UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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Climate Change, Extreme Weather,	)	Docket No. AD21-13-000
And Electric System Reliability	)	
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Mr. Chairman and Commissioners, thank you for hosting this technical conference.

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 fuse characteristics of climate risk accurately into the evolving risk-based electric reliability framework. Doing so informs stakeholders on how best to revise current policies, protocols and inputs in a manner that maximizes net benefits to society.

The overall risk profile of climate change warrants dedicated evaluation consistent with a March 2021 Government Accountability Office report that suggests the Commission "identify and assess climate-related risks and plan a response."[1] I stress 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.

The timescale and spatial granularity of climate risk often struggles to translate into the predominate electric reliability risk paradigm. Climate impacts vary by region, at minimum stressing the need for the Commission to consider regional heterogeneity in climate risk assessment and risk management architectures. For example, mandatory reliability standards are typically a blunt tool that applies irrespective of region, however they could be adopted to performance risk assessments that permit regional tailoring. Still, even regional differentiation may be overly blunt. For example, the proximity of electric infrastructure to coastlines at risk of more frequent and intense storm surges is on a scale of tens of miles, not the hundreds of miles or more that define a reliability region.

The temporal risk profile of climate change carries an inverse relationship between the magnitude and confidence level of effects. In other words, the severity and uncertainty of climate change effects increase over time. This places a premium on the need to institutionalize dynamic risk assessment that drives continuous improvement in planning processes and uses current, verifiable and reliable data

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[1] "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.

inputs as knowledge of climate change effects evolve over time. As the severity of climate effects increase over time, the reliability priority is long-term assessment and planning practices.

Given the multi-decade nature of electric infrastructure, today's reliability policy decisions will affect the risk exposure of the electric system as climate effects worsen by midcentury. Generally, planning and assessment tools fail to account for this. For example, the assessment period of the North American Electric Reliability Corporation's (NERC) 2020 Long-Term Reliability Assessment (LTRA) only extends to 2030, while it is unclear to the extent climate change effects in the assessment period are accounted for in load forecasts, outage rates and other assumptions.[2]

Climate change will likely exacerbate deficiencies in existing long-term planning frameworks. Current deficiencies include disjointed state-federal coordination; siloed reliability institutions; incongruous market and reliability policy development; absence of economic criteria in reliability policy; uniform treatment of heterogeneous customer reliability preferences; mismatched generation to transmission 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.

Climate risk should be incorporated into a holistic revisit of reliability policy consistent with contemporary risk management practices that maximize net benefits. The explicit adoption of economic criteria—which is long overdue in this industry—naturally makes the integration of the value of lost load (VOLL) into planning processes desirable. Incorporating an administrative central estimate of VOLL is most useful for reliability services where benefits and costs are allocated in a uniform fashion like transmission expansion. Current transmission planning is suboptimal because of siloed processes for evaluating economic and reliability criteria. Integrating VOLL is one way to bridge the gap.

The immense distribution of VOLL between and within consumer segments, as well as across end uses for the same consumer, indicates massive heterogeneity in reliability benefits. For example, a recent assessment placed VOLL in the Midcontinent Independent System Operator between $3,600 and $3,900 per megawatt-hour (MWh) for residential customers, $32,000/MWh for manufacturing and $73,000/MWh for non-manufacturing commercial customers.[3] Despite this, reliability standards and protocols predominately treat firm load as homogenous. For example, comparing the heterogeneity of VOLL to the implied VOLL of the 1-in-10 standard, which ranges roughly from $30,000/MWh to

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[2] "2020 Long-Term Reliability Assessment," North American Electric Reliability Corporation, December 2020. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf.

[3] Potomac Economics, "2020 State of the Market Report for the MISO Electricity Markets," Independent Market Monitor for the Midcontinent ISO, May 7, 2021, p. 26. https://www.potomaceconomics.com/wp-content/uploads/2021/05/2020-MISO-SOM_Report_Body_Final.pdf.

$100,000/MWh depending on interpretation, indicates the standard is far too strict for some consumers and perhaps too lenient for others.[4] Such estimates tend to focus on short duration events only.

Differences between VOLL estimates for short and long-duration outages are essential, especially in a world with more extreme weather. Estimates of long-duration VOLL are sparser, but literature on it from climate-induced extreme weather is emerging.[5] It is worth comparing the nature of damages caused by the California rolling outages in August 2020 to the sustained outages in Texas in February 2021. The implications may be to differentiate reliability policy by short and long duration outage type.

It is possible that the 1-in-10 standard may be too stringent for short duration outages but too lenient for long duration outages. A tragic indicator of the latter is how the Electric Reliability Council of Texas used the 2011 winter event as a basis for assessing prospective extreme winter weather risk, which proved to understate generator outage risk and demand levels severely.[6] Although the consequences of the California event were far less severe, it revealed potential shortcomings in resource planning targets; the extreme heat wave was a 1-in-30 year event based on historical data but climate change may have altered the probability of such an event from historical averages.[7]

Given extensive VOLL heterogeneity by event type and end use, a policy objective of maximizing net benefits would prioritize enabling differentiated reliability services to flourish. A great place to start is converting uniform resource adequacy and emergency protocols to paradigms that reflect variances in consumer preferences. This encompasses many areas from enabling automated price-responsive demand to deeper tiering of emergency load curtailment. This also trickles down to unleashing local innovative mitigation strategies like sectionalized distribution circuits, which requires coordination with state authorities, but events like those in Texas this February underscore the value.[8] This is essential to aligning reliability policy with economic incentives, and the case is made stronger as the climate changes.

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[4] Harvard Electricity Policy Group, "Rapporteur's Summary Session One: REV and Beyond: Looking Ahead to Technology Disruption," Harvard Kennedy School, June 1-2, 2017, p. 24. https://hwpi.harvard.edu/files/hepg/files/rr-87-june2017.pdf

[5] See e.g., Sunhee Baik et al., "Estimating what US residential customers are willing to pay for resilience to large electricity outages of long duration," *Nature Energy*, March 16, 2020. https://www.nature.com/articles/s41560-020-0581-1?utm_source=nenergy_etoc&utm_medium=email&utm_campaign=toc_41560_5_3&utm_content=20200319&WT.ec_id=NENERGY-202003&sap-outbound-id=D508492744DEF3A19D4D18E5CA4AC701F7DF84C9&mkt-key=005056B0331B1ED7AAA5D714ACCD9BAF.

[6] Bill Magness, "Review of February 2021 Extreme Cold Weather Event – ERCOT Presentation," Electric Reliability Council of Texas, Feb. 24, 2021, p. 19. http://www.ercot.com/content/wcm/key_documents_lists/225373/2.2_REVISED_ERCOT_Presentation.pdf.

[7] "Root Cause Analysis: Mid-August 2020 Extreme Heat Wave," California Independent System Operator, California Public Utilities Commission and California Energy Commission, Jan. 13, 2021. http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

[8] Testimony of Beth Garza To the House Committee on Science, Space, and Technology, Hearing on "Lessons learned from the Texas blackouts: Research needs for a secure and resilient grid," March 18, 2021. p. 3. https://science.house.gov/download/garza-testimony.

Incentive-based risk policy should underscore reforms that better align the incentives of market participants with the efficient and reliable planning and operation of the system. This cultivates an environment of better voluntary, decentralized risk-informed decision making that is better suited to the dynamic profile of climate risk. Rate incentives, on the other hand, have a poor track record of correcting for risk alignment deficiencies, and often carry costs in excess of their benefits.

One area that the decentralized model may struggle with, however, is common mode failure. Climate change is affecting the correlation between generation and transmission outage causes, which the historical reliability paradigm presumed were 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.

Common mode policy framing should ensure the planning process aligns risk incentives rather that supplants the role of market forces. Common mode risk is difficult to identify and manifests in varied circumstances that are likely too diverse for uniform policy tools. For example, common mode failure may require special sophistication in transmission planning and market design, such as probabilistic methods in capacity accreditation processes on a zonally differentiated basis that satisfy robustness criteria defined by common mode scenarios. This applies to both mitigating reliability events as well as avoiding restoration delays like a single point of failure in the blackstart resources system network.

Overall, the Commission should prioritize improving reliability policy that is inclusive of climate change, but not merely motivated by the effects of it. It appears that climate change primarily exacerbates existing reliability policy deficiencies. For example, a given reliability policy reform that may yield a 4:1 benefit-cost ratio under static climate conditions may yield a 5:1 ratio with climate change. Refinements, such as extending long-term reliability assessment ranges or more accurate information inputs, may suffice to account for climate change where the existing reliability framework includes the risk vector. Any new categorical risks may warrant dedicated policy instrument responses, such as those tied to common mode failure.

Thank you for your diligence examining these important matters.

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