UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Climate Change, Extreme Weather, and Electric System Reliability	Docket No. AD21-13-000

COMMENTS OF THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

The National Rural Electric Cooperative Association (NRECA) submits the following comments in response to the Commission's March 15, 2021, Supplemental Notice of Technical Conference Inviting Comments. NRECA appreciates the Commission's attention to matters of climate change, extreme weather, and electric system reliability. NRECA submits these comments to provide the broad perspective of its members on the issues discussed in the Supplemental Notice. Individual cooperatives may file comments reflecting their specific views and experiences.

I. Summary of Comments

NRECA approaches the questions posed in the Supplemental Notice with a view toward the transformation of the electric power sector that is occurring and is expected to continue in coming years. The Commission should consider the impact of climate change and extreme weather on electric system reliability together with—and not in isolation from—other technological, economic, and public policy changes affecting the electric utility industry. These changes are interrelated, and they should be evaluated together when identifying and addressing risks to electric system reliability.

If the Biden Administration's goal of achieving carbon-free electricity by 2035 and a "net-zero" carbon economy by 2050 are implemented through legislation or regulation, it will drive significant changes to how electricity is generated, distributed, and used. If this policy does move forward, NRECA believes such a transition must be accomplished through a just and reasonable approach over a reasonable and realistic period of time, account for regional differences in energy resource availability and support funding for a range of energy technologies that will be needed to achieve these goals. This transition must ensure the availability of affordable, reliable electricity to every community, including the rural communities electric cooperatives serve.

NRECA's comments below on the questions in the Supplemental Notice include the following points.

- Electric system reliability is broader than the reliability of the bulk power system (BPS) and includes the reliability of electric service to end-use consumers—or in the case of electric cooperatives, distribution cooperative consumer-members.
- Most challenges to electric system reliability, including those due to extreme weather events, are local in nature—primarily on the distribution system, requiring local solutions by utilities working with their communities.
- There is long-term value in maintaining a balanced portfolio of generation resources. As the generation mix changes, grid operators must continue to have available to them the operating characteristics necessary for reliable management of the grid, including flexible, dispatchable conventional resources such as coal- and gas-fired generation.
- A balanced generation resource portfolio, in addition to a geographic diversity of generation resources, will help mitigate risks of common mode failures.

- Local, state, and regional planning is the key to addressing the risks arising from potential common mode failures in different regions of the country.
- It may be time for the Commission to examine whether additional coordinated operating and planning measures are needed to ensure both electric system reliability and natural gas system reliability, and to mitigate the risks of common mode failures on both systems.
- A significant expansion of both transmission and distribution systems will be needed to support deployment of the renewable resources and the increased electrification of homes and businesses, including electric vehicle (EV) charging requirements.
- Changes to modeling and planning assumptions used for transmission and resource adequacy planning can be identified and implemented through established planning mechanisms at the local, state, and regional level.
- Several North American Electric Reliability Corporation (NERC) reliability standards address planning for and responding to extreme weather events. NRECA supports NERC's continuing work on these issues, including its deadline for completing its current cold weather project.
- The state and local regulatory authorities, RTOs/ISOs, and local cooperative boards that typically establish resource adequacy requirements are well positioned to address the need for seasonable assessments and requirements.
- Uncertainty in the level and timing of electric demand, e.g., from increased electrification and extreme weather in the "shoulder" seasons, may make the scheduling of generation resource maintenance outages more challenging.

Coordination of outages will be important to mitigate impacts on electric system reliability.

- The Commission should recognize that many of the needed steps to achieve greater electric system resilience will be identified and implemented through established planning mechanisms at the local, state, and regional levels. The Commission should aim to facilitate, and not impede, policy innovation at the local, state and regional levels.

II. NRECA's Interests in This Proceeding

NRECA is the national trade association representing nearly 900 local electric cooperatives and other rural electric utilities. America's electric cooperatives are built by and owned by the people that they serve and comprise a unique sector of the electric industry. From growing regions to remote farming communities, electric cooperatives power 1 in 8 Americans and serve as engines of economic development for 42 million Americans across 56 percent of the nation's landmass. Electric cooperatives operate at cost and without a profit incentive.

NRECA's member cooperatives include 63 generation and transmission (G&T) cooperatives and 834 distribution cooperatives.[1] The G&T cooperatives generate and transmit power to distribution cooperatives that provide it to the end-of-line co-op consumer-members. Collectively, G&T cooperatives generate and transmit power to nearly 80 percent of the distribution cooperatives in the nation. The remaining distribution cooperatives receive power directly from other generation sources within the

[1] See https://www.cooperative.com/maps-facts-figures/Documents/Co-op-Facts-and-Figures.pdf

electric utility sector. Both distribution and G&T cooperatives share an obligation to serve their members by providing safe, reliable, and affordable electric service.

The questions raised in the Supplemental Notice affect the interests of NRECA's member cooperatives in multiple respects—as load-serving entities; distribution utilities; transmission customers; transmission owners and operators; electric generation owners and operators; buyers and sellers in wholesale electricity markets; and owners, operators, and users of the BPS.

Cooperatives own and maintain 2.6 million miles, or 42 percent of the nation's electric transmission and distribution lines, including over 44,000 miles of transmission lines. Cooperatives serve an average of eight customers per mile of line and collect annual revenue of approximately $19,000 per mile; other utility sectors average 32 customers and $79,000 in annual revenue per mile.

Electric cooperatives generate about 5%, and deliver about 12%, of U.S. electricity. Electric cooperatives rely on a broad portfolio of fuels, including clean and renewable resources, as well as energy efficiency efforts, to maintain safe, reliable, and affordable power for their communities. For 2019 (the latest complete year for which figures are available) cooperatives' aggregate retail sales of electricity were derived from a fuel mix consisting of 32% coal, 32% natural gas, 19% renewable, 15% nuclear, and 2% oil and other.

The majority of G&T electric generation remains coal-fired, in part because federal law made it uneconomic to use natural gas for electric generation from 1978 through most of the 1980s, a period that coincided with a growth in electric cooperative loads but preceded open access transmission service that supported entry in wholesale electricity markets. Additionally, many rural cooperatives were located near coal sources. Today, cooperatives are reducing emissions through a combination of emission-reduction measures at power plants and by switching to natural gas and renewables. More than 95% of electric cooperatives provide electricity generated from renewable resources. From 2010 to 2019, cooperative renewable energy capacity increased 151% from 4 gigawatts (GW) to 10 GW. Cooperatives have plans to add 6 GW of renewable capacity from 2020 to 2023, including more than 4 GW of solar capacity. More than 475 cooperatives in 33 states use wind energy to serve 2 million homes, the majority of it contracted through power purchase agreements.

Many consumers in rural communities are less affluent than those in other parts of the nation. In 2019, the median household income for electric cooperative consumer-members was 11% below the national average. Electric cooperatives serve 92% of the 395 persistent poverty counties in the U.S. Many of these economically disadvantaged consumer-members live in areas with harsh winters and without access to natural gas. Most other heating alternatives, like propane and heating oil, are comparatively expensive. Many cooperative consumer-members depend on cooperative-generated electricity for heating during winter months. Especially because many rural households lack viable heating alternatives, it is vitally important to these households that electric system reliability be maintained and that electric rates remain reasonable.

Both G&T and distribution cooperatives are "load-serving entities" under section 217 of the Federal Power Act (FPA).[2] Some G&T cooperatives are

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[2] 16 U.S.C. § 824*q* (2018). In section 217(b)(4), Congress required the Commission, when exercising its authority under Part II of the FPA to act "in a manner that facilitates the planning

Commission-jurisdictional public utilities, but the vast majority of cooperatives are outside the Commission's regulatory authority under most provisions of Part II of the FPA pursuant to section 201(f) of the act.[3] NRECA member cooperatives include registered entities subject to the reliability standards developed by NERC and approved by the Commission under section 215 of the FPA.[4]

III. Comments on Questions in Supplemental Notice

In these comments, NRECA provides a perspective of its members on the issues described in the questions in the appendix to the Supplemental Notice. NRECA looks forward to the upcoming technical conference and to an opportunity to provide more detailed comments after the technical conference. NRECA approaches these questions with a view toward the transformation of the electric power sector that is occurring and is expected to continue in coming years.

The Biden Administration's goal of achieving carbon-free electricity by 2035, coupled with economy wide "net-zero" carbon by 2050, may drive significant changes to how electricity is generated, distributed, and used by customers.

NRECA believes such a transition must be accomplished through a just and reasonable approach over a reasonable and realistic period of time, account for regional differences in energy resource availability and support funding for a range of energy

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and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy" their service obligations. 16 U.S.C. § 824q(b)(4).

[3] 16 U.S.C. § 824(f) (2018).

[4] 16 U.S.C. § 824o (2018).

technologies that will be needed to achieve these goals. This transition must ensure the availability of affordable, reliable electricity to every community.

The success of any transition will depend on many different factors yet to be resolved. The pace of the transition will have significant implications for electric system reliability and affordability. Electric utilities will need to either replace or retrofit with carbon capture technology considerable fossil-fuel generating assets while concurrently adding significant new generation to support the rapid electrification of other segments of the economy, including transportation. This underscores the importance of recognizing and addressing current limitations of commercially viable, affordable, and always-available carbon-free energy technologies to power our economy through the transition and beyond. In addition, expediting permit approvals will be necessary to build out significant new transmission and distribution facilities. Financial support to ease the impact on cooperative communities and rural economies will be critical.

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?

In this context, NRECA interprets the term "electric system reliability" to include the reliability of electric service to end-use consumers—or in the case of cooperatives, distribution cooperative consumer-members. Thus, electric system reliability is broader than the reliability of the Bulk Electric System (BES) addressed by NERC reliability standards. Critically for electric cooperatives, electric system reliability includes local distribution system reliability, which is the responsibility of state and local regulatory authorities, including the elected boards of distribution cooperatives. Utilities engage in ongoing planning for extreme weather events at the BES level as well as at local distribution systems. Planning processes have to be cognizant of broader grid interconnectivity, but also mindful of regional and local transmission topology. As later questions suggest, electric system reliability may be considered to include the reliability of generation fuel sources, water supplies, telecommunications services, and other inputs used in generating, transmitting, and distributing electric energy.

Overall, the U.S. has a remarkably reliable electric system. Cooperatives and other utilities, NERC, the Commission, and state and local utility regulators have worked diligently to ensure this. The electrification and digitization of the economy have heightened awareness and concerns about electric system reliability. Consumers and businesses expect and depend on reliable, high-quality electric service. Critical sectors of the economy and essential public services, including water, telecommunications, transportation, fuel production, health care, banking, and finance depend especially heavily on reliable electric service.

In assessing the most significant challenges posed to electric system reliability due to climate change and extreme weather events, NRECA notes that most challenges to electric system reliability, including those due to extreme weather events, are local in nature—primarily on the distribution system, requiring local solutions by utilities working with their communities.

The second installment of DOE's Quadrennial Energy Review (QER) concluded that most power outages occur because of problems at the distribution level and not the BPS level.[5] In a 2016 report, the Electric Power Research Institute concluded that

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[5] DOE, *Transforming the Nation's Electric System: The Second Installment of the Quadrennial Energy Review* at p. 4-5 (2017).

"[b]ased on a reliability measure of average total duration of the interruptions experienced by a customer, more than 90% of the minutes lost by consumers annually are attributable to distribution events."[6]

Upgrading and maintaining distribution systems to reduce their vulnerability to extreme weather-related failures is a cost-effective way to enhance electric system reliability. Dedicating federal support to help harden the grid, as well as providing support when recovering from outages would help address these challenges. For example, cooperatives support efforts to streamline approval processes to assure more timely access to transmission and distribution infrastructure crossing federal lands to support routine and emergency vegetation management and maintenance practices in utility rights-of-way necessary to enhance system reliability and mitigate wildfire risks.

Although the Commission should continue to guide and assist electric utilities, NERC, and state and local regulators in these efforts to ensure electric system reliability in the face of extreme weather events, major Commission intervention does not appear warranted at this juncture. Electric utilities such as co-ops should remain the locus for decision-making on investments to ensure electric system reliability. By preserving local control and enabling local planning, the Commission can best ensure cost-effective investments in infrastructure and practices to ensure electric system reliability in the face of extreme weather events. In addition to efforts to harden local resources, ensuring reliable connections with our neighbors is also important for resilience.

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[6] Electric Power Research Institute, *Electric Power System Resiliency: Challenges and Opportunities* 35 (2016), available at https://www.naseo.org/Data/Sites/1/resiliency-white-paper.pdf

Within RTOs/ISOs, the market rules will need to compensate resources properly to ensure reliable operation during the transition. As the generation portfolio changes to include more intermittent resources, RTO/ISO markets will need to ensure that they incentivize the operating capabilities of the generation resources needed to assure reliability. As discussed under question 5, market rules will need to address common mode failures resulting from extreme weather events.

NRECA lists here the major near-, medium- and long-term challenges to electric system reliability due to climate change and extreme weather events that NRECA member cooperatives have identified. Several of these challenges are discussed in the responses to later questions.

a. Near-term challenges

1. Whether there is adequate fuel security for gas-fired electric generation during extreme weather events.

2. Whether planning for potential weather events using standard 1-in-10-year models leaves the electric system unprepared for more extreme weather events.

3. Whether utility reliance on neighboring utility systems is inadequate when widespread extreme weather events can limit regional availability.

4. Whether wholesale market rules provide inadequate compensation for reserve generation resources that may only be needed during extreme weather events (or similar exigent circumstances).

5. Whether to reconsider the planned retirement of controllable generation resources that can better respond to changing system conditions, including those resulting from extreme weather events.

b. Medium-term challenges:

1. Whether a balanced portfolio of generation resources can be maintained that continues to provide essential reliability services and fuel diversity.

2. Whether actions to decarbonize the electric system can be undertaken simultaneously with actions by other sectors of the economy (e.g.,

transportation) and businesses and households generally to decarbonize by increasing their reliance on the electric system.

3. Whether actions to decarbonize the electric system and the broader economy can be undertaken within the framework of increased permitting, siting, and land use concerns.

4. Whether infrastructure updates to electric system and natural gas transmission and storage will keep pace with increasing electric demands and changing generation resources.

5. Whether regional and interregional transmission planning, expansion, and cost-allocation policies will support planning for needed transmission infrastructure.

c. Long-term challenges:

1. Whether a balanced portfolio of generation resources can be maintained that continues to provide essential reliability services and fuel diversity.

2. Whether cost-effective new technologies will be developed to enable a net-zero carbon electric utility sector and other sectors of the economy while maintaining electric system reliability.

3. Whether the transmission infrastructure will be built to enable a net-zero carbon electric utility sector and other sectors of the economy while maintaining electric system reliability.

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?

Electric utilities continue to upgrade their systems to withstand or mitigate risks to their generating assets, along with the transmission and distribution system. While these efforts ensure a consistently high level of reliability, outages driven in part by severe weather still do occur. In the last decade, several high-profile natural disasters have caused widespread electric outages and infrastructure damage.

The National Oceanic and Atmospheric Administration (NOAA) reported that the U.S. has sustained 285 weather-related disasters since 1980 where overall damages/costs reached or exceeded $1 billion (in 2020 inflation-adjusted dollars). The total cost of these 285 disasters exceeds $1.875 trillion.[7] The second installment of DOE's QER found that extreme weather conditions, such as hurricanes, blizzards, thunderstorms, and heat waves, were the leading cause of power outages, especially widespread outages.[8] Indeed, DOE noted that all 12 of the largest outages in 2015 measured by the numbers of customers affected were related to weather.[9]

Extreme weather risks may require changes to the ways in which generation, transmission, substation, or other facilities are designed, built, sited, and operated. Solutions will be mostly region specific and will vary with the specific weather risks, and the specific costs and potential benefits of different possible approaches. Most of the necessary decision-making and policy-making will be at state and local levels. For example, utilities in some warm-weather states may consider implementing measures to winterize certain generation, transmission, and distribution facilities (which is a matter of routine in cold-weather states) to mitigate reliability risks to the electric system from extreme cold-weather events. The weather risks and mitigation measures are likely to be site-specific.

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[7] See NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2021), available at https://www.ncdc.noaa.gov/billions/ or https://www.doi.org/10.25921/stkw-7w73.

[8] *See Transforming the Nation's Electric System: The Second Installment of the Quadrennial Energy Review* at p. 4-28.

[9] *See id.*

Generation resources have withstood risks from extreme weather events, including hurricanes and extreme cold since the beginning of the modern power grid. Additional winterization, storm-hardening, and flood control measures may be warranted by some utilities and local communities. Inherently, these measures will be location-specific.

Moreover, gas-fired electric generation facilities and natural gas supply, storage, and transportation facilities may need to be operated in a more coordinated manner to ensure that needed generation is able to operate during extreme weather events when electric and heating loads need to be met.

The growth of distributed energy resources (DER) increases operational complexity on local distribution systems. Extreme weather events will require greater planning and communication between resource owners, distribution operators, and transmission operators to ensure DER visibility, operational coordination, and electric system reliability.

Some cooperatives have undertaken programs to evaluate and prioritize the replacement or modification of aging wires infrastructure. In part because of weather-related concerns, some cooperatives and other utilities have started using transmission structures made of steel and concrete. Similarly, cooperatives have continued replacing, upgrading, hardening, and maintaining distribution facilities to reduce their vulnerability to extreme weather-related failures and cost-effectively enhance electric system reliability. The IEEE Standards Association concluded that the data from industry studies "strongly suggests that effective pole maintenance and vegetation management programs are likely to produce a positive cost-benefit ratio."[10]

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?

Long-term changes in weather patterns (apart from high-impact, low-frequency extreme weather events) may warrant long-term changes in the way utilities design, build, and site generation, transmission, substation, or other facilities. Design changes are likely to be the most important long-term effect, although the siting of facilities (e.g., in low-lying areas or along vulnerable seacoasts) may also occur.

Beyond these direct effects of long-term changes in weather patterns are the larger indirect effects of changes in the electric system driven by technological, economic, and policy changes. For example, changes in the composition of the generation resource mix will require changes in the way many existing generation facilities are operated and changes in the way new facilities are designed, built, sited, and operated. DER growth will require substantial changes to the way distribution systems are designed, built, and operated. These changes in the central-station and distributed resource mix, coupled with changes in peak demand patterns resulting from greater electrification (e.g., EV charging) may lead to substantial changes in the way the electric system, in particular distribution and transmission facilities, is operated and, over time, designed and built.

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[10] IEEE Standards Association, *Grid Resilience and the NESC* 10 (2018).

Scheduling requirements for long duration outages for larger baseload units likely will become more complicated. The opportunities today to use "shoulder" seasons (i.e., the times between winter and summer peak periods) may be lost due to beneficial electrification creating near-constant load requirements on a year-round basis.

Outage scheduling may need to be addressed for renewables, because high penetration of wind or solar in the future could create conflicts with meeting reserve margins. For example, substation maintenance that could require a GW-sized solar array to come offline for an extended period might create localized problems.

As more intermittent renewable generation is included in the resource mix, flexible, dispatchable conventional generation, such as coal- and gas-fired generation, is needed to ensure grid support and system reliability, as reliability analyses by NERC and RTOs/ISOs have confirmed. Given the operational importance of those resources, it will be important to prioritize and to secure the fuel supply and fuel-delivery systems in managing the grid's generation-fleet transition. Natural gas supply, transportation, and storage planning and operations will need to be coordinated with the needs of the gas-fired generation facilities in their regions of service. Moreover, the events during Winter Storm Uri last February highlighted the need for this coordination even beyond electric service reliability and cost to end-use consumers.

There is long-term value in maintaining a balanced portfolio of generation resources. The changing generation resource mix at the BPS level has focused attention on the value of "essential reliability services" such as voltage support and frequency response.[11] Thus, Commission Order No. 842 requires newly interconnected generators

[11] See, e.g., Comments of NERC, Grid Resilience in Regional Transmission Organizations and Independent System Operators, Docket No. AD18-7-000 at 17-18 (2018); Comments of NERC,

to be capable of providing "primary frequency response" as a condition to interconnecting to the grid.[12] Additional focus will be needed to ensure that grid operators have available to them, in the changing generation resource mix, the operating characteristics necessary for reliable management of the grid in this transition.

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?

The electric sector's dependence on gas, water, transportation, and telecommunications services means these services are potential vulnerabilities to electric system reliability.

For example, the prolonged shutdown of the Aliso Canyon natural gas storage field in California, concerns about wintertime fuel security in New England, and Winter Storm Uri have focused attention of the electric sector's dependence on natural gas supply, storage, and transportation infrastructure and services.

Grid Reliability & Resilience, Docket No. RM18-1-000 (Oct. 23, 2017). *See also* Reliability, Resiliency, and Affordability of Electric Service in the United States Amid the Changing Energy Mix and Extreme Weather Events, Testimony of James B. Robb, U.S. Senate Committee of Energy and Natural Resources (Mar. 11, 2021), available at https://www.energy.senate.gov/services/files/EB1D7E02-BC93-4DFF-A6A9-002341DA34CF

[12] Essential Reliability Services and the Evolving Bulk Power System – Primary Frequency Response, Order No. 842, 162 FERC ¶ 61,128, *reh'g denied and clarified*, 164 FERC ¶ 61,135 (2018).

The converse also may be true. During Winter Storm Uri, some electric compressor stations that support the flow of natural gas were forced offline during the rotating blackouts.

A common mode failure can arise if extreme weather conditions disrupt a fuel supply or feed process used by multiple electric generation resources. For example, in some geographic regions, extreme winter storms may freeze natural gas production and supply equipment, coal piles, wind turbines, and cooling-water intake systems to nuclear generators. A common mode failure also could arise if a hurricane damages multiple transmission structures, affecting the transmission of power from multiple connected generators and disrupting the communications infrastructure.

Geographic diversity of generation resources, which is made possible by a transmission grid with sufficient transmission capacity and geographic size, would help mitigate the risk of some common mode failures. This appears to have been the experience in the Southwest Power Pool (SPP), the Midcontinent Independent System Operator (MISO), and non-RTO/ISO balancing authorities during Winter Storm Uri. But as the simultaneous events in the Electric Reliability Council of Texas (ERCOT) showed, some extreme weather events may be so widespread that they affect the resources of an entire geographic region.

In addition to geographic diversity, a balanced generation resource portfolio will help mitigate risks of common mode failures. With the growing share of gas-fired generation, NERC has noted the possibility of common-mode outages affecting multiple gas-fired generation resources.[13] NERC has concluded that in addition to the "essential reliability services" needed as the resource mix changes, "fuel assurance and diversity are critical elements of a reliable and resilient system."[14]

High concentrations of non-dispatchable generation over a large region may also lead to reliability issues during an extreme weather event. For instance, during a heat wave, utilities or regions with high amounts of solar may rely on imports from neighboring utilities or regions in the evening hours. However, if neighboring utilities or regions also have high amounts of solar generation, there may not be extra capacity to share.

Local, state, and regional planning is the key to addressing the risks arising from potential common mode failures in different regions of the country. Many of the risks of common mode failures due to extreme weather events can be addressed within existing planning processes and procedures and coordination mechanisms. In regional planning and reliability organizations, planning could be expanded to include analysis of the risks arising from potential common mode failures identified in that region. The results of that analysis may lead to consideration of changes in transmission planning processes, operational rules, and market rules.

With the growth of DER, resource visibility and coordination are critical, and, as noted above, common mode failures involving the outage of telecommunications services during extreme weather events may warrant attention by planning authorities.

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[13] Comments of NERC, Grid Resilience in Regional Transmission Organizations and Independent System Operators, Docket No. AD18-7-000 at 18.

[14] *Id.*

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 previously has addressed issues of gas-electric coordination.[15] It may be time to examine whether additional coordinated operating and planning measures are needed to ensure both electric system reliability and natural gas system reliability, and to mitigate the risks of common mode failures on both systems. Each extreme weather event affecting these systems is an opportunity to analyze and learn new and improved approaches to planning and operations practices between energy systems.

Natural gas pipeline availability for generation facilities is a major concern of NRECA member cooperatives. Natural gas pipelines should be deemed to be critical electric loads that must be identified in advance and exempted from electric load curtailments during times of grid stress. One preliminary finding from the recent outages in Texas was that the failure to identify certain natural gas infrastructure as critical electric loads exacerbated the ability to keep natural gas flowing to homes and businesses when load shedding was required. Within this context, natural gas resources also may fill reliability gaps resulting from intermittent wind and solar generation. However, it is important that a solution to one problem—registering natural gas suppliers as critical loads—does not have the unintended consequences of creating undue hardship for residential customers, for example, by shifting a disproportionate share of outages on them during extreme weather events. A coordinated planning approach will improve coordinated operations between energy systems during emergency events.

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[15] See Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities, Order No. 809, 151 FERC ¶ 61,049, *order on clarification*, 152 FERC ¶ 61,095 (2015).

Moreover, natural gas pipelines need to raise the priority given to continued service to electric generation facilities. As we electrify our economy and increase the use of intermittent renewable resources on the BPS, the need for flexible and dispatchable natural gas generation is critical to ensuring grid stability and BPS reliability.

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?

Twenty-four states and the District of Columbia have established economy-wide greenhouse gas emissions targets, including a regional cap-and-trade program in most northeastern states. In addition, 30 states and the District of Columbia have a renewable portfolio standard (RPS), and five states have a clean energy standard.[16]

While no uniform federal requirements are currently in place, as noted above, the administration's climate initiative could have a sweeping impact on electric utilities as well as other sectors of the economy. Much of the broader economy's emission reductions will result from increased electrification. To meet this growing electric demand, and to replace retiring fossil generation, a considerable build-out of generation with low or no greenhouse gas emissions will be needed, while simultaneously maintaining existing zero-carbon generating resources such as nuclear and hydropower.

[16] See https://www.c2es.org/document/greenhouse-gas-emissions-targets/#:~:text=Currently%2C%2024%20states%20and%20the,%E2%80%9Cnet%2Dzero%E2%80%9D%20targets ; http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2020/09/RPS-CES-Sept2020.pdf

Along with the build-out of renewable generation, a significant expansion of both transmission and distribution systems will be needed to support deployment of the renewable resources and the increased electrification of homes and businesses, including EV charging requirements.

According to the recent National Academies of Science, Engineering and Medicine report, *Accelerating Decarbonization of the U.S. Energy System*, utilities will need to increase generation by 20% in 2030 and up to 170% by 2050 to electrify the economy. This includes a two- to three-fold increase in wind generation and a four-fold increase in solar generation in the next decade – which will require flexible, dispatchable resources to be available to ensure reliability is maintained. Transmission will need to expand by 60% in 2030 and three-fold by 2050 to support the added generation needs. Significant funding will be necessary to build out the grid, support technological breakthroughs, fund EV charging stations, and other measures to mitigate some of the costs along with streamlining of approvals to rapidly build out the infrastructure.

As noted above, established local, state, and regional planning mechanisms are the proper means to evaluate and address the challenges posed to electric system reliability by climate change and extreme weather events (including the NERC Standards Project 2019-06 Cold Weather). Several possible steps have been described above, including changes in planning criteria, enhanced planning models, grid hardening, improved permitting and siting, improved vegetation management, changes in operating rules and changes in wholesale capacity, energy and ancillary services market rules.

NRECA member cooperatives are evaluating and addressing the challenges posed to electric system reliability due to climate change and extreme weather events as a component of each cooperative's overall planning responsibility. As load-serving entities with a legal obligation to serve their members, electric cooperatives engage in long-term planning to manage risk and optimize their facilities, systems, and operations to meet a myriad of organizational goals. These include safety, affordability, reliability, regulatory compliance, environmental sustainability, power quality, fuel supply risk, fuel price risk, and energy and capacity price risks. NRECA member cooperatives also will continue to seek long-term access to transmission to meet their service obligations and wholesale market structures and rules that work for all cooperatives, including small utilities. Moreover, NRECA observes that the framework that the Commission is developing to address environmental justice concerns would include the economically challenged rural communities many of its members serve. Consideration of the cost impact on these rural communities of any policies must factor into any changes in policies the Commission may advance to address the challenges of climate change. Rural consumers deserve reliable power, and they deserve power they can afford.

As noted in the response to questions 1, 3, and 5 above, NRECA member cooperatives generally support Commission action to improve the coordination of natural gas and electric generation operations as well as continuing Commission action to evaluate and address the effects of increased electrification and increased intermittent generations resources on electric system reliability.

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?

There is no uniform answer to these questions because changes to weather conditions and consumption trends vary by location. Some cooperatives report that they are considering whether the standard 1-in-10-year planning criterion is adequate for their transmission, distribution, and resource adequacy planning. Few utilities rely entirely on historic weather data for their planning assumptions, preferring to use some form of weather forecasts from NOAA and other sources in their planning and operations.

Changes to modeling and planning assumptions used for transmission and resource adequacy planning can be identified and implemented through established planning mechanisms at the local, state, and regional level.

From the perspective of an electric cooperative, planning for electric system reliability will be addressed in the cooperative's long-term planning process, driven by the needs of the cooperative's consumer-members and thus the local communities it serves.

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?

See NRECA's responses to questions 1, 2, 3, 5, and 10 for discussions related to these questions.

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?

All real-time system operators have procedures to manage extreme weather events. Efforts are underway to consider changes to operating practices based on lessons learned from the outages experienced in California in August 2020 and from Winter Storm Uri in February 2021.

As a general practice, real-time operating procedures are reviewed, modified, and used as a basis for training to incorporate lessons learned from extreme weather events. In addition to planning for increased severity and frequency of weather events, some cooperatives have initiated additional assessments or lessons learned to include the following:

- Resource adequacy measures and reserve margins
- Load forecasting, including severe temperature forecasts
- Coordinated communications
- Natural gas supply and infrastructure
- Dual-fuel unit availability and testing.

Several NERC reliability standards address planning for and responding to extreme weather events, including EOP-011 (Emergency Operations), IRO-008 (Reliability Coordinator Operational Analysis and Real-time Assessments), TOP-001 (Transmission Operations), and TOP-002 (Operations Planning).[17] Specifically, NRECA supports the NERC Board of Trustees' deadline for completion of NERC's Project 2019-06 (Cold Weather) by June 2021. The proposed draft Reliability Standards EOP-011-2, IRO-010-4, and TOP-003-5 address planning and managing cold weather events and will enhance the reliability of the BES.

As noted earlier, continued DER growth will require local distribution system operators to coordinate their planning and real-time operations, including real-time communications, with DER owners and operators and with transmission owners and operators.

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?

In addition to its annual Long-Term Reliability Assessments, NERC issues Summer and Winter Assessments, and other special assessments on the short-term adequacy of electricity supplies in the United States and Canada for summer and winter

[17] See NERC's listing of these and other related approved and effective reliability standards at https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States

peak demand periods.[18] All utilities in the NERC regions participate either directly or indirectly in this ongoing NERC assessment process.

ISOs and RTOs also perform assessments of their region's readiness prior to summer and winter peak periods.[19]

State and local regulatory authorities, RTOs/ISOs, and local cooperative boards typically establish resource adequacy requirements and are well positioned to address the need for seasonable assessments and requirements.

Winterization requirements for natural gas supply, storage, and transportation facilities should be undertaken in coordination with the operators of the gas-fired electric generation served by these facilities. Seasonal resource adequacy assessments necessarily will require a much higher degree of certainty regarding fuel supply, and that means the natural gas supply and delivery systems to electric generation facilities.

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?

NERC Reliability Standard IRO-017-1 (Outage Coordination) ensures that "outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon."[20] Reliability Coordinators have the opportunity to

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[18] See https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

[19] See https://www.pjm.com/-/media/library/reports-notices/testimony/2021/20210304-testimony-of-evelyn-robinson-before-the-indiana-senate-utilities-committee.ashx (discussing PJM winter-related assessment actions)

[20] https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=IRO-017-1&title=Outage%20Coordination&Jurisdiction=United%20States

make the necessary changes in outage planning processes as the resource mixes in their region changes.

Electric utilities already consider reliability risks in their outage planning process, within the limits of flexibility of addressing the maintenance needs of facilities. Baseload generation (including coal, gas combined cycle, and nuclear) will still be needed because increased beneficial electrification (especially EVs) and behind-the-meter generation will alter peaks. Major maintenance outages for these resources generally occurs during non-peak "shoulder" periods when electricity demand is lower, but these changes to demand could lead to higher and less predictable demand and make scheduling significant maintenance more challenging. As demand shifts or increases in the future, coordination of outages will be important to mitigate impacts on electric system reliability.

Under the administration's net-zero carbon goal, the electrification of the U.S. economy likely will cause a shift in how and when electricity is used. For example, electrifying the transportation sector will likely impact "non-peak" periods as many vehicles reasonably would be expected to recharge overnight, which means an increased need for electricity from baseload generation in regions of the country where the output from renewable generation is more limited, or non-existent, at nighttime.

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?

NRECA will not address these issues at this time.

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?

NRECA member cooperatives continue to work with their consumer-members, with other cooperatives, with other utilities, and with officials in their local communities on ways to improve the recovery from weather-related outages.

Cooperatives have established an effective mutual assistance network that has become more efficient and sophisticated over time. The cooperative mutual assistance network is activated well before any significant weather event such as a hurricane or an ice storm. Daily conference calls are held starting when the disaster is predicted, weather patterns are followed closely and analyzed frequently. If the path of the storm is relatively predictable (a hurricane, for example) the co-ops begin in advance to plan for the numbers of crews and types of equipment that will be needed for post-event restoration. If the co-op predicts that the extent of the damage will surpass its ability to restore power quickly and safely, the co-op can call on any of the 1,000 signatories to the mutual assistance agreement for assistance. For “no-notice” events such as earthquakes or tsunamis, communication and coordination begin as soon as communication can take place with the impacted area.

Cooperatives and other utilities will need visibility concerning energy technologies integrated into distribution systems by other entities that could affect safety, reliability, and security of distribution systems, including storage and other DERs. To ensure timely recovery, distribution operators need to know the location and operation of all DER connected to the distribution system. Distribution operators also need communication protocols such as IEEE 1547-2018 to communicate with DER. Electric system reliability and timely recovery will require greater communication and coordination between distribution system operators and DER owners and operators.

Several examples of ongoing coordination can be noted in this connection:

- Electric cooperatives participate in the Department of Energy's annual Clear Path exercise. For eight years, DOE and stakeholders have simulated a variety of disaster scenarios in differing geographies to test response times and preparedness. Electric cooperatives also participate in state and regional disaster exercises.

- Sharing of spare parts inventories and equipment.[21]

- Local or regional emergency preparedness planning and drills with electric utilities and other entities.

- Information sharing through the Electricity Information Sharing and Analysis Center (E-ISAC) and the Electricity Subsector Coordinating Council (ESCC).

- Maintaining strategic partnerships with critical vendors to alert them of the need for additional equipment and staffing inventories before extreme weather events occur.

- Voluntary, internal "lessons learned" exercises performed by NRECA member cooperatives.

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?

NRECA will not address these issues at this time.

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[21] *See* Jurisdictional Regional Equipment Sharing for Transmission Outage Restoration Participants, 163 FERC ¶ 61,005 (2018) (approving RESTORE Agreement).

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 recognize that many of the needed steps to achieve this goal will be identified and implemented through established planning mechanisms at the local, state, and regional levels. The Commission's foremost goal should be to do no harm – to facilitate, not impede, policy innovation at the local, state and regional levels.

Electric cooperatives will continue to seek transmission service and wholesale market structures and rules that enable all cooperatives, including small utilities, to obtain a balanced portfolio of resources to meet their service obligations and provide safe, affordable and reliable service to their consumer-members.

In considering ratemaking practices and wholesale market design policies to address electric system reliability, the Commission should afford the RTOs/ISOs the flexibility to determine their region's particular needs and devise the appropriate solutions through their stakeholder processes and including engagement with state regulators. Possible Commission actions preferably would take the form of directing consideration of various factors in the planning process or market design rather than mandating particular utility practices or market rules.

As a general matter, the Commission's ratemaking practices should compensate resources for reliability-enhancing services at market-based rates where feasible—provided that market competition will result in just and reasonable prices. Where competition is lacking and sellers may exercise market power, the Commission should establish effective market-power mitigation measures or cost-of-service rates.

In addition, the Commission must abide by and implement Congress' directive in FPA section 217(b)(4) that the Commission use its authority in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy their service obligations.[22]

Below are some concrete near-term actions the Commission should consider.

a. Issue a separate notice of inquiry and hold a technical conference to address gas-electric coordination issues.

As discussed above, the need for fuel security during past extreme weather events in some geographic regions has been evident.

b. Reform RTO/ISO capacity markets to allow effective state and local resource planning and ensure electric system reliability.

The capacity markets in the three eastern RTOs should be reformed to enable electric cooperatives and public power utilities to plan for and self-supply capacity to meet their resource adequacy requirements. Cooperative self-supply of capacity is fully consistent with competitive wholesale capacity markets.[23] Allowing cooperatives to plan for their own capacity needs in the light of climate change and extreme weather events will help ensure greater electric system reliability. Unlike existing RTO/ISO Minimum Offer Price Rule (MOPR) constructs, any MOPR should be confined to its original, narrow purpose of mitigating actual buyer-side market power, not to override state and local resource policies.

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[22] *See supra* note 2.

[23] *See* Initial Submission of National Rural Electric Cooperative Association, Docket Nos. EL16-49, EL18-178, ER18-1314 (filed Oct. 2, 2018) (eLibrary accession number 20181002-5204); Reply Submission of National Rural Electric Cooperative Association, Docket Nos. EL16-49, EL18-178, ER18-1314 (filed Nov. 6, 2018) (eLibrary accession number 20181106-5222).

Moreover, rather than mandating that all Commission-jurisdictional RTOs/ISOs adopt one-size-fits-all capacity markets, the Commission should leave these matters to be resolved by the RTOs/ISOs, the appropriate state and local officials, and other stakeholders, in light of local conditions. Thus, as the regional generation resource mix changes and becomes more diverse, the Commission should permit and encourage RTOs/ISOs to devise market rules that fairly and reasonably compensate different types of resources for their relative support of the grid, to encourage entry (and discourage retirement) by resources that will ensure electric reliability in the face of extreme weather events. For example, the RTO/ISO may wish to consider whether wholesale market rules provide inadequate compensation for reserve generation resources that may only be needed during extreme weather events (or similar exigent circumstances). Likewise, the RTO/ISO may wish to consider whether to provide greater compensation to resources that are available year-round rather than seasonally.

c. Support the needed transmission build-out with a clear articulation of cost-allocation rules.

As noted above, new transmission facilities will be needed to support the changing resource mix and electrification of the economy. This includes transmission upgrades needed to deliver the output of renewable generation resources in rural areas to serve urban areas. Planning should focus on the obligations of the load serving entities and, as discussed earlier, should result from an open process. Rural consumers should not face a disproportionate cost burden for these transmission facilities. The Commission should apply and enforce the established transmission ratemaking principle requiring costs to be allocated to and borne by the beneficiaries. Good ratemaking policy will encourage support for the needed and correct transmission build-out of the future.

d. Allow RTOs and ISOs sufficient time to comply with and implement the Commission's electric storage rule (Order 841) and distributed energy resource aggregation rule (Order 2222).

Complying with and implementing these rules is extraordinarily complex and requires the RTOs/ISOs to coordinate not only with transmission owners, but also with distribution utilities and state and local regulatory authorities. The Commission should give the RTOs/ISOs sufficient time to consult with distribution utilities and their state and local regulators so that cooperatives and other local utilities can continue to provide safe, affordable, and reliable electric service. NRECA appreciates the Commission's recent actions approving RTO/ISO requests for extension of the compliance deadlines.

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?

The BES is undergoing significant changes in generation mix which makes it important for NERC, regional entities, and owners, operators, and users of the BES to evaluate whether these changes will result in the need to modify Reliability Standards to ensure BES reliability. NRECA member cooperatives generally believe that the current standards development process is adequate for this task. No Commission intervention appears warranted at this juncture.

Moreover, in the spirit of "do no harm," the Commission should not impose operational requirements on utilities or create market incentives that pose risks to BES reliability, as appears to be case with the Commission's recent Managing Transmission Line Ratings proposal.[24]

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?

NRECA will not address at this time.

Respectfully submitted,

s/ Mary Ann Ralls

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[24] See Comments of National Rural Electric Cooperative Association and Large Public Power Council, Managing Transmission Line Ratings, Docket No. RM20-16-000 (corrected version filed March 23, 2021).