UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Technical Conference to Discuss Climate Change, Extreme Weather, & Electric System Reliability	))	Docket No. AD21-13-000

Comments of the R Street Institute

I. Issue Summary

On March 16, 2021, the Federal Energy Regulatory Commission (Commission or FERC) issued a notice regarding a technical conference inviting comments on matters related to electric reliability threats posed by climate change and extreme weather events.[1] The conference will be held from June 1 to June 2, 2021 with pre-conference comments due by April 15, 2021.

II. Summary of R Street Position

Climate change adaptation is a societal risk management exercise. Independently, electric reliability policy has evolved toward a risk management framework. As such, it is important to accurately fuse characteristics of climate risk into the evolving risk-based electric reliability framework. Overlaying climate risk onto the preexisting and potential future configurations of reliability risk frameworks helps inform policy makers in revising current policies, protocols, and inputs in a manner that maximizes net benefits to society.

Infusing climate risk into reliability policy must account for the varied reliability frameworks in practice today. Reliability policy is a culmination of state, regional and federal policies, which has resulted in a patchwork of regulatory architectures that treat exogenous risk very differently. For example, regulatory architectures that socialize risk will require more administrative adjustment, whereas those that privatize risk can focus on risk incentive alignment and risk-informed decision making. Further, climate impacts vary by region, stressing the need for the Commission to consider regional heterogeneity in climate risk assessment and risk management architectures.

New or worsening threat vectors, including climate change impacts and intentional infrastructure attacks, can exacerbate deficiencies in existing grid reliability risk management frameworks. Current reliability policy deficiencies include disjointed state-federal coordination, siloed reliability institutions, incongruous policy development, absence of economic criteria in reliability policymaking, uniform treatment of heterogeneous customer reliability preferences, mismatched generation to transmission

[1] Federal Energy Regulatory Commission, *Climate Change, Extreme Weather, and Electric System Reliability*, Docket No. AD21-13-000, March 15, 2021. https://www.ferc.gov/media/ad21-13-000-supplemental-notice-technical-conference-inviting-comments.

and distribution standards, retrospective rather than anticipatory planning inputs and understatement of the risk profile of common mode failure. Further, many climate change mitigation pathways will exacerbate these reliability policy deficiencies as the resource mix integrates more variable- and use-limited resources.

The effects of climate change alone are unlikely to provide the primary justification, at least on a benefit-cost basis, for addressing near-to-medium term deficiencies in reliability policy. But they do create a more compelling rationale for pursuing a "no regrets" reliability policy reform that would greatly increase societal net benefits.

III. Responses to Commission Questions

R Street provides the following answers to the questions posed by the Commission.

1. What are the most significant near-, medium-, and long-term challenges posed to electric system reliability due to climate change and extreme weather events?

The overall risk profile of climate change warrants dedicated evaluation. A March 2021 Government Accountability Office report suggests that the FERC should "identify and assess climate-related risks and plan a response."[2] R Street stresses that the Commission account for the differences in the spatial and temporal dimensions of climate risk in a systematic review of potential bulk electric reliability impacts.

As the question implies, the near-, medium- and long-term effects of climate change vary substantially. Since the question does not define these timeframes, the Commission must be careful in interpreting responses across different implied timelines. This is critical for gauging climate change impacts, because the time horizon is significant given the elongated distribution of longitudinal effects. For example, medium-term effects may be interpreted by the electric industry parlance as 5-10 years, but may account for several decades in climate science.

The peer-reviewed literature explains how the rate of change is a key driver of climate impact analysis. For example, the Climate Framework for Uncertainty, Negotiation, and Distribution delineates that the marginal economic damages of climate change depend on the rate of change and vary by sector.[3] The most severe and uncertain climate effects, such as those relating to positive feedback loops, typically exceed the investment time horizon of most electric infrastructure, i.e., greater than 50 years. Thus, to align with investment timeframes, reliability policy should focus on climate risks incurred over the next several decades. Such areas benefit from high confidence among the climate science community,

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[2] "Electricity Grid Resilience: Climate Change Is Expected to Have Far-reaching Effects and DOE and FERC Should Take Actions," Government Accountability Office, March 2021, p. 48. https://www.gao.gov/assets/gao-21-346.pdf.

[3] National Academies of Sciences, Engineering, and Medicine, *The Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use*, (The National Academies Press, 2010), p. 260. https://www.nap.edu/read/12794/chapter/7#260

though the exacerbation of tail events like extreme weather makes for a complex risk profile and deserves special attention.

Given the pace of investment and long-lived nature of electric infrastructure, climate risk over the next decade will most affect electric operating conditions. Further, operating policy reforms can be adjusted more readily within a decade as new information becomes available, whereas planning processes can "lock-in" climate risk exposure for decades to come.

Given the range of uncertainty, the broad spectrum of climate science interpretation and the propensity for "crisis-driven" policymaking to amplify risks, the Commission should limit its perspective to peer-reviewed literature and encourage regional stakeholders to adopt positions consistent therewith.[4] The electric industry should not reinterpret environmental science, but rather rely on the expert judgement of the scientific community to assess which and to what degree exogenous factors demand reliability policy adjustment. Failing this, the industry risks biased responses instead of a dispassionate, evidence-based approach that ages well with new information. Recent reports by the National Academy of Sciences (NAS)[5] and Government Accountability Office (GAO)[6] serve as reputable and current summaries of the body of evidence on this subject.

The Commission should seek to distinguish which climate effects exacerbate existing reliability threat vectors, as opposed to creating new ones. Refinements, such as more accurate information inputs, may suffice to adjust reliability risk management to account for climate change. Any new categorical risks may warrant dedicated policy instrument responses.

It is possible that the incremental effect of climate change could create new threshold determinations for reliability policy. For example, it is possible for some regions to flip from summer to winter peaking, affecting the associated impact on planning, operations, and reliability norms and standards, all of which are built from historical experience.

The most significant challenge to addressing climate-related reliability risk is an outmoded regulatory construct. The key challenge for the Commission is how to best translate climate science into an electric reliability policy milieu that currently possesses pronounced deficiencies in risk management practices. These shortcomings include disjointed state-federal coordination, siloed reliability institutions, incongruous policy development, absence of economic criteria in reliability policymaking, uniform treatment of heterogeneous customer reliability preferences, mismatch of generation to transmission and distribution standards, retrospective rather than anticipatory planning inputs and understatement of the risk profile of common mode failure.

[4] National Academies of Sciences, Engineering, and Medicine, *The Future of Electric Power in the United States*, (The National Academies Press, 2021), p. 23. https://www.nap.edu/download/25968.

[5] Ibid.

[6] "Electricity Grid Resilience." https://www.gao.gov/assets/gao-21-346.pdf.

Climate risk should be incorporated into a holistic revisit of reliability policy consistent with contemporary risk management practices that maximize net benefits. In particular, a stronger focus on risk incentive alignment and private sector risk-informed decision making, as well as the use of economic criteria in administrative processes, is long overdue, especially when accounting for climate change induced risk profiles.

2. With respect to extreme weather events (e.g., hurricanes, extreme heat, extreme cold, drought, storm surges and other flooding events, or wildfires), have these issues impacted the electric system, either directly or indirectly, more frequently or seriously than in the past, and if so, how? Will extreme weather events require changes to the way generation, transmission, substation, or other facilities are designed, built, sited, and operated?

Extreme weather events are clearly becoming more common and present a growing threat to electric reliability. However, the sample size of extreme weather events is very limited, which complicates their attribution to climate change. Regardless, the electric industry should examine its risk profile to extreme weather based on recent events. The industry should integrate climate science data into the projected frequency and intensity of similar events in order to compile an accurate composite profile of future climate risk exposure. This will require changes to technology choice criteria, equipment design, construction, siting and operations for generation, and transmission and substation systems.

The GAO and NAS reports provide quality summaries of extreme weather risk across the integrated supply chain of power production and delivery. Recent events not fully captured by these reports elucidate several additional points. As indicated by the February 2021 cold weather event, every form of generation fuel is vulnerable to severe weather.[7] As evidence confirms both the increase in severe weather events and their corresponding impact on electric infrastructure, the Commission should seek specific subsequent information to construct a climate risk profile for generation and transmission that can be evaluated within current reliability risk management frameworks.

At the distribution level, during a 2006 heat storm in California, the Pacific Gas and Electric Company (PG&E) had to replace nearly 1,000 transformers due to the configurations of those transformers. These transformers, located near San Jose and Livermore, were designed to cool off in the night, as fog and Pacific off-shore breezes come in. However, the heat intensity and dearth of cooling weather phenomena extended demand throughout the night, leading to transformer failure.[8] Similarly, flooding

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[7] Devin Hartman, "Blackouts and Bias: Clearing Up the Grid Narrative," R Street Blog, Feb. 18, 2021. https://www.rstreet.org/2021/02/18/blackouts-and-bias-clearing-up-the-grid-narrative.

[8] See, e.g., David R. Baker, "Electrical transformers just can't take the heat / Smaller devices used on usually cool coast particularly hard hit," *SFGate*, July 26, 2006. https://www.sfgate.com/news/article/Electrical-transformers-just-can-t-take-the-heat-2515333.php.

during Hurricane Harvey inundated substations, delaying power restoration to thousands until a temporary substation could be constructed in Houston.[9]

3. Climate change has a range of other impacts, such as long-term increases in ambient air or water temperatures that may impact cooling systems, changes in precipitation patterns that may impact such factors as reservoir levels or snowpack, and rising sea levels among others. Will these impacts require changes to the way generation, transmission, substation, or other facilities are designed, built, sited, and operated?

Changes in weather conditions materially affect the reliability parameters of electric infrastructure, such as ambient air and wind speed effects on transmission line capacity. These effects stress the value of reforms intended to internalize weather risk, like the pending rulemaking on adjusting transmission line ratings to account for ambient conditions.[10] Water temperatures can have a pronounced effect on cooling systems for thermal plants. For example, extreme heat and drought in Texas during the summer of 2011 shrunk cooling water lakes, limiting cooling capacity at many power plants, including multiple coal units that were unable to continuously operate at full output. The GAO found that changing precipitation patterns can create water shortages for hydro and nuclear plants.[11]

It is critical to note that the nature and degree of climate impacts vary by region and sub region. Chart 1 provides a general characterization of this regional variance. The policy takeaway is that prudent climate risk management action varies by region and uniform practices will not maximize net benefits to society. Although some climate effects, such as warmer temperatures and more heat waves, are expected in all regions, the magnitude of effect will vary considerably across geographies.

Chart 1. Potential Climate Change Effects Vary by Region

	Warmer temperatures and more heat waves	Increasing precipitation or heavy downpours	Decreasing water availability	Increasing wildfires	Increasing sea-level rise and storm surge	Increasing frequency and intensity of hurricanes	Permafrost thaw
Northwest	Expected	Expected	Expected	Expected	Expected		
Northern Great Plains	Expected	Expected	Expected	Expected			
Midwest	Expected	Expected	Expected				
Northeast	Expected	Expected	Expected	Expected	Expected	Expected	

[9] Amy Fischbach, "Hurricane Harvey Floods Entergy's Substations and Infrastructure," *T&D World*, Sept. 15, 2017. https://www.tdworld.com/electric-utility-operations/media-gallery/20970184/hurricane-harvey-floods-entergys-substations-and-infrastructure.

[10] Federal Energy Regulatory Commission, *Managing Transmission Line Ratings*, Notice of Proposed Rulemaking, Docket No. RM20-16-000, Nov. 19, 2020. https://www.ferc.gov/media/rm20-16-000.

[11] "Electricity Grid Resilience," p. 16. https://www.gao.gov/assets/gao-21-346.pdf.

Southwest	Expected		Expected	Expected	Expected		
Southern Great Plains	Expected		Expected		Expected	Expected	
Southeast	Expected		Expected		Expected	Expected	
Alaska	Expected		Expected	Expected			Expected
Hawaii and U.S. Territories	Expected	Expected			Expected	Expected	

Source: Derived from the Government Accountability Office review of Department of Energy reports, Fourth National Climate Assessment and other sources.[12]

4. What are the electric system reliability challenges associated with "common mode failures" where, due to a climate change or extreme weather event, a large number of facilities critical to electric reliability (e.g., generation resources, transmission lines, substations, and natural gas pipelines) experience outages or significant operational limitations, either simultaneously or in close succession? How do these challenges differ across types of generation resources (e.g., natural gas, coal, hydro, nuclear, solar, wind)? To what extent does geographic diversity (i.e., sharing capacity from many resources across a large footprint) mitigate the risk of common mode failures?

Climate change will exacerbate a key deficiency in current reliability frameworks: most consider generation and transmission outages to be independent events. Focus must be placed on correlated outages, both in reliability assessments as well as in planning and operating protocols at the state and federal levels. For example, common mode failure may require special sophistication in market design, such as probabilistic methods in capacity accreditation processes that ensure robustness to key common mode scenarios.

New research is creating greater insights, and forthcoming research would benefit from additional direction from the Commission. For example, a January 2021 report from the Electric Power Research Institute found a systematic understatement of the depth and probability of high impact common mode events.[13] It specifically found the need to trend disruptive event probabilities upward to account for climate impacts.[14]

Geographic diversity is generally a proxy for more granular risk elements, such as weather pattern diversity. Shared infrastructure is a key common mode issue sometimes correlated with spatial patterns, but the two do not necessarily have a causal relationship. Generally, greater interregional connectivity

[12] "Electricity Grid Resilience: Climate Change Is Expected to Have Far-reaching Effects and DOE and FERC Should Take Actions," Government Accountability Office, March 2021, p. 18. https://www.gao.gov/assets/gao-21-346.pdf.
[13] R. B. Hytowitz, "Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource Adequacy," Electric Power Research Institute, Jan. 28, 2021. https://www.epri.com/research/products/000000003002019300.
[14] Ibid.

enables trade gains that yield economic and reliability benefits, but this interaction must not expand the scope of a single common mode threat vector.

5. Are there improvements to coordinated operations and planning between energy systems (e.g., the natural gas and electric power systems) that would help reduce risk factors related to common mode failures? What could those improved steps include?

The Commission should seek to "finish the job" on natural gas-electric industry coordination and fuel assurance. There is room to increase transparency and reduce transaction costs in gas-electric operations and planning for normal and extremely cold conditions. February 2021 revealed the critical gas infrastructure was not given priority electric service, which resulted in gas system failures that created adverse electric reliability feedback effects.

6. How are relevant regulatory authorities (e.g., federal, state, and local regulators), individual utilities (including federal power marketing agencies), and regional planning authorities (e.g., RTOs/ISOs) evaluating and addressing challenges posed to electric system reliability due to climate change and extreme weather events and what potential future actions are they considering? What additional steps should be considered to ensure electric system reliability?

Given the enormous breadth of activities across these actors and the selection bias of participating in this limited proceeding, this question would be better addressed through the use of a survey instrument. One common thread appears to be that different actors are using different sets of assumptions about climate risk. This may result in uneven and perhaps contradictory institutional responses, especially between states. At minimum, the Commission could catalog approaches across Regional Transmission Organizations (RTOs) and offer to serve as a resource to states to extend observations and analysis in a useful format. One particular mechanism is suggested in the answer to question 17.

Additional steps should focus on how to value and compensate resources for rendered reliability services. For example, robust implementation of Order 2222 will help in diversifying the types of resources available to system planners at both the distribution and wholesale level. As the system evolves, there will be a greater need for flexible resources, like DER, to provide the system with the needed resources. Further, a greater diversity of many smaller resources reduces contingency risk from the reliance on fewer, larger central plants.

7. Are relevant regulatory authorities, individual utilities, or regional planning authorities considering changes to current modeling and planning assumptions used for transmission and resource adequacy planning? For example, is it still reasonable to base planning models on historic weather data and consumption trends if climate change is expected to result in extreme weather events that are both more *frequent and more intense than historical data would suggest? If not, is a different approach to modeling and planning transmission and resource adequacy needs required? How should the benefits and constraints of alternative modeling and planning approaches be assessed?*

Basing reliability frameworks on historical data is perhaps the single most incongruent practice for appropriately incorporating climate risk. The Fourth National Climate Assessment notes that the most vulnerable infrastructure is the one designed for historical climate conditions, whereas the remedy is "[f]orward-looking infrastructure design, planning, and operational measures" that "reduce exposure and vulnerability to the impacts of climate change."[15] As a sober case in point, the extreme winter scenario the Electric Reliability Council of Texas (ERCOT) used going into last winter was based on the winter events of 2011; the February 2021 weather profile was far more extreme.

The reliance on historic data has resulted in many planning parameter deficiencies. This includes transmission planning that does not reflect future conditions, which heavily skews the costs and benefits of potential projects. Climate change also reduces the utility of past generator performance to indicate future performance, which can have major capacity accreditation repercussions.

Alternative tools and techniques should focus on improving planning for the expected, not merely what has been recently experienced. Projections are, however, inherently more difficult to develop than the evaluation of past performance. This opens up key processes to greater discretion over ex ante analysis, such as over modeling techniques and inputs, rather than verifiable ex post analysis. Converting to projection-based systems is substantively sound, but must be executed in a way that limits discretion to verifiable expert judgment. Otherwise stakeholders will massage the ambiguity in a way that serves their self-interest and create controversy and constant projection adjustments that result in artificial investment risk.

The mitigation of future reliability risk must also account for the role of distributed energy resources (DERs), which do not have much of a historical basis. Not all RTOs accurately account for the growth of DERs across their footprint. The growth of DERs will require a new type of evaluation as system needs may be better solved at the distribution level, and aggregated DER can be used by the RTO to address wholesale and transmission needs. There is a need to further break down entry barriers for non-traditional, demand-side resources to be treated comparably to the supply side. For example, RTOs may not be treating demand-side resources in their supply-side stack.

8. Are relevant regulatory authorities, individual utilities, or regional planning authorities considering measures to harden facilities against extreme weather events (e.g., winterization requirements for generators, substations, transmission circuits, and interstate natural gas pipelines)? If so, what measures? Should additional measures be considered?

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[15] "Fourth National Climate Assessment," U.S. Global Change Research Program, revised 2020, p. 30. https://nca2018.globalchange.gov/downloads/NCA4_2018_FullReport.pdf.

Many actions are being undertaken to “harden” the grid. For example, this includes using more durable poles, made of concrete instead of wood, to withstand severe weather and elevating the substations on infrequent flood plains. Such measures can be very expensive and there remains no clear prudency gauge for these resilience measures. See response to question 13 on different VOLL estimates.

9. How have entities responsible for real-time operations (e.g. utilities, RTOs/ISOs, generator operators) changed their operating practices in light of the challenges posed by climate change and extreme weather events and what potential future actions are they considering? What additional steps should be considered to change operating practices to ensure electric system reliability?

RTO/ISOs and market participants are best suited to provide detailed responses here. The main issues real-time operations should focus on are severe weather readiness and constraints on generator availability, neither of which historically warranted much attention in regards to climate change. The ability to proactively diagnose correlated derates and outages will help pre-position the fleet to avert reliability threats that may not otherwise be evident to the grid operator in individual generator’s physical parameters.

10. Are seasonal resource adequacy assessments currently performed, and have they proven effective at identifying actual resource adequacy needs? If they are used, is there a process to improve the assessments to account for a rapidly changing risk environment such as that driven by climate change? If seasonal resource adequacy assessments are performed, are probabilistic methods used to evaluate a wider range of system conditions such as non-peak periods, including shoulder months and low load conditions?

Expanding resource adequacy mechanisms to winter is low hanging fruit, and much progress has been already made. This is especially important as winter peak load grows relative to summer peaks, though resource adequacy is becoming less a function of demand levels and increasingly a function of correlated generator derates and outages. Thus, recent patterns of emergency events increasingly implicate shoulder periods.

Further, resource adequacy is not only a function of nameplate capacity, but also of the appropriate capacity type, especially given greater flexibility constraints as the resource mix evolves. Overall, resource adequacy must migrate towards bolstering capacity planning parameters for year-round reliability in a manner that avoids inadvertent favoritism towards certain resources. Solutions might include focusing on coincident portfolio performance across a year rather than needing uniform requirements for all resources to have equal availability throughout the year.

This topic warrants independent dedicated investigation.

11. Are any changes being considered to the resource outage planning process? For instance, should current practices of scheduling outages in perceived "non-peak" periods be re-evaluated, and should the consideration during planning of the reserve needs during non-peak outage periods be improved?

RTO/ISOs have taken various actions in this regard. A stricter administrative role is warranted for cost-of-service generators, who lack the incentive to minimize planned outages and time them during lower price periods and avoid high price periods, signaling reliability stress. Accordingly, merchant generators do not require planned outage micromanagement, except in the potential case of nuanced physical withholding. Further, RTO/ISOs with resource adequacy responsibility should, at minimum, have some level of veto authority over planned generator outages.

12. Mass public notification systems (e.g., cellphone texts, emails, smart thermostat notifications) are sometimes used in emergencies to solicit voluntary reductions in the demand for electricity. To what extent are such measures used when faced with emergencies related to climate change or extreme weather events, have they been effective in helping to address emergencies, and is there room for improvement?

There is ample room to improve mass public notification systems. The ERCOT's approach to public curtailment appeals during the February 2021 event is a key case in point. The intentional notification delay in the ERCOT's approach received heavy scrutiny. This delay maximized alignment of voluntary curtailment—prone to fatigue effects—with the depth of the supply shortfall. Further, expert debriefs of the event identified "very little information and data" about the status and direction of the system and how to prepare for personal social wellbeing.[16]

Economic principles ought to be applied to reliability policy, beginning with the recognition that customer heterogeneity for value of lost load (VOLL) is immense. Unfortunately, regulatory tools continue to socialize the cost and consequences of supply shortfalls. This begs for a policy redirection to induce voluntary curtailment of low value load and decrease involuntarily curtailment of high value load.

13. What measures are being considered to improve recovery times following extreme weather event-related outages? For example, are there potential changes to operating procedures, spare equipment inventory, or mutual assistance networks under consideration? What additional steps should be considered to improve recovery times?

Efforts to improve recovery periods should be based on overall cost-benefit analysis, with the benefits portion informed by long-duration VOLL. This is decidedly different, in the aggregate, than most VOLL

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[16] Testimony of Varun Rai, House Committee on Science, Space, and Technology, 117th Congress, March 18, 2021, p. 4. https://science.house.gov/imo/media/doc/Dr.%20Rai%20Testimony.pdf

estimates, which emphasize brief outages. Further, many parties with high short-term VOLL have low long-term VOLL, such as industrial customers, while parties with low short-term VOLL have higher long-term VOLL, like residential customers.

14. Given the key role blackstart resources play in recovering from large-scale events on the electric system, how is the sufficiency of existing blackstart capability assessed, and has that assessment been adjusted to account for factors associated with climate change or extreme weather events? For example, is the impact of potential common mode failures considered in the development of black start restoration plans (including but not limited to common mode failure impacts on generation resources, transmission lines, substations, and interstate natural gas pipelines)? Should these be addressed?

The pool of blackstart resources should be immune to a single form of common mode failure. Technical standards for blackstart resources may wish to examine portfolio effects, as technology-specific standards will not account for many forms of common mode failure that manifest only in region-specific contexts at certain levels of resource penetration.

The Commission should strongly encourage reducing the barriers that currently limit a robust mix of blackstart resources. The Commission may benefit from coordinating with the Department of Energy, where industry stakeholders have considered forming a working group to explore barrier removal to unconventional blackstart resources. These include distributed energy resources, like industrial cogeneration, which are typically not owned by utilities. This should also include emerging technologies, which often face accidental barriers to entry from institutional parameters designed around conventional resources. Key emerging technologies are becoming competitive; for example, vendors are starting to develop commercial grade battery-assisted blackstart resources.[17]

15. What actions should the Commission consider to help achieve an electric system that can better withstand, respond to, and recover from climate change and extreme weather events? In particular, are there changes to ratemaking practices or market design that the Commission should consider?

The Commission should revisit previous records and literature on electric resilience to frame answers to this question, which could warrant an independent docket. For example, expert convenings on grid resilience note that resilience measures should "adopt the customer perspective and focus on restoration of service in event of an outage, which is the main element of resilience not well captured in traditional reliability planning."[18] Generally, reducing barriers to new entry and transferring risk

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[17] Eric Wesoff, "Morning Brief: GE completes first battery-assisted black start, Acciona to invest $4B in PV and wind," *PV Magazine*, March 2, 2020. https://pv-magazine-usa.com/2020/03/02/morning-brief-ge-completes-first-battery-energy-storage-assisted-black-start-acciona-to-invest-4b-in-pv-and-wind.

[18] Karen Palmer, et al., "Economic Approaches to Understanding and Addressing Resilience in the Bulk Power System: A Workshop Summary," Resources for the Future and R Street Institute, June 2018, p. 3. https://media.rff.org/documents/RFF_workshop_summary_final_0.pdf.

management to competitive enterprise while simultaneously incentivizing risk management is the preferred method to facilitate organic market responses to resilience challenges—climate-related and otherwise. Eliminating barriers to new entry with pronounced reliability benefits include avoiding inadvertent conventional resource bias in capacity market rules and eliminating the right of first refusal for regional transmission projects, as well as providing a level playing field for new entrants to local transmission projects.[19]

16. Are there opportunities to improve the Commission-approved NERC Reliability Standards in order to address vulnerabilities to the bulk power system due to climate change or extreme weather events in areas including but not limited to the following: transmission planning, bulk power system operations, bulk power system maintenance, emergency operations, and black start restoration? For example, should the Reliability Standards require transmission owners, operators or others to take additional steps to maintain reliability of the bulk power system in high wildfire or storm surge risk areas? Should the Reliability Standards require the application of new technologies to address vulnerabilities related to extreme weather events, such as to use new technologies to inspect the bulk power system remotely?

There are ample opportunities to improve reliability standards, especially when addressing climate risk in an economically efficient manner. First, reliability standards should not deter emerging technologies simply because their performance profile is less understood; standards sometimes force unconventional resources to have a production profile comparable to conventional ones. Second, adapting reliability standards for climate risk without addressing fundamental flaws in those standards' development and review processes may forego better pathways or even create negative net benefits.

Climate change will increase the likelihood of low and very low probability events, which most reveal the consequences of framework deficiencies. Generally, even a qualitative comparison of benefits to costs is lacking. This has already become a pronounced problem for other low-probability, high-impact events, such as reliability standards for supply chain standards and electromagnetic pulse (EMP) mitigation, where consumers—the primary beneficiaries and funders of reliability standards—were concerned that benefits would not exceed costs.[20] The benefits of climate-related policy changes are easier to quantify than some "existential" threats like EMP and should not be excluded from cost-benefit analysis. Members of the North American Electric Reliability Corporation's (NERC) Members Representatives Committee have long encouraged NERC's risk-based standards to account for cost as well as risk.[21]

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[19] See, e.g., Devin Hartman, "Enabling New Transmission Entrants: Unleashing Bottom-up Grid Reliability Improvements," R Street Blog, March 3, 2021. https://www.rstreet.org/2021/03/03/enabling-new-transmission-entrants-unleashing-bottom-up-grid-reliability-improvements.

[20] See, e.g., "Sector 8 Policy Input for the NERC Board of Trustees & Member Representatives Committee," Electricity Consumers Resource Council. https://elcon.org/wp-content/uploads/ELCON-Policy-Input-002.pdf.

[21] Howard Gugel, "Supply Chain Report," North American Electric Reliability Corporation, May 8, 2019, p. 10. https://www.nerc.com/gov/bot/MRC/Agenda%20Highlights%20nad%20Minutes%202013/MRC%20Presentation%20Package%20-%20May%208,%202019.pdf.

Employing a cost-benefit framework may also reveal that the "1-in-10" standard is too stringent for some minor reliability events, but too weak for major events. For example, VOLL studies indicate that the 1-in-10 standard may be excessive (incremental costs exceed benefits) for brief rolling outages.[22] But reducing system black event causes, or accelerating the recovery of long-duration outages, may create very positive net benefits when applied to events likely to occur less than once per decade. Further, climate change may increase the probability of some events previously considered to be once-every-few-decades to once-a-decade occurrences, which would trigger a different designation of risk under the current framework.

Climate risk, as a component of grid resilience, should prompt a revisit of the gulf between generation and transmission and distribution (T&D) standards. Despite the events of February 2021, the data indicate that T&D systems are by far the most vulnerable system segment. However, the average T&D component "loses load" for a time period about 200 times greater than the generation standard for loss-of-load-expectation.[23]

There is also ample evidence, such as cold weather readiness responses to pre-February 2021 severe weather events, that reliability assessments and standards are detached from the underlying state and regional institutional context. For example, the recommendations of FERC and ERC's joint staff report on the cold weather reliability event of in January 2018 lacked key state and regional regulatory context, instead focusing on myopic reliability policy tools, namely standards.[24] The report should have suggested the pursuit of policy instruments that better address root causes of generator investment and operating behavior. Harmonizing reliability policy instruments first requires coordination across reliability institutions.

The reliability institution disconnect is especially potent in two arenas: wholesale market design in restructured states and public utility commission (PUC) prudency processes in regulated states, which generally have greater effect on generation investment and operating reliability than standards. Further, the disconnect means standards are often duplicative or counteract market ability to achieve voluntary reliability actions through "incentive compatibility" and the discretion of PUC prudency determinations for cost recovery approvals. For example, the optimal level of fuel firming during extreme cold events is not a one-size-fits-all industry practice, but rather is achievable in competitive markets through proper market design, or based on the portfolio of regulated utility holdings as gauged by a PUC. But these reliability institutions operate in an information constrained environment that will only be exacerbated by climate change. The NERC's emphasis on providing higher quality information—such as

[22] Palmer et al., p. 2. https://media.rff.org/documents/RFF_workshop_summary_final_0.pdf.
[23] Ibid., p. 3.
[24] "The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018," Federal Energy Regulatory Commission and North American Electric Reliability Corporation, July 2019, pp. 80-102. https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf.

contextualized risk mitigation strategies and analytics—to market designers, PUCs, and the private sector is supported by electricity consumers.[25]

Since climate-related reliability risk varies by region and sub region, uniform reliability standards do not align well with technology- or method-specifying standards. Reliability standards that are instead performance-based could be adapted to better suit region-specific climate risk profiles.

17. Where climate change and extreme weather events may implicate both federal and state issues, should the Commission consider conferring with the states, as permitted under FPA section 209(b), to collaborate on such issues?

Yes. Reliability policy straddles state and federal jurisdictions, and the current level of coordination needs improvement irrespective of climate change. This is even more important as reliability threats increase. A joint FERC-state board, which R Street has recommended repeatedly, would suitably address these demands.[26]

The severity of this problem is growing at an alarming rate. A new report from the National Academy of Sciences flagged that the patchwork policies of federal, state, regional and local authorities have elevated the challenge of identifying "who is in charge of planning, developing, and ensuring the integrity of the future power system."[27] This incongruency may already be contributing to reliability consequences, and certainly spurs policy uncertainty that leads to unnecessarily higher costs.

This state-federal reliability policy disconnect was evident in two prominent blackout events across four RTO/ISOs over the last year alone. As noted by former FERC Chairman Cheryl LaFleur, the 2020 California blackouts "led to a frenzy of hot takes and finger-pointing" resulting from a lack of clear accountability for resource adequacy as "the roles of the CAISO and the state regulators to keep the lights on are quite tangled."[28] Meanwhile, state and federal stakeholders remain confused and disjointed over the severe winter weather events of February 2021. In particular, it is apparent that federal reliability standards under FERC and NERC oversight and ERCOT market design under Texas oversight did not and are not evolving in a coordinated fashion. SPP and MISO, which also experienced

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[25] See, e.g., "Policy Input Package," North American Electric Reliability Corporation, August 2020, p. 1. https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Policy-Input-Package-August-2020-PUBLIC-POSTING.pdf.
[26] See, e.g., Travis Kavulla, "Problems in Electricity Market Governance: An Assessment," *R Street Policy Study* No. 180, August 2019, pp. 15-16. https://www.rstreet.org/wp-content/uploads/2019/08/FINAL-RSTREET180.pdf.
[27] National Academies of Sciences, Engineering, and Medicine, p. viii. https://www.nap.edu/download/25968.
[28] Cheryl A. LaFleur, "What's Ailing California's Electric System?", *State of the Planet*, Sept. 2, 2020. https://blogs.ei.columbia.edu/2020/09/02/whats-ailing-californias-electric-system.

rolling blackouts in February, have a different coordination problem: state procurement is increasingly misaligned from regional operating condition, elevating bulk reliability risk.[29]

It is imperative for future reliability policy to harmonize the actions of federal and state authorities, at least to a basic degree. For example, reliability standards should be contextualized to state and regional regulatory conditions and not be duplicative with or contradict PUC prudency processes or RTO market design elements, which are intended to ensure reliable investment and operations. It is also critical to align PUC processes in regulated states with the future planning and operating conditions of RTOs, namely in the California Independent System Operator (CAISO), the Southwest Power Pool (SPP) and the Midcontinent Independent System Operator (MISO). The more pressing climate-electric reliability intersection is likely resource-mix decarbonization—led by unconventional resources—as opposed to climate adaptation.

IV. Conclusion

RSI respectfully requests the Commission consider the comments contained herein.

Respectfully submitted,

/s/ Devin Hartman
Devin Hartman
Director, Energy and Environmental Policy

R Street Institute
1212 New York Ave. NW, Suite 900
Washington, D.C. 20005
(202) 525-5717
dhartman@rstreet.org

April 15, 2021

[29] See, e.g., "Resource Availability and Need: 2020 Focus," MISO, March 2020. https://cdn.misoenergy.org/20200304%20RASC%20Item%2002%20RAN%20Overview%20(RASC009%20RASC010%20RASC011%20RASC012)432103.pdf.