.”

<sup>5</sup> ISO-New England (ISO-NE) and PJM Interconnection, L.L.C. (PJM), raised longer-term resilience concerns, which are addressed in detail below.

<sup>6</sup> “*Informational Filing on the Definition of Adequate Level of Reliability*,” NERC (May 10, 2013), [https://www.nerc.com/pa/Stand/Resources/Documents/Adequate\\_Level\\_of\\_Reliability\\_Definition\\_\(Informational\\_Filing\).pdf](https://www.nerc.com/pa/Stand/Resources/Documents/Adequate_Level_of_Reliability_Definition_(Informational_Filing).pdf) (hereinafter NERC Reliability Filing).

<sup>7</sup> Comments of the North American Electric Reliability Corporation, at 6 (May 9, 2018), Docket No. AD18-7 (hereinafter NERC Comments).

<sup>8</sup> See Alison Silverstein, Rob Gramlich, & Michael Goggin, *A Customer-focused Framework for Electric System Resilience*, at 63, GRID STRATEGIES, LLC (May 2018), <https://gridprogress.files.wordpress.com/2018/05/customer-focused-resilience-final-050118.pdf> (hereinafter Silverstein Report) (“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.”). The Silverstein Report is included as an attachment to these comments and has also been filed separately in the instant docket. See Report by Alison Silverstein Consulting and Grid Strategies LLC (May 8, 2018), Docket No. AD18-7.

flexibility to be able to develop region-specific solutions based on discussions with local stakeholders. This means that a federal one-size-fits-all approach is not only without record-support, but also would be inefficient in solving any identified resilience needs.

**Third**, while the evidence supports that the grid is resilient and reliable, to the extent the Commission intervenes, it should focus its efforts on policies and procedures that protect customer interests, increase cross-regional collaboration, interconnection, and consistency, and remove barriers to the continuing integration of renewable technologies, energy storage, demand response, energy efficiency, and distributed energy resources (DERs).<sup>9</sup> The vast majority of customer disruptions occur because of failures of the distribution system—not due to weaknesses in the BPS.<sup>10</sup> As such, many of the most effective resilience strategies fall outside of the Commission’s jurisdiction. However, the Commission could bolster resilience by taking actions that support and leverage customer participation in providing services that make the distribution system more resilient. For example, the Commission could act to integrate DERs connected to the distribution system into wholesale markets. The Commission also could improve resilience by streamlining regional transmission planning initiatives by modernizing Order 1000 to better facilitate the integration of non-wires solutions to meeting transmission constraints. These types of policies would be a value-add to the work already being done at the regional level—without creating a solution in search of a problem.

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<sup>9</sup> This proceeding provides the Commission with the opportunity to ensure that its gas market rules reflect contemporaneous and evolving market conditions. As explained in comments filed in the instant docket by Environmental Defense Fund, the Commission can enhance resilience and advance gas-electric coordination by resolving the contract gap between pipelines and their new largest user—electric generators. *See generally* Comments of the Environmental Defense Fund (May 9, 2018), Docket No. AD18-7.

<sup>10</sup> Silverstein Report, *supra* note 8, at 4.

## II. PROCEDURAL BACKGROUND

The Commission initiated this proceeding in its January 8, 2018 order unanimously rejecting Secretary of Energy Rick Perry's (Secretary or Secretary Perry) proposed "Grid Resiliency Pricing Rule" (Proposed Rule).<sup>11</sup> The Proposed Rule recommended that some RTOs'/ISOs' operating capacity markets be directed to establish a tariff mechanism by which so-called "reliability and resilience resources" would recover their costs and a return on equity.<sup>12</sup> The Proposed Rule—without explanation or justification—defined "reliability and resilience resources" to be those that are: (1) located in an RTO/ISO with an energy and capacity market; (2) provide "essential reliability services"; and (3) have 90 days of on-site fuel supply.<sup>13</sup> In other words, the Proposed Rule attempted to preference and guarantee profits for coal and nuclear power plants to the detriment of competitive wholesale markets and all other supply resources.<sup>14</sup>

In rejecting the Proposed Rule, the Commission concluded that, contrary to the requirements of section 206 of the Federal Power Act (FPA),<sup>15</sup> the Secretary had failed to show that current RTO/ISO tariffs are unjust, unreasonable, unduly discriminatory, or preferential.<sup>16</sup> The Secretary had failed to demonstrate that there is even a resilience crisis in need of a solution, let alone that the Proposed Rule was an appropriate solution to the alleged "crisis." In fact, the

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<sup>11</sup> Grid Resiliency Pricing Rule, 82 Fed. Reg. 46,940 (proposed Oct. 10, 2017), *rejected by Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,012 (2018), Docket Nos. RM18-1 and AD18-7 (hereinafter Proposed Rule).

<sup>12</sup> *See id.*

<sup>13</sup> *See* 162 FERC ¶ 61,012, at P 2.

<sup>14</sup> *E.g.*, Proposed Rule, 82 Fed. Reg. at 46,943 ("Ultimately, the continued closure of traditional baseload power plants calls for a comprehensive strategy for long-term reliability and resilience."); Letter from Secretary Rick Perry to Neil Chatterjee, Chairman, Cheryl A. LaFleur, Commissioner, and Robert F. Powelson, Commissioner, at 1 (Sept. 28, 2017) ("[T]he resiliency of the electric grid is threatened by the premature retirements of ... traditional baseload resources.").

<sup>15</sup> 16 U.S.C. § 824e(a) (2012).

<sup>16</sup> 162 FERC ¶ 61,012, at P 14.

Department of Energy (DOE) study cited by Secretary Perry in support of the Proposed Rule (the DOE Staff Report) concluded that the grid has become more resilient over time—not less.<sup>17</sup> There was “no evidence” in any “Commission proceeding[] indicating that any RTO/ISO tariffs are unjust and unreasonable because they do not adequately account for resilience.”<sup>18</sup> Contrary to the Secretary’s claim that grid resilience is threatened by coal and nuclear power plant retirements,<sup>19</sup> the Commission stated that “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.”<sup>20</sup> Further, the Secretary had failed to demonstrate how the Proposed Rule was not unduly discriminatory against other generation resources with “resilience attributes,”<sup>21</sup> which were left uncompensated by the Proposed Rule.

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<sup>17</sup> *Staff Report to the Secretary on Electricity Markets and Reliability*, at 63, DOE (Aug. 2017), [https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability\\_0.pdf](https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf) (hereinafter DOE Staff Report) (“Overall, at the end of 2016, the [BPS] had more dispatchable capacity operating at high utilization rates than it did in 2002,” despite the fact that 11 percent of the capacity available in 2002 had retired); *see also* Silverstein Report, *supra* note 8, at 8; (DOE “found that while cumulative power plant retirements have been significant, the [BPS] remains reliable.”); David Roberts, *Rick Perry and his own grid study are saying very different things: The analysis finds that the grid is perfectly reliable without coal plants*, VOX (Aug. 24, 2017), <https://www.vox.com/energy-and-environment/2017/8/24/16195620/rick-perry-grid-study-nothingburger>. A leaked preliminary version of the DOE Staff Report, which had not yet undergone Secretary Perry’s review, went even further: “The power system is more reliable today due to better planning, market discipline, and better operating rules and standards.” Catherine Traywick, Ari Natter, & Jennifer A. Dlouhy, *Renewable Energy Not a Threat to Grid, Draft of U.S. Study Finds*, BLOOMBERG (July 14, 2017), <https://www.bloomberg.com/news/articles/2017-07-14/renewable-energy-not-a-threat-to-grid-draft-of-u-s-study-finds>.

<sup>18</sup> 162 FERC ¶ 61,102, at P 15 & n.25.

<sup>19</sup> Proposed Rule, 82 Fed. Reg. 46,940, 46,941 (proposed Oct. 10, 2017), *rejected by* 162 FERC ¶ 61,012.

<sup>20</sup> 162 FERC ¶ 61,102, at P 15.

<sup>21</sup> *Id.* at P 16. As noted by Commissioner Glick in concurrence, DOE has acknowledged that resources other than coal and nuclear have resilience benefits. *Id.* at 1–2 (Commissioner Glick, concurring) (DOE’s “own staff Grid Study concluded that changes in the generation mix, including the retirement of coal and nuclear generators, have not diminished the grid’s reliability or otherwise posed a significant and immediate threat to the resilience of the electric grid. To the contrary, the addition of a diverse array of generation resources, including natural gas, solar, wind, and geothermal, as well as maturing technologies, such as energy storage, distributed generation, and demand response, have in

While the Commission concluded that the “Proposed Rule failed to satisfy the fundamental legal requirements of section 206 of the FPA,”<sup>22</sup> the Commission stated that “it must remain vigilant with respect to resilience challenges.”<sup>23</sup> As such, the Commission initiated the instant proceeding and set the following goals for further inquiry: “(1) to develop a common understanding among the Commission, industry, and others of what resilience of the [BPS] requires; (2) to understand how each [RTO/ISO] assesses resilience in its geographic footprint; and (3) to use this information to evaluate whether additional Commission action regarding resilience is appropriate at this time.”<sup>24</sup> The Commission directed the RTOs/ISOs to comment on these issues by March 9, 2018, with other interested entities filing comments by May 9, 2018.<sup>25</sup>

### **III. COMMENTS**

#### **A. Defining Resilience**

The Commission offered the following definition of “resilience” and asked the FERC-jurisdictional RTOs/ISOs for comment: “The 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.”<sup>26</sup> The RTOs/ISOs provided a wide range of responses. These responses ranged from general agreement but noting the challenges in

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many respects contributed to the resilience of the [BPS]. The record in this proceeding does not demonstrate any need for the Commission to interfere with the continued evolution of the [BPS].”).

<sup>22</sup> *Id.* at P 17.

<sup>23</sup> *Id.*

<sup>24</sup> *Id.* at P 18.

<sup>25</sup> *Id.* at P 18–19 (setting the initial deadlines for comments for RTOs/ISOs to March 9, 2018, and for all others to April 9, 2018); *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61,256, at P 3 (2018), Docket No. AD18-7 (extending the comment deadline for non-RTOs/ISOs to May 9, 2018).

<sup>26</sup> 162 FERC ¶ 61,012, at P 23. ERCOT also provided comments and is included within the discussion of RTO/ISO comments.

differentiating resilience from reliability,<sup>27</sup> to offering modifications to expand or tighten the definition,<sup>28</sup> to criticizing the definition for failing to outline the RTOs'/ISOs' specific resilience obligations.<sup>29</sup> The comments indicate the variation in how “resilience” is defined, and, critically how it is differentiated from “reliability” and the reliability measures already in place both at the Commission and at the grid operator level.

Notwithstanding this variation, the grid operators agree that resilience and reliability overlap significantly.<sup>30</sup> For example, New York Independent System Operator (NYISO) stated

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<sup>27</sup> Joint Comments of the Electric Reliability Council of Texas, Inc. and the Public Utility Commission of Texas at 2 (Mar. 9, 2018), Docket No. AD18-7 (hereinafter ERCOT Comments) (agreeing with the proposed definition but noting the overlap between resilience and reliability); Response of ISO New England Inc. at 33 (Mar. 9, 2018), Docket No. AD18-7 (hereinafter ISO-NE Comments) (explaining that resilience is addressed in part through reliability); Response of the New York Independent System Operator, Inc. at 3–4 (Mar. 9, 2018), Docket No. AD18-7 (hereinafter NYISO Comments) (offering general support for the proposed definition but noting the overlap between resilience and reliability).

<sup>28</sup> Comments and Responses of PJM Interconnection, L.L.C. at 9–10 (Mar. 9, 2018), Docket No. AD18-7 (hereinafter PJM Comments) (deeming the definition “acceptable” but offering several revisions); Comments of Southwest Power Pool, Inc. on Grid Resilience Issues at 2–3 (Mar. 9, 2018), Docket No. AD18-7 (hereinafter SPP Comments) (characterizing FERC’s definition as “reasonable” but expanding its resilience discussion to include the additional concepts of “robustness,” “resourcefulness,” “rapid recovery,” and “accountability”); Responses of the Midcontinent Independent System Operator, Inc. at 10 (Mar. 9, 2018), Docket No. AD18-7 (hereinafter MISO comments) (stating that MISO’s definition “generally aligns” with FERC’s proposal but proposing expanding the discussion to include the “changing nature of the electric grid”).

<sup>29</sup> Comments of the California Independent System Operator, Inc. at 8 (Mar. 9, 2018), Docket No. AD18-7 (hereinafter CAISO Comments) (“The CAISO notes that the concept of ‘resilience’ presented in the Resilience Order is general and somewhat vague. It includes no clear objective criteria, metrics, or standards to evaluate whether the existing grid is resilient. Similarly, it does not (1) instruct entities on the specific steps they should take to achieve the desired level of resilience or (2) specify any compliance obligations entities have to ensure the grid remains resilient.”); PJM Comments, *supra* note 28, at 9–10 (proposing a modified definition “to ensure the definition (i) accurately reflects what RTOs are capable of doing to protect the [bulk electric system] from vulnerabilities and threats, and (ii) does not impose upon RTOs additional liabilities and the imposition of a new duty and standard of care to which they are obligated to comply.”).

<sup>30</sup> See, e.g., Silverstein Report, *supra* note 8, at 11–12 (“Grid operators ... view resilience as part of their existing responsibility” and existing reliability measures “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.”).

that reliability and resilience “are highly intertwined and often indistinguishable”<sup>31</sup> and that the “requirements for reliable operation of the electric system encompass many aspects of resiliency.”<sup>32</sup> Likewise, the state-jurisdictional Electric Reliability Council of Texas (ERCOT) wrote that “[a]nticipating and responding to foreseeable [BPS] disturbances is ... already an essential part of ERCOT’s defined mission.”<sup>33</sup> This interrelationship led ISO-New England (ISO-NE), Midcontinent Independent System Operator (MISO), and Southwest Power Pool (SPP), to use the word “reliability” *within* their discussions of a proposed “resilience” definition. For example, ISO-NE argued that “[f]or the [BPS] to be *resilient* ... aspects of *reliability* need to be addressed.”<sup>34</sup> MISO stated that resilience includes “the ability to adapt to ongoing changes and supply portfolio evolution to ensure that grid performance remains *reliable*.”<sup>35</sup> SPP generally supported the Commission’s definition, but added that “a well-thought-out discussion of resilience may often require reference to *reliability-centered* practices and principles.”<sup>36</sup>

NERC also recognizes this overlap.<sup>37</sup> In comments filed in the instant docket, NERC stated that resilience is incorporated within its definition of “adequate level of reliability” *and*

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<sup>31</sup> NYISO Comments, *supra* note 27, at 3.

<sup>32</sup> NYISO Comments, *supra* note 27, at 4.

<sup>33</sup> ERCOT Comments, *supra* note 27, at 2.

<sup>34</sup> ISO-NE Comments, *supra* note 27, at 33 (emphases added).

<sup>35</sup> MISO Comments, *supra* note 28, at 10 (emphasis added).

<sup>36</sup> SPP Comments, *supra* note 28, at 3 (emphasis added).

<sup>37</sup> Even the Proposed Rule intuitively recognized this overlap, as it used the terms “resilience” and “reliability” seemingly interchangeably. *See, e.g.*, Proposed Rule, 82 Fed. Reg. 46,940, 46,941 (proposed Oct. 10, 2017), *rejected by Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,012 (2018), Docket Nos. RM18-1 and AD18-7 (“The *resiliency* of the nation’s electric grid is threatened by the premature retirements of power plants that can withstand major fuel supply disruptions caused by natural or man-made disasters and, in those critical times, continue to provide electric energy, capacity, and essential *grid reliability services*. *These fuel-secure resources are indispensable for the reliability and resiliency of our electric grid—and therefore indispensable for our economic and national security.*” (emphases added)).



*that a BPS that meets the “adequate level of reliability” standard is resilient.*<sup>38</sup> Similarly, the former NERC Chairman testified before the House Subcommittee on Energy in September 2017 that grid “resilience is reflected through NERC’s programs,” including *within* its definition of “adequate level of reliability.”<sup>39</sup>

This ambiguity underlies PJM Interconnection, L.L.C.’s (PJM) and the California Independent System Operator’s (CAISO) concerns about the Commission imposing additional “resilience” criteria beyond existing reliability mandates. In calling the Commission’s definition “general and somewhat vague,”<sup>40</sup> CAISO stated that the Commission also failed to (1) “clearly articulate the difference” between resilience and reliability, (2) sufficiently explain “why a new, wholly separate concept” of resilience is needed, or (3) provide “clear objective criteria, metrics, or standards to evaluate whether the existing grid is resilient.”<sup>41</sup> CAISO then correctly outlined the risks in creating a one-size-fits-all resilience approach:

There can be significant differences among regions for purposes of assessing and achieving resilience. The needs, circumstances, and conditions that exist in each region are unique and can vary significantly, as regions face different risks, threats, and operational challenges and have vastly different resource mixes and load curves, fuel supply options, and environmental requirements. Resilience must account for regional differences, and entities in each region must have flexibility to determine what capabilities are needed to maintain reliability and resiliency based on the specific circumstances in their region.... The Commission should also recognize that any risks to the resilience of the electric system are not limited to [RTOs/ISOs].... Ensuring resilience potentially requires the involvement and

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<sup>38</sup> NERC Comments, *supra* note 7, at 6; *see also* NERC Reliability Filing, *supra* note 6 (providing the definition of “adequate level of reliability”).

<sup>39</sup> Testimony of Gerry W. Cauley, “Powering America; Defining Reliability in a Transforming Electricity Industry” at 1 & n.1, 6, U.S. House of Rep. Subcommittee on Energy, Sept. 14, 2017, <https://www.nerc.com/news/Documents/HEC9-14-17%20Cauley%20Testimony%20Final.pdf>.

<sup>40</sup> CAISO Comments, *supra* note 29, at 8.

<sup>41</sup> CAISO Comments, *supra* note 29, at 8, 10.

actions of a host of entities other than ISO's [*sic*] and RTOs.... Resilience cannot be broad-brushed.<sup>42</sup>

Relatedly, PJM expressed concerns about the definition imposing “a new duty and standard of care to which [it is] obligated to comply.”<sup>43</sup> These concerns are reasonable, given that, as outlined below, within the rubric of reliability, the RTOs/ISOs comprehensively defend against resilience threats within their scope of authority. These defenses vary among each RTO/ISO, as each grid operator faces different resilience challenges given the unique attributes of each region. As such, while the proper solutions for PJM may not work in NYISO—and vice versa—both PJM and NYISO consider resilience part of their existing responsibilities.

Fortunately, dividing initiatives clearly into either a “reliability” or “resilience” bucket is unnecessary to achieve a resilient and reliable grid. Rather, the Commission should focus its attention on a strategy's result, *i.e.*, will the action benefit electric customers? This is not solely because “customers pay the ultimate price for power outages,”<sup>44</sup> but also because customers already pay for resilience via existing NERC reliability standards, policies, and procedures, and Commission rules and orders.<sup>45</sup>

In a report published on May 2, 2018 (the Silverstein Report), energy analysts Alison Silverstein, Rob Gramlich, and Michael Goggin explain that although many discussions—including in the instant docket—focus on the BPS, a more effective resilience discussion would

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<sup>42</sup> CAISO Comments, *supra* note 29, at 7–8; *see also* SPP Comments, *supra* note 28, at 19 (“SPP agrees with the Commission’s premise that a one-size-fits-all approach is not appropriate given the differences that can exist between the various regions the BPS serves.”).

<sup>43</sup> PJM Comments, *supra* note 28, at 9–10.

<sup>44</sup> Silverstein Report, *supra* note 8, at 3.

<sup>45</sup> SPP similarly advocated for a benefit-focused approach. SPP Comments, *supra* note 28, at 19 (“In evaluating present requirements and determining whether changes may be necessary for resilience, SPP believes it is important to weigh the benefits against the costs. Changes to requirements to address resilience could increase the costs of transmission owners’ systems, and those increased costs would ultimately impact transmission customers and their end-use customers.”).

focus “on customers’ experiences, rather than the grid alone.”<sup>46</sup> As the report states, 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.”<sup>47</sup> A customer-focused approach would ensure that the Commission uses its authority to encourage policies and procedures that will have the greatest impact on the customer experience—without unnecessarily imposing additional costs. This is particularly important since “many of the best solutions to maintain and enhance resilience lie beyond the limits of the [BPS] and federal jurisdiction.”<sup>48</sup> Such is the focus of the next two sections of these comments.

## **B. The Grid is Resilient and Reliable**

In rejecting the Proposed Rule, the Commission observed that “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.”<sup>49</sup> Unsurprisingly, the RTOs’/ISOs’ responses to the January 8 order reinforce this prior finding. *The RTOs/ISOs agree that the BPS is resilient and reliable today.*<sup>50</sup> Resilience is achieved through implementation of a variety of existing mechanisms, including existing NERC reliability standards and Commission-approved RTO/ISO-specific initiatives targeted to address each regional grid’s unique threats. This consensus is instructive since, as Commissioner Chatterjee outlined in concurrence to the January 8 order, “the

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<sup>46</sup> Silverstein Report, *supra* note 8, at 3.

<sup>47</sup> Silverstein Report, *supra* note 8, at 3.

<sup>48</sup> Silverstein Report, *supra* note 8, at 5–6.

<sup>49</sup> *Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,012, at P 15 (2018), Docket Nos. RM18-1 and AD18-7.

<sup>50</sup> See, e.g., CAISO Comments, *supra* note 29, at 5–6, 12; ERCOT Comments, *supra* note 27, at 2; ISO-NE Comments, *supra* note 27, at 12–13; MISO Comments, *supra* note 28, at 2; NYISO Comments, *supra* note 27, at 3; PJM Comments, *supra* note 28, at 4; SPP Comments, *supra* note 28, at 18.

RTOs/ISOs are well-positioned to understand the specific resilience risks in their footprints,”<sup>51</sup> or—as the facts support—the lack thereof.

The RTOs’/ISOs’ assessment also is consistent with that of most energy analysts, including those at DOE.<sup>52</sup> In addition to stating that the grid is reliable,<sup>53</sup> the DOE Staff Report acknowledged that NERC, “the primary entity responsible for ensuring BPS reliability ... believes BPS reliability is adequate.”<sup>54</sup> And, as noted above, NERC reiterated in the instant docket that a BPS that meets its adequate level of reliability standard is also resilient.<sup>55</sup>

Further, *five of the seven grid operators expressed no BPS resilience concerns, despite retirements of traditional baseload generation—the alleged cause for the resilience “crisis” cited by Secretary Perry*. MISO declared explicitly that its grid “is resilient.”<sup>56</sup> CAISO, NYISO, and ERCOT all stated that they proactively address grid resilience issues.<sup>57</sup> SPP offered that current NERC standards are “sufficient to address current and future needs with regards to

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<sup>51</sup> *Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,012, at 3 (2018), Docket Nos. RM18-1 and AD18-7 (Commissioner Chatterjee, concurring).

<sup>52</sup> Ironically, the DOE Staff Report cited by Secretary Perry as the basis for the Proposed Rule stated in a section entitled “Resilience” that the BPS is reliable today. *See DOE Staff Report, supra* note 17, at 63. *See also* Silverstein Report, *supra* note 8, at 8; Roberts, *supra* note 17.

<sup>53</sup> DOE Staff Report, *supra* note 17, at 63. *See also* Silverstein Report, *supra* note 8, at 8; Roberts, *supra* note 17.

<sup>54</sup> DOE Staff Report, *supra* note 17, at 63–64.

<sup>55</sup> NERC Comments, *supra* note 7, at 6; *see also* NERC Reliability Filing, *supra* note 6.

<sup>56</sup> MISO Comments, *supra* note 28, at 2.

<sup>57</sup> CAISO Comments, *supra* note 29, at 5–6, 12 (“The CAISO proactively considers and addresses the specific reliability and resilience-related challenges it faces on many fronts and through many tools at its disposal” and “[t]he CAISO identifies risks to resilience in its balanced authority area through a comprehensive and coordinated effort that involves numerous planning, monitoring, special study, coordination, and forecasting activities.”); NYISO Comments, *supra* note 27, at 3 (NYISO “has a proven track record of success in addressing the challenges and opportunities facing the [BPS] and wholesale energy markets in New York”); ERCOT Comments, *supra* note 27, at 2 (“ERCOT [has] always taken action, when appropriate and feasible, to ensure the ERCOT system is able to withstand foreseeable system disturbances.”).

enhancing resilience for the BPS.”<sup>58</sup> As noted above, DOE has acknowledged that significant increases in wind and solar generation, among other factors, have contributed to the currently reliable grid; despite traditional generation retirements, “at the end of 2016, the system had more dispatchable capacity capable of operating at high utilization rates than it did in 2002.”<sup>59</sup>

CAISO’s collaboration with developer First Solar and the National Renewable Energy Laboratory on a 300 megawatt (MW) solar power plant is just one example of how renewable energy can sustain system reliability:

This project demonstrated that advanced power electronics and solar generation can be controlled to contribute to system-wide reliability. It was shown that the First Solar plant can provide essential reliability services related to different forms of active and reactive power controls, including plant participation in [automatic generation control (AGC)] primary frequency control, ramp rate control, and voltage regulation. For AGC participation in particular, by comparing the [photovoltaic (PV)] plant testing results to the typical performance of individual conventional technologies, we showed that regulation accuracy by the PV plant is 24–30 points better than fast gas turbine technologies. The plant’s ability to provide volt-ampere reactive control during periods of extremely low power generation was demonstrated as well.<sup>60</sup>

The remaining two grid operators, PJM and ISO-NE, expressed discrete long-term reliability and resilience concerns. While several of Public Interest Organizations and other groups address these concerns in depth in separate comments filed in the instant docket,<sup>61</sup> we note briefly the following.

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<sup>58</sup> SPP Comments, *supra* note 28, at 18.

<sup>59</sup> DOE Staff Report, *supra* note 17, at 63.

<sup>60</sup> Clyde Loutan, *et al.*, *Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant*, v, NREL (March 2017), <https://www.nrel.gov/docs/fy17osti/67799.pdf>.

<sup>61</sup> See the comments filed in the instant docket by the Massachusetts Attorney General’s Office, New Hampshire Office of the Consumer Advocate, RENEW Northeast, Acadia Center, Conservation Law Foundation, Environmental Defense Fund, Natural Resources Defense Council, PowerOptions, Inc., Sierra Club, Union of Concerned Scientists, and Vermont Energy Investment Corporation (hereinafter Joint Requesters Comments); RENEW Northeast, Conservation Law Foundation, Natural Resources Defense Council, Sierra Club, and Sustainable FERC Project (Clean Energy Advocates Comments); Comments of Consumer and Public Interest Advocates, (May 9, 2018), Docket No. AD18-7.

ISO-NE agrees that “the instruments and procedures it has developed and implemented”<sup>62</sup> have resulted “in a robust, reliable, and therefore resilient, [BPS].”<sup>63</sup> ISO-NE’s long-term concerns derive from an “Operational Fuel Security Analysis” (OFSA) it conducted in January 2018, in which ISO-NE evaluated numerous scenarios modeling a severe winter in 2024-2025. Based on the OFSA, ISO-NE concluded that it may face fuel security issues due to regionwide challenges in obtaining natural gas during constrained cold weather periods.<sup>64</sup>

As outlined in a May 3, 2018 study conducted by energy analysts Paul Peterson, Doug Hurley, and Pat Knight and filed in the instant docket by a diverse group of New England stakeholders, including several of the Public Interest Organizations,<sup>65</sup> the OFSA suffers from methodological and data-based flaws that render its results erroneous.<sup>66</sup> Specifically, ISO-NE used unreasonable assumptions regarding (1) consumer electricity and gas demand and (2) the renewable, electricity imports, and LNG variables contained within its reference case.<sup>67</sup> As New England Clean Energy Advocates explain, the OFSA also failed to assess the probability of potential fuel security risks, as it failed to reflect both the region’s current trajectory and reasonably expected changes to the resource mix.<sup>68</sup>

After the OFSA’s release, several ISO-NE stakeholders requested a new “business-as-usual” case that included more reasonable assumptions about future loads and available

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<sup>62</sup> ISO-NE Comments, *supra* note 27, at 12–13.

<sup>63</sup> ISO-NE Comments, *supra* note 27, at 12–13.

<sup>64</sup> ISO-NE Comments, *supra* note 27, at 4–5.

<sup>65</sup> *See generally* Joint Requesters Comments, *supra* note 61.

<sup>66</sup> Joint Requesters Comments; *see generally* Paul Peterson, Doug Hurley, & Pat Knight, *Understanding ISO New England’s Operational Fuel Security Analysis*, SYNAPSE ENERGY ECONOMICS, INC. (May 3, 2018), <https://www.clf.org/wp-content/uploads/2018/05/Understanding-ISO-NE-OFSA1.pdf>.

<sup>67</sup> Peterson, *supra* note 66, at ii.

<sup>68</sup> *See* Clean Energy Advocates Comments, *supra* note 61.

resources as a replacement for ISO-NE’s original, flawed reference case in the OFSA. ISO-NE agreed to model this business-as-usual case and fifteen scenarios based on it, including several of ISO-NE’s worst-case, low-probability-of-occurrence/high-impact failure scenarios (including the loss of a major interstate pipeline compressor station). ***The results showed no operational or reliability threats and no instances of rolling blackouts during an extremely cold winter.***<sup>69</sup>

Further, the stakeholder scenarios outlined numerous ways in which ISO-NE could reduce or eliminate potential reliability concerns, including concerns about an evolving resource mix.<sup>70</sup>

Further, ISO-NE draws conclusions from the OFSA that are not supported by its own analysis.<sup>71</sup> For example, while ISO-NE suggested in its comments that renewable energy may drive fossil-fired generators retirements<sup>72</sup> that could lead to fuel insecurity, its OFSA data shows precisely the opposite: continued growth in renewable energy (and energy efficiency) will make the region’s grid more fuel secure, and progressively more, rather than less, reliable and resilient.<sup>73</sup>

Regarding PJM, PJM agrees that its “BPS is safe and reliable today – it has been designed and is operated to meet all applicable reliability standards.”<sup>74</sup> Further, PJM’s own research shows that it can maintain long-term resilience and reliability through a variety of resource portfolios, including those with “very high renewable penetration—dozens of times

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<sup>69</sup> Peterson, *supra* note 66, at ii–iii.

<sup>70</sup> Peterson, *supra* note 66, at iii; *see also* Clean Energy Advocates Comments, *supra* note 61, at A-7–A-10.

<sup>71</sup> Clean Energy Advocates Comments, *supra* note 61, at 8–11.

<sup>72</sup> *E.g.*, ISO-NE Comments, *supra* note 27, at 32 (“More renewable resources can help lessen the region’s fuel-security risk depending on the type and quantity, but are likely to drive coal- and oil-fired generator retirements.”).

<sup>73</sup> Clean Energy Advocates Comments, *supra* note 61, at 11–13, A-9–A-10.

<sup>74</sup> PJM Comments, *supra* note 28, at 4.

higher than current levels[.]”<sup>75</sup> But PJM’s comments also expressed concerns that its grid could struggle in the future as coal and nuclear generation continue to retire, citing high-impact events such as the 2014 Polar Vortex and 2018 Cold Snap as support.<sup>76</sup> As noted by comments filed in the instant docket by consumer and public interest advocates, PJM’s experiences with the 2014 Polar Vortex and the 2018 Cold Snap actually show that (1) PJM’s resource adequacy and operational procedures are sound, (2) generation outages do not pose an imminent threat to reliability or resilience, and (3) non-generation options are highly effective for maintaining reliability and resilience.<sup>77</sup>

As noted by Commissioner Glick, “a diverse array of generation resources, including natural gas, solar, wind and geothermal, as well as maturing technologies, such as energy storage, distributed generation, and demand response, have in many respects contributed to the resilience of the [BPS].”<sup>78</sup> SPP’s record-setting integration of significant wind- and renewable generation resources shows that high renewable penetration can be achieved while maintaining—and in fact, enhancing—reliability and resilience.<sup>79</sup> For instance, the Public Service Company of Colorado controls its wind generation “to provide both up and down

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<sup>75</sup> Silverstein Report, *supra* note 8, at 39.

<sup>76</sup> See generally PJM Comments, *supra* note 28.

<sup>77</sup> See Comments of Consumer and Public Interest Advocates, *supra* note 61.

<sup>78</sup> *Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,012, at 2 (2018), Docket Nos. RM18-1 and AD18-7 (Commissioner Glick, concurring).

<sup>79</sup> Further, despite this extensive wind and renewable integration, SPP has not experienced any “real time” reserve margin levels low enough to trigger any studies regarding lack of capacity based on issues with a specific fuel source. SPP Comments, *supra* note 28, at 9; see also News Release, SPP sets wind and renewable penetration records (Dec. 4, 2017), <https://www.spp.org/about-us/newsroom/spp-sets-wind-and-renewable-penetration-records/>. SPP’s experience is not unique. For example, last year, during a one-day experiment, Great Britain’s national grid successfully supplied the country’s electricity needs without the need for any coal generation. *British power generation achieves first ever coal-free day*, THE GUARDIAN (Apr. 21, 2018), <https://www.theguardian.com/environment/2017/apr/21/britain-set-for-first-coal-free-day-since-the-industrial-revolution>.



regulation reserves”<sup>80</sup> and is able to “use wind reserves as an ancillary service for frequency regulation by integrating the wind power plants in their footprint to provide AGC.”<sup>81</sup> Further, as energy storage, demand response, energy efficiency, and DERs continue to expand, the role of legacy technologies will change. Private corporations already recognize this and are implementing these technologies to reduce their carbon footprints.<sup>82</sup> As outlined by CAISO:

There are no baseload coal resources in the CAISO balancing authority area, and the one remaining nuclear unit is scheduled to retire in 2024. Where other regions are experiencing an influx of natural gas-fired resources, such resources are declining in number in the CAISO footprint. Although the CAISO will need gas fired resources to provide vital reliability services for the foreseeable future, the CAISO system is changing at a rapid pace to one where renewable and other non-carbon emitting resources, both grid connected and behind-the-meter, will serve much of the load and, ultimately, be called upon to provide a significant portion of needed reliability services.<sup>83</sup>

Moreover, the RTOs/ISOs have and continue to actively address issues, including resilience and reliability issues, without explicit direction from the Commission, as “grid operators ... view resilience as part of their existing responsibility.”<sup>84</sup> In the January 8 order, the Commission asked the RTOs/ISOs to outline the steps they take to identify, anticipate, and mitigate resilience risks.<sup>85</sup> The RTOs’/ISOs’ responses confirm that they engage in a wide range of preventative actions that ensure resilience and reliability, though the specific mechanisms differ depending on the unique needs of each region.

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<sup>80</sup> Loutan, *supra* note 60, at 7.

<sup>81</sup> Loutan, *supra* note 60, at 7.

<sup>82</sup> See, e.g., Peter Maloney, *How Walmart is leveraging DERs for its 100% renewable energy goal*, UTILITY DIVE (Oct. 25, 2016), <https://www.utilitydive.com/news/how-walmart-is-leveraging-deres-for-its-100-renewable-energy-goal/428952/>.

<sup>83</sup> CAISO Comments, *supra* note 29, at 1–2.

<sup>84</sup> Silverstein Report, *supra* note 8, at 11–12.

<sup>85</sup> *Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,012, at PP 25–27 (2018), Docket No. RM18-1 and AD18-7.

*First*, the RTOs/ISOs already prepare for adverse conditions, which relate to resilience and reliability across the time scale of the power grid, from seconds to years. Examples include: (1) system planning, including reserve margins, capacity markets, and resource adequacy programs; (2) operational practices and assessments; (3) practice drills; and (4) the applicability of local or regional reliability standards in supplement to national NERC reliability standards.

Reserve margins “enhance resilience by helping to absorb and adapt to a sudden disturbance on the grid,”<sup>86</sup> thereby reducing both the probability and magnitude of an outage.<sup>87</sup> DOE reports that “all regions project more than sufficient”<sup>88</sup> reserve margins, “despite the loss of traditional baseload capacity since 2002.”<sup>89</sup> The RTOs’/ISOs’ responses echo this conclusion.<sup>90</sup>

Similarly, CAISO and ERCOT both described the importance of their resource adequacy programs in protecting the BPS.<sup>91</sup> NYISO also outlined its “extensive system planning” and how

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<sup>86</sup> Silverstein Report, *supra* note 8, at 12.

<sup>87</sup> Silverstein Report, *supra* note 8, at 12.

<sup>88</sup> DOE Staff Report, *supra* note 17, at 65.

<sup>89</sup> DOE Staff Report, *supra* note 17, at 65–66.

<sup>90</sup> *E.g.*, ISO-NE Comments, *supra* note 27, at 4 (“ISO-NE’s work in planning, markets, and operations to help ensure that the region has the power resources and transmission facilities necessary to meet demand and reserve requirements results in a [BPS] that has many attributes of a resilient system, as defined by the Commission.”); SPP Comments, *supra* note 28, at 9 (“SPP has not experienced ‘real time’ reserve margin levels ... low enough to trigger special studies of lack of capacity in connection with a specific fuel type.”); MISO Comments, *supra* note 28, at 31 (“Resource planning reserve margins based on loss of load expectation criteria, together with planning for deliverability of all network resources, ensures robustness of supplies against greater than typical forced outage conditions.”); NYISO Comments, *supra* note 27, at 8 (“The reserve margin is intended to address potential contingencies and other unanticipated events that may result in the need for additional resource capability to adequately serve system needs.”); *see also* PJM Comments, *supra* note 28, at 65–66 (noting that its capacity markets “were designed with key features that work to ensure a more resilient BPS.”).

<sup>91</sup> CAISO Comments, *supra* note 29, at 63, 119–20 (“The CAISO performs numerous planning studies to support the continued, reliable operation of the transmission system,” followed by an expanded discussion of CAISO’s resource adequacy program); ERCOT Comments, *supra* note 27, at 11 (“ERCOT conducts a variety of assessments of the sufficiency of resources to meet projected future load.”).

it helps to ensure reliability both now and in the future.<sup>92</sup> ISO-NE similarly explained how it revised its auditing requirements in 2013 to help bolster its reliability assessments.<sup>93</sup> ERCOT noted that it visits generators in its territory each winter to ensure that proper weatherization practices are in place.<sup>94</sup> PJM and MISO outlined practice drills they conduct involving a wide range of RTO/ISO stakeholders.<sup>95</sup> MISO noted that it frequently discovers resilience threats through simulations.<sup>96</sup> Lastly, local and regional standards, such as New York’s Reliability Council, the Northeast Power Coordinating Council, and the Western Electricity Coordinating Council, as well as state commissions, create reliability standards that supplement NERC’s mandatory standards.

**Second**, the RTOs/ISOs already assess transmission resilience and reliability through a variety of mechanisms that are tailored to regional needs and circumstances. These include MISO’s disaster recovery plans,<sup>97</sup> NYISO phasor measurement tools,<sup>98</sup> CAISO’s regional planning tools,<sup>99</sup> ERCOT’s geographic diversity studies,<sup>100</sup> SPP’s remedial action schemes,<sup>101</sup> and ISO-NE’s transmission planning assessments,<sup>102</sup> among others.

Relatedly, in September 2017, PJM held its Grid 20/20 event to address resilience and reliability issues. In its comments, PJM highlighted that Grid 20/20 enabled PJM “and its

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<sup>92</sup> NYISO Comments, *supra* note 27, at 12.

<sup>93</sup> ISO-NE Comments, *supra* note 27, at 59.

<sup>94</sup> ERCOT Comments, *supra* note 27, at 18.

<sup>95</sup> PJM Comments, *supra* note 28, at 15; MISO Comments, *supra* note 28, at 36.

<sup>96</sup> MISO Comments, *supra* note 28, at 36.

<sup>97</sup> MISO Comments, *supra* note 28, at 19.

<sup>98</sup> NYISO Comments, *supra* note 27, at 13.

<sup>99</sup> CAISO Comments, *supra* note 29, at 88.

<sup>100</sup> ERCOT Comments, *supra* note 27, at 8.

<sup>101</sup> SPP Comments, *supra* note 28, at 14.

<sup>102</sup> ISO-NE Comments *supra* note 27, at 40.

stakeholders, including representatives of state regulatory agencies,”<sup>103</sup> to discuss resilience within a broader framework, including “at the transmission and distribution levels.”<sup>104</sup> These stakeholder meetings and initiatives are effective because they allow the RTOs/ISOs to create tailored, regional solutions that are appropriate for their unique circumstances. The Commission already has recognized the value of these initiatives, noting in the January 8 order:

[T]he concept of resilience necessarily involves issues, topics, and questions that extend beyond the Commission’s jurisdiction, such as distribution system reliability and modernization. The Commission encourages RTOs/ISOs and other interested entities to engage with state regulators and other stakeholders through Regional State Committees or other venues to address resilience at the distribution level.<sup>105</sup>

**Third**, the RTOs/ISOs already implement a variety of programs and tools to protect the grid against cyber and other security threats. NYISO “has a comprehensive program for addressing physical and cybersecurity risks.”<sup>106</sup> MISO, CAISO, SPP, ISO-NE, and ERCOT have adopted and implemented robust cybersecurity procedures.<sup>107</sup> In March 2017, PJM initiated a Security and Resilience Advisory Committee, which is tasked with identifying priority reliability initiatives, including cyber intrusions and other security threats.<sup>108</sup> The RTOs/ISOs also all participate in NERC’s biennial GridEx, which simulates a grid cyber and/or physical attack.<sup>109</sup>

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<sup>103</sup> PJM Comments, *supra* note 28, at 15.

<sup>104</sup> PJM Comments, *supra* note 28, at 15.

<sup>105</sup> *Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,012, at P 19 n.31 (2018), Docket No. RM18-1 and AD18-7.

<sup>106</sup> NYISO Comments, *supra* note 27, at 25.

<sup>107</sup> MISO Comments, *supra* note 28, at 5–6; CAISO Comments, *supra* note 29, at 21; SPP Comments, *supra* note 28, at 18; ISO-NE Comments, *supra* note 27, at 39; ERCOT Comments, *supra* note 27, at 19.

<sup>108</sup> PJM Comments, *supra* note 28, at 14.

<sup>109</sup> See *GridEx*, NERC, <https://www.nerc.com/pa/CI/CIPOutreach/Pages/GridEX.aspx> (last accessed May 8, 2018).

**Fourth**, the RTOs/ISOs already plan for Black Start conditions.<sup>110</sup> For example, last year, CAISO launched a Black Start stakeholder initiative, in which it asked stakeholders to comment on an issue paper outlining its Black Start procedures and plans.<sup>111</sup> ERCOT noted in its comments that it holds a biannual Black Start Gas Coordination Working Group, which brings together pipeline owners, generation operators, government representatives, and other stakeholders, to ensure that ERCOT can quickly and efficiently restart the grid.<sup>112</sup> This month, the Commission and NERC released a study confirming that the grid operators “currently have sufficient blackstart resources in their system restoration plans, as well as comprehensive strategies for mitigating against loss of any additional blackstart resources going forward.”<sup>113</sup> This includes the incorporation of battery technology, such as the California Imperial Irrigation District’s successful May 2017 demonstration of black starting through battery storage systems.<sup>114</sup>

**Fifth**, the RTOs/ISOs share information to prepare for changes in the fuel mix and supply. Examples include, but are not limited to, MISO’s coordination with PJM on the Joint and

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<sup>110</sup> See, e.g., PJM Comments, *supra* note 28, at 69–70 (“Black Start Service supports reliability by designing specific generators whose location and capabilities are required to quickly re-energize the transmission system after a blackout.”); MISO Comments, *supra* note 28, at 45 (“MISO provides other generation and transmission services that support resilience [including] Black Start service[.]”); CAISO Comments, *supra* note 29, at 138, 145–47 (“The CAISO has several other mechanisms to support reliability and resilience ... [including] Black Start.”).

<sup>111</sup> Market Notice, New Initiative: Black Start and System Restoration Phase 2, CAISO (Jan. 17, 2017), [http://www.caiso.com/Documents/NewInitiativeBlackStart-SystemRestorationPhase2\\_Call012417.html](http://www.caiso.com/Documents/NewInitiativeBlackStart-SystemRestorationPhase2_Call012417.html).

<sup>112</sup> ERCOT Comments, *supra* note 27, at 19.

<sup>113</sup> *Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans*, 2, FERC (May 2018), <https://www.ferc.gov/legal/staff-reports/2018/bsr-report.pdf>; see also Robert Walton, *FERC-NERC: Grid operators have sufficient blackstart capabilities*, UTILITY DIVE (May 3, 2018), <https://www.utilitydive.com/news/ferc-nerc-grid-operators-have-sufficient-blackstart-capabilities/522671/>.

<sup>114</sup> Andy Colthorpe, *California battery’s black start capability hailed as ‘major accomplishment in the energy industry’*, ENERGY-STORAGE NEWS (May 17, 2017), <https://www.energy-storage.news/news/california-batterys-black-start-capability-hailed-as-major-accomplishment-i>.

Common Market initiative<sup>115</sup> and CAISO's preparation and coordination efforts with local and other regional entities.<sup>116</sup> As noted by MISO, its coordination with PJM "is a good example of a ruleset that provides mutually beneficial support built upon industry leading operational coordination."<sup>117</sup>

*Last*, the RTOs/ISOs learn from history to adapt and prepare for future events. NYISO stated that it "continually assesses New York's electric system to ensure the ongoing reliability and resilience of the system."<sup>118</sup> These include holistic short-term and long-term assessments of resource adequacy, along with targeted after-the-fact reviews of significant operational events.<sup>119</sup> For example, after Winter 2013-2014, NYISO implemented a new reserve region for Southeastern New York and increased New York's statewide reserve requirement by almost 2,000 MW.<sup>120</sup> These operating reserves bolster "system resiliency by providing ready access to additional resource capacity to respond to, and expeditiously recover from, system disturbances."<sup>121</sup>

NYISO is not alone. SPP reported that it regularly engages in post-event studies of events that affect the SPP footprint, such as tornados, flooding, and ice.<sup>122</sup> These reviews have led to specific system-wide recommendations regarding communications with federal agencies,

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<sup>115</sup> MISO Comments, *supra* note 28, at 17, 45.

<sup>116</sup> CAISO Comments, *supra* note 29, at 13 (noting that CAISO "regularly communicates and coordinates with other entities, including neighboring balancing authorities and knowledgeable third parties having responsibilities (and specific knowledge) in [specific] areas, to identify risks and assess their potential impact.").

<sup>117</sup> MISO Comments, *supra* note 28, at 9.

<sup>118</sup> NYISO Comments, *supra* note 27, at 14.

<sup>119</sup> NYISO Comments, *supra* note 27, at 14.

<sup>120</sup> NYISO Comments, *supra* note 27, at 7.

<sup>121</sup> NYISO Comments, *supra* note 27, at 7.

<sup>122</sup> SPP Comments, *supra* note 28, at 14.

transmission owners and operators, and with reliability and planning coordinators.<sup>123</sup> Similarly, after the 2004 Cold Snap, “ISO-NE developed new operational procedures, and enhanced operational tools to mitigate fuel-security risk,” including the development of procedures designed to improve communication on generator availability during severe weather.<sup>124</sup> Moreover, CAISO extensively discussed in its comments measures it implemented following the unexpected closure of the San Onofre Nuclear Generating Station (SONGS) and the 2016 limited operation of the Aliso Canyon Natural Gas Storage Facility.<sup>125</sup> Regarding SONGS, CAISO coordinated with transmission owners, state-level agencies, and with the Governor to identify both short-term solutions and long-term plans.<sup>126</sup> Regarding Aliso Canyon, CAISO worked with state and local agencies, as well as industry, to assess resilience and reliability threats through a series of assessments, which “identified mitigation measures to reduce the impacts of the event, maintain reliability, and enhance its ability to address similar events in the future.”<sup>127</sup>

Relatedly, both PJM and MISO noted explicit steps they took after the 2014 Polar Vortex to ensure grid resilience. MISO coordinated with its Electric and Natural Gas Coordination Task Force to produce an issue paper outlining observations, challenges, and lessons learned.<sup>128</sup> These reviews “resulted in MISO being better prepared for the extreme cold snap that occurred in January 2018,”<sup>129</sup> including the establishment of an internal gas/electric coordination team. Likewise, PJM conducted root cause analyses and implemented “changes to its rules regarding operations and planning, increased staffing, enhanced power flow models, implemented new

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<sup>123</sup> SPP Comments, *supra* note 28, at 14.

<sup>124</sup> ISO-NE Comments, *supra* note 27, at 56.

<sup>125</sup> *E.g.*, CAISO Comments, *supra* note 29, at 16–18.

<sup>126</sup> CAISO Comments, *supra* note 29, at 17.

<sup>127</sup> CAISO Comments, *supra* note 29, at 18.

<sup>128</sup> MISO Comments, *supra* note 28, at 38.

<sup>129</sup> MISO Comments, *supra* note 28, at 38.

tools and technologies, created generator preparedness, checklists, updated its formula for resource adequacy and made market rules changes including Capacity Performance.”<sup>130</sup> The following winter, despite even higher peak loads, PJM saw improved generator performance.<sup>131</sup>

This non-exhaustive list highlights both that the RTOs/ISOs already view resilience as part of their existing responsibility<sup>132</sup> and that they are effective in evaluating procedures to ensure grid resilience. As such, the Commission should resist imposing additional resilience requirements—which would manifest as higher customer costs—without evidence of need.

### **C. Efforts to Pursue and Avoid as the Grid Continues to Evolve**

The Commission should be wary of mere duplication in the name of being proactive. While there is no urgent need for the Commission to act in the name of resilience, the Commission can use its regulatory authority to support what the RTOs/ISOs are doing already and to benefit end-use consumers. Examples include supporting policies that protect customer interests, encourage collaboration and consistency, and continue to remove barriers to the integration of new technologies and customer-owned resources into wholesale power markets (*e.g.*, renewable technologies, energy storage, demand response, energy efficiency, and DERs).

Most critically, the Commission should ensure that any new resilience requirements have a direct and quantifiable beneficial impact on customers. This is because customers are the ones who ultimately will pay for implementing new requirements. As noted in the Silverstein Report, “[w]e do not build electric generation or transmission for their own sakes. Every element of the end-to-end power system ... exists to provide energy services for end-use customers.”<sup>133</sup> As

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<sup>130</sup> PJM Comments, *supra* note 28, at 54.

<sup>131</sup> 2015 Winter Report, at 5-6, PJM (May 13, 2015), <http://www.pjm.com/-/media/library/reports-notices/weather-related/20150513-2015-winter-report.ashx?la=en>.

<sup>132</sup> Silverstein Report, *supra* note 8, at 11–12.

<sup>133</sup> Silverstein Report, *supra* note 8, at 13.



NERC and the RTOs/ISOs have a robust set of systems in place to ensure that the BPS remains resilient, the Commission should act carefully in imposing new resilience standards.

To that end, the Commission should resist the call from Secretary Perry to focus on generation resilience due to the risks of high-impact, low frequency events, such as the 2014 Polar Vortex and Superstorm Sandy.<sup>134</sup> The data does not support this focus. As noted in the Silverstein Report, “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 [BPS] resilience beyond the engineering-based reliability services already being procured.”<sup>135</sup> Rather, the data supports that RTOs/ISOs could do more to avoid and minimize customer outages—and thereby improve reliability and resilience—by helping to strengthen distribution systems’ resilience against severe weather events, rather than by focusing on resilience at the BPS level. This is because “the vast majority of outages across the power system are caused by severe weather rather than generation-level failures (including fuel supply failures).”<sup>136</sup> Most of these outages harm distribution assets “in common ways, leading to the conclusion that one can have the greatest practical impact on resilience and reliability by addressing”<sup>137</sup> transmission and distribution systems “and grid operation rather than generation and fuel issues.”<sup>138</sup>

As noted by Rhodium Group, between 2012 and 2016, weather caused ***96 percent of domestic outage-hours; comparatively, less than .01 percent of custom outage-hours were***

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<sup>134</sup> Proposed Rule, 82 Fed. Reg. 46,940, 46,945 (proposed Oct. 10, 2017), *rejected by Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,012 (2018).

<sup>135</sup> Silverstein Report, *supra* note 8, at 7.

<sup>136</sup> Silverstein Report, *supra* note 8, at 13.

<sup>137</sup> Silverstein Report, *supra* note 8, at 13.

<sup>138</sup> Silverstein Report, *supra* note 8, at 13.

*caused by generation shortfalls or fuel supply.*<sup>139</sup> A recent DOE study likewise found that **90 percent of electric power interruptions were on the distribution system.**<sup>140</sup> Given the role distribution plays in resilience, many of the most effective resilience solutions fall outside of the Commission’s jurisdiction.<sup>141</sup>

This does not mean, however, that the Commission is powerless to assist resilience and reliability efforts. Should the Commission choose to act, it should first develop a framework for addressing resilience in conjunction with reliability and convene stakeholders across the transmission and distribution systems to discuss the best uses for consumers’ money for reliability and resilience services. Procedurally, the first step could be to initiate a technical conference. The Commission also could help to facilitate reliability and resilience by focusing on measures that affect planning and markets. With respect to planning, the Commission could help the RTOs/ISOs learn more from one another and better share resources, as well as integrate technologies that strengthen or fall outside of the distribution system. This includes supporting greater collaboration and coordination among the RTOs/ISOs and the distribution system, as well as integrating technologies, such as DERs, into the transmission system.

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<sup>139</sup> Trevor Houser, John Larsen, & Peter Marsters, *The Real Electricity Reliability Crisis*, RHODIUM GROUP (Oct. 3, 2017), <https://rhg.com/research/the-real-electricity-reliability-crisis-doe-nopr/>; see also Silverstein Report, *supra* note 8, at 3 (“Based on historic events ... the vast majority of outage events arise at the distribution and transmission levels from weather events.”); see also Silverstein Report, *supra* note 8, at 18–19.

<sup>140</sup> Silverstein Report, *supra* note 8, at 4, 16; see also Silverstein Report, *supra* note 8, at 54 (“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.”).

<sup>141</sup> The Commission could, however, coordinate with the National Association of Regulatory Utility Commissioners (NARUC) on these initiatives. See, e.g., *Federal Government Collaboratives: Reliability and the Environment*, NARUC, <https://www.naruc.org/our-programs/federal-government-collaboratives/> (last accessed May 8, 2018).

Strengthening interregional planning requirements is one way to effectively support reliability and resilience.<sup>142</sup> As demonstrated above, the RTOs/ISOs currently conduct robust resilience-based planning—including transmission planning—within their own regions. But, as also explained above, the challenges and solutions applicable to each RTO/ISO are different. Currently, the RTOs/ISOs are required to engage in interregional planning under the Commission’s Order 1000. However, the existing requirements are limited and thus interregional planning efforts have resulted in very few interregional transmission upgrades, even though studies have identified many economically beneficial projects. The regional differences and criteria limit the ability of the regions to come to agreement to fund identified upgrades and essentially offer an off-ramp under the regional review that follows interregional planning efforts. Strengthening the transmission connections among the regions can allow for each region to offer more assistance to the other under extreme events. At the same time, such upgrades provide improved access to low-cost resources and more robust joint market operations.

As MISO noted, greater interregional coordination would improve resilience, as it allows each RTO/ISO to “leverage the inter-regional diversity of load and supply generation [of each RTO/ISO] to support resilient operations.”<sup>143</sup> Thus, greater interregional planning would improve reliability and resilience by allowing RTOs/ISOs to harness the unique resilience strengths of each region. Specifically, increased coordination of generation and transmission outages among the regions can improve operations across the seams, reduce congestion, and improve resilience.

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<sup>142</sup> See generally Comments of Americans for a Clean Energy Grid (May 8, 2018), Docket No. AD18-7.

<sup>143</sup> MISO Comments, *supra* note 28, at 9.

The RTOs/ISOs recognize the relationship between interregional coordination and resilience. For example, CAISO stated that the design of each aspect of the BPS “affects the resilience of the system.”<sup>144</sup> Similarly, MISO outlined that it “seeks to identify the set of local and regional transmission solutions that ... ensure the reliable and resilient operation of the transmission system,”<sup>145</sup> while ERCOT noted that, “[w]hen planning new transmission projects, ERCOT strives to build greater resilience in the system.”<sup>146</sup> ISO-NE has invested approximately \$10 billion in reliability-based transmission since 2002.<sup>147</sup> SPP stated that improved transmission not only helps to bring “low-cost, renewable energy to market,” but also helps “resilience by creating and strengthening alternate paths within SPP.”<sup>148</sup> Finally, NYISO explicitly noted that “resiliency is closely linked to the importance of maintaining and expanding interregional interconnections[.]”<sup>149</sup> Essentially, interregional planning leads to smarter planning, which results “in better performance, better reliability, more renewable energy, [] lower greenhouse gas emissions [and] ... most importantly, it will save US ratepayers lots and lots of money.”<sup>150</sup> As such, the Commission should consider taking actions that promote strong requirements for interregional planning and coordination.

Such improvements are not isolated to interregional coordination. DOE has acknowledged that DERs can reduce peak loads, provide reactive power and voltage support, and “decrease the vulnerability of the electric system to threats from terrorist attacks, and other

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<sup>144</sup> CAISO Comments, *supra* note 29, at 51.

<sup>145</sup> MISO Comments, *supra* note 28, at 15.

<sup>146</sup> ERCOT Comments, *supra* note 27, at 8.

<sup>147</sup> ISO-NE Comments, *supra* note 27, at 14–15.

<sup>148</sup> SPP Comments, *supra* note 28, at 8.

<sup>149</sup> NYISO Comments, *supra* note 27, at 4.

<sup>150</sup> David Roberts, *We need lots more power lines. Why are we so bad at planning them?* VOX (June 9, 2016), <https://www.vox.com/2016/6/9/11881556/power-lines-bad-planning>.

forms of potentially catastrophic disruptions, and ... increase the resiliency of other critical infrastructure sectors.”<sup>151</sup> DOE has further recognized the benefits of storage in helping customers recover from extreme weather events.<sup>152</sup> Both distributed generation and storage, which are sited closer to customers with fewer potential points of failure between them, could contribute more to reducing vulnerability for customers. In addition, DOE has acknowledged that “renewable resources have a positive impact on dependencies and supply chain interruptions because, unlike fossil fuel power plants, they do not depend on other infrastructure to provide their fuel,”<sup>153</sup> and in times of drought, “resources such as wind and solar have a positive impact on grid resilience because they are not water-intensive.”<sup>154</sup>

Further, these inverter-based resources can provide essential reliability services more quickly than traditional thermal power plants, a fact that should be considered if resilience is about the rate of recovery from an outage. For example, various frequency response services can respond on different timescales, and inverter-based technologies can respond faster and more accurately than traditional thermal plants, which reduces the amount of response needed.<sup>155</sup>

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<sup>151</sup> See generally *The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Their Expansion: A Study Pursuant to Section 1817 of the Energy Policy Act of 2005*, DOE (Feb. 2007), <https://www.ferc.gov/legal/fed-sta/exp-study.pdf>.

<sup>152</sup> DOE Staff Report, *supra* note 17, at 63 & n.aaa.

<sup>153</sup> Benjamin L. Preston, *et al*, *Resilience of the U.S. Electricity System: A Multi-Hazard Perspective*, at 28, DOE Office of Energy Policy and Systems Analysis (Aug. 18, 2016), <https://www.energy.gov/sites/prod/files/2017/01/f34/Resilience%20of%20the%20U.S.%20Electricity%20System%20A%20Multi-Hazard%20Perspective.pdf>.

<sup>154</sup> *Id.*

<sup>155</sup> Comments of American Wind Energy Association at 4, Docket No. RM16-6-000 (“The fast controls inherent in modern wind turbines allow them to respond to frequency deviations more quickly and accurately than many conventional generators.”); *see also* Comments of Energy Storage Association at 6, Docket No. RM16-6-000 (“Higher-performing, fast frequency response resources provide greater system benefits than slower frequency response resources precisely because they reduce overall frequency response service needed.”).

Additionally, in addressing resilience and reliability issues, the Commission must use market-oriented solutions that are resource- and technology-neutral. For example, the Commission can support resilience and reliability by assisting with the ongoing development of (and RTO/ISO coordination with) energy storage, demand response, energy efficiency, privately-owned microgrids, scarcity pricing, and smart/automated distribution infrastructure. With respect to DERs, specifically, the RTOs/ISOs already are taking important steps towards DER integration. For example, CAISO's 4,900 MW of DERs can provide 163 MW of frequency response<sup>156</sup> and NYISO is developing a DER Roadmap.<sup>157</sup> The Commission can further support resilience and reliability by taking steps to fully integrate DERs into wholesale power markets and planning. As noted in the Silverstein Report, "markets best support reliability and resilience when they allow all sources to contribute, including [DERs]—distributed generation, demand response and distributed storage."<sup>158</sup> NERC also has recognized the resilience and reliability benefits of DERs, noting that DERs "provide reliability services now"<sup>159</sup> and could provide "even more so in the future" through increased visibility.<sup>160</sup>

By supporting DER integration, for example, the Commission also would help promote flexibility. Flexibility improves resilience as a more flexible grid can more quickly and more

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<sup>156</sup> See *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Comments of Public Interest Organizations at 4–5 (Feb. 14, 2017), Docket Nos. AD16-20, RM16-23, and RM18-9 (hereinafter DER-PIO Comments).

<sup>157</sup> See DER-PIO Comments, *supra* note 156, at 4–5.

<sup>158</sup> Silverstein Report, *supra* note 8, at 51.

<sup>159</sup> See DER-PIO comments, *supra* note 156, at 4–5.

<sup>160</sup> See DER-PIO comments, *supra* note 156, at 4–5. Additionally, the recently revised Institute of Electrical and Electronics Engineers (IEEE) 1547 standard for the interconnection and interoperability of DERs will mean that DERs will improve local reliability services support on the distribution system, and should therefore help improve reliability. See *IEEE Standard 1547-2018*, IEEE <http://standards.ieee.org/findstds/standard/1547-2018.html> (last accessed May 8, 2018). DERs, combined with grid modernization, which will create two-way power flows on the distribution system and smarter switching (self-healing), should also decrease the frequency and duration of local power outages making the system more reliable.

efficiently respond to and recover from grid disruptions.<sup>161</sup> In fact, NERC’s essential reliability services include flexibility or ramping.<sup>162</sup> The Commission could also support other market design features that incentivize flexibility, including scarcity pricing and more active price-responsive demand participation.<sup>163</sup> As noted by ERCOT, scarcity pricing helps maintain flexibility as it supports resilience without requiring additional regulatory oversight, as these “mechanisms are designed to alleviate the need for many resilience-based regulatory controls.”<sup>164</sup>

Further, integration of these technologies benefits all, because they help industry while also lowering customer costs. For example, industry experts have noted that “[m]odernizing and digitizing the grid is a growth opportunity for utilities because it accommodates increasing customer demand and takes advantage of DERs’ ready supply of power. This boosts reliability, adds sustainability, improves efficiency and security, and enhances performance.”<sup>165</sup> But, these technologies also help customers; for example, PJM’s capacity market costs would have gone up by about \$2 billion in the 2019-2020 Base Residual Auction had demand response and energy efficiency initiatives been excluded,<sup>166</sup> and these costs would have been passed onto consumers.

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<sup>161</sup> See, e.g., ERCOT Comments, *supra* note 27, at 5; see also *How Energy Storage Works*, UNION OF CONCERNED SCIENTISTS, <https://www.ucsusa.org/clean-energy/how-energy-storage-works#.Ws5jY4jwaUk> (last accessed Apr. 11, 2018).

<sup>162</sup> See *Essential Reliability Services Whitepaper on Sufficiency Guidelines*, NERC (Dec. 2016), [https://www.nerc.com/comm/Other/essntlrbltysrvscstskfrcDL/ERSWG\\_Sufficiency\\_Guideline\\_Report.pdf](https://www.nerc.com/comm/Other/essntlrbltysrvscstskfrcDL/ERSWG_Sufficiency_Guideline_Report.pdf).

<sup>163</sup> Silverstein Report, *supra* note 8, at 51.

<sup>164</sup> ERCOT Comments, *supra* note 27, at 5; *How Energy Storage Works*, *supra* note 161.

<sup>165</sup> Frédéric Abbal, *Reduce Power Outages by Unleashing the Digital Power Distribution Grid*, SCHNEIDER ELECTRIC (Sept. 23, 2017), <https://blog.schneider-electric.com/utilities/2017/09/23/reduce-power-outages-unleashing-digital-power-distribution-grid/>.

<sup>166</sup> See DER-PIO Comments, *supra* note 156, at 12.

The Commission can help support DER integration by finalizing its DER Proposed Rule in a manner that incentivizes these resources to participate robustly in the organized wholesale markets. The Commission’s recent technical conference on DERs was a great first step. As noted above, any Commission resilience and reliability efforts should focus on customer benefits, as customers “pay the ultimate price for power outages.”<sup>167</sup> DER resources, by definition, are sited close to customers and can be capable of remaining operational even when the transmission or distribution systems experience disruptions. Thus, a rule that ensures that grid operators gain visibility on DERs and provides DERs with appropriate opportunities to earn wholesale market revenues would support growth in DERs, which are an essential part of a resilient grid, as they can provide energy—especially to critical loads—when other parts of the grid are out of service.

Additionally, the Commission could support resilience and reliability by encouraging better recognition of the contributions of renewable energy resources in existing capacity markets. For example, in PJM, certain capacity resources, like wind, solar, and demand response related to cooling loads, are largely excluded from capacity markets because of arbitrary requirements necessitating that the capacity be transacted in year-long increments. A seasonal capacity period would enable resources that are stronger in the summer or winter to be properly compensated for their capacity, therefore improving reliability and resilience, without inflating costs.<sup>168</sup>

Last, when attempting to support and encourage the expansion of these types of resources, the Commission should be careful to not conflate generation attributes or capacity

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<sup>167</sup> Silverstein Report, *supra* note 8, at 3.

<sup>168</sup> For a more expansive discussion of these issues, see Jennifer Chen, *Principles for Harmonizing State Policies with Markets*, NRDC (May 11, 2017), <https://www.nrdc.org/experts/jennifer-chen/principles-harmonizing-state-policies-markets>.



with products or services that supports resilience. DOE's 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."<sup>169</sup> While "[s]upply characteristics may help some resources provide a service or product ... they are not a service or product per se."<sup>170</sup> Further, "[c]ompensating for raw capacity has been shown to lead to poor incentives to actually deliver services"<sup>171</sup> that have a direct impact on resilience.

#### IV. CONCLUSION

The Public Interest Organizations appreciate this opportunity to provide comments on these critical questions of grid resilience and reliability. A thorough review of the RTOs'/ISOs' comments makes it clear that there remains no generally accepted definition of resilience, resilience and reliability are deeply intertwined, and that devoting efforts towards categorizing initiatives into firm "resilience" or "reliability" baskets could cause duplication and higher customer bills without any added benefit. The evidence further shows that there is no crisis of resilience and reliability today and no meaningful likelihood of one in the future. The future is bright, but can be made even brighter by the Commission supporting policies and programs that either improve cross-regional communication and interconnection, advance gas-electric coordination, or improve the integration of clean energy technologies; this should be done with a recognition that much of the most-impactful resilience work needs to be done on systems outside of the Commission's jurisdiction, particularly the distribution system.

Respectfully submitted this 9th day of May, 2018,

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<sup>169</sup> Silverstein Report, *supra* note 8, at 50.

<sup>170</sup> Silverstein Report, *supra* note 8, at 50.

<sup>171</sup> Silverstein Report, *supra* note 8, at 50.

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Attachment 1  
*The Silverstein Report*

# **A Customer-focused Framework for Electric System Resilience**

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May 2018

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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.

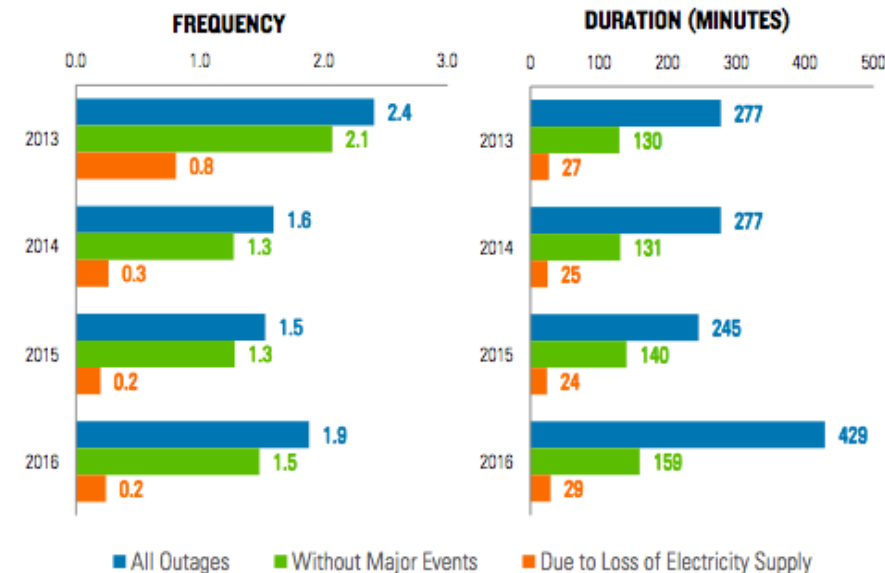
Based on historic events, however, the vast majority of outage events arise at the distribution and transmission levels from weather events. The Rhodium Group finds that the bulk of outage events are due to routine causes (local storms, vegetation, squirrels, equipment problems), and the Department of 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.

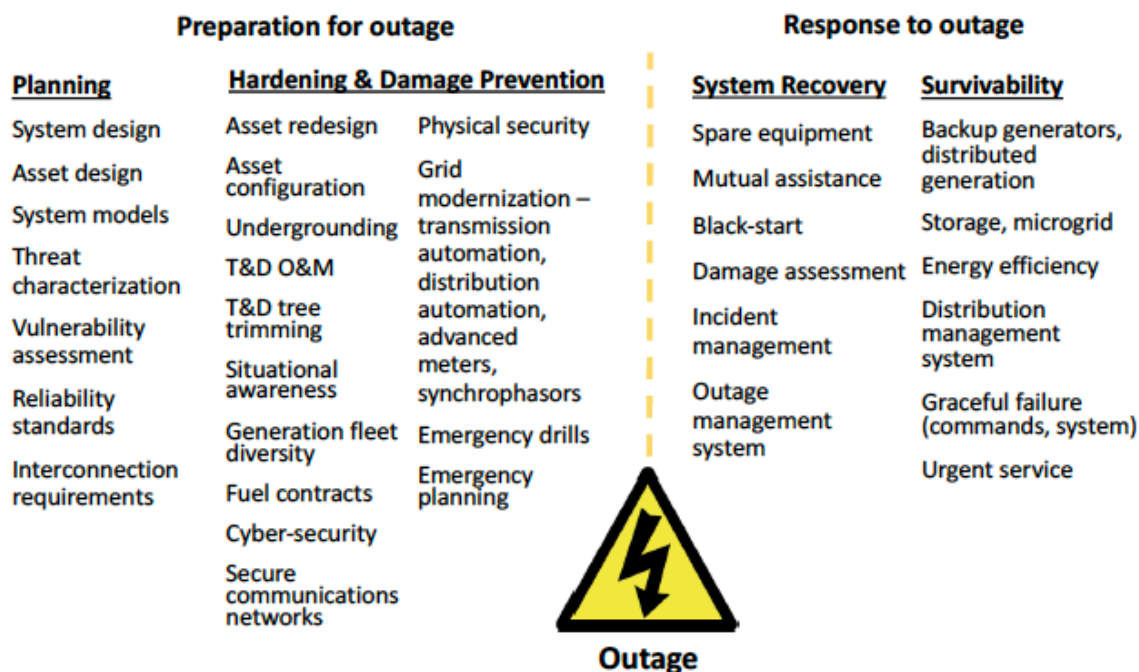
Most outage events and threats have common consequences -- they damage distribution and transmission assets, causing customers to lose electric service. A proactive approach to reliability and resilience would take an all-hazards approach and focus on how to address and mitigate these common consequences, 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.<sup>1</sup>

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)

	High Value	Low Value
<b>Grid operator, reliability coordinator</b>	Interconnection rules	Generation capacity payments
	Schedule coordination	
	Fuel coordination	
	Emergency planning and drills	
	System & asset models	
	Situational awareness	
<b>T&amp;D, Genco Capital</b>	Distribution pole hardening	T&D undergrounding
	Additional transmission paths and loops	Coal & nuclear subsidies
	Back-up communications	
	Transmission automation	
	Distribution automation	Generator weatherization
<b>T&amp;D, Genco O&amp;M</b>	Tree trimming	Fuel supply guarantees
	Cyber security & secure communications networks	
	Physical security	
	Mutual assistance	
	Strategic spare equipment & mobile substations	
	Situational awareness, system monitoring, PMUs	
	Emergency planning and drills	
	Outage management system	
<b>Customer</b>	Distributed generation, back-up generators	
	Emergency supplies	Insurance
	More efficient building shells	Distributed storage
	Community critical infrastructure hardening	

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

<sup>1</sup> 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.<sup>2</sup> 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.”<sup>3</sup> 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,”<sup>4</sup> 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,”<sup>5</sup> 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 undervalued grid reliability and resilience attributes and should be modified accordingly.

On January 8, 2018, FERC issued an Order unanimously denying DOE’s proposed rule.<sup>6</sup> 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.”<sup>7</sup> FERC thanked the Secretary for reinforcing, “the resilience of the bulk power system as an important issue that warrants further attention,”<sup>8</sup> and opened a docket for the present inquiry.<sup>9</sup>

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<sup>2</sup> DOE Secretary Perry (2017a).

<sup>3</sup> DOE (2017b).

<sup>4</sup> DOE (2017c).

<sup>5</sup> DOE Secretary Perry (2017b).

<sup>6</sup> FERC (2018), Order 162 FERC ¶61,012.

<sup>7</sup> FERC (2018), paragraph 15.

<sup>8</sup> *Ibid.*, paragraph 1.

<sup>9</sup> 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."<sup>10</sup> 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.*<sup>11</sup>

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.<sup>12</sup> 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."<sup>13</sup> 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.<sup>14</sup> NERC defines reliability as the ability of the electric system to supply power at all times and withstand sudden disturbances<sup>15</sup> – 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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<sup>10</sup> FERC (2018), paragraph 23.

<sup>11</sup> *Ibid.*, paragraph 24.

<sup>12</sup> *Ibid.*, paragraph 12.

<sup>13</sup> 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."

<sup>14</sup> NERC (2013b).

<sup>15</sup> 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.<sup>16</sup>

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.

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<sup>16</sup> 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;<sup>17</sup> Hurricane Matthew caused 2.5 million customers to lose power in October 2016;<sup>18</sup> and the January 2016 snow and ice storm affected 14 states and over a million customers lost power.<sup>19</sup> 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

<sup>17</sup> DOE EIA (2012).

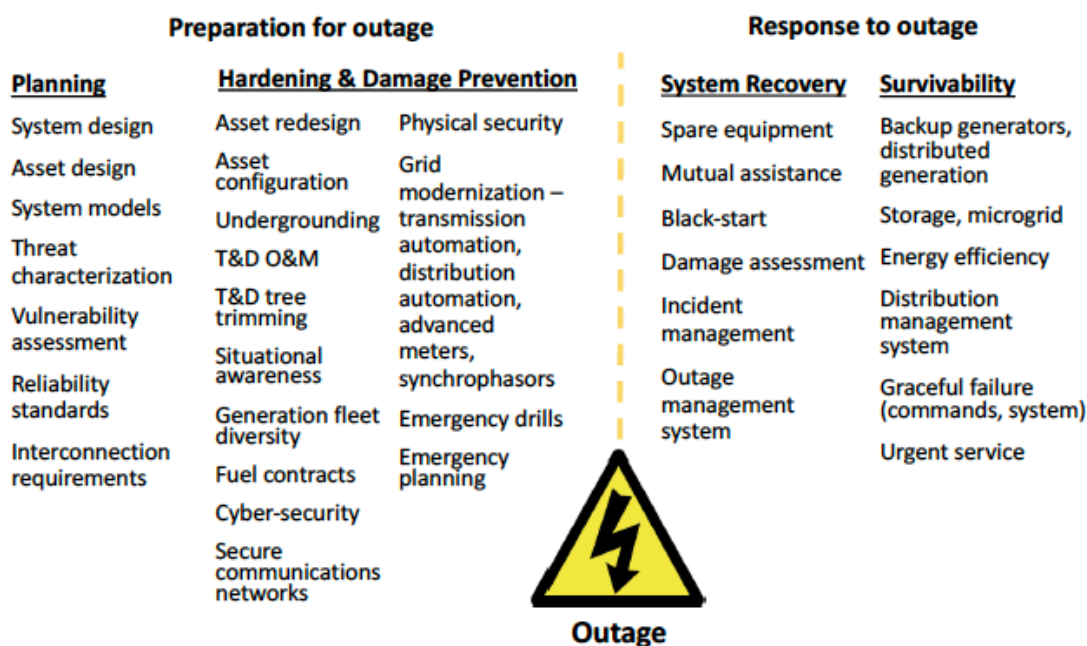
<sup>18</sup> DOE EIA (2016c).

<sup>19</sup> DOE EIA (2016a).



existing responsibility.<sup>20</sup> 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.<sup>21</sup> 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).

<sup>20</sup> 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)

<sup>21</sup> 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).

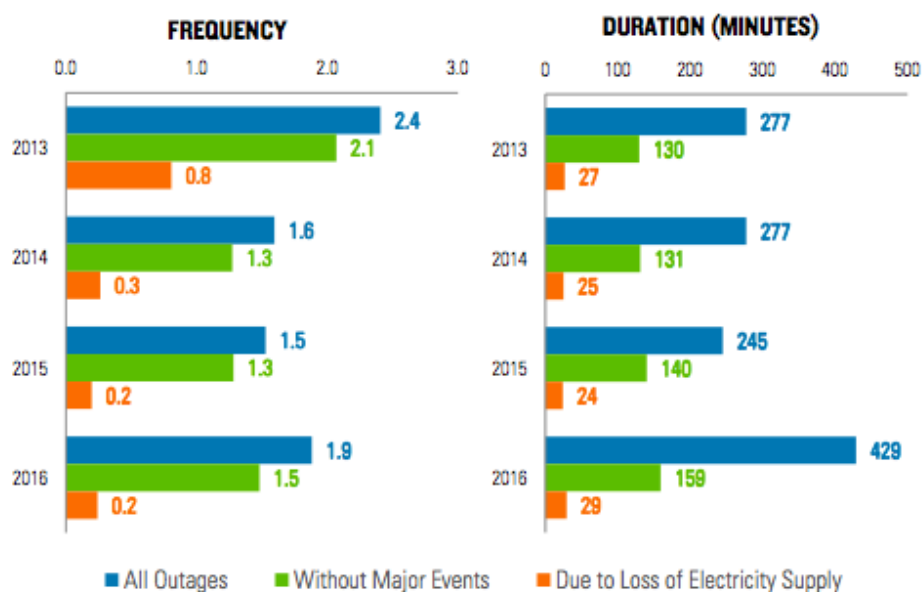
This section reviews the causes and consequences of customer outages across the entire power system - not just on the bulk power system -- and then looks at the cost of those outages to customers and society. This examination shows that the vast majority of outages across the power system are caused 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<sup>22</sup> 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.<sup>23</sup>

**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.

<sup>22</sup> 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.

<sup>23</sup> 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.<sup>24</sup> 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.”<sup>25</sup> 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.<sup>26</sup>
- 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.”<sup>27</sup>
- The Executive Office of the President reported that, “[s]evere weather is the leading cause of power outages in the United States.”<sup>28</sup>
- 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”.<sup>29</sup>
- 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%).<sup>30</sup>
- 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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<sup>24</sup> Marsters et al. (2017).

<sup>25</sup> EIA (2018).

<sup>26</sup> DOE EIA (2018).

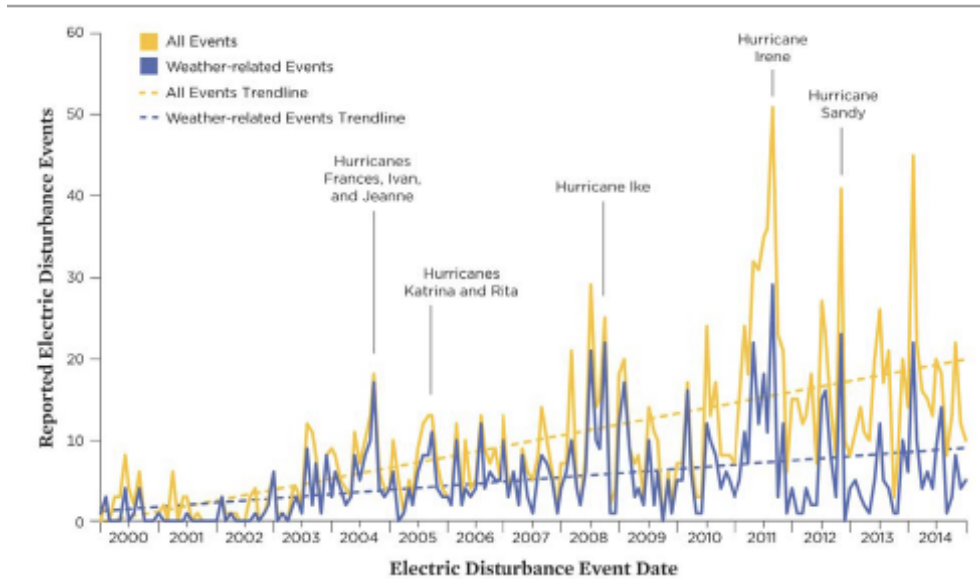
<sup>27</sup> LaCommare, Larsen & Eto (2015).

<sup>28</sup> Executive office of the President (2013), p. 3.

<sup>29</sup> Schaller and Ekisheva (2016).

<sup>30</sup> 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.<sup>31</sup> The U.S. Department of Energy’s Quadrennial Energy Review<sup>32</sup> (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.<sup>33</sup>*

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

<sup>31</sup> 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.

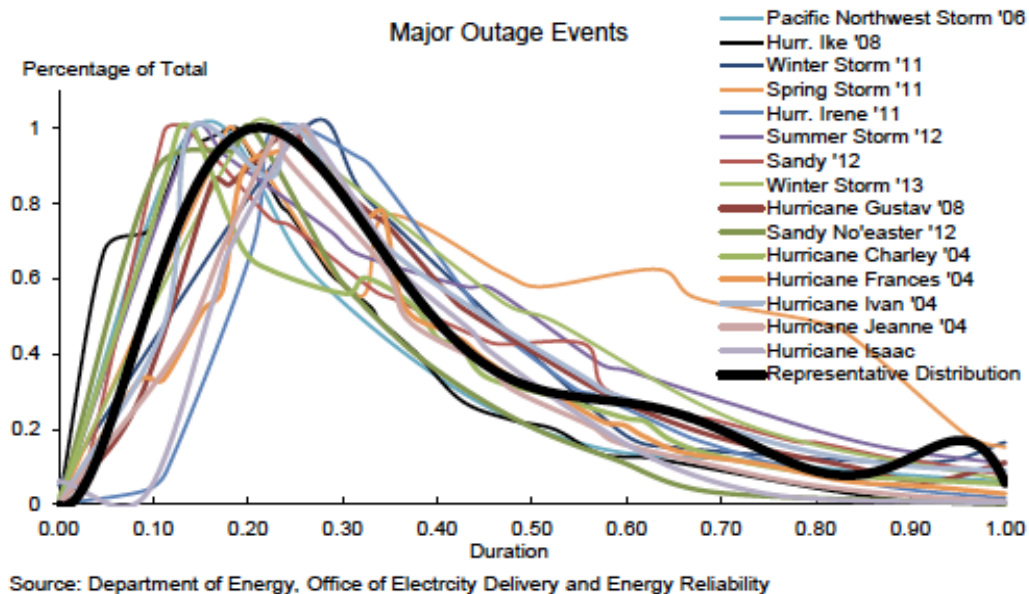
<sup>32</sup> U.S. DOE QER (2017a), p. 4-5. Other than the timing difference between development of these QER outage estimates in 2017 and the EIA estimate cited earlier (published in 2018), the authors are not aware of the reasons why these two DOE average outage duration estimates differ by over an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

<sup>33</sup> DOE QER (2017a), p. 4-5.

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

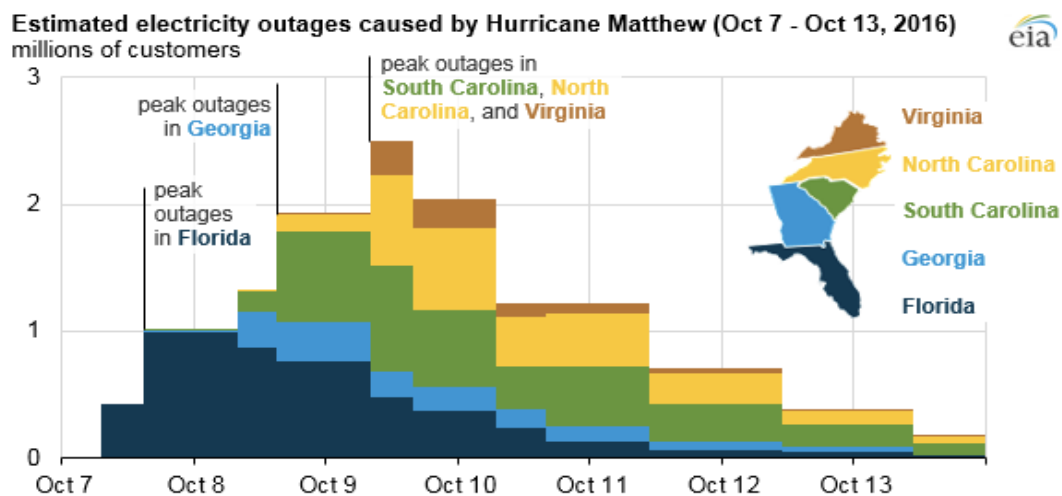
**Figure 4 – Number of customers out of power over the course of major weather outage events, 2004-2013**

(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))



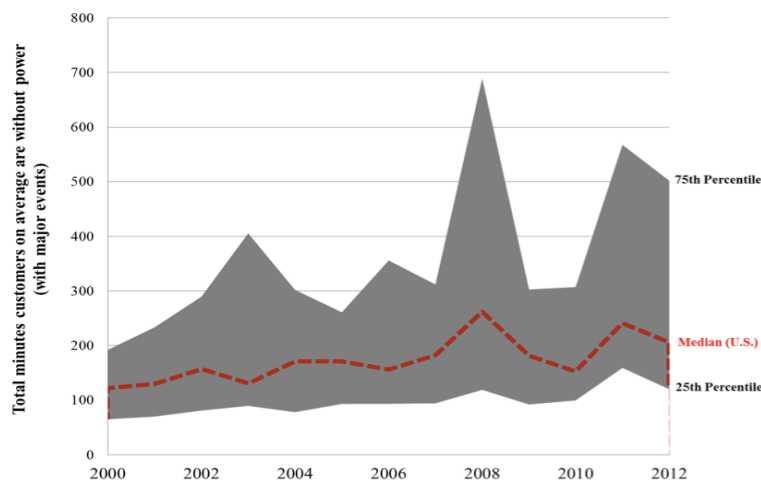
<sup>34</sup> Executive Office of the President (2013), p. 20.

Analysis drawing from earlier Lawrence Berkeley National Laboratory (LBNL) work on distribution system outages<sup>35</sup> 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.”<sup>36</sup>

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.<sup>37</sup> 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.”<sup>38</sup>

## 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).

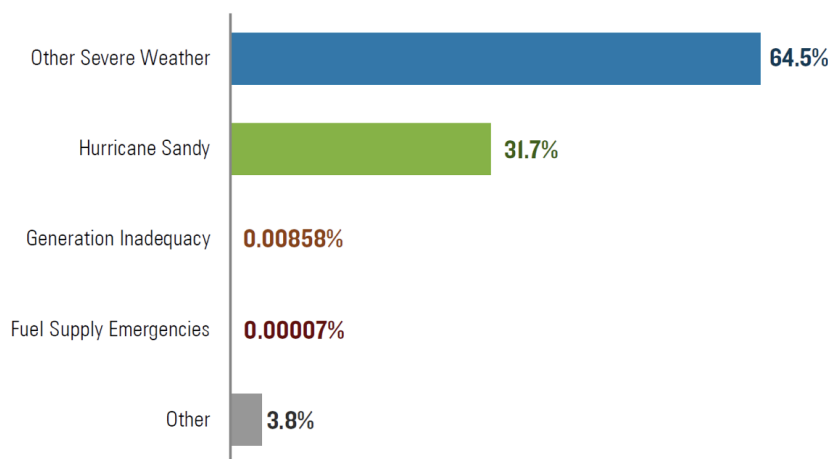
37 LaCommare et al. (2015).

38 Stanford University (2015).

events).<sup>39</sup> 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.<sup>40</sup>

**Figure 7 – Cause of major electricity outages by customer-hours disrupted in the U.S., 2012-2016**

Source: Marsters et al. (2017)



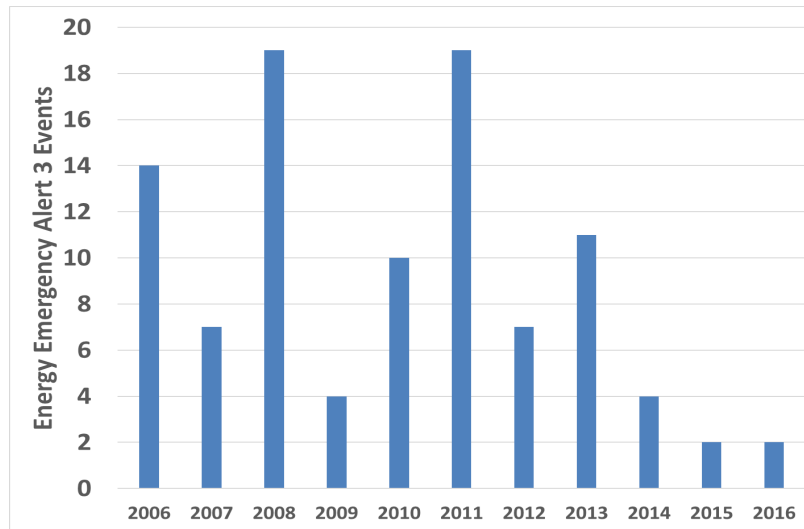
NERC tracks data that help indicate the frequency of outages resulting from generation shortfalls. Energy Emergency Alerts are issued when generation supply is inadequate to meet demand and firm load must be shed. The number of such events has trended strongly downward over the last 5 years from an already 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.

<sup>39</sup> Houser, Larsen & Marsters (2017), using Form OE-417 data.

<sup>40</sup> 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).<sup>41</sup> 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:

<sup>41</sup> 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.<sup>42</sup>

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
<b>Medium and Large C&amp;I (Over 50,000 Annual kWh)</b>						
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
<b>Small C&amp;I (Under 50,000 Annual kWh)</b>						
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
<b>Residential</b>						
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.<sup>43</sup> 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.<sup>44</sup> These data

<sup>42</sup> Executive Office of the President (2013), p. 3.

<sup>43</sup> 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.

<sup>44</sup> 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.<sup>45</sup>

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.<sup>46</sup> 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).<sup>47</sup> 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,<sup>48</sup> 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.<sup>49</sup>

## 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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<sup>45</sup> LBNL ICE Calculator.

<sup>46</sup> 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.

<sup>47</sup> Eto (2017), p. 12.

<sup>48</sup> Santos-Lozado (2018).

<sup>49</sup> 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**

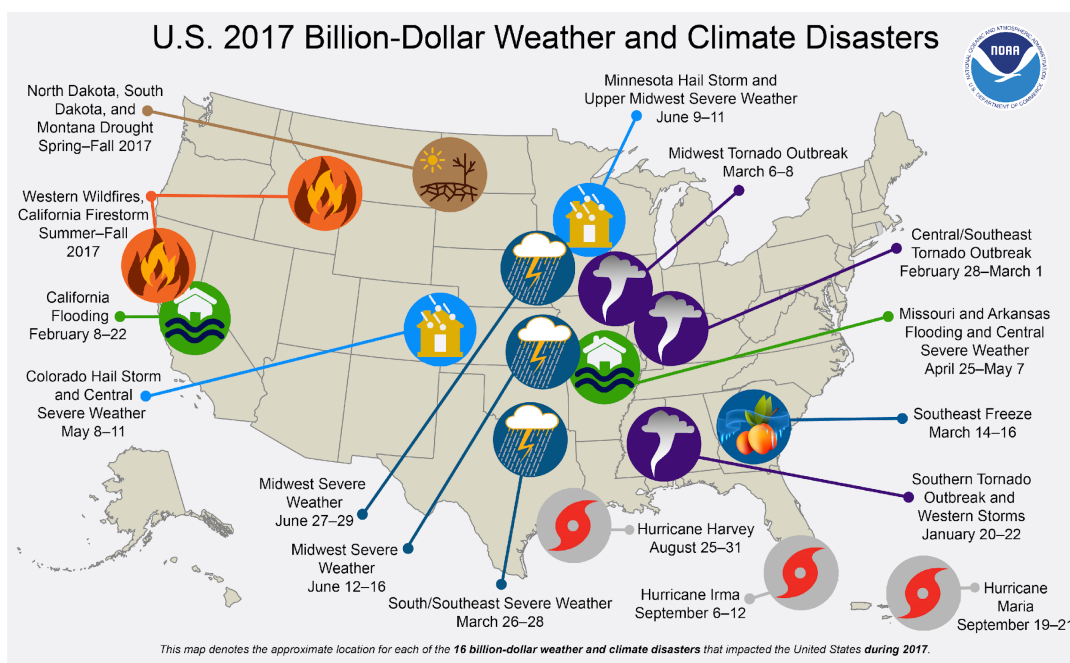
(Source: DOE QER (2017) Figure 4-8, p.4-26)

Threat		Intensity	System Components				
			Electricity Transmission	Electricity Generation	Electricity Substations	Electricity Distribution (above)	Electricity Distribution (below)
Assessment of Risk & Resilience							
Natural/Environmental Threats							
Hurricane	Low (<Category 3)	●	●	●	●	●	●
	High (>Category 3)	●	●	●	●	●	●
Drought	Low (PDSI>-3)	●	●	●	●	●	●
	High (PDSI<-3)	●	●	●	●	●	●
Winter Storms/Ice/ Snow	High (PDSI<-3)	●	●	●	●	●	●
	Low (Minor icing/snow)	●	●	●	●	●	●
Extreme Heat/Heat Wave		●	●	●	●	●	●
Flood	Low (<1:10 year ARI)	●	●	●	●	●	●
	High (>1:100 year ARI)	●	●	●	●	●	●
Wildfire	Low (>Type III IMT)	●	●	●	●	●	●
	High (Type I IMT)	●	●	●	●	●	●
Sea-Level Rise		●	●	●	●	●	●
Earthquake	Low (<5.0)	●	●	●	●	●	●
	High (>7.0)	●	●	●	●	●	●
Geo-magnetic	Low (G1-G2)	●	●	●	●	●	●
	High (G5)	○	●	○	●	○	●
Wildlife/Vegetation		●	●	●	●	●	●
Levels of Risk			Current Status of Risk Management Practice				
○ Low	● High	○ Nascent: critical vulnerabilities exist					
● Moderate	○ Unknown	● 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.<sup>50, 51</sup> 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<sup>52</sup> 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.<sup>53</sup>

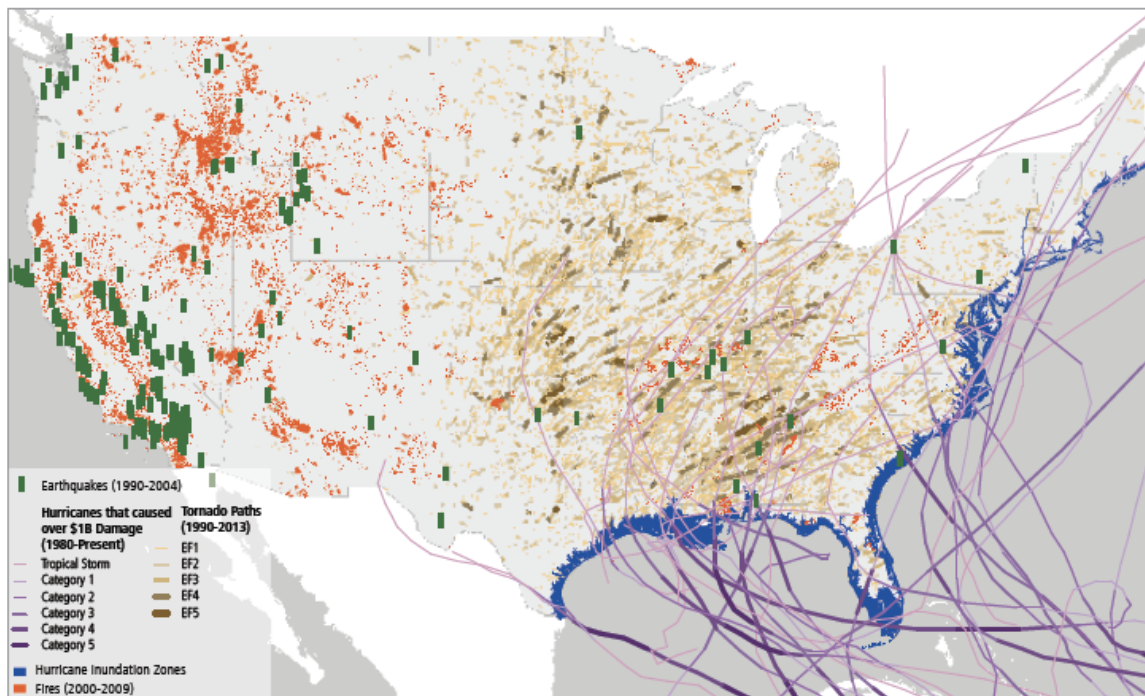
<sup>50</sup> The U.S. National Oceanic and Atmospheric Administration’s (NOAA) NCEI (2018a).

<sup>51</sup> 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>

<sup>52</sup> 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.)

<sup>53</sup> 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, tsunamis, 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.<sup>54</sup> The LaCommare team reports that the number of customer outage minutes has been increasing significantly over time due to more severe weather events.<sup>55</sup>

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

<sup>54</sup> Larsen, Sweeney et al. (2014), p. 29.

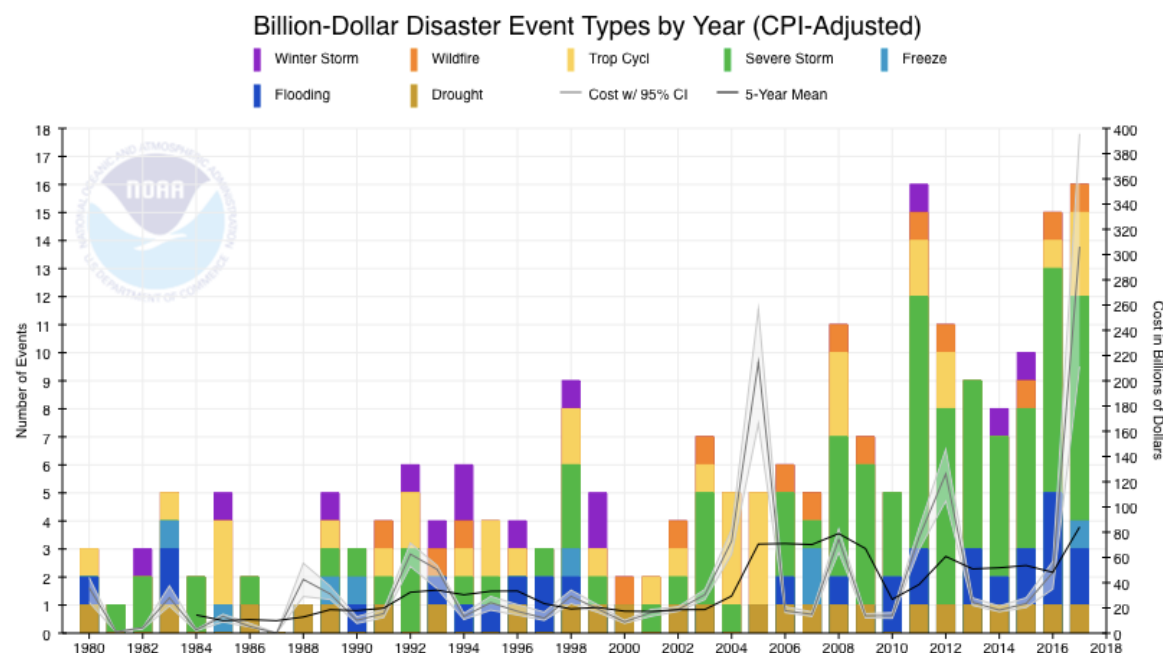
<sup>55</sup> LaCommare, Larsen & Eto (2015).



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.<sup>56</sup>

**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.<sup>57</sup>

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).<sup>58</sup> A new report from the National Oceanic and Atmospheric Administration warns that expected high tide flooding events will increase significantly – as much as every other day by the year

<sup>56</sup> U.S. NOAA NCEI (2018a).

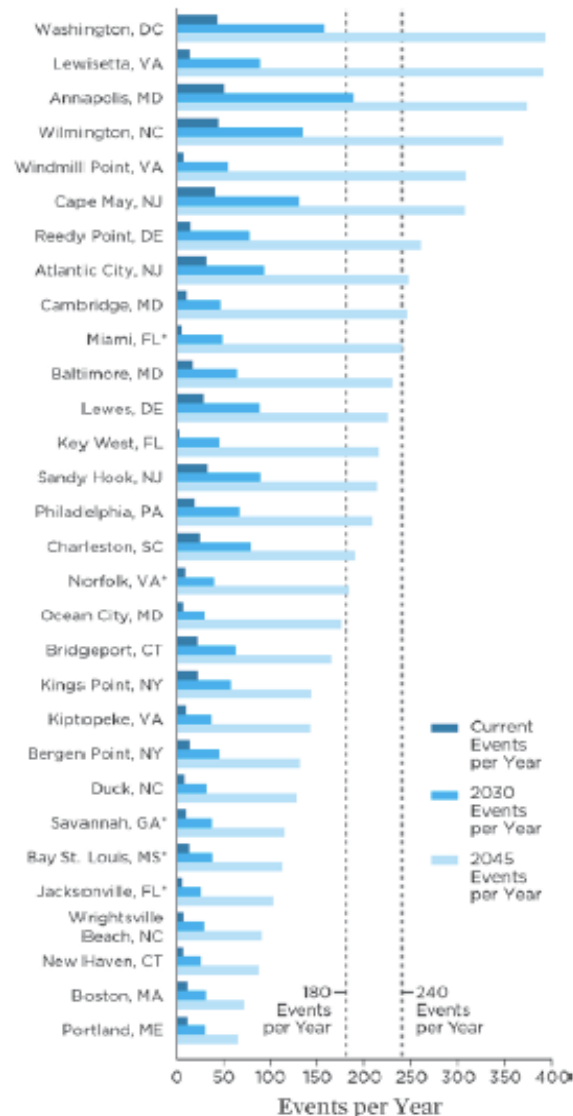
<sup>57</sup> Wuebbles, Fahey, Hibbard, *et al.* (2017), pp. 12-34.

<sup>58</sup> U.S. NOAA NCEI (2018a).

2100 – within the Northeast and Southeast Atlantic, the Eastern and Western Gulf coast, and the Pacific Islands;<sup>59</sup> 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.<sup>60</sup>

**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

<sup>59</sup> U.S. NOAA (2018).

<sup>60</sup> 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.<sup>61</sup>

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.<sup>62</sup>

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<sup>61</sup> Schlesinger (2018), and Wing, Bates et al. (2018).

<sup>62</sup> 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.<sup>63</sup>

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

<sup>63</sup> 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.<sup>64</sup>

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.<sup>65</sup>

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.<sup>66</sup>

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,<sup>67</sup> and recent reports that Russia-linked hackers are infiltrating the U.S. grid.<sup>68</sup> 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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<sup>64</sup> Cemp & Grant (2018).

<sup>65</sup> Idaho National Laboratory (2016), p. 2.

<sup>66</sup> Cemp & Grant (2018).

<sup>67</sup> See, e.g., the SANS Institute (2016) and Dunietz (2017).

<sup>68</sup> U.S.-CERT Alert (2018).

for later system access.<sup>69</sup> 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.”<sup>70</sup>

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.<sup>71</sup>

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....”<sup>72</sup> Analysts report that China, Russia, North Korea and other nations “likely have the capability to shut down the U.S. power grid,”<sup>73</sup> 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

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<sup>69</sup> U.S.-CERT Alert (2018).

<sup>70</sup> St. John (2018).

<sup>71</sup> See, for instance, Campbell (2016) testimony.

<sup>72</sup> Ibid.

<sup>73</sup> 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."<sup>74</sup> 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).<sup>75</sup> 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.<sup>76</sup> 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.<sup>77</sup>

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.<sup>78</sup> 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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<sup>74</sup> U.S. DOE (2017c).

<sup>75</sup> Submissions to FERC by SPP, NYISO, MISO, and ERCOT, March 9, 2018, FERC Docket No. AD18-7.

<sup>76</sup> 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.

<sup>77</sup> 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.

<sup>78</sup> 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
<b>Voltage support</b>							
Key: <b>Green</b> is positive, <b>yellow</b> is medium, and <b>red</b> indicates that in most cases the resource does not provide that service.							
Reactive power and voltage control	Green	Green	Yellow	Green	Yellow	Yellow	Green
Voltage and frequency disturbance ride-through	Green	Yellow	Yellow	Green	Yellow	Yellow	Yellow
<b>Frequency support</b>							
Note: For the following reliability services, <b>yellow</b> 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)	Yellow	Yellow	Yellow	Green	Yellow	Yellow	Yellow
<b>Ramping and balancing</b>							
Frequency regulation	Yellow	Yellow	Yellow	Green	Green	Yellow	Red
Dispatchability / Flexibility / Ramping	Yellow	Yellow	Yellow	Yellow	Green	Yellow	Red
Peak energy, winter (color reflects risk of common mode unavailability reducing fleetwide output below accredited capacity value)	Green	Yellow	Yellow	Green	Yellow	Yellow	Green
Peak energy, summer (color reflects risk of common mode unavailability reducing fleetwide output below accredited capacity value)	Yellow	Green	Green	Green	Yellow	Green	Green

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.<sup>79</sup> 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

<sup>79</sup> 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.<sup>80</sup> 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.<sup>81</sup> 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.<sup>82</sup> 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."<sup>83</sup> PJM's 2017 reliability report found that a number of scenarios with greatly reduced coal and nuclear capacity should remain reliable and resilient.<sup>84</sup>

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

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<sup>80</sup> ISO-NE (2018c).

<sup>81</sup> ISO-NE (2018a).

<sup>82</sup> ISO-NE (2018e).

<sup>83</sup> PJM (2018), p. 1.

<sup>84</sup> 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.”<sup>85</sup> At its peak, 40,200 MW of PJM’s generation capacity was unable to operate, or 20% of the total capacity on the system.<sup>86</sup> 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.<sup>87</sup> 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)

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

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<sup>88</sup> -- 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.”<sup>89</sup>

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

<sup>85</sup> Ott (2018), p. 3.

<sup>86</sup> Ibid., p. 4.

<sup>87</sup> Ott (2018), p. 5.

<sup>88</sup> The numbers reported in the study are “unforced capacity,” so nameplate capacity is much higher than shown.

<sup>89</sup> 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.<sup>90</sup> 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.”<sup>91</sup> 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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<sup>90</sup> 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).

<sup>91</sup> 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
<b>Hardening</b>	Physical changes that improve the durability and stability of specific pieces of infrastructure	Raising and sealing water-sensitive equipment
<b>Security measures</b>	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
<b>Maintenance and general readiness</b>	Routine efforts to minimize or prevent outages	Vegetation management and regular inspection and replacement of worn-out components
<b>Modernization, control enhancements, and smart-grid technology</b>	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
<b>Diversified and integrated grid</b>	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
<b>Redundancy, backup equipment, and inventory management</b>	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
<b>Mutual aid programs</b>	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
<b>Succession training, knowledge transfer, and workforce development</b>	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
<b>Business continuity and emergency action planning</b>	A formal plan that addresses actions and procedures to maintain operations preceding an event	Components including employee awareness, training, and exercising
<b>Models</b>	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;<sup>92</sup> 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.<sup>93</sup>

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.”<sup>94</sup> Many Class A office buildings have backup generation.<sup>95</sup>
- 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.<sup>96</sup>
- 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.<sup>97</sup>
- 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.<sup>98</sup>
- 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.<sup>99</sup>
- 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.<sup>100</sup>

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<sup>92</sup> Zheng (undated).

<sup>93</sup> Gilmore & Lave (undated).

<sup>94</sup> Satow (2013).

<sup>95</sup> Leighton (2013).

<sup>96</sup> Phillips (2016), p. xi.

<sup>97</sup> New York State press release (2016).

<sup>98</sup> 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>.

<sup>99</sup> Chesto (2018).

<sup>100</sup> 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.<sup>101</sup>
- 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.<sup>102</sup>

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.<sup>103</sup>

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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<sup>101</sup> See, e.g., Gardner (2017), Navigant (2017), Castillo, Johnston (2017).

<sup>102</sup> See Ribeiro, Mackres et al. (2015).

<sup>103</sup> 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.<sup>104</sup>

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

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<sup>104</sup> See Keogh & Cody (2013).



- Spare equipment programs such as Spare Transformer Equipment Program<sup>105</sup> and Grid Assurance<sup>106</sup>
- Mutual assistance alliances with other utilities<sup>107</sup>
- 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<sup>108</sup>
- 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.”<sup>109</sup> 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.”<sup>110</sup>

#### 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.

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<sup>105</sup> See EEI (undated).

<sup>106</sup> See AEP (2016).

<sup>107</sup> See EEI (2016).

<sup>108</sup> Walton (2018).

<sup>109</sup> Ibid.

<sup>110</sup> Luna (2018).

TVA has created a matrix of threats to its transmission system and identified solutions to harden against, detect, and recover from each.<sup>111</sup> 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."<sup>112</sup> 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.<sup>113</sup>

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.<sup>114</sup>

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

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<sup>111</sup> Clem & Grant (2018).

<sup>112</sup> MISO (2018), p. 4.

<sup>113</sup> MISO (2018), p. 18.

<sup>114</sup> 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 an 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."<sup>115</sup> 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.<sup>116</sup> 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.<sup>117</sup> MISO "uses its value-based planning approach to proactively identify infrastructure that is valuable under a number of long-term future scenarios."<sup>118</sup> 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.<sup>119</sup> 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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<sup>115</sup> NERC Transmission System Planning Performance Requirements, standard TPL-001-4.

<sup>116</sup> MISO (2018), p. 19.

<sup>117</sup> Pfeifenberger & Chang (2016).

<sup>118</sup> MISO (2018), pp. 15-16.

<sup>119</sup> 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.”<sup>120</sup> The lack of situational awareness has been a significant contributing factor in many real-world blackouts.<sup>121</sup>

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.<sup>122</sup> 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.<sup>123</sup> 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

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<sup>120</sup> Ibid., p.31.

<sup>121</sup> FERC and NERC (2012).

<sup>122</sup> See MISO (2018), p. 19.

<sup>123</sup> 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.<sup>124</sup> 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.<sup>125</sup> There is no obvious service for resilience that is not already covered

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<sup>124</sup> Giberson (2017).

<sup>125</sup> 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.”<sup>126</sup> 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.<sup>127, 128</sup>

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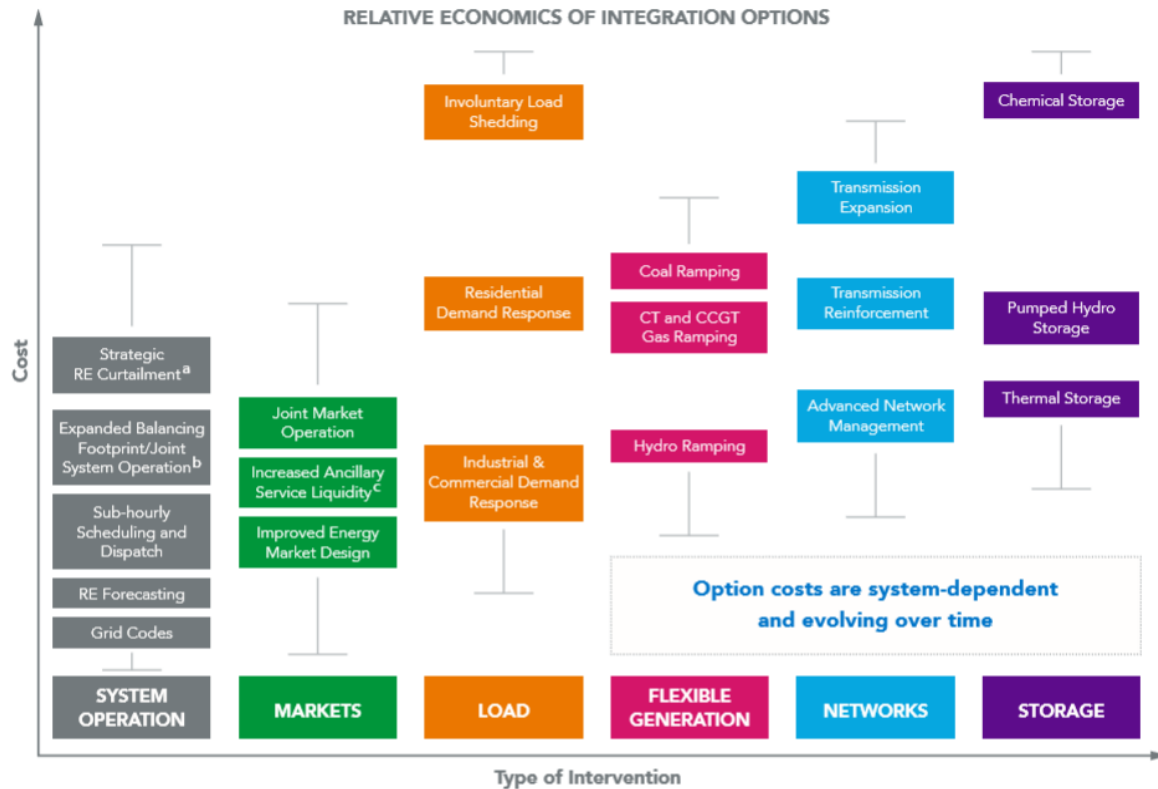
<sup>126</sup> U.S. DOE (2017b), p. 3.

<sup>127</sup> Cochran, et al. (2014), p. 11., and Milligan, Frew, Zhou et al. (2015).

<sup>128</sup> 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.<sup>129</sup>

## 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.<sup>130</sup>

## 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

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<sup>129</sup> Kristov (2017).

<sup>130</sup> 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.<sup>131</sup>

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.

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<sup>131</sup> 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.<sup>132</sup> 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?

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<sup>132</sup> 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?<sup>133</sup>

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,<sup>134</sup> 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

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<sup>133</sup> 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.

<sup>134</sup> 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.<sup>135</sup> 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.<sup>136</sup> But regulators have a hard time estimating the value of those benefits to customers.<sup>137</sup>

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).<sup>138</sup> Tools such as LBNL's outage calculator<sup>139</sup> 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.

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<sup>135</sup> LaCommare, Larsen & Eto (2017), p. 4.

<sup>136</sup> *Ibid.*, pp. 2-3.

<sup>137</sup> *Ibid.*

<sup>138</sup> Sullivan, Schellenberg & Blundell (2015).

<sup>139</sup> 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.<sup>140</sup> 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.<sup>141</sup> This analysis examined the prudence 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.<sup>142</sup> 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.<sup>143</sup> 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.<sup>144</sup> 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.<sup>145</sup> 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.

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<sup>140</sup> Watson & Burlingame (2013).

<sup>141</sup> DC PSC Order No.17697 (2014).

<sup>142</sup> DC PSC Order No. 17697 (2014), p.86.

<sup>143</sup> McLaren & Mullendore (2018).

<sup>144</sup> Huntoon (2015).

<sup>145</sup> 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.<sup>146</sup>

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.<sup>147</sup>

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<sup>146</sup> See Preston, Backhaus et al. (2016).

<sup>147</sup> 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.<sup>148</sup>

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.<sup>149</sup>

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.<sup>150</sup>

#### **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.<sup>151</sup> 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.<sup>152</sup> 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.<sup>153</sup>

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.

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<sup>148</sup> Greenley (2018).

<sup>149</sup> *Ibid.*, p.10.

<sup>150</sup> Clem & Grant (2018).

<sup>151</sup> Xcel (2011), p. 2-9.

<sup>152</sup> SPP (2016).

<sup>153</sup> PJM Value Proposition, MISO Value Proposition.



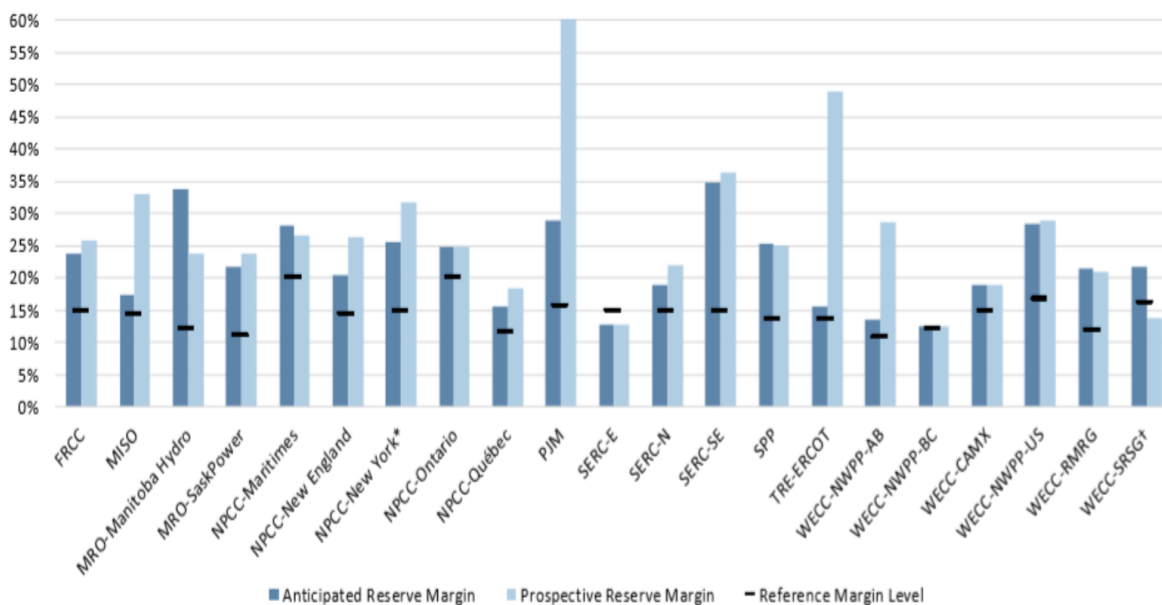
Greater west-to-east transmission capacity in PJM would have saved PJM consumers hundreds of millions of dollars during that event alone. The next extreme event might more strongly affect western PJM, causing greater demand and price spikes and generator unavailability there than in eastern PJM, so over 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,”<sup>154</sup> 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)

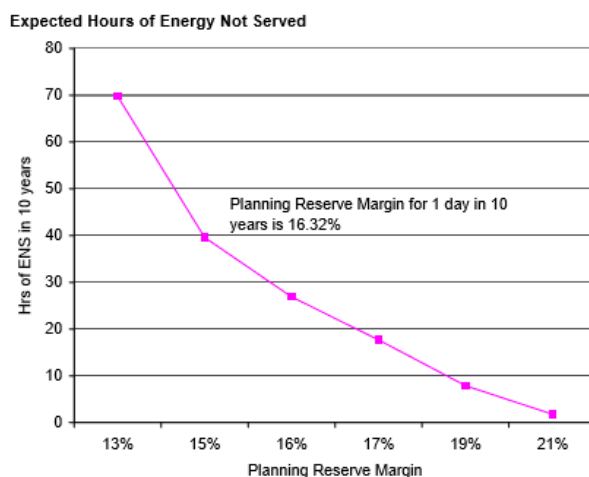


<sup>154</sup> NERC (2017c).

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**

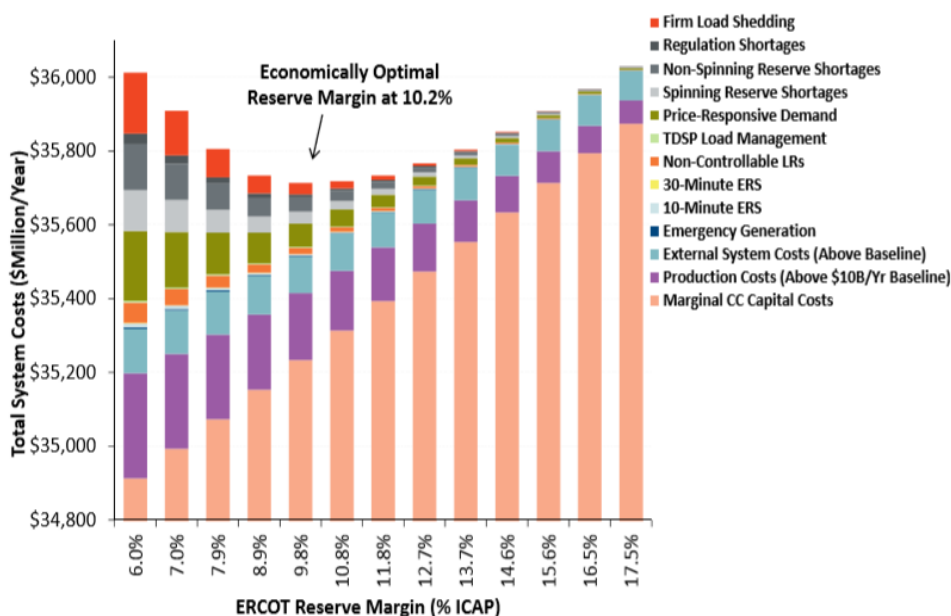
(Source: Xcel Energy (2011), p. A-1)



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.<sup>155</sup> 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.

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<sup>155</sup> Wilson (2010).

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

	High Value	Low Value
<b>Grid operator, reliability coordinator</b>	Interconnection rules	Generation capacity payments
	Schedule coordination	
	Fuel coordination	
	Emergency planning and drills	
	System & asset models	
	Situational awareness	
<b>T&amp;D, Genco Capital</b>	Distribution pole hardening	T&D undergrounding
	Additional transmission paths and loops	Coal & nuclear subsidies
	Back-up communications	
	Transmission automation	
	Distribution automation	Generator weatherization
<b>T&amp;D, Genco O&amp;M</b>	Tree trimming	Fuel supply guarantees
	Cyber security & secure communications networks	
	Physical security	
	Mutual assistance	
	Strategic spare equipment & mobile substations	
	Situational awareness, system monitoring, PMUs	
	Emergency planning and drills	
	Outage management system	
<b>Customer</b>	Distributed generation, back-up generators	
	Emergency supplies	Insurance
	More efficient building shells	Distributed storage
	Community critical infrastructure hardening	

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
<b>Voltage support:</b> Reactive power and voltage control	<a href="#">Provides, and can provide while not generating by using power electronics.</a>	<a href="#">Provides, and can provide while not generating by using power electronics.</a>	<a href="#">Could provide, though this would require detailed knowledge of distribution system state and dispatch</a>	<a href="#">Power electronics provide fast and accurate response</a>	Must be generating to provide	Must be generating to provide	Must be generating to provide
<b>Voltage support:</b> Voltage and frequency disturbance ride-through (also important for frequency support)	<a href="#">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.</a>	<a href="#">Can thanks to power electronics, but standards have prevented use of capability</a>	NA	<a href="#">Power electronics isolate battery from grid disturbances</a>	<a href="#">Generators often taken offline by grid disturbances.</a>	<a href="#">Generators and essential plant equipment, like pumps and conveyor belts, often taken offline by grid disturbances.</a>	<a href="#">Generators and essential plant equipment, like pumps, often taken offline by grid disturbances.</a>
<b>Frequency support:</b> Frequency stabilization following a disturbance (through primary frequency response and inertial response to disturbances)	<a href="#">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.</a>	<a href="#">Can provide downward frequency response today, can provide upward frequency response and fast power injection if curtailed.</a>	<a href="#">Load resources currently provide this in ERCOT through autonomous controls when frequency drops below a certain point</a>	<a href="#">Power electronics provide very fast and accurate power injection following a disturbance</a>	<a href="#">Only 10% of conventional generators provide sustained primary frequency response</a>	<a href="#">Only 10% of conventional generators provide sustained primary frequency response</a>	<a href="#">Nuclear plants are exempted from providing frequency response, but they do provide inertia.</a>



<b>Ramping and balancing: Frequency regulation</b>	<a href="#">Fast and accurate response. Can provide but often costly, particularly for upward response. Provides on Xcel's system.</a>	<a href="#">Fast and accurate response. Can provide but often costly, particularly for upward response.</a>	<a href="#">Autonomous loads like water heaters can provide, though the cost of disruption may be too great for other DR</a>	<a href="#">Very fast and accurate response</a>	Must be generating to provide	<a href="#">MISO data show a large share of coal plants provide inaccurate regulation response</a>	Does not provide
<b>Ramping and balancing: Dispatchability / Flexibility / Ramping</b>	<a href="#">Fast and accurate response. Can but often costly, particularly for upward response. Provides on Xcel's system.</a>	<a href="#">Fast and accurate response. Can provide but often costly, particularly for upward response.</a>	Many forms of DR are likely to be energy limited or too expensive for longer duration deployment	<a href="#">Many types of batteries will be energy limited for longer-duration events, particularly if state of charge is not optimal going into event</a>	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
<b>Ramping and balancing: Peak energy, winter</b> (color reflects risk of common mode unavailability reducing fleetwide output below accredited capacity value)	<a href="#">Wind plants typically have high output during periods of extreme cold, as seen in ERCOT in 2011 and much of the country in 2014.</a>	Solar plants have lower output during the winter.	Many DR programs are not currently designed for winter peak demand reduction	<a href="#">Good, though will be energy limited for longer-duration events</a>	<a href="#">High gas demand can cause low gas system pressure, fuel shortages. Can be mitigated with dual fuel capability or firm pipeline contracts.</a>	<a href="#">Many coal plants failed due to cold in ERCOT in February 2011, polar vortex event in 2014, and other events.</a>	<a href="#">Some failures due to extreme cold.</a>
<b>Ramping and balancing: Peak energy, summer</b> (color reflects risk of common mode unavailability reducing fleetwide output below accredited capacity value)	<a href="#">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.</a>	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	<a href="#">Good, though will be energy limited for longer-duration events</a>	<a href="#">Gas generators experience large output de-rates when air temperatures are high.</a>	<a href="#">Coal plants experience de-rates when cooling water temperatures are high.</a>	<a href="#">Nuclear plants experience de-rates when cooling water temperatures are high.</a>