S. HRG. 117–117

THE RELIABILITY, RESILIENCY, AND AFFORDABILITY OF ELECTRIC SERVICE IN THE UNITED STATES AMID THE CHANGING ENERGY MIX AND EXTREME WEATHER EVENTS

HEARING

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED SEVENTEENTH CONGRESS

FIRST SESSION

MARCH 11, 2021

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THE RELIABILITY, RESILIENCY, AND AFFORDABILITY OF ELECTRIC SERVICE IN THE UNITED STATES AMID THE CHANGING ENERGY MIX AND EXTREME WEATHER EVENTS

THURSDAY, MARCH 11, 2021

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The Committee met, pursuant to notice, at 10:04 a.m. in Room SD–106, Dirksen Senate Office Building, Hon. Joe Manchin III, Chairman of the Committee, presiding.

STATEMENT OF HON. JOE MANCHIN III, U.S. SENATOR FROM WEST VIRGINIA

The CHAIRMAN. Let me begin by saying that I think that we can all agree that reliable, affordable and dependable energy is a hallmark of an advanced economy and critical for businesses and residential consumers alike to thrive. Our North American electric grid is a marvel of engineering and the envy of the world. But ongoing and increasing changes in the generation mix and outside forces like cyber threats and weather events that test the grid also highlight the importance of a resilient grid. This topic is squarely within the jurisdiction of this Committee and it is critical that we, state and local governments, and grid operators around the country be two steps ahead in planning for these changes and threats and how to ensure that we strike the right balance between resilience, reliability and affordability.

At the top of everyone's mind is the recent winter storm that brought Siberian weather to much of the country, and West Virginia was not spared. We had over 100,000 people that lost power, mostly due to downed distribution lines and poles because of the ice. Of course, the impact on Texas has gotten the most publicity with 4.4 million Texans without power for days resulting in billions in damages and billions more in sky-high energy bills and, tragically, dozens of deaths. I understand the Texas legislature has held several hearings and they are working to get to the bottom of why the Texas grid was so unprepared to weather the storm as are NERC and FERC. And the Texas grid operator, ERCOT, has provided us with a written statement. I have the written statement here which I am going to ask unanimous consent to enter into the record now and I encourage all of our members, if you get a chance, to read it. It's pretty interesting.

Do I have any opposition?
If not, so be it. We will enter it.
[The ERCOT written statement follows:]

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SENATE ENERGY COMMITTEE HEARING ON RESIELIENCY – MARCH 11, 2021

Statement by Bill Magness, President and Chief Executive Officer, ERCOT

My name is Bill Magness, currently President and Chief Executive officer of the Electric Reliability Council of Texas, commonly known as ERCOT.

Last month's winter storms had a devastating impact on Texas. The extended disruption of electric service to millions of Texans during this extreme cold weather event resulted in impacts to the health and safety of many.

We all know that it is very hard to maintain civilization in the modern way that we live without electricity service. What we do every day at ERCOT is intended to keep that service flowing. Decisions are made to ensure that, despite challenging circumstances, we continue to have a system to run. Today, we are experiencing electricity service in Texas in the background of our lives—it's flowing, it's warming, it's powering our commerce. If we hadn't made the decisions we made during the week of February 15th, we may still be talking about how to get the power back on.

Let me give you a bit of background to explain ERCOT's role in the provision of electric power in Texas. We manage the flow of electric power to more than 26 million Texas customers -- representing about 90 percent of the state's electric load. As the independent system operator for the region, ERCOT schedules power on an electric grid that connects more than 46,500 miles of transmission lines and 680+ generation units. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for 8 million premises in competitive choice areas. ERCOT is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. Its members include consumers, cooperatives, generators, power marketers, retail electric providers, investor-owned electric utilities, transmission and distribution providers and municipally owned electric utilities.

ERCOT is not a policy-making body. We implement the policies adopted by the Public Utility Commission of Texas and the Texas Legislature. ERCOT's role is to serve in a capacity similar to that of an air traffic controller. We oversee the electric grid that powers about 90% of the people and about 75% of the land mass in the state of Texas. Generators produce power from a variety of sources, such as gas, coal, wind, solar and nuclear. That generation is connected by about 46,500 miles of transmission lines that crisscross the ERCOT region. 24 hours a day, 7 days a week, ERCOT monitors the entirety of the system to make sure that when transmission lines go down, that we can work around them; we talk to generators, instructing them to bring load on or back it down as needed; we oversee the scheduling of maintenance; and more. This work is done with one purpose—to maintain the 60 Hz frequency that is needed to ensure the stability of the grid. It is a constant balancing act to manage supply and demand to ensure a stable frequency. ERCOT does not own generation or operate generation. We do not own transmission lines. We are the people and the software that manage the whole enterprise.

During the week of February 15, the Texas electric market experienced more demand than available supply. At its worst, this storm took out 48.6% of the generation available to ERCOT. We always keep reserves, but when there is record demand and half of the available generation is lost, there's going to be a problem. As supply quickly diminished, the frequency of the grid dipped perilously low. This crisis required ERCOT to use controlled load shedding to balance the system and prevent a devastating blackout of the entire electric grid. Avoiding a complete blackout is critical. Were it to occur, the Texas grid could be down for several days or weeks, while the damage to the electrical grid was repaired and the power restored in a phased and highly controlled process. The costs of restoration of the system, the economic loss to Texas, and the personal costs to the wellbeing of Texas citizens would be unfathomable.

That's why, when demand for power exceeds supply, ERCOT must issue directives to all electric transmission providers to shed load, i.e., to institute measures to reduce power consumption. In severe cases, these directives require the transmission providers to implement rolling blackouts as occurred the week of February 15. These rolling blackouts are managed by the transmission providers. ERCOT issues the directive to reduce power consumption under a predetermined equitable formula necessary to maintain the integrity of the grid and avoid a catastrophic blackout.

The Texas Legislature and our Texas Public Utility Commission are currently engaged in an effort to determine what changes in law and regulations are needed in order to avoid a repeat of the events of the week of February 15. We at ERCOT are working day and night to provide policymakers with the information they need to ensure that Texas electric suppliers maintain the necessary capacity and resiliency to meet the demand created by unprecedented winter weather events. ERCOT is committed to doing our part in achieving this goal.

We look forward to working with our stakeholders and state leaders to implement improvements to Texas' grid resiliency and the ERCOT wholesale market.

/s/ Bill Magness
ERCOT President and CEO

ercot

Review of February 2021 Extreme Cold Weather Event – ERCOT Presentation

Bill Magness
President & Chief Executive Officer
ERCOT

ERCOT Public

Disclaimer

Information in this presentation is preliminary and represents the best available data at the time it was created.

ERCOT Corporate Governance

- **Founded in 1970**
- **Texas non-profit corporation with members from seven market segments:**
  - Consumers (Commercial, Industrial, Residential)
  - Cooperatives
  - Independent Generators
  - Independent Power Marketers
  - Independent Retail Electric Providers
  - Investor-Owned Utilities
  - Municipals
- **The Texas Legislature enacted laws which govern all activities of ERCOT – See Public Utility Regulatory Act (PURA) Section 39.151.**
- **The Public Utility Commission of Texas (PUC) has complete authority over ERCOT's finances, budget and operations, with oversight by the Texas Legislature.**
  - Approves ERCOT Bylaws
- **16-member ERCOT Board composition is established by law:**
  - 5 Unaffiliated Directors (independent from ERCOT Market Participants); all must be approved by the PUC for three-year terms with a maximum of two renewals
  - 8 Directors each elected annually by different Market Segments
  - Office of Public Utility Counsel (represents Residential Consumer Market Segment)
  - ERCOT Chief Executive Officer
  - PUC Chairman (non-voting)

ERCOT's Role

- **Fulfills four responsibilities required by law as the independent organization certified by the PUC (PURA Section 39.151):**
  - Maintain electric system reliability
  - Facilitate a competitive wholesale market
  - Ensure open access to transmission
  - Facilitate a competitive retail market
- **Manages the flow of electric power over the bulk power system to approximately 26 million Texas end-use customers.**
  - About 90% of the state's electric load
  - Over 680 generation units
  - Over 46,500 miles of transmission lines
- **Must, at all times (24/7/365), balance all consumer demand in the ERCOT region (load) and the power supplied by companies who generate electricity (generation) while maintaining system frequency of 60 Hz.**
- **Performs financial settlement for the competitive wholesale bulk power market and administers retail switching for nearly 8 million premises in competitive choice areas.**

ERCOT's Role (continued)

ERCOT does **not**:

- Own, operate or have any enforcement authority over any electric generation facilities or any electric transmission or distribution lines or substations.
- Sell or send bills for retail electricity to residences or businesses.
- Control or operate electric service to local areas, neighborhoods or individual premises.
- Establish pricing or rates for retail electric customers.
- Have any direct customer relationships with the public.

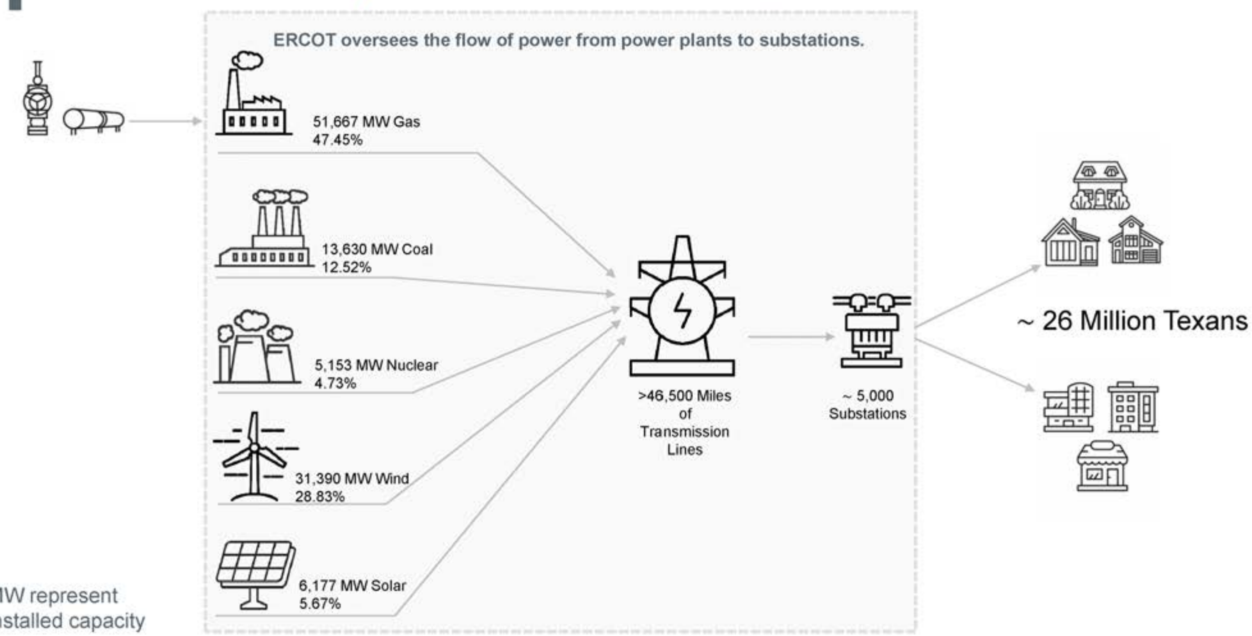
ERCOT Budget & Funding

- **Budget is approved by the Board and the PUC biennially.**

- **Funded by a System Administration Fee to cover its system costs.**
  - Current fee is 55.5 cents per megawatt hour (MWh).
  - One megawatt of electricity can power about 200 Texas homes during periods of peak demand.
  - Average cost of $7/year (50-60 cents/month) for residential households.

- **ERCOT does <u>not</u> set consumer electric rates.**
  - Rates are either set by the PUC or companies that sell electricity at retail to end-use customers.
  - Additional transmission costs are proportionally passed on to customers.

Electric Generation, Transmission & Distribution Overview



MW represent installed capacity

Pre-Event Operational Preparation

- Canceled transmission maintenance outages affecting over 1,600 transmission devices and delayed other outages.
- Reviewed planned generation outages for potential early return to service.
- Noted potential for 11,100 MW of forced outages due to gas restrictions based on gas company communications – more units affected during this event compared to previous cold weather events.
- Began using maximum icing potential for wind forecasts.
- Waived COVID restrictions and brought additional support staff on-site.
- Prepared facilities for extended on-site staffing, activated additional remote engineering/support staff.
- Began regular calls with Chief System Operators (18 over 8 days).
- Requested TCEQ/DOE enforcement discretion for power plant emissions during anticipated event.
- Supported Railroad Commission of Texas review of natural gas priority.

All available generation was online on February 14.

Pre-Event Communications

November 5	ERCOT meteorologist issues winter outlook for Market Participants and public noting the "very good" chance for an extreme cold weather event during winter 2020/2021.
February 3	ERCOT meteorologist warns Market Participants and the public of coldest weather of the year. Weather updates continue.
February 8	Operating Condition Notice issued for extreme cold weather event, posted on public website.
February 10	Advisory issued for extreme cold weather event posted on public website. Issued grid conditions update for market media representatives.
February 11	Watch issued for cold weather event (hotline calls made, notice to Market Participants, posted on public website). News release on extreme weather expected, social media outreach.
February 12	Texas Energy Reliability Council meeting.
February 13	State Operations Center news conference: forecast Conservation Alert. Emergency notice issued for extreme cold weather event, posted on public website. Texas Energy Reliability Council meeting.
February 14	Issued conservation appeal by news release, performed social media outreach, held media briefing.

Overview of Cold Weather Event

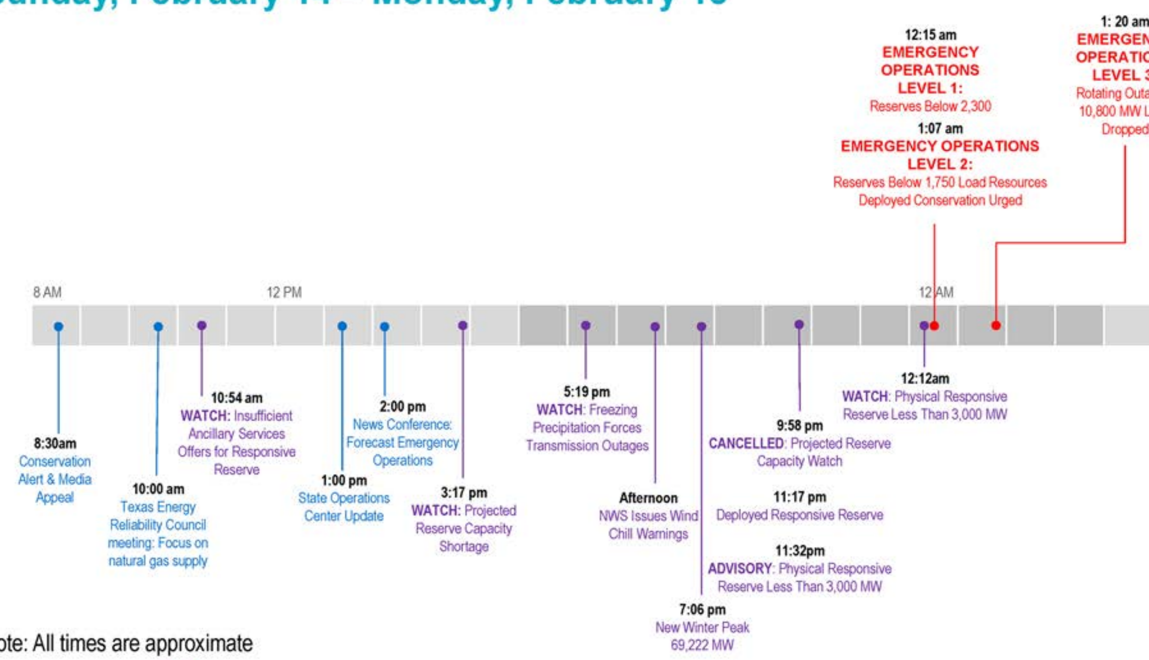
- Record-setting, sub-freezing temperatures and wind chills across the state.

- Approximately 48.6% of generation was forced out at the highest point due to the impacts of various extreme weather conditions.

- Controlled outages were implemented to prevent statewide blackout.
  - Electric demand had to be limited to available generation supply.

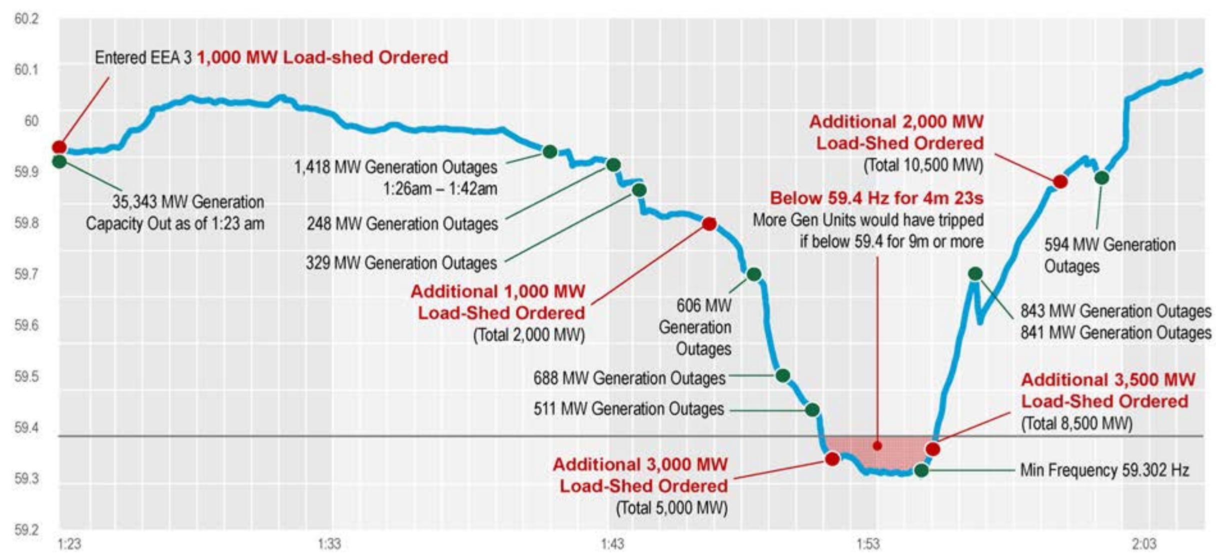
- Local utilities were limited in their ability to rotate outages due to the magnitude of generation unavailability and the number of circuits with critical load.

Sunday, February 14 – Monday, February 15

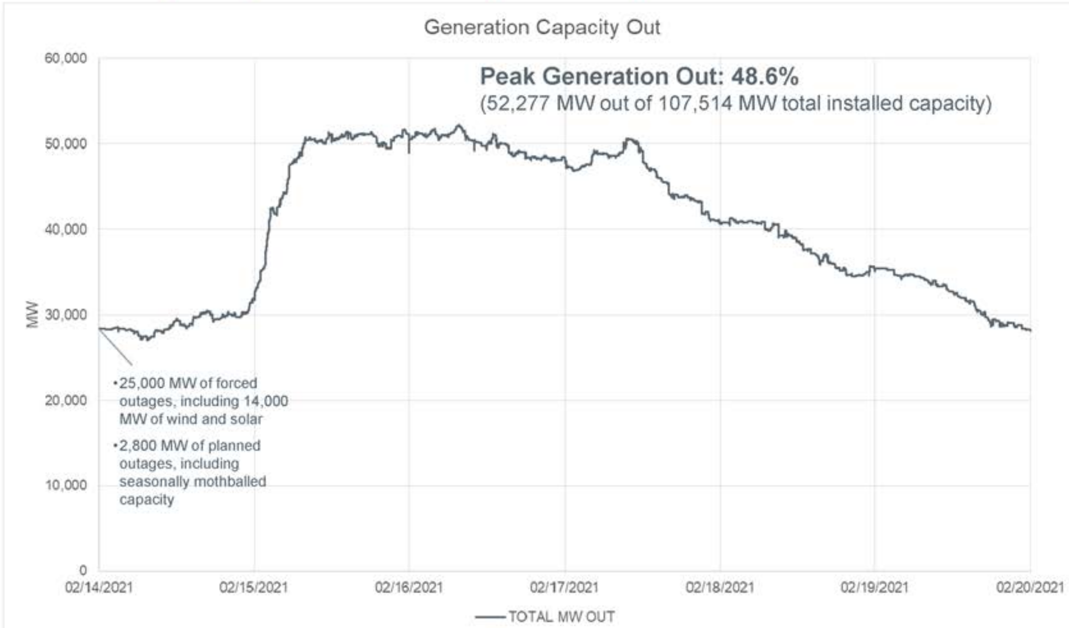


Note: All times are approximate

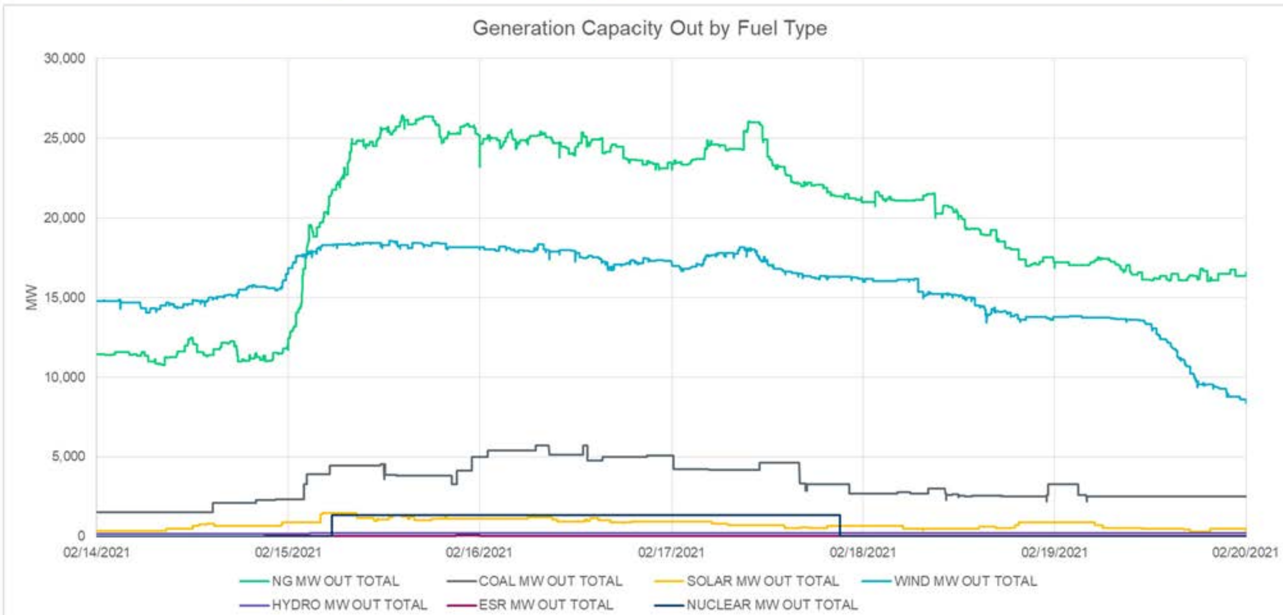
Rapid Decrease in Generation Causes Frequency Drop



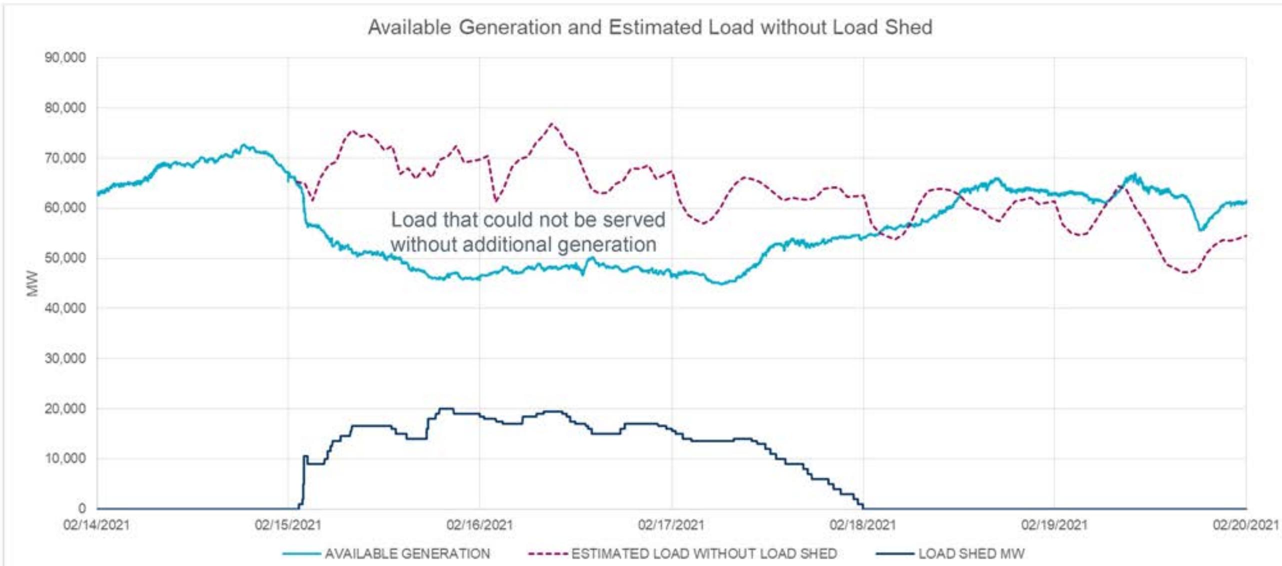
Generation Capacity Out February 14 – 19, 2021



Generation Capacity Out by Fuel Type



Available Generation and Estimated Load Without Load Shed



Available Generation shown is the total HSL of Online Resources, including Quick Starts in OFFQS. The total uses the current MW for Resources in Start-up, Shut-Down, and ONTEST.

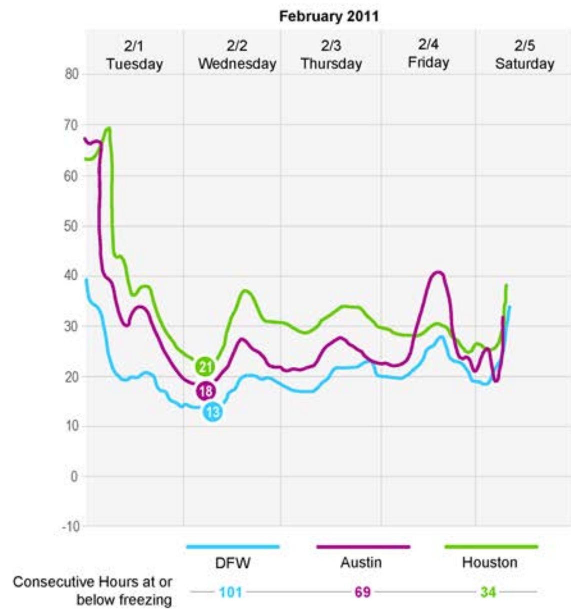
Key Events (Monday, February 15 – Friday, February 19)

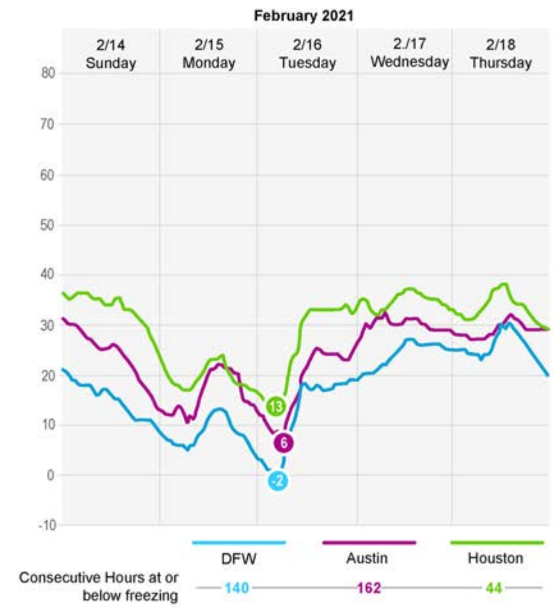
- More than 16,500 control room calls with generators and transmission owners (normal: ~5,000/week).
- Multiple daily coordinating calls between transmission owners and operations management.
- Monday, February 15
  - Up to an additional ~24,000 MW net generation unavailable due to extreme weather; loss of generation was 52,277 MW (approximately 48.6%) at the highest point.
  - 20,000 MW peak load shed.
  - Limited gas availability for gas-fired power plants.
  - Multiple DC-Tie constraints due to neighboring area emergencies.
  - Daily Texas Energy Reliability Council meetings.
- Tuesday, February 16
  - No net gain in generation as some generators were restored and others became unavailable.
  - Decreased volume of controlled outages during the day, increased for evening peak.
- Wednesday, February 17
  - Moderating temperatures allowed reduction in controlled outages, small net gain in generation.
- Thursday, February 18
  - Continued gain in generation.
  - 12:42 a.m. - Canceled last controlled outage orders - some outages remained due to ice storm damage; need for manual restoration and return of large industrial facilities.
- Friday, February 19 (all times approximate)
  - 9 a.m. - Returned to emergency operations level 2
  - 10 a.m. – Returned to emergency operations level 1
  - 10:35 a.m. – Returned to normal operations

Generation Weatherization

- Generation owners and operators are not required to implement any minimum weatherization standard or perform an exhaustive review of cold weather vulnerability. No entity, including the PUC or ERCOT, has rules to enforce compliance with weatherization plans or enforce minimum weatherization standards.
- In 2011, the PUC amended its rules to authorize ERCOT to conduct generator site visits to review compliance with weatherization plans. Spot checks include reviewing the weatherization plan, verifying that plant personnel are following the plan and providing recommendations based on PUC requirements, lessons learned or best practices.
- We currently perform spot checks at power plant units at the rate of about 80/year. Whenever possible, a Texas Reliability Entity (TRE) representative joins ERCOT for these spot checks.
- While we request and review detailed plant records, the only entity that can confirm that a plant is "weatherized" to any particular standard is the entity that owns or operates the plant.
- Each year, TRE and ERCOT host an annual workshop on weatherization with generation owners to review lessons learned and best practices.

2011 vs. 2021 Event Temperature Comparison





2011 vs. 2021 Event Comparison

	2011	2021
Maximum generation capacity forced out at any given time (MW)	14,702	52,277
Generation forced out one hour before start of EEA3 (MW)	1,182	2,489
Cumulative generation capacity forced out throughout the event (MW)	29,729	46,249*
Cumulative number of generators outaged throughout the event	193	356
Cumulative gas generation de-rated due to supply issues	1,282	9,323
Lowest frequency	59.58	59.30
Maximum load shed requested (MW)	4,000	20,000
Duration load shed request (hours)	7.5	70.5
Estimated peak load (without load shed)	59,000	76,819

*Note: "Cumulative" values for 2021 were calculated using NERC 2011 report methodology. Cumulative amount for 2021 starts at 00:01 on February 14, 2021

Load Shed Ordered By Transmission Owner

Transmission Operator	% of MW
AEP Texas Central Company	8.7
Brazos Electric Power Cooperative Inc.	4.95
Brownsville Public Utilities Board	0.37
Bryan Texas Utilities	0.51
CenterPoint Energy Houston Electric LLC	24.83
City of Austin DBA Austin Energy	3.71
City of College Station	0.28
City of Garland	0.75
CPS Energy (San Antonio)	6.79
Denton Municipal Electric	0.48
GEUS (Greenville)	0.15
Lamar County Electric Cooperative Inc*	0.07
LCRA Transmission Services Corporation	5.96
Oncor Electric Delivery Company LLC	36.01
Rayburn Country Electric Cooperative Inc.	1.3
South Texas Electric Cooperative Inc.	2.52
Texas-New Mexico Power Company	2.62
ERCOT Total	100.00

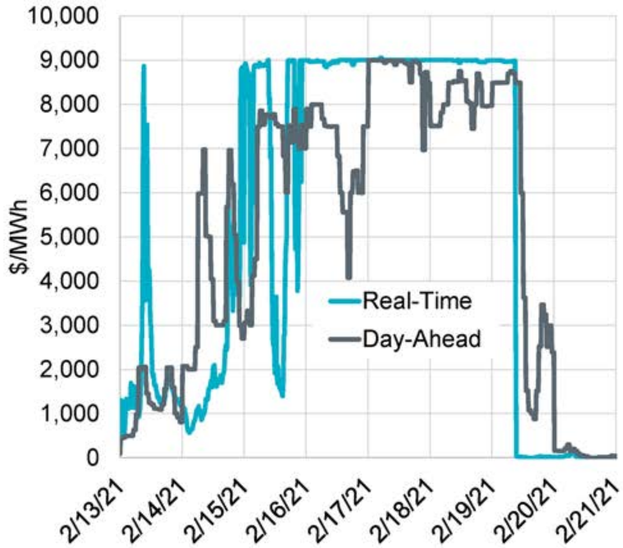
Status of Recommendations After February 2011

A report published by the North American Electric Reliability Corporation following the February 2011 cold weather event contained several recommendations applicable to ERCOT. Over the past 10 years, ERCOT has made changes that support those recommendations.

Significant modifications include:

- Implemented the Seasonal Assessment of Resource Adequacy report that includes an analysis for extreme winter weather.
- Began a resource weatherization process that includes an annual workshop, review of resource weatherization plans and spot checks of facilities.
- Added additional staff (Shift Engineer and Resource Reliability Desk) in the control room.
- Modified the Ancillary Services procurement to allow additional procurement in anticipation of severe weather.
- Established the Gas Electric Working Group and created a notification procedure for QSEs to notify ERCOT if there are anticipated fuel restrictions.
- Modified the survey sent to natural gas generators that collects fuel switching capability for some resources in preparation for each winter season.
- Changed the rules and processes for withdrawing approval of resource outages in anticipation of severe weather.

Real-Time and Day-Ahead System-Wide Pricing



Average system-wide pricing around the event relative to other historical periods (in $/MWh)

Date Range	Real-Time	Day-Ahead
2/14/21 2/19/21	$6,579.59	$6,612.23
January '21	$20.79	$21.36
February '20	$18.27	$17.74

This data is using the ERCOT Hub Average 345-kV Hub prices

Hedging by Market Participants

- ERCOT has limited visibility into other methods of hedging that Market Participants may engage in, including but not limited to commodities exchanges and bilateral contracts.

- With the information available to ERCOT, the level of energy hedging by Load Serving Entities varied from fairly long to fairly short relative to their physical load. This could also vary by operating day for the same entity.

- These positions would have been affected by load reductions resulting from the instructed firm load shed and other losses of load, as well as loss of generation through de-ratings or outages that occurred during the event.

The CHAIRMAN. Let me be clear, today's hearing is not a referendum on Texas. We have seen the impact of extreme weather events to our electric grid across the country whether that be the 2014 polar vortex, the extreme heat in California last summer or the extreme cold around the country last month. We need to incorporate all the lessons learned from those events into our future planning, particularly as we can expect both our energy mix and weather patterns to be different in the next decade than they were in the last decade. As part of that future planning, we need to take into account the need for a diverse fuel mix with a broad array of emissions-reducing technologies and include an honest assessment of where our weak spots are and where we need to invest with an eye to balancing the cost of reliability and the resilience with affordability.

I have said, time and time again, that we need to address climate change, and we have to do it through innovation not elimination. As a staunch proponent of an all-of-the-above energy policy, I want to emphasize that we need to be thinking about all of our fuel sources. We have to use all of the resources we have in the cleanest way possible, but we need to be "eyes-wide-open" that none of them are 100 percent immune to weather disruptions, whether that be freezing wind turbines, disruptions to our natural gas production and delivery systems or frozen coal stockpiles—all of which we saw happen just last month. That may take investment in weatherization and infrastructure which, of course, comes with big price tags and leads me back to affordability.

Reliable, resilient power does us no good if families and businesses cannot afford it on a daily basis. While we typically think about this in terms of the cost of a kilowatt-hour, we also cannot deny the incredible costs associated with major disruptions. By that I mean, not only the potential loss of life but also the price tag that comes with scarcity and rebuilding or repairing infrastructure, both energy and otherwise. Although not labeled as such, those costs are passed along to all of us whether through utility and service bills or through our taxes. We truly cannot sacrifice reliability, resiliency or affordability when it comes to our electricity if we want to continue to thrive.

It is incredibly important that we strike the right balance between all of these attributes as we look to the future. There is not one answer to that equation, but you sure know when you have gotten it wrong. I look forward to hearing from our panel of witnesses about exactly what happened in recent grid outage events, what lessons we should learn from them, and what we should all be thinking about moving forward to strike the right balance.

I want to welcome our panel, but right now we have a quorum. So we are going to go to our vote and then we will go right to Senator Barrasso for his opening statement, and I will introduce our panel just a few minutes later.

[MOVE TO BUSINESS MEETING FOR VOTE.]

[HEARING IS RESUMED.]

The CHAIRMAN. Let me just finish up by welcoming our panel, and then Senator Barrasso will give his opening statement.

We want to thank all of you for taking the time to be here and bringing your expertise to our panel. We have Mr. Jim Robb. He is President and CEO of North American Electric Reliability Corporation (NERC). We have Mr. Mark Gabriel, Administrator and CEO of Western Area Power Administration (WAPA). We have the Honorable Pat Wood, III, CEO of Hunt Energy Network and former FERC and Texas Public Utility Commission Chairman; Mr. Michael Shellenberger, Founder and President of Environmental Progress; and Mr. Manu Asthana, President and CEO of the PJM Interconnection.

I want to thank you all for being with us today in person and virtually, and I look forward to your expert analysis and the discussion today.

I am going to now turn to Senator Barrasso for his statement.

STATEMENT OF HON. JOHN BARRASSO, U.S. SENATOR FROM WYOMING

Senator BARRASSO. Well, thank you very much, Mr. Chairman, and thank you for calling this important hearing.

We all agree that affordable, reliable and resilient electric service is essential for every American. Electricity is needed for virtually all aspects of our lives. That is why I have been a strong advocate for generating electricity from a diverse set of resources, including coal, uranium, natural gas, hydropower, wind and solar. It is also why I have been especially supportive of energy resources that are capable of generating electricity at all times of the day and night, what is known as baseload capacity and it is why we need to be realistic about the limitations of energy resources such as wind and solar that cannot generate electricity all the time.

Increasingly, the national discussion on electricity has centered around a single metric, how much greenhouse gas does a source of electricity produce? The discussion has failed to pay sufficient attention to the questions of reliability, resiliency and affordability. During last month's cold snap, coal played a critical role in maintaining power in Oklahoma and other states. In addition, nuclear power by one standard outperformed all other energy sources in Texas, and hydropower was essential to keeping the lights on in Western states. We must ensure that our grids can provide electricity at all times and at prices that American families and businesses can afford. The American public deserves to know what policies and measures are necessary to ensure that that happens. The public also deserves to know what policies and measures make that objective much more difficult to achieve. Today's hearing should help address these important issues.

Electric systems in this country are among the best in the world, and they are always evolving. The men and women who built and operate them are tremendously capable. These professionals must work with the grids we have today and not with the grids that we wish we could have in 15 or 25 years. The blackouts that we witnessed in California in 2019 and 2020, as well as the blackouts across the central part of the country last month, are unacceptable.

What is also unacceptable are proposals that would make blackouts more likely or more devastating for the American people. For example, President Biden has pledged to "achieve a carbon pollution free power sector by 2035." This is the goal no state, not even California, has set for itself. President Biden has also pledged to cut "the carbon footprint of our national building stock in half by 2035" and to "ensure 100 percent of new sales for light- and medium-duty vehicles will be zero emissions." In other words, President Biden wants to saddle our electric grids with the additional burdens of powering our transportation fleet and heating buildings currently served by natural gas or oil.

As Bloomberg New Energy Finance report stated last month, "the transition to electric heating and transport drives up electricity demand while tremendous growth of wind and solar strain the grid." So President Biden's proposals could concentrate our nation's vulnerabilities to bad weather events, terrorism or cyber-attacks on the electric grid. Rather than learn from the blackouts in California and the blackouts last month, some in Congress are doubling down. Last week, House Democrats introduced a bill to require that the country's power sector be 80 percent carbon free in less than ten years and 100 percent carbon free by 2035. Now like President Biden's plan, their legislation would also push additional burdens on America's electric grids through the electrification of buildings and vehicles that would otherwise rely on oil or natural gas.

We should pursue ways to generate electricity that produces less greenhouse gas emissions. We must not do so at the expense of the reliability, resiliency or affordability of electric services. That means supporting the continuation and expansion of electricity generation from nuclear power, from hydropower, natural gas and for coal.

Thank you, Mr. Chairman.

The CHAIRMAN. Thank you, Senator.

Now we are going to hear from——

Senator HEINRICH. Mr. Chairman?

Before we start, I am just curious. I noticed there is no one from ERCOT on our list of witnesses today, and I am just wondering why that is.

The CHAIRMAN. Senator Heinrich, it sure was not for a lack of inviting them. We invited everybody from ERCOT and spoke to everybody that is still left, which I am not sure anybody is left.

Senator HEINRICH. So ERCOT chose not to be here.

The CHAIRMAN. Well they needed to remain available to their direct regulators, which is the Texas legislature, and they have been in conversations with them. But I think you are going to enjoy this panel and we have an experienced person in Mr. Wood who knows it inside and out. So we are looking forward to hearing from him too.

Let's get started now, if you don't mind, with our panel and we will start with Mr. Robb, President and CEO of North American Electric Reliability Corporation.

STATEMENT OF JAMES B. ROBB, PRESIDENT AND CHIEF EXECUTIVE OFFICER, NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Mr. ROBB. Good morning, Chairman Manchin, Ranking Member Barrasso and members of the Committee, thank you for having me here at this very timely hearing.

The recent tragic loss of life and human suffering in Texas and the middle South states starkly demonstrate the essentiality of a reliable electric system. As you know, NERC and FERC have begun to work on a joint inquiry into the root causes of this event. We are committed to quickly getting to the facts as to what actually happened, implementing appropriate measures within our authority and communicating other implied actions to policymakers and industry. There are three major trends which are fundamentally transforming the bulk power system and challenging our historic reliability paradigms.

First, the system is decarbonizing rapidly and this evolution is altering the operational characteristics of the grid. Policies, economics and market designs are resulting in significant retirements of traditional generation. New investment is increasingly focused on developing carbon free generation with variable production profiles and in this resource mix, natural gas-fired generation is becoming ever more critical, both for bulk energy to serve load and balancing energy to support the integration of these variable resources.

Second, the grid is becoming more distributed. The improved economics of solar is a key example. These smaller scale resources have been deployed on both the bulk electric as well as distribution systems and, in many cases, reside behind the meter.

And third, the system is becoming increasingly digitized through smart meters and digital control systems. These investments greatly enhance the operational awareness and efficiency of grid operators, but at the same time it heightens our exposure to cybersecurity risk. And extreme weather, as we have recently experienced this past month, stresses this emerging electric system in new and different ways.

Our reliability assessments are one important way we evaluate the performance of the grid, identify reliability trends, anticipate challenges and provide a technical platform for important policy discussion. With growing reliance on variable and just-in-time resources, we are developing more advanced ways to study energy supply risk. Our assessments consistently have identified three regions of the country particularly exposed to these dynamics—California, Texas and New England. Last August, a massive heat wave across the West caused an energy supply shortage in California in the early evening. Solar energy was ramping down and the grid operator was unable to import power as planned due to high demand throughout the West. CAISO was forced to cut power to approximately 800,000 customers. Among the lessons learned from this event are: one, the critical need for reliable ramping resources to balance load; and, second, the need for improved ways to estimate resource availability when the system is under stress.

In New England, cold weather exacerbates its dependence on limited pipeline capacity and a handful of critical fuel assets. An early January cold snap in 2018 led to natural gas shortages and fuel oil was burned to preserve reliability. Had that cold snap not abated when it did, the fuel oil inventory would eventually be exhausted and ISO New England almost certainly would have needed to shed load. It was a classic near-miss event.

Insufficient and inadequate weatherization of generation in Texas and the middle South states has been a growing concern for us since 2012. After a cold weather event caused load shedding for three million customers in Texas in 2011, we developed a winter preparation guideline to focus industry on best practices and started conducting significant outreach on winter preparedness. Following additional extremes and unplanned load shedding in that region in 2018, we concluded that these events could no longer be treated as rare and that a mandatory approach was warranted. As a result, NERC began the process of adding mandatory weatherization requirements into our reliability standards.

In addition to these weatherization initiatives, I'd like to leave the Committee with four main points to consider.

First, more investment in transmission and natural gas infrastructure is required to improve the resilience of the electric grid. Increased utility-scale wind and solar will require new transmission to get power to load centers.

Next, the regulatory structure and oversight of natural gas supply for the purposes of electric generation needs to be rethought. The natural gas system was not built and operated with electric reliability first in mind. Policy action and legislation will likely be needed to assure reliable fuel supply for electric generation as the critical balancing resource, natural gas, is the "fuel that keeps the lights on."

Third, the electric and natural gas systems must be better prepared for extreme weather conditions which are frankly becoming more routine. Regulatory and market structures need to support this planning and the necessary investment to assure reliability.

And finally, investment in energy storage or alternative technologies needs to be supported to have a viable alternative to natural gas for balancing variable resources. A technology which can be deployed cost-effectively and at massive scale with adequate duration to deal with supply disruption lasting for days rather than hours, is required.

Thank you again for the opportunity to be here today.

[The prepared statement of Mr. Robb follows:]

"Reliability, Resiliency, and Affordability of Electric Service in the United States Amid the Changing Energy Mix and Extreme Weather Events"

March 11, 2021

Before the Committee on Energy and Natural Resources
United States Senate
Washington, DC

Testimony of James B. Robb
President and Chief Executive Officer
North American Electric Reliability Corporation

The bulk power system is undergoing major transformation that must be understood and planned for to preserve reliability. A rapidly changing generation resource mix is driving this transformation. Traditional baseload generation plants are retiring, while significant amounts of new natural gas and variable generation resources are being developed. During this transition, natural gas-fired generation is becoming more critical to provide both "bulk energy" and "balancing energy" to support the integration of variable resources. Extreme weather exacerbates the challenges of the transforming grid while also stressing the system in unique ways. This transition requires the electric industry to reconsider how the system is planned and operated.

With a highly reliable and secure bulk power system (BPS) at the core of NERC's mission, NERC is focused on proactively addressing the reliability risks of the transforming grid. This testimony examines BPS reliability through the lens of recent extreme weather events. Through this examination, we discern key observations and steps for consideration to further assure reliability and resilience during this transformation.

About NERC

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority with a mission to assure the effective and efficient reduction of risks to the reliability and security of the grid. Designated by the Federal Energy Regulatory Commission (FERC) as the Electric Reliability Organization (ERO) for the United States, NERC develops and enforces reliability and security standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC performs a critical role in situational awareness and information sharing to protect the electricity industry's critical infrastructure against cyber and physical threats to the BPS. Through delegation agreements and with oversight from FERC, NERC works with six

Regional Entities on compliance monitoring and enforcement activities. Collectively, NERC and the Regional Entities comprise the ERO Enterprise. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves nearly 400 million people in the continental United States, Canada, and Mexico.[1]

Central United States Cold Weather Event of February 2021

Extreme, record-breaking arctic weather descended upon the central part of the nation during the second week of February, forcing power outages throughout the region. States in the middle south were especially hard hit, particularly Texas where the extreme cold forced generators offline, resulting in a massive deficit of energy to serve customers during record winter demand conditions. The system operator for the majority of Texas – the Electric Reliability Council of Texas (ERCOT) – was forced to order unprecedented load shedding as a last resort measure to restore frequency and protect system stability. At its peak, 52,277 MW of generation across *all* fuel types within ERCOT were unavailable, or 48.6% of total installed capacity.[2] The crisis lasted more than a week, ultimately subjecting more than 4 million Texans to localized blackouts and millions more to a range of compounding impacts. Many municipal water systems failed with 14 million under boil-water notices. Natural gas deliveries were curtailed due to frozen infrastructure and little to no dual-fuel capability was available in Texas. This serves as a sobering reminder of the essentiality of electric service to support all other critical infrastructures. And, most tragically, lives were lost in the crisis.

While the scale in Texas was especially dramatic, extreme winter weather also caused significant forced outages and load shedding in states throughout the central part of the country from North Dakota to Louisiana. To maintain system stability, the Midcontinent Independent System Operator (MISO) ordered 1,430 MW of load shedding on February 16, affecting citizens from southern Louisiana, Arkansas, Mississippi, east Texas, and Illinois. MISO reported a peak of 59,322 MW of generation was unavailable throughout the entire balancing authority area on February 14. This includes 8,081 MW that was weather related. The Southwest Power Pool service area experienced 3,443 MW of load shedding and the loss of 25,000 MW of generation across a range of resources. Outages occurred in Arkansas, Louisiana, Texas, Oklahoma, Kansas, Missouri, Nebraska, North Dakota and South Dakota. This crisis shows the increased vulnerability of the electric supply system to an extreme common condition that spans electric systems.

The human toll – suffering, death, and economic loss – makes the 2021 extreme cold weather event highly significant. To be clear, load shedding is an unwelcome last resort measure to avoid uncontrolled cascading outages across an entire interconnection. Faced with untenable choices during an emergency event when decisions must be made within minutes, actions taken by grid operators helped prevent even more widespread suffering. Data presented by

[1] See appendix for a map depicting the footprints of NERC and the Regional Entities.

[2] Presentation to ERCOT Board of Directors, "Review of February 2021 Extreme Cold Weather Event," ERCOT, February 24, 2021.

ERCOT show the entire electric system was within minutes of frequency and voltage collapse, necessitating the dramatic action they took.

To promote learning and risk reduction, NERC and the Regional Entities study reliability events and take appropriate and positive actions. On February 16, FERC and NERC announced a joint inquiry into the Midwest and South-Central states cold weather event. The joint inquiry will examine how the extreme weather impacted operations of the bulk power system in the affected regions of the country. The joint inquiry team includes Regional Entities from the impacted areas[3] and the Department of Energy (DOE). The FERC/NERC/Regional Entity Joint Staff Inquiry (Joint Inquiry) will cover three general themes:

1. Comprehensive, detailed analysis of the event and root causes
2. Commonalities with other cold weather events, including the 2011 winter event that also impacted Texas
3. Findings and recommendations for further action

Prior to the next winter preparation season, the inquiry team expects to issue a preliminary summary with the final report to follow. Working with FERC, NERC will move forward expeditiously on action items within our authority, including any necessary enhancements to mandatory reliability standards. As recently stated by FERC Chairman Glick, actions calling for further attention must not languish on the shelf.

Cold Weather Preparation – Reliability Guidelines and Mandatory Standards

February 2011 was the first well-studied cold snap to hit Texas and the southwest region since NERC was certified as the ERO. Temperature lows were in the teens for five consecutive mornings and there were many sustained hours of below freezing temperatures throughout Texas and in New Mexico. In 2011, between February 1-4, 210 individual generating units within ERCOT's footprint experienced either an outage, a derate, or a failure to start.[4] At the peak of the crisis, a controlled load shed of 4,000 MW affected 3.2 million customers in Texas. During the course of the event, power losses also occurred in parts of New Mexico and Arizona.

The extreme low temperatures also affected natural gas production and service. From February 1 through February 5, an estimated 14.8 Bcf of production was lost. These declines propagated downstream through the rest of the gas delivery chain, ultimately resulting in natural gas curtailments to more than 50,000 customers in New Mexico, Arizona, and Texas.[5]

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[3] Texas RE, Midwest Reliability Organization, and SERC Reliability Corporation.

[4] FERC/NERC report, "Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations."

[5] FERC/NERC staff report, *"Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011,"* 9 .

Following the 2011 event, FERC and NERC produced a joint inquiry report, "Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations." Key recommendations included:

- Generation owners and operators should ensure adequate construction, maintenance and inspection of freeze protection elements such as insulation, heat tracing and wind breaks.
- Reliability coordinators and balancing authorities should require generators to provide accurate data about the temperature limits of units so they know whether they can rely on those units during extreme weather.
- Balancing authorities should review the distribution of reserves to ensure that they are useable and deliverable during contingencies.
- Finding that natural gas service was also impacted by the event, state lawmakers and regulators in Texas and New Mexico, working with industry, should determine if weather-related production shortages can be mitigated through the adoption of minimum winterization standards for natural gas production and processing facilities.

After significant consideration, NERC and the electric industry pursued and published a Reliability Guideline in 2012 to help industry develop their own readiness program for generating units throughout North America. NERC holds a "Winter Preparation for Severe Cold Weather" webinar every year before the winter season to reinforce the guideline's recommendations. Regional Entities conduct similar outreach to industry within their respective footprints.

The guideline provides a framework for developing an effective winter weather readiness program for generating units. The focus is on maintaining individual unit reliability and preventing future cold weather-related events. A collection of best industry practices, the guideline calls for an evaluation of potential problem areas with critical equipment, systems testing, training, and event communications. The guideline has been updated based on industry experience and learnings from subsequent cold weather events. These events include the 2014 Polar Vortex and the cold weather event of January 17, 2018 that impacted the south-central area of the country.[6] Version three of the winter readiness guideline was published in June 2020.[7]

Reliability Guidelines have the advantage of addressing certain risks where quick action is desirable or those risks categorized as high impact, low frequency or rare. However, the extremes of 2011, 2014, and 2018 demonstrated that these events could no longer be treated

[6] FERC/NERC staff reports, "Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011" and "The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018."

[7] "Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices – Version 3," NERC.

as rare. Further, in the past decade, the generation fleet has transformed to one that is more sensitive to weather with extreme temperatures.

Accordingly, to address the risk of extreme cold weather, NERC concluded that mandatory standards addressing cold weather risks were warranted. In September 2019, NERC initiated development of new cold weather requirements through enhancements to existing mandatory reliability standards.[8] After considering stakeholder comments, NERC expects to submit the proposed standards to NERC's Board of Trustees (BOT) in June. The final winterization requirements will be filed with FERC following BOT approval. The standards will support reliability of the BPS by helping to ensure that generator units are prepared for cold weather and enhancing situational awareness in the operational planning and operations timeframes. A set of draft standards are posted for comment through March 12 and include draft requirements for the following:

- Cold weather preparedness plans developed, maintained, and implemented by generators for each unit, incorporating freeze protection measures based on geographic location and plant configuration
- Annual maintenance and inspection of generation unit freeze protection measures
- Adoption of cold temperature operating parameters, including minimum design temperature and historical performance during cold weather in the previous five years
- Awareness training on the roles and responsibilities of site personnel
- Communication of specific unit limitations to Reliability Coordinator and Balancing Authorities for use in setting operating processes, determining contingency reserves, and performing operational planning analysis

Until a cold weather standard is approved and enforceable, NERC is also considering use of additional reliability tools, such as our alert system, to understand winter preparation status and incorporate plant preparation status into our annual seasonal assessment.

Western Heatwave Event of August 2020

During the middle of August, a massive heat wave developed across the West, forcing high temperatures 15 to 30 degrees above normal, breaking many daily highs. The California Independent System Operator (CAISO) reported that the August extreme heat was a 1-in-30 year weather event. On August 18, the Western Interconnection hit a new peak demand of 162,000 MW.[9] CAISO implemented numerous operational actions to balance resources with customer demand. In terms of energy supply, the extreme heat reduced electricity output from thermal resources, which typically operate less efficiently during temperature extremes. In addition to below normal hydro conditions, utility-scale and behind-the-meter solar generation output was reduced due to wildfire smoke and cloud cover.[10] High electricity demand across

[8] Project 2019-06 Cold Weather, NERC.

[9] Presentation, "Western Interconnection August Heat Wave Event," WECC, October 20, 2020.

[10] "Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave," CAISO, CPUC, CEA joint report, January 13, 2021, 21-22.

the West limited CAISO's ability to import energy from neighboring areas. During the early evening hours of August 14-15 when solar energy production naturally declines, CAISO was forced to resort to controlled load shedding of approximately 1,800 MW to maintain system stability. Power outages lasting between 8-to-150 minutes, impacting approximately 800,000 customers served by utilities regulated by the California Public Utilities Commission.[11]

This heatwave event occurred across the entire Western Interconnection. The widespread nature of this heatwave reduced options to mitigate impacts as exports to California dried up due to the need for organizations to serve their native loads. Though not as dramatic as the recent cold weather event, it is another example of an extreme common condition that overwhelmed the electric system. It demonstrates that these conditions can occur in summer or winter and for which industry needs to plan.

NERC and the Western Electricity Coordinating Council, the Regional Entity serving the Western Interconnection, are conducting a review of the Western heatwave event through our Event Analysis program. This review is nearing completion. We will provide the committee with the final report. A separate joint analysis by CAISO and California energy regulators was published on January 13, 2021. The report finds that issues with calculating resource planning targets and market practices contributed to the supply deficits during the extreme heat contradictions.

Identifying and Communicating Reliability Risk

Section 215(g) of the Federal Power Act requires NERC to assess the reliability and adequacy of the BPS. Through our reliability assessments, NERC evaluates the performance of the BPS, identifies reliability trends, anticipates challenges, and provides a technical platform for important policy discussions. The breadth and fidelity of NERC assessments evolve with our understanding of risk and improved tools. As the resource mix has shifted to be increasingly reliant on variable generation, wind and solar, and "just in time" natural gas deliveries, we began introducing fuel risks into our seasonal assessments and developed more probabilistic analysis of reliability.

By identifying and quantifying emerging reliability and security issues, NERC provides risk-informed recommendations and supports a learning environment for industry to pursue improved reliability performance. These recommendations, along with the associated technical analysis, provide the basis for actionable enhancements to resource and transmission planning methods, planning and operating guidelines, security, as well as NERC reliability and security standards. In short, NERC's independent assessments provide critical insights necessary for assuring reliability and security of a rapidly changing electricity sector.

Applying peak demand scenarios, the *2020/2021 Winter Reliability Assessment* includes the below map depicting regions in North America where there is heightened reliability risk due to potential extreme weather or fuel supply disruptions. In this assessment, NERC warns of the

[11] Ibid, 35.

potential for extreme generation resource outages due to severe weather in winter and summer, and the potential need for grid operators to employ operating mitigations or Energy Emergency Alerts (EEA) to meet peak demand.[12] The assessment highlights that during extreme and prolonged winter conditions, vital natural-gas fuel supplies for electricity generation can be at risk in New England, California and the southwestern United States. High reliance on natural gas-fired generation and limited natural gas infrastructure elevates reliability risk in these areas.

For this assessment, NERC analyzed severe weather scenarios that incorporated generation outages under peak load conditions. NERC noted particular reliability risk in areas within MISO, the Canadian Maritimes, Texas, the Rocky Mountain Reserve Group and the Northwest Power Pool.

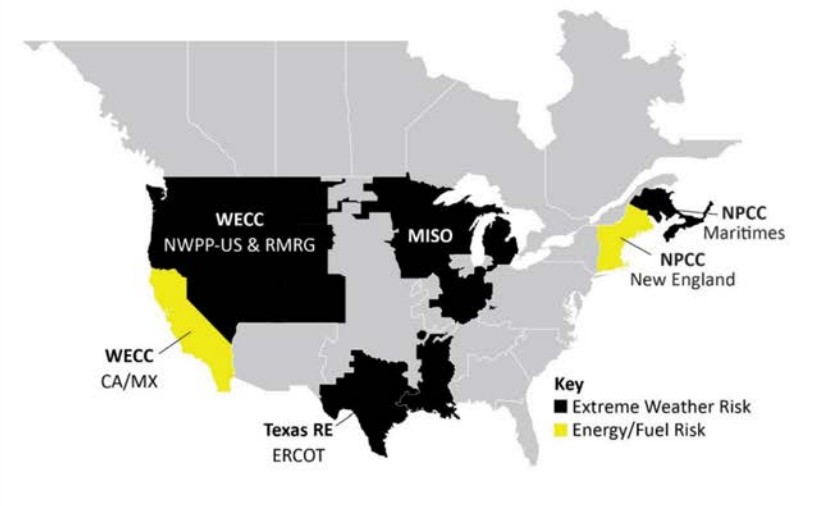

Figure 1: Areas with Reliability Risks during Extreme Weather Events and/or Fuel Supply Disruptions

Source: *2020/2021 Winter Reliability Assessment*, NERC.

Over the years, NERC's assessments have continued to identify three areas of primary concern: California, Texas, and New England. While recent events in the central-south and western parts of the country have attracted national attention, New England is another region that NERC has identified as particularly vulnerable to extreme cold weather.

[12] *2020/2021 Winter Reliability Assessment*, NERC, 6, 27.

New England

New England's exposure to extreme weather is exacerbated by its limited pipeline capacity to import gas and its dependence on a handful of critical fuel assets. NERC has continually identified fuel supply risk in New England, noting, "A standing concern is whether there will be sufficient electrical energy available to satisfy electricity demand while satisfying operating reserves during an extended cold spell given the existing resource mix and seasonally-constrained, fuel delivery infrastructure."[13] New England secures fuel reliability through dual-fuel capability in its natural gas fleet. A cold snap in December 2017/January 2018 led to natural gas shortages and fuel oil was burned to preserve reliability. If the cold front had not dissipated after January 8, several more hours of freezing weather would have exhausted the fuel oil in inventory and ISO-New England would have been forced into load shedding to preserve reliability. It was a near-miss event.

ERCOT/Texas

NERC's assessments have consistently highlighted reliability risk in Texas. As far back as nine years ago, the *2012 Long-Term Reliability Assessment* expressed this warning about ERCOT:

> Starting as early as next year, the [ERCOT] Planning Reserve Margin is projected to be below the NERC Reference Margin Level. Specifically, for 2013 the Anticipated Reserve Margin of 13.4 percent is below the ERCOT planning target (NERC Reference Margin Level) of 13.75 percent. At these levels, the risk of insufficient generation resources to meet peak demand increases beyond the accepted target. Throughout the 10-year assessment period, the Planning Reserve Margin continues to degrade and is projected to fall below five percent by 2017 and approximately zero by 2020 if more resources are not acquired.[14]

Concern for ERCOT's reserve margins has been a standing concern in NERC's assessments. In the most recent *2020/2021 Winter Reliability Assessment*, NERC warns of the potential for extreme generation resource outages in ERCOT due to severe weather in winter and summer, and the potential need for grid operators to employ operating mitigations or energy emergency alerts to meet peak demand.[15] *2020 State of Reliability* finds that Texas continues to have insufficient resources to meet the reference margin level but still successfully met demand throughout the 2019 summer season.[16] NERC's *2020 Long-Term Reliability Assessment* points to low operating reserves during the summer and during the months of March and October of the study years (2022 and 2024).[17]

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[13] *2020/2021 Winter Reliability Assessment*, NERC, 18.
[14] *2012 Long-Term Reliability Assessment*, NERC, 11.
[15] *2020/2021 Winter Reliability Assessment*, NERC, 6, 27.
[16] *2020 State of Reliability*, NERC, ix.
[17] *2020 Long-Term Reliability Assessment*, NERC, 6.

California

NERC assessments have also identified energy sufficiency issues in California before the 2020 summer event. The *2019 Long-Term Reliability Assessment* discusses a need for flexible resources to meet increasing ramping and variability requirements, noting, ". . . as solar generation increases in California and various parts of North America, system planners will need to ensure that sufficient flexibility is available to operators to offset variability and fuel uncertainty."[18] In discussing the California region, NERC's *2019 Summer Reliability Assessment* concludes, "Extreme outages may result in insufficient resources at peak load."[19] The high-risk scenario in the *2020 Summer Reliability Assessment* predicted, "Operating mitigations and EEAs [Energy Emergency Alerts] may be needed under extreme demand and extreme resource derated conditions."[20]

Findings and Recommendations

Managing the pace of change is the central challenge for reliability. The rapid evolution of the generation resource mix is altering the operational characteristics of the grid. We highlighted this issue most visibly in our 2018 special assessment of baseload generation retirements and it has been a recurring theme of our outreach to federal and state regulators.[21] It is imperative to understand and plan for the different operating characteristics of variable, inverter-based resources. This includes time to study, plan for, and develop effective solutions to the challenges. Variable energy resources can provide ramping and other essential reliability services, yet existing regulatory models and contracts do not always value these capabilities. Sound policies, both public and market-based, should support a reliable energy transition.

More transmission and natural gas infrastructure is required to improve the resilience of the electric grid. Electric transmission investment must keep pace with the increase in utility scale wind and solar resources, which are generally located outside of major load centers. Transmission investments can also strengthen the ability to wheel power to different load centers improving resilience through redundancy. Additional pipeline infrastructure (including gas storage) is needed to reliably serve load and enable natural gas as a balancing resource. Many are discussing the merits of a national transmission system similar to the interstate highway system, point-to-point DC lines, and other interconnections. Whatever approaches may ultimately be pursued, few long-haul transmission lines and pipelines are actually being planned and built.

Natural gas is essential to a reliable transition. As variable resources continue to replace other generation sources, natural gas will remain essential to reliability. In many areas, natural gas-fueled generation is needed to meet energy demand during shoulder periods between times of high and low renewable energy availability. And on a daily basis in areas with significant solar

[18] *2019 Long-Term Reliability Assessment*, NERC, 8.
[19] *2019 Summer Reliability Assessment*, NERC, 29.
[20] *2020 Summer Reliability Assessment*, NERC, 33.
[21] *Generation Retirement Scenario*, NERC, December 2018.

generation, the mismatch between the solar generation peak and the electric load peak necessitates a very flexible generation resource to fill the gap. Natural gas generation is best positioned to play that role. The criticality of natural gas as the "fuel that keeps the lights on" will remain unless or until very large-scale battery deployments are feasible or an alternative flexible fuel such as hydrogen can be developed. Growing reliance on natural gas for electric generation is driving a variety of actions within the industry and across interdependent infrastructure sectors to manage risks to natural gas fuel supply. Most areas are reliant on natural gas to meet on-peak electricity demand. Unlike generation with on-site fuel storage, natural-gas-fired generators depend on the natural gas pipeline system to deliver just-in-time fuel for electricity production. Unless they are dual-fuel units with onsite fuel oil, they can be particularly sensitive to extreme cold temperature, and should be winterized to reduce the risk to their ability to operate. Further, growth in the use of natural gas as a fuel for electric generation and other applications can stress the natural gas supply infrastructure when necessary expansions do not keep pace. The problem is particularly acute during extremes.

<u>Regulation and oversight of natural gas supply for electric generation needs to be rethought.</u> – While natural gas is key to supporting a reliable transformation of the grid, the natural gas system is not built and regulated to serve the needs of an electric power sector that is increasingly dependent upon reliable natural gas service. As it relates to BPS reliability, clear regulatory authority is needed over natural gas when used for electric generation.

<u>Planning for extreme weather.</u> The BPS must remain reliable and resilient during all operating conditions. As the recent extreme weather events show, industry should proactively plan for and recover from rare events. NERC reliability assessments and reliability standards are identifying and attempting to address these risks within our authorities. Regulatory and market structures need to support this planning, prioritize reliability, and support necessary investments.

<u>Resource adequacy does not guarantee energy sufficiency.</u> A diverse generation portfolio strengthens reliability and resilience, yet the benefits of diversity are lost when all resources underperform or fail. All generation sources have energy limits and physical constraints, and these limits and constraints need to be accurately accounted for in seasonal and long-term planning assessments. While it is premature to draw hard conclusions before the joint inquiry is complete, thermal and variable resources in ERCOT, MISO, and SPP were forced offline or failed to perform as expected during the extreme cold weather event. The event is not a debate about one resource or another. The joint inquiry will look at all generation failures and their root causes.

<u>Energy storage can and will be a game changer.</u> As the technology continues to develop and economics continue to support the growing penetration of energy storage, these resources will become a game changer. However, we have to appreciate the gap that currently exists and the

scale that we need to obtain. NERC recently completed a battery storage study.[22] The assessment emphasizes the reliability benefits that battery energy storage systems can offer, such as providing peaking capacity; minimizing the need for new generation and transmission infrastructure; and providing essential reliability services such as frequency response. The assessment stresses the need to plan for a significant increase in the critical mass of battery storage or other balancing resource (such as hydrogen) *at scale* before natural gas reduces its role as the critical fuel for electric reliability that it is today. Investment in energy storage technologies and/or a hydrogen production and delivery system will be required if the vision of a largely/completely decarbonized electric system can be realized.

Market Issues. While electricity market issues are outside of NERC's direct purview, policymakers, planners, and market operators need to understand how electricity market policies value reliability and incentivize investments in hardening energy infrastructure.

Conclusion

Managing extreme weather impacts and a transforming grid is highly complex, requiring significant coordination among widely diverse policymakers and stakeholders. North America has four distinct interconnections. The owners, operators, and users of the BPS number in the thousands and have varied corporate structures. Some entities are vertically integrated, while others operate as unbundled entities in regional wholesale markets. These entities are overseen by a diversity of regulators at the local, state, provincial, and federal levels. Energy is being supplied from new sources that create new opportunities as well as challenges for the grid. All these factors must be well coordinated during the transformation in order to preserve reliability.

While reliability of the BPS incorporates certain standing principles, there is no one-size-fits-all approach. Rather, states and regions adopt solutions that work for them based on the availability of energy resources, energy infrastructure, and policy preferences. Reliability and resilience to extreme events must be a key factor of all discussions as we move forward. We have seen what happens when reliability is not planned for or fully incorporated into the planning and development of the changing resource mix.

Thank you for the opportunity to participate in this hearing. NERC greatly appreciates the committee's interest in our independent work. Working with FERC, industry, policymakers, and all stakeholders, NERC is uniquely situated to assure reliability for the nearly 400 million people in North America who depend on our work. Given myriad challenges, NERC's mission has never been more important.

[22] "Impacts of Electrochemical Utility-Scale Battery Energy Storage Systems on the Bulk Power System," NERC, February 2021.

APPENDIX

Footprints of NERC and the Regional Entities

The CHAIRMAN. Thank you, sir.

Now we are going to have Mr. Mark Gabriel, Administrator and CEO of Western Area Power Administration.

I think we have him by video.

Mr. Gabriel.

STATEMENT OF MARK A. GABRIEL, ADMINISTRATOR, WESTERN AREA POWER ADMINISTRATION, U.S. DEPARTMENT OF ENERGY

[Delayed audio feed.]

Mr. GABRIEL [continuing]. The Western Area Power Administration, a federal Power Marketing Administration responsible for selling and delivering wholesale power from 57 hydroelectric dams to about 700 utilities, military bases, Native American tribes, national laboratories and 15 Central and Western states. WAPA's territory spans 1.3 million square miles and our 17,236-mile transmission system, one of the largest in the United States, is an integral part of the high voltage power grid in the West that ensures reliable electricity for more than 40 million Americans. A mentor once told me early in my career that electrons follow the laws of physics and electricity follows the law of the politics and really, only one of these can be amended.

WAPA's system experiences 99.99 percent uptime and America possesses the most reliable grid in the world thanks to our professional utility industry overseen by industry and government regulatory agencies and a common commitment to keeping the lights on all while the competitive grid keeps costs as affordable as possible. We also operate a resilient system weathering disruptions like storms, wildlife interactions, vehicle accidents, routine maintenance and emergency situations and safely returning power to citizens. However, when the system is pushed beyond its limits due to extreme weather, such as Winter Storm Uri or the August 2020 heat wave in California, we experience the consequences of operating and maintaining a competitive grid focused mainly on low cost. On February 15th and 16th, SPP directed rolling blackouts across much of its territory to protect the grid and the communities that rely on it from damaging and prolonged outages.

At WAPA, 21 customers experienced outages for an average of 55 minutes and up to 2 hours. Fortunately, WAPA and the Army Corps of Engineers sent 27,150 megawatt-hours of additional hydropower to SPP between February 15th and 18th, enough to power nearly 800,000 homes. In the August 2020 heat wave, WAPA did not lose power. But between August 14th and 15th, WAPA and the Bureau of Reclamation supplied 5,400 megawatt-hours of surplus federal hydropower to California to limit the effects of the energy emergency without impacting our customers. In both cases and then in Texas the markets worked according to the design. The grid did not collapse, load shedding and conservation appeals helped, all available resources were generating and the prices increased when the megawatts were scarce.

However, this also showed the system's weaknesses. First, every form of generation can be disrupted by extreme temperatures. Second, a competitive market can discourage long-term capital investment in reliability and resilience measures. And finally, costs move in both directions in competitive markets and electricity will flow often at times at practical prices. WAPA prepares for price fluctuations as well as drought by maintaining a financial reserve at the Treasury, carefully coordinated with our customers and this is really aimed at avoiding rate shock.

Increasingly severe weather disasters are straining the grid, including WAPA's, in the 2018 Carr Fire. We are responding to more destructive ice storms, snowstorms, tornadoes, wildfires and high wind events. We've deployed personnel, equipment and materials to restore power after hurricanes, typhoons and volcanoes. Looking forward, we anticipate investing $1.3 billion in our system over the next decade to assure reliability—reliability being the confidence that the lights will turn on when we need them. Resilience is the ability to prevent and withstand and recover from destructive threats and events.

Ideally, we'd invest more in resilience emphasizing defense-critical electric infrastructure, artificial intelligence, hardening facilities, redundant services, black start capabilities, replacing wood with steel and increasing the movement of energy between the Eastern and Western grids to the seven interties. Integrating AI, machine learning and advanced technology solutions into grid operations can improve real-time situational awareness, including knowing what is losing power when electricity is proactively cut to protect the grid, a shortfall today. Today's market structure, in some ways, disincentives utilities from necessary resilience and modernizing investments.

In conclusion, power and gas markets in the United States are marvelously efficient at driving out inefficient generating units, increasing financial liquidity and expanding the sale of electricity. However, the real question is whether electricity and to a lesser extent, natural gas, are logical commodities to participate in open markets. Unlike pork bellies and orange juice, trading electrons has consequences far greater than the availability of bacon or a morning refreshment.

Thank you, Mr. Chairman. I'd be pleased to answer any questions that you or the Committee may have.

[The prepared statement of Mr. Gabriel follows:]

STATEMENT OF
MR. MARK A. GABRIEL
ADMINISTRATOR
WESTERN AREA POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY
BEFORE THE
ENERGY AND NATURAL RESOURCES COMMITTEE
U.S. SENATE

MARCH 11, 2021

"HEARING ON THE RELIABILITY, RESILIENCY, AND AFFORDABILITY OF ELECTRIC SERVICE"

Thank you, Chairman Manchin, Ranking Member Barrasso, and Members of the Committee. My name is Mark A. Gabriel, and I am the Administrator of the Western Area Power Administration (WAPA). I am pleased to speak to you today regarding WAPA's role in supporting the reliability, resilience, and affordability of electric service.

WAPA is one of four Power Marketing Administrations (PMAs) within the U.S. Department of Energy (DOE). Our responsibilities are to market and transmit wholesale electric hydropower from 14 multiuse water projects; to provide an integral transmission system for delivering that power; and to manage the Transmission Infrastructure Program (TIP), all to benefit the American public. WAPA markets and transmits hydropower from 57 Federal dams operated by the Bureau of Reclamation (Reclamation), the U.S. Army Corps of Engineers, and the International Boundary and Water Commission. This power benefits rural economies, Native American tribes, Federal and state agencies, and others who, in turn, serve more than 40 million Americans in the West. Our efforts to control costs, eliminate waste, and seek efficiencies help keep our rates among the lowest in the country and support economic prosperity and viability of the Western United States.

At the same time, we are reinvesting in our system to prepare for a new energy economy where renewable, intermittent generation resources dominate the marketable power supply and the transmission system becomes even more critical to transporting energy from where it is created to where it is used. In this testimony, I will share the value of hydropower, our response to recent national disasters, our commitment to maintain our historic levels of reliability and our plans to improve resilience through our existing programs, sensible investments, and increased advanced technology.

WAPA's Assets

WAPA's footprint encompasses about 1.3 million square miles of diverse ecosystems and populations, from urban to rural, plains to mountains, and deserts to forests. Spanning 15 states, the communities WAPA serves have a wide variety of energy interests and needs; we are cognizant that what works in Texas will likely not work in California, and the needs of customers in Arizona differ from the needs of customers in Colorado.

WAPA owns, operates, and maintains $4.3 billion in power transmission assets on behalf of the Federal government and is one of the 10 largest transmission organizations in the Nation. We need to make well-informed, prudent, and realistic decisions about how to invest in our infrastructure to affordably support future needs. In the next 10 years, WAPA anticipates significant reinvestment in our assets. These would likely be the largest investments since the infrastructure was originally built in the middle of the 20th century.

WAPA continues to work with customers to flatten peaks in anticipated spending and provide measured and attainable financial expectations. The bulk of investment will maintain and upgrade the core transmission assets in our system, including more than 100,000 structures along 17,236 miles of high-voltage transmission lines, 324 substations, and 291 high-voltage transformers.

Value of Hydropower

WAPA markets and delivers hydropower, providing unparalleled benefits to Americans in the Western United States. WAPA's rates are often among the lowest in the country, or the lowest rates for an entire state, such as in Arizona.

In an average year, WAPA markets and delivers more than 25,000 gigawatt-hours of hydroelectric power. This amount represents 100 percent of annual energy needs for about 2.3 million average American homes. All this power is sold at cost.

According to the DOE's Hydropower Vision Report, the U.S. hydropower fleet is comprised of approximately 2,200 power plants with a total capacity of roughly 102 gigawatts, including 95 percent of U.S. energy storage capacity (23 gigawatts) in the form of pumped storage. Hydropower employs around 66,500 workers.

Hydropower is a unique generation source, providing both grid stability and low-cost, low-carbon energy. According to the U.S. Energy Information Administration, it is one of the largest generators of clean, low-carbon electricity, representing seven percent of total U.S. electricity generation and 39.5 percent of renewable electricity generation in 2018. According to the DOE's Hydropower Vision Report, the Nation's hydroelectric fleet avoids about 225 million metric tons of carbon pollution in the U.S. each year, equivalent to the emissions of 42 million passenger cars.

In addition to its low-carbon benefits, hydropower provides the large rotating inertia required for a reliable electric grid and abundant capacity to meet energy demand at a moment's notice. Hydropower is also not reliant on daily weather. For those reasons, it is the ideal partner to wind, solar, and potentially non-hydro battery storage. We experience the benefits of this partnership as members of the Southwest Power Pool (SPP) Regional Transmission Organization, where hydropower from the Pick-Sloan Missouri Basin Program – Eastern Division provides the reliable energy backbone for the upper part of SPP's service territory, moderates costs to consumers, provides stability to wind and solar generation, and supports improved river and dam operations.

We are also working with our customers to identify opportunities to interconnect transmission-scale battery storage to WAPA's system. Customers and WAPA alike can take advantage of the benefits battery storage offers, including balancing load, increasing resource diversity, and managing changes in water availability.

One of the key challenges for today's electric utilities, and arguably the top challenge, is the decrease of inertial capacity required for a healthy system and lack of financial compensation for the remaining capacity. Each year, we are losing more of the stability that makes a resilient system possible while leaning more on low-carbon, reliable hydropower as a baseload resource and one of the few capable of restarting a system after a massive outage (also known as black start).

Black start is the provision of startup energy to restore power to generation facilities after a massive power system disturbance, similar to the Northeast outage in August 2003 or the Southwest outage in 2011. It is an oft-overlooked requirement that powerplants need energy to operate; without electricity, they suffer the same outages as residences and businesses. To provide this startup energy to a powerplant, utilities have placed emergency on-site generators at select plants and designated them black-start units. Hydropower frequently provides these capabilities in the Western United States.

Hydropower currently also supports national security. In addition to providing black-start capabilities, hydropower directly supplies many of the Nation's military bases and DOE's National Laboratories. WAPA supplies power to more than two dozen military bases and other highly sensitive facilities across the West. Many WAPA customers are similarly distributors of power to the bases and national security facilities. As part of the Defense Critical Electric Infrastructure Program, we have been working with the Department of Defense to secure direct feed power to the most critical bases in the West.

Despite the many benefits of hydropower, only three percent of dams in the U.S. can produce electricity, representing the potential for additional hydropower to be added to the grid by adding generation equipment to non-powered dams.

We collaborate closely with the generating agencies, power customers, and other stakeholders to assure the enduring value of the hydropower product in the face of drought, new regulations, and other constraints. The Federal dam system in the United States provides several valuable services to the American people that must be balanced for maximum benefit.

Responding to Natural Disasters

Our fundamental responsibility is to keep the lights on for more than 40 million Americans. In no situation is this more evident than in responding to natural disasters and severe weather within and outside of WAPA's territory.

Recently, Winter Storm Uri brought historic freezing temperatures to our Upper Great Plains (UGP) region, which covers all or parts of North Dakota, South Dakota, Montana, Nebraska, Iowa, and Minnesota. The majority of our UGP territory is a member of the Southwest Power Pool Regional Transmission Organization (SPP), a market operator and reliability coordinator in 17 central states that manages the reliability and buying and selling of energy and transmission for participating utilities. Due to the severity of the storm, SPP, implemented emergency energy alerts and rolling blackouts to preserve and protect the power grid, from irreparable damage and extended outages for the first time in its 80-year history.

On February 16, SPP directed WAPA to begin shedding load, the industry term for proactively cutting power to customers to protect the grid and consumers from widespread, uncontrolled, and dangerous long-term power outages. These rolling outages affected 21 WAPA customers in UGP for an average of 55 minutes and as long as 122 minutes. SPP was unable to meet demand because extremely low temperatures forced a number of generating resources offline, especially natural gas.

WAPA and SPP learned many lessons from this event, especially regarding advanced and frequent communication with our customers. The SPP and WAPA systems worked as designed during the energy emergency, sparing many communities from life-threatening situations and preventing damage to electrical infrastructure that could have taken months to repair.

The situation highlighted inherent weaknesses in our current energy environment, including that cold impacts every form of generation. We also learned what is missing from our situational awareness of the grid, specifically what loses power, when we are required to disconnect electricity to small, defined areas for discrete periods of time. There is no grid visibility or granularity to that level of detail. We generally know where the outage will occur in terms of surface area, but not what connections will be affected, residential, industrial, commercial, water plants or the Bakken Oil Field.

WAPA was not directly affected by the events in Texas. Through SPP, we provided surplus hydropower through the ties connecting to the Electric Reliability Council of Texas grid once SPP's energy emergency had concluded.

In August 2020, WAPA responded to support the California energy crisis. Between August 14 and 19, WAPA and Reclamation supplied California with 5,400 megawatt-hours (MWh) of hydropower during the state's first energy emergency in nearly 20 years.

Reclamation generated the power using its fleet of Federal hydroelectric dams in the West, including, among others, 18 dams in the Central Valley Project in northern California; Glen Canyon Dam in Page, Arizona; Hoover Dam on the border of Arizona and Nevada; Morrow Point Dam in western Colorado; Davis Dam in Arizona; and Parker Dam in California.

WAPA then transmitted the energy via its high-voltage transmission system into the California Independent System Operator's (CAISO) service territory, while continuing to reliably serve WAPA's customer loads. WAPA's Sierra Nevada region provided more than

3,300 MWh, while the Colorado River Storage Project provided nearly 1,900 MWh and Desert Southwest provided more than 200 MWh.

In some cases, WAPA was able to offset this generation and continue to meet its customers' demand by increasing hydropower output from other dams to provide power to local areas.

Hydroelectric dams are crucial sources of reserve energy in case of system emergencies. The large reservoirs, such as Lake Mead and Lake Powell, function as enormous batteries and can quickly dispatch a large amount of electricity on the grid. WAPA and Reclamation have plans in place with several utilities to provide emergency power from Federal hydroelectric powerplants.

As regular members of the Federal Emergency Management Agency's (FEMA) disaster response teams, WAPA employees have been activated to support power restoration in Hawaii after a volcanic eruption in 2018 and in Guam and the Northern Mariana Islands after they were struck by 2018's two strongest storms. We deployed personnel to advise power restoration following 2020's Hurricane Laura and sent line crews and other specialists to help rebuild the power grid following Superstorm Sandy, Hurricane Irma, and Hurricane Maria.

Employees, along with others carrying out Emergency Support Function-12 responsibilities within the National Response Framework, liaise between FEMA and the local utilities on power restoration plans; visit work crews to identify priorities and needed materials; and remove barriers to acquisition and transportation.

Severe natural disasters have recently struck WAPA facilities as well. In July 2018, the Carr Fire in northern California directly affected WAPA's system and that of its customers. At the fire's height, the Sierra Nevada region had 15 high-voltage transmission lines out of service, fires at the gates of its substations, and about a dozen hydroelectric generators out of service. Despite the unprecedented emergency situation, WAPA continued supplying power to the area, and worked one-on-one with communities to keep as many homes and businesses as energized as possible.

Once the fire passed, our maintenance workers, some of whom had been evacuated and some of whom sustained fire damage to their own property, immediately went to work repairing damaged assets, including replacing a number of steel structures destroyed by the "firenado" in Redding, California. Once WAPA's facilities were fully energized, our staff lent support to our neighbors and Reclamation to rebuild their systems.

That experience galvanized WAPA to more stringently apply vegetation management best practices, collaborate with customers, and set new standards. WAPA and many other utilities have common practices within their vegetation management programs, including multiple ground and aerial inspections a year. Lines at WAPA are inspected twice a year, except in California, where WAPA inspects our 1,000 miles of line five times a year. Crews observe and report any obvious issues to dispatchers while also recording their findings on inspection tools that feed into WAPA's Reliability-Centered Maintenance program for further action as needed.

We also contract with independent third-party inspectors to identify, validate, and review vegetation management work.

We have established relationships with land and fire management agencies at the state and local levels, such as CALFIRE, to ensure seamless coordination and communication during wildfire events. We also have trained on and incorporated the National Incident Management System vernacular and processes used by most of the Nation's first responders.

Our integrated vegetation management (IVM) program, championed by the Desert Southwest region, is highly effective and economical. IVM uses a two-stage approach: 1) reclaiming easement areas by clearing out tall-growing vegetation, leaving only low, natural vegetation in place; and 2) applying herbicides the following year to keep vegetation growth low.

The result is reduced ecological impact and savings compared to a one-time complete removal process. Removing fast or tall-growing vegetation allows the fire to pass under the transmission line without impacting it. This is important because maintaining a reliable flow of electricity is critical for serving customers in towns and cities across the West, especially when there is a fire or other natural disaster.

Each region also customizes their vegetation management based on the unique ecosystems present in their territory, whether it is forest, mountains, desert, or prairie. Following the devastating 2018 wildfire season, California passed a new law, SB 901, that required utilities to proactively work to mitigate the risk of wildfires started by power lines. Although WAPA is not subject to California jurisdiction, in certain cases we have chosen to comply with state requirements.

Our September 2019 Wildfire Mitigation Plan identifies specific steps to minimize the probability that our facilities may start, or contribute to, a wildfire. The plan establishes and maintains consensus and communications about de-energizing lines in response to a wildfire threat. It also outlines our expanded on-the-ground detailed inspections, vegetation and fuels inspections, potential risk and equipment failure detection technologies, and aerial inspection methods.

We are also participating on a local ad-hoc committee with other utilities to review wildfire mitigation efforts, remain compliant with California general orders and resource codes on vegetation management, and coordinate regularly with CALFIRE on fuel reduction projects, incident response teams, fire suppression efforts, and educational events. Since 2015, we have reinvested over $78 million in the California system for preventive maintenance and upgrades.

In the Rocky Mountain region, which covers Colorado, Wyoming, and parts of Nebraska and Kansas, WAPA's Natural Resources team partnered with the U.S. Forest Service to gain access and conduct machine clearing in rights of way on two national forests that had only been hand-cut for over a decade, leaving potentially dangerous fuel buildup under the lines. WAPA was unable to properly maintain its lines on these two forests because of a lack of mechanized clearing.

Through this partnership, WAPA was given permission to clear vegetation that had grown under and around its transmission lines, an area threatened this year by the Wyoming-Colorado Mullen Fire. This effort garnered a Gears of Government award in 2020 from the Executive Office of the President, recognizing the team's exceptional work to deliver key outcomes for the American people, specifically around mission results, customer service, and accountable stewardship.

Maintaining a Reliable Grid

WAPA's system experiences 99.999 percent uptime, contributing to the overall top reliability of the American grid. WAPA also operates a resilient system, weathering disruptions including storms, wildlife interactions, vehicle accidents, routine maintenance, and emergency situations with consumers unaware of most disruptions thanks to our system's redundancy and ability to section off problematic equipment.

To achieve this reliability and resilience, the organization focuses on security, quality, resilience, and availability; a best-in-class Reliability-Centered Maintenance program; a mature asset management program; aggressive integrated vegetation management; long-term capital planning; and support from our customers. We also participate in industry leadership and research groups, like the Electricity Subsector Coordinating Council and Institute of Electrical and Electronics Engineers, to seek and share leading industry practices with other utilities.

Utilities, including WAPA, continue to reinvest in their transmission systems. One of WAPA's core principles is to deliver services at the lowest possible cost in accordance with sound business practices. All WAPA investments are based on these core tenets, striving to enhance reliability and resilience of the high-voltage transmission system. This has resulted in an industry-leading system reliability rating, while keeping power, transmission, and other associated rates at levels that enable WAPA's customers to provide competitive energy prices. Through our 10-year capital planning process, we anticipate investing $1.3 billion in our system over the next decade to ensure reliability. The 10-year capital planning process is a data-driven, well-defined methodology, fed by WAPA's asset management program, designed to maintain our transmission system to reliable standards.

WAPA's Asset Planning and Management program, established in 2014, uses objective data combined with field expertise to manage our assets based on risk and criticality. We use these data to communicate asset needs with customers and make informed business decisions so that the right investments occur in the right place at the right time and maximize the value of maintenance and capital efforts.

The Asset Planning and Management program continues to expand its database with new asset classes to better forecast and develop our annual budgets and 10-year capital plans. In the next few years, the program will incorporate health and condition factors for station batteries, two additional types of transformers, and network equipment. This year's new asset classes included load tap changers, transformer bushings, cranes, and power circuit breakers under 100 kilovolts.

The program is also seeking ways to more efficiently acquire large power transformers by reducing the procurement lead time from two years to between nine and 12 months. This will support lifecycle replacements, periodic system additions, and allow WAPA to more quickly recover from an unexpected loss of power transformers including a high-impact, low-frequency event.

One opportunity to increase the national power sector's reliability is to increase the capacity of our existing grid through rebuilds, modernizations, and capacity upgrades. Another is to build new transmission infrastructure to both transport the remote renewable energy resources to where the population resides and to better balance energy supply and demand. In the central U.S., new generation sources are not limited by lack of demand or siting issues, they are stymied by lack of transmission capacity. If there is not adequate transmission capacity to accept the new generation, regardless of its source, the plant cannot be built. Late last year, both SPP and Midcontinent Independent System Operator markets publicly announced and agreed to jointly study the problem of constrained transmission capacity.

Both new transmission projects and upgrades, large and small, continue to stall across the U.S. Several reasons have been cited for the recurring failure of transmission projects including limited financing; transmission siting, environmental reviews and permitting; and a poor return on equity making transmission an unprofitable venture for investors. In addition, changes in the marketplace may have raised the risk profile to unacceptable levels for traditional utilities, and some newer entrants may not yet have the long-term financial backing or experience to commit to the decades necessary for transmission contracts.

The American Recovery and Reinvestment Act of 2009 provided WAPA with $3.25 billion in borrowing authority to fund transmission projects within its service territory that deliver, or facilitate the delivery of, power generated by renewable energy resources. WAPA staff also possesses the experience and connections to navigate the difficult path to build transmission. Since 2009, we have funded the construction of two transmission projects and supported the development of a third. There are at least eight other projects in the queue, which are delayed by lack of offtake partners and demand for the power.

Bolstering Resilience in the Energy Frontier

Reliability is the confidence that the lights will turn on when we need them. It is a key pillar and tenet when operating a bulk electric system and is engrained in the culture at WAPA, as it is with any transmission provider operating and maintaining their respective portions of the electrical grid. For WAPA, system reliability is focused on safely and effectively delivering Federal hydroelectric power from 57 dams in the West. Much of utility-scale electric power reliability is dictated by sound business practices, regulatory directives, and industry standards that guide day-to-day operations across North America.

Resilience, conversely, is the ability to prevent, withstand, and recover from disruptive threats and events, such as natural or manmade disasters. When considering resilience during natural disasters, weather is not a root cause for an outage. If utilities eliminate weather as a root cause, they can ascertain the true weaknesses in an electric system, specifically which advancements need to be made most urgently to improve resilience as well as reliable energy delivery. Rapidly advancing societal and technological changes are reshaping the energy landscape, and nefarious actors see electricity as a primary venue to disrupt the American economy and our way of life, necessitating a grid that is smarter, more connected, more secure, and more resilient.

Investing in more resilience, placing special emphasis on defense-critical electric infrastructure, would include hardening facilities, increasing redundant services, expanding and enhancing network communications systems, replacing wood with steel, and upgrading operations centers.

WAPA seeks to meet these challenges by developing a more resilient grid that responds to changing customer needs while defending against and combating physical and cyber threats. WAPA's resilience strategy focuses on enhancements to situational awareness, bulk electric system facilities and systems, black start and cranking paths, and the Eastern and Western Interconnection direct-current interties.

Upgrading the East-West interties that transfer power between the Eastern and Western Interconnections would cost effectively improve system flexibility and economic performance across the country. Access to power from the adjacent grids allows utilities to delay construction of powerplants needed to meet peak power demands.

These interties have the potential to transfer Arizona solar to energize East Coast evenings or share Iowa wind to support the energy needs of California mornings, but today are constrained by outdated technology and system limitations. Doubling the existing transfer capability between the two main grids in the U.S. would increase the bi-directional transfer capacity to 2,640 megawatts (MW)—about the equivalent of the seven large mainstem Federal hydroelectric dams along the Missouri River, six 600-MW natural gas plants or 66 20-MW battery storage systems. These upgrades could be completed faster and cheaper than building those new facilities or a transmission "superhighway."

WAPA is also actively engaging in industry efforts to mitigate the effects of geomagnetic disturbances (GMD) and electromagnetic pulses (EMP). WAPA has been involved in preparing for and mitigating possible GMD and geomagnetically induced currents (GIC) disturbances since the beginning of the 21st century. By partnering with the Electric Power Research Institute's SUNBURST program, which collects diverse GMD-related data across the U.S., WAPA is contributing to a body of industry data that can help scientists model GICs, forecast when they will happen and develop ways to protect the grid. Specifically, the UGP region has equipped two substations with GIC-monitoring equipment conceived, designed and implemented by WAPA employees. The technology provides real-time situational awareness of GMD impacts on the transmission system to control center operators. As the technology has proven successful, WAPA intends to widen the network to its other regions as well as its neighbors and utility customers. WAPA is also supporting DOE efforts to study, prepare for, mitigate and describe EMP as required by the March 26, 2019 Executive Order on EMP. We continue to support scientific research and development, such as the Electric Power Research Institute's 2019 EMP report, share timely knowledge through industry forums, encourage readiness, and analyze policy needs for the future.

A comprehensive grid resilience approach includes awareness and hardening of physical assets. Grid surveillance is the process of obtaining situational awareness of the electrical grid through active data-gathering with appropriate analysis and interpretation of data. Sound decision-making leverages the knowledge gleaned through situational awareness. Using this approach, risks can be identified and prevented; responses can be more proactive than reactive.

Electric utilities potentially could integrate artificial intelligence (AI), machine learning (ML), and advanced technology solutions into grid operations to improve real-time situational awareness. Three potential equipment types for AI and ML technologies are transformers, transmission lines, and synchrophasors. These technologies could provide instant, real-time data leading to better ways to operate the grid while under stress.

Incorporating AI and ML could impact real-time contingency analysis, electricity dispatch, voltage and frequency management, energy and demand balancing, protective relaying, geomagnetically induced current monitoring, and system simulations. Advanced AI predictive modeling and forecasting could help electric utilities to track and respond to disruptive weather patterns before they occur, potentially improving contingency planning and limiting or preventing unnecessary damage or outages. With greater modeling and dynamic monitoring of weather and other factors, utilities will be able to better estimate the effects of weather on available capacity and energy, allowing us to recognize and respond faster to emerging contingencies.

Finally, AI and ML could be deployed to analyze data being captured in utilities' asset management programs to optimize equipment investment.

Closing Statement

The industry is experiencing a wave of unprecedented changes and opportunities. The challenges before the energy industry are vast, but not insurmountable.

We remain steadfast to our mission, yet how we accomplish it is changing. Together, we can chart the course toward securing a reliable, resilient, and affordable energy future.

Thank you, Chairman Manchin. I would be pleased to answer any questions that you or the Committee members may have.

The CHAIRMAN. Thank you, Mr. Gabriel.
Now we have the Honorable Pat Wood.
Mr. Wood.

STATEMENT OF HON. PAT WOOD, III, CHIEF EXECUTIVE OFFICER, HUNT ENERGY NETWORK, AND FORMER CHAIRMAN, FEDERAL ENERGY REGULATORY COMMISSION

Mr. WOOD. Thank you. Thank you, Chairman Manchin.

[Mic was off.]

The CHAIRMAN. Do you have your—there you go.

Mr. WOOD. All right, sorry about that. It's been a few years since I've been here now, and I don't remember how to do it.

Senator Heinrich, I'm the B Team. Sorry that ERCOT couldn't be here, but I think I can——

Senator HEINRICH. We are thrilled to have you.

Mr. WOOD. Thank you, thank you, I appreciate being here.

I was a state and federal regulator, as Chairman Manchin mentioned. Since y'all have saw me last, 16 years ago, as I testified on the Energy Policy Act of 2005 as Chairman of FERC, in support of the NERC's formalization and the formal role that NERC and FERC would have over reliability of all the continental U.S., I've been involved in a lot of things that I think bear on what we are talking about today, so I'm happy to share any perspective with the Committee during any questions. But I've been a wind developer, developed LNG projects; I've been Chairman of a company that had coal and gas operations throughout the country, Dynegy; was a founding board member of SunPower, I remain on that board, which is one of the top three solar companies in the United States; also on the board of Quanta Services, which is the largest utility construction firm building telecom, natural gas and, importantly, power lines. We are a joint venture operator with a Canadian utility of the Puerto Rico grid. That handover will happen this summer. So I get to talk about resilience. The people in the system of Puerto Rico are a full hearing and a full case of their own.

Today I'm CEO of the Hunt Energy Network. We're building storage, batteries, small batteries at the distribution level around the State of Texas. I think the role of energy storage in the future is going to be one that will be just nowhere to go but up. As we bring on intermittent resources, I understand members' concerns and lived through them as well, with intermittent resources, our variable resources, that we've got to do something to firm those up. Storage is that golden bullet that as a regulator I didn't have 15, 20 years ago when we were talking through market issues across from California to New England. But storage is just beginning. It's got to scale up, but it's a pretty interesting place to be.

So I don't speak for any of those companies, but yet, I'm informed by my experience with all of them and I do think that the years that have happened and, particularly these last three or four across the country, that I personally lived through a drought, two hurricane hits in Houston, this weather event in Texas last week or last month, the President's Day freeze that went to all 254 counties of the state with a winter weather warning which we've never, ever had, statewide. It tells me the world is changing and the modeling that we have done cannot just look in the rearview mirror and say how we're going to avoid the next pothole that we just ran through, but has to be much more creative and much more imaginative about the world that we see coming. It is the role of government, even for right of center people like me, it is the role of government to help marshal those resources and pull the right people and the right visions together so that we do think about infrastructure in a new way.

One of those ways that certainly came up was the events in my home state last month. I think at the end of the day our legislature is deeply involved in that review as we speak. In fact, ERCOT is, in fact, testifying today as is my successor as Chairman of the Public Utility Commission, working through the financial issues. But the operational issues which Mr. Robb and the NERC and the FERC will review under their mandate, will probably include familiar ones as well as some new ones. The failure of power plants to perform, which I think, in Figure 3 of my testimony might be a good place to look that it really was across all energy resources. Some did better than others, but all were, in fact, impacted below what we had expected them to be. Failures in the natural gas system which feeds about half of our power in Texas, failures on that system to perform. The interplay between the two which was pointed out in the NERC's 2011 report continues to be a large issue.

Commercial issues, market rule implementations, again scenario planning, the public communication issues were big issues for our legislature last month, that the lack of—we know more about when Amber Alerts go out about somebody that got kidnapped in the State of Texas than we knew about a shellacking that was coming that would affect four and a half million people. So that was a significant impact.

And then finally, the one that was most customer impacting was the management of the outages by our local utilities, that was a significant shortfall that is being remedied as we speak, because it could happen again as soon as this summer. So we always have to be ready, we have to be vigilant, but most of all we have to be creative.

[The prepared statement of Mr. Wood follows:]

TESTIMONY OF PAT WOOD, III
CEO, HUNT ENERGY NETWORK
BEFORE THE UNITED STATES SENATE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
MARCH 11, 2021

Chairman Manchin, Senator Barrasso, and Members of the Committee:

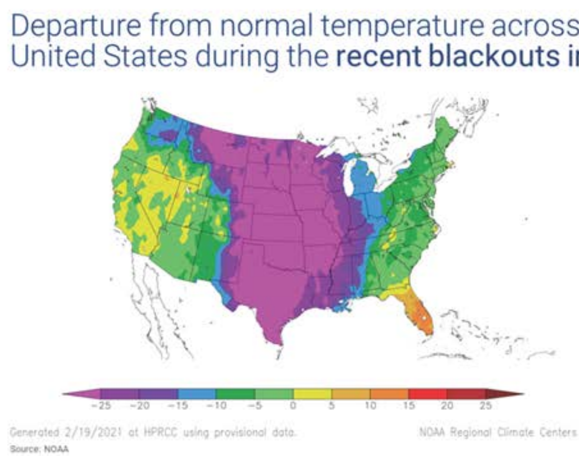
Sixteen years ago, as Chairman of the Federal Energy Regulatory Commission (FERC), I last testified before this Committee in support of what became the Energy Policy Act of 2005. Among other things, that law responded to the 2003 Northeastern North America Blackout by formalizing the role of the North American Electric Reliability Council (NERC) and the role of the FERC in overseeing NERC and enforcing its reliability standards across the continental United States. It also gave the FERC enforcement authority that it lacked to fully address some issues that arose in the 2000-2001 Western Markets energy crisis.

At the end of my term, my family and I went back home to Texas, where, before chairing FERC, I led the Public Utility Commission of Texas (PUCT) during our establishment of competitive wholesale and retail power markets. Motivated by my experiences in the Western Markets energy crisis of 2000-2001, the expansion of competitive wholesale power markets to two-thirds of the country, and the 2003 Blackout, I got to work on developing energy infrastructure. Since then, I've been involved with wind, solar, coal, gas and LNG projects and companies. I was a driver in the Texas Competitive Renewable Energy Zone transmission expansion, the largest U.S. grid expansion project in decades. Today, at the Hunt Energy Network, my team and I are developing a network of distribution-interconnected storage projects across the Texas ERCOT grid.

It is from those experiences that I respond to the Committee's charge, which is to examine the reliability, resiliency, and affordability of electric service in the United States amid the changing energy mix and extreme weather events.

The testimony that I would have given a month ago would have been significantly different than what I share today in some regards. The winter storm that struck the Plains and South Central states in mid-February, including all 254 counties of Texas, was the third most intense storm in 130 years of recorded Texas weather. It was historic in duration, geographic expanse and low temperature. Figure 1 shows the geographic reach of the storm and its comparison to normal February temperatures for the week of Presidents' Day.

Figure 1. Winter Storm Uri departure from normal temperatures. (Week of 2/15/2021)



Source: NOAA

The resulting failure of our energy system to perform as planned led to deaths, suffering and property damage. Hearings in the Texas Legislature these past two weeks have indicated that every segment of our energy and water infrastructure had significant failures, and a comprehensive root cause analysis of the energy infrastructure issues is underway.

The three pillars I have followed throughout my regulatory career are robust infrastructure, balanced market rules, and vigilant oversight. I believe those pillars provide the best way for me to discuss the Committee's charge for today: reliability, resilience, affordability and the changing resource mix.

Reliability

The beating heart of electric reliability is the real-time, short-term balance of a power system -- keeping the supply of power and demand in balance so the frequency of the real time system stays at or very near 60 Hz. Reliability also requires widespread situational awareness so the grid operator and others can see and react to deviations from NERC reliability standards, starting with the all-important 60 Hz frequency requirement. And grid reliability has long-term dimension that depends on a robust infrastructure -- a stout system of power generation, power delivery and demand assets that can integrate effectively through a wide range of potential future developments and challenges.

Reliability standards are developed by the cross-industry collaborative process at NERC and overseen by the regional reliability organizations under it. When enforcement of the NERC standards is required, FERC performs that role. Most NERC rules and FERC approvals are balanced but conservative, and they do not stretch the boundaries of possible reliability conditions, threats and solutions.

The day-to-day vigilant oversight of the grid -- the "air-traffic controller" function -- is handled every second of every day by regional grid operators such as ERCOT and PJM. Outside the organized markets, individual utilities (or "balancing areas") such as Western Area Power Administration (WAPA) perform this role. As we saw in ERCOT last month, lacking adequate generation and storage, the system operator's only option is to cut demand to avoid risking the collapse of frequency and voltage; failure to do so to rebalance the system could lead to a cascading blackout which could damage generators and create a widespread, lengthy electric outage.

As with other outage reports performed in recent years for events around the country, I am certain the NERC/FERC investigation of the Texas Presidents' Day storm response will address the critical real-time decisions ERCOT made on and before February 15th. As of today, I am not aware of any evidence that ERCOT had alternatives to significant load shedding in real-time. System operators prepare for such events and hope to never have to exercise load shedding protocols -- but their responsibility is to protect the entire grid in real time, and I support ERCOT's decision to shed load for that purpose.

NERC and FERC are responsible for the effective operation and economics of the bulk power system (generation transmission, and competitive wholesale markets and resources). But the distribution utilities that deliver power directly to customers play an important role in reliability. They are the regulated entities that ERCOT ordered to reduce load immediately. They did so using pre-established plans for rolling outages. Designated critical facilities such as hospitals, nursing homes, and jails were properly exempted from outages following standard practices, and the remaining customers shared the burden of the forced demand reductions.

From public testimony it appears, however, that many critical loads within Texas such as natural gas and water infrastructure may not have been recognized as critical facilities, so those were turned off pursuant to the outage orders. Much of Texas' natural gas production and processing plants now use electricity in their processes; without electricity, wellheads froze (produced gas often contains water) and gas processing also froze up. It has been reported that the production of Texas natural gas was cut in half by Friday, February 19th. With Texas supplying 40 percent of the nation's natural gas, this had significant availability and price impacts across the country.

As Figure 2 demonstrates, natural gas prices across the country escalated significantly above the typical winter prices ($7-$10 per MMBtu) during the event. This price run-up actually began several days before as gas customers increased purchases in anticipation of the cold weather ahead, while gas production facilities (and windmills) in western Texas began to freeze up under unusually damp conditions.

Figure 2. Spot Prices at U.S. Regional Gas Hubs (2/16/2021)

Source: IEA based on ICE NGX

The interface of the gas and electric systems was an issue in the 1989 and 2011 Texas power outages. Though it remains terribly important, true integration remains unresolved and thus should remain in keen focus. Unlike in the summer, when natural gas is flowing largely to fuel power plant demand, in the winter, natural gas is also supplying heating to homes and businesses, which understandably enjoy a statutory priority for service in Texas. However, because most of Texas has historically experienced relatively mild winters, now over two-thirds of Texas homes are heated by less efficient electric heat rather than by natural gas. (That number was less than 8% in 1970). This means that the multi-day power outages experienced by 4½ million Texans caused even greater human misery as their all-electric homes became progressively colder.

Back to the outage management process. As was widely reported in the local Texas media, many facilities such as commercial buildings (downtown office buildings) were preserved from outages despite not being occupied. These may have had backup generators or been on the same circuits as critical facilities. It is clear that state regulators and distribution utilities need to reassess, redefine and update the identification and designation of "critical" in utility outage plans and implementation processes. And that list would be different in summer peaks than in winter peaks. Revisions of this nature have already occurred in California as they have refined wildfire-driven outage management. Texas utilities have made large regulated investments in smart metering and distribution IT capability, but those cannot be used for granular outage management. It will be necessary for distribution utilities to reengineer their circuits and feeders system-wide to divide their grids into a large number of smaller, sectionalized feeders that can be individually shut off, with less load on feeders containing critical facilities. That way, future outages can be managed in a more granular fashion that rotates the pain across a larger part of the customer base. During the Texas outages, if the distribution utilities had been able to phase interruptions among more customers on a granular basis, we might have avoided leaving 4.5 million customers continuously out of service for up to four days and lessened the disastrous overall impact on the public. Unfortunately, unlike the telecom network where data speeds can be slowed at times of network congestion, currently there are no dimmer switches on many parts of the distribution network. It's either on or off.

In most other weather scenarios, like flood or hurricanes, windstorms or thunderstorms, electric distribution systems bear the brunt of the impact. As with gas and water utility operations, oversight for system reliability falls upon local or state regulators. Those regulators often set infrastructure performance standards for such items as frequency and duration of outages, response times, and in the case of gas and water, product quality standards. In my experience, these sorts of clear minimum performance standards make it clear to the regulated companies what the goal is and allow them to manage the most effective plan to address the reliability issue.

Resiliency

Resiliency has short-term and long-term dimensions. Long-term, power system resiliency relates to the foundational ability of a system to perform over many seasons and years. It has a planning and economic dimension different from shorter-term reliability and is a central focus of the robust infrastructure pillar of effective market structure. In the context of the power system, resiliency encompasses power generation plants, fuel resources, transmission and distribution, security from physical and cyber attacks, redundancy and the customer interface. The key focus of resiliency planning is "what can the customer depend on if a stress event lasts for a day, a week or even longer?"

Over the short term, power system resilience incorporates operational considerations such as assuring that the system has effective situational awareness, emergency operation plans and skills, backup equipment and spare parts. All these elements, and others, reduce the impact of a disaster and restore electric and other services as quickly as possible for customers and communities.

Most power system damage and resiliency events in my lifetime have been transmission- or distribution-related outages. Our mostly above-ground, highly visible infrastructure has always been susceptible to weather threats such as hurricanes, ice, floods, tornadoes, etc. And customers have become used to the rapid manual repairs to the damaged facilities. The Texas Presidents' Day event had a comparatively modest negative impact on the wires, but a dramatic impact on the availability of generation.

Every NERC region, including ERCOT, performs Summer and Winter Reliability Assessments each year for the upcoming season. The ERCOT Winter Assessment released in October modeled an "extreme/contingency case" with a forecast demand at 67.2 GW and generation at 68.6 GW. This would have required some emergency measures, but not rolling outages. But on Presidents' Day the projected 8am demand was much higher than this extreme case -- 74.5 GW, equal to the ERCOT all-time summer peak in August 2019. And the average available generation supply that day ended up being at 49.0 GW, a dramatic shortfall that led to the outages called by ERCOT at 1:23am that morning. Without question, the planning process needs to be changed, and significantly. As a Houstonian who has lived through three major hurricanes, a drought and two monster winter storms since 2005, I can assure you that the weather isn't what it used to be, and we must model, and prepare for, more extreme cases in our infrastructure planning.

Figure 3 compares the performance of the various generation resources connected to the ERCOT grid with their actual performance on Presidents' Day. A comparison of the Dependable Capacity in ERCOT's seasonally-adjusted resource adequacy study (column 3) with the actual Average Generation (column 4) shows a large drop-off of generation across the board. Another view of the hourly sources of generation over February 5-18, 2021 against the temperature is shown as the final page of the Appendix.

Figure 3: Analysis of ERCOT Presidents' Day Generation Resources

	Winter Nameplate Rating (MW)	Winter Dependable Capacity (MW)	2/15 Average Generation (MW)
Gas	51,523	51,523	32,108
Wind	28,755	7,070	3,153
Coal	13,630	13,630	8,616
Nuclear	5,153	5,153	4,141
Solar	4,898	304	805
Hydro & Biomass	619	499	189
TOTAL	**104,578**	**78,179**	**49,102**

Source: ERCOT, EIA

Regulators use a mixture of rules and incentives are used to achieve resiliency in power markets. State governments have passed regulations in many of these areas, and NERC has adopted standards applicable in most areas. These come with penalties for non-compliance. Regulators use carrot-and-stick incentive/penalty structures, which can drive technological innovation and creative solutions to resiliency challenges. PJM and ISO New England's capacity performance markets are one example of this; Texas' energy-only market with price caps set up to the "value of lost load" is another.

In 2016, Texas regulators introduced an administrative price adder to increase market clearing prices as excess capacity dwindled, sending an earlier and more pronounced price signal to both supply and demand resources. As the numbers in Figure 3 above show, last month Texas had plenty of steel in the ground, but not enough of that steel capacity worked to produce energy when Texans needed it most.

We don't yet know the reasons why each of those generators failed to be available when we needed them last month, so I'm not jumping to conclusions and solutions yet. If the data show there were inadequate steps taken to preserve power infrastructure, then we need a weatherization solution, possibly a mandate, much like airline safety standards. If the data indicate shortcomings in the natural gas production and delivery systems that support about half of the power in ERCOT, that has different solutions. Those may include gas wellhead, processing plant and pipeline weatherization and a requirement for gas-fired power plants to have dual-fuel backups or on-site LNG storage, as we have in New England. If commercial issues are a major cause of failure to perform, that leads to possible solutions including changes in power plant gas contract requirements or when "force majeure" can be invoked.

Transmission is an important resilience measure because severe weather and other disruptions are not as geographically broad as the entire grid. In many previous events, transmission delivered available supplies from neighboring states and regions to the region hardest hit. We do not have a good way to pay for lines between regions. Improved planning processes and tax credit for inter-regional transmission might improve the economics of lines around the country that have been proposed but do not have any clear customer or market to reward their impact or reliability and resilience.

Issues relating to physical and cyber attacks on the power system are serious resilience threats that also deserve attention. One discrete issue that did arise when I chaired FERC related to the lack of availability of key transmission and distribution equipment from domestic sources. If transformers are damaged, their replacements from overseas can take months to be delivered and installed. To my knowledge, we still do not have enough spare transformers to mitigate this risk. The recent SolarWinds cyber attack indicates potential areas of vulnerability as well. Electromagnetic Pulse is another relevant threat being addressed by the Department of Homeland Security.

Resilience is broader than just the power system – as this Texas event, Hurricane Harvey and other past disasters have shown, resilience also encompasses the question of, how prepared are our communities and fellow Americans to cope when unexpected events happen? And what can we do at the local level to mitigate the negative social impacts? Do we have backup generation, water, temporary housing, medical equipment, and telecommunications to address the gap when our interdependent critical infrastructures fail under extreme weather and other attacks? Over the longer term, issues like building codes come into focus as well.

The core lesson from recent experience is that we have not been aggressive or creative enough to imagine and model the breadth of "black swan" events that could occur. Although we hope these events will not happen, it is our collective responsibility to assume that they might, and to plan for them accordingly.

Affordability

The bottom line is, how much risk are we willing to prepare for and insure against, and how do we pay for those preparations? As a utility regulator, my fundamental job was to look at how the energy (and telecom) industries could best support economic development in Texas and the nation. Having straddled the divide between traditional cost-of-service regulation and modern market-based competition, I can assure you the competitive model is the better way to bring price, service and technological innovation benefits to customers. Texas was once the nation's 21st most expensive state in terms of power rates; now it is the 43rd. This has enabled significant business growth and improved customer welfare. (In the appendix, find my rebuttal of a recent inaccurate news story on this issue). Even in parts of the nation where electric competition is not as robust, the presence of market prices is a helpful reference point for regulators, investors and elected officials. Importantly, "competition" does not mean "deregulation," as reliability, economic and customer protection regulations still apply in competitive energy sectors.

In my career, I have had first-hand experience with a number of reliability events: the 1989 Texas winter outage, the 2000-2001 Western Markets energy crisis, the 2003 Northeastern North America Blackout, the 2011 Groundhog Day Texas outages, the 2014 Midwest polar vortex, the 2018 New Years' Northeast winter and the 2021 Texas Presidents' Day outages. All of these show that achieving a reliable, resilient energy system has a cost.

While we have occasional transmission outages, the redundancy and oversight of the transmission system generally has kept those outages from harming customers directly. Distribution outages, often weather driven, tend to be more frequent and more localized, and they do affect customers directly. Customers have expectations about how long their power may be out – those expectation generally relate to where you live and what caused the outage. But generation supply outages are rare. Texas has experienced a supply event roughly every ten years. Customers expect that the redundancy and diversity of power supply will always be sufficient. Last month in Texas, it was not.

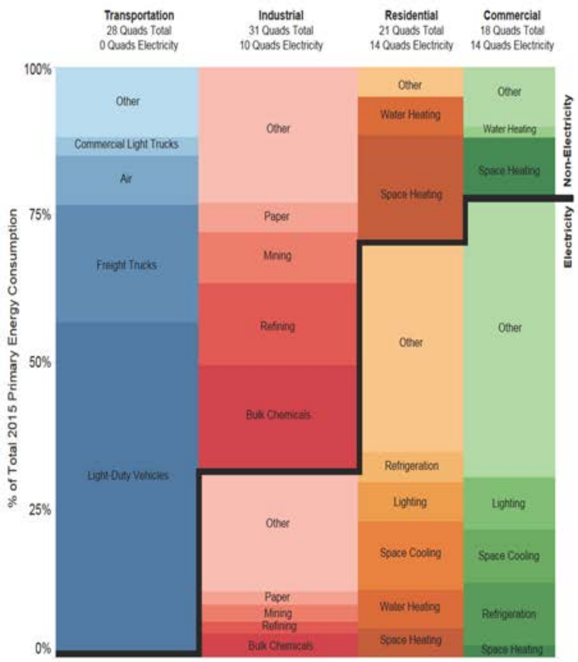
Prices in wholesale energy markets, like those of many other commodities, have always been volatile. For that reason, retailers, utilities, and marketers perform the valuable function managing the volatility risks in power procurement through contracts and financial instruments, and engaging with end-use customers in mitigating the price impacts. The party that bears these risks varies depending on the regulatory regime. Under the traditionally regulated, vertically integrated utility model, all costs are reviewed by regulators and, if approved, passed through on customer bills. In a more competitive environment, customers can select among different rate plans, including a fixed-price, fixed-term supply contract from one of many suppliers. Such contracts, selected by over 90 percent of Texas retail electric customers, push the risk (and reward) of managing the price volatility onto the energy supplier. Suppliers who are less successful in managing those risks are pushed out of the market.

After the financial costs from expensive Texas Presidents' Day event period are finalized, I expect we will see all of these outcomes. Regulated utilities inside ERCOT will recover many costs from their ratepayers, and some retailers will exit the market moving their customers to a PUCT-approved provider. But most customers, who mostly have fixed-price power contracts, were not exposed to the high real time prices and will pay their regular rate for their monthly consumption.

Affordability requires tradeoffs. Do we design hospital intensive care capacity to account for a once-a-century pandemic? Should southern state highway departments invest in salt trucks and snow plows that sit idle until the next ten-year major winter storm? The more modular and cheaper a fix is, the easier it is to just use more redundancy to improve resilience. Many types of lower-cost technologies are starting to come into the power industry. Many are options like energy efficiency, photovoltaics and storage, that customers can adopt directly, reducing their dependence on the power system.

As Figure 4 shows, there are large segments of our economy that could be electrified. This will be a large growth driver – and challenge -- for the power industry. The flat load growth we have experienced over the past 15 years, due to efficiency gains, is only temporary. The coming growth in electric demand will trigger the need for more (likely low-carbon) resources, but these greater volumes will provide a larger base over which to spread the expected greater costs.

Figure 4: Potential Electrification of the U.S. Economy



Source: NREL

<u>Changing resource mix</u>

Our nation has diverse resource capabilities and no single national power portfolio. The Pacific Northwest is rich in hydropower; the Midwest, coal; the Plains states, wind; the Southwest, solar; and many regions, natural gas.

Texas is blessed with as many energy resources from above the ground as we have below ground. That affects how we can think about the future for the country. Renewables have become the dominant additions to the power system because their costs have fallen so dramatically over the last 15 years. Driven by customer demand, an open market and the elimination of many barriers to entry, large numbers of wind farms, solar plants, and storage facilities are being built across

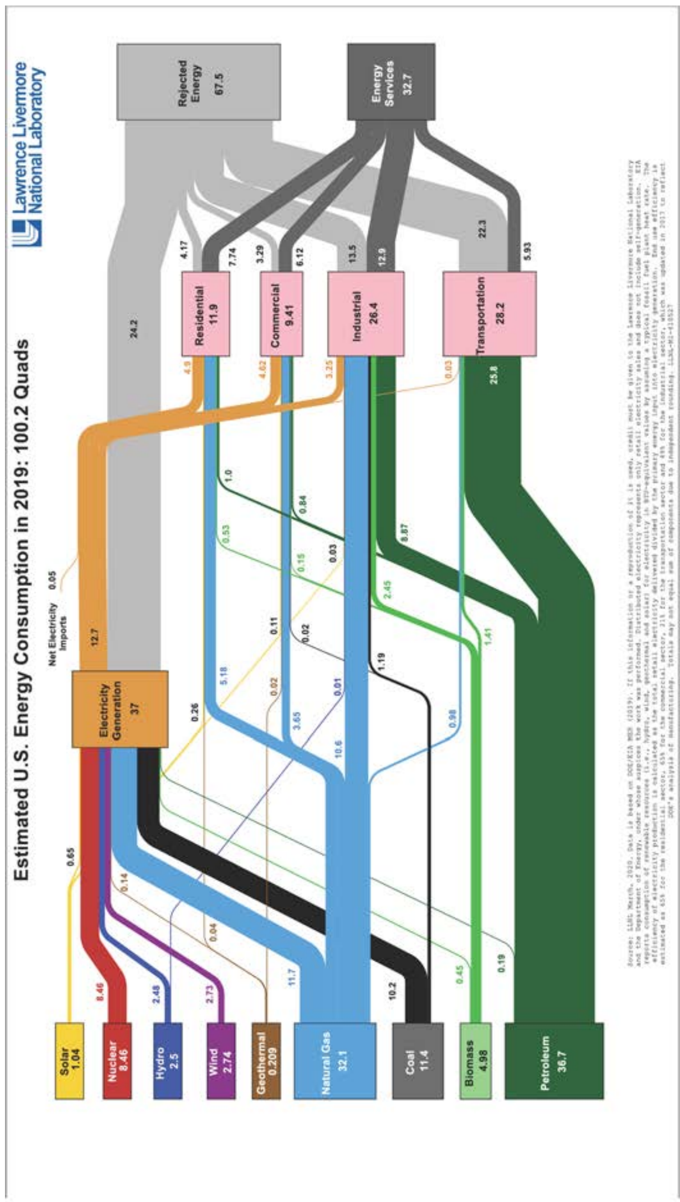
Texas to develop this rich resource base. In just two decades, Texas has added enough wind to become the nation's leader in wind production, and added enough solar to become second in solar production. Although Texas adopted our renewable portfolio standards (RPS) in 1999, mostly private investment has shot through all of our renewable resource mandates and goals. Today, in a post-RPS market, customer demand and low resource costs have yielded over 30,000 MW of in-state renewable investment, with an additional 60,000 MW of proposed projects in various stages of regulatory review.

This means that the Texas power grid is where the low carbon future is already being realized. We continue to learn how to better hit the balance between affordability, reliability and the environment. If something doesn't work right, we will fix it – and, using the innovation and creativity that our open system has welcomed for a generation now, we will build it back better than before. We have no alternative.

The variable nature of wind and solar resources mean we will continue to need a diverse set of firm, low-carbon generation and storage resources at the bulk system and customer levels, plus transmission and energy efficiency. What I lived through with the Presidents' Day outages, though, makes it clear to me that we will need a diverse resource mix for many years to come. Four-hour batteries, cloudy skies and still winds cannot keep the lights on for a week or longer. Over the past three weeks, I have read more about carbon capture use and sequestration (CCUS) technology than ever before. I thank you for using the proven two-pronged approach of federal tax incentives and public R&D dollars to stimulate innovation in CCUS, and I ask you do more. The same goes for small modular reactor nuclear technology, which could become a cost-effective and durable addition to power grids across the nation in the future.

We are swiftly moving to the day when we get a much larger percentage of energy in a given year from low variable cost, low/zero carbon resources. But during critical stress periods, I want to know that firm and dispatchable resources will also be there – although not working as many hours of the year as they do today, and not emitting as much, if any, CO_2. We will have to figure out new, market-based ways to pay for that dispatchable resource availability. We figured out how to perfectly land that dune-buggy on Mars last month; we'll figure out how to clean up (or offset) fossil fuel supply and emissions impacts. I don't ever want to have to look at the Daily Outlook graph on my ERCOT app again and worry about how keep the lights on.

The easiest solution to both reliability and pollution is the energy you never need to consume -- efficiency. My politics run conservative, and the operative root word there is "conserve." The most impactful chart in my career is the annual Lawrence Livermore National Lab's Energy Flow Chart (next page). I am struck by the level of "rejected" (wasted) energy in our overall system (upper right light gray box) and know we have a long way to go to shrink that box. Reducing that wastage should be task number one on our national to-do list because efficiency will save us money, protect our neighbors, create good jobs, enhance our global economic competitiveness, and take some pressure off of the supply side of our energy infrastructure. Good bipartisan energy policies already point in that direction, and I have faith that market-driven innovation will get us there.


Estimated U.S. Energy Consumption in 2019: 100.2 Quads
Lawrence Livermore National Laboratory
Solar 1.04
Nuclear 8.46
Hydro 2.5
Wind 2.74
Geothermal 0.209
Natural Gas 32.1
Coal 11.4
Biomass 4.98
Petroleum 36.7
Net Electricity Imports 0.05
Electricity Generation 37
Residential 11.9
Commercial 9.41
Industrial 26.4
Transportation 28.2
Rejected Energy 67.5
Energy Services 32.7

LETTER TO THE EDITOR, WALL STREET JOURNAL

Dear Editor,

Your February 24th story on Texas power rates is incorrect and misleading. Opponents of competition reheat this tired idea every couple of years, but I was disappointed to see it in the likes of the Journal.

As a part of their flawed and impossible to replicate analysis, your reporters assert that the most recent average Texas competitive rate was 13 cents per kilowatt-hour. But, just a short week after a severe test of our energy markets, every single one of the 88 residential plans on the state-sponsored clearinghouse website (powertochoose.org) prices the average kwh charge at less than 13 cents, and three-fourths of the rates offered average less than 11 cents. (2000 kwh usage, Houston, 3 to 48 month fixed-rate plans).

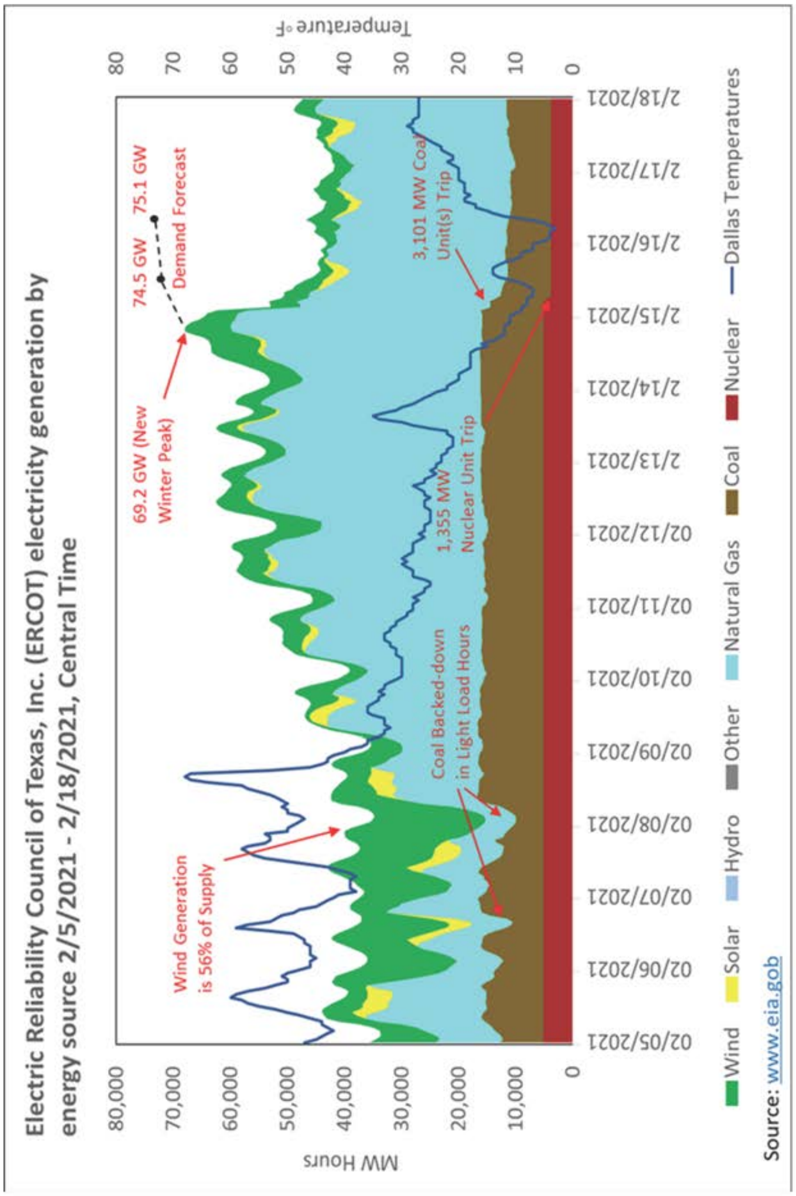
Commercial and industrial customers have similarly benefitted from our competitive wholesale and retail markets. Furthermore, the EIA* itself ranks Texas at the bottom (#43 out of 50) of the list of states on retail electricity rates.

Regulated utilities that had to purchase additional gas and electricity at high prices last week have already announced their plans to charge those excess costs from their captive customers. In the competitive retail market, practically all have fixed contracts and are free to choose a more attractive offer if their supplier tries to bill them for past losses. Businesses that bet wrong own that risk, not captive "ratepayers."

Mother Nature took a swing at Texas last week, and we have problems to fix – which we will – but the Texas competitive electricity system will continue to support our strong economy.

Pat Wood III
Houston, Texas
(713) 454-9592
pat@patwood.net

Wood is past chairman of the Public Utility Commission of Texas and of the Federal Energy Regulatory Commission


Electric Reliability Council of Texas, Inc. (ERCOT) electricity generation by energy source 2/5/2021 - 2/18/2021, Central Time
MW Hours
Temperature °F
Wind Generation is 56% of Supply
Coal Backed-down in Light Load Hours
1,355 MW Nuclear Unit Trip
69.2 GW (New Winter Peak)
74.5 GW
75.1 GW
Demand Forecast
3,101 MW Coal Unit(s) Trip
Wind
Solar
Hydro
Other
Natural Gas
Coal
Nuclear
Dallas Temperatures
Source: www.eia.gob

The CHAIRMAN. Thank you, Mr. Wood.

Now we are going to have Mr. Michael Shellenberger, Founder and President of Environmental Progress.

STATEMENT OF MICHAEL D. SHELLENBERGER, FOUNDER AND PRESIDENT, ENVIRONMENTAL PROGRESS

Mr. SHELLENBERGER. Thank you and good morning, Chairman Manchin, Ranking Member Barrasso and members of the Committee. I'm grateful of the Committee for inviting my testimony.

In its 2017 report the National Academies of Science warned that our electricity grids were becoming increasingly complex and vulnerable due to restructured energy markets and the increased use of variable energy sources. While all energy sources failed to perform as anticipated in mid-February, some performed better than others. The capacity factors for nuclear, natural gas, coal and wind in Texas during the four days of load shedding were 79 percent, 55 percent, 58 percent and 14 percent, respectively. Experts today agree that weather-dependent energy sources over the last decade have made the grid more sensitive to extreme weather. Last August, California's grid operator attributed, on a conference call, the lack of energy supply to the state's closure of nuclear and natural gas plants and its overestimation of what renewables could contribute. California's share of non-hydro renewables increased from 14 to 39 percent of electricity from 2011 to 2020. The impacts on affordability were serious. Our cost of electricity rose eight times more than the rest of the United States. And today, Californians pay 50 percent, over 50 percent more, than the national average.

Economists at the University of Chicago found that electricity customers in 29 states had paid $125 billion more for electricity than they would have in the absence of renewable energy mandates. What makes electricity reliable, resilient and affordable is the generation by a few large, efficient plants with the minimal necessary wires and storage. I think this is the most important conclusion. The basic picture is that a simpler grid is more reliable, resilient and affordable, creates more reliable, resilient and affordable electricity. Industrial solar and wind projects require between 300 to 400 times more land than nuclear plants or natural gas plants and the best available science calculates that if the U.S. were to try to generate all of its energy with renewables, we would need to increase the amount of land required for energy from 0.5 percent to 25 or even 50 percent.

Opposition to significantly expanding transmission comes from communities and conservationists across the U.S. For example, a federal judge last year blocked a transmission line at the behest of plaintiffs proposed to be built straight through a whooping crane habitat in Nebraska because transmission lines are the number one cause of mortality among whooping cranes. Most of today's storage lasts for minutes, not hours, not months, or seasons. We see the impact of this in Germany. In January and February of this year, Germany's renewables produced just two-thirds of the electricity they produced in January and February of last year despite a four percent increase in solar panel and wind turbine capacity, simply because of annual variability of wind and sun. Germany has only been able to manage the seasonal fluctuations from intermittent renewables by maintaining diverse fleet of coal, natural gas and nuclear power plants and at a very high cost. France, today, spends just over half as much per kilowatt of electricity that produces one-tenth of the carbon emissions of German electricity and that's because France's grid is preponderantly nuclear, whereas Germany is phasing out nuclear.

The most influential proposal for 100 percent renewable energy in the United States relies upon a tenfold increase in the power of existing hydroelectric dams in the United States, but the real potential of pumped hydroelectric storage, according to the Department of Energy, is just one percent of that. California has a major network of dams but we haven't converted them into batteries because you need just the right kind of dams and reservoirs. It's a very expensive retrofit and we need the water for our farms and cities. As a result, California has had to curtail electricity coming from our solar farms and pay Arizona to take excess electricity during sunny days.

The U.S. has reduced its greenhouse gas emissions between 2011 and 2020 more than any other nation in history. But now, emissions prices and resiliency risks are rising if the U.S. closes the nuclear reactors in California, Illinois, Michigan, Ohio, New York and Pennsylvania that prevented wider power outages over the last three years. Although Texas lost one of its four nuclear reactors after cold water affected a sensor automatically shutting down a reactor, it returned to service within 36 hours, helping to end the power cuts. Meanwhile, nuclear reactors in other cold snap states operated normally.

The Senate can play a constructive role by taking action now to prevent the closure of these nuclear plants which have proven essential to maintaining a diversity, reliability and affordability of supply as well as, I might add, the sustainability of our energy mix.

Thank you very much.

[The prepared statement of Mr. Shellenberger follows:]

Testimony
before the
United States Senate
Committee on Energy and Natural Resources

For a hearing to examine the reliability, resiliency, and affordability of electric service in the United States amid the changing energy mix and extreme weather events

Written statement submitted by:

Michael D. Shellenberger
Founder and President
Environmental Progress
2569 Telegraph Avenue
Berkeley, CA 94704

March 11, 2021

Good morning Chairman Manchin, Ranking Member Barrasso, and members of the Committee. I am grateful to the Committee for inviting my testimony, and for your willingness to hear from someone who is neither a grid operator nor an electric industry participant, but someone whose perspective has been shaped by two decades of research, writing, and action motivated by a concern for necessary improvements in the reliability, affordability and environmental sustainability of electric service.

Congress took questions relating to the security of America's electricity supply seriously before more than a dozen states experienced energy shortages last month, but those events make this hearing all the more urgent. In 2012, 2017, and 2021 the National Academies of Science and Engineering published three separate reports on threats to the grid, resilience, and the future of electricity. [1] In its 2017 report, the Academies warned that U.S. electrical grids were increasingly "complex and vulnerable."[2]

Over the last 25 years, increasingly decentralized electricity generation in restructured electricity markets, along with growth in the number of regulatory institutions, has resulted in "divergent interests of federal, state, regional and local authorities," wrote the Academies in the 2021 report. Electricity experts are not able to clearly answer the question, "who is in charge of planning, developing and ensuring the integrity of the future power system?"[3] The Federal Energy Regulatory Commission and-the North American Electric Reliability Corporation are tasked to ensure electrical grid reliability and resilience. However, the Academies noted, "they too face short-term pressures and fiscal constraints."[4]

Meanwhile, many experts see in recent trends an inevitable transition away from coal and nuclear power plants, designed to function as baseload capacity, toward variable renewable energy sources with just-in-time natural gas back-up. The price of solar panels and wind turbines has declined 75 percent and 25 percent, respectively, since 2011.[5] The U.S. Energy Information Administration ("EIA") estimates renewables will be a larger source of electricity than natural gas in the United States by 2050. In that same time, EIA projects renewable electricity will rise from 28 percent to 50 percent of global generation.[6]

But events in mid-February throughout the center of the country, including Texas, and last summer in California, suggest that attempting to replace nuclear plants with variable renewable energy sources could make electricity grids less resilient. While energy sources across all categories failed in mid-February, they didn't all fail equally. The capacity factors for nuclear, natural gas, coal, and wind in Texas during the four days of load shedding during the cold snap were 79 percent, 55 percent, 58 percent, and 14 percent, respectively.[7]

Nuclear plants are among the most reliable components of America's power grids. Nuclear plants operate as a national fleet at 94 percent annual capacity factor, thanks to tightly choreographed refueling operations that barely interrupt eighteen-month continuous uptime at most facilities.[8] The hardening required of nuclear plants first in response to 9/11 and then in response to the loss of Fukushima Daiichi in 2011 has further ensured their contribution to reliability, resiliency, and affordability.[9]

Although Texas lost one of four of its nuclear reactors after cold water affected a sensor, automatically shutting down the reactor, it returned to service within 36 hours, and thus in time to help end the power cuts. Meanwhile, nuclear reactors in other cold snap states, Nebraska, Kansas, Arkansas, Missouri, Illinois, Minnesota, Wisconsin, Ohio, and Michigan, operated normally.[10]

Even if all Texas wind turbines had been winterized, it is unlikely that they would have contributed significantly to electricity supply because wind speeds in cold snaps are so low. It is for that reason that grid operators do not rely on wind turbines to provide more than trace amounts of power during those periods. And, indeed, while wind turbines north of Texas functioned more or less as intended, during the cold snap, they produced very little power for their grids.[11]

Part of the reason for inadequate in-state electricity supply in California last August was that state regulators had closed in-state baseload power plants. "People wonder how we made it through the heat wave of 2006," said the CEO of California's grid operator, CAISO, at the time. "The answer is that there was a lot more generating capacity in 2006 than in 2020.... We had San Onofre [nuclear plant] of 2,200 megawatts, and a number of other plants, totaling thousands of megawatts not there today."[12]

Electricity lost from the closure of California's San Onofre nuclear plant undermined electricity affordability as well as reliability. It was mostly replaced by electricity from natural gas, which raised the costs of generating electricity by $350 million.[13]

California regulators in 2020 over-estimated the contribution they could reasonably expect from renewables. "The situation could have been avoided," said the CEO of CAISO. "For many years we have pointed out that there was inadequate supply after electricity from solar has left the peak. We have indicated in filing after filing after filing that procurement needed to be fixed. We have told regulators over and over that more should be contracted for. That was rebuffed. And here we are."[14]

Texas and California show that policymakers and regulators have struggled to manage the grid's high and rising level of complexity, with troubling consequences. Are we so confident that reducing energy diversity while pushing more variable energy onto electrical grids is the best path forward in terms of reliability, affordability, and sustainability?

Affordability and Sustainability: Lessons from Around the World

California offers a relevant real-world picture of the impacts of significantly expanding reliance on variable renewable energy sources while reducing reliance on nuclear energy. California significantly expanded its use of renewable energy starting in 2011. That year, California generated 13.5 percent of its in-state electricity from all non-hydroelectric renewables. In 2020, California generated 39 percent of its in-state electricity from them.[15] As a consequence of purchasing and integrating variable renewable energy onto its grid, California's electricity prices rose 39 percent in the decade from 2011 to today, despite persistently-low-priced natural gas, which made doing so easier and more affordable.[16]

California retail electricity prices rose eight times faster than the nationwide average between 2011 and 2020. Today, California households pay 55 percent more than the national average per kilowatt-hour of electricity. In 2020, California's electricity prices rose 7.5 percent, compared to just 0.25 percent in the other 49 states.[17]

The impact of variable renewable energy sources on electricity prices can be seen in the more than two-dozen states that have had in place renewable energy mandates. "Cumulatively," wrote the authors of a University of Chicago report on the impact of variable renewables on electricity prices, "consumers in the twenty-nine states studied paid $125.2 billion more for electricity than they would have in the absence of the policy." The study authors concluded that higher variability was the main driver of higher costs.[18]

With France and Germany, we can compare two major (sixth and fourth largest) economies, which are highly proximate geographically and at similarly high levels of economic development, on a decades-long time scale.[19] France spends just over half as much per kilowatt-hour for electricity that produces one-tenth of the carbon emissions of German electricity.[20] Electricity prices in Germany have risen 50 percent in the 15 years since 2007.[21] In 2019, German electricity prices were 45 percent higher than the European average.[22]

A study published in late 2019 found that Germany's nuclear phase-out is costing its citizens $12 billion per year.[23] In response to Fukushima, the Japanese government shut down its nuclear plants and the cost of electricity went up. As a result, 1,280 people died from cold from unaffordable electrical power, researchers calculate, between 2011 and 2014.[24]

Some of the cost of variable renewable energy sources comes in the form of the transmission lines they require. With funding from Bill Gates, the analytical group Breakthrough Energy Sciences last week estimated the U.S. could reduce carbon emissions 42 percent and generate 70 percent of its electricity from carbon-free sources by 2030. But Breakthrough Energy calculated that the cost of new transmission, distribution, and storage would be $1.5 trillion.[25]

And that amount does not include the costs associated with local and state political opposition. In their 2021 report, the Academies noted that while variable renewable energy sources like solar and wind appear to be popular in public opinion surveys, "political uncertainties concern the durability of policy support for renewables when deployed at large scales, especially where it is highly visible and potentially conflicts with other land uses."[26]

Local community and environmental opposition to transmission is a national and international phenomenon. A federal judge last year blocked a transmission line proposed to be built straight through whooping crane habitat in Nebraska because transmission lines are the number one cause of mortality among whooping cranes.[27] Of the 7,700 new kilometers of transmission lines Germany needed for the energy transition, only eight percent have been built. Community and conservationist resistance has been a significant factor.[28]

The land requirements of industrial renewable energy projects are two orders of magnitude larger than those of nuclear and natural gas plants. Industrial solar and wind projects require between 300 and 400 times more land than nuclear plants.[29] If the United States were to try to generate all of the energy it uses with renewables, 25 percent to 50 percent of its land would be required, according to the best-available study by a leading energy analyst and advisor to Bill Gates.[30] By contrast, today's energy system requires just 0.5 percent of land in the United States.[31]

Many energy experts are enthusiastic about solar panels, but new information has called the social and ethical value of the technology into question. The average annual pay of a power plant operator is $79,400 per year versus $46,900 for a solar installer, according to Bureau of Labor Statistics data analyzed by NBC News. [32] That appears to be in part because so much of the economic value of solar panels is at the place of manufacture, not installation.[33]

As troubling is evidence that cost declines of solar panels, most of which are made in China, appear to stem from the involuntary labor of a persecuted Muslim minority, the Uighurs. In January the U.S. State Department deemed China's treatment of the Uighurs to be genocide.[34]

Ninety-five percent of the global solar panel market contains Xinjiang silicon. While there has been talk of bringing solar manufacturing to the U.S. and Europe, doing so would significantly increase prices.[35] There is proposed Senate legislation to ban imports from Xinjiang unless they are certified, and similar legislation in introduced into the House. But given the fungible nature of silicon, some fear the Chinese government could evade such controls.[36]

And more decentralized electrical generation makes the grid more vulnerable. "We're adding a lot of stuff at the grid edge," said the lead author of the Academies' 2012, 2017, and 2021 reports, "and if I start building microgrids does that increase my potential vulnerability? The answer is, 'Yes, of course. The more complicated I make it, the more attack surfaces and, hence, the more possibilities of failure.'"[37]

The Costs of Maintaining Reliability With Variable Renewable Energies

While the switch from nickel-cadmium to lithium-ion batteries allowed for the proliferation of cell phones, laptops, and other electric appliances, it has not allowed and will not allow for the cheap storage of the grid's electricity. One of the largest lithium battery storage centers in the world is in Escondido, California. But it can only store enough power for about twenty-four thousand American homes for four hours.[38]

And storage does not easily solve the problem of long-term, seasonal variability. In January and February of this year, Germany's renewables produced just two-thirds of the electricity they produced in January and February of 2020, despite a four percent increase in solar panel and wind turbine capacity, simply because of annual variability of wind and sun.[39]

Germany has only been able to manage the seasonal fluctuations from intermittent renewables by maintaining a large and diverse fleet of coal, natural gas, and nuclear power plants. Germany added 150 percent of its total capacity in coal, natural gas, and nuclear in the form of new wind and solar capacity, which was part of why Germany's electricity prices have risen to the highest levels in Europe.[40]

One study by a group of climate and energy scientists found that when taking into account continent-wide weather and seasonal variation, for the United States to be powered by solar and wind, while using batteries to ensure reliable power, the battery storage required would raise the cost to more than $23 trillion.[41]

Most proponents of variable renewable energy thus look elsewhere for storage solutions. The most influential proposal for 100 percent renewable energy in the U.S. was created by a Stanford professor who relied on the conversion of existing hydroelectric dams into giant batteries.[42]

But in 2017, scientists writing in the *Proceedings of the National Academies of Science* observed that the 100 percent renewable proposal rested upon the assumption that we can increase the amount of power from U.S. hydroelectric dams ten-fold when, according to the Department of Energy, the real potential is just one percent of that. Without all that additional hydropower, the 100 percent renewables proposal does not work on its own terms.[43]

California is a world leader when it comes to renewables and has a major network of dams but hasn't converted them into batteries because you need the right kind of dams and reservoirs, and even then, it's an expensive retrofit. In addition, there are many other uses for the water that accumulates behind dams, namely irrigation and water supply for cities. Without large-scale ways to back up solar energy, California has had to block electricity coming from solar farms when it's extremely sunny, and pay neighboring states to take it, in order to avoid adding much energy on the grid during hours of peak solar production.[44]

Germany will have spent $580 billion on renewables and related infrastructure by 2025, according to energy analysts at Bloomberg[45] and Germany generated 37.5 percent of its electricity from wind and solar in 2020, as compared to the 70 percent France generates from nuclear.[46] Had Germany invested the $580 billion it's spending on renewables and their grid upgrades into new nuclear power plants instead, it could be generating 100 percent of its electricity from zero-emission sources and have sufficient zero-carbon electricity to power all of its cars and light trucks (if electrified) by 2025, as well.[47]

From this information we can gain a clearer picture of electric reliability, resiliency, and affordability. What tends to make electric grids more reliable, resilient, and affordable is the generation of electricity by a few large, efficient plants with the minimal amount necessary of wires and storage. What tends to makes grids less reliant, resilient, and affordable is significantly increasing the number of power plants, wires, storage mechanisms, people, and organizations required for operating them.

Loss of Nuclear Plants Threatens Reliability, Affordability, and Sustainability

The U.S. reduced its greenhouse gas emissions between 2000 and 2020 more than any other nation in history in absolute terms, according to preliminary analysis by the Rhodium Energy Group. U.S. greenhouse gas emissions in 2020 were 21 percent below 2005 levels, which is nearly a one-quarter larger reduction than that promised by the United States under the Copenhagen Accord target of a 17 percent reduction. Even without the pandemic, emissions would have declined 3 percent in 2021, Rhodium estimates.[48]

The premature closure of nuclear plants threatens reliability, resiliency, affordability, as well as America's reductions in greenhouse gases. Without state or federal action, the US will close twelve nuclear reactors by 2025, which constitute 10.5 gigawatts of highly-reliable, low-cost, and low-carbon power.[49] Despite ratcheting regulations, the cost of operating America's nuclear plants fell from $44.57 per megawatt-hour on average in 2012 to $30.42 in 2019.[50]

But restructured wholesale electricity markets, low-priced natural gas, and subsidized variable renewable energy have undermined the economics of nuclear power plants, including those that prevented wider power outages during the recent cold snap. Those plants are Byron and Dresden in Illinois, Palisades in Michigan, Davis-Besse and Perry in Ohio, and Beaver Valley in Pennsylvania. If those nuclear plants are lost, grids may suffer from energy shortages during future heat waves or cold snaps.

The U.S. might achieve higher levels of electricity resiliency, reliability, affordability, and sustainability by reconsidering whether nuclear power plants are really so unattractive, and wholesale markets really so efficient.

In restructured markets, as more renewables are integrated into the system, the costs to keep reliable baseload power plants in service keep rising. In Texas, there was no mechanism to ensure that baseload plants were ready for the weather. As a result, many were in seasonal shutdown for repairs, or had not been winterized. In Germany, the government has had to resort to various mechanisms to prevent utilities from going bankrupt.[51]

Restructured electricity markets did not result in the oft-promised lower prices in California, Texas, or the U.S. as a whole.[52] And from 2010 to 2019, consumers from across the U.S. who purchased electricity from electricity retailers paid $19.2 billion more than they would have had they purchased power from legacy utilities, according to a recent ***Wall Street Journal*** analysis.[53]

According to the Academies, the older model of regulated and vertically integrated electric utilities were better at taking a "longer-term perspective" that can take into account "broader societal benefits" than today's tangle of federal and state agencies, electric utilities, and power companies.[54]

While a significant amount of electricity policy is determined by the states, the Senate can play a constructive role in maintaining the reliability, resiliency, affordability, as well as the diversity and sustainability, of our grid by taking policy action now to keep operating the nuclear plants that have been critical to preventing power outages in recent years.

Thank you again for the opportunity to testify and I look forward to your questions.

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The CHAIRMAN. Thank you, Mr. Shellenberger.

Now we have Mr. Manu Asthana, President and CEO of PJM Interconnection.

Mr. Asthana.

STATEMENT OF MANU ASTHANA, PRESIDENT AND CEO, PJM INTERCONNECTION

Mr. ASTHANA. Thank you. Good morning, Chairman Manchin, Ranking Member Barrasso, members of the Committee. My name is Manu Asthana, and I'm the CEO of PJM Interconnection. On behalf of PJM, it's a pleasure to be here with you today and to participate in this hearing and share my perspectives on reliability, resilience, and affordability of the bulk power grid.

PJM is a grid operator. We're based in Valley Forge, Pennsylvania, and our organization was formed in 1927. We have grown over time to now serve 65 million people who live in 13 states and the District of Columbia. We serve one-fifth of the nation's population.

I wanted to start today just by saying that the reliability of the bulk power system is our organization's driving purpose. Watching the human impact of the recent events in Texas has been a sobering reminder of the importance of that purpose. I can tell you that I personally feel the weight of the responsibility that we, as PJM and our members, have to keep the power flowing every day.

I wanted to really cover four points in my opening remarks today.

The first point is that the PJM grid is strong and it has performed well, including during the recent winter storm where we were able to keep the power flowing and actually export record amounts of electricity to support our neighbors in their time of need.

The second point I wanted to make today was that resilience is critical and it takes deliberate effort. We at PJM regularly think about what could go wrong, but there are going to be things that happen that we didn't anticipate. The COVID pandemic is a good example. PJM has had a pandemic plan since 2006, yet so much about this event has been unexpected. We've had to learn. We've had to adapt. We've taken significant steps to preserve our ability to control the grid, including building a third control room and having teams of operators live onsite for up to ten weeks, in some cases, just so that we have a backup plan to our backup plan. Our pandemic response is one demonstration of how seriously we take resilience.

The third point I wanted to share with you today is, notwithstanding the first two points, there is more work to be done both on reliability and on resilience. We at PJM have studied and responded to extreme events, including the 2011 Southwest blackouts as well as the 2014 polar vortex that hit our system. And while we don't have all the facts yet about the recent ERCOT event, there are at least three questions we believe that we and our stakeholders and our regulators must address in our own backyard. The first question is while our approach to winterization has shown dividends, it is an incentive-based approach and we're asking if we need to implement more binding winterization standards and other specific resilience standards for high-impact, low-probability events, no matter if those events are caused by climate change or otherwise. The second question we're asking is whether we need to add circuit breakers to scarcity pricing for power, as well as for gas, during extended periods of shortage or natural disasters. And the final question we're asking is what additional planning and coordination is needed to ensure that inputs to power generation, like natural gas, are protected during load shed events. I'm sure there are going to be more questions, but those are the ones that are on our mind at the moment.

Finally, the fourth point I wanted to share with you today is that the development of renewable generation on PJM's grid is accelerating, and we are committed to ensuring grid reliability through this transition. Today, PJM has over 145,000 megawatts of generation in our interconnection queue. Of this, 92 percent is wind, solar, battery or a hybrid of these technologies. And renewables, while they're intermittent, certainly can carry a portion of the grid reliability needs. We saw that during the winter storm. I'm happy to share some of that data later. However, we must ensure that our markets support an adequate supply of dispatchable, backup generation well into the future, if we're going to keep our grid reliable. We are currently engaged with our stakeholders on this very subject.

Thank you for your focus on these important issues. I look forward to your questions.

[The prepared statement of Mr. Asthana follows:]

U.S. Senate Committee on Energy & Natural Resources

Testimony of Manu Asthana

President and CEO, PJM Interconnection

March 11, 2021

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Contents

Introduction

I am Manu Asthana, president and CEO of PJM Interconnection. On behalf of PJM, it is a pleasure to participate in this hearing and share PJM's perspective on the reliability, resilience and affordability of the bulk power grid.

Based in Valley Forge, Pennsylvania, PJM Interconnection ensures the reliable flow of power to 65 million customers in 13 states and Washington, D.C. As such, we're responsible for ensuring reliable and efficient delivery of electricity over the bulk electric system to one-fifth of the nation.

The PJM grid consists of 85,103 miles of transmission lines and approximately 1,200 generation sources, along with more than 500 demand response and energy efficiency providers. We are interconnected with our neighboring systems in the Eastern Interconnection, which geographically includes over two-thirds of the United States and Canada. PJM delivers power from the high-voltage transmission grid to local distribution utilities, who then are responsible for delivery to end-use customers.

Figure 1. PJM Service Territory

Our markets exist to reinforce grid reliability by ensuring that, in addition to our reliability requirements on generators, market signals work in tandem with those requirements to support reliable operations. For example, our capacity market is designed to procure resources available to meet projected peak demand and other contingencies three years ahead of time. Through our Day-Ahead and Real-Time markets, we produce a security-constrained economic dispatch across our footprint, ensuring that the most efficient and cost-effective mix of resources are called on each hour of each day to achieve reliability at the least cost to customers. In addition, in any given hour we either export excess power supplies to our neighbors or import needed power from those neighbors, which helps support reliable and cost-effective operations throughout the Eastern Interconnection.

Executive Summary

My testimony addresses the three key foundations which are the subject of this hearing – reliability, resilience and affordability. Relative to these three guiding principles, a few key points are central:

- Reliability and security of the bulk-power grid is our first priority and our organization's driving purpose.
- Our grid is strong, with a set of diverse generation resources, healthy reserves, a robust transmission system that is interconnected with our neighbors, and a transparent planning process – each of which helps maintain reliability in adverse conditions. Nevertheless, ensuring the continued strength and reliability of the grid requires our constant attention. We meet this challenge with the strong and helpful support of our transmission and generation owners, our states, our large and diverse stakeholder community, and industry partners such as the natural gas pipeline companies that support gas-fired generators in our footprint. The Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) are important overseers in this effort.
- PJM prepares for threats to the bulk power system by stress testing the system and analyzing literally millions of possible contingencies. This contingency analysis includes analysis of planned as well as unplanned transmission and generation outages, impacts of extreme weather, fuel shortages and other scenarios. Additionally, because it is impossible to foresee every possible contingency, PJM and its members expend considerable effort preparing to recover from unforeseen disturbances on the grid.
- PJM's markets exist to deliver reliability at the lowest cost over time. Our capacity market is designed to procure adequate resources, three years forward, to be available to cover projected peak demand as well as a reserve for contingencies. Our energy and ancillary services markets perform a security-constrained unit commitment and dispatch to ensure selection of the lowest-cost resource mix to serve customers while respecting the physical limits of the grid.
- In addition to reliability, affordable electric service has been one of the bedrock principles since the early development of electricity to light our homes and businesses. Our markets, in combination with our operations and planning functions, are estimated to deliver $3.2 billion to $4 billion in annual efficiencies for customers. As we prepare for the grid of the future, we need to continue to ensure that affordability remains a key component of our collective thinking.
- The transition to a more decarbonized grid has been underway in PJM for the last 15 years, and this now appears to be accelerating as a result of policy choices by a number of our states, technology advances and evolving consumer preferences.
- As we see significant growth in intermittent renewable generation on the grid, ensuring continued reliability will remain our top priority. This will require deliberate and thoughtful effort and partnership among multiple parties, including PJM, our states, our transmission and generation owners and other stakeholders, and regulators such as FERC and NERC. Along with our stakeholders, we are adopting a more precise method to calculate the capacity value of intermittent resources during periods of peak demand. Going forward, we will need to consider new reliability products and services to ensure adequate availability of dispatchable supply resources at all times.

- By the same token, improvements to load and renewable generation forecasting, the setting of reserve margin targets (including consideration of the potential for extreme weather events), as well as enhancing the visibility and dispatchability of distributed energy resources, will all need further development going forward. Thoughtful approaches and carefully synchronized timing of all of these efforts will be needed, both at the PJM stakeholder level and at FERC, to ensure this transition is successful.
- As we have seen in many past situations, events such as extreme temperatures do not always occur as simple stand-alone events. Rather, there is often a correlation of events, such as extremely cold temperatures coupled with ice storms or the potential for multiple cybersecurity intrusions for which we need to plan. PJM is committed to learning from extreme grid events, whether they happen in our region or elsewhere. We will evaluate the analyses of the recent events in Texas in light of lessons learned from our own past experiences. Some key questions we are considering include:
    - *While most generation on our system has prepared for cold weather, should additional FERC policies, NERC standards and PJM rules be established to focus on winterization of resources, and to address additional areas of resilience of both the grid and generating units?*
    - *Should enhanced "circuit breakers" be established in power and gas markets to protect consumers from extreme prices during periods of extended scarcity, market dysfunction or compromised system operation?*
    - *What further coordination with transmission and distribution providers, fuel suppliers and generation owners is warranted to lower the risk that supply of fuel and other critical inputs to the production of electricity is disrupted during stress conditions?*

  Answering these questions will require coordination among PJM, FERC, NERC, the gas industry, states and stakeholders.
- PJM believes that our markets should be designed to accommodate state policies related to the generation resource mix, while also ensuring that we have the products (and adequate compensation to providers) in place, in a timely manner, to meet the reliability needs of the system going forward. We are presently involved in a series of workshops with our stakeholders on these very issues, and it will take continued federal leadership, coordination with our members, states and other stakeholders to accomplish this goal.

Reliability: Job #1

At PJM, reliability is our top priority. We understand the profound implications of what we do and how important electricity is to daily life. We understand that we must prove ourselves every day by ensuring the reliable delivery of electricity that is so central to the economy and health and well-being of the 65 million Americans in our footprint.[1]

PJM has been ensuring reliability at the bulk power level to our region going back to 1927, when three utilities recognized the synergies of sharing power and created the first continuous power pool.

[1] I am attaching to this testimony the white paper "Reliability in PJM: Today and Tomorrow," which provides additional explanation of how PJM addresses reliability through our markets, planning and operations functions.

That value proposition endures today: Both in regions with regional transmission organizations (RTOs) and those without RTOs, the industry has a long history of mutual support. However, PJM's regional approach, operating across a very large footprint with many more resources and tools available, ensures a stronger grid than might exist if every utility in our system had to ensure reliability solely on their own. PJM's rigorous planning process ensures a reliably planned system for the long term over a wide range of operating conditions.

Reliable operation is complex, involving multiple layers of protection. It involves 24/7 system monitoring and dispatch by trained operators, coordination with other operating entities and industry sectors in real time, markets that support reliability and resource adequacy over the long term, and extensive regional transmission planning to ensure the grid is equipped to serve future needs.

Stress Testing: A Key Component of Reliable Operations

Testing for different scenarios and stress testing the system is an integral part of both daily operations and our long-term planning. By way of example, we analyze changes to the expected load forecast due to weather conditions, the effect of the pandemic, and other near-term events, including:

- Maintenance outages of transmission and generating facilities
- Impact of sudden unplanned outages of generation or transmission
- Forecasted adverse weather conditions across the footprint
- Fuel-related contingencies such as loss of pressure or supply on natural gas pipelines that serve PJM
- System stability including the impact of periods of low wind availability

In addition, through our open and transparent transmission planning process, we are analyzing the need for upgrades and new transmission build-outs through a five, eight and 15-year-forward, multi-scenario analysis, which includes:

- Producing a load forecast that accounts for multiple scenarios including factors such as changing weather patterns, different levels of economic growth, and customer-driven energy efficiency and demand response actions that impact electricity demand
- Examining fuel security by analyzing 324 winter scenarios in which we varied factors such as the generation fuel mix, winter weather severity and duration, level of gas availability, oil refueling capability, system-wide forced outage levels, and the number, severity and duration of pipeline disruptions
- Developing an annual Installed Reserve Margin (14.7 percent in 2021) to ensure the availability of sufficient generation resources during stressed system conditions
- Ensuring the stability of the system both under normal and adverse conditions
- Complying with NERC and local reliability criteria
- Finding opportunities to use transmission to lower customer costs through market efficiency projects

- Working with transmission owners on plans to mitigate or eliminate the risk of cyber or physical damage to our most critical facilities through build-outs and upgrades that go above and beyond what is required today under NERC standards
- Providing our states with the tools to develop transmission projects that meet particular state policy goals

In both real-time and day-ahead operations, we are able to utilize a host of tools, rooted in both market signals and longer-range transmission planning, to keep the system operating reliably and resiliently to meet not just normal operating conditions, but when it is necessary to "expect the unexpected."

Addressing Extreme Weather Conditions

I wish to address the issue of preparation for temperature extremes, both from the point of view of PJM operations and, in the separate section below, from the point of view of how PJM's market design reinforces reliable operations.

Although I am not here to say that we couldn't face challenges during extreme weather conditions (indeed, no one can), PJM has a large, multi-state geographic footprint, a diverse fuel mix, a robust reserve margin and strong interconnections with our neighboring systems, all of which help keep the power flowing. Most generating resources in our footprint are built with freezing temperatures in mind, and our members prepare and winterize, in part, because of the nature of the region, which covers much of the Atlantic seaboard and upper Midwest.

PJM and its member companies plan throughout the year for winter – and summer – conditions. We have incorporated into our manuals an extensive pre-winter preparation checklist. This checklist, directed to generators, covers a variety of winterization actions to be undertaken. Generators report the results of their analysis to us through our electronic e-DART reporting system. Even though the reporting is voluntary today, we have received a high level of generator compliance, particularly from those units that otherwise could face the most weather-related impacts. In addition, at the start of the summer and winter season, we conduct emergency response drills with our members and natural gas pipeline operators, and survey generators regarding their fuel inventory.

PJM and members' preparation includes everything from increasing staffing for weather emergencies, if needed, to coordinating maintenance activities that ensure equipment is ready for winter conditions. The extensive preparations of our members, and the close coordination with those members and other stakeholders, support PJM's readiness to address unforeseen outages or other system disruptions. All these elements have contributed to a definite trend of improved performance of our generation resources.

We saw this during the severe weather in mid-February of this year that impacted much of the country. Although the weather was not as cold in most of our region (although we did see extremely cold temperatures in the western portion of our region around Chicago), PJM generators demonstrated high availability to operate reliably under winter conditions. That, combined with a strong transmission system, enabled us to export as much as 15,700 MW of electricity – a record amount – to support our neighbors who were experiencing extreme weather conditions. This was more than three times the megawatts we would export on an average day.

The entire Eastern Interconnection, although stressed in the southwest, was certainly stronger as a result of this massive level of exports and support by PJM to neighboring systems. And, as noted previously, our neighbors have provided us support at times when the shoe was on the other foot, and system conditions in PJM could be alleviated with imports from our neighbors.

Resilience: Beyond Reliability

As we have said, the system is sound today. PJM's transmission system consists of a robust 500 kV and 765 kV "backbone" that has withstood extreme weather conditions and has continued to perform well. However, the grid needs constant attention. Part of that task requires policymakers, transmission owners and grid operators like PJM to address the need for specific improvements to ensure that the grid is not just reliable, but also is resilient going forward, to withstand some of the extreme conditions we could well be experiencing in the future.

The distinction between resilience and reliability has been extensively debated in a now-closed docket before FERC. PJM defines resilience as: "preparing for, operating through, and recovering from events that impose operational risk, including but not limited to, high-impact, low-frequency events that today are not typically addressed by industry reliability standards."

Perhaps as a prime example: We are in the middle of a high-impact, and hopefully low-frequency, event in the form of the COVID-19 pandemic. And while PJM has had a pandemic response plan in place since 2006, this event has demonstrated how we need to "expect the unexpected" and ensure that the system is resilient to withstand those unexpected events.

PJM has responded to this challenge by staying focused on building resilience to the impacts of the pandemic into our operations, remaining flexible and learning as we go. We have successfully run our operations, planning and markets with 90 percent of our workforce working remotely. Operators on campus are now in their second round of sequestration to ensure continued operation of the grid. We improvised a third control room as a backup to our two existing control rooms, which normally support each other. And we have managed to conduct about 400 meetings with our stakeholders, all remotely.

Another example of PJM preparing for a resilient grid can be seen through detailed work we performed on:

- Impacts of future generation unit retirements and changing fuel mix[2]
- Analysis of the security of fuel supplies and fuel delivery mechanisms in PJM[3]
- Potential security disruptions to the natural gas pipeline system and its impact on PJM generation

PJM and its stakeholders continue to add extreme scenarios for consideration in our operations and planning processes.

[2] PJM's Evolving Resource Mix and System Reliability, March 30, 2017

[3] Fuel Security Analysis: A PJM Resilience Initiative, Dec. 17, 2018

Learning from Extreme Events

PJM is committed to learning from extreme grid events, whether these occur in our region or elsewhere, and to using these lessons learned to improve the reliability and resilience of our system. Some examples include:

- Review of Southwest 2011 Winter Event: PJM established winterization steps to be taken by generation unit owners and established a reporting system to PJM, as well as provisions to secure additional reserves to address both winter and summer stressed conditions.
- 2014 Polar Vortex Event: PJM made changes to its capacity market design to provide significant penalties for poor generator performance and payments for superior generating performance during identified stress conditions.
- Gas/Electric Coordination: PJM established protocols with natural gas pipelines serving our region to ensure real-time communication and contingency analysis during times of stressed conditions on the interstate pipeline system.
- 2021 Cold Weather Grid Operations: PJM is carefully monitoring the information coming out of the various reviews in ERCOT and will evaluate lessons learned from that analysis, with an eye toward examining what is applicable to our region. However, I believe at least three important questions arise for broader consideration by PJM, our members and our regulators, given what we know so far:
    1) *While most generation on our system has prepared for cold weather, should additional FERC policies, NERC standards and PJM rules be established to focus on winterization of resources and to address additional areas of resilience of both the grid and generating units?*
    2) *Should enhanced "circuit breakers" be established in power and gas markets to protect consumers from extreme prices during periods of extended scarcity, market dysfunction or compromised system operation?*
    3) *What further coordination with transmission and distribution providers, fuel suppliers and generation owners is warranted to lower the risk that supply of fuel and other critical inputs to the production of electricity is disrupted during stress conditions?*

Answering these questions will require sound coordination among PJM, generation, transmission and distribution owners, FERC, NERC, the gas industry, states and other stakeholders.

PJM Markets Reinforce Reliability & Support Affordability

As I stated earlier, the markets PJM administers serve to reinforce reliable grid operation efficiently. The markets have also opened the door to new, innovative products such as Energy Efficiency and Demand Response, which function to reduce electricity demand and save customers money.

Even fully regulated states benefit from the organized wholesale markets. Utilities located in those states can buy and sell electricity in the markets when they need to, or when it makes economic sense. Regulated utilities and states also benefit from the transparency of wholesale market prices – using them as a comparison when making electricity supply investment decisions.

The PJM market design integrates reliability with affordability by selecting the lowest-cost power source, wherever it is located, to provide electricity to wherever it is needed, subject to physical network transfer limits over a wide region. Our primary markets are the energy and capacity markets. Each market serves a separate function, but they work in tandem.

I will describe the capacity market first, because although it represents about 20 percent of our total market, it is squarely aimed at maintaining reliability. PJM's capacity market was implemented to secure enough power supplies at locations they are needed to make sure that sufficient supply is available to meet peak demand three years into the future, taking into account anticipated outages of individual resources and required reserves for other contingencies. Under a normal schedule, we hold a three-year-forward auction in May. That is extremely valuable from a reliability perspective.

The capacity market also helps provide an investment signal to attract new efficient generation and to retire older, less efficient generation. It can help to avoid some of the volatility we would otherwise see in an energy-only market. The design of the capacity market also results in the purchase of resources beyond the minimum reliability requirement, providing additional reliability for unforeseen events, with each megawatt of reliable supplies beyond the minimum being procured at a declining cost to the customer. Moreover, as noted below, the capacity market has encouraged innovation and led to the penetration of Energy Efficiency and Demand Response as market products that can be called upon to cut demand in times of stress, further bolstering reliability.

Figure 2. Increasing Demand Resources in the Capacity Market

As a result of extreme weather conditions our region realized during the Polar Vortex of 2014, we made notable changes to our market design to ensure that the market both rewards superior generator unit performance and penalizes poor generator unit performance. During the 2014 Polar Vortex, up to 22 percent of generators in our footprint were unavailable as a result of forced outages.

As a result of the winterization procedures, which I described above, along with the incentive and penalty reforms we instituted in 2016, we have seen a notable improvement in generator performance including during periods of extreme weather. Forced outages during the recent cold weather in the PJM region peaked at 9.8 percent during the coldest weather of Feb. 15-17, compared with the 22 percent during the 2014 Polar Vortex, as noted above.

Nevertheless, we are not resting on these past achievements but looking forward to ensure that grid reliability is maintained under a paradigm of more extreme weather and a changing generation portfolio. I address this further in The Energy Transition section on page 10.

The largest of the PJM markets is the Energy Market, making up the majority of wholesale electricity costs. While the capacity market prepares for the future, the Energy Market addresses near-term need. Energy prices are produced on average every five minutes, as the most cost-effective resources across the PJM region are dispatched to serve ever-changing demand.

Available & Affordable Electricity

In aggregate, our markets have helped support an overall decline in total wholesale costs in recent years. Total wholesale prices were $43.41 in 2020, down 38 percent from 2014. PJM's wholesale prices have been essentially flat for two decades and are competitive with other regions of the country. The Energy Market, which is about 60 percent of the PJM markets, saw historic low prices in 2020.

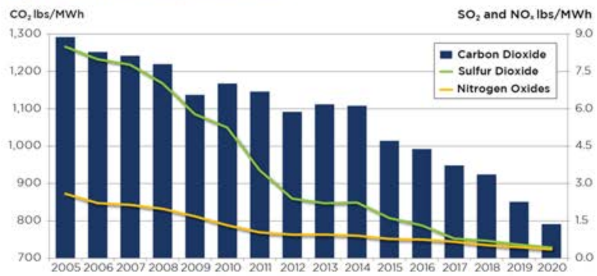
Figure 3. Total Wholesale Cost (2014-2021)

I should also note that wholesale costs are just one component of the overall customer bill. Customer bills include generation and transmission charges for services that flow through PJM as well as distribution-level charges of each utility and, in some cases, additional charges from competitive retailers. Those distribution charges are determined by each state public utility commission.

The Energy Transition

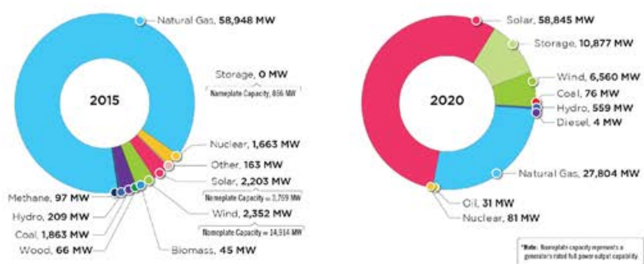
The transition to a more decarbonized grid has been underway in PJM for the last 15 years. Emissions rates in PJM are down drastically since 2005 – CO_2 by nearly 40 percent, sulfur dioxide by 95 percent and nitrogen oxides by 86 percent, driven in part by a transition from coal to natural gas-fired generation.

Figure 4. PJM System Average Emission Rates



As a result of policy choices by some PJM states, evolving consumer preferences and technology advancements, this decarbonization trend appears to be accelerating. PJM's interconnection queue, consisting of generator projects studying the possibility of development and interconnection into PJM's grid, has expanded significantly and is dominated by wind, solar, battery or hybrid projects.

Figure 5. Profile of New Generation Seeking to Interconnect onto the PJM Grid



The continued move toward decarbonization of the electric sector is a reality that PJM is committed to help facilitate in a manner that ensures grid reliability and uses our regional scale and competitive markets, wherever possible, to deliver efficiency for customers. It is a change that has great promise to spur new innovative technologies that can support grid reliability.

Nevertheless, ensuring grid reliability through this transition will require deliberate and thoughtful effort and partnership by and among several parties, including PJM, our states, our transmission and generation owners and other stakeholders, FERC and NERC. The transition drives us and our stakeholders to consider a number of overarching issues, including:

- As we see an increasing level of intermittent resources in the supply portfolio serving PJM customers, we could face energy prices falling significantly, due to declining marginal costs and the fact that these resources using the wind or sun to generate power effectively have no fuel costs. At the same time, we will need to ensure adequate compensation mechanisms for the back-up dispatchable generation – be it fossil generation or batteries – that will be needed given the intermittent nature of renewables. This may make the capacity market even more important in ensuring that we have adequate reserves. As an alternative, RTOs and ISOs could develop and provide compensation mechanisms for new flexible ancillary services. PJM has begun this process with FERC's approval last year of our proposal to improve our overall pricing of reserves needed to maintain reliability each day.
- While the output of intermittent resources is less predictable on an individual unit basis, a substantial portfolio of such resources across a wide, diversified geography will contribute to the capacity needs of the system during peak periods. Along with our stakeholders, PJM is in the process of adopting a more accurate approach, called effective load carrying capability, to calculate the capacity value of intermittent resources during periods of peak demand. This will be an important component of our approach to reliability in coming years.
- Load forecasting, particularly in a post-COVID-19 environment, will prove to be more challenging. We have already made substantial improvements in our load forecasting within PJM. However, as we face the potential for more extreme weather, questions will be raised as to the extent to which we consider the possibility of extreme weather conditions dramatically affecting the demand for electricity, and the level of reserves that we need in order to "expect the unexpected."
- The proliferation of "behind-the-meter" distributed energy resources can enhance reliability and provide customers with new self-help opportunities in times of system stress. However, for this to work well, we will need to ensure adequate visibility as the system operator and the ability, with customer consent, to dispatch those resources as a tool to ensure reliability. We have made a good start on this path through FERC's Order 2222, but this effort will require a great deal of communication, coordination and cooperation among resource aggregators, customers, the system operator and the distribution utility.
- In today's paradigm, we set reliability requirements to avoid a triggering event that could occur in the loss of load under a "one day in ten years" standard. However, as we have seen in many past situations, events such as extreme temperatures don't often occur as simple stand-alone events. Rather, there is often a correlation of events, such as extremely cold temperatures coupled with ice storms, or the potential for multiple cybersecurity intrusions, for which we need to plan. Great strides have been made in how we drill and plan for these multiple events all hitting us at once, as I noted above. But the industry planning standards will need to continue to evolve to incorporate the potential for an increased correlation of multiple events occurring at the same time, and indeed, planning for more extreme scenarios is likely to come at additional cost, which will need to be carefully considered. This will require an increased focus from the industry as a whole as well, as by NERC and state and federal regulators.

I present these not as insurmountable challenges by any means, but as illustration of the need to coordinate the timing and substance of policymaking, industry evolution and technological development, so as to ensure that we continue to maintain a reliable power grid as we transition to a more decarbonized world.

Both the Congress and FERC play a key role in ensuring that the transition I described above occurs smoothly and enhances grid reliability. For one, we need to ensure that the laws and the decarbonization goals that Congress, FERC and the states set can be reliably implemented. The industry *can* adapt, and RTOs are an excellent vehicle – as are the markets they administer – to reflect those policies in investment signals that help develop a cleaner generation fleet. Communication between policymakers and grid operators will be key to crafting workable goals and laws going forward.

On the markets side, there will need to be regulatory support for accommodating state policies regarding the generation resource mix while also ensuring that we have the products (and adequate compensation to providers) in place, in a timely manner, to meet the reliability needs of the system going forward. We are presently involved in a series of workshops with our stakeholders on these very issues.

We are encouraged by a series of technical conferences which the Commission just announced to analyze the impact of climate change on ensuring a resilient grid. At the end of the day, although regional differences exist, policy direction would be helpful to ensure that all regions are working seamlessly toward the same goal using the same playbook and applying the same minimum standards. By the same token, modernizing the existing transmission system will provide a multitude of benefits, including designs that can withstand more extreme events, lower frequency and shorten duration of outages, reduce public and employee safety risks, and use advanced technology to improve system operability, efficiency and security.

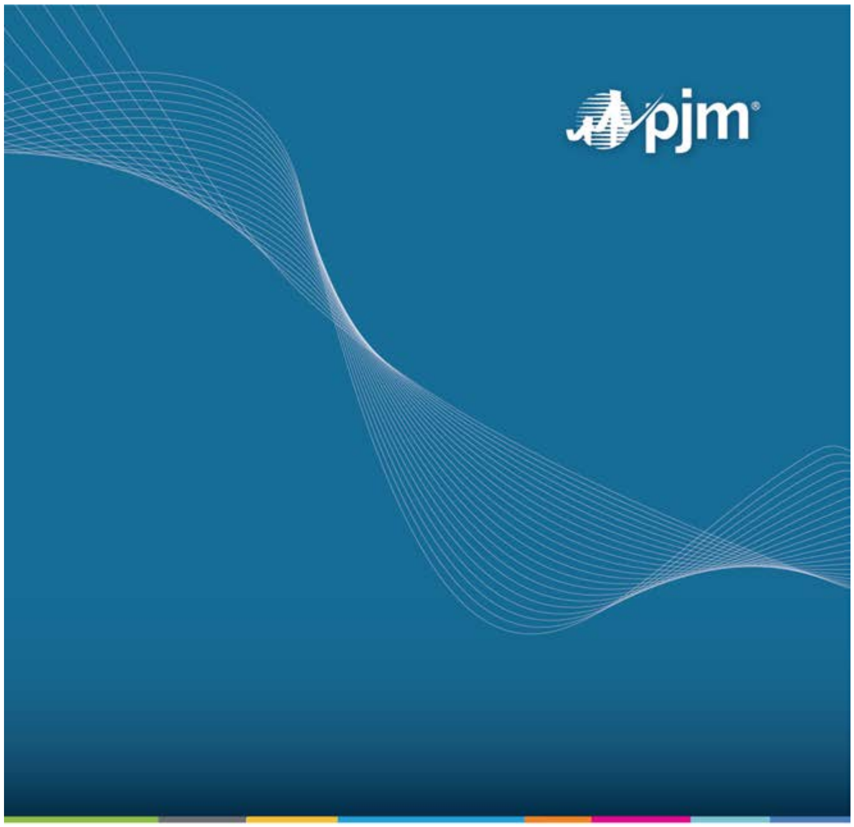
In Conclusion

Thank you again for the opportunity to share PJM's perspectives on these important issues that face our nation.

In closing, I want to reiterate that the reliability and security of the bulk power system continues to be PJM's top priority.

As a large, interconnected grid, we ensure reliability through our markets, operations and regional transmission planning and through the significant efforts of our member companies. PJM is committed to accommodating state policy choices, and as we progress toward the Grid of the Future together, we must do so with reliability at the core of our common purpose and with careful consideration of the costs customers will be asked to pay.

And we look forward to working further with Congress, FERC, NERC and our partners across the energy industry, as well as our states and stakeholders, on additional actions to ensure reliability, affordability and resilience in a changing world.



Reliability in PJM: Today and Tomorrow

Supplement to the Testimony of Manu Asthana

PJM Interconnection
March 11, 2021

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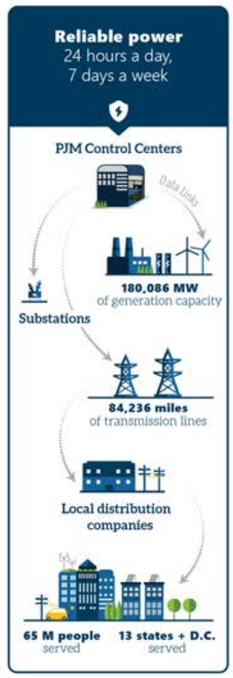
Contents

I. Introduction

Reliable and affordable electricity is essential to modern society. We depend on it every day to power our homes and businesses, and to support critical services such as health care, communications and transportation. This past year in particular has highlighted the need for reliable power amid the global pandemic – allowing people to work and connect remotely while supporting both the treatment of patients and the search for a vaccine.

PJM Interconnection, as a regional transmission organization (RTO), is responsible for the reliable operation of the power grid within its territory, which serves 65 million customers in 13 states and the District of Columbia. PJM works with its member companies to coordinate the production and instantaneous delivery of wholesale electricity across its footprint.

The job of ensuring safe and reliable bulk power system operations – keeping the lights on – is PJM's most important priority. It involves around-the-clock system monitoring and the dispatch of power by trained operators; real-time coordination with other operating entities and industry sectors; and extensive planning to ensure the grid is equipped to serve future needs.



The Changing Energy Landscape

A broad set of trends is reshaping the electric industry today, thus planning for the grid of the future is of particular importance. One such trend is the increasing number of states and stakeholders that are adopting decarbonization goals of varying ambition.

Renewable resources, whose power is intermittent in nature, are coming online at an escalating rate, and are expected to dramatically alter the resource mix over time. Currently, 92% of the 145 gigawatts[1] in the PJM interconnection queue – where generation projects apply to connect to the PJM system – are solar, wind, storage or combinations of wind/solar with storage resources, known as hybrids.

This will correspond with a rapid proliferation of distributed energy resources (DER) – smaller generation resources with limited visibility to PJM operators. At the same time, we expect significant new investment in grid modernization, coupled with intense innovation in technology, data management and new business models.

The Federal Energy Regulatory Commission (FERC), which regulates the interstate transmission of electricity and wholesale power markets, has supported the integration of DER into the wholesale electricity markets through the recent issuance of Order 2222. The purpose of this order is to remove barriers to entry for smaller-scale generation and storage on the

[1] 145 gigawatts in the PJM interconnection queue refers to the nameplate capacity of all projects.

distribution system, along with demand response and energy efficiency, by allowing those resources to aggregate and directly compete against larger, more traditional generation in the markets.

These emerging trends have benefits and offer new opportunities. They also begin to present new challenges for grid operators such as PJM. At the highest level, they largely represent a shift from what has long been a model in which the demand for electricity, or load, is predictable and supply is controllable, to one where they may be less so.

PJM anticipates that maintaining reliability in this new paradigm will require consideration of changes to the rules and processes followed in executing its core functions of planning, markets and operations. The topics discussed in this paper represent areas where change may be necessary to ensure a reliable future.

Framing the Discussion

The purpose of this paper is to help frame the forthcoming discussions on system reliability with policymakers and stakeholders, and begin reviewing how PJM's core functions, market rules, operations and planning processes should evolve to maintain reliability in the face of the changes occurring in the electric industry.

To help ground those discussions, the paper provides an overview of bulk power system reliability in terms of four basic building blocks that a grid operator must have in place today and plan to provide for in the future: adequate supply, accurate forecasting, robust transmission and reliable operations.

The paper then reviews how PJM achieves reliability today through each of these building blocks. It lays out how emerging trends in the industry will impact each aspect of reliability and highlights how PJM will need to evolve to ensure future system reliability.

The paper concludes with the next steps to continue the discussion with policymakers and PJM stakeholders on exploring the changes needed to support industry trends and future grid reliability.

Reliability Standards

The North American Electric Reliability Corporation (NERC), with oversight from FERC, is the regulatory entity responsible for developing and enforcing reliability standards in North America that PJM and other system operators must follow to ensure the safe and reliable operation of the grid.

NERC defines reliability of the bulk power system in terms of two fundamental aspects: Adequacy and Operating Reliability (also called Security). Adequacy refers to the ability of the electric system to supply the aggregate electric power and energy requirements of consumers at all times, while Operating Reliability refers to the system's ability to withstand sudden disturbances, such as the unanticipated loss of system components. The four building blocks of reliability discussed in this paper support these two fundamental principles.

The intent of NERC Reliability Standards is to help ensure an "adequate" level of reliability. It is not possible, or economically feasible, to plan and operate the system in a manner that is perfectly reliable with no risk of power outages or blackouts. Many grid operators in the U.S., including PJM, set a target level of reliability to ensure that available resources on the system will be able to meet the demand for electricity and avoid involuntary customer load shed with a risk of no more than once in 10 years – known as loss-of-load-expectation (LOLE).

Grid resilience is another important concept that is intertwined with reliability. Resilience involves preparing for, operating through, and recovering from events that impose operational risk, including but not limited to high-impact, low-frequency events not addressed by typical reliability standards. Those events may include a physical or cybersecurity attack, major disruption to generator fuel supplies, or the extended pandemic that we are currently facing. These events may be less frequent, but have the ability to significantly disrupt the bulk power system.

II. The Building Blocks of Reliability

This section provides a general overview of the four building blocks of reliability that any grid operator must have in place today and plan to provide for in the future.

Adequate Supply

Adequate Supply addresses whether there is sufficient generation and other resources, including demand response, available on the system to meet customer demand. This involves having adequate 1) capacity to meet peak demand on the system, 2) energy to meet the day-to-day and intraday demand and 3) ancillary services and reliability attributes, which refer to the essential grid services and resource characteristics needed to maintain system balance and stability and support the reliable operation of the grid.

Capacity

Capacity represents the capability of a resource to provide power or reduce demand as needed, particularly during emergencies. An adequate level of capacity helps ensure the availability of sufficient resources on the system to meet the peak demand of customers during the year, which, in PJM, occurs during the hottest summer days or coldest winter days when air conditioners or heaters are used most. This requires keeping a certain amount of capacity reserves above the expected annual peak load on the system to account for factors such as generator outages or times that customer demand exceeds expected levels.

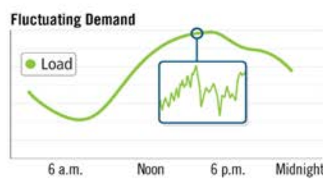
Traditionally, the amount of capacity on the system is measured in terms of installed reserve margin, which represents the level of capacity reserves – typically expressed as a percentage in excess of annual peak load – needed to satisfy some level of reliability criteria. As noted previously, most grid operators in the U.S., including PJM, use an LOLE reliability criterion of one day in 10 years.

Energy

Energy is the actual production of power over a period of time, often expressed in megawatt-hours (MWh). At a high level, the consistent delivery of electricity to consumers is what reliability is about. While adequate capacity ensures available resources to cover the peak demands during the year, sufficient energy is needed to meet the daily, hourly and sub-hourly demand of customers. Grid operators schedule resources to provide energy in advance of each day, and then adjust those schedules as needed throughout the day to balance supply and demand.

Ancillary Services and Reliability Attributes

Ancillary services and reliability attributes[2] are necessary to maintain system balance and support the reliable operation of the grid beyond the basics of providing real power. Certain ancillary services, such as frequency response, operate almost instantaneously in an automated fashion to keep the system frequency in check. Others operate more slowly but also help maintain system balance as load fluctuates second-to-second and hour-by-hour throughout the day. The reliability attributes and ability to provide ancillary services are not uniform across all resource types. Therefore, it is important that the evolving set of resources on the system, in aggregate, are capable of providing the level of services and attributes needed to support the reliable operation of the grid as requested by the system operator.



If an adequate level is not preserved, system operators may not be able to keep the system in balance, which can result in involuntary load shedding, rotating blackouts or even the complete collapse of the power grid. The following is a list of reliability services and attributes that are critical to ensuring reliable operation of the grid.

Frequency Response

The frequency of alternating current on the transmission system (scheduled to 60 Hertz in the U.S.) is a key indicator of the system's health and stability. It is impacted by any imbalance between load and generation, such as that which happens when turning on lights or when a generator trips offline. Frequency deviates upward when generation exceeds demand, and deviates downward when generation is insufficient. Frequency response is how quickly the

[2] PJM published a white paper in 2017 on fuel diversity and reliability, with detailed descriptions of reliability attributes.

system handles those deviations and returns the system to the scheduled frequency and is provided through the interaction of three components: inertial, primary and secondary frequency response.

Types of Frequency Response

INERTIAL	PRIMARY	SECONDARY
Inherently provided through kinetic energy stored in the rotating mass of synchronous generators to arrest changes in frequency	Autonomous and automatic reaction of a generator, or other resource, to rapidly change its output to control for frequency deviations	The centralized re-dispatch of resources capable of quickly adjusting their output. Also known as automatic generation control (AGC) or regulation
Immediate	*Within Seconds*	*Seconds to Minutes*

Ramping

Ramping is the ability of a generator to increase or decrease its output to help maintain supply-and-demand balance on the system in response to a control signal provided by the grid operator. This reliability attribute can be further broken down into the following categories and services:

- **Regulation** (i.e., Secondary frequency response): Resources capable of following automatic generation control signals and adjusting their output to manage minute-to-minute fluctuations in system demand
- **Load-Following** (Dispatchable): Ability of a resource to adjust its output to follow fluctuations in system demand throughout the day.
- **Operating Reserves:** An amount of generation or load curtailment that can be deployed within a defined timeframe to recover from a sudden supply shortage. Reserves come in different time steps such as 10 minutes, 30 minutes and 90 minutes. Reserves also come in different categories such as synchronized and non-synchronized.

Commitment Flexibility

Commitment flexibility is characterized by the ability of a resource to cycle (start up and shut down multiple times during a day) on demand, its total time to start, minimum run-time and the number of starts per day. Flexible resources capable of coming on- or off-line for short periods support reliability when system load, interchange or generator output change rapidly.

Voltage Control

System voltage is the second key indicator of system health and stability. Voltage on an electric line is similar to water pressure in a hose; it is needed to ensure sufficient flow. If voltages drop too severely, the low voltages can cascade through the system and lead to a localized or widespread blackout. If voltages get too high, it can cause failure or permanent damage to system equipment. Voltage control is a resource's ability to either inject or absorb "reactive power" to maintain or restore system voltage to prescribed levels following a disturbance. Reactive power (measured in Mega VARs) cannot be easily transmitted over long distances like real power (measured in megawatts), and therefore requires resources used for voltage control to be located in close proximity to consumers or areas where voltage regulation is challenging.

Availability

Availability is a measure of the resource's ability to perform when needed by system operators. For thermal generation, it considers the probability that a resource will be on a forced outage when needed, due to equipment failures, inability to secure fuel, or other reasons. Availability for intermittent and storage resources is based on their expected ability to perform when needed during peak periods of demand, or those with the highest loss-of-load risk. Generally, resources with higher availability reduce uncertainty and provide a greater reliability value to system operators than resources with poor availability.

Black Start Capability

Black start capability is a reliability attribute provided by units that have the ability to start up and deliver electricity to the power grid without an outside source of power. Unlike services and attributes that routinely support reliability, these units are used for system restoration by helping to re-energize the grid following the unlikely event of a widespread outage or blackout.

Accurate Forecasting

Accurate forecasting plays an important role in maintaining the reliability and efficiency of the power grid. Predicting the total demand, and net demand (demand minus solar and wind output), for electricity for the next hours and days, as well as many years into the future, allows for reliable planning and operation of the system.

Load Forecasts

Planning for the grid of the future requires the development of long-term load forecasts that address a myriad of underlying drivers, including weather, economics and customer behavior. These forecasts, made multiple years in advance, become the basis for the extensive, comprehensive planning needed to identify required transmission enhancements to the system, as well as the system's future capacity needs.

Short-term load forecasts are necessary for grid operators to balance the supply of electricity with ever-changing demand, typically over time horizons of minutes to days. The models and techniques used for short-term load forecasting vary, but generally consider many of the same factors as long-term load forecasts.

Distributed Energy Resources (DER)

Distributed energy resources, such as rooftop solar installed on the customer's side of the electric meter and electric vehicles, can reduce or increase the amount of electricity a customer draws from the grid depending on their operating state. The ability to forecast the proliferation and output of different types of DER on the system directly impacts the accuracy of the long- and short-term load forecasts that are needed for grid reliability.

Renewable Output

Intermittent renewables, particularly wind and solar, are greatly influenced by the weather, and outputs vary throughout the operating day with the resource's energy source. The output of solar resources, which largely depends on incoming solar radiation and weather conditions, tends to be more predictable than wind as it typically tracks the rising and setting of the sun. In order to balance supply and demand, grid operators must be able to forecast the output of intermittent resources with reasonable accuracy to ensure that other, dispatchable resources are available and scheduled to meet the net demand remaining on the system.

Robust Transmission

Electricity is a real-time, on-demand commodity used virtually the moment it is created. Like any commodity, it must be delivered from the point of production – a generator – to the point of consumption – our homes and businesses. Transmission lines are the highways across which electricity is delivered. At its most fundamental, the transmission system ensures that electricity can be delivered reliably across the grid to customers the instant it is needed via the distribution system.

Transmission reliability is a function of thermal, voltage, stability and short-circuit power system fundamentals. The standards for these are set by NERC.

Thermal Overloads

Power flows across each transmission facility according to the relationship of its impedance (opposition to electrical flow) with respect to the broader network. Thermal ratings, or the amount of power that can be reliably transmitted through a given facility, are established by examining the most limiting element of a facility: for example, transmission cable or substation terminal equipment. PJM identifies facilities that have power flow loadings that exceed applicable thermal ratings for pre-contingency conditions and for the loss of a single or multiple generator(s), transmission line(s), transformer(s), or combinations of those elements.

Voltage Limits

Voltage is critical to reliable, on-demand electricity delivery. NERC standards require that a transmission system remain stable within applicable thermal ratings and within established substation voltage ranges. Both voltage that is too low and voltage that is too high can become a serious concern, depending on the availability of resources – both generation and transmission – to produce or absorb reactive power to aid in voltage control.

In real time, operators use transmission system equipment to control voltage, up to and including switching transmission lines in and out of service, switching capacitors or reactors, or adjusting voltage set points on static volt ampere reactive (VAR) compensators.

System Stability

System instability can arise under any number of conditions. The most common condition, however, is when a fault occurs on the transmission system, resulting in a generator going into an over- or under-speed condition, causing it to trip off-line. Under such conditions, if there is insufficient inertia to compensate, that generator may shut down, along with additional cascading transmission and generator trippings, up to the point where blackouts can occur. PJM performs multiple tiers of stability analysis, consistent with NERC criteria, to develop transmission solutions that ensure generators remain synchronized with the rest of the grid.

Short Circuit Limits

NERC requires that each bulk electric system circuit breaker have adequate fault-interrupting capability in order to isolate the transmission facility and remove the fault, or abnormal electric current, from negatively influencing the broader transmission system. PJM runs short circuit simulations that utilize circuit breaker ratings provided by the transmission owner to evaluate the breaker-interrupting capabilities. Any deficiencies in breaker ratings are identified by PJM, and necessary enhancements are developed by both PJM and the transmission owner. Solutions may require replacing the breaker itself to implement a higher current-interrupting rating, or sometimes even redesigning significant portions of the electrical infrastructure. All breakers whose calculated fault currents exceed breaker-interrupting capabilities are considered overdutied, or operating in excess of equipment ratings, and are reported to transmission owners for confirmation and solution development where required.

Reliable Operations

A system is only reliable when operated properly. A robust system may be planned and designed well, but if it isn't operated properly it will not be reliable. This is particularly true for the bulk electric system, as unexpected disturbances on the system can quickly escalate to cascading failures and widespread power outages if not handled properly. To keep the system reliable, grid operators work around the clock to monitor and control the system, directing how much energy should be supplied by generators to match the demand, ensuring transmission lines and facilities stay within their operating limits and constantly preparing for the unexpected.

Supply and Demand Balance

The demand on the system changes throughout the day, and one of the essential roles of a system operator is to maintain the balance between the supply and demand for electricity. System operators maintain that balance by sending signals to generation resources to increase or reduce their output to match the demand on the system.

They also commit additional resources to respond to increases in demand or loss of generation, as well as directing controllable loads to curtail energy usage at times. Maintaining system balance is essential to grid stability and keeping system frequency at 60 Hz, the standard for all of North America.

As the supply and demand change throughout the day, operators must also monitor the transmission network to ensure that the power flows on transmission lines and facilities do not exceed their ratings, as this can lead to equipment damage and cascading failures on the system.

Preparation for the Unexpected

Part of reliable operation is to expect and prepare for the unexpected. Unanticipated events like the loss or reduction in output of a generator or generators, a sudden shift in load, or the failure of a piece of transmission equipment due to severe weather like thunderstorms or tornados, can all affect the reliability of the bulk electric system. System operators proactively take actions to position the system to operate reliably through these events and hold resources in reserve to restore supply-and-demand balance following an event.

A recent example of this occurred in PJM on Feb. 12, 2021, when PJM issued a Cold Weather Alert for the western part of the RTO. Temperatures were forecasted to be in the single digits and lower across much of the region. The purpose of a Cold Weather Alert is to prepare personnel and facilities for expected extreme cold weather conditions. PJM dispatchers then recall or cancel non-critical generation and transmission maintenance outages, and generation owners and transmission owners make final preparation for cold weather operation.

Coordination with Asset Owners and Neighbors

Operators of the bulk electric system coordinate closely with other operating entities, such as generation and transmission owners, as well as other system operators, to maintain grid reliability. There are times that transmission and generation owners need to take their equipment or facilities off-line for maintenance or improvements. System operators coordinate with these entities to plan sufficient time for maintenance activities while maintaining reliability during that time.

PJM and other system operators are linked by transmission infrastructure throughout the Eastern Interconnection. These system operators coordinate with neighboring operators, because the power-flows across the border of two regions affect reliability. During extreme conditions, PJM can provide megawatts to bolster a neighboring system facing major outages. PJM is also able to receive power from neighboring systems. Geographic diversity can also bolster reliability. In PJM, for instance, weather patterns impacting Illinois are not likely to be affecting Virginia in the same way. During the severe winter storms of February 2021, the eastern portion of PJM's footprint experienced milder weather than the western half, and PJM's generators were able to export record amounts of electricity to surrounding systems.

III. PJM: Achieving Reliability Today and Tomorrow

The following sections review how PJM maintains reliability today for each building block and highlights key areas of change that will need further discussion and exploration to ensure the continued reliability of the grid.

How PJM Maintains Adequate Supply

Adequate supply is largely achieved in PJM through system planning and the operation of competitive wholesale markets. Markets provide a powerful tool for attracting investment in new generation and technology at the lowest cost, and support reliability by providing financial incentives and encouraging competition to provide electricity where and when it's needed. PJM markets that support adequate supply are the capacity market, energy market and ancillary service markets. Each of these markets serves a separate function, but all work together to provide the right price signals and revenues to resources that are needed to achieve adequate supply.

Administering the Capacity Market

PJM's capacity market, called the Reliability Pricing Model (RPM), promotes reliability through competitive auctions that secure capacity resources to meet system reliability three years in advance. The auctions allow both new and existing resources to participate, and provide forward price signals that support the efficient entry and exit of resources on the system. PJM secures capacity in the auctions on behalf of load-serving entities – including local utilities, competitive suppliers and public power – using a sloped demand curve that sets the clearing price.

A few additional key elements of PJM's capacity market design include:

Locational pricing to reflect transmission limits and promote capacity in locations where it is most needed

Performance obligations to require committed resources to be available and respond when needed in real-time, or face significant financial penalties

Non-discriminatory and open participation for a variety of resources types, including generation, demand response, and energy efficiency

PJM's capacity construct also allows for certain load-serving entities, particularly utilities, to opt out of RPM auctions and instead satisfy the capacity obligations of their load through self-supply or bilateral contracts. This option is called the Fixed Resource Requirement (FRR) Alternative.

Administering the Energy Market

PJM's energy market secures electricity to meet consumer demand during the course of the day (Real-Time Market) and also for the next day (Day-Ahead Market). It is the largest of the PJM markets, typically making up about 60 percent of wholesale electricity costs. Both the Day-Ahead and Real-Time Markets focus on procuring electricity at the lowest cost to meet consumer needs. Prices in the energy market are based on the concept of Locational Marginal Pricing, or LMP (see sidebar below).

2020 Total Wholesale Cost

Day-Ahead Market

The Day-Ahead Market is a forward market where electricity is procured for the following operating day. Hourly prices are calculated based on generation offers, demand bids from load-serving entities, and other transactions that are submitted to the market. PJM clears the market in a least-cost manner ensuring that cleared demand is met with the lowest cost supply. Resources that clear in the Day-Ahead Market have a financial obligation to provide power the following day, with any deviations from the cleared amount settled in the Real-Time Market.

After the posting of Day-Ahead Market results, PJM performs a second resource commitment, known as the Reliability Assessment and Commitment (RAC) run, which includes updated resource offers and availability, as well as updated load forecast information, to commit any additional resources needed for reliability the next day.

Real-Time Market

The Real-Time Market, or balancing market, is a spot market where PJM procures electricity for immediate delivery. Every five minutes, PJM provides dispatch signals indicating to resources what their energy output should be in order to follow fluctuations in demand and supply and maintain grid balance at the lowest cost.

Locational Marginal Pricing (LMP)

- LMP reflects the price of electricity and the cost of congestion and losses at points across the power grid.
- These prices serve as benchmark signals for market participants to make decisions about future investments.
- Higher LMPs signal where new generation is needed most and where new transmission would relieve congestion and provide the greatest economic benefit to consumers.
- Lower LMPs signal where demand customers can locate to find the cheapest power.

Administering Ancillary Service Markets

PJM operates ancillary service markets for both regulation (i.e. secondary frequency response) and several reserve products. The commitment of energy, reserves and regulation are co-optimized through various market clearing processes, with the objective of finding the most economical set of resources to meet the combined requirements.

Regulation Market

PJM's regulation market provides market-based compensation to resources for providing regulation. Resources in the regulation market must follow one of two types of regulation signals: the Regulation A signal that is primarily followed by conventional generation resources capable of quickly adjusting their output up or down, and the dynamic Regulation D signal intended for faster resources such as batteries. The market clears and commits resources on an hour-ahead basis via co-optimization with energy and reserves to satisfy the regulation requirements of the RTO. Signals for regulation are sent out every two seconds to resources providing regulation to help keep the system in balance and frequency at 60 Hz.

Reserve Markets

PJM's reserve markets provide compensation to resources that provide various types of operating reserves. The market rules were recently amended[3] to procure three reserve products in both day-ahead and real-time:

- Synchronized Reserves with a 10-minute or less response time
- Non-synchronized Reserves with a 10-minute or less response time
- Secondary Reserves with a 30-minute or less response time

The procurement of these products will eventually incorporate Operating Reserve Demand Curves (ORDCs), or sloped demand curves that provide incrementally higher price signals as the system's reserve levels decrease. The quantity of reserves required by the ORDCs considers the loss of the single largest contingency on the system, as well as the uncertainty inherent in the forecasts of wind and solar output, generator outages and net interchange with neighboring systems.

Services Not Compensated Through Markets

There are certain ancillary services that are not explicitly modeled in PJM markets today. Some of these services are compensated under the PJM Tariff and others are not.

- **Voltage Control**: Generators capable of providing reactive power support can be compensated through rate-based monthly payments at a rate filed and approved by FERC, as well as lost opportunity credits to the extent a resource is redispatched at PJM's direction to address a voltage concern on the grid.
- **Black Start Capability**: PJM uses a request-for-proposal (RFP) process to evaluate future needs and procurement of black start resources, which includes an economic evaluation. Selected resources are eligible to receive payments for recovery of the cost of providing black start service.
- **Inertial and Primary Frequency Response**: Generators that provide these types of frequency response are not explicitly compensated for this service under today's rules.

[3] FERC order approving PJM's reserve market enhancements was issued in May 2020 with new rules taking effect in May 2022

Future of Adequate Supply

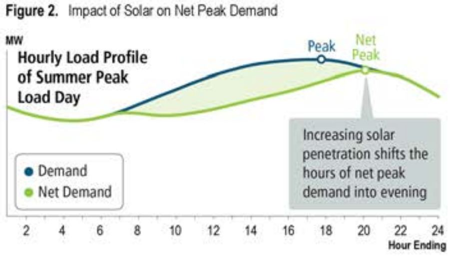
The changes occurring in the electric industry and evolving resource mix have the potential to significantly impact the provision of adequate supply and reliability in PJM.

Greater Focus on Adequate Energy, Net Peak Demand

Historically, adequate system capacity has resulted in adequate energy, as most traditional generation is capable of running 24 hours a day. As the level of renewables and storage rises, however, ensuring adequate energy across all hours of the day will be an increasingly important consideration, because the available output of those resources can vary significantly throughout the day. Resource output can vary with the energy source (in the case of wind and solar), or may be limited in the number of run hours at full output (in the case of storage).

In addition, the rise of solar generation on the PJM system will change the hours most at risk of load shed. Historically, this has been the hours of peak demand in the summer, when temperatures are at their highest. In a system with a high penetration of solar, those hours of risk shift to later in the evening, when the sun is setting and solar performance is decreasing while temperatures remain high (See Figure 2 below). This has been observed in California, which has a much higher penetration level of solar than PJM at this time. The California ISO, in their report[4] on the August 2020 rotating outages, pointed to the shifting risk from gross- to net-peak demand as a key contributor, and an area that requires further attention in the future.

Figure 2. Impact of Solar on Net Peak Demand



Evolving Reliability Contributions and Criteria

PJM recently made an important first step in evaluating the reliability contribution of renewable resources with a filing on effective load carrying capability (ELCC), currently pending before FERC. ELCC replaces the existing methodology of determining the capacity value of renewables, which only considers performance during certain peak hours in the summer. ELCC uses a more robust, probabilistic analysis that considers the contribution to reliability that resources provide during all hours of high risk, including net-peak-demand hours, and accounts for the limited duration of storage resources.

Another area to explore is the reliability criterion that PJM uses in the capacity construct, currently set to a maximum frequency of one loss-of-load event every 10 years on average. This is also known as the 1-in-10 LOLE standard. LOLE has historically worked well to ensure resource adequacy in PJM, but does not account for load shed duration or magnitude. That means a load shed event of one MW in one hour is currently treated the same as a 1,000 MW load shed across 10 hours. The transition from conventional generation capable of 24-hour output to resources with shorter output durations can result in more, disparate load shed events which would be better represented in reliability criteria considering duration and/or amount of load shed.

[4] Final Root Cause Analysis report on California August 2020 rotating outages

Explicit Modeling of Certain Ancillary Services and Reliability Attributes

Today, PJM has an adequate supply of services and attributes; some are explicitly modeled and compensated in the PJM markets, others are not. As the supply mix continues to evolve, the levels of reliability attributes and ancillary services required will also change. Further, renewable resources interconnecting into PJM today and in the future may not be capable of providing the same ancillary services and reliability attributes as the resources they are replacing. To ensure reliability in the grid of the future, certain ancillary services and reliability attributes may need explicit modeling, with set requirements, to keep an adequate aggregate level on the system. It may be valuable to explore where and how market-based mechanisms can be used to send appropriate price signals for these services.

Inertial Frequency Response

The inertial frequency response of the system drops as large synchronous generators are retired and replaced with inverter-based resources such as wind, solar, and storage. This can be a concern in a grid with high penetration of renewables, as it can result in a faster and larger frequency decline following a system disturbance because of a reduced level of reliance on generators with large rotating masses[5]. In the future, consideration of how to incentivize inertial frequency response may become necessary to ensure an adequate supply on the system at all times and appropriately compensate those resources providing the service.

Ramping and Commitment Flexibility

The influx of intermittent resources on the system, with outputs that can rapidly change throughout the day based on weather, will require an adequate level of ramping and commitment flexibility. These are resources that can be dispatched up and down, or cycled on and off in relatively short periods of time at PJM's direction, to maintain supply and demand balance throughout the day. The need for ramping and commitment flexibility has been shown in other regions with greater levels of renewable penetration than currently seen in PJM, such as California ISO and the Midcontinent ISO, which explicitly model and compensate flexible ramping products in their markets.

How PJM Forecasts System Needs

Accurate forecasting enables PJM to make decisions about how to plan and operate the power grid in a reliable manner, and how to effectively administer competitive power markets. PJM engineers and operators use a variety of tools and data sources to plan for the system and anticipate how much electricity consumers will use in both the near- and long-term.

Forecasting Long-Term Load

PJM's load forecast model produces a 15-year forecast for each PJM zone, sub-zone (Locational Deliverability Areas), and the RTO. The model estimates the historical relationship between load (peak and energy) and a range of different drivers, including weather variables, economics, calendar effects, end-use characteristics (equipment/appliance saturation and efficiency) and distributed solar generation, and leverages those relationships to derive forecasted load.

[5] NERC March 2020 whitepaper on frequency response and impact of inverter-based resources

- **Weather conditions** across the RTO are accounted for by calculating a load-weighted average of temperature, humidity and wind-speed data from over 30 identified weather stations across the PJM region.
- **Calendar effects** are unique variables for the day of the week, month and holidays.

- **Economic impacts** on load forecasting are addressed by one indexed variable that incorporates six economic measures. This allows for localized treatment of economic effects within a zone. PJM contracts with an outside vendor to provide economic forecasts for all areas within the PJM footprint.
- **Distributed solar generation** acts to lower load from what it otherwise would be. Recent years have witnessed a significant ramp-up in behind-the-meter distributed solar resources. PJM's load forecast accounts for this increase – which reduces PJM's total load -- taking into account PJM's own experience and vendor-supplied forecasts. These forecasts consider assumptions for federal and state policy, net-energy metering policy, energy growth, solar photovoltaic capital costs, power prices and other factors.
- **End-use characteristics** are captured through three distinct variables designed to capture the various ways in which electricity is used, including weather-sensitive heating, weather-sensitive cooling and non-weather-sensitive use. Each variable addresses a collection of different equipment types, accounting over time for both the saturation of that equipment type as well as its respective efficiency. For instance, the cooling variable captures the increasing efficiency of central air conditioning systems.
- **Plug-in Electric Vehicles (PEVs)** are now also an explicit adjustment to account for charging at peak load and to maintain reliability as the PEV share of overall number of vehicles on the road continues to grow.

Historically, economic growth has meant an increase in electricity demand. But today, notably, PJM's load forecast model recognizes the weakening of the relationship between energy and economics. In large part, this reflects the continued evolution of a more service-driven economy, which is less energy-intensive than a manufacturing economy, combined with the accelerated proliferation of more energy-efficient electrical appliances and equipment.

Forecasting Short-Term Load

PJM regularly prepares short-term load forecasts used in maintaining day-to-day reliability of the system and in power market activity. PJM prepares two primary short-term products:

- **Hourly Forecast:** An hourly forecast that looks seven days ahead. Members often use this forecast in planning their bidding strategies in the Day-Ahead and Real-Time energy markets.

- **Five-Minute Forecast:** A five-minute forecast that looks at conditions for five-minute intervals, six hours ahead. This forecast is used by PJM's SCED tool, which helps PJM operators dispatch power plants in the most economic order throughout the day, as they continuously balance electricity supply and demand.

PJM utilizes both vendor and in-house forecast models to generate short-term load forecasts, including neural network models that use machine-learning algorithms, models that use pattern-matching algorithms looking for similar historical days and blended models that consider both. These models consider factors including weather, calendar effects, measured and historical loads, and behind-the-meter solar projections. If the models are unable to produce sufficiently accurate results, such as during storms or unanticipated changes in human behavior, PJM operators can step in and modify the forecasts based on their experience and judgement.

Forecasting Renewable Output

In addition to behind-the-meter distributed solar, accurate forecasts of grid-connected solar and wind generation are important to the reliable operation of the power grid. In the long term, projection of renewable generation is important in determining a resource's reliability value, as their output and penetration levels impact the demand patterns and hours of loss-of-load risk in PJM. PJM's ELCC filing in October 2020 proposed utilizing a vendor forecast to develop the level of renewable penetration expected in PJM up to 10 years in the future.

In the short term, projection of renewable generation throughout the operating day has a direct impact on the reliable and efficient dispatch of other resources to meet net demand. PJM forecasts solar and wind data for each grid-connected solar park and wind farm, using various vendors. To account for error in those forecasts in the future, PJM will consider the uncertainty of renewable output in determining the operating reserve demand curves used to set prices in its reserve markets[6].

Future of Accurate Forecasting

PJM's load forecasting model has gotten more complex in parallel with the electric system overall, and future models are likely to become still more complex. This complexity ensures a more accurate model, as recent history has indicated. Incorporation of energy efficiency trends and behind-the-meter solar began with the 2016 load forecast. Techniques refined in 2020 and again in 2021 have yielded even more accurate modeling.

Forecasting models are built to understand the underlying drivers of historic patterns in order to make informed forecasts. Energy efficiency is a prime example: data is now showing lesser impacts to load growth from energy efficiency than were experienced from 2010–2019.

DER Visibility

The ability to forecast the volume and types of DER on the system directly impacts the accuracy of the long- and short-term load forecasts. In the future, as the penetration level of DER rises, it will become increasingly important for PJM to have visibility into the output and impact of distributed resources on the system. PJM plans to collaborate closely with distribution system operators to have that visibility. FERC Order 2222 may help improve that visibility to the extent DER chooses to participate in the PJM wholesale markets.

[6] This will be future practice starting in May 2022, as part of PJM's reserve market enhancements

Long-Term Load Forecast Model

Long-term load forecast models support future reliability by allowing system operators to properly plan for transmission upgrades and the capacity needs of the system. Two areas of recommendation to support the future accuracy of the long-term load forecast model are:

- **Exploring the benefits of adopting an hourly load forecast model.** As part of the ELCC work, PJM utilized a model with hourly load forecasts, along with hourly generation profiles that captured the intermittency of renewable resources and the limited duration of output from energy storage resources. Further review of the benefits of an hourly load forecast model should be explored and considered for use in different planning studies, such as the annual Reserve Requirement Study that determines the reserve targets used in the capacity market.
- **Utilizing consultants to review load forecast models and provide recommendations for improvement.** Supplementing the years of experience and expertise of PJM planning engineers can only serve to further sharpen the accuracy of the load forecasts.

Renewable Output Forecast Improvements

Grid operators rely on accurate short-term predictions of demand and net demand to efficiently schedule resources and maintain system balance. As the penetration level of renewables continues to rise on the system, PJM will need to explore ways to handle the additional uncertainty to net demand on the system, or improve the accuracy of forecasts, to maintain reliability.

One option for handling the additional uncertainty would be to commit additional operating reserves on the system, as the operating reserve demand curves are designed to do. However, that may not be the most cost-effective solution as the volume of renewables continues to increase.

A few areas to explore that may improve our forecasting of renewable output include:

- Swapping or adding vendors to provide more accurate renewable forecasts
- Enhancing the modeling of weather patterns and individual resource characteristics to predict the output of renewable resources
- Enhancing market incentives for operators of renewable generation to provide accurate forecasts

How PJM Plans a Robust Transmission System

PJM is required by NERC to plan and operate transmission facilities at 100 kV and above, as well as lower-voltage facilities if requested by the transmission owner. In response to identified regional reliability, market efficiency or public policy needs, PJM staff recommends projects to include in the PJM Regional Transmission Expansion Plan (RTEP), to be approved by the PJM Board of Managers.

New transmission projects serve one or more operational purposes, for example:

- **Increase power-flow capability** – New lines and transformers, existing line re-conducting and bus reconfigurations

- **Provide voltage support and improve generating-unit stability** – New devices like shunt capacitors and static VAR compensators
- **Ensure safe transmission line operation** – New substation equipment like circuit breakers, switches, relay protection and control equipment, and instrumentation

Frequently, new facilities built to serve one purpose address others as well.

Developing the Regional Transmission Expansion Plan

PJM's comprehensive RTEP process identifies the need for changes and additions to the system up to 15 years into the future. PJM's regional planning approach makes the transmission planning process more efficient by considering the region as a whole, rather than as individual states or separate transmission zones. Transmission system enhancements are driven by a variety of evolving and interrelated industry, market, and public policy issues (see Figure 3).

Figure 3. Transmission System Enhancement Drivers

As noted earlier, PJM's regional planning process spans transmission owner (TO) zonal boundaries and state boundaries to address the comprehensive impact of many system enhancement drivers, discussed earlier. Operationally, the system enhancements arising out of PJM's RTEP process reduce emergency procedures and alerts, increase operating margins, and improve the ability to import/export power with neighboring grid systems. RTEP projects are planned to address one of more of the following criteria described below.

Baseline projects:
Address reliability criteria violations including thermal, voltage, short circuit and stability, TO criteria violations, and those violations driven by market efficiency, as well as expansions required to meet public policy.

Network projects:
Ensure that new generation and merchant transmission projects interconnect reliably to the grid as submitted through PJM's interconnection queue.

Supplemental projects:
Identified by TOs to address their own local transmission reliability needs. These projects direct repairs or improvements to local transmission lines and equipment, and address local operational issues, customer load growth and resilience. Even though the TO develops these projects, PJM reviews them to evaluate their impact on the regional transmission system, to coordinate necessary construction outages, and to implement necessary changes in PJM models and system operations.

Baseline Reliability

Baseline reliability analyses assess base-case thermal and voltage conditions under defined test conditions for load deliverability and generation deliverability under summer peak load, winter peak load and light load system conditions. Contingency analyses examine all PJM bulk electric facilities, lower-voltage facilities monitored by PJM and critical facilities in systems adjoining PJM, including tie lines. All reliability analyses are conducted to ensure compliance with NERC and PJM regional criteria.

Transmission Owner Criteria

The PJM Operating Agreement specifies that individual transmission owner planning criteria are to be evaluated as a part of the RTEP process, in addition to NERC and PJM regional criteria. Frequently, transmission owner planning criteria address specific local system conditions, such as in urban areas. Transmission owners are required to report their individual local planning criteria annually through FERC Form 715. As part of its RTEP process, PJM applies transmission owner criteria to the respective facilities that are included in the PJM Open Access Transmission Tariff facility list.

Operational Performance

Under the PJM Operating Agreement, PJM may also identify transmission enhancements to address system limitations encountered during real-time operations, often under recurring similar system conditions. To that end, PJM planners meet with operations staff to assess the need for transmission enhancement plans that would address identified thermal, reactive, stability and other issues. Over the past several years, for example, some operators have experienced high-voltage alarms under light load conditions. Additional studies replicating operating conditions have revealed that reactors were needed in certain areas to resolve the issue.

Generator Deactivation

When generation owners decide to retire a facility, they are required to notify PJM of their intent. These generator deactivations alter power flows that can cause transmission line overloads and, given reductions in system reactive support from those generators, can undermine voltage control requiring system reinforcement.

Addressing Aging Infrastructure

The regional high-voltage transmission system is aging; many facilities were placed in service in the 1960s or earlier. They are deteriorating and reaching the end of their useful lives.

Nearly two-thirds of all bulk electric system assets in PJM are more than 40 years old and more than one-third are more than 50 years old. Some local, lower voltage equipment, especially below 230 kV, is approaching 90 years old. Most of this equipment – cable, tower structures and tower foundations, for example – is outdoors and deteriorates with age. Some tower structures – often at 115 kV and 138 kV voltage levels – were originally constructed of wood and have begun to deteriorate; others originally constructed of iron exhibit significant rusting and degradation. Loss of structural integrity subjects transmission lines to increased maintenance costs and reliability risks.

Addressing this deterioration and the associated costs and risks is subject to each transmission owner's broader asset-management strategy. Once a transmission owner determines a facility to be at its end of useful life, replacement of those facilities offer the opportunity to explore the use of newer technologies that will result in a more efficient transmission system.

Evaluating New Service Requests

New service requests include generator interconnection requests as well as merchant transmission interconnection, merchant network enhancements, long-term firm transmission service and incremental auction revenue rights. A new service request is assigned a queue position only when all Tariff-required information, data, executed agreements and deposits are submitted. PJM then conducts deliverability and other tests to identify and solve any NERC, regional and transmission-owner reliability criteria violations that may require transmission system reinforcement to ensure deliverability.

Under the terms of PJM's Reliability Assurance Agreement, in order to qualify as a capacity resource, sufficient transmission capability must exist to ensure that generator output is deliverable to PJM's aggregate network load under peak load conditions at the requested interconnection point. PJM's annual RTEP cycle encompasses studies that assess transmission expansion plans needed to ensure the ongoing deliverability of all generators within PJM.

Supporting Public Policy

PJM's State Agreement Approach (SAA) embodies an Operating Agreement RTEP process to identify required transmission to be built for and funded by a state or multiple states to meet public policy objectives. One or more states may voluntarily agree to fund transmission system enhancements to address public policy requirements like delivering offshore wind-powered generation.

States can request that PJM study a project designed to address public policy requirements. Or, they may ask PJM to study a project to meet reliability or market efficiency needs through existing RTEP process avenues. Regardless, PJM can only implement public policy requirements if sufficient direction is provided. The translation of policy objectives into planning criteria must be reasonably evident and not depend heavily on subjective judgment.

Accounting for Congestion's Impact on Reliability

PJM operates the grid by scheduling and directing the lower-cost power resources to generate electricity first, incrementally adding more expensive resources as they are needed, and using the highest-cost resources only during the relatively brief periods of peak customer demand. Comprehensive reliability planning ensures that peak demand can be met without encountering reliability criteria violations.

For hours other than those during peak load conditions, market economics drive how generation is dispatched and power flows to customers across transmission facilities. At times, transmission can become limited by ratings on transmission equipment, creating congestion. PJM system operators must reroute power flow by deploying higher-cost generating units to avoid overloads and risk losing transmission equipment. Such operation creates market inefficiencies for which PJM planning studies seek transmission solutions so that reliability is preserved and the lowest-cost power can reach the greatest number of customers.

Future of Robust Transmission

PJM continues to expand RTEP process flexibility to build the grid of the future through the integration of new technologies, renewable generation, distributed resources, and federal and state RTO policies while simultaneously maintaining a reliable, efficient and resilient regional bulk electric system. PJM will continue to explore synergies between the identification of expected aging infrastructure facilities and future system needs that are driven by the increase in renewable generation.

Evolving the Interconnection Process

The grid continues to support a historic and unprecedented generation shift, as coal-fired generation retires and is replaced by gas generators and renewables like solar, wind and battery storage. On the load side of the equation, distributed energy resources (DER) and energy efficiency are off-setting most new load growth.

A robust transmission system enables new technologies to be sited, configured and operated reliably. New transmission assets maintain grid reliability, permitting older generators to retire without causing transmission line overloads or other reliability criteria violations. New natural gas and renewable generation relies on new transmission in order to sell reliable, economic power into PJM markets.

The size and fuel type of generation projects seeking interconnection in PJM continues to change. New resources are now primarily renewable and storage. Such projects tend to be smaller in size compared to conventional base-load generation. As part of this generation shift, PJM's queue volume has grown as a result: There were 970 new service requests in 2020, more than double the 470 projects proposed just two years prior. At the end of 2020, PJM initiated a series of workshops to begin exploring potential reforms to the interconnection process to enhance queue efficiency and other growing stakeholders concerns. PJM looks forward to working with stakeholders to develop necessary changes through this process.

Integrating Offshore Wind Power

Interest continues to increase in large-scale offshore wind generation projects driven by state initiatives. PJM is engaging states, transmission developers and other stakeholders interested in pursuing implementation of PJM's State Agreement Approach for developing offshore wind to achieve state objectives. PJM continues to add process detail to the SAA, based on experience to date, to enable states to pursue those objectives. PJM is also currently conducting educational outreach to states and multi-state coordinated offshore wind studies to identify transmission needs.

Modernizing the Transmission System

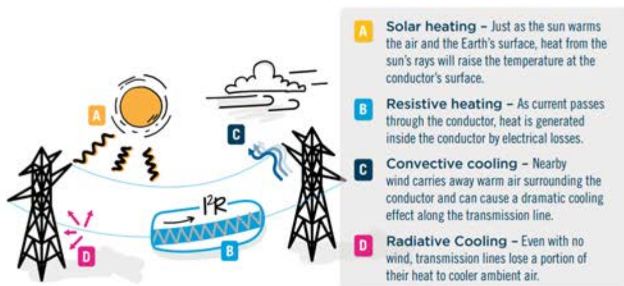
Modernizing the existing transmission system will provide significant benefits: withstanding more extreme events, lowering the frequency and shortening the duration of outages, reducing public and employee safety risks, and improving system operability, efficiency and security. Doing so will ensure a future characterized by enhanced reliability, cost savings, and environmental and societal benefits.

The last five years have brought substantial modernization to system infrastructure. Enhancement of existing equipment, coupled with the application of new tools, has increased efficiency of the equipment and of system operation. Technologies like these are providing PJM with additional tools and operating flexibility to ensure reliability at the lowest cost. Various technologies provide a range of benefits, including the following:

- **Flexible AC Transmission Systems (FACTS)** devices take more conventional power system components – capacitors and reactors – and integrate them in various configurations with intelligent power electronics, high-speed thyristor valve technology and voltage-sourced converter (VSC) technology. By doing so, FACTS devices can directly support additional transmission line power flow with reactive power injections at their point of interconnection, and can indirectly control power flow by modulating transmission line impedances.

- **Transmission Line Technology** includes new developments such as implementation of composite-core conductors that can lower line losses by 25 percent to 40 percent compared to traditional aluminum-conductor steel-reinforced cable.
- **Storage as a Transmission Asset** may connect to the transmission system as a transmission facility used to address and solve a PJM RTEP system reliability violation. The rules to govern this are being considered in our stakeholder process.
- **Dynamic Line Rating Technology**, shown in Figure 5, uses advanced sensors and software to monitor real-time conductor temperature along a transmission line. This data is then used to calculate an actual rating for the line based on environmental conditions that may identify additional capacity on transmission lines. Such technology can potentially relieve congestion, create economic efficiencies and contribute to system resilience by providing better real-time transmission monitoring capability.

Figure 5. Dynamic Line Rating Technology



CIP-014-02 Critical Facilities

Concerns across the industry about grid security and resilience continue to grow. NERC's CIP-014-2 standard for critical infrastructure requires transmission owners to identify and protect transmission stations and transmission substations – and their associated primary control centers – that could cause instability and uncontrolled separation if rendered inoperable or damaged as a result of a physical attack. Specifically, PJM continues to support efforts to eliminate current vulnerabilities for CIP-014 critical infrastructure while also working to develop RTEP resilience criteria to avoid and mitigate the risk of future CIP-014 critical infrastructures facilities.

How PJM Operates Reliably

Operating reliably, simply put, is keeping the bulk power system secure and serving load – and is always PJM's first priority. Reliable supply of electricity is essential to the economy and to the health and well-being of the 65 million Americans in our footprint. While the PJM system features a diverse fleet of generation, with healthy reserves and a robust transmission system, the reliability of the grid still requires constant attention.

PJM's specialized team of system operators work around the clock, along with operators throughout the footprint from various member companies, to maintain the uninterrupted flow of high-voltage electricity. PJM system operators use advanced analysis tools to monitor and control the bulk electric system from two redundant control centers. They constantly adjust generation output to match the load on the system, while respecting equipment limits such as thermal ratings and voltage levels, and continuously prepare for the unexpected.

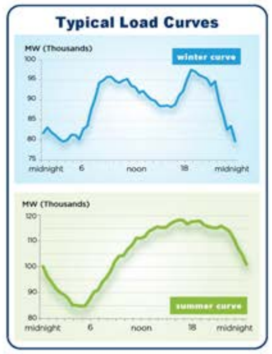
The control centers require extensive telecommunication facilities to support voice communications with other operating entities, while also transferring the vast amounts of data and control signals needed to operate the system.

PJM's operations team works closely with transmission-owning members and generation owners to plan for maintenance activities and to coordinate operations in real time. PJM's system operators also coordinate operations with neighboring regions to support reliability on both sides of the borders with these adjacent systems.

Figure 6. System Operations – PJM Control Room

Balancing Generation with Load

The demand on the system changes throughout the day, and one of the essential roles of a system operator is to match the load with generation resources. As load begins to increase in the early morning hours of the day, system operators provide signals to generation resources to produce more power to match the increasing demand for electricity. System operators continue to increase the amount of power being generated until the peak of the day. After the peak of the day, operators begin to reduce the amount of power being produced by sending signals to the resources to reduce power. That cycle is repeated every day of the year.



Power flows from the generators to the loads across the transmission system. Just like any machine, the transmission system has limits that must be respected in order to be reliable. Transmission system facilities have ratings that specify the amount of power that can reliably be transferred across the facility. Every system operator must make sure that the amount of power being transferred across a facility does not exceed the rating of the facility.

Preparing for Extreme Conditions

Reliable operation starts with preparing the system for the next peak season, whether it be summer or winter. Seasonal studies are completed to assess the reliability of the system for the upcoming peak season. These operational studies stress test the system to identify issues that may require special operating plans and include sensitivity analyses to evaluate a range of credible scenarios that may include, for example, higher loads resulting from extreme cold weather or the loss of multiple generators connected to a common gas pipeline. Such studies help to prepare personnel for the types of conditions they may see during the next peak season.

HOW WE GET READY

Summer Checklist

1. *Perform sensitivity studies.
2. Perform summer operating study.
3. Review ReliabilityFirst summer assessment.
4. Facilitate operator training seminar.

Winter Checklist

1. Hold winter prep meeting with members.
2. Members complete fuel survey.
3. Meet with gas pipelines.
4. Generators verify checklist is complete (Manual 14D Attachment N).
5. Meet with Interstate Natural Gas Assoc. of America and other grid organizations.
6. Generators participate in cold weather testing.

PREPARATION STEPS FOR BOTH SEASONS

- **Assess** seasonal weather outlook.
- **Review** load and capacity outlook.
- **Check** for manual or rule changes.
- **Coordinate** pre-season meetings with neighbors.
- **Run** Emergency Operations Procedures drill.

** This also may be done to prepare for winter.*

In addition to planning for the peak season, spring and fall have their own operational challenges. Transmission and generation outages are typically scheduled in this time of year, and unseasonably high electricity demand brought on by abnormal weather patterns can stress the system.

When operating the grid day to day or week to week, system operators do not have perfect foresight of what may happen through the next operating period. Load – or demand – on the system, which is a function of many things, including weather, may be higher or lower than forecast. Thermal generators may have mechanical problems and be forced to reduce their output or disconnect from the system entirely. Solar output varies based on the intensity of the sun. Wind turbines' output depends on wind speeds and other factors.

PJM's system operators, with the help of the advanced tools noted above, prepare for the loss of both generation resources and transmission facilities by evaluating thousands of what-if scenarios, and take action to adjust the system if any single contingency would result in a facility operating outside of prescribed limits. Operators act before the event occurs so that if it were to happen, all of the remaining facilities would not exceed applicable power flow or voltage limits. Operating in this way is essential for ensuring reliability and preventing cascading transmission failures.

Coordinating Gas and Electric Operations

With the tremendous growth in natural gas-fired generation over the last decade, it has become increasingly critical to the reliability of the bulk electric system that PJM operations are coordinated with the operators of the interstate pipelines that fuel natural gas generators, many of which share the same pipeline for fuel supply.

PJM prepares for failures that may occur on interstate pipeline facilities, as they can impact generators operating on the bulk electric system. PJM has already taken actions to enhance coordination with gas pipeline systems. PJM's gas electric coordination team monitors conditions on pipeline systems and advises markets and operations of conditions that may impact the availability of resources. In addition, tools have been developed to enhance situational awareness of pipeline conditions and how they may impact operations. In 2018, PJM changed our market-clearing timeline to better align with the gas nomination cycles. In 2019 and 2020, PJM organized exercises with natural gas pipeline operators to simulate pipeline outages and their impacts to the generation fleet. This remains an area of on-going focus for PJM.

Initiating Emergency Procedures

Severe weather, such as tornados, derechos and hurricanes, or extended periods of heat or cold, can cause multiple facilities to be automatically removed from service. Other natural disasters, such as mudslides and earthquakes, can threaten multiple bulk electric system elements at the same time, or in a very short period of time, before system adjustments can be made.

In those cases, system operators may need to rely on emergency procedures to maintain the reliability of the bulk electric system. These emergency procedures can be implemented quickly with little or no advance notice, and in some cases may include disconnecting load, also known as load shedding. The overall reliability of the bulk electric system is of utmost importance, and these emergency procedures are only used as a last resort.

Future of Reliable Operations

Operations will need to continue to evolve as the system evolves.

Coordination with the gas pipeline systems will become increasingly important as the penetration of gas-fired resources continues to increase. The proliferation of intermittent resources will also increase the need for controllable resources such as gas-fired combustion turbines and combined-cycle plants that can ramp and/or start up quickly.

As previously noted in the forecasting section of this paper, behind-the-meter rooftop solar is not visible to PJM but appears as an offset to load, and its output varies based on weather and cloud cover. Their increasing penetration will require PJM to continue enhancing our models, tools and our daily forecasting capabilities.

And there are many other types of distributed energy resources connecting to the system with their own impacts, including combined heat and power, other behind-the-meter generators, and batteries. Recent FERC Order 2222 will ensure that these resources can participate in PJM's wholesale markets through aggregators, which will allow PJM to dispatch them similarly to how we currently dispatch a large power plant connected to the transmission system.

DER also connect to the distribution system, operated by the local utility or other distribution system operators, or DSOs, rather than bulk grid operators. Just as PJM coordinates operations with adjacent transmission system operators, PJM will therefore need to coordinate operation of the DER with the various DSOs that they are interconnected with.

Operations will also need to continue to integrate controllable loads into the operation. Controllable loads have participated in PJM's markets and have been integrated into operations for many years as demand response and price-responsive demand. PJM is also beginning to see distributed energy resources looking to combine into microgrids that may be connected to the system and may operate as an island – apart from the grid – from time to time.

As controllable loads continue to increase on the system, it may be more efficient to control the demand for electricity instead of – or in combination with – controlling generation, which is how the system has traditionally operated. This could provide another tool for system operators to manage intermittency issues with renewable resources.

IV. Next Steps

The PJM system is reliable today. In the future, the emerging trends reshaping the electric industry have the potential to significantly impact the manner in which reliability is maintained.

In this paper, we reviewed some of those trends and highlighted certain areas within PJM where change may be necessary to ensure a reliable future. These areas touched on all four building blocks of reliability and each of PJM's core functions of planning, markets and operations.

In the coming months and years, PJM plans to further explore the topics and areas of change introduced in this paper with policymakers and stakeholders. This process has already begun. PJM set up two four-part stakeholder workshops, one focusing on improvements to the interconnection process, and the other examining potential enhancements to the capacity market. This paper is intended to help facilitate discussions in those areas, as well as others. Additional research will look to dive more deeply into the various topics noted in this paper, providing analysis and potential market design changes for consideration where appropriate.

The CHAIRMAN. Thank you, to all of you, thank you so much. I will start the questioning now.

Mr. Wood, you have a very unique perspective having first been Chairman of the Texas Public Utility Commission and then Chairman of FERC. There has been a lot of discussion and blame cast on Texas for the way the grid was designed to be self-contained, seemingly to avoid federal oversight of the energy market, and how the inability to import power made the situation worse last month. My question would be, you have been on both sides of this. So what is so bad about FERC oversight?

Mr. WOOD. That's true, I have been.

[Laughter.]

I've chaired both sides of the river and I have tried to be the voice of calm to both sides of it's not so bad on the other team. There are some unique attributes of Texas that, and particularly in the power market that when I went from that role to the one at FERC, I would have lost. For example, as we were setting up our power market in Texas, we ordered the utilities to become part of the RTO, become the equivalent of PJM up here.

Utilities still have that option to pull in and out and use that power, I think sometime not in a great way, to undermine the market. And I would love for that not to have been an issue.

The CHAIRMAN. I think my question would be this. Since you have seen both up close and personal, what is the objection? Now, what? Is FERC over-reaching or is the Federal Government over-reaching? Is it higher prices or less competitiveness or what, what would be the objection from Texas about FERC oversight?

Mr. WOOD. I think the issue that mattered the most to me was the ability to have a single regulator over the retail and the wholesale market. We had the ability to put that vision in place that Governor Bush and the bipartisan legislature said they wanted for both wholesale competition and four years later for a competitive retail market. We were able to plan our transmission grid and pay for it in a simple way. We were able to interconnect our generation plants in a straightforward and simple way. So we didn't have to negotiate that with other states or negotiate that with the Federal Government. It just was an easier thing to do.

The CHAIRMAN. Sure.

Mr. WOOD. I wish that the whole nation had that kind of unified vision. We've got to look to the Congress for that and I know it's been hard to get over past generation.

The CHAIRMAN. Mr. Asthana, as you know, my home State of West Virginia is in PJM service territory, and 100,000 of my constituents were without power last month as a result of the winter storm, but it was a different story from what we saw in Texas. In West Virginia it was because of downed power lines and poles, for the most part. You mentioned in your written testimony some of the lessons learned from the 2014 polar vortex that impacted West Virginia and surrounding states.

Do you believe that lessons learned from 2014 were implemented in a way that lessened the potential impact of the winter storm last month? Because a lot of West Virginians do not. So what are some of your early lessons learned from last month that you would prevent the next time?

Mr. ASTHANA. Yes, Senator Manchin, thank you for the question. And West Virginia is a very important part of PJM. I do believe that the lessons from 2011, as well as 2014, were learned and were implemented and I'll point to three. We implemented a winterization checklist and reporting back to us for our generators, we implemented underperformance penalties for generators who didn't show up with their commitments, and we implemented much more stringent gas to power coordination. And as a result, we saw in 2014, forced outages of 22 percent. We lost 22 percent of our fleet. Last month that number was less than 10 percent, so there have been significant improvements since 2014 directly as a result of the lessons learned there.

The CHAIRMAN. Thank you.

Mr. Robb and then Mr. Wood could finish up on this, if he would like to jump in. But Mr. Robb, just directly to you. ERCOT is designed to have a minimal backup generation and a high price cap that is intended to incentivize generators to be available when needed. Several of the country's grid operators operate a capacity market to pay generators to make more power plants available years into the future, like PJM, for example. These are two approaches to balancing reliability and affordability. Can you shed some light on whether ERCOT's high price cap approach, where power prices shot up to $9,000 per megawatt-hour for days, worked? The bills consumers are receiving sound like price gouging to me. Is a high price cap a reasonable way to incentivize generators to be ready?

Mr. ROBB. Senator Manchin, I appreciate that question.

I'm not a market design expert, so I can't really comment on whether the price cap was appropriate or not. I think in any way, it did not adequately incent generation to be online during this past event.

The CHAIRMAN. Well, based on recent events, what do you think is the best way to line up sufficient capacity to come online when needed so we don't run into this lack of ability?

Mr. ROBB. It either needs to be rewarded through a market mechanism such as a capacity market or a very high price opportunity as they've elected to do in Texas or administratively determined through a regulatory proceeding at a state commission.

The CHAIRMAN. So, Mr. Asthana, you have a much lower price cap, coupled with the capacity market. Can you explain why PJM took that approach and what the tradeoffs are?

Mr. ASTHANA. Yeah, absolutely.

We took that approach because we have a multi-state jurisdiction that we serve and we wanted to make sure that we had capacity available three years into the future and the three-year figure is selective because that's roughly the amount of time it took to build a generator that would have made up that capacity.

I do want to say though, that I think the underlying explanation is more complex. I think it's easy to think oh, if only Texas had a capacity market, this wouldn't have happened. I think Texas could have had a higher reserve market, perhaps, but it's important to note that going into this winter Texas had reported a reserve margin for this winter of 43 percent. And so, it was not a shortage of capacity. It was this incredibly cold weather for which the capacity was not prepared. And you know, we think that could happen to us. We have prepared a lot, but we're very focused on making sure that we are continuing to be prepared.

The CHAIRMAN. Thank you very much.

Senator Barrasso.

Senator BARRASSO. Thank you, Mr. Chairman.

Mr. Gabriel, you are the Administrator, the CEO of the Western Area Power Administration and in that role the territory that you serve includes California as well as parts of Texas and other states affected by the cold weather we had last month. So I have a series of very short questions for you.

Do you agree that we should produce electricity from a diverse set of energy resources, including resources that are capable of producing electricity at all times of day and night?

Mr. GABRIEL. Yes, I do.

Senator BARRASSO. Good. And with the blackouts that we witnessed in California last August, would they have been avoided if California had simply installed more solar panels?

Mr. GABRIEL. I do not believe that that would be the case. You need a diversity of generating resources, Senator.

Senator BARRASSO. So with the blackouts that we witnessed in Texas, Oklahoma and Kansas last month, would they have been avoided if these states had simply installed, say, more wind turbines?

Mr. GABRIEL. Again, I think a diverse portfolio is required to keep all of these grids operating. It's really one of the foundational concepts for the grids in the United States.

Senator BARRASSO. Would the impact of the blackouts that we witnessed in Texas, Oklahoma, Kansas and elsewhere last month have been worse if no one had access to natural gas and everyone had to rely on electricity to heat their homes?

Mr. GABRIEL. Well again, not operating the grid in Texas, but certainly making sure that we've got diverse portfolios which, certainly in this day and age, needs to include natural gas.

Senator BARRASSO. And would the impact of the blackouts that we witnessed in California in 2019 and '20 and across the middle of the country last month, would they have been even worse if everyone, including emergency responders, had to rely exclusively on electricity to power their vehicles?

Mr. GABRIEL. Well again, we've got to make sure that we've got sufficient supply and sufficient generation whether it's vehicles, whether it's powering homes or businesses. It's crucial to have a real diverse portfolio.

Senator BARRASSO. Mr. Shellenberger, first, thanks for making the trip coming here all the way from Berkeley, California. You know, you have written and you say, "California's big bet on renewables and shunning of natural gas and nuclear is directly responsible for the state's blackouts and high electricity prices." Could you expand upon your comments for the Committee?

Mr. SHELLENBERGER. Well, sure. There was a root cause analysis published by the California Public Utilities Commission and California Energy Commission and the California grid operator, CAISO, which made a very similar point, though in a more muted fashion. That point was made very dramatically in the midst of the crisis last August in a conference call with reporters where the grid operators specifically pointed to the closure of San Onofre Nuclear Power Plant which was about 2,200 megawatts of power as well as the closure of natural gas plants as the, really, the main factors that resulted in the shortage of energy.

Senator BARRASSO. You know, you have written and you said, I quote, "Some have long pointed to batteries as the way to integrate unreliable renewables onto the grid. However, batteries," you say, "are simply not up to the task today." And you went on to explain, "Indeed, for renewables to work, batteries would need to be able to store the power for weeks and, perhaps, even months." Can you expand upon the comments for the Committee?

Mr. SHELLENBERGER. Sure. Well, we have one of the largest battery installations in the world in Escondido, California, and it provides power for 16,000 Californians for about four hours. That is almost 40 million Californians. The cost is prohibitively high and, in fact, most advocates of renewables now no longer think that lithium batteries are going to be an important form of storage beyond, you know, managing minutes or hours. But as I pointed out, the reason that Germany was able to prevent similar power outages this year was simply that they maintained a very large coal, natural gas and nuclear fleet to be available when the sun is not shining and the wind is not blowing.

Senator BARRASSO. Thanks, Mr. Shellenberger.

Mr. Robb, if I could ask you. In your written testimony, you made the following observation. You said, "Over the years NERC's assessments have continued to identify three areas of primary concern: California, Texas and New England." While recent events in the central, south and western parts of the country have attracted national attention, New England is another reason—a region that you have said is identified as particularly vulnerable to extreme cold weather. You noted that New England's problems include its limited pipeline capacity to import gas and its dependence on a handful of critical fuel assets.

So in light of the problem, should we discourage the construction of new natural gas pipelines or retire power plants that are capable of producing electricity at all times?

Mr. ROBB. Thank you for that question, Senator Barrasso, and we strongly believe that more natural gas infrastructure—and natural gas infrastructure including storage, pipeline capacity—needs to be a strong policy focus. New England desperately needs more gas capacity to be resilient to the winter.

Senator BARRASSO. Mr. Chairman, finally, I have an article that was in Greentech Media from last August, titled, "California's Shift from Natural Gas to Solar is Playing a Role in the Rolling Blackouts." The article quotes the CEO of the California grid operator as saying, "The situation we are in could have been avoided." The article goes on to say that the California grid operator has told California regulators for years that there is inadequate power available during the hours when the solar generation has left the system.

I ask unanimous consent, Mr. Chairman, that we include this article in the record.

The CHAIRMAN. Without objection.

Senator BARRASSO. Thank you, Mr. Chairman.
[Greentech Media article follows:]

GRID EDGE (/ARTICLES/CATEGORY/GRID-EDGE)

California's Shift From Natural Gas to Solar Is Playing a Role in Rolling Blackouts

California's grid operator warns that the state has become overly reliant on power imports: "The rest of the West is hot too."

JEFF ST. JOHN

AUGUST 17, 2020

California may see rolling blackouts for weeks to come, grid operator CAISO warns.

California was beset by its first rolling blackouts since the 2001 energy crisis, as a heatwave slammed the Western U.S. Friday and Saturday. Electricity demand for air conditioning throughout the region stretched California's power capacity (https://www.greentechmedia.com/articles/read/western-heat-wave-tests-californias-clean-grid-transition) and limited the state's ability to import power from nearby states.

But the blackouts were also a side effect of the state's increasing shift to solar power (https://www.greentechmedia.com/articles/read/western-heat-wave-tests-californias-clean-grid-transition) and away from natural-gas-fired generators, according to state grid operator CAISO and Wood Mackenzie analysts. This shift pushed back the moment of "net peak" demand on the state's grid — a measure of total demand minus renewable energy's contribution — into later in the evening, leaving CAISO with less dispatchable generation to fill in shortfalls between supply and demand.

With high heat and peak electricity demand expected to continue throughout the week, California may be forced to rely on rolling blackouts for the immediate future, CAISO President Stephen Berberich said in a Monday meeting. Gov. Gavin Newsom declared a state of emergency (https://www.gov.ca.gov/wp-content/uploads/2020/08/8.16.20-Extreme-Heat-Event-proclamation-text.pdf) on Monday allowing backup generators, including those deployed to customers facing wildfire prevention blackouts (https://www.greentechmedia.com/articles/read/why-pges-wildfire-blackout-resiliency-plans-rely-so-much-on-backup-diesel-generators), to be used to combat outages, and demanded an investigation into the causes of the grid shortages.

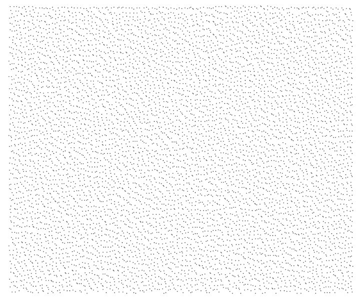
But without changes to how the state manages its grid capacity needs, the same shortfalls could plague the state for years to come, Berberich said, in a scathing attack on what he called California policymakers' failure to prepare for this eventuality. "The situation we are in could have been avoided," he said in Monday's meeting. CAISO has told regulators for years that "there is inadequate power available during the net peak, the hours when the solar [generation] has left the system."

Friday and Saturday's rolling blackouts, or "Stage 3 Electrical Emergencies" in CAISO parlance, forced utilities to cut off power to hundreds of thousands of customers between the hours of 6 p.m. and 8 p.m. Those are the hours when solar generation drops to zero, leaving CAISO with a "net peak" that comes one to two hours after its peak demand hour on the system.

Why more solar can't help solve California's "net peak" problem

CAISO's peak demand levels over the weekend were lower than its historical highest peaks in 2006 and 2017. But "the operational challenge that we face now is more around that net peak event," Berberich said, which includes accounting for increasing demand from rooftop solar-equipped customers as their own self-supplied solar power dissipates. "That solar resource is fading fast, and we have to ramp up other resources quickly to meet that net peak event."

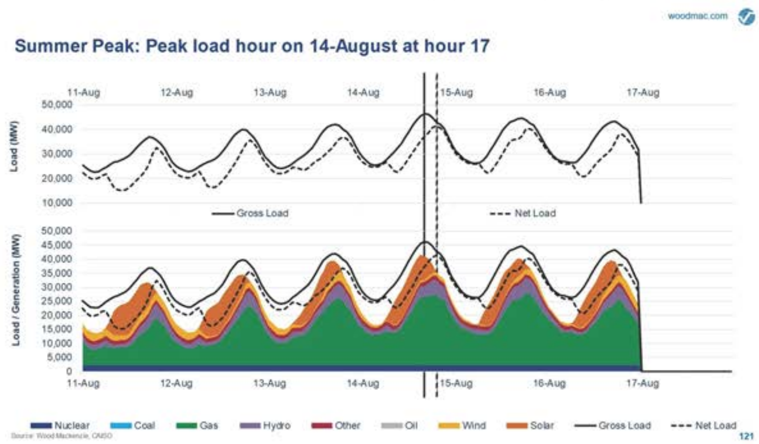
California has also lost a good deal of the generation capacity that it had in years past, Berberich noted. "In 2006, we had a lot more capacity on the system," including the now-closed San Onofre nuclear power plant and thousands of megawatts of natural-gas plants that have since closed. California is set to close even more gas-fired power plants in the coming years, including several coastal plants targeted for retirement to reduce their harmful effects on marine ecosystems.



Wade Schauer, Americas research director at Wood Mackenzie Power & Renewables, noted that California has shut down about 5 gigawatts of dispatchable generation since 2018, while it has only added about 2,200 megawatts of "non-intermittent" generation since then.

California "just hasn't done enough to keep resource adequacy where it should be, and the reserve margins have gotten tighter more quickly," Schauer said. The chart below from WoodMac indicates how California's total generation capacity has fallen below both gross peak and net peak needs, leaving a gap that must be made up from imports from other states.

Many of those states have retired their own generating (https://www.greentechmedia.com/articles/read/navajo-generating-station-coal-plant-closes-renewables) capacity in recent years and are experiencing the same heat wave, so they have been unable to provide CAISO the level of additional supply it needs, Schauer added.



CAISO's 2020 Summer Loads and Resources Assessment (PDF (http://www.caiso.com/Documents/2020SummerLoadsandResourcesAssessment.pdf)) noted that its system saw 1,926 megawatts of dispatchable capacity retire from June 2019 to June 2020. While it has added 3,423 megawatts of capacity over the same time, only 1,734 megawatts of that is dispatchable. CAISO does have access to about 1,300 megawatts of demand response to reduce peak demand and can call on customers to reduce energy, but those steps weren't enough to mitigate the shortages on Friday and Saturday.

That assessment also pointed out that CAISO's daily peak period has "shifted to later in the day when solar generation is near or at zero levels, resulting in the CAISO's highest demand levels being supplied by the remaining non-solar fleet. With lower than normal hydro conditions, the CAISO may have to rely more heavily on imports from neighboring [balancing authorities] during the CAISO summer peak hours. However, if a heat wave occurs that impacts a broader area than [the territory of] CAISO, the availability of surplus energy to import into the CAISO could be diminished."

More rolling blackouts to come

Berberich said in Monday's meeting that CAISO has "pointed out in filing after filing that the load procurement system was broken and needs to be fixed" to cover the hours when California's solar resource fades to nothing while homes and businesses remain heavy users of air conditioning.

CAISO's warnings went unmet from the California Public Utilities Commission, which regulates how utilities procure generation assets and sets the rules of the state's Resource Adequacy program to assure grid reliability, he said. CAISO's warning last year that the state would experience a shortfall of 4,700 megawatts of resource adequacy by 2022 was met by a CPUC decision to require utilities to procure 3,300 megawatts of resources by 2023

(https://www.greentechmedia.com/articles/read/california-demands-3-3gw-of-new-resources-by-2023-to-meet-looming-grid-shor), an amount Berberich said is inadequate.

CAISO was able to meet peak demand during the 2017 heat wave largely through imports from other states that weren't experiencing the same heat, Berberich said. But CAISO has warned "time after time that imports are drying up," a prediction that came true on Friday and Saturday "because the rest of the West is hot too."

The CPUC's order for utilities and other "load-serving entities" such as community-choice aggregators to procure 3,300 megawatts of resource adequacy has so far been met with contracts to build battery systems (https://www.greentechmedia.com/articles/read/pge-energy-storage-procurement-california) to store solar power for injection into the grid in the evening. CAISO has about 200 megawatts of storage interconnected to its system at present, and all indications are that it performed well in playing a role in meeting CAISO's needs, Berberich said.

Expanding that energy storage capacity can help shift solar power into the evening hours now facing grid shortages. But "batteries [alone] won't fix this problem," he said, since they can't generate their own power. "Solar power will have to be overbuilt to charge the batteries" as well as provide power to the grid.

Implications for 100 percent carbon-free energy goals?

Berberich's comments underscore the debate over how states like California can reach their 100 percent carbon-free energy goals without relying on fueled generators to provide emergency grid capacity.

Recent studies indicate that reaching a 90-percent renewable grid (https://www.greentechmedia.com/articles/read/90-clean-grid-by-2035-is-not-just-feasible-but-cheaper-study-says#:~:text=Energy-,90%25%20Clean%20Grid%20by%202035%20Is%20Not%20Just%20Feasible% and relying on natural gas for the remaining 10 percent of power is economically feasible by the mid-2030s. But converting the power grid to run entirely on renewable resources could be much more expensive, since such a path may need to rely on building excess solar and wind capacity and battery storage to cover shortfalls such as those the state is now facing.

"For those who say we can rely on our reserves, you are wrong," Berberich said in response to criticism that CAISO called its emergencies while it still had reserve generation capacity available. CAISO must retain its roughly 3,000 megawatts of reserve capacity to prevent the possibility of an even more widespread grid collapse, which could occur if a power plant were to drop offline or a key transmission line were to be forced out of service, he said.

Similar conditions could force more rolling blackouts in California through this week.

"A persistent, record-breaking heat wave in California and the Western states is causing a strain on supplies, and consumers should be prepared for likely rolling outages during the late afternoons and early evenings through Wednesday," CAISO wrote in a Sunday statement (http://www.caiso.com/Documents/Flex-Alert-Issued-Next-Four-Days-Calling-Statewide-Conservation.pdf) instituting a "Flex Alert" asking Californians to conserve energy from 3 p.m. to 10 p.m. to reduce load on the grid.

CAISO is calling for help from other utilities across the Western U.S., and has secured commitments from the Los Angeles Department of Water and Power, U.S. Department of Defense facilities, and industrial and commercial entities to reduce demand. Still, it could face the need to call for hundreds of megawatts of rolling blackouts starting around 3 p.m. on Monday, and up to 4,000 megawatts starting around 7 p.m..

"We are scouring every corner of our world" for additional capacity, Berberich said. But the persistent heat across the Western U.S. has left neighboring utilities and generators with little to spare.

The CHAIRMAN. Next we have Senator Cantwell.

Senator CANTWELL. Thank you, Mr. Chairman. Thank you for holding this important hearing. I am definitely for a smarter, cleaner, more secure, more resilient grid. I personally think that that takes a level of investment. We have had a couple of big studies recently talk about this. There was an MIT study and then a University of California study that found that investing $100 billion in transmission expansion could achieve a cleaner grid and help reduce wholesale costs. So I was wondering if I could get you gentlemen to give me an assessment of whether you think modernization of our grid is an investment we should be seeking and do you think that the private sector will make those investments or are we talking about some federal cost share here and do you think that that is in the tens of billions of dollars or hundreds of billions of dollars? How would you characterize the modernization and the investment that we need to make? And if you could just go quickly, that would be great. So I am asking you, do you believe we need that investment, at what level and what is the mix——

Mr. WOOD. I'll jump in and——

Senator CANTWELL [continuing]. Mix of federal and private investment?

Mr. WOOD. I'll jump in, Senator Cantwell, and it's a great question. We do need the backbone. The vision from the President and from many in the industry is going to need to be enabled by a substantially stouter transmission grid that will move the resources from where they are to where the people are. And I think that's probably a nine-figure number. It's a lot of money. But it's over time and it's, quite frankly, as we learned in Texas, when you spend money on transmission, you save a lot more than you spend on getting low-cost power into your power system.

Mr. ROBB. So, I'll go next. You know, this country has remarkable natural resources all around the country. They're not always near where people live, where the power needs to go and this concept of a national transmission grid is something that's very worthy of consideration. We've not studied the reliability impacts of it, other than to note that diversity is reliability's friend. So that's a good thing. I would probably concur with your assessment as to the cost of it.

I think the gating factor, though, that I think this Committee needs to be aware of is that it's probably not the need for transmission or the desire to fund transmission but the ability to site transmission that is the biggest obstacle of the development of that system.

Senator CANTWELL. Well, certainly——

Mr. GABRIEL. Yeah, and I'm happy to comment as well, Senator.

Look, I think the industry has done a pretty good job investing in what I'll describe as traditional transmission. I think what we also have to look at and understand is how can we use the existing transmission system differently? For example, there are seven ties between the Eastern and Western grid that are perfect examples of 1980s technology which could clearly be upgraded and, quite frankly, could be done within a two-to-four-year timeframe. So we'd have some immediate benefit there.

I also think that in addition, obviously, permitting takes time and funding is important, but right now there's a bit of a challenge with getting people to agree to the offtake. Transmission construction requires long-term, offtake agreements. Folks are hesitant to get into that. So if something can be done to clearly incent folks to agree to take the power that would really, I believe, free up the entire situation.

Senator CANTWELL. Thank you. Thank you.

I am going to skip Mr. Gabriel because I actually think I know what he thinks, just being the Western Power Grid. I think I know what you have been up to.

I just want to point out though that in Texas, I understand, that 96 percent of its projects in the ERCOT pipeline are either wind or solar. With Texas being an ultimate free market it tells me something, that people are going after that.

But I would like to talk about where the money went in Texas. Mr. Wood, it is good to see you again. Obviously, you and I talked a lot about the Western energy crisis and where the money went in that situation. But I want to understand because according to watchdog firms, Texas power markets overcharged energy users $16 billion. That left prices at $9,000 per megawatt-hour, the grid emergency standard, for longer than necessary. Are you familiar with this analysis and do you agree with those conclusions?

Mr. WOOD. I am familiar with the analysis. I think that the conclusions quantify that as if every megawatt-hour had been sold at $9,000. Of course, 90 percent of the business in Texas is done bilaterally by contract. So I think a number of customers were exempt from that. But——

Senator CANTWELL. Do you—well, that is what I am actually worried about.

Mr. WOOD. Yeah.

Senator CANTWELL. Like that, the consumer here.

Mr. WOOD. Correct.

Senator CANTWELL. Just like in the Western energy market. Do you think consumers should be reimbursed?

Mr. WOOD. That issue, the legislature is having a hearing on it today. Were I in that seat, I would have agreed with the Independent Market Monitor.

Senator CANTWELL. Do you know of any Enron traders who were involved in both the Texas and California markets that are employed at ERCOT trading now?

Mr. WOOD. I will have to check. I'm not aware of any.

Senator CANTWELL. Mr. Chairman, I think we have seen what happened here, at least in the detail. I am not talking about the crisis itself, but the aftermath, and I think we just need better tools to protect consumers and businesses from these kinds of spikes in rate. Mr. Wood knows that I fought diligently against our state having to pay 3,000 times the rate in long-term contracts that were fraudulently manipulated, so we passed laws here to try to protect people. Mr. Chairman, you said it best, price gouging should not be tolerated in these kinds of emergencies.

Thank you, Mr. Chairman.

The CHAIRMAN. Thank you, Senator.

Now we have Senator Daines.

Senator DAINES. Thank you, Mr. Chairman.

According to recent reports the Pacific Northwest, including Montana, will face a shortage of power supplies to meet peak load conditions. This means that while Montana and the Northwest can currently meet day-to-day demand, there is a real threat that during peak conditions we could face the same issues that we have seen in places like California, Texas and others most recently. It is my understanding that Montana electricity distributors are worried about generation resources to meet peak demand and the problem will only get worse if we continue to shut down coal and other baseload and flexible generation across the region.

I respect Senator Heinrich's comments earlier about him and Texas. I can tell you in Montana, it was not because of natural gas freezing up. We are used to cold weather and without the baseload of coal, we would have had some serious issues here last winter and even during the summer months of last year. While in Montana we have a great balance with hydro and coal providing baseload, a growing wind generation as well across the state, if the Biden Administration moves blindly, which we are seeing them doing today, to shut down all fossil fuel generation, that balance will be threatened and reliability concern turns into a stark reality.

Mr. Shellenberger, how does a rapid move away from traditional baseload and flexible power sources without new, equally flexible and stable generation affect the reliability of the grid?

Mr. SHELLENBERGER. Well, thank you, Senator. I think it's a really important question and it also relates to the former question by Senator Cantwell which is that if you're building additional transmission the assumption would be that you're bringing power from somewhere else, but if wind is already low during the cold snap and you build more transmission to more wind turbines, it's not going to increase, it's not going to do much for you. Similarly, in California since peak demand was occurring when the sun was going down, more transmission lines from solar plants isn't going to help us. So there's really no substitute for having baseload power. If we lose those baseload plants, we're just going to see more and more episodes like the ones that we saw last month and also in California last summer.

Senator DAINES. So, Mr. Shellenberger, with Montana and regional baseload influx with generation sources declining, it is creating a scarcity of resources to meet peak demand, as you articulated. As we have seen recently, what happens regionally can also affect Montana communities so the need for balance, it cannot just be focused on any one state, certainly for the nation of the interconnectivity of the grid. What steps can we take to ensure balance? I think that is a really key word right now and missing in this dialogue in Washington, DC, is balance and reliability throughout multi-state markets.

Mr. SHELLENBERGER. Well, yeah, you're raising the right concern, I think. And it's obviously up to the Senators to understand how these issues relate to both state and local, but what I would point out is that this rising complexity itself poses a significant problem. I mean, in all three of the National Academies of Science's reports from 2012, 2017 and just recently last month, they pointed to complexity overwhelming the regulators. And I have to say that when I read the other witnesses' statements, I was struck by, that the solution to the complexity is to add more complexity to the system and that starts to become troubling, I think, when you have a system that nobody seems to completely understand and how problems emerge really counter to what experts have been predicting.

Senator DAINES. Question for Mr. Gabriel. There have been recent calls to breach hydropower dams in the Columbia-Snake River System. As you know, having spent years at WAPA, hydropower provides strong baseload power for Western Montana and much of the Pacific Northwest. My question is how would a move to breach dams affect the supply of flexible, baseload energy in the region? And by the way, zero carbon emissions as well.

Mr. GABRIEL. Thank you, Senator.

Obviously we are not widely in support of breaching dams for all the reasons you said, in addition to things like black start capability, resilience and reliability. You've got to consider in the United States only three percent of the 90,000 dams have power capabilities to them and, if anything, I think it's a valuable discussion to have to make sure that we are thinking about increasing hydropower as it is a carbon free resource and one that can help bolster a grid in times of great stress.

Senator DAINES. Thank you. I remember I was just struck when it came to Congress, hydro is not classified as a renewable source of energy. That was the political incorrectness here at Washington, DC, and we finally got that changed, but it is zero carbon emissions. It is about as renewable as you can get as we watch what happens in a place like Montana, a headwaters state, but thank you for that answer.

Mr. Shellenberger, back to you. Instead of moving to shut down coal and natural gas plants to meet carbon goals, we should be focusing on innovation and working to expand the carbon capture technology, that we have been talking about here in the Committee, throughout the United States. The question is, how can we use CCUS technology to keep and grow jobs in rural Montana while at the same time protecting baseload power and ensuring a reliable grid?

Mr. SHELLENBERGER. Well, thank you, Senator.

I think it's, this is clearly an issue that matters to the Senate, it should matter to the Senate. We've built these carbon capture and storage demonstration projects and then we become frustrated when they don't work out right away. I think we need to have more patience than that. Certainly, in the case of carbon capture and storage, also in the case of nuclear, too often, I think, we build these projects and then we're disappointed when they don't come to fruition. And I would just add too that I think when we're thinking about our nuclear plants, because it is such an important technology for national security, we also need to be, I think, considering federal action to protect those plants which are currently not being valued for their contribution to reliability and resiliency and affordability in different restructured energy markets.

Senator DAINES. Thank you. Thank you, Mr. Chairman.

The CHAIRMAN. Thank you, Senator.

And now we have Senator Heinrich.

Senator HEINRICH. Thank you, Chairman.

I have heard some interesting things here today. One is that coal is baseload generation, and I say that because the average capacity factor for coal generation in the U.S. now sits well below 50 percent. So the average offshore wind capacity factor is higher in Europe than the U.S. coal capacity factor. And we have to recognize that part of that is because coal has become completely unaffordable as a power source. If you look at Lazard or any of the independent analysis of what wholesale costs are for various different generation sources—you have solar at $0.03 to $0.04 a kilowatt and wind at $0.03 to $0.05 a kilowatt, and then you have coal at $0.07 to $0.16 a kilowatt or nuclear at $0.13 to $0.20 a kilowatt—you understand what some of the market pressures are here and why we are being asked, for example, to subsidize nuclear power.

So moving from that to what we went through, and Mr. Wood, I want to start with you and I will begin just by thanking you for the work that you did to clean up the mess that Enron gave us. I think the work that you did on the FERC was incredibly important. But I would ask what policies you think would be wise to accelerate the deployment of the storage that you mentioned on the grid, both in Texas and nationally?

Mr. WOOD. Well, I think getting diversity in the supply chain. We clearly are dependent on China and a few other countries in East Asia for the current technologies that, I think Mr. Shellenberger pointed out correctly, that there are a lot of things other than lithium-ion batteries, but those are what are in all the EVs and certainly all the storage technologies. So the cost upstream, if there could be some, you know, American or at least North American, European supplies to that.

The policies in the U.S. make it easy, make it as easy to interconnect the battery, as we've made it to connect gas plants and windmills.

Senator HEINRICH. Yes.

Mr. WOOD. We're, of course, version 1.0 talking with our utilities. They haven't done it before, but it's not easy, learning to get these things done one by one. I think the market policies in most of the organized markets are very friendly to batteries. So I think we've got that box checked.

Senator HEINRICH. So interconnection is really a big challenge.

Mr. WOOD. Interconnection is important.

Senator HEINRICH. I am going to skip over the pricing issue which seems to be an enormously important thing if that $16 billion figure is accurate. Jumping forward a little bit, would it have been helpful for Texas to be able to import power, either from the East or the West in this recent episode? Because I noticed that El Paso power, for example, did not have the same rolling blackouts.

Mr. WOOD. Correct.

Senator HEINRICH. Because they were able to pull from the Western grid.

Mr. WOOD. And they're directly interconnected with it. We do have some gates in the wall.

Senator HEINRICH. You have DC connections, but you do not have direct connections.

Mr. WOOD. Correct. That's right. And there actually are proposals to put more of the DC ties in both East and West. To be honest, a few gigawatts wouldn't have hurt, but it wouldn't have saved us from, really, what was a 20-gigawatt shortfall.

Senator HEINRICH. Shortfall.

What was the single largest shortfall, from which generation source if you look at——

Mr. WOOD. Well, our largest supplier on a normal day is gas, so the impact of gas dropping both at the supply level and then at the power plant level. That's the interesting thing to figure out is how much was related to the lack of winterization which we should have learned from the 2011 experience, how much was done from that and how much actually had to do with the supply system or the upstream issues from the gas wells——

Senator HEINRICH. Yes.

Mr. WOOD [continuing]. All the way down to the power plant.

Senator HEINRICH. Right.

So for Mr. Asthana at PJM, I am curious. We have talked about the need for increased transmission, but there are also technologies like power flow control that can help us use the existing transmission much more effectively. Dynamic line ratings, storage as transmission, and topology optimization as well while other countries have started to really utilize those things in order to, oftentimes, make an electron take the longer way around so we can more effectively use our existing grid. We have not done a lot of that in the U.S. What role could those play in the future?

Mr. ASTHANA. Yeah, Senator Heinrich, I think that that's a great question. At PJM we're involved in almost all of those technologies, either in implementation or in piloting. So dynamic line readings, you talked about carbon core conductors, storage as a transmission asset. We're adding synchrophasors to our system with the help of a DOE grant. And the purpose of all of this is to squeeze more capacity out of the existing transmission system, because it's hard to site new transmission while increasing reliability. So you're going to see those technologies on our system, you're seeing them already, but you'll see them in larger deployment very soon.

Just one more point, if I could quickly make about your earlier question about coal. You know, in this recent cold snap, in PJM, coal was about 32 percent of the generation. Gas was about 32 percent of the generation. Nuclear was 26 percent of the generation. And so, just from a fuel diversity perspective, as a grid operator, I do think as we go through this transition, it's really important to make sure that we can hold onto those dispatchable resources until we have something to fill the gap with, whether that something is batteries or something else.

Senator HEINRICH. Thank you, Chairman. I apologize for running over.

The CHAIRMAN. Thank you, Senator.

Now we have Senator Hoeven.

Senator HOEVEN. Thank you, Mr. Chairman. I appreciate it.

Recently I asked former Secretary of Energy, Dan Brouillette, to give me his thoughts in regard to the importance of baseload energy, particularly as we saw the weather event last month and its impact across the country, particularly in Texas. Mr. Chairman, I would like to submit that letter for the record.

The CHAIRMAN. Without objection.

Senator HOEVEN. Thank you.

[Letter from Hon. Dan Brouillette regarding baseload energy follows:]

March 11, 2021

The Honorable John Hoeven
United States Senator
338 Russell Building
Washington DC 20510

Dear Senator Hoeven:

In response to your request to provide perspective to the committee on the role of baseload generation during times of high energy demand, based on my experience responding to requests for emergency relief to maintain the reliability of the system, I offer the following observations:

1) Studies have shown consistently that when our electricity system is stressed during hot days in summer or cold days in winter—when your constituents need it the most—it is baseload generation that is relied upon to provide dispatchable, predictable power. The Department of Energy's government-owned and government-operated National Energy Technology Lab (NETL) conducted an exhaustive study following the Polar Vortex in 2014 and the "bomb cyclone" of 2018, and found that in each instance, the generation used most reliably to meet the increase in demand due to those weather conditions was produced by nuclear, coal, oil and natural gas. These reports illustrate the importance of maintaining generation from sources currently scheduled for (or are at the risk of) closure and the need to construct and operate sufficient gas pipelines to ensure access to and delivery of natural gas. Additional Pipeline Capacity and Baseload Power Generation Needed to Secure Electric Grid | netl.doe.gov

2) The debate in Texas concerning which generation source performed poorly really misses the point. Wind and solar are important sources of supply but are intermittent and operate at lower capacity rates than nuclear, coal or natural gas generation. Even before the freeze occurred in Texas, ERCOT was expecting only a fraction of the wind capacity to be available. By contrast, baseload generation is always available.

3) Two decades ago, FERC initiated what can best be described as an experiment with electricity markets. As we sit here in 2021, the jury is still out on the results. Recent reports reveal customers have not achieved the cost savings they were promised. In fact, customers may have been paying more than if utilities had remained integrated and cost regulated. Deregulation Aimed to Lower Home-Power Bills. For Many, It Didn't. - WSJ. Many are also uncertain about FERC's experiment because, like President Jimmy Carter, governments and grid managers still ask Americans to adjust thermostats to avoid blackouts, to wear sweaters to avoid brownouts, to purchase "energy efficient" appliances that cannot efficiently perform the very functions for which they are designed, to reduce their use of electricity so the grid doesn't collapse...in other words, to simply "do without." A review of NOAA data shows that the weather is not the root cause of brownouts and blackouts in America; it's the lack of baseload generation capacity that is creating a shortage of on-demand or "dispatchable" electricity production.

4) We now know, however, that these "bid-based" markets fail to recognize the value of baseload electricity generation. They have a variety of mechanisms that are assumed to incent the power industry to have sufficient capacity available during times of need. But whether it's PJM or New England ISO with capacity markets, or the California ISO and MISO with ready "must-run" units, or ERCOT with its energy-only market, each have shown they are imperfect designs resulting in orders to shed load, reduce demand or face blackouts, almost always with tragic results. To ensure power is available to all when it is needed most, these "markets" should be designed to adequately price

reliability and resiliency in addition to capacity and the cost of energy. Currently, the reliability and resiliency of generation sources is not appropriately factored into electricity prices.

5) It is also important to recognize that stress on the system is not always caused by peak loads. Last summer, when I issued an emergency order in California, demand was *not* at a record level. Several natural gas units were readily available, but absent my emergency order, emission rules limited their ability to produce electricity. Additionally, the state's environmental policies prematurely closed other baseload units, resulting in an overall generation deficit. It is becoming more and more apparent that decisions to close plants are creating generation deficiencies and imbalance: the power simply might not be available when consumers need it.

6) Interconnecting ERCOT with the East and West Interconnect is not likely the answer. Many have said that the Texas blackouts could have been avoided if its grid were not isolated from the rest of the nation's bulk power system. These arguments suggest that being more fully interconnected with the West and East regions could have allowed generation from the surrounding region to flow into Texas. However, other regions were likely experiencing similar demands on their systems and it's not clear that any additional power would have been readily available. Furthermore, ERCOT's independence may have prevented its blackouts from spreading throughout other regions, as experienced in the 2003 blackouts.

7) A weather event should not be the cause of regional blackouts or statewide brownouts. In recent years, high performance computing and artificial intelligence analytics have improved modeling for both industry planners and investors. The technology used on the grid has greatly improved since the blackouts of 18 years ago. Load demands are becoming more and more predictable, and an imbalance of demand and supply of electricity is avoidable if the value of baseload generation is appropriately recognized and utilized.

Leadership comes with responsibility—responsibility to make hard decisions to avoid disastrous results based on sound engineering principles and the laws of physics. The problems faced by ERCOT last month and California last summer could have been avoided if their decisions had followed those principles.

Sincerely,

The Honorable Dan R. Brouillette

Senator HOEVEN. I will just read a couple of excerpts from it.

First, "The Department of Energy's National Energy Technology Lab conducted an exhaustive study following the Polar Vortex in 2014 and the "bomb cyclone" of 2018 and found that in each instance the generation used most reliably to meet the increase in demand due to those weather conditions was produced by nuclear, coal, oil and natural gas." And, quote, "These reports illustrate the importance of maintaining generation from sources at risk of closure."

One other excerpt, the current market construct of the various grid operators, quote, "fails to recognize the value of baseload electricity generation." And that's why these markets should be better, quote, "designed to adequately price reliability and resiliency in addition to capacity and the cost of energy" so, quote, "power is available to all when it is needed most."

Again, that is from the letter from former Secretary Dan Brouillette which I just introduced into the record. I would like to thank him for that response and his letter.

Mr. Robb, do you agree that baseload coal and nuclear are essential to grid reliability during extreme weather events?

Mr. ROBB. So we don't have authority over resource selection and fuel type. We try to make sure that our work is fuel agnostic. However, diversity of resource has been brought up many times, is a great thing for reliability. And I think until there's an alternative, those resources are going to continue to play an important role in the reliability and security of our electric grid.

Senator HOEVEN. How do we incentivize that? How do we make sure that we have that fuel diversity to give us that stability on the grid?

Mr. ROBB. Well again, I think that's up to local/state policy that affects resource selection and/or market incentives in market competitive states to ensure that those characteristics are appropriately rewarded and the technology continues to be developed to provide alternatives and/or to make those resources more compatible with the energy vision we have as a country.

Senator HOEVEN. What is NERC doing to make sure that the regional transmission operators, RTOs, ensure we retain the baseload generation and the fuel mix that we are talking about needing during weather events so that we have the reliability that we need as well as affordability on the grid at all times?

Mr. ROBB. So we do not get involved in market rule determination or some of the questions that you raise there. However, all of the market operators are subject to our reliability standards which are mandatory and enforceable that require them to produce contingency plans for all sorts of unanticipated events and be prepared to take appropriate action to preserve reliability of the system.

Senator HOEVEN. Mr. Asthana, you referenced the importance of the fuel diversity mix, including baseload for reliability of the grid at all times and particularly through extreme weather events, correct?

Mr. ASTHANA. Right, Senator Hoeven, although just with one minor—I would say coal is no longer baseload on our system. It has a capacity factor of 36 percent. So the only traditional baseload resource we have is nuclear which runs 95 percent of the time, but

I think your point is spot on which is we do need a diversity of resources.

Senator HOEVEN. Mr. Wood, do you agree that generational assets that can provide electricity in all weather events—hot, cold, windy, calm, et cetera—should be fairly compensated for their reliability?

Mr. WOOD. I absolutely do.

Senator HOEVEN. Okay, and then, how can we better ensure that we maintain that mix and properly incentivize them so that we have them in adequate proportion to the intermittent sources as well?

Mr. WOOD. I think that's the challenge and that means we've got to specify that firmness and dispatchability is a resource that we're willing to pay for. Different markets can do that in different ways, but at the end of the day, I'm certainly one who has sat in the dark for a few days last month. I can vouch for the fact that I want every kilowatt regardless of how it's generated to be on the grid on these stress days. And if we aren't paying enough to make that happen, we've got to figure out how to do it.

Senator HOEVEN. And if we don't, then we will repeat what happened last month with that extreme weather event, correct?

Mr. WOOD. We will and certainly weatherization issues are an important part of making the existing facilities we have. I'm not willing to give up that we don't have a good portfolio. I do think Texas had 100 gigawatts of nameplate capacity, but it didn't show up when we needed it. And so, the operational aspects of it are important too, Senator, and I want to make sure that we cover, really, both.

Senator HOEVEN. Right, very much so.

Thank you so much for your, all of you, for your responses. I appreciate it very much.

Thank you, Mr. Chairman.

The CHAIRMAN. Thank you, Senator Hoeven.

Senator Hirono.

Senator HIRONO. Thank you, Mr. Chairman. I thank all the panelists.

Mr. Robb, according to the Associated Press about 80 people died as a result of the winter storms last month, and, as you described in your testimony, after a winter storm in 2011 caused power outages and reduced gas production in Texas and neighboring states, NERC and FERC issued recommendations to state regulators to weatherize their power and gas systems. Were those recommendations followed by regulators and elected officials in Texas?

Mr. ROBB. So we will know the answer to that when we complete our inquiry into this most recent event. The recommendations that were put in that report were not subject to audit and compliance monitoring from our agency, so I really don't know the answers to what actions were actually taken, but we'll find out as we work through our inquiry.

Senator HIRONO. Well, considering the massiveness of the failure in Texas, I think that they probably did not follow your recommendations very well.

In September 2019, NERC initiated development of new cold weather requirements through enhancements to existing mandatory reliability standards, standards which your testimony states will be submitted for approval to NERC's Board of Trustees in June. How do you think adoption of those mandatory standards would have affected the response to this February storm?

Mr. ROBB. There's no doubt that they would've helped. I think one of the things that we don't yet know that we, again, we will uncover through this inquiry, is whether the power plants were weatherized adequately for the conditions that were in place, whether the fuel system, basically the natural gas system in Texas, would have been able to deliver fuel to those plants. That's a major open issue and one we want to get to the bottom of.

Senator HIRONO. Well, considering that we have this kind of massive power outage of 2011 and now in 2021, do you expect these kinds of weather conditions to be recurring, and do we need to make sure that we plan for them because to have literally hundreds of thousands of people without power for days on end is simply unacceptable?

Mr. ROBB. Yes, there's no question in my mind that the electric system and the natural gas system need to start planning for more extreme weather events as more routine occurrences, as opposed to treating these events as, you know, one-off, high-impact, low-frequency events. They're happening far too frequently.

Senator HIRONO. So just say yes or no. Do the other panelists agree that these are conditions that are going to occur more frequently and they are not just once in a thousand-year occurrences?

Anybody disagree with that kind of assessment?

Mr. WOOD. Senator, I do not. As I said in my opening statement, the impact on four and a half million people is pretty arresting and it's not anything we need to be doing every ten years.

Senator HIRONO. Thank you.

Mr. SHELLENBERGER. I agree as well.

Senator HIRONO. Okay, so I think all of our panelists agree we need to prepare, better prepare.

Commissioner Wood, as you know, Hawaii has six island power grids so we are definitely not connected to any other state, clearly, and not even to each island. And so, they cannot share power with each other. Hawaii has hosted several DOE-funded projects to evaluate how microgrids could, with local distributed power supplies, help communities maintain power for critical services while the larger electric grid is shut down due to storms or possibly cyberattacks. You describe in your testimony how Texas should consider creating smaller circuits to allow grid operators to conduct more targeted outages in the event of another extreme weather event. Do you think there are benefits to microgrids to support critical services and, if so, what more do regulators need to do to encourage their use?

Mr. WOOD. You're right on, Senator. I mean, I'm doing that for my day job. We're putting small batteries at the distribution level and enabling those things to happen. There's a lot more technology that is on the way that's part of the open system we have in Texas that was intended to bring that sort of innovation in, but microgrids are a big part of the future. They would have been a real asset for us, as they are for you in the islands for resilience purposes last month and I think the future is nowhere but up for the microgrids.

Senator HIRONO. I hope that, in fact, Texas will follow that kind of assessment and recommendation because my understanding of Texas is that basically the power there is in a competitive, free marketplace model, and I do think that there are some commodities such as electricity that are so basic that I do not know if free market is the best system to deliver those necessary commodities.

Thank you.

Mr. WOOD. I'd love to continue that debate.

[Laughter.]

But I think we're all in service of the fact that we want what's best for our customers at a good price, but we want the electricity to stay on.

Senator HIRONO. Thank you.

The CHAIRMAN. Senator Lankford.

Senator LANKFORD. Thank you, Mr. Chairman.

Mr. Gabriel, let me ask a quick question. I have several questions to be able to go through with other folks here, but I am tracking through the Biden team that they have announced that they want the power sector to be 100 percent renewable by 2035. I would assume that is going to require some transmission lines and trying to be able to connect places that have more renewables to places that do not. Mr. Gabriel, would you make that same assumption as well, that we are going to have to have an increased number of transmission lines to be able to hit that kind of goal by 2035?

Mr. GABRIEL. Yeah, yes, I do and I also believe in work to have to upgrade some of the existing transmission system that we have.

Senator LANKFORD. Well, I noticed, just for what you are dealing with, we started pulling through what, I love the name of this, the TransWest Express Transmission Project. I love the name "express" in there, the TransWest Express Transmission Project. It looks like this project started in 2007 and still has not commenced construction yet at this point based on permitting, studies, rights-of-way, surveys. Is that correct?

Mr. GABRIEL. That's correct. I've only been here since 2013 and I will say in 2015, I signed the Record of Decision for the project to move forward. It was similar to the comment I made earlier. Someone's got to agree to the offtake in order for these lines to be built so that there can be transmission agreements. And that's really been the hang-up thus far.

Senator LANKFORD. So this conversation about let's just quickly do renewable power and we will send it all over the country and get it done, begs the question of how are you going to do transmission lines for that when we have a transmission line project that started for you in 2007 and is still not close to being complete at this point? Sometimes 2035 seems like a long way away unless you are doing capital projects and permitting and such and it is actually not that far away nor realistic.

Mr. Shellenberger, let me ask you some serious questions.

You had a very intriguing line in your statement where you talked about complexity and it being one of the challenges. What I heard from you, basically, was just because we can do that does not mean it is actually the right way to do it. There seems to be a lot of work on—yes, this could be done, but it makes it so incredibly complicated, it drives up the cost—as you talked about before. If we are to clean the slate, as you are looking at it with your studies, what is a clean, straightforward way to be able to provide clean energy for the United States? Less complex.

Mr. SHELLENBERGER. Yeah, thank you, Senator. That's a great question. I think that there's a lot of folks in the sector who are good engineers and when they're asked the question of whether they could do something they answer truthfully and say, yes, they could, but they don't finish the sentence in the ways that you just did which is that all of that additional complexity brings challenges to resiliency, affordability and reliability. And that's just very well established in the literature that the more complex the system is, the more expensive it is.

I interviewed the lead author of the National Academies of Science's report, you know, they were very clear about this issue. I mean, ideally you have—and we also know that larger plants are more efficient—so what you want is a grid with the least number of power plants that you need and the least amount of associated wires and transmission and storage. Every time you put energy into storage and you take it back out, you're doing two energy conversions and so you're paying a very significant penalty, even in pumped hydro which is currently our most efficient form of storage. So yeah, I mean, I just think, I think this kind of headlong pursuit into more complexity and more transmission and more storage, you just have to kind of ask, is that really in the best interest of the American people?

Senator LANKFORD. It is a very interesting insight.

Mr. Robb, I want to ask a little bit about natural gas because we have had a lot of conversation about that, whether it is working, not working, the details. It is interesting to me, if I look at the Southwest Power Pool that I happen to live in and I had the wonderful experience of experiencing four hours with no power a couple of weeks ago when it was kind of chilly at night. So for all of us that looked at not only reliability, but resiliency of it, natural gas has been in this conversation. When I talk to folks in natural gas, they will say it is a unique challenge that they are getting because they are approaching a tipping point for them to say, natural gas is quick to be able to turn on, but when you are not asked for much for a long period of time, and then suddenly you ask for a lot in a short period of time, especially in an extremely cold weather event, then suddenly it is like, you know what? We cannot turn it all on that fast, that much.

Is there a tipping point that you are seeing for providing other fuels that are out there then, for instance, where 40, 50, 60 percent renewables and you have a very small portfolio of natural gas and then the wind stops blowing and it is a cloudy day and you suddenly do not have those and you ask natural gas to turn on 50 percent suddenly that that is just not realistic because what is upstream is not able to turn on that fast? Is that a realistic conversation?

Mr. ROBB. I think that is the conversation that needs to take place. Natural gas, natural gas plants are the most flexible that we have in the system to accommodate the variability that we see with large amounts of variable resources, and it is a real challenge for the natural gas industry to provide that kind of capacity that quickly. It's not designed to do that, but that's what the electric industry needs. And this is the question that, I think, policymakers and, probably, legislators are going to have to tackle which is how do we create a construct for natural gas to be able to serve these very unique needs of the electric system for which it's not designed to do.

Senator LANKFORD. Right.

Mr. ROBB. And that's going to require a fair amount of investment and some important policies.

Senator LANKFORD. And that will require some storage and other things we have talked about before.

Mr. ROBB. Exactly.

Senator LANKFORD. Increased storage capacity for natural gas can offset some of that as well.

Mr. ROBB. Exactly.

Senator LANKFORD. I would love to get into a dialogue with you, I just do not have time on this. But you had some really interesting conversations about home heating oil versus natural gas in the Northeast and some of the challenges there. I am always fascinated when I talk to my friends from New England who want to talk to me about carbon footprint when home heating oil has a 40 percent plus higher carbon footprint than natural gas does. In the Midwest we use natural gas. They use home heating oil then lecture us about carbon footprints. Always a fascinating conversation, but I would love to have that some time.

Mr. ROBB. We have a great dinner conversation ahead of us.

The CHAIRMAN. Senator Wyden.

Senator WYDEN. Mr. Chairman, thank you for holding this very important hearing. I will start this discussion by saying your grandfather's power lines were fit for your grandfather's weather events, and what we have to have is a modern system of power lines to deal with today's weather events.

This morning I introduced legislation to begin the modernization of America's power infrastructure so that we can deal with these horrendous weather events that we have been seeing around the country. Oregon saw a once-in-a-century windstorm last fall that ignited horrible wildfires. We just had massive power outages in our state. I spent days in a dark basement. Members of Congress are able, after a few days, to get up and get on with their lives, but we had a lot of Oregonians who had been hurting even before this happened and, now, they are in even worse shape. So this is a huge matter of public safety as well as a jobs issue and a climate issue. My legislation creates incentives for the private sector to step up and put in place those more modern systems so that we can deal with today's blackouts and wildland fires and this means everything from spring cleaning utility poles and power lines, undergrounding equipment when possible and cleaning brush and hazard trees.

So my question is for Mr. Wood, the former Chairman of the Federal Energy Regulatory Commission. Mr. Wood, as you heard me say, "grandfather power lines" okay for "grandfather weather" are not fit for today. And so I introduced legislation to update the system. It would make available funds for agencies like Power Marketing Administrations, like Bonneville Power Administration, to install some of the changes that I am talking about—underground power lines and strengthening overhead lines and installing equipment to monitor the grid during the serious weather. What do you think of something like this and what kind of additional funding do you think would be necessary to harden the power grid, especially in rural areas?

Mr. WOOD. Nice to see you again, Senator Wyden. I cannot emphasize enough how important robust infrastructure is, at both the local distribution level and up at the transmission level, for the future. The impact of severe changes in the weather that we have all lived through and actually I was so busy with our own outages in Texas, I wasn't aware of what you all had gone through in Oregon. That was quite substantial.

I think that the hardening of the infrastructure has a cost, from my regulatory mindset. With the larger utilities it's easier to recover that cost over a large area. And I've been a big fan of recovering transmission costs over the RTOs or the larger areas. I know we don't have those in the West yet, but that's been a great way to pay for big transmission. But the rural areas are oftentimes in co-ops or small utilities that don't have the ability to really internalize the broad costs just within their company.

And so I understand that your bill attempts to address some of that through cost sharing mechanisms. I think that we can't leave rural America behind. I think we learned during COVID, we can't do it on broadband, but we have never been able to do it on electrification since we fixed that issue a century ago. And it's no different today. You're right. Your grandfather's lines aren't what we need for the 21st century and starting with the rural aspects that you're talking about in your bill make a lot of sense to me.

Senator WYDEN. Well, thank you. We have appreciated your input over the years and that is the whole point of the $10 billion matching grant program for organizations like Power Marketing Administrations such as Bonneville. Because there are going to be some costs associated with this, but to me, there are also huge costs if we do nothing and we saw that all over the country, whether it is Texas, whether it is Oregon, we have seen it all over the country.

Same question for you, Mr. Gabriel, with respect to funding for the types of activities that I just outlined, do you think that would be useful? Is that something we could build on?

Mr. GABRIEL. Absolutely. Certainly any type of non-reimbursable funding that we could get to help bolster the system. Keep in mind, we already put $160 million or so every year in the WAPA system. Of course, the challenge, as Mr. Wood said, is most of WAPA's customers, many like BPA are very small municipalities, co-ops and rural folks. So adding a significant burden to them would be a challenge, but with any money that's available we'd want to add more sensors. We want to make sure that we're bolstering lines, and something as simple as switching from wood poles to steel is a huge expense but something that would clearly help grid resilience.

Senator WYDEN. Well, thank you both and we are going to want your counsel on this. As with a lot of issues, people are going to say, can we afford it? I think when you look at the other side of the coin, you cannot afford not to do this and I appreciate both of you.

Thanks for the time, Mr. Chairman.

The CHAIRMAN. Thank you.

Senator Marshall.

Senator MARSHALL. Thank you, Mr. Chairman, good to be here today. Thanks to all the witnesses.

I want to focus on the financial aspect of this, just for a second. I feel like I am here with the weight of three million Kansans who are waking up to utility bills which are just through the roof. I feel like I have the weight of 90, 100 different municipalities who were buying natural gas on the spot market. Municipalities who, in three days' time, spent more than they were planning on spending in the next five years. And the questions I am going to ask you are questions I have been asked dozens of times that I do not have an answer on yet. So please do not take them personally, but somehow I have to get answers to figuring out what happened financially.

I am certain we saw on the spot market the rates went up at least ten, you know, multiples of ten, sometimes more than that. I understand what happened to the supply. I understand that the wind turbines froze, the gas heads froze, the natural gas plants were affected, that some of the coal was frozen together by snow and all those things happening, but one thing that has been pointed out to me is, as we saw this spike in the price of it go up and stay up for three days, it went down so quickly. If it was just supply/demand, Mr. Wood, how would you answer that? Why would the price go down so quickly if there was truly a supply shortage? How did it go down quickly in three days? And if there was anything nefarious where would you look?

Mr. WOOD. Senator, on gas or on power?

Senator MARSHALL. Let's talk on natural gas, yes, sir.

Mr. WOOD. On the gas issue, clearly once constraints are overcome, whether that's wellheads come back online, you're right, that would generally be something that would be phased in. I mean, we went from 20 BCF coming out of Texas, for example, down to about 10, over that full week. So through the 15th through the 19th, Monday through Friday, it went down. And I don't, so you're talking about the price going back down to 10 from 900?

Senator MARSHALL. It went down really quickly.

Mr. WOOD. It was an issue when we looked in the California energy crisis that Senator Cantwell referred to earlier. It is always, it is a very open and transparent market. Scarcity pricing and market manipulation sometimes are two sides of the same coin. It depends what a jury thinks about it. But when you've got a scarce supply of something, you want to charge for it. In Texas, for example, I think probably in most of the states, our attorney general is pursuing actions now looking at gas and power trades because it is illegal to price gouge in an emergency.

Senator MARSHALL. Well, you see, you brought up the term "price gouging." Who would have profited from this? Would it have been on the markets, people that are playing the markets? Was it the producer that owned the gas well? Who profited in this scenario?

Mr. WOOD. Whoever has, I think in general economics, whoever has a precious commodity at a time it's most precious. And so, that could be the person that has it in storage, the person who is flowing it from a wellhead, whoever has title to that gas at that time. It could be anybody. It could be, you know, a landowner in the middle of Kansas or Oklahoma or Texas that has title or royalties to the gas.

So it honestly depends on where you are at the moment and where the gas is, where the title to the gas is at that moment.

Senator MARSHALL. How can we figure out who had it then? How can we follow the money?

Mr. WOOD. It took us years in the California——

Senator MARSHALL. Are you convinced that we used all the storage up that we had?

Mr. WOOD. I do not have any data that tells——

Senator MARSHALL. Does anybody know if we used all the storage up? Any other witnesses?

Mr. ROBB. I do not.

Senator MARSHALL. Who can explain to me—am I past my time? No, I still have a minute left.

The CHAIRMAN. You are right, you have one minute.

Senator MARSHALL. One minute left.

You know, I am going to guess it is Mr. Wood. How could FERC investigate, if there was anything nefarious, what does that process look like? And I am not saying there is. It is just hard for me to imagine just, prices going up exponentially. And again, I think about, you know, my parents on fixed income, what is happening to their electric bill and their heating bill coming up right now as well. How would FERC investigate this?

Mr. WOOD. FERC does have authority over market manipulation, just markets in general, in the interstate markets, of course, interstate natural gas pipelines serve Kansas, Oklahoma and parts of Texas as well. We have an intrastate, that's separate, but the Commodity Futures Trading Commission, they were certainly involved with us 20 years ago when we unpacked issues in the California crisis. The state attorney's general, as I mentioned, the one in Texas, is already investigating this issue. Those three camps, FERC, CFTC, for the futures——

Senator MARSHALL. And your experience is, that takes decades to go through that process.

Mr. WOOD. Well, no, it doesn't. I mean, you can unpack, in this digitized age, we have a lot more capability in 2021 than we did in 2001 to review trades in this matter or in any matter much more expeditiously.

Senator MARSHALL. Thank you. I am past my time. I yield back.

The CHAIRMAN. Thank you, Senator.

And now we have Senator King.

Senator KING. Thank you, Mr. Chairman.

I spent a good deal of my professional life in energy. I have developed hydro projects, biomass projects, wind projects and energy efficiency and I want to add—the watch word of today's hearing seems to be diversity is good—I want to add another phrase: there is no free lunch in energy; everything has costs and benefits and they need to be carefully calculated and weighed as we are moving through. Of course, one of the costs is contribution of CO_2 to climate change.

First, Mr. Wood, a somewhat facetious question, but can you tell us, unequivocally, that wind turbines did not cause the problem in Texas?

Mr. WOOD. They did not cause the problem. They were, honestly, the only thing was like gas and coal and——

Senator KING. Everything.

Mr. WOOD. Everything could've helped solve it faster, but, you know, wind was slow to get back and so was coal and so was gas.

Senator KING. And I want to mention that the wind project that I worked on in Maine has been online ten years, in Maine.

Mr. WOOD. There you go.

Senator KING. And has never been down because of the cold that I know of. It was a question of they are not weatherizing their turbines.

Mr. WOOD. Absolutely, right.

Senator KING. So there is nothing intrinsic in wind power that cannot survive cold weather.

Mr. Robb, and I don't want to dwell on this. I think you said something important in your earliest testimony. I consider the gas pipeline infrastructure part of the grid because of the dependency in New England. It is 60 percent, as you know, of our electric supply. And we have to treat it that way and we have to be sure that it is regulated and protected. I am surprised in this hearing nobody has talked about cyber because after an immediate weather event, cyber is our next most dangerous problem and I am particularly worried about the gas pipeline system.

Mr. Robb, I realize you do not have that in your jurisdiction. It is not even in FERC's jurisdiction, but we have to remedy that.

Mr. Robb, on cyber, do you pen test your utilities? Do you do red teaming on your utility's cybersecurity?

Mr. ROBB. We do not, but the Department of Energy does.

Senator KING. Okay. I would urge you to do so too. I don't think it would hurt to have multiple, because the grid is probably one of the primary targets in terms of a catastrophic cyberattack.

My friend from PJM, Mr. Asthana, what are we going to have to do in terms of modifications to the grid to accommodate the growth of electric vehicles? Obviously it is going to be an additional strain on the grid, most of it will probably come at night, but can you give me just a short answer on what you anticipate?

Mr. ASTHANA. Yeah, it's a really thoughtful question, Senator King. In terms of electric vehicles, part of the benefit of them is that the charging does come at night and both the transmission grid and the distribution grid is built for peak load. And so, load is less at night and so some of this electric vehicle load will just, sort of, fit in under the existing grid. I do think there are going to have to be reinforcements.

Senator KING. It would actually have the impact of lowering transmission and distribution costs for all consumers because you would be using more kilowatt-hours on the same infrastructure. Is that correct?

Mr. ASTHANA. Yeah, it might lower the unit cost. It wouldn't lower the total cost.

Senator KING. Right.

Mr. ASTHANA. But I think the really exciting part of electric vehicles—and PJM did a study with the University of Delaware on vehicle to grid. We actually piloted having vehicles provide regulation services off of their batteries and, you know, people were able to earn $100 a month in the pilot. So I think there's a lot of capability that will come to the grid that hopefully can add resilience through EVs as well.

Senator KING. Great, thank you very much.

Mr. Shellenberger, I am not going to spend a lot of time, I think I disagree with pretty much everything you have said and I would like to spend some time with you offline to discuss it. But you did a calculation, which you announced, of how much it costs to do renewables. Do you remember that? You said $116 billion or something like that. I would like you to do that calculation again, for this Committee, if all of that capacity and energy came from new nuclear power. I would like to see that calculation.

Mr. SHELLENBERGER. Yeah, we did two calculations actually. We did a calculation that found out that Germany had spent the $580 billion that its plants ran on renewables, nuclear not only would have 100 percent zero emissions energy——

Senator KING. I would like you to do the calculation that I asked you to do because nuclear is unbelievably expensive, multiples of anything else. So if you would please do that calculation of—just take exactly the capacity and energy that you used for the renewables and pretend that instead of renewables it would come from newly franchised nuclear plants and let's see what the comparison is. Can you do that?

Mr. SHELLENBERGER. Yeah, and we have done those. What gets misleading is when you're counting the electricity cost from a solar panel when the sun is shining and imagining that that's the cost that you're paying for a solar-powered grid. All of the transmission and storage and all of the additional costs associated with having variable renewables are externalized onto the grid.

Senator KING. Did you include those in your calculation?

Mr. SHELLENBERGER. We did and——

Senator KING. Yes, so give it to me for nuclear. This is a simple question.

Mr. SHELLENBERGER. Sure.

Senator KING. Just take the number of megawatts and the production and calculate it if it were new nuclear and give me the number. Can you do that?

Mr. SHELLENBERGER. Sir, you didn't let me finish the answer which was that we did California——

Senator KING. I don't want you to give me the answer now. I am running out of time. I want you to give me the answer in writing. If you could do that, I would appreciate it.

Mr. SHELLENBERGER. Yeah, and I just need you to specify what the question is. Is it for the entire United States?

Senator KING. I just want you to do the same. You announced a calculation in your testimony that was some big number, $160 billion was the incremental cost of renewables for this amount of power for—I don't know whether it was a year or five years. That was in your opening statement. I just want you to do the same calculation for the same amount of power as if it was generated by new nuclear plants.

Mr. SHELLENBERGER. Oh, I see, you mean the University of Chicago study that found that renewables cost $125 billion across 29 states?

Senator KING. Yes, that is it. That is it. Yes.

Mr. SHELLENBERGER. Senator, I would be delighted to do that and send it to you.

Senator KING. Thank you.

And one other, well, I think I am out of time.

I would like, Mr. Gabriel, for the record, if you could give me an answer as to whether you consider the grid instability problems a wires problem or a technology software problem. In other words, do we have to rebuild all the wires and towers or do we have to modify the way the grid is managed? I am out of time so if you could supply that for the record for the Committee, I would appreciate it.

Mr. GABRIEL. Happy to do so.

Senator KING. Thank you, Mr. Chairman.

The CHAIRMAN. Senator Cortez Masto.

Senator CORTEZ MASTO. Thank you. Thank you for this conversation today. I so appreciate the Chair and Ranking Member holding this hearing.

Let me just say from the outset, I also agree with my good colleague, Senator King, on electric vehicles. There is potential there. We saw the benefits, particularly in what happened in this winter storm, on President's Day in Texas, and so I have a lot of legislation around this space. It is the future, and we should not ignore it.

But let me jump back to the issue of winterization and weatherization and what we were seeing in some of these winter storms and with the infrastructure. So, Mr. Asthana, let me ask you this. In your written testimony you noted that PJM instituted incentives and penalties which prompted your power generators to winterize. And as a result, you said you have seen improvements in generator performance in the face of extreme weather. So in your opinion, would these necessary improvements have been made if PJM did not institute those incentives and penalties?

Mr. ASTHANA. Senator Masto, I can give you my opinion. It's impossible to know for sure because we didn't run that kind of factual. What we did was we did implement performance penalties after the 2014 Polar Vortex. And what we saw happen, and I believe that the performance penalties certainly helped it happen, was that the forced outage rate went from 22 percent back in 2014 to less than 10 percent in this most recent winter event. And so, there's certainly an improvement, a significant improvement. And I think the performance penalties and the incentives have helped.

Senator CORTEZ MASTO. Well and thank you for that because that is the question I have then for the rest of the panelists. Is there a role for Congress to play here to ensure that we are addressing the needed winterization and weatherization across the country? And if there is a role for Congress, what is the most effective incentive to compel those needed investments? That is what I am looking for.

Mr. Robb, let me start with you.

Mr. ROBB. Sure.

Senator CORTEZ MASTO. Do you have any ideas for how or what role Congress could play?

Mr. ROBB. So, I think with the existing authorities that we have, that Congress has already given to FERC and to NERC, we can address the weatherization issue within the power generation sector. I think the area that Congress should reflect on and potentially take action on is to think about how that extends into the natural gas and fuel sectors because having a great winterized plant with no fuel in front of it isn't very valuable and that's where our authorities, right now, stop. And I think that's an important thing to work on.

Senator CORTEZ MASTO. Thank you.

Mr. Gabriel, your thoughts?

Mr. GABRIEL. Well, I couldn't agree more than with Jim. Natural gas is really the fuel that we use in these emergency situations. Of course, running hydropower, we're fairly well winterized, other than, obviously, there's times when the rivers freeze and we've got some challenges. But it's really, what do we need for backup fuel and that line of natural gas is absolutely critical.

Senator CORTEZ MASTO. Thank you.

Mr. Wood.

Mr. WOOD. I would say, Senator, that the Texas example being, of course, the one I'm coming from, the legislature here, our legislature in Austin, has bills before it that would require weatherization for both the natural gas and the power industry. And I expect in light of what happened last month, those will be adopted and they will be stout. And that's, to me, akin to the airline industries is you don't have standards and good ideas, you have rules or you don't say anything at all. And so, this is the rule and it didn't work after 2011. So it'll work now because it'll be compulsory, and there will be performance penalties.

Senator CORTEZ MASTO. That is what I want to verify. I know Mr. Robb talked about there is an investigation underway right now with respect to what happened in Texas. At the end and in conclusion of that investigation, how can we be assured that Texas will take the appropriate action? And what I am hearing from you is that there will be penalties associated with their failure to take any appropriate action?

Mr. WOOD. Yes, ma'am. Unfortunately, due to the short timeframe of the Texas legislature I think the remedy will come before the analysis is through. But there is broad consensus that there—that this weatherization issue, again, as the weather events become more extreme, if we don't do it now, we'll have to do it again in the future. So let's just do it now. Other states may already have this authority. So I would probably check to make sure that states can't do it. If they can't do it, then the feds certainly should. But let the state closest to the people handle that problem.

But obviously, mine did not. So we got the message from our citizens last month to fix the problem and bipartisan bills have been filed in that regard.

Senator CORTEZ MASTO. Thank you. I notice my time is up. Thank you, everyone.

The CHAIRMAN. Our final Senator to grill our panelists is going to be Senator Kelly.

Senator KELLY. Well, thank you, Mr. Chairman. When you are at the end of the line here, a lot of the questions you have have already been asked and answered. I appreciate all of you for being here in person and virtually.

I want to start with Mr. Gabriel. So I want to expand a little bit on what Senator Cortez Masto was getting at and expand on how climate change is affecting water supplies and hydropower generation in the Colorado River Basin. We are going to transition for a second from Texas to California. During last year's extreme heat wave in California, energy from the Glen Canyon Dam and the Hoover Dam and Parker Davis Dam that could have been delivered to Arizona customers was called upon to keep the California grid from completely collapsing.

So against the backdrop of some climate change and increasing population growth in the State of Arizona and in the Colorado River Basin, in general, do you think hydropower is going to become a more valuable resource in years to come and should WAPA and its ratepayers be compensated for supporting black starts when power grids in other areas go down?

Mr. Gabriel.

Mr. GABRIEL. Yeah, thanks for the question, Senator Kelly.

Certainly WAPA's customers are compensated in terms of sales but hydropower is going to become more and more valuable as we add more renewables to the grid because of its baseload characteristics. Certainly in an emergency situation, hydropower has got serious advantages in that we don't need electricity to make electricity which is, kind of, a typical situation in many power plants. One of the real challenges though that we have is hydropower is not necessarily compensated for its black start capability. And of course, that's the capability of rebuilding the grid should the lights go out.

And I think it's something that really needs to be dealt with over time and I know it's sort of an embedded question in there. We always work to replace the power for our customers in Arizona and other states by buying it on the market. But remember, first and foremost, physics beats philosophy. So we want to keep the physics of the system alive and work diligently to make sure that we do whatever we can to keep the grid up and operating. Thank you for the question.

Senator KELLY. What would it take to put that compensation in place? How would that work?

Mr. GABRIEL. Well, I think there's several models that can be used. In several of the markets, hydropower is compensated for its black start and for its reliability and for its capacity. Given the fact that we really don't have a market yet in much of the West, I think that's going to be one of the critical issues that has to be determined as the West decides what its future is going to do, what it's going to look like in the market.

Senator KELLY. All right, thank you.

And for Mr. Wood, I know we talked a lot about Texas here already today. This weather event recently curtailed about 40 percent of the gas that gets delivered to Southwest Gas which has a service territory across Southern Arizona. During the event the price of gas for Southwest Gas went up from about $2.50 for a dekatherm to about $300. More than an order of magnitude. Fortunately we have some pretty good storage in the state that allowed us to weather the storm in Texas but the effect on Arizona customers might not be fully known because the way Southwest Gas does their billing on a 12-month rolling average.

I know we talked about this a little bit and we only have a little bit of time left, but I understand that Texans are hesitant to embrace federal energy regulation. But what assurances do Arizona customers have that Texas will move quickly to address the vulnerabilities to extreme weather?

Mr. WOOD. Well, I wish I could be the one to guarantee we're going to do it. But I mean, there are elected people back home working on this issue today. It was an emergency item added by Governor Abbott immediately after the event last month, Senator Kelly. And again, very strong bipartisan hearings last week on these issues. I think the bill is in markup probably in the next seven days, so——

Senator KELLY. And so, the Texas legislature is in session right now. Do you know when that session ends?

Mr. WOOD. Memorial Day.

Senator KELLY. Memorial Day. So if it does not get done before Memorial Day, it will be another two years.

Mr. WOOD. Or a special session which is possible because of the energy issues being so important, those will, perhaps, if not resolved by the end of—I think this is done before then though, Senator. I mean, the dynamics are too intense.

Senator KELLY. Has Governor Abbott committed to a special session to get this done if it goes beyond Memorial Day?

Mr. WOOD. I have not heard that. I honestly think he expects it to be done before they even do the budget.

Senator KELLY. Okay, thank you.

The CHAIRMAN. Thank you, Senator.

I want to thank all the witnesses for being here with us this morning and for your insight and responsiveness to all of our questions on this extremely important topic. It is truly timely and we appreciate very much the effort you made to be here.

Members will have until 6 p.m. tomorrow to submit additional questions for the record.

The Committee stands adjourned.

[Whereupon, at 12:17 p.m. the committee adjourned.]

APPENDIX MATERIAL SUBMITTED

U.S. Senate Committee on Energy and Natural Resources
March 11, 2021 Hearing: The Reliability, Resiliency, and Affordability of Electric Service in the United States Amid the Changing Energy Mix and Extreme Weather Events
Questions for the Record Submitted to Mr. James B. Robb

Questions from Chairman Joe Manchin III

Question 1: Extreme weather events, physical attacks, and cyber-attacks are occurring more frequently. We must continue to make the infrastructure of our nation reliable, resilient and responsive but we must also have the ability to recover from the loss of service and loss of equipment as expeditiously as possible.

a. **Do you believe that it is prudent to require utilities to have executable plans that outline how they would recover from a catastrophic event and require that plan to incorporate best practices used by other industries as well as include a reserve of equipment that is readily available and dedicated to these events?**

It is critical for utilities to develop, practice, and periodically update plans for recovering from major events. NERC's emergency operations standards address many of these objectives. For example, NERC's Reliability Standard, Emergency Preparedness and Operations EOP-006-3, requires reliability coordinators to develop and implement restoration plans when blackstart resources are utilized to re-energize a shutdown area of the bulk electric system (BES), or separation has occurred between neighboring reliability coordinators, or an energized island has been formed on the BES within the reliability coordinator area. Restoration plans must be shared with transmission operators and neighboring reliability coordinators, reviewed every thirteen months, and coordinated with neighboring reliability coordinators. Other requirements include system restoration training and restoration drills, exercises, or simulations. EOP-005-3, System Restoration from Blackstart Resources, requires transmission operators to develop and implement a restoration plan to restore the system when blackstart resources are required.

Regarding equipment reserves, industry maintains numerous mutual assistance programs and arrangements for the sharing of spare transformers.

b. **Would there be value in creating something like the Grid Ex event that would simulate low frequency high impact events and correlated outages to test the resilience of the electric grid in extreme situations?**

There is considerable value in entities practicing their emergency response plans for low frequency, high impact events. NERC's GridEx program incorporates these types of events.

Question 2: A report released last week by ICF International claimed that U.S. utilities may have to invest more than an additional $500 billion in the next three decades to safeguard critical energy systems against damage from extreme weather. This "resilience gap" is driven largely by the need to harden infrastructure against the effects of climate change, including heat waves, extreme storms, sea-level rise, and wildfires. Stakeholders have specifically asked NERC to update the reliability standards to address climate change.

a. **How is climate change addressed by existing reliability standards?**

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Among other objectives, reliability standards are designed to broadly support bulk power system (BPS) resilience, including for extreme weather. NERC Reliability Standards work together to establish a portfolio of performance-based outcome, risk reduction, and capability standards designed to support reliability. Several Reliability Standards relate to the BPS's capability to withstand disturbances in anticipation of potential events, manage the system after an event, and/or prepare to restore or rebound after an event. For example, NERC has developed the following:

• Reliability Standard TPL-001-4, Transmission System Planning Performance Requirements: providing planning performance requirements in anticipation of potential events, including studying extreme events, which include the loss of a large gas pipeline, wildfires, and extreme weather;

• Reliability Standard EOP-004-3, Event Reporting: requiring that entities report disturbances and events threatening reliability;

• Reliability Standard EOP-005-2, System Restoration from Blackstart Resources: including requirements pertaining to preparation for system restoration from Blackstart resources after an event, including developing a pre-defined restoration plan and verifying through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function;

• Reliability Standard EOP-006-2, System Restoration Coordination: requiring that plans and personnel be prepared to support system restoration after an event;

• Reliability Standard EOP-011-1, Emergency Operations: requiring operating plans to mitigate emergencies;

Comments filed with FERC in 2018 provide additional detail on how Reliability Standards and other NERC programs support resilience of the BPS. These comments are posted here.

b. Are there ways to better address climate change risk in reliability standards?

NERC continuously studies evolving risk, and, when warranted, develops new or updated Reliability Standards. For example, as discussed in NERC's written testimony, NERC is currently developing enhancements to three Reliability Standards addressing cold weather winterization activities.

NERC's assessments may provide additional considerations for Reliability Standards enhancements. Such enhancements could include:

- Reliability Standard requirements for the Reliability Coordinator, Balancing Authority, or Planning Coordinator to determine the temperature to which plants in their respective areas must weatherize.

- Reliability Standard requirements for the Reliability Coordinator or Balancing Authority to develop seasonal emergency energy management plans, to address conditions such as wildfires, extreme hot and cold temperatures, and severe storms (i.e. hurricanes).

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- Reliability Standard requirements for the Reliability Coordinator to develop a rolling three week emergency energy management plan.
- Reliability Standard for the development of a Seasonal Energy Management Plan based on regional extreme weather scenarios, to be assessed as part of NERC's seasonal assessments, and to include weatherization, fuel availability, projected unit maintenance, electric supply to gas wellheads and compressors, operating procedure, and so on; and a determination of the sources of energy and the degree of certainty with each source.

Question 3: The events in Texas last month illustrate just how intertwined our electric system is with our natural gas production and delivery systems.

a. What do you view as the benefits or drawbacks of the inter-dependence of the electric and natural gas systems?

The electric and natural gas systems are growing increasingly interdependent. As the bulk power system undergoes major transformation, natural gas-fired generation is becoming more critical to provide both "bulk energy" and "balancing energy" to support the integration of variable resources. However, greater reliance on natural gas and renewable energy also places greater emphasis on fuel supply risk which much be addressed. Further, the reliance of the natural gas industry on electric power exacerbates the risk, as electric load serving natural gas facilities such as wellheads, processing plants and compressor stations become critical to the continued reliable operation of the bulk power system.

b. What can we do to enhance coordination and fix existing and future vulnerabilities resulting from this inter-dependence?

More transmission and natural gas infrastructure is required to improve the resilience of the electric grid. Electric transmission investment must keep pace with the increase in utility scale wind and solar resources, which are generally located outside of major load centers. Transmission investments can also strengthen the ability to wheel power to different load centers improving resilience through redundancy. Additional pipeline infrastructure (including gas storage) is needed to reliably serve load and enable natural gas as a balancing resource.

Regulation and oversight of natural gas supply for electric generation needs to be rethought. While natural gas is key to supporting a reliable transformation of the grid, the natural gas system is not built and regulated to serve the needs of an electric power sector that is increasingly dependent upon reliable natural gas service. Further, there needs to be an understanding of the growing interdependencies of the natural gas industry on electric power and the need to preserve capabilities on the natural gas system to support electric generation. As it relates to BPS reliability, clear regulatory authority is needed over natural gas when used for electric generation.

Question from Senator James E. Risch

Question: Over the last few weeks, we have seen a number of high profile cyber incidents reported in the news. We know our nation's critical infrastructure is a top target for bad actors and that these threats

are persistent, increasing, and growing in sophistication. The Idaho National Lab is not only our nation's lead nuclear laboratory, it is also the go to lab for cybersecurity solutions. What do you see as the biggest cyber challenges facing our nation's energy infrastructure?

Myriad security challenges face our nation's energy infrastructure. Among the greatest threats are nation-state and other sophisticated actors, insider threats, and protecting a system that is becoming increasingly digitized through smart meters and digital control systems.

The December 2020 supply chain compromise conducted by a sophisticated advanced persistent threat (APT) reinforced that basic tenants and principles enshrined in the NERC CIP standards, and underscored the need for agile coordination and information sharing. The specific techniques and tactics used by adversaries remained similar to previous years, but their unique deployments and targeting shifted, highlighting a greater focus on supply chains.

Social engineering is another challenge we face. Targeted phishing and other forms of social engineering exploit human fallibility and trust to gain an initial foothold into targeted systems. Phishing continues to be widely used because it continues to deliver results for adversaries, and the most advanced examples of targeted spear phishing are practically indistinguishable from legitimate email traffic.

For insider threats, recruiting a willing or coerced insider to facilitate access is a highly effective (but riskier to the adversary) tactic. Employees, subcontractors, and other business affiliates have good access to the targeted organization and are often knowledgeable about sensitive, non-public systems of particular value. Insider threats are unwittingly facilitated by lax organizational security cultures.

NERC's Electricity Information Sharing and Analysis Center works with INL, to include a focus on national security capabilities on industrial cyber security, operational technology, and control systems through the guidance of DOE. In addition, the E-ISAC consults with INL on NERC's biennial exercise, GridEx, to identify potential cyber threats that players can exercise against.

What has becoming increasingly apparent, as we look forward to the grid of the future, system design must not only consider cyber-security, it must be designed to provide robust cyber-security, rather than bolted on as an afterthought. NERC is working with industry, IEEE, DOE, and INL to develop models and simulation tools that will enable a stronger cyber defense for the grid of the future.

Questions from Senator Maria Cantwell

<u>Question 1</u>: Using Federal Cost-Share Program to Promote Grid Investment

Numerous studies have demonstrated the need and the many benefits of investing in new and upgraded transmission, but the question remains on how to incentivize that investment at the scale and speed we need to meet national decarbonization and grid resilience imperatives.

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- **If the federal government funded a cost-share program to upgrade and expand the national transmission system, do you have any ideas how to design an effective cost-share program?**

Please see below response.

- **What criteria do you think the federal government should use to decide how to competitively allocate a potentially limited amount of program funds?**

Please see below response.

- **Could a cost-share program be based on, or expanded from, the existing DOE Smart Grid Investment Grant program?**

Please see below response.

- **What level of federal investment in a cost-share program is needed to make a difference?**

Please see below response.

- **Do you know of any existing programs that work well and could be a model for a new federal cost-share program?**

As discussed in testimony, NERC's technical assessments emphasize the need for more transmission infrastructure to improve the resilience of the electric grid. Electric transmission investment must keep pace with the increase in utility scale wind and solar resources, which are generally located outside of major load centers. Transmission investments can also strengthen the ability to transfer power to different load centers, improving resilience through redundancy. While NERC has not evaluated the design elements of a cost-share program to upgrade and expand the national transmission system, NERC assessments find that more investment in transmission is needed to support clean energy policy goals and grid transformation. Difficulty in siting and permitting long-haul transmission lines is a central challenge. To the extent a cost-share program could also be tied to addressing siting and permitting challenges, such a program could have laudable benefits.

Question 2: Potential Benefits of a National Backbone

Studies have shown that greater interconnectedness of the grid also lowers electricity rates by providing increased access to the least cost sources of generation in addition to making the grid more resilient. At the end of 2019, there was 734 gigawatts of proposed generation — 90 percent of which are new wind, solar, and storage projects —waiting in interconnection queues nationwide.

Despite the significant economic potential, much of it in rural parts of the nation, we are not planning for or building the national high voltage transmission backbone that is needed to take advantage of these incredible energy resources. The challenge seems to be figuring out the most effective way to monetize

those benefits and bring a portion of those long-term payoffs forward so they can help pay for the needed upfront capital to make these infrastructure investments.

- **Would the creation of a national backbone help clear the existing queue of new generation projects waiting to connect to the grid?**

A high voltage transmission backbone would provide more options to deliver power over long distances, connecting, for example, renewable resources in remote areas where there is excess capacity to load centers where power is needed.

- **If the U.S. had a national backbone in place, would that have potentially helped avoid or mitigate the power crisis in Texas last month or California last August?**

A more interconnected system could provide additional options to deliver power to Texas and California. Yet the potential of a national backbone to mitigate issues in Texas and California would depend upon how the system is designed to support these areas, and the availability of resources to serve load when needed during emergency conditions.

- **Will private sector markets build a national backbone or should the federal government, through the existing Power Marketing Administrations or another federal entity, build and operate such a system?**

NERC has not formulated a view on the relative roles of the private sector and federal government. Quite clearly, development of a national backbone would be a highly complex undertaking, requiring significant coordination and cooperation across multiple states, tribes, and other jurisdictions. Accordingly, should Congress take action in this area, Congress should consider policy options to address the long-standing jurisdictional issues that have historically made it difficult to site long-haul transmission lines.

Questions from Senator Lisa Murkowski

Question 1: Texas' power outages occurred as a result of a math problem, not a problem of political viewpoint. Historically, utilities held reserve margins of 20 percent. Recently, though, these reserve margins have fallen to 15 percent or even lower. The combined effects of lower reserve margins and increasingly extreme weather events jeopardize the availability of electric utilities to respond to peak demand. How can we get this math right to ensure reserve margins can respond to unforeseen increases in demand during extreme weather events?

Reserve margin analysis based on unit capacity is a traditional metric to plan for peak demand scenarios. As this question points out, capacity does not guarantee energy sufficiency. A diverse generation portfolio strengthens reliability and resilience, yet the benefits of diversity are lost when all resources underperform or fail due to common environmental conditions or common mode failures. The assumption made in the older resource mix was that fuel was always available. The new resource mix we are evolving to includes added uncertainties in fuel availability, driving the need for energy planning alongside capacity planning. All generation sources have energy limits and physical constraints, and these limits and constraints need to be accurately accounted for in seasonal and long-term planning assessments. While it is premature to draw hard conclusions before the joint inquiry is complete, thermal and variable resources in ERCOT, MISO, and SPP were forced offline or failed to perform as expected during the extreme cold weather event. Root cause analysis of generation failures will help inform strategies for strengthening resilience in Texas and neighboring regions.

Question 2: I understand that FERC and NERC have opened a joint inquiry into the operations of the bulk power system during the recent cold snap that swept through the Midwest and South-Central states. Did FERC or NERC predict reliability issues regarding extreme weather events on the nation's grid in previous reliability assessments, and how will you incorporate these increasingly severe and lethal threats to grid reliability, resilience, and affordability into future assessments?

NERC's testimony discusses numerous previous assessments that highlight extreme weather reliability risk in the Midwest and South-Central states, California, and New England. Specifically, NERC's 2020-2021 Winter Reliability assessment identified these areas as having a high risk to extreme weather. California, Texas and New England continue to be areas of focus in our assessments. To date, significant issues have occurred in California and Texas, while New England experienced a recent near miss event. As the resource mix has shifted to be increasingly reliant on variable generation, wind and solar, and "just in time" natural gas deliveries, we began introducing uncertainty of fuel risks into our seasonal assessments and developed more probabilistic analysis of reliability.

Question 3: During the recent cold snap and whenever we have a prolonged blackout, we are reminded of just how critical it is that power continue to flow. We know that a catastrophic failure of electric service is simply unacceptable in today's world.

In light of the experience that many recently suffered with a loss of power for only about three days, and considering the potential for a loss of electricity over many states such as we saw in 2003, and taking into account what we have learned about the threat of major cyber-attack and other "low frequency/high impact" events on today's interconnected electric grids that could produce a loss of electricity for a much longer duration over much wider areas --

a. **What is the plan for assuring the grids covered by the regional reliability entities that report to NERC and the broader interconnections are protected against a major cyber-attack?**

The security landscape is dynamic, requiring constant vigilance and agility. NERC assures grid security through a comprehensive series of complementary strategies involving mandatory standards, information sharing, and partnerships. NERC's mandatory critical infrastructure protection standards (CIP standards) are a foundation for security practices. They provide universal, baseline protections. Due to the ever-evolving nature of cyber threats, security cannot be achieved through standards alone. Vigilance also requires the agility to respond to new and rapidly changing events. Accordingly, NERC's Electricity Information Sharing and Analysis Center (E-ISAC) serves as the information sharing conduit both within the North American electricity industry and between the electricity industry and government for cyber and physical security threats. The E-ISAC facilitates communication of important or actionable information, and strives to determine and maintain "ground truth" during rapidly evolving security events. The E-ISAC also plays a key role in cross-sector coordination, focusing on sectors with which electricity has interdependencies, such as natural gas, water, and other critical infrastructure. Mandatory standards, coupled with effective mechanisms to share information, provide robust and flexible tools to protect the BPS. NERC works closely with the Department of Energy (DOE), Department of Homeland Security (DHS), FERC, and the Electricity Subsector Coordinating Council (ESCC) to further the public-private partnership so important to addressing security. NERC's biennial GridEx exercise is the largest of its kind in the sector and helps industry and government exercise their emergency response plans, and drive new and innovative approaches to reduce security risk to the electric grid.

Further, it is becoming increasingly apparent, as we look forward to the grid of the future, system design must not only consider cyber-security, it must be designed to provide robust cyber-security, rather than bolted on as an afterthought. NERC is working with industry, IEEE, DOE, and INL to develop models and simulation tools that will enable a stronger cyber defense for the grid of the future.

b. Insofar as the military doctrines of nation-states such as Russia, China, North Korea and Iran includes nuclear electromagnetic pulse (EMP) as extensive cyber threat, what is the electric sector's plan, at the utility, reliability regional entity, and national level to assure the grids are protected against that threat?

Recognizing the risk potential from electromagnetic pulses (EMPs), NERC launched an effort to better understand reliability concerns associated with EMPs and to identify ways to enhance resilience in the face of these concerns. NERC created the EMP task force in April 2019 to identify key issues and scope opportunities for action. At its November 2019 meeting, NERC's Board accepted the EMP task force's report that included a series of strategic recommendations. The EMP Task Force has focused its attention and offered recommendations or suggested next steps in five areas: policy, research and development, vulnerability assessments, mitigation guidelines, response and recovery. The successor to the EMP task force – the Electromagnetic Pulse Working Group – is a collaboration with industry which has developed a work plan comprised of 18 specific tasks. These include:

- Establishment of BPS performance expectations for all sectors of the BPS regarding a predefined EMP event.
- Identification and support of additional research to close existing knowledge gaps into the complete impact of an EMP event to understand vulnerabilities, develop mitigation strategies, and plan response and recovery efforts.
- Supporting development of tools and methods (and make available) for system planners and equipment owners to use in assessing EMP impacts on the BPS.
- Developing a guideline for industry to use in developing strategies for mitigating the effects of a high-altitude EMP on the BPS.

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c. **Insofar as a natural event such as a geomagnetic disruption (GMD) is statistically likely to occur at some point, how are you working (and with whom) to plan for and assure that the grids are protected against and able to recover from that threat?**

Two reliability standards address the risk of geomagnetic disturbances. The first standard, EOP-010-1 – Geomagnetic Disturbance Operations, took effect in April 2015. The standard requires entities throughout North America to have GMD operating procedures that can mitigate the potential impacts of GMD on the grid.

The second standard, TPL-007 – Transmission System Planned Performance for Geomagnetic Disturbance Events, was first approved by FERC in September 2016 and has been subsequently revised and enhanced. This GMD Planning Standard requires entities throughout North America to perform state-of-the-art vulnerability assessments of their systems and equipment for potential impacts from a severe 1-in-100 year benchmark GMD event (including the potential for localized peak effects), and mitigate against identified impacts. When needed, mitigation could include changes in system or equipment design, or the installation of hardware to monitor or reduce the flow of geomagnetically-induced currents (GIC).

NERC has continued an active and collaborative GMD research and development project with the Electric Power Research Institute which recently completed their work. We have also kept stakeholders informed of these efforts, and until recently had a standing Geomagnetic Disturbance Task Force tasked with coordinating the research results. NERC coordinates with government, public, and private research organizations in the U.S., Canada, and other countries to advance understanding of GMD risks. NERC also has a GMD data collection program to help validate models and further assess GMD risks and mitigation efforts.

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QUESTIONS FROM RANKING MEMBER JOE MANCHIN III

Q1. Extreme weather events, physical attacks, and cyber-attacks are occurring more frequently. We must continue to make the infrastructure of our nation reliable, resilient, and responsive, but we must also have the ability to recover from the loss of service and loss of equipment as expeditiously as possible.

Do you believe that it is prudent to require utilities to have executable plans that outline how they would recover from a catastrophic event and require that plan to incorporate best practices used by other industries as well as include a reserve of equipment that is readily available and dedicated to these events?

A1. Yes. The Western Area Power Administration (WAPA) has executable plans that include these elements. WAPA and other Registered Entities of the North American Electric Reliability Corporation (NERC) have broad-based executable plans for High Impact Low Frequency events including extreme weather events, physical attacks, and cyber-attacks. These plans are reviewed and training is performed annually. The executable plans are based on electric industry best practices including North American Transmission Forum (NATF) peer reviewed programs and National Institute of Standards and Technology (NIST) multi-industry cyber frameworks.

WAPA participates in some, but not all, electric industry equipment reserve sharing groups. These groups restrict utilization of reserve equipment to High Impact Low Frequency events. Although there are sparing programs for physical disruptions such as damage from extreme weather and physical attacks, there are not currently sparing programs for replacement of equipment taken out of service due to cyber-attacks. WAPA is limited in the degree to which it can participate in certain industry reserve programs because WAPA lacks dedicated equipment due to constraints in customer funding.

Q2. A report released last week by ICF International claimed that U.S. utilities may have to invest more than an additional $500 billion in the next three decades to safeguard critical energy systems against damage from extreme weather. This “resilience gap” is driven largely by the need to harden infrastructure against the effects of climate change, including heat waves, extreme storms, sea-level rise, and wildfires.

How are you monitoring the impacts of climate change on your system?

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A2. WAPA monitors system hydrology to forecast hydropower generating capacity and works with generating agency partners to monitor drought and climate change impacts. WAPA participates in ongoing drought contingency activities, such as the Colorado River Basin Drought Contingency Plan (DCP). The DCP was signed in 2019 and is designed to reduce risks from ongoing drought and involves the seven Colorado River Basin states, local water agencies, Tribes, non-governmental organizations, Mexico and the Department of the Interior.

Q2a. How are you incorporating those findings into your system planning?

A2a. WAPA's capital plans are developed on a ten-year rolling basis and updated annually to ensure infrastructure needs are addressed across WAPA's 15-state footprint to support the delivery of Federal hydropower to Federal customers. In all cases, WAPA's system planning and maintenance focus on reliability as a primary driver. In order to adapt its operations to evolving climatological and industry conditions, WAPA has:

- Modified its transmission tower replacement strategy to increasingly incorporate steel poles versus more vulnerable wood poles in areas subject to wildfires.
- Initiated a project to reduce fire risk in some areas in Northern California by expanding existing transmission rights-of-way and updating operation and maintenance plans for long-term management of vegetation and protection of sensitive resources within the rights-of-way.
- Joined the Northwest Power Pool to expand WAPA's access to generation resources to support its responsibilities as a Balancing Authority operator in the Bulk Electric System (BES).

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QUESTIONS FROM SENATOR JAMES E. RISCH

Q1. Mr. Gabriel, ensuring the cybersecurity of our electric grid is of the utmost importance. In Idaho, we are home to the Idaho National Laboratory – the leading national lab when it comes to ensuring the cybersecurity of the US grid. If the last few weeks and months have made one thing abundantly clear, it is that we simply cannot keep certain cyber attackers out of some of our most important systems and networks. I understand WAPA has engaged with INL's Consequence-driven, Cyber-informed Engineering (CCE) team to help your organization defend itself from Top Tier cyber adversaries.

Would you share your understanding of how this effort will put WAPA in a more confident position?

A1. The fundamental assumption behind CCE is to assume that a breach has already occurred, and therefore one must design systems to mitigate the effects of that breach. With the assistance of INL's CCE team, the Western Area Power Administration (WAPA) is incorporating those principles and aims into the design and deployment of a new Supervisory Control and Data Acquisition (SCADA) system.

Q2. Late last year, the Department of Energy established the Operational Technology (OT) Defender Fellowship, a collaboration between the Idaho National Lab and the Foundation for Defense of Democracies' Center for Cyber and Technology Innovation. Based on recommendations of the U.S. Cyberspace Solarium Commission, the fellowship aims to deepen cybersecurity knowledge for key private sector professionals and strengthen critical relationships between energy sector and government. This inaugural class of eleven individuals, includes a senior WAPA employee.

What benefit do you hope this employee will receive from participating in this program?

A2. First and foremost, WAPA hopes that our participant will develop relationships with other OT cyber defenders that encourage sharing of knowledge and best practices. WAPA also views this as a seed effort wherein she can use her newly gained knowledge and skills to improve our own practices in this vital arena.

Q3. Over the last few weeks, we have seen a number of high-profile cyber incidents reported in the news. We know our nation's critical infrastructure is a top target for bad actors and that these threats are persistent, increasing, and growing in sophistication. The Idaho National Lab is not only our nation's lead nuclear laboratory, but also the go to lab for cybersecurity solutions. What do you see as the biggest cyber challenges facing our nation's energy infrastructure?

A3. The biggest challenge is building the necessary skillset within the workforce. Skilled cyber defenders who understand energy delivery systems are extremely hard to find and almost impossible to recruit. Current training programs are not delivering them in the numbers required and with the skills needed.

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QUESTIONS FROM SENATOR MARIA CANTWELL

Q1. **Using Federal Cost-Share Program to Promote Grid Investment**

Numerous studies have demonstrated the need and the many benefits of investing in new and upgraded transmission, but the question remains on how to incentivize that investment at the scale and speed we need to meet national decarbonization and grid resilience imperatives.

- If the federal government funded a cost-share program to upgrade and expand the national transmission system, do you have any ideas how to design an effective cost-share program?

A1. While Western Area Power Administration (WAPA) WAPA does not have any direct experience with running such programs, it is our understanding that cost share efforts are particularly beneficial in reducing project risk in the early stages of transmission development before construction. The most challenging pre-construction issues for transmission developers are costs related to permitting, siting, incentives for states and landowners as well as system upgrades for interconnection to the existing grid. In addition, WAPA believes equivalent opportunities for transmission investment by publicly owned utilities (e.g., municipal electric utilities, cooperative utilities, tribal utility authorities, and special-purpose utility districts) may be beneficial, because they may not have access to incentives more relevant to investor-owned utilities and other private developers.

Q1a. What criteria do you think the federal government should use to decide how to competitively allocate a potentially limited amount of program funds?

A1a. Projects could be considered based on their specific project benefits (e.g., decarbonization, reliability and cost benefits) and resulting system characteristics (e.g., projects adopting a longer-term perspective of impacts with respect to system planning and decision-making; projects reducing dramatically the level of energy poverty; interregional transmission projects that unlock constrained resources for strong and equitable economic growth; projects developing a secure system that can minimize risks from disruptions and respond in a flexible and adaptive manner; projects implementing specific transmission technologies that increase the rate of innovation and performance without compromising affordability).

Q1b. Could a cost-share program be based on, or expanded from, the existing DOE Smart Grid Investment Grant program?

A1b. WAPA's understanding is that the Smart Grid Investment Grant (SGIG) program aimed to accelerate the modernization of the nation's electric transmission and distribution systems. The program selected projects—electricity providers across the Nation with plans to upgrade their systems—through a merit-based, competitive solicitation.

Q1c. What level of federal investment in a cost-share program is needed to make a difference?

A1c. WAPA does not have any direct experience with administering a Federal cost-share program to be able to appropriately evaluate the potential impact.

Q1d. Do you know of any existing programs that work well and could be a model for a new federal cost-share program?

A1d. As indicated above, WAPA does not have any direct knowledge and experience on the effectiveness of Federal cost-share programs.

Q2. **Potential Benefits of a National Backbone**

Studies have shown that greater interconnectedness of the grid also lowers electricity rates by providing increased access to the least cost sources of generation in addition to making the grid more resilient. At the end of 2019, there was 734 gigawatts of proposed generation — 90 percent of which are new wind, solar, and storage projects —waiting in interconnection queues nationwide.

Despite the significant economic potential, much of it in rural parts of the nation, we are not planning for or building the national high voltage transmission backbone that is needed to take advantage of these incredible energy resources. The challenge seems to be figuring out the most effective way to monetize those benefits and bring a portion of those long-term payoffs forward so they can help pay for the needed upfront capital to make these infrastructure investments.

- Would the creation of a national backbone help clear the existing queue of new generation projects waiting to connect to the grid?

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Q2a. A national transmission backbone could provide critical linkages between remote generation resources and private utility customer service areas (load centers). This would indirectly support integration of new generation projects currently in interconnection queues across the country.

- If the U.S. had a national backbone in place, would that have potentially helped avoid or mitigate the power crisis in Texas last month or California last August?

A2a. Robust transmission infrastructure inherently protects reliability by providing multiple pathways from diverse generation resources to load centers and by providing redundancies in the event of contingency events such as extreme weather.

Q2b. Will private sector markets build a national backbone or should the federal government, through the existing Power Marketing Administrations or another federal entity, build and operate such a system?

A2b. Due to the magnitude of the capital required and the complexities associated with commercial commitments or merchant business models, siting, permitting, funding, cost allocation, benefit allocation, and impacts to communities, such issues would need to be addressed in order for the private sector to finance and develop a national backbone.

Each Power Marketing Administration (PMA) has unique statutory authorities and missions. Because this type of investment could produce significant but diffuse societal benefits, any role the PMAs or another Federal entity might play would require additional authority and explicit mechanisms to ensure that Federal hydropower customers are protected from direct and indirect cost impacts.

Q3. **Infrastructure Rights-of-Way**

The past year has demonstrated that reliable electricity and broadband access are essential to modern life. Both these services rely on rights-of-way to bring services to American households and businesses.

- Do you support the concept of pairing new transmission and high-speed internet infrastructure into the existing rights-of-way?

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A3. In most cases, pairing new transmission and high-speed internet infrastructure can be an efficient means of expanding broadband access. To add access to WAPA's fiber assets for non-electric utility use to future rights-of-way acquisitions, WAPA would need Congressional authority to acquire rights outside existing legislative guidelines. Most of WAPA's existing rights-of-way would need to be renegotiated to effectuate non-electric utility use of fiber assets.

Q3a. How could surface transportation rights-of-way be used to build out additional electricity transmission capacity? Do you see this opportunity linked with future demand for EV charging?

A3a. The existing right-of-way contracts for surface rights dictate how they may be used and additional uses may require renegotiation. Electric vehicle charging may be a joint-use opportunity with distribution lines, but this is not WAPA's area of expertise.

- Do you think a federal "Dig Once" policy could facilitate the use of existing rights-of-way to build new transmission capacity?

A3b. Existing rights of way typically must be addressed on a case-by-case basis to determine suitability for high-voltage electric transmission lines. For safety and reliability reasons, high-voltage electric transmission lines are traditionally above ground and require a wide right-of-way. However, it may be possible to place high voltage lines underground in a limited number of circumstances and developers are exploring the possibility of placing underground lines in existing rights of way. For both rights of way yet to be acquired and existing rights of way, each site would need to be evaluated for its ability to meet the industry's strict safety and reliability standards.

Q4. **Need for Offtakers to Build New Transmission**

WAPA's Transmission Infrastructure Program has provided support for building new non-federal transmission lines across much of the West since the program was authorized by Congress in 2009. Under the program, WAPA has authority to issue loans to private developers of new transmission lines that would energize new renewable energy projects.

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As you mentioned during the hearing, many of those projects remain stuck because of a lack of critical mass from "off-takers" for power carried by the lines before they are constructed.

- This problem represents a chicken-and-egg problem: does a transmission line need contracts with subscribers before it can be built, or does it need to get built before subscribers sign up?

A4a. From the perspective and experience of WAPA's Transmission Infrastructure Program, the typical business model requires sufficient commercial commitments (transmission service agreements and concomitant, creditworthy evidence of power purchase commitments) for each project to justify any project investment. Merchant transmission without committed transmission service agreements to deliver power are in various stages of planning but thus far are uncommon due to the financial risk involved for either public or private financial institutions.

- In WAPA's experience, would that kind of authority assist in getting more new transmission lines constructed that would serve the public interest?

A4b. Since 2009, WAPA borrowing authority to finance transmission and related facilities, managed through WAPA's Transmission Infrastructure Program, has assisted in two new transmission lines being built that facilitate the reliable delivery of renewable energy as per statutory directive. This authority was made permanent and codified in the *Hoover Powerplant Act of 1984* (as amended) and continues to stand ready to assist in the development and expansion of transmission within WAPA's footprint.

Q5. **Upgrading Direct Current Ties**

During the hearing you identified, as prime examples of existing infrastructure in need of an upgrade, the seven DC ties connecting the Eastern and Western Interconnections in the United States.

- What type of upgrades are available today that would more efficiently and effectively utilize these seven DC ties and how long would it take to install them?

A5. There are two main high voltage direct current (HVDC) technologies: line commutated-converters (LCC) and voltage source converters (VSC). Most of the DC tie systems in operation today are based on LCC technology. Upgrading the legacy DC ties with the latest advances in LCC technology would result in modern control electronics using light pulses over fiber and the cooling systems would be more robust. If VSC technology were used to replace the legacy DC ties, weak alternating current systems could be better accommodated, and reactive power could be better controlled. WAPA anticipates the engineering, procurement, and construction process for upgrading a DC tie would take 30 to 36 months.

Q5a. What would be the benefits from upgrading these interconnections? Would these benefits be primarily local, regional, national? Would the benefits be continual or only realized during low frequency-high risk events such as the extreme Midwest cold snap last month?

A5a. Under normal operating conditions, there is the potential to optimize system diversity in terms of resource type, time zone, and geography by expanding connectivity between the Eastern and Western U.S. As one example, when California and the Southwest have solar overgeneration in the mid-afternoon, the Central U.S. is at or near peak electricity demand. When the sun is setting on the West coast and solar generation drops rapidly, the Central U.S. is past peak electricity demand for the day and has excess generating capacity. Power could conceivably flow back and forth between the East and West depending upon the time of day and weather, which could provide both reliability and economic benefits to multiple regions and nationally on a continuous basis. During high impact events such as the August 2020 heat wave across the West and the February 2021 winter weather event in the Central U.S., additional transfer capacity between the East and West would have allowed more entities to assist the entity or regions experiencing the event.

Analyses of various options to increase transfer capability would be essential. A primary goal of the analyses could be to explore whether expanding the DC ties, constructing DC lines between strong transmission substations in the Eastern and Western Interconnections, or tying the AC systems together and synchronizing the Interconnections would provide the greatest benefit.

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DOE has exceptional resources embedded in the National Laboratories both in terms of staff expertise and computing capability that could be leveraged to do this work. The ability of the National Laboratories to perform the analyses would be dependent upon the prioritization of work by DOE. The National Renewable Energy Laboratory in particular has significant experience analyzing this portion of the Bulk Electric System and has already performed significant work on this topic under the DOE Interconnections Seam Study.

The analyses could be done in collaboration with one or more of the DOE National Laboratories, the Southwest Power Pool (SPP) Regional Transmission Organization (RTO), and electricity providers along the seam between the Eastern and Western Interconnections. SPP's participation would be essential because its service territory encompasses the entire Western edge of the Eastern Interconnection. Understanding the magnitude of benefits associated with various options could provide the needed incentive for public and private investment.

Q5b. How much would these upgrades cost? Could federal investment dollars be leveraged to make these upgrades in a timely way?

A5b. Although high-level evaluations of (1) the cost of upgrading the WAPA-owned Miles City DC tie and the Sidney DC tie and (2) the cost of building new DC lines have been performed, estimates for expansion of the AC infrastructure and synchronization of the interconnections have not been performed. Further analysis would be needed.

Q6. **PMA Borrowing Authority**

The *American Recovery and Reinvestment Act of 2009* provided both WAPA and BPA additional borrowing authority to support transmission system planning, operations, and construction.

- Can you describe how WAPA used this authority, the resulting benefits, and any lessons learned on the use of those funds?

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A6. WAPA's borrowing authority provided in The *American Recovery and Reinvestment Act of 2009* was made permanent and codified in the *Hoover Powerplant Act of 1984* (as amended). This $3.25 billion borrowing authority is managed as a revolving loan program by WAPA's Transmission Infrastructure Program (TIP). WAPA's TIP has successfully issued loans to three transmission projects which have either been fully paid or are in active repayment status. TIP has numerous other projects in its pipeline at various stages of development. Completed projects include:

- Montana-Alberta Tie Line. This 214-mile, 230 kV transmission line was placed into service in 2013 and is delivering wind power from Montana to connected markets. This loan was fully repaid.
- Electric District No. 5 to Palo Verde Hub. This 109-mile contracted transmission project added 410MW of capacity to solar-rich Arizona and was placed into service in 2015. It also includes 254 MW connecting to the Palo Verde hub that services consumers in Arizona, Southern California and Nevada. This loan is in active repayment.
- Transwest Express is a proposed 725 mile, 500kV high-voltage direct current transmission line intended to export Wyoming wind power through Utah to Nevada. The project's developer repaid a $20.3M pre-development loan and this project is still in final development.

Q6a. If WAPA received additional borrowing authority, could that result in investments in additional needed transmission capacity?

A6a. WAPA is currently focused on administering the $3.25 billion borrowing authority Congress has already provided.

Q6b. How much additional borrowing authority would be needed to make a difference?

A6b. WAPA is not seeking additional borrowing authority at this time.

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QUESTIONS FROM SENATOR LISA MURKOWSKI

Q1. Extreme weather events underscore the need for more power generating facilities. We need to remember that electric generating facilities using renewable or conventional resources don't just turn on and off like a light switch. They take time to get up and running. However, hydroelectric dams could serve as critical emergency power supplies using large reservoirs that function as batteries. Could you elaborate on WAPA's response to California's energy emergency and your plan to use emergency power from federal hydroelectric facilities?

A1. Western Area Power Administration (WAPA)'s operation of projects for power output, excluding statutory requirements, is and will continue to be mainly for the benefit of WAPA's power customers. WAPA's customers are in the areas affected by the extreme weather events, so while WAPA's hydropower does help maintain the stability of the grid, the obligation to deliver power to power customers is paramount. During the summer of 2020 the California Independent System Operator (CAISO) initiated Stage 2 and Stage 3 emergencies, impacting millions of customers across California.

Three of WAPA's regional offices, the Sierra Nevada Region (SNR) the Desert Southwest Region (DSW), and the Colorado River Storage Project Management Center (CRSP) assisted California by adjusting energy schedules. Normally, all energy output from the hydropower projects in all three regions is contractually fully allocated to customers with very little excess available. To provide extra energy to assist California, all three offices coordinated with the Bureau of Reclamation (Reclamation) in their respective areas to shift water and energy schedules to provide as much assistance as possible while always adhering to statutory and contractual requirements. Reclamation operates the hydropower projects in WAPA's marketing areas under many environmental and regulatory constraints including water quality, fish propagation and temperature controls. Although Reclamation was able to modify schedules during the August 2020 California emergency to allow WAPA to deliver emergency energy to neighboring entities, Reclamation must adjust subsequent operations to make up for the water and energy delivered or received differently than originally anticipated.

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Q2. As one of the four power marketing administrations serving 15 states, WAPA needs to function well regardless of any physical disruptions or cyber-attacks. Can you elaborate on the efforts WAPA is taking to bolster grid resiliency beyond the requirements set and speak to the most pressing threats to maintaining affordable, reliable power in an evolving market?

A2. Through the Idaho National Laboratory's Consequence-driven, Cyber-informed Engineering (CCE) effort, we are seeking to design a SCADA system that is capable of functioning while breached. We adhere to the NERC Critical Infrastructure Protection Standards, and as a Federal Civilian Executive Branch agency, our information technology (IT) and operational technology (OT) systems are compliant with the requirements of the NIST Cybersecurity Framework.

In all cases, WAPA utilizes industry best practices and engages in peer reviews and audits to ensure readiness and preparation. As specific examples in addition to those mentioned above, WAPA:

- Develops and maintains reliability plans as required by applicable reliability organizations (e.g., NERC, the Western Electricity Coordinating Council, and the Midwest Reliability Organization).
- Participates in mutual aid agreements with other electricity providers.
- Engages extensively in industry forums including the Electric Power Research Institute (EPRI), North American Transmission Forum (NATF), and the Edison Electric Institute (EEI) Spare Transformer Equipment Program (STEP).
- Partners with the Federal Emergency Management Agency (FEMA) to provide restoration after declared natural disasters under Emergency Support Function (ESF) 12 as part of the National Response Framework.

Investments for national resiliency, as differentiated from utility-specific investments for system reliability, is challenging for all utilities due to funding availability, adherence to beneficiary pays principles, and complexities associated with cost recovery. WAPA's Federal customers repay, with interest, all investments in transmission infrastructure directly associated with delivery of Federal hydropower to Federal load. WAPA adheres judiciously to beneficiary pays for all customer-funded investments. System resilience investments that have broad regional or national benefits require more complex funding models based on studies identifying beneficiaries and appropriate cost allocation.

Q3. During the recent cold snap and whenever we have a prolonged blackout, we are reminded of just how critical it is that power continue to flow. We know that a catastrophic failure of electric service is simply unacceptable in today's world.

In light of the experience that many recently suffered with a loss of power for only about three days, and considering the potential for a loss of electricity over many states such as we saw in 2003, and taking into account what we have learned about the threat of major cyber-attack and other "low frequency/high impact" events on today's interconnected electric grids that could produce a loss of electricity for a much longer duration over much wider areas --

Q3a. What is the plan for assuring the grids covered by the regional reliability entities that report to NERC and the broader interconnections are protected against a major cyber-attack?

A3. WAPA will continue working with DOE HQ elements to include the Office of Cybersecurity, Energy Security, and Emergency Response; Office of Electricity; the Office of Intelligence and Counterintelligence; DOE laboratories; the Power Marketing Administrations; and engage with electric industry organizations such as Electric Power Research Institute (EPRI) and the North American Transmission Forum (NATF) on grid-related cybersecurity initiatives to leverage collective expertise, best practices, and emerging capabilities. NERC continues to expand and improve the Critical Infrastructure Protection (CIP) standards, the implementation of which provides the bulk of grid cybersecurity.

Q3b. Insofar as the military doctrines of nation-states such as Russia, China, North Korea and Iran includes nuclear electromagnetic pulse (EMP) as extensive cyber threat, what is the electric sector's plan, at the utility, reliability regional entity, and national level to assure the grids are protected against that threat?

A3b. WAPA will monitor the Department of Energy's Office of Cybersecurity, Energy Security, and Emergency Response (CESER) efforts with respect to the research program aimed at protecting infrastructure from electromagnetic pulse (EMP) interference. This program is collaborating with many utilities and national labs on efforts to test, model, and assess systemic vulnerabilities to EMP and geomagnetic disruption (GMD), and already has nine pilot projects underway as part of the agency's Lab Call for EMP/GMD Assessments, Testing, and Mitigation.

Q3c. Insofar as a natural event such as a geomagnetic disruption (GMD) is statistically likely to occur at some point, how are you working (and with whom) to plan for and assure that the grids are protected against and able to recover from that threat?

A3c. WAPA is, and has been, involved in mitigating possible GMD effects for over twenty years. WAPA participated in the Electric Power Research Institute's (EPRI) Sunburst program, which collected diverse data on geomagnetically induced currents (GICs). We comply with GMD-related NERC regulations, alerts, and data requests. Standard Operating Procedures have been developed for GMD alerts in advance of potential storms. WAPA employs personnel to keep abreast of GMD issues and novel technology such as the neutral blocking device which blocks GICs in transformer neutrals.

WAPA also participates in industry forums such as those facilitated by EPRI, NATF, and EEI that address resiliency issues and industry best practices. WAPA partners with FEMA to provide restoration aid after declared natural disasters under Emergency Support Function (ESF) 12 as part of the National Response Framework.

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QUESTIONS FROM SENATOR JOHN HOEVEN

Q1. During last month's extreme winter weather event, Southwest Power Pool (SPP) implemented "controlled interruptions of service," or rolling blackouts, across its region which included North Dakota. Concerns were raised that rolling blackouts had the potential to put critical natural gas infrastructure at risk in the Bakken, which would have interrupted the delivery of natural gas to homes or natural gas peaking plants.

To be better prepared in the future, is WAPA working with its utility customers to identify critical infrastructure that must be protected during power supply disruptions, including energy, health care, and other infrastructure critical to public safety?

A1. Yes, Western Area Power Administration (WAPA) is working with customers to identify critical infrastructure to protect during power supply disruptions and improve processes during such extreme weather events.

As a transmission operator, the control that WAPA has is limited to lines that connect to the bulk electric system and therefore cannot make surgical curtailments. Since WAPA's responsibility for, and knowledge of, customers' systems is limited, we coordinated curtailments with local utilities. In fact, some local utilities managed curtailments on their systems to ensure that the level of load SPP required to be curtailed was maintained until system operators directed them to restore the load. WAPA continues to collaborate with customers to evaluate lessons learned and plan for future extreme system conditions. As part of these discussions, WAPA has requested that local utilities develop their own load curtailment plans that could be incorporated into our plans. This will allow the local utility to conduct their own timely curtailments that integrate into SPP's and WAPA's transmission system emergency operating requirements. If the load serving entity doesn't have the capability to conduct timely curtailments, WAPA will work with them on which lines to curtail.

Additionally, WAPA is working with customers on processes to ensure that they have better knowledge of system conditions leading up to load shedding events. This will allow both WAPA and the local utility to be on the same page and better prepared when load curtailments are required.

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QUESTIONS FROM SENATOR ANGUS S. KING, JR.

Q1. Do you consider the problems we are facing in terms of grid reliability and security to be mostly a wires problem or a technology software problem? In other words, to meet U.S. electricity needs going forward, do we have to rebuild all the wires and towers or do we have to modify the way the grid is managed?

A1. Challenges to system reliability are not just a wires or software technology problem, and improving one will not eliminate the need to improve the other. The primary cause of the February extreme weather curtailment event was not wire or software oriented. Wires and software, however, did play a role in the magnitude of the event. The probability that load would need to be curtailed during the event in February was increased due to restrictions in the transfer capability of the wires to deliver energy from one geographical area of the system to another. Increasing the capacity of the wires will help avoid these kinds of curtailments in the future. However, there will still be physical limits to the amount of energy that can be transferred through the wires. Software technology would make it easier to operate the electrical power system during timeframes when the system is stressed to its limits and may help us fully utilize the capacity that is available. But software cannot overcome the physical capacity limits of the wires to transmit power.

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Questions from Chairman Joe Manchin III

Question 1: Siting transmission lines is extremely difficult and yet many are calling for major expansion in our transmission infrastructure. Having served as Chairman of FERC and having been involved in the largest U.S. grid expansion project in decades, I am curious what your views are on the best way to enable transmission build out where we need it.

Response: Robust infrastructure is key to competitive markets, clean energy, reliability, and resilience. We have experience with building large scale transmission. The project you referenced, the 2006-2013 Texas Competitive Renewable Energy Zone (CREZ) transmission, was a $6.9 billion, 3500-mile project initiated by a bipartisan Texas Legislature to expand the grid to where the best renewable resources were (the Texas Panhandle, principally) and to beef up the overall grid to accommodate this power. This process built upon a statewide planning analysis and then an allocation of the construction responsibility to several transmission utilities through a competitive process. The result has been a breathtaking addition of some 30,000 MW of new low-cost resources (mostly wind and solar) to our 100,000 MW grid. The phrase "if you build it, they will come" is often uttered when speaking about this successful process. The capital cost was the largest for a single transmission project in recent U.S. history, but it has been offset several times over by the resulting marked decreases in wholesale power costs in the ERCOT market. The simple policy for utility cost allocation is that all ERCOT transmission is paid for equally by all ERCOT customers. Utilities have a clear path to rate recovery through the regulated rates, siting is approved by the same Commission that sets the rates, and transmission remains a relatively small part of a customer's bill (<10%).

Similarly, many Central states, New England, California, and the Northwest have also completed significant transmission projects in the last two decades. Planning, siting and cost allocation are the three key issues in all contexts.

Most states are in multi-state regional transmission organizations (RTOs). California and New York, like Texas, have a single state independent system operator (ISO). In these multi-state organized markets, planning is done on a regional basis, siting is administered by the states, and the costs of many of the larger transmission projects are allocated under varying tariff formulas to the customers across the market.

Outside of the organized markets, i.e., in the non-California West and in the Southeast, there is no regional transmission tariff, and, if any regional transmission is even proposed, a more ad-hoc process must be used to plan, site and allocate the cost of regional transmission projects. It is difficult to reach agreement on how to assign costs to all the many beneficiaries across those large areas, particularly those who lie outside the service footprint or the state lines of the transmission builder. Stacked, pancaked rates for each utility discourage long-distance transmission of power. In addition, generation owning utilities do not wish to enable lower priced competition, electricity doesn't flow in a straight line, countless beneficiary studies support every conceivable result, and landowners are impacted by rights-of-way.

When I was at FERC, we reversed the trend of under-investment in a few regions such as New England and improved reliability and competition dramatically. Around 2007-2009, the Commission worked with states in the MISO and SPP regions to plan and broadly allocate costs. Having regional planning process and a tariff

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through which to recover costs was a major benefit of those newly-created RTOs. MISO MVP projects and SPP Priority Projects show how large-scale transmission can be built in the multi-state FERC jurisdictional context. But to remove all doubt and make headway constructing the 21st century power grid, clear direction should be given to FERC to bring more order to this process: confirming its authority to require the planning of large-scale interstate transmission, setting timetables (and backstops) for state siting processes, and clarifying broad authority to allocate approved costs broadly across all users and beneficiaries.

Backstop federal siting is an important tool to be available for all the reasons Congress included Sections 1221 and 1222 in the Energy Policy Act of 2005. The Bush administration actively advocated for these provisions. Congress could now act to clarify Section 1221 in light of the 4th Circuit Court's pinched interpretation of when federal backstop siting is triggered (558 F.3d 304 (4th Cir. 2009)).

a. Do you have recommendations on cost allocation and/or how to improve regional transmission planning?

Response: FERC has statutory authority over interstate transmission in these two key areas. Congress could strengthen that authority to provide regulatory certainty and avoid lengthy court appeals. When MISO imports 13 GW from PJM as they did during the Presidents Day winter storm, and at other times PJM imports similar amounts of power from MISO, who benefits? I have not seen any regional backbone transmission project or any project between regions that was not used and useful to everyone in these better-connected regions. By improving both economics and grid reliability, customers in both regions benefit. So, customers in both regions should pay for expanded inter-regional transmission. The same is true for all other neighboring regions, and even for connections between the Eastern and Western Interconnections.

Question 2: I understand that when you were Chairman of the Board at Dynegy, before it was acquired by Vistra, you had an up-close view of some of the realities of retiring coal plants, specifically the impacts on the workforce. As we tackle climate change, we cannot abandon these communities that helped fuel this nation for generations and develop its industrial might along the way.

a. Have you observed programs or policies that have helped traditional energy workers transition when faced with plant closures?

b. What are your views on how to address this crisis in these communities and other fossil fuel producing regions?

Response: Of our Dynegy coal-fired plants in Illinois, we worked hard to maintain our coal-fired fleet despite challenging economics in the MISO market and environmental regulations governing emissions. We ended up closing our Wood River plant and one unit of our Baldwin plant to comply with our emissions-related settlement with the State and the Sierra Club. To minimize layoffs, we offered comparable positions at our nearby power plants. Combined with retirement planning, we were able to accommodate most employees who were interested in relocating. We merged into Vistra Corp. in 2018 and I am aware that Vistra has closed or announced plans to close additional plants.

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In California, due to once-through cooling water regulations, we were forced to close our Morro Bay and Moss Landing natural gas-fired plants along the Pacific Ocean. Following our merger, Vistra converted the Moss Landing site into the world's largest lithium-ion battery storage facility. I am not aware of how many jobs were able to be retained as a result. The advantages of repurposing existing power station sites include long-established zoning, robust interconnections with the transmission grid, and availability of skilled workers in the community.

Even as we move to a lower carbon electricity system, the Texas experience has convinced me we need to maintain sufficient firm dispatchable capacity for extreme weather events. This may require some changes to market designs to ensure the plants and their employees are available to provide power at these crucial times, even while we endeavor to reduce the carbon emissions from these plants. More broadly, the state and local governments have an important role in supporting job retraining and continuance of health and pension benefits for the experienced men and women who have worked in these industries for their careers. In the difficult Base Realignment and Closure process in the 1980s and 1990s, there was a strong job retraining and local community reinvestment linkage that could be applied to communities impacted by the energy transition.

Question 3: You have a unique perspective having first been Chairman of the Public Utility Commission of Texas (PUCT) and then Chairman of FERC. There has been a lot of discussion about the way the Texas grid was designed to be self-contained, seemingly to avoid federal oversight of the energy market, and how the inability to import power that made the situation worse last month. Can you help me understand what's so bad about FERC oversight?

Response: Nothing is bad about either regulatory regime. I, perhaps better than anyone, can attest to that. Both Texas and the FERC have consistent policies regarding economic regulation of the wholesale power industry, and FERC now has oversight (through NERC) of the reliability of all power grids, including ERCOT. But having been head of both regulatory agencies, I can attest that Texas' combined wholesale and retail jurisdiction has allowed my State to much more easily implement a comprehensive vision for a restructured market. The Texas Legislature directed the PUCT to develop a competitive wholesale market in 1995, parallel to FERC's efforts under Order No. 888. And building on that reform, Texas moved to a competitive retail market in 1999 legislation, with market opening in 2002. The advantage of Texas' structure is that these moves were integrated and coordinated with one regulator in charge of both the vision and execution of market structure and operation. In 1999, the regions of Texas under FERC wholesale regulation were not deemed to be sufficiently competitive to support retail customer choice in those regions, so market opening was delayed there. Today, with the subsequent implementation of robust wholesale markets in the MISO and SPP while and after I served at FERC, it is appropriate for Texas to complete the transition for the rest of the State.

Once I got to FERC in 2001, I better appreciated that varying state policy approaches can, at times, be hard to accommodate across a multi-state regional grid operator (RTO). Not impossible, of course, but more complex. And even in California and New York, the other two states beside Texas that have a single state grid operator (ISO), there have been tensions between the federal vision for wholesale competition and the state vision for

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retail customer service. This is not necessarily bad; in fact, more conflict between FERC and the California parties in the mid 1990's over the lack of readiness to implement the state's restructured market design may have avoided the 1999-2000 energy market crisis. But, by and large, reasonable regulators have been able to work together over the past quarter-century to minimize these tensions and deliver value for customers. Texas admittedly has it easier because of the "one stop shop." Bipartisan political consensus supportive of competition and friendly toward renewables' place in our "all-of-the-above" power portfolio has provided a good climate for infrastructure investment of all kinds

One particular issue that was critical in the formation of the competitive ERCOT market was the requirement that transmission owners form the ERCOT ISO. Under FERC regulation to date, joining an RTO/ISO has been at a utility's option; at times, this has given utilities an undue leverage vis a vis other market participants in governance and other matters. And a couple of utilities have actually withdrawn from an RTO. Of course, this disadvantage can and should easily be remedied by Congress by making it mandatory for all utilities to join an RTO.

In addition, as noted in my response to your earlier question, the ability to regionally plan transmission, get utilities to build it and allocate costs to customers pay for it has been a particular success of the Texas/ERCOT model. FERC has been able to implement the planning and timely cost recovery aspects of the ERCOT model in the multi-state RTOs, but cost allocation remains a difficult process. As noted above, however, we have seen success inside both the MISO and SPP regions constructing multi-state transmission projects.

But in one final area, ERCOT has had no distinct advantage, and that is with inter-regional transmission. As noted in my testimony, ERCOT can lawfully add DC interconnections with neighboring regions without changing its jurisdictional status. I think it should do so, both for reliability and for economic export reasons. I doubt that even a quadrupling of our present interconnections to other grids would have avoided our need to drop significant load in the Presidents Day freeze, as the regions to our east were also suffering shortages. But some incremental imports, particularly from the west (where the weather was not as severe and where we have no interconnections today) would have helped on the margin. Also, as I saw in 2003 Northeast Blackout, where black start was required to reenergize the grid here and in Canada, power restoration was much shorter there than it would have been had Texas suffered a blackout, because the rest of the Eastern Interconnection was able to support the ramping up of generation and load in the Northeastern states and Ontario.

Whether the transmission projects are DC (as are used between the North American Interconnections) or AC, it takes hard work -- even zeal -- to get a multi-state transmission project permitted and built. Compared to in-region transmission, experience to date has shown that the regional interconnectors tend to be under-utilized. And, once they are finally constructed, ERCOT faces the same problems as do the FERC-jurisdictional grid operators regarding the cost recovery of such projects' costs from multiple ISO/RTOs: who pays and how much? Ideally, FERC should be able to allocate costs to each region based on historic load flows.

Question from Senator James E. Risch

Question: Over the last few weeks, we have seen a number of high profile cyber incidents reported in the news. We know our nation's critical infrastructure is a top target for bad actors and that these threats are

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persistent, increasing, and growing in sophistication. The Idaho National Lab is not only our nation's lead nuclear laboratory, it is also the go to lab for cybersecurity solutions. What do you see as the biggest cyber challenges facing our nation's energy infrastructure?

Response: At the invitation of your predecessor from Idaho, I had a most memorable visit to Idaho Falls in 2004. After being shown the general capabilities of INL, I had clearance to witness and be briefed about the real-time penetration attempts on our power and telecommunications networks across the country. It was the most sobering experience of my entire tenure at FERC and led me to augment the duties of our newly-formed Reliability Division to encompass cybersecurity concerns. With the 2005 Energy Policy Act, the newly formalized NERC has taken the task of adopting cybersecurity standards for the nation's power system, and I follow their efforts closely to this day. The Department of Energy and ARPA-e investments in cybersecurity research over the last decade have been significant. I believe that penetrations into our grid through both hardware and software weaknesses will happen, and that our focus should be on redundant and independent operating systems across the power sector to reduce the impact of successful attacks. I also think it is important for the federal government to be even more active sharing ongoing information regarding threats with the industry, so the industry can be better prepared to respond to pending and active attacks.

A successful cyberattack could have a similar, if not worse, detrimental impact to customers that the Texas winter storm just had. So that puts the issue of mitigation of harm high on my list. This involves issues such as local government coordination planning, utility management of outages and restorations, backup equipment inventories, redundant sources of power for critical facilities, relief to displaced people, and black start capability, to name a few.

Questions from Senator Maria Cantwell

Question 1: Using Federal Cost-Share Program to Promote Grid Investment

Numerous studies have demonstrated the need and the many benefits of investing in new and upgraded transmission, but the question remains on how to incentivize that investment at the scale and speed we need to meet national decarbonization and grid resilience imperatives.

- If the federal government funded a cost-share program to upgrade and expand the national transmission system, do you have any ideas how to design an effective cost-share program?

Response: I agree that large scale transmission is needed and there is a national interest in getting it built. There is an interesting contrast between interstate motor vehicle highways that have 90 percent federal funding and the interstate power transmission highways, which have no straightforward way to recover costs. We have 500 transmission owners who can recover costs in rates for investments on their local systems but no functioning way to do it for lines that cross many other utility systems and states.

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In my testimony I suggested a tax credit for large scale high voltage transmission. The industry knows how to use tax credits, as you know from your leadership on the Senate Finance Committee. But considering the considerable cost and long time-table required to build projects of this magnitude before they would be able to generate taxable revenue, it would be better to directly fund the planning and construction phases up front, and allow rates over time to repay the Treasury down to the appropriate cost-share. One positive difference with highways is that most transmission is privately developed and owned, and we have many private companies able and willing to build and own the infrastructure. What they need is a clearer path for getting paid for that investment.

There may be other policies such as the government reserving capacity on large scale lines where transmission customers can pay taxpayers back over time when they connect in the future. This would be similar in concept to the Bonneville Power Administration's Network Open Season approach that worked in your region a decade ago.

- What criteria do you think the federal government should use to decide how to competitively allocate a potentially limited amount of program funds?

Response: The government could base investments on the distance, capacity, and access to resource diversity of transmission investments. What is really needed for reliability and clean energy is resource diversity, such that weather, wind, sun, and demand in one place are less correlated with weather, wind, sun, and demand in other distant places. Transmission planners or DOE experts could identify which lines access the most diversity.

- Could a cost-share program be based on, or expanded from, the existing DOE Smart Grid Investment Grant program?

Response: Yes, my understanding is that this program, which I believe you helped create in the 2007 EISA, is available to be used for large scale transmission investments as much as Congress wishes to put into it.

- What level of federal investment in a cost-share program is needed to make a difference?

Response: Recognizing that 90 percent of highways are federally funded and tax credits usually cap at 30% of an investment, those provide a range of options. Ratepayers and taxpayers are largely the same; it really comes down to what is the simplest way to get the project done. In my experience, a generous federal contribution can expedite the process, so I would answer your question: 30%-50%. This need not lead to federal ownership of the facilities; utilities and private developers can build and maintain the transmission lines.

- Do you know of any existing programs that work well and could be a model for a new federal cost-share program?

Response: The Transportation Infrastructure Finance and Innovation Act loans used in the transportation context may be a good model.

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<u>Question 2</u>: Potential Benefits of a National Backbone

Studies have shown that greater interconnectedness of the grid also lowers electricity rates by providing increased access to the least cost sources of generation in addition to making the grid more resilient. At the end of 2019, there was 734 gigawatts of proposed generation — 90 percent of which are new wind, solar, and storage projects —waiting in interconnection queues nationwide.

Despite the significant economic potential, much of it in rural parts of the nation, we are not planning for or building the national high voltage transmission backbone that is needed to take advantage of these incredible energy resources. The challenge seems to be figuring out the most effective way to monetize those benefits and bring a portion of those long-term payoffs forward so they can help pay for the needed upfront capital to make these infrastructure investments.

- Would the creation of a national backbone help clear the existing queue of new generation projects waiting to connect to the grid?

<u>Response</u>: Yes, a national backbone grid would be very beneficial for clean energy, reliability, and resilience. Large scale regional and inter-regional transmission would help unlock these interconnection queues.

- If the U.S. had a national backbone in place, would that have potentially helped avoid or mitigate the power crisis in Texas last month or California last August?

<u>Response</u>: Mitigate, yes. Avoid -- unlikely in Texas due to the very significant shortfall in generation, but possibly in California due to the availability of power from the central plains that could have been delivered with long enough transmission lines. During some previous reliability events, available resources from neighboring states and regions were delivered into the region in need. When the extreme weather impacts a broad region, however, all available power is needed region-wide and little surplus is available anywhere. And that is where a backbone spanning the country can make a difference. We will never be able to forecast and plan for everything that may affect generation and load, but a robust national transmission grid is a very reliable way to be prepared for many uncertain but possible scenarios.

- Will private sector markets build a national backbone or should the federal government, through the existing Power Marketing Administrations or another federal entity, build and operate such a system?

<u>Response</u>: Government partnership for permitting and financing can be very beneficial, but I have confidence in our public and private utilities' abilities to build and operate such a system. During the California energy crisis, WAPA was able to upgrade Path 15 to help the situation significantly in a way that the state-regulated utility was unable to do on its own. That action became the model for Section 1222 of the Energy Policy Act. I think DOE should be prepared to utilize that authority working with private developers where it may be useful. Having been a regulator for a decade, I should point out that, in the end, the biggest challenge will be in siting the needed facilities. The hardest decisions I have had involve making eminent domain determinations affecting landowners' property.

Question 3: Infrastructure Right-of-Ways

The past year has demonstrated that reliable electricity and broadband access are essential to modern life. Both these services rely on rights-of-way to bring services to American households and businesses.

- Do you support the concept of pairing new transmission and high-speed internet infrastructure into the existing right-of-ways?

Response: Yes. Both transmission and broadband are needed, and if they can be paired in rights of way, that could be beneficial.

- How could surface transportation right-of-ways be used to build out additional electricity transmission capacity? Do you see this opportunity linked with future demand for EV charging?

Response: That is an option that I hope the Departments of Transportation and Energy evaluate, particularly in thinking about the eminent domain difficulties I noted above. It might not work everywhere, but we need to try a lot of different approaches for this very important and difficult challenge. Your suggestion about the link between highways and electric vehicle charging is a good one which I have heard discussed in several EV forums in recent years. With some technological advancements, I would expect this to be a fruitful synergy in coming years.

- Do you think a federal "Dig Once" policy could facilitate the use of existing right-of-ways to build new transmission capacity?

Response: I do think we need to make maximum use of any new corridors and plan for the long-term so we do not have to expand them or re-construct in the future. We know we will need to move very large amounts of power between and across regions, so we should plan for the long-term future. I have a concern, though, about the concentration of multiple facilities in a single corridor. It could reduce the overall system redundancy that makes our energy systems stronger in the face of physical and cyber-attacks, and extreme weather.

A "Dig Once" policy implies an undergrounding of power transmission. This raises technological issues for long-distance transmission, that, while not insurmountable, will require further advancement. In shorter-distance applications, however, undergrounding of higher voltage transmission is feasible, albeit more costly, as we found working through ISO-New England transmission upgrades in Connecticut during my term at FERC.

Questions from Senator Lisa Murkowski

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Question 1: The California Independent Systems Operators are pushing to increase their planning reserve margins from 15 percent to 17. 5 percent. Do you support increasing the regulatory requirement for planning reserve margins to procure additional capacity to maintain grid reliability for unexpected weather events?

Response: Each region has different ways to ensure sufficient energy supplies. In the past, annual planning reserve margins were the focus when systems were entirely dependent on relatively expensive, dispatchable coal/nuclear/natural gas/hydroelectric plants. Today, though, with the changing nature of the grid and the rapid increase in variable resources, we cannot manage reliability using capacity metrics alone. Instead, we will plan for energy and capacity and ancillary services in a more granular matter knowing they will vary by season and time of day. In the Texas Presidents Day storm, it does not appear that the reserve margin was the problem. The initial data indicate that the problem was with the operation and fuel supply of the plants that were there. So we need to focus on performance, gas supply, winterization and various other measures.

Question 2: I understand that FERC and NERC have opened a joint inquiry into the operations of the bulk power system during the recent cold snap that swept through the Midwest and South-Central states. Did FERC or NERC predict reliability issues regarding extreme weather events on the nation's grid in previous reliability assessments, and how will you incorporate these increasingly severe and lethal threats to grid reliability, resilience, and affordability into future assessments?

Response: There were warnings in such previous reports. I know Texas policy makers have reread these reports and are presently working on legislation to mandate weatherization of the State's power and natural gas infrastructure. Other legislation regarding readiness planning, drills and public communications strategies are also included in the emergency legislative requests from Governor Abbott. I expect that such legislation will be adopted in the next 7 weeks.

All of the entities and policy-makers who bear responsibility for our energy systems, as well as all citizens, should be paying attention to the broad magnitude of threats we face. We must do extensive scenario analysis on how to improve energy reliability and resilience. And importantly, we need mitigation plans to protect customers and our communities from unavoidable occasions like hurricanes and winter storms and human-caused attacks when we cannot do everything needed to keep the power on for all.

Question 3: Was the former Administration right to issue an Executive Order to protect our bulk power system from foreign-sourced bulk power equipment, and what do you suggest the Biden administration do in place of this order?

Response: When President Trump issued the Executive Order you referenced, I recall thinking that its application to hardware based on country of manufacture may be overly broad. Around that time, I discussed this issue with former Texas Congressman Will Hurd, whom I respect on national security matters. And, like most Americans I have followed the unfolding revelations arising from the recent Solar Winds software security breach. As a result, I have concluded that a strong focus on *both* hardware and software vulnerabilities in our energy and telecommunications infrastructure is a compelling national security issue. It is not inappropriate to consider the origin of the hardware and software. I am pleased to see that senior members of President Biden's

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administration are also concerned about cybersecurity, and I recommend that their focus be not only on hardware, but also on the software used across all infrastructure.

Question 4: As a result of ERCOT's $9,000 per megawatt-hour cost for electricity, a large household in Texas that would pay $30 for 0.5 per megawatt-hour under a week of normal prices is faced with an electric bill of $4,500. I understand the burden of high energy costs because Alaska has some of the highest costs in the nation, with some rural Alaskans spending up to half of their disposable income on energy. How do we ensure that lower-income communities are not disproportionately impacted by energy emergencies?

Response: I should note that of the 7 million customers in the competitive retail market in ERCOT, only a small number of them (~30,000) were on wholesale index programs offered by two providers. One of those providers (Evolve/Odyssey) has absorbed the excess costs that would otherwise have been borne by their retail customers; the other provider (Griddy) has declared bankruptcy. (I was a former Griddy customer, and should note that I was made fully aware of the risks of such an offering when and after I signed up). Almost all of the remaining 6.97 million customers have standard fixed price contracts of varying lengths and have been billed accordingly for their February kWh usage. A couple of retail providers were unsuccessful managing the price risk in the winter storm and have exited the market; their customers were automatically moved to a fallback provider under PUCT-overseen rates and have the opportunity to sign up with a new provider. All other retailers appear to have managed their portfolios adequately, and they continue to serve customers. I reviewed a number of large and small retailer websites today and found that the customer offerings today are at the same low rates that they were before the storm. A regret I have from this experience is that the backlash against Griddy will discourage a focus on dynamic, real-time price signals, when, in fact, real time price signals of perhaps a more muffled sort should be a goal for all of us. If more Texans knew that the power supplies were maxed out in the early hours of Presidents' Day, and had at least *some* financial incentive to conserve at that hour, they could have lessened the severity of the outage.

In ERCOT, there are also municipal and cooperative utilities that do not offer customer choice; depending on those utilities' successes in managing their procurements during the winter storm, their customers may or may not see future rate increases to keep these not-for-profit utilities whole.

I continue to believe that a competitive wholesale and retail market is the best protection for low income customers, indeed -- for all customers. Counter to a poorly researched press report on the Texas power rates under competition, the facts show that competitive power rates have dropped markedly since 2002, causing Texas to move from the 21st most expensive state to the 43rd today. But as we also learn from the Texas experience, this outcome requires vigilant oversight -- and not just market oversight, but reliability oversight as well.

Although my climate in Houston is quite different from yours in Alaska, I do think there is more we can all do with either public funds or through utility-collected funding to help lower income customers better repair and then insulate their homes. Modern building codes address this issue for many, but a good number of customers across the nation don't have sufficient construction of their homes to protect them from extreme heat or extreme cold. While such investments are certainly good for those customers, as we learned in the Texas, such investments also benefit all of us who share the power grid.

ENVIRONMENTAL PROGRESS

NATURE AND PROSPERITY FOR ALL

U.S. Senate Committee on Energy and Natural Resources
March 11, 2021 Hearing: The Reliability, Resiliency, and Affordability of Electric Service in the United States Amid the Changing Energy Mix and Extreme Weather Events
Questions for the Record Submitted to Mr. Michael Shellenberger

Questions from Senator James E. Risch

Question 1: The Idaho National Lab is the nation's lead nuclear energy laboratory. Nuclear energy provides resilient and reliable power that can operate through a variety of weather conditions. The existing fleet of nuclear reactors provides nearly 20 percent of the emission free power in the United States, and as we heard last week from the Deputy Secretary nominee, Dave Turk, we need to maintain our existing fleet of reactors and push forward with urgency to develop and deploy advanced reactors.

Mr. Shellenberger, do you agree with Mr. Turk's sentiments about the importance of nuclear energy?

Answer 1:

Nuclear energy is the only way to lift all humans out of poverty while reducing our negative environmental impacts.

Countries that don't keep their traditional reactors, and build more of them, have historically failed to develop new successful designs. The countries successfully building and operating the type of advanced reactor referred to by the Senator have done so while expanding their traditional fleet and exporting the same designs abroad.

Our allies are asking for our traditional large nuclear plants. Our current large light water reactor design, the AP-1000, is nearing completion in its only active project, at Plant Vogtle in Georgia. But that's where we are dropping the ball: we have no more projects planned to take advantage of our hard-won lessons in how to organize our labor and management to complete a nuclear project.

It is very unlikely that success will emerge against the historical pattern by losing our traditional abilities and starting anew with novel designs. On the other hand, America successfully developed and tested many different novel designs for commercial advanced nuclear designs from 1950 to 1989 while building its traditional style of nuclear plants in large numbers. Those novel reactors produced commercial electricity, but none of them were commercially viable, as is the outcome with most R&D efforts.

Question 2: At the Idaho National Lab, we are also leading a tri-lab (INL/NREL/NETL) effort on integrated energy systems – particularly coupling nuclear with hydrogen production. Integrated energy systems will provide more flexibility to the grid, especially as we see more renewables added to the energy mix.
Can you share your thoughts on the opportunity for integrated energy systems and hydrogen to improve the reliability and resiliency of the grid?

Can you share your thoughts on the opportunity for integrated energy systems and hydrogen to improve the reliability and resiliency of the grid?

Answer 2:

Insofar as Integrated Energy Systems allow for the use of existing nuclear's full potential, I believe they are a positive for grid resilience. If Energy Systems research and expenditure is used as an excuse to build transmission lines to weather-dependent energy sources, remove reliable traditional power plants, and make the grid more expensive to consumers without any apparent gain for them, I do not support these efforts.

Another way to name "integrated energy systems" is to call them "codependent energy systems". What we saw in Texas is that natural gas was required both for heating and for electricity generation, but electricity generation was also required in parts of the gas grid to keep the fuel flowing. So when total energy demand was high, gas supplies became strained, and then electricity supplies became strained, and then gas supplies became even more threatened. This is integration. This is codependency.

In a system where we are dependent on hydrogen to be produced and transported, but much of the energy is coming from weather-dependent and therefore climate-dependent energy, the level of danger to society increases dramatically from a week or season or even a multi-year period of surprising weather. Adding a hydrogen system delivers only costs, and, potentially, physical danger, to consumers compared to today's natural gas system, while delivering abstract, distant advantages of potentially lower global carbon dioxide emissions if the energy sources used are themselves clean. Therefore, using a potential hydrogen system's future buildout as an excuse to fragilize the grid today is a very bad plan for the nation.

However, if the energy for hydrogen comes from essentially weather-proof nuclear power, using always-on electrolyzers to minimize the additional costs of hydrogen as compared to today's natural gas, then the maximum benefits can be conferred to the public and to the environment.

Questions from Senator Maria Cantwell

Question 1: Using Federal Cost-Share Program to Promote Grid Investment

Numerous studies have demonstrated the need and the many benefits of investing in new and upgraded transmission, but the question remains on how to incentivize that investment at the scale and speed we need to meet national decarbonization and grid resilience imperatives.

- If the federal government funded a cost-share program to upgrade and expand the national transmission system, do you have any ideas how to design an effective cost-share program?

- What criteria do you think the federal government should use to decide how to competitively allocate a potentially limited amount of program funds?

- Could a cost-share program be based on, or expanded from, the existing DOE Smart Grid Investment Grant program?

- What level of federal investment in a cost-share program is needed to make a difference?

- Do you know of any existing programs that work well and could be a model for a new federal cost-share program?

A cost-sharing program would require split federal government's infrastructure investment with that of another party, presumably utility companies. Most financing for new transmission today comes from investor-owned utilities, which are the regulated natural monopolies of each region's transmission infrastructure.

Since 2006, FERC has allowed utilities to earn a higher return-on-equity on transmission projects than investors usually demand for their relatively low risk profile. This is similar in nature to the rate-of-return allowances which used to incentivize new generation, prior to deregulation. These incentives have worked; transmission investment grew 13 percent a year[1] between 2005 and 2016, a period in which generation capacity grew by less than 1 percent a year.[2]

Indeed, environmental concern, not monetary cost, is the most significant barrier to building new transmission. What the solar industry called 'onerous' regulations to transmission building in New England have actually served to protect the precious forest habitat of minks, mooses, eagles, and other iconic Maine wildlife.[3] In Nebraska, a 250-mile long HVDC line, billed in part to "provide development of renewable energy projects", was cancelled after conservationists demonstrated its risk to the barely-recovering whooping crane population.

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[1] https://www.eia.gov/todayinenergy/detail.php?id=34892
[2] https://www.eia.gov/electricity/data.php
[3] https://maineaudubon.org/news/new-england-clean-energy-connect-and-the-impacts-of-forest-fragmentation/

The Committee should know that the significance of a cost-share program, or perhaps any federal aid for transmission, will be to channel the nation's political will to the side of developers and utilities, against activist and state environmental agencies.

If the United States is to pick favorites among industries for the national good, it should consider which path meets the imperative for grid resilience and decarbonization with the least environmental and social cost.

If, instead, the federal government were to channel this political will into keeping and expanding our nation's nuclear plants, which do not require new transmission corridors, we could advance towards our carbon targets without destructive battles against nature conservation.

Limited program funds, from any type of transmission funding program, should be restricted to building transmission that connects secure, firm resources to load. Building transmission to spread out the connected area of weather-dependent resources, including using these resources plus transmission to displace and remove firm resources from the system, would be extremely dangerous and should be disallowed in any transmission buildout.

During Winter Storm Uri, the area of the United States without significant wind available was immense. Manygrids — ERCOT, SPP, PJM, and MISO — all lost much of their wind production simultaneously, and, as usual, lost their solar resources within a few hours of each other every day all year.

Connecting this area with itself using extensive transmission, and then using that transmission along with resultant average wholesale market prices as an excuse to remove today's reliable power plants, will make us significantly more vulnerable when a similar or worse storm comes.

Question 2: Potential Benefits of a National Backbone

Studies have shown that greater interconnectedness of the grid also lowers electricity rates by providing increased access to the least cost sources of generation in addition to making the grid more resilient. At the end of 2019, there was 734 gigawatts of proposed generation — 90 percent of which are new wind, solar, and storage projects —waiting in interconnection queues nationwide.

Despite the significant economic potential, much of it in rural parts of the nation, we are not planning for or building the national high voltage transmission backbone that is needed to take advantage of these incredible energy resources. The challenge seems to be figuring out the most effective way to monetize those benefits and bring a portion of those long-term payoffs forward so they can help pay for the needed upfront capital to make these infrastructure investments.

- Would the creation of a national backbone help clear the existing queue of new generation projects waiting to connect to the grid?

If building a national backbone served to increase the weather-dependency and land consumption of our energy system, this would be a reason not to do it. A national backbone should make us stronger, not paralyze us when unfavorable weather conditions arose across the continent.

It is difficult to conceive of how this "clearing" of the existing queue of new wind and solar projects would not interfere with the sustainability of operations of existing power plants. Indeed, to compete with and even eliminate traditional power plants is the actual purpose of the "national backbone" as openly and broadly stated before the Texas blackouts revealed just how vulnerable we are to large weather systems.

If Texas had been better connected before the blackouts, extremely low wholesale prices coming out of ERCOT into surrounding markets may have substantially damaged the revenue and operations of power plants in the surrounding markets before the storm, as this is of course what it had done to itself. As it was, the surrounding markets did not have extra generation available in many hours of the crisis.

And if there had been more of the same types of generation that performed extremely poorly during the crisis but all built up and connected due to a national backbone grid, then the results could have been positively catastrophic.

The capacity factor of wind turbines across much of the USA fell to the low single digits in the worst hours of the cold weather. This occasionally occurred during hours when solar was at zero power over much of the USA.

That means that 650 GW of new wind and solar would have, during the crisis, fallen to as low as 30 GW or even lower, depending on the locations of these projects. But because these 650 GW of projects would need to "eat" during the other hours of the year, taking revenue from the hundreds of gigawatts of firm generators that did in fact bail us out during the crisis, the situation for the nation would have been dire indeed.

- If the U.S. had a national backbone in place, would that have potentially helped avoid or mitigate the power crisis in Texas last month or California last August?

No, not if the persistently low wholesale prices from a connected grid were allowed to do what they've done in Texas and California that made those states so fragile to disruptive weather patterns, namely: promote weather-dependent energy and severely stress or even close down reliable traditional generators. The extreme financial stress placed by California and Texas wholesale markets on traditional generators, and the loss of the centralized planning and execution skills of their former vertically-integrated utilities has clearly damaged both states' abilities to respond to difficult weather.

A national backbone is just as likely to spread the California and Texas disorders to more states, rather than to use the traditional strength and high reserve margins of un-restructured states to subsidize poor planning and bad weather-dependency problems California and Texas.

- Will private sector markets build a national backbone or should the federal government, through the existing Power Marketing Administrations or another federal entity, build and operate such a system?

Our deregulated ("restructured") electricity markets are apparently breaking our backbone as we speak, hence the occasion for these hearings. The federal government should act to eliminate these. Then we can see about repairing the damage with steps that could include more transmission. The old wisdom of grid management, that generation should be spread around approximately in proportion to regional population and load, remains the best way to guide our thinking about electricity resilience and reliability. The fact that this wisdom is supposedly obsolete, just because it is absolutely incompatible with the expansion of weather-dependent energy sources in remote areas, should cast doubt on the idea of a "national backbone" of transmission as currently proposed.

However if we find that only some states or regions are prepared to build more firm nuclear capacity, then there could be a justification for bringing weather-independent nuclear power from those productive regions of the country to the benefit of consumptive regions. This occurs in Europe today with France supplying its neighbors with energy as those neighbors strip out their reliable nuclear capacity. France's neighbors are working to increase the transmission capacity from France into their country for this purpose. This model may be necessary in the United States and should be a central object of study in any National Backbone proposal.

Question 3: Infrastructure Right-of-Ways

The past year has demonstrated that reliable electricity and broadband access are essential to modern life. Both these services rely on rights-of-way to bring services to American households and businesses.

- Do you support the concept of pairing new transmission and high-speed internet infrastructure into the existing right-of-ways?

Yes, assuming that costs of any electricity transmission built using this approach are paid for by the new weather-dependent energy resources that apparently require this new infrastructure to make money, despite these same energy resources being so vulnerable to the weather patterns that crippled their output during the Texas blackouts.

- How could surface transportation right-of-ways be used to build out additional electricity transmission capacity? Do you see this opportunity linked with future demand for EV charging?

Electrifying our transportation fleet means that we will have much greater consistent demand on our energy supplies. But weather-dependent energy is seasonal. EV charging infrastructure must not be confused with the problems of weather-dependent energy supplies. If new transmission is required to increase the number of reactors at our existing nuclear plants in order to supply year-round electricity for new purposes that demand year-round electricity, and this transmission cannot be simply added to existing corridors, then we should consider using these surface transportation right-of-ways.

- Do you think a federal "Dig Once" policy could facilitate the use of existing right-of-ways to build new transmission capacity?

Dig Once policies require excavators to coordinate with the government whenever ground is broken on a public right-of-way. Reducing the number of unnecessary future excavations required to add crucial infrastructure is a worthwhile goal, but it can have unintended consequences which extend the time and paperwork for simple infrastructure improvements. To reiterate, I believe the costs for new transmission infrastructure should be borne by the developers whose projects make it necessary. As adding weather-dependency to our country is bad for our security and national wealth, A Dig Once policy should not be an excuse to socialize the cost of intermittent weather-dependent energy farms.

Question from Senator Lisa Murkowski

Question: Can you elaborate on the importance of conventional baseload generating power facilities like nuclear to maintain affordable and reliable electricity delivery, and the importance of maintaining the availability of baseload power generation as sources of renewable energy on the grid grows?

Answer: "Baseload" is the minimum amount of demand for power on a grid over a span of time, and baseload generating facilities are those *capable* of being always-on power plants while being efficient at doing so, to meet at least this minimum need. About 50 percent of energy demanded in the United States is 'baseload'. Power plants are base-load in contrast to peaking power-plants, which are turned on only when demand is especially high, and intermittent renewables, which cannot respond at all to our demand.

A misconception that existed among energy experts for many years is that baseload power-plants cannot meet peak needs. The experience of nations like France, Sweden, and Iceland, which rely almost exclusively on the baseload technologies of nuclear, hydro, and geothermal for energy, shows otherwise. Baseload technologies can be modified to follow load. And, as my organization's research has shown, the commonality in major countries which have successfully decarbonized is the use of clean, nuclear energy for baseload.

What is increasingly recognized as true by these same experts is that intermittent power-plants cannot alone meet the needs of an electrified society. If electric vehicles, for instance, are to replace internal combustion engines on the road, the United States will require up to 25 percent more electricity capacity. It is impossible for wind and solar to provide electricity in reliable amounts at the hours needed to charge electric vehicles; experiments in demand-shifting and energy storage have proven only to work on a fraction of the scale needed for nation-wide grid resiliency.

Questions from Senator Angus S. King, Jr.

Questions: In your testimony, you cited a University of Chicago study which purported to determine the incremental cost of renewables against an unspecified (by you) base case. In several points in your testimony, you advocate for nuclear power and a centralized (large power plant centric) grid. Please supply the committee with a cost analysis of supplying the same amount of energy and capacity as assumed in the Chicago study through the construction and operation of a new nuclear plant. Please include the implicit cost of the Price-Anderson Act in your calculations as well as what assumptions you make with regard to recapture of construction costs through the hypothetical utility's rate base. Also, please provide your estimate of the period necessary to design, permit, and construct such a plant.

The University of Chicago study measures the effect of Renewables Portfolio Standards on retail electricity price and carbon emissions across states. A Renewable Portfolio Standard is a mandate to increase the share of electricity generated from renewable sources to some predetermined target by a given year. The renewables share and target year varies from state-to-state.

The definition of renewable also varies widely from state to state. This lack of coherency stems from the fact that "renewable" is a spiritual and aesthetic idea, without a direct relationship to either the carbon intensity achievable in the real world by a grid using such technologies or on the life-cycle energy or material requirements of the technology itself. Zero-carbon hydroelectric dams, for example, are considered a renewable source in most states, but in California, only relatively inefficient small dams count as renewable. On the other hand, most states count biomass, which often induces deforestation and can emit as much or more CO_2 as coal, among renewable sources of energy, while none count carbon-free nuclear electricity as renewable. Renewable energy was never intended to solve climate change; instead, it was imagined and then designed as a gateway to a low-powered society.

Definitions aside, there are important reasons to measure the cost of renewables through their end effect on electricity prices *as delivered to consumers*, rather than through incremental cost of capacity or generation. First, renewables come with a variety of so-called ancillary costs to the grid. These costs are not borne by the banks or developers who profit from renewables, but instead show up over years in consumer electricity bills. For example, new wind and utility-scale solar requires the build-out of miles of new transmission lines. Second, renewables impose externalities on communities, which are often unaccounted for in immediate cost. The hefty costs of environmental litigation and habitat alteration associated with land-intensive renewables aren't wholly borne by speculators and developers, but are instead passed on to ratepayers. Lastly, every renewable built today necessitates an increase in a back-up, peaker capacity. The owners of these peaker gas plants need to be compensated for the high uncertainty of their returns; this cost is passed along to consumers.

Thus, the real cost of renewable electricity is best measured by its effect on consumer prices. The UChicago study found that states which, on average, mandated an increase in renewables generation of just 1.8 percent over 7 years, saw their retail electricity prices increase 11 percent over neighboring states without such mandates. Despite the falling cost of solar and wind over time, their effect on retail electricity prices deepened with time. States which mandated an average 4.3 percent increase in renewables generation over 12 years saw their electricity prices increase by 17 percent. In total, the consumers of states with renewable portfolio standards paid 125 billion dollars more than they would have in the absence of such a policy.

How might we compare this to the costs of nuclear build-out? In a counterfactual world, new nuclear would receive as much state aid as new renewables today. This would drive the financial risk and capital cost of nuclear power down. From this point, it is extremely difficult to compare the expected delivered cost of Vogtle units 3 and 4, about $100 per MWh over the first 40 years of operation and around a quarter of that for the following 40 years and beyond, with what would be achieved if we were able to capture the experience and learning from this first effort in subsequent projects. For one, we'd be starting the plants in construction with finalized blueprints, which did not occur with Vogtle. Designs were finalized only through trial and error on the job. According to EIA assumptions of overnight and O&M cost, with an interest rate of 3 percent and a term of 40 years, new nuclear's LCOE is $50/MWH. When adjusting for the social cost of carbon, IEA finds a cost of $30/MWH.

This question asks for comparative capacity and energy. But as seen in Texas, grid operators strongly "derate" the effective capacity of renewable energy supplies to account for bad weather during peak demand events, which of course typically occur during bad weather. A lesson from Texas is that they did not even derate wind and solar enough to accommodate the extreme low production values actually observed. This means that any attempt to compare "capacity" for wind and solar will quickly balloon the amount of wind and solar required to levels far beyond any plausible need for that quantity of energy supplied.

If we then attempt to address this severe lack of firm capacity by adding storage to make up for it, then we rapidly balloon the actual costs of the system, as far more storage is required to make up for wind and solar needing to be derated by to as little as 99% in Texas in peak demand hours than it is to help out nuclear, which is typically not derated at all by grid operators. In Texas, nuclear unfortunately fell to 73% at moments, while averaging 79%, due to the temporary shutdown of one reactor by an erroneous automatic safety trip.

It should be further noted that grid spending and storage spending to run an as-yet experimental weather-dependent grid is unknown and could very well be catastrophically high or even untenable, despite modeling studies from scholars indicating that theoretically it could work. On the contrary, costs of high-nuclear grids are very well known in real life from direct and extensive experience, and appear to be very low in comparison with even much lower-penetration, much higher residual carbon grids. France versus Germany is the canonical example, with France's electricity costing little more than half as much delivered to consumers while persistently being ten times lower carbon per unit electricity generated.

The Price-Anderson Act is in fact a hallmark of international diplomacy; its passage, in conjunction with the international Paris Convention, Vienna Convention, and Convention on Supplementary Compensation, has allowed for capital exchange and technology transfer in civil nuclear that is unparalleled by any other energy industry.

The Price-Anderson does not relieve nuclear operators of any implicit cost. In fact, the act channels liability to the operator of nuclear plants, holding them solely and wholly liable for any accident, *including* those caused by any acts of god, like terrorism and storms. This clarity of liability is unprecedented in any industry insurance plan. The first tier of the insurance policy requires that the first 450 million dollars of off-site damage be covered by plant operators. So far, all but 151 million dollars of nuclear incident has been confined by this first tier of liability. The second tier of the insurance policy, up to 13.5 billion dollars, is covered by the operators of other US reactors (who would otherwise have nothing to do with the accident). Above 13.5 billion dollars, Congress is allowed to decide who will foot the bill of an accident; it could very well pass a bill requiring that the nuclear industry pay. As such, it is not a subsidy. To this day, the United States taxpayer has paid zero dollars for a nuclear accident, and the nuclear exports allowed by Price-Anderson have generated hundreds of billions in tax revenue and created tens of thousands of American jobs. Congress allows limits on liability all of the time, including on medical malpractice lawsuits, and against airlines, and yet never do people mislabel those limits "subsidies."

A regulated asset base model remains the most sustainable and fair way to allocate consumer costs while encouraging large, bold public infrastructure projects. Contrary to economists' fears that a lack of competition would encourage complacency, old-style utilities which avoided deregulation have undertaken significant risk while maintaining or adding to consumer surplus. Utilities like the Southern Company, which took on big (and failed) risks in installing clean coal, and in rebooting the American nuclear industry, were still able to keep their retail electricity prices low, charging sustained, equitable rates, while maintaining large reserve margins to prevent what happened in Texas and California. The Tennessee Valley Authority, the hallmark of FDR and the New Deal, maintained low costs and reliable electricity after it installed a new reactor at Watts Bar plant in 2016, which powers 1.2 million households a year. Other countries are now turning to this model, after unsuccessful experiments with deregulated markets. In fact, the originator of the deregulated market, the United Kingdom, is considering a return to regulated asset-based models, to solve its "missing money" problem with regards to new capacity on the grid.

There is a lot of complexity and nuance buried in the Senator's question. An attempt to make a seemingly simple capacity comparison leads us to explore the significant derating of renewable capacity. An attempt to quantify the costs of Price-Anderson leads us to discover a monumental diplomatic achievement which has cost the American taxpayer zero and yielded billions in economic benefits, And a cost for new nuclear that compares favorably (if we use American technology) with any other technology for creating a low-carbon grid.

U.S. Senate Committee on Energy and Natural Resources
March 11, 2021 Hearing: The Reliability, Resiliency and Affordability of Electric Service in the United States Amid the Changing Energy Mix and Extreme Weather Events

Questions for the Record Submitted to Mr. Manu Asthana

For Public Use

Questions from Chairman Joe Manchin III

Question 1: Extreme weather events, physical attacks, and cyber-attacks are occurring more frequently. We must continue to make the infrastructure of our nation reliable, resilient, and responsive, but we must also have the ability to recover from the loss of service and loss of equipment as expeditiously as possible.

a. **Do you believe that it is prudent to require utilities to have executable plans that outline how they would recover from a catastrophic event and require that plan to incorporate best practices used by other industries, as well as include a reserve of equipment that is readily available and dedicated to these events?**

PJM Response: We at PJM fully concur with the need not only to maintain a reliable and resilient infrastructure but also to have in place plans to recover and restore a functioning grid as soon as possible.

Within the PJM region, recovery plans for such eventualities already exist and are practiced on a regular basis. Specifically, PJM memorializes in its Manual 13 (*Emergency Operations*) our detailed plans for operating the system in response to a number of different grid emergencies including capacity shortages, extreme weather events, geomagnetic disturbances, sabotage or terrorism emergencies, and transmission security emergencies. In addition, PJM maintains in its Manual 36 (*System Restoration*) a detailed recovery plan in response to loss of all or portions of the grid. The plan centers on restoration of the bulk power electric grid in response to one of these events and includes specific provisions concerning communications during an emergency to the public and certain government agencies [e.g., the Federal Emergency Management Agency, the Department of Energy, the North American Electric Reliability Corporation (NERC), and state public utility commissions]. The PJM manuals were developed with the endorsement of PJM stakeholders who, as a stakeholder body, encompass all aspects of the industry from generation and transmission owners to customers within the PJM region.

Complementing that plan, individual distribution utilities have restoration plans. Those plans address priorities for restoration of particular customer classes and also address emergency communications. These plans are also coordinated with state emergency management agencies and are practiced through organized drills on a regular basis.

The industry has also worked extensively to address the need for reserves of critical equipment that would be needed as part of a grid restoration. For example, the industry – with PJM support – created banks of spare transformers to be available in emergencies. Considering the size and specialized construction needed for transformers, absent this bank of spare transformers, replacement of this asset could take months.

For example, the North American Transmission Forum's Regional Equipment Sharing for Transmission Outage Restoration (RESTORE) program, identifies an inventory of designated spare equipment to be called upon only after a particular type of "triggering event." Under the program, a triggering event is an event that:

- Is catastrophic in nature; and
- Creates an urgent grid need in which, for an extended period, the affected utility loses its ability to serve significant load; or
- Represents a risk that a participating transmission owner could, in the near future lose its ability to serve significant load levels or is otherwise unable to maintain grid stability.

PJM's transmission owners participate in this and other similar programs, or maintain their own inventory of spare transformers, and work with PJM to help identify the spare critical equipment needed for such programs.

PJM will also assess the reliability risk associated with lower voltage transformers and the potential need for additional spare transformers. If risks are identified, PJM may perform an analysis similar to the probabilistic risk analysis performed for the 500/230 kV transformers.

PJM recognizes these Transmission Owner efforts. However, PJM notes that there are additional resilience actions that deserve further consideration by policymakers. On March 9, 2018, in FERC Docket No. AD18-7-000, PJM filed over 15 specific recommendations with the Commission that would enhance the resilience of the grid. A copy of the Executive Summary of PJM's comments is attached. Although that docket has been closed by the Commission, PJM looks forward to working with the Commission, states and stakeholders on these important resilience issues through the Commission's recently opened docket on Climate Change, Extreme Weather and Grid Reliability Docket No. AD 21-13.

Question 2: A report released last week by ICF International claimed that U.S. utilities may have to invest more than an additional $500 billion in the next three decades to safeguard critical energy systems against damage from extreme weather. This "resilience gap" is driven largely by the need to harden infrastructure against the effects of climate change, including heat waves, extreme storms, sea-level rise, and wildfires.

a. **How are you monitoring the impacts of climate change on your system?**

b. **How are you incorporating those findings into your system planning?**

PJM Response: Because of the exposed nature of electric infrastructure to severe weather conditions, PJM closely monitors both short- and long-term weather patterns. PJM has on staff a full-time meteorologist for the purpose of monitoring weather conditions as they affect grid operations.

PJM also addresses catastrophic events in planning and operations, which could include a catastrophic event caused by extreme weather or climate change. Extreme weather events from climate change could manifest itself through the atypical loss of generation, transmission and natural gas pipelines or an atypical combination thereof. PJM's operations and planning studies, and NERC reliability standards, address the atypical loss of generation, transmission and natural gas pipelines that may result from extreme weather events, among others.

For example, under NERC reliability standard TPL-001-4, PJM staff annually studies extreme events to evaluate their impact on the transmission system. An extreme event is defined as having a reasonable possibility of occurring and of being outside the normal types of events studied in TPL-001-4. Under PJM's process, an analysis is performed annually for a near-term (year one through five) study by a current five-year-out Regional Transmission Expansion Plan (RTEP) case, which shows system performance following an extreme event contingency as listed in Table 1 of TPL-001-4. This analysis includes a review of impacts to existing and planned facilities, as well as all projected firm transfers of electricity consistent with the corresponding RTEP case. Reactive power resources are included consistent with the corresponding RTEP case to ensure that adequate reactive resources are available to meet system performance. All effects of existing and planned protection and control devices including backup and redundant systems are also studied. This study assesses the impact of the extreme events that are identified as required in the NERC TPL-001-4 reliability standard.

While PJM does perform extreme event analysis under TPL-001-4 and incorporates the results into the RTEP process, the standard itself does not require the reinforcement of the system to mitigate this risk. Moving forward, the industry may want to explore methods to perform this analysis in a Monte Carlo simulation to examine which facilities are most at risk from extreme events and more susceptible to cascading, instability or separation and consider mitigation measures for those facilities.

Additionally, PJM incorporates gas pipeline contingency analysis as a part of both our annual assessment of the PJM footprint as well as near real-time assessments undertaken in anticipation of extreme weather. The gas pipeline contingency set includes gas pipeline contingencies caused by the failure of a gas pipeline or loss of a compressor station. The gas pipeline contingency analysis list is reviewed periodically to validate its accuracy.

In addition to the annual studies noted above that are done over the longer planning horizon, PJM completes seasonal operating studies (two per year: summer and winter). These seasonal operating studies assess the PJM system as it is expected to exist during the upcoming peak season. These studies include several sensitivity studies to determine the impact of Maximum Credible Disturbances that are similar to the extreme events noted above that are assessed for the planning horizon pursuant to the NERC Reliability Standard TPL-001-4.

In response to a Federal Energy Regulatory (FERC) and NERC staff report titled *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*, NERC and the electricity industry are also developing revisions to reliability standards to enhance the reliability of the bulk electric system during cold weather events. This is a good development and a step in the right direction. Nevertheless, the industry should also consider additional system hardening standards for extreme events going forward.

Importantly, however, while the studies above address the atypical loss of generation, transmission and natural gas pipelines that may result from some extreme weather events, the studies and reliability standards do not evaluate all scenarios and outages that could result from some extreme weather event. For example, PJM does not currently study all of the facilities that could be impacted by all extreme weather events (e.g., PJM does not currently study all of the facilities that could be impacted by a 500-year flood along the east coast). While conducting such studies would be prudent, there are currently no NERC or FERC requirements or standards that would require reinforcing the system for such extreme events. Therefore, absent more clear resilience standards, a host of objections could be raised by PJM stakeholders that ultimately bear responsibility for paying for such upgrades. Further direction and support from FERC and NERC would be most appropriate to define and set a benchmark for industry planning for resilience of the grid to withstand such extreme events. As noted above, PJM requested such direction and provided a concrete list of over 15 recommendations in response to the Commission's original resilience docket, FERC Docket No. AD18-7-000. PJM intends to raise these issues again at FERC's upcoming technical conference on Climate Change, Extreme Weather, and Electric System Reliability (Docket No. AD21-13-000) to be held on June 21 and 22, 2021.

Question 3: The events in Texas last month illustrate just how intertwined our electric system is with our natural gas production and delivery systems.

a. **What do you view as the benefits or drawbacks of the inter-dependence of the electric and natural gas systems?**

b. **What can we do to enhance coordination and fix existing and future vulnerabilities resulting from this inter-dependence?**

PJM Response: There is no question that the increased deployment of highly efficient natural gas combined cycle generating units in the PJM region underscore the increasing interdependency of the electric system and natural gas production and delivery systems. In our region, natural gas is a highly reliable abundant fuel source. The PJM region also contains an abundance of natural gas storage fields and a rich and diverse set of natural gas pipelines delivering natural gas from the Marcellus and Utica shale gas regions to generation facilities throughout the PJM region. All of these factors have led to a significant increase in development of new highly efficient natural gas combined cycle units.

Of course, with the increased interdependency comes the need for increased coordination. PJM has worked with each of the pipelines serving our region to enhance that coordination. We have established a "gas desk" in our control room facility to monitor pipeline deliveries, particularly during the winter season, and to coordinate operational data with our pipeline partners. We can report a good deal of cooperation among the pipelines serving our region with PJM operators.

Nevertheless, the regulatory paradigms associated with each industry are markedly different. For example, the need for new transmission facilities are determined by an analysis of power flows on the system and whether NERC reliability criteria are satisfied. The costs of such facilities are paid for by the beneficiaries of new transmission lines as determined by an analysis of power flows both before and after the line is operating. By contrast, the need for new pipelines is established not by an assessment of regional need, but instead by contractual expressions of interest by "anchor shippers" which, in some cases, can be affiliates of the pipeline itself. The costs of new pipelines are paid for by these anchor shippers even though the larger region may benefit from the existence of that pipeline. This difference in how the need for new infrastructure is determined as between gas and electric can create challenges in ensuring that the respective needs of each system are aligned.

The ability of a power generator to vary its demand on the pipeline system in response to changing demand from electric customers can sometimes be limited, especially on cold winter days when the generation owner could be required to purchase gas at the same level throughout a 24-hour period (known as "ratable takes"). These ratable takes help the pipeline to manage pressure but are not well suited for meeting the needs of a generator to rapidly ramp up or ramp down its power input in response to grid conditions.

Finally, although interstate natural gas pipelines are required to serve all customers on a nondiscriminatory basis, whether they are local distribution gas utilities or power generators, local distribution companies – which provide distribution pipeline service to generation owners connected directly to them (known as "behind-the-city gate") – do not have a similar obligation under state law. This can lead to potential curtailment of power generators needed to serve customers leaving end-use customers with gas supply in their home or business but not necessarily electricity to serve their needs.

Much has been done to increase coordination, but more work is needed. FERC had sponsored a series of gas/electric coordination workshops under then FERC Commissioner Phil Moeller. Consideration should be given to reinstituting those workshops, so the work of each region on these issues can be transparently shared with other regions and the general public.

Moreover, further direction and support from FERC and NERC would be most appropriate to define and set a benchmark for industry planning for resilience of the grid to withstand such extreme events. As stated above, in 2018, PJM requested such direction from FERC and provided a concrete list of over 15 recommendations in response to the Commission's original resilience docket, FERC Docket No. AD18-7-000. PJM intends to raise these issues again at FERC's upcoming technical conference on Climate Change, Extreme Weather, and Electric System Reliability to be held on June 21 and 22, 2021.

Question from Senator James E. Risch

Question: Over the last few weeks, we have seen a number of high profile cyber incidents reported in the news. We know our nation's critical infrastructure is a top target for bad actors and that these threats are persistent, increasing, and growing in sophistication. The Idaho National Lab is not only our nation's lead nuclear laboratory, it is also the go to lab for cybersecurity solutions. What do you see as the biggest cyber challenges facing our nation's energy infrastructure?

PJM Response: Our adversaries are becoming increasingly capable and determined. This is evident in the increase in high-consequence offensives from both nation states and criminal actors. Recent activities have highlighted the capabilities and sophistication of cyberattacks.

The biggest cyber challenges lie in working to stay-ahead of the adversaries. The adversaries are well funded and incented to identify weaknesses in the nation's energy infrastructure. Today, adversaries increasingly focus on attacks to operational technology including supply chain and ransomware attacks. The adversaries focus on critical infrastructure beyond electricity including gas pipelines, water infrastructure, telecommunications and finance. The industry challenge is to be aware of the interdependencies between all the critical infrastructures. An important acknowledgement is that the adversary will evolve and biggest challenges today will not be the biggest challenges tomorrow.

Threat intelligence and best-practice sharing are critical to managing any cybersecurity program in an evolving threat landscape. We rely on our government partners and vendors to share relevant information that we can use to detect attacks and protect our systems and data. The Electricity Information Sharing and Analysis Center ("E-ISAC") is the hub of information sharing for the electric industry and continues to improve its information sharing programs, making them an essential platform for industry members to share threats with each other. In addition, we receive threat indicators from the Department of Homeland Security and government-informed analysis from the Cyber Risk Information Sharing Program ("CRISP").

As we look forward, the protection of our nation's critical infrastructure must continue to evolve. We must capitalize on the strengths of government and industry partners with clearly defined roles that allow for a powerful force of teamwork. Management of cybersecurity will need to adapt to changes on the electric grid, including the increased focus on distributed technology. Distributed technology introduces a large attack surface for adversaries, and we must plan and prepare for that.

Questions from Senator Maria Cantwell

Question 1: Using Federal Cost-Share Program to Promote Grid Investment

Numerous studies have demonstrated the need and the many benefits of investing in new and upgraded transmission, but the question remains on how to incentivize that investment at the scale and speed we need to meet national decarbonization and grid resilience imperatives.

a. **If the federal government funded a cost-share program to upgrade and expand the national transmission system, do you have any ideas how to design an effective cost-share program?**

   PJM Response: PJM's competitive markets, the largest in the world, are enabled by more than 84,200 miles of transmission at 100 kV and above. A robust transmission system lowers the net costs of electricity to consumers by allowing the next most-cost-effective megawatt to be dispatched. This reduces overall production costs for generators and costs for end users of electricity. Transmission lines link PJM zones together, allowing them to share capacity and leverage load diversity to reduce the need for additional generation by up to \$3.78 billion annually. (See, e.g., the following PJM white paper on the value of new and existing transmission equipment, lines and other assets for PJM Interconnection stakeholders and other engaged parties: PJM Interconnection, L.L.C, *The Benefits of the PJM Transmission System*, https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/the-benefits-of-the-pjm-transmission-system.pdf (Apr. 16, 2019)).

   The transmission system, since its inception, is largely made up of private utilities who develop and construct new transmission and are awarded a return on that investment by the Federal Energy Regulatory

Commission. Notable exceptions exist in the form of Power Marketing Agencies such as BPA, TVA and WAPA and in large public power agencies such as the Los Angeles Department of Water and Power. However, at least in the Eastern Interconnection, public power agencies make up a much smaller part of the overall transmission investment.

At least in the PJM region, the primary issue raised by transmission owners is associated with permitting and siting and litigation over the allocation of the costs of new transmission. However, a federal cost share program could certainly accelerate the build out of the national transmission system and is worthy of consideration.

- **What criteria do you think the federal government should use to decide how to competitively allocate a potentially limited amount of program funds?**
- **Could a cost-share program be based on, or expanded from, the existing DOE Smart Grid Investment Grant program?**
- **What level of federal investment in a cost-share program is needed to make a difference?**
- **Do you know of any existing programs that work well and could be a model for a new federal cost-share program?**

PJM Response: See response to question no. 1 above.

Question 2: Potential Benefits of a National Backbone

Studies have shown that greater interconnectedness of the grid also lowers electricity rates by providing increased access to the least cost sources of generation in addition to making the grid more resilient. At the end of 2019, there was 734 gigawatts of proposed generation — 90 percent of which are new wind, solar, and storage projects —waiting in interconnection queues nationwide.

Despite the significant economic potential, much of it in rural parts of the nation, we are not planning for or building the national high voltage transmission backbone that is needed to take advantage of these incredible energy resources. The challenge seems to be figuring out the most effective way to monetize those benefits and bring a portion of those long-term payoffs forward so they can help pay for the needed upfront capital to make these infrastructure investments.

a. **Would the creation of a national backbone help clear the existing queue of new generation projects waiting to connect to the grid?**

PJM Response: *Defining and Identifying the Benefits and Cautions Associated with a "National Backbone"*: At the outset, PJM suggests clarification around the term "national high-voltage transmission backbone." There already are regional transmission backbones which are characterized by extra-high-voltage transmission facilities, generally at 500 and 765 kV voltage levels. These regional backbones, which are interconnected within the Eastern, Western and Texas interconnections collectively, represent the grids that provide reliable service throughout the nation.

The larger issue for policymakers is whether there should be a policy-driven directive to build out the grid to meet a public policy objective. Such policy-driven directives could require build-out of transmission to wind-rich areas in advance of specific projects seeking interconnection and/or additional interconnections between regional grids. There are benefits and detriments to such approaches.

Some of the benefits include:

1. Diversification of some of the locational risk from intermittent renewable resource penetration could improve the overall capacity view of renewables as a class;
2. Investment in, policy-driven transmission build-outs, whether intra- or inter-regional could accelerate achievement of decarbonization goals; and
3. Inter-regional transmission links could be very helpful to grid reliability in periods of stress, and can be helpful in providing black-start services.

There are also risks including:

1. To design such a grid to access more renewable generation, one would have to predict where this generation would most efficiently be built in the future. To the extent these predictions were incorrect, some of the buildout cost could be wasted leading to stranded costs borne by customers;
2. Another risk is that shifting the allocation of costs from the generation developer directly to consumers can shift risk and sometimes create incentives to site generation in less efficient places.
3. Siting of transmission is a long, expensive and laborious process and a multi-state siting process will be very time consuming and have a low probability of success. Optimizing existing transmission corridors with advanced transmission line design and high temperature conductors may advance the interconnection of queued generation more quickly.

Overall an investment in "backbone" type transmission can be very helpful in certain cases, but may not be the right solution in all instances. Specifically, any such plan needs to be evaluated in light of several regional factors including pre-existing transmission networks, state and federal policy objectives, resource availability and cost effectiveness. The transparent nature of stakeholder processes within Regional Transmission Organizations provide an appropriate forum for such discussions and analyses.

Interrelationship with the Interconnection Queue: The size of the interconnection queue and backlog issues are affected by several matters. These include the following policies that impact the size and complexity of the interconnection queues and queue process:

- Congressional policy in the form of the wind production tax credit and solar investment tax credit both of which, due to their requirements associated with when construction must commence, drive an increased level of renewable projects to enter the queue all at once in response to the legislative deadlines; and

- The requirements of FERC Order 2003 which require an exact and binding determination of the costs that the interconnecting customer causes through its proposed interconnection so as to shield customers from absorbing any of those costs.

If either a national backbone transmission grid (presumably using a portion of federal funding) were constructed as the question suggests or changes were made to the existing FERC Order 2003 policy, the transmission providers (in most cases the RTOs and ISOs across America) would be able to focus the interconnection queue process on the electrical and physical requirements of interconnecting new facilities without having to also determine, through complex studies, the exact "but for costs of each new interconnection. This would help to speed the interconnection queue process but, on the other hand, could be seen by customers as shifting to them costs which otherwise should be borne by developers who will benefit from that interconnection. These policy questions are worthy of further examination and deliberation by the FERC and by this Committee.

b. **If the U.S. had a national backbone in place, would that have potentially helped avoid or mitigate the power crisis in Texas last month or California last August?**

PJM Response: Based on the preliminary information available to date, while more transmission may have helped, it is not clear it would have avoided the crises. While transmission is sometimes the best solution to ensuring the reliability of the bulk power system, at other times generation investment, demand response, or energy efficiency investment is needed. As a result, we need to be careful to invest in the right mix of all these solutions to deliver reliability as efficiently as possible.

Within the Eastern Interconnection, the ties between utilities are quite strong as is a long history of mutual support. For instance at the height of the cold weather spell in the Midwest earlier this year, PJM was exporting as much as 15,700 MW, a record, to our neighbors to assist them in meeting their load requirements. The strong transmission grid in the Eastern Interconnection made those transfers possible.

c. **Will private sector markets build a national backbone or should the federal government, through the existing Power Marketing Administrations or another federal entity, build and operate such a system?**

PJM Response: As noted in response to Question #1, at least in our region, the impediments to additional transmission are largely driven by permitting and siting challenges and litigation over who pays for such transmission projects. Were there to be an intense focus on these issues among applicable federal and state regulators, the private sector, interested in earning a return on new transmission investment, would most likely be willing to fund the necessary transmission build-out. Moreover, the private sector is more likely to respond to market-based incentives.

Question 3: Infrastructure Right-of-Ways

The past year has demonstrated that reliable electricity and broadband access are essential to modern life. Both these services rely on rights-of-way to bring services to American households and businesses.

a. **Do you support the concept of pairing new transmission and high-speed internet infrastructure into the existing right-of-ways?**

PJM Response: PJM is not directly involved in determining the best location to site new transmission facilities. However, the use of existing right of way and the pairing of new transmission and high-speed internet infrastructure has proven a very viable means to site needed new infrastructure. Particularly in a densely populated region such as the PJM region, new greenfield right of way can be difficult to find and can carry with it many environmental challenges. It is for this reason that we have seen a number of "wreck and rebuild" projects which enhance transmission capability using existing rights of way.

b. **How could surface transportation right-of-ways be used to build out additional electricity transmission capacity? Do you see this opportunity linked with future demand for EV charging?**

PJM Response: Although PJM is not directly involved in determining the best location to site new transmission facilities, we have seen the increased siting of new transmission lines along public highways and rail lines. Moreover, should there be concentrations of demand for EV charging, say along a national highway, "Park and Ride" lot, step-down facilities could be created to service EV charging. The economics of any such application would need to be addressed on a case by case basis. Nevertheless, system planners at both the transmission and distribution levels will need to give increased attention to ensuring adequate infrastructure that supports customer-convenient EV charging stations in their planning and siting decisions.

c. **Do you think a federal "Dig Once" policy could facilitate the use of existing right-of-ways to build new transmission capacity?**

PJM Response: PJM does not have field crews nor are we directly involved in the construction or maintenance of physical facilities. Rather those tasks rest with the transmission and distribution utilities within our region.

Transmission facilities today largely consist of overhead wires anchored to towers in the ground. By contrast, laying of cable for a fiber optic network can involve an entirely different and more extensive level of excavation through a dedicated trench. There have been instances where fiber optic cable for communications is co-located on transmission towers. In these latter instances, a flexible federal policy may help to ensure coordinated development of both communications and electric transmission infrastructure in a manner that meets the needs of the public which ultimately demands timely provision of both services. On the other hand, each individual situation is different and strict application of a "Dig Once" policy may inhibit timely development and installation of needed transmission or communications technology. As a result, this area may not lend itself to an across-the-board legislative solution.

Questions from Senator Lisa Murkowski

Question 1: Your testimony states that PJM has a robust reserve margin. Can you discuss PJM's planning reserve margins and what your company is doing to go beyond NERC's Reference Reserve Margin?

PJM Response: The PJM installed reserve margin target represents the level of reserves PJM needs to procure over and above the forecast of peak demand for electricity in a given year. The installed reserve margin is set by PJM using established tools to forecast the demand for electricity at peak periods in the summer and winter and also takes into account the potential loss of generation due to forced outages as well as the level of support available from our neighbors. Based on this analysis and input from stakeholders, PJM establishes the installed reserve margin target on an annual basis.

PJM has designed its procurement of capacity so as to recognize the value to reliability and to customers of procuring additional resources over and above the installed reserve margin target. Specifically, PJM utilizes a sloped demand curve that recognizes when there is additional generation available. The rationale for the sloped demand curve is anchored in the fact that it is in the interest of customers to procure additional reserves at an overall declining price. In effect, by use of the sloped demand curve in PJM's procurement of capacity, the customer realizes the benefits of additional reliability to respond to stresses on the system such as loss of generating units, at a declining overall price per megawatt of capacity procured.

As noted in Mr. Asthana's testimony, PJM is willing to work with customers and stakeholders to further analyze whether additional enhancements need to be made to the determination of needed reserve levels to reflect the potential stresses on the system resulting from a correlation of extreme events such as cold temperatures and losses of generating units due to flooding and icing occurring over multiple days. There is no one clear way either to model these events or to find the proper balance between, on one hand ensuring adequate reserves during extended extreme weather events vs. on the other hand, ensuring that the cost of electricity remain reasonable and affordable to the citizens and businesses in our 13-state footprint. PJM intends to work with its stakeholders on these complex matters in this area so as to further improve the reliability of electricity supply and delivery to the 65 million Americans we serve.

Question 2: According to the Energy Information Administration, natural gas accounted for almost 40 percent of generation capacity last year. There is broad recognition that conventional power generating resources will continue to play an important part in providing affordable and reliable electricity if winterized. Will conventional sources of baseload power generation - like natural gas, coal, and petroleum - remain a part of PJM's energy mix even as the U.S. pursues cleaner sources of power generation?

PJM Response: The PJM region will continue to need supporting dispatchable generation to make up for the intermittent nature of renewable generation. Today, that generation will come from fossil resources although in the future new technology such as enhanced duration batteries may begin to displace some of those fossil resources. The fossil generation that will be needed to support the grid cannot be characterized in the future as "baseload generation." In fact, it may only be called to operate more like a peaking plant today than a more traditional coal fired or nuclear generator.

In the future, there will be an increased need for generating plants that are able to quickly ramp up and down and otherwise have flexibility to meet the variable nature of solar and wind output.

Question 3: Similar to Texas, but for different reasons, Alaska is not connected to the national grid. Instead, we rely on our Railbelt grid and the 200 microgrids, which are built to withstand the harsh winters and surprisingly hot summers. Microgrids have transformed energy systems in rural Alaska communities, allowing them to maintain reliable power generation using diesel fuel while incorporating locally available resources like hydro or wind to reduce energy costs and emissions. Are microgrids cost-effective assets to

improve the reliability of the national grid, and could you speak to the PJM`s work in this space, particularly the Microgrid Center of Excellence?

PJM Response: In a state like Alaska, microgrids may well be more efficient for remote communities. With regard to the transmission system within PJM that is serving significantly more densely populated areas, the bulk power system still provides benefits over microgrids; however, microgrids within the bulk power system can be an excellent combination for those customers who want or need extraordinary reliability or resilience.

Microgrids offer increased reliability and resilience within the bulk power system. A standalone microgrid outside of a larger grid system can be costly. Microgrids tend to be more cost effective for customers and communities that are already connected to a larger grid system only when they have a need for extraordinary reliability and resilience standards (e.g., hospitals, labs, critical infrastructure) or where there is some other social or local driver (e.g., New Jersey post Hurricane Sandy). The scale and interconnectedness of power grids still brings tremendous value and reliability to millions of Americans.

Often times, the economic value proposition for microgrids is dependent upon those resources within the microgrid also providing wholesale services to PJM or other competitive markets. The formation of a microgrid is typically made up of distributed energy resources and with the recent FERC Order 2222, efforts are under way to further offer wholesale participation opportunities for distributed energy resources that also operate as part of a microgrid. The potential proliferation of distributed energy resources may translate to more microgrids within the PJM grid.

The wholesale power market offers both revenue and cost saving opportunities through the use of microgrids. Examples of the use of microgrids to generate revenue or reduce electric power costs and investment expenditures in PJM include the Borough of Berlin, PA, which runs its microgrid up to 100 hours annually to reduce coincident peak charges, the Philadelphia Navy Yard (Microgrid Center of Excellence), and Princeton University.

Recently, PJM and its stakeholders have been working to ensure that resources within a microgrid have adequate access to wholesale markets and that their operation, when islanded from the bulk power system, is visible to grid operators.

Question 4: A focus of this Committee has been keeping pace with evolving threats to our nation`s energy security, which includes cyber and physical threats. I was discouraged to see President Biden suspend the Executive Order on Securing U.S. Bulk-Power Systems because we can`t forget to protect the grid from foreign adversaries as we work to strengthen the grid against climate change. PJM purchases electrical equipment from around the world. How do you protect your supply chain?

PJM Response: PJM`s supply chain cybersecurity focuses on hardware, software and services that we utilize to serve our mission. PJM does not own the electrical equipment or administrate procurement of electrical equipment and that is a function of the transmission and generation owners.

The current version of the NERC Cybersecurity Supply Chain Risk Management standard has been effective as of Oct. 1, 2020. This standard provides an excellent starting point for advancing controls to mitigate the risks associated with threats and vulnerabilities in the supply chain. Supply chain standards and best practices need to evolve continually. The breadth and depth of the supply chain creates unique and significant challenges. Coordinated and prioritized actions between industry and government are critical success factors. Reliable and secure supply chain management will require broad cross-sector engagement, broad government engagement and a significant shift in how vendors and service providers deliver products and services to substantially mitigate supply chain risks.

There is a role for our government partners to provide clear direction about vendors who put national security at risk. Additionally, the DOE and other government partners are in a position to develop testing and certification programs and will need to find the balance between government programs and competitive third-party programs.

Question 5: During the recent cold snap and whenever we have a prolonged blackout, we are reminded of just how critical it is that power continue to flow. We know that a catastrophic failure of electric service is simply unacceptable in today's world.

In light of the experience that many recently suffered with a loss of power for only about three days, and considering the potential for a loss of electricity over many states such as we saw in 2003, and taking into account what we have learned about the threat of major cyber-attack and other "low frequency/high impact" events on today's interconnected electric grids that could produce a loss of electricity for a much longer duration over wider areas --

a. **What is the plan for assuring the grids covered by the regional reliability entities that report to NERC and the broader interconnections are protected against a major cyber-attack?**

PJM Response: Ensuring grid protection against a major cyberattack is a collaborative effort between industry and government partners. Partnership and collaboration are essential to any cybersecurity or physical security program. The importance of working across the industry, and with our state and federal government partners – and even across other critical infrastructures like telecom, finance, water and gas – to share threat information and best practices cannot be overstated. Threat intelligence and learning from others in relation to threats and prevention is critical to managing any cybersecurity program.

PJM and the electricity industry have a good start through industry compliance efforts, which focus on best practices. The CIP standards provide a strong baseline for protecting and defending our critical assets. Incident response for cyber and physical events has been a high priority of the electricity subsector and has resulted in a number of vital efforts that have prepared us for coordinated response to high-consequence events.

The industry principally utilizes the Cybersecurity Framework, developed by the National Institute of Standards and Technology, as an approach to managing cybersecurity. The framework focuses on the principal functions to identify, protect, detect, respond and recover. Cybersecurity best practices begin with protecting our assets, detecting bad actors, responding to events and recovering from events. Establishing key performance indicators (KPI) and metrics for each of the principal functions is essential. You cannot control the reconnaissance that an adversary is doing, but you can control the layers of defense and the action you take to avoid or mitigate a breach.

One of the most important programs that the electricity industry has engaged in is the NERC GridEx program. This program exercises extreme events occurring across multiple electricity utilities, and includes both cyber and physical injects. It exercises coordination between utilities, the E-ISAC, and participating state and federal government entities. Lessons learned from these exercises improve the ability of utilities and government entities to work through unforeseen future events by having ready plans that have been tested through hypothetical, extreme scenarios. PJM also performs drills with the members in our footprint, building off the NERC GridEx experiences. Incident response is critical and requires preparation and practice. Moreover, as noted above, PJM receives threat indicators from the Department of Homeland Security and government-informed analysis from CRISP, which is a program that facilitates the timely sharing of cyber threat information and develops situational awareness tools to better protect against and respond to cybersecurity threats. CRISP is an excellent public private partnership that leverages the expertise of PNNL to provide enhanced situational awareness to aid in determination of depth and breadth of malicious activity.

b. **Insofar as the military doctrines of nation-states such as Russia, China, North Korea and Iran includes nuclear electromagnetic pulse (EMP) as extensive cyber threat, what is the electric sector's plan, at the utility, reliability regional entity, and national level to assure the grids are protected against that threat?**

PJM Response: The electric sector is actively working on addressing the risk posed by EMP. PJM has collaborated, and continues to do so, with NERC, EPRI, and DOE to assess the susceptibility of the grid to EMP. PJM Manual 13 (*Emergency Operations*) contains procedures for EMP events as well.

In 2015, EPRI initiated a 3-year project to study the impacts of EMP. The research included both large-scale power system simulations and hardware testing. In 2019, NERC launched the EMP Task Force to share best practices and develop reliability guidelines. In 2020, DOE released an unclassified HEMP waveform that can be used as a benchmark in power system studies.

Some utilities, when appropriate, have also included EMP specifications in their facilities.

c. Insofar as a natural event such as a geomagnetic disruption (GMD) is statistically likely to occur at some point, how are you working (and with whom) to plan for and assure that the grids are protected against and able to recover from that threat?

PJM Response: PJM's plans in this area are supported by two key NERC reliability standards: Geomagnetic Disturbance Operations (EOP-010), and Transmission System Planned Performance for Geomagnetic Disturbance Events (TPL-007).

These two standards impose a compliance obligation on the electric grid owners and operators to mitigate the risks associated with a 1-in-100 year GMD event. To put that in perspective, the 1989 geomagnetic event that resulted in the Quebec blackout lies around 1-in-50 year event. As another point of reference, you could compare the GMD standard to other terrestrial weather design basis – in general, wind loading, icing, and other conditions are designed around 1-in-50 year events. NERC's GMD standard has one of the most stringent requirements with respect to the return period.

PJM's GMD mitigation strategy is based on three pillars: (1) Equipment Hardening, (2) Situational Awareness, and (3) Operational Procedures.

PJM has worked closely with our TOs and GOs to engineer solutions using each of these pillars. Utilities have taken multiple actions to harden the grid – for example, enhancing of protection system, modifying transformer specifications, etc.

PJM also collaborates with NASA and NOAA to improve GMD forecast capabilities. PJM's operators receive NOAA's early warnings (typically more than 14 hours ahead) and can position the system to withstand the impacts of GMD in these instances. Situational awareness is enhanced with real-time geo-magnetically induced currents (GIC) measurements from the field. In the case of a severe storm, PJM's operators would declare conservative operations and follow operating procedures described in PJM's Manual 13, section 3.8, which outlines PJM's GMD Operating Plan and sets forth our emergency procedures for preparing for and operating through these type of events.

Attachment 1

Executive Summary from PJM Comments Filed in

FERC Docket No. AD18-7-000 (Grid Resilience in Regional Transmission Organizations and Independent System Operators

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Resilience in Regional Transmission Organizations and Independent System Operators	)))))	**Docket No. AD18-7-000**

COMMENTS AND RESPONSES OF PJM INTERCONNECTION, L.L.C.

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March 9, 2018

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Resilience in Regional Transmission Organizations and Independent System Operators	)))))	**Docket No. AD18-7-000**

COMMENTS AND RESPONSES OF PJM INTERCONNECTION, L.L.C.

PJM Interconnection, L.L.C. ("PJM") hereby submits its comments and responses ("Comments") to the resilience issues and inquiries identified in the Federal Energy Regulatory Commission's ("Commission") Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures issued on January 8, 2018.[1] Through these Comments, PJM:

- outlines the considerable steps PJM and its stakeholders have undertaken, or have actively underway, to enhance the resilience of the portion of the Bulk Electric System[2] ("BES") operated by PJM, and

[1] *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61,012 (2018) ("Grid Resilience Order"). In the Grid Resilience Order the Commission (1) terminated the proceeding regarding the proposed rule on Grid Reliability and Resilience Pricing submitted to the Commission by the Secretary of the United States Department of Energy ("DOE") that was focused on providing cost-of-service compensation to generators with on-site fuel capability, and (2) initiated the above-captioned proceeding on Grid Resilience in Regional Transmission Organizations and Independent System Operators. The Grid Resilience Order directed each Regional Transmission Organization ("RTO") and Independent System Operator ("ISO"), including PJM, to submit initial comments and responses to the Commission on resilience in order to enable the Commission to holistically examine the resilience of the bulk power system. Hereinafter, RTOs and ISOs are referred to collectively as RTOs.

[2] In its questions, the Commission referenced the resilience of the bulk power system. In its responses, PJM is addressing resilience as it relates to the Bulk Electric System. The North American Electric Reliability Corporation ("NERC") defines Bulk Power System as: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. NERC defines Bulk Electric System as: "Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy…" (the detailed list of systems modifying the definition are not provided herein). *See Glossary of Terms*

- details specific action steps the Commission (in some areas working with other federal and state agencies) could undertake to enhance overall resilience of the BES not just in the PJM Region but potentially across the nation.

Just as with so many issues before the Commission, enhancing grid resilience requires a careful balancing of many competing interests. Ultimately, the goal is to ensure that the BES can continue, into the future, to meet the needs of customers for the reliable and secure delivery of electricity at a price which remains just and reasonable. PJM has approached these Comments by striving to balance those different concerns and interests.

I. INTRODUCTION

There are a number of important initiatives that are underway and others that should be enhanced and made part of the Commission's focus with respect to system resilience. Defining resilience is an important first step as outlined below. Addressing the issues raised in the Commission's inquiries to the RTOs is an important second step.[3]

As a multi-state RTO, PJM has visibility into interstate and inter-system resilience vulnerabilities and restoration challenges. PJM's role in the resilience effort is not an exclusive role, but a partnership role that involves interaction and coordination with member Transmission Owners,[4] Load Serving Entities, end-use customers, the Commission, other federal and state agencies and regulatory commissions, and other stakeholders. But given the interconnected nature of the electric power grid, there is an important federal interest that must be recognized and advanced in addressing resilience. As a result, as proposed herein, the Commission should

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Used in NERC Reliability Standards, North American Electric Reliability Corporation (Jan. 31, 2018) ("NERC Glossary"), www.nerc.com/files/glossary_of_terms.pdf.

[3] Although PJM is supportive of this docket starting with an inquiry to the RTOs, grid resilience issues are not limited to RTOs. If anything, because of their scale and scope, RTOs are best able to evaluate overall grid resilience issues of the BES in their footprints. But the scope of the Commission's effort should in no way be limited to RTOs since many if not most BES grid resilience issues are truly national in scope.

[4] All capitalized terms that are not otherwise defined herein have the meaning as defined in the PJM Open Access Transmission Tariff ("Tariff"), Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), and Reliability Assurance Agreement Among Load Serving Entities in the PJM Region.

advance additional processes that could help with additional coordinated identification, authentication and mitigation of future grid resilience challenges, and authentication and mitigation of the vulnerabilities that currently exist.

To be clear, the PJM BES is safe and reliable today – it has been designed and is operated to meet all applicable reliability standards. However, improvements can and should be made to make the BES more resilient against known and potential vulnerabilities and threats. In many cases, resilience actions are anchored in, but go beyond what is strictly required for compliance with, the existing reliability standards. As a result, PJM has identified a number of recommended initiatives.

II. EXECUTIVE SUMMARY

In its broadest sense, resilience involves preparing for, operating through, and recovering from events that impose operational risk, including but not limited to high-impact, low-frequency events. However, resilience is not only about high-impact, low-frequency events. Rather, resilience also involves addressing vulnerabilities that evolved over time and threaten the safe and reliable operation of the BES (or timely restoration), but are not yet adequately addressed through existing RTO planning processes or market design. Many of the actions, policies, procedures, and market structures designed to improve system resilience are scalable and applicable to a wide range of potential risks and impacts. The challenge lies in the nature of high-impact, low-frequency events, because they are not amenable to quantitative, probability-based analyses commonly used for risk management[5] due to the difficulty of predicting the timing and impact of their occurrence. Probabilities of high-impact, low frequency events are generally unknown or extremely difficult to quantify, and the consequences or impacts of high-

[5] *See e.g.* Kaplan, S. and Garrick, B.J. (1981). On the Quantitative Definition of Risk. *Risk Analysis* 1(1).

impact, low-frequency events - although assumed to be intolerably high in terms of both human and economic costs - are difficult to quantify. Prudent resilience efforts to address verifiable vulnerabilities and threats are worthwhile despite the uncertainty, and can be effectively and efficiently managed through the use of a range of complementary analyses and strategies.

Accordingly, PJM requests that the Commission take the following actions to enhance resilience of the grid and interrelated systems that depend on the BES.

- Finalize through this proceeding a working definition and common understanding of grid resilience, clarifying that resilience resides within the Commission's existing authority with respect to the establishment of just and reasonable rates, terms and conditions of service under the Federal Power Act ("FPA").[6]
- Establish a Commission process, either informally through one or more of the Commission's existing offices, or formally through a filing process, that would allow an RTO to receive verification as to the reasonableness of its assessments of vulnerabilities and threats, including Commission utilization of information that may be available to it, but not available to the RTO because of national security issues. Those assessments, once verified, could then form the basis for RTO actions under its planning or operations authority consistent with its tariffs. Simply put, in coordination with other federal agencies such as the United States Department of Defense ("DOD"), DOE, United States Department of Homeland Security ("DHS"), as well as NERC, the Commission needs to provide intelligence and metrics to apply to resilience vulnerability and threat analyses that can then guide and anchor subsequent RTO planning, market design, and/or operations directives.[7]
- Articulate in this docket that the regional planning responsibilities of RTOs currently mandated under 18 CFR § 35.34(k)(7), and the NERC TPL standards (which among other things require RTOs to plan to provide reliable transmission service and assess Extreme Events to the BES), includes an obligation to assess resilience. The Commission should consider, after confirming that resilience is a component of such planning, initiating appropriate rulemakings or other proceedings to further articulate the RTO role in resilience planning including

[6] *See, e.g.,* Section 215, 16 U.S.C. §824o.

[7] Through this process, PJM would be seeking verification that its vulnerability identification or threat assessment is consistent with information (including classified information not necessarily available to PJM) held by the federal government and thus should be used to guide future actions. The verification would be solely of the identified vulnerability or assessed threat and would not preclude challenges in the context of a rate proceeding or otherwise as to the cost efficiency of addressing the vulnerability or threat.

affirmative obligations and standards to plan, prepare, mitigate, etc. As part of this effort, the Commission should reconcile its continued interest in transparency in planning processes under Order Nos. 890 and 1000 with the challenges of public disclosure of significant grid resilience vulnerabilities. Working with stakeholders, PJM has begun this process to include existing standards like NERC CIP-14 critical facilities and urges the Commission to provide assistance to ensure that the goals of transparency and information to end users do not become a means to disclose grid vulnerabilities that can be exploited by those with bad intent.

- Require that all RTOs (and jurisdictional transmission providers in non-RTO regions) submit a subsequent filing, including any necessary proposed tariff amendments, to implement resilience planning criteria, and develop processes for the identification of vulnerabilities, threat assessment and mitigation, restoration planning, and related process or procedures needed to advance resilience planning.
- Request that all RTOs (and jurisdictional transmission providers in non-RTO regions) submit a subsequent filing, including any necessary proposed tariff amendments, for any proposed market reforms and related compensation mechanisms to address resilience concerns within nine to twelve months from the issuance of a Final Order in this docket. PJM, together with its stakeholders, is already actively evaluating such potential reforms that advance operational characteristics that support reliability and resilience, including (i) improvements to its Operating Reserve market rules and to shortage pricing, (ii) improvements to its Black Start requirements, (iii) improvements to energy price formation that properly values resources based upon their reliability and resilience attributes, and (iv) integration of distributed energy resources ("DERs"), storage, and other emerging technologies. A deadline for submission of market rule reforms that the RTO feels would assist with its resilience efforts would help ensure focus on these issues in the stakeholder process.
- Request that PJM submit a subsequent filing, including any necessary proposed tariff amendments, to permit non-market operations during emergencies, extended periods of degraded operations, or unanticipated restoration scenarios. Such filings could including provisions for cost-based compensation when the markets are not operational or when a wholesale supplier is directed to take certain emergency actions by PJM for which there is not an existing compensation mechanism.[8]
- Establish improved coordination and communication requirements between RTOs and Commission-jurisdictional natural gas pipelines to address resilience as it relates to natural gas-fired generation located in RTO footprints. With respect to interstate pipelines, PJM respectfully requests that the Commission launch

[8] Any such RTO procedures would be limited, and would not interfere with DOE emergency actions under FPA, sections 202(c) or 215A. 16 U.S.C. §§ 824a(c), 824o-1.

additional initiatives addressing the interaction between RTOs and interstate natural gas pipelines as follows:

- PJM supports additional reforms to Order No. 787 to avoid the variable levels of information sharing provided by different pipelines in the PJM Region that resulted from the strictly voluntary nature of Order No. 787.
- PJM requests additional efforts by the Commission to encourage sharing of pipelines' prospective identification of vulnerabilities and threats on their systems and, sharing on a confidential basis in real-time, the pipeline's modeling of such contingencies and communication of recovery plans. This would ensure that the RTO has the best information in real-time to make a determination whether to increase Operating Reserves or take other emergency actions in response to a pipeline break or other contingencies occurring on the pipeline system. Although a degree of effective coordination and communication with the pipelines serving the PJM Region has been achieved, more of a focus on real time coordination of modeling of contingencies and real-time communication of same would ensure greater consistency in coordination and information and can bring gas/electric coordination, to the next level to face the next generation of resilience issues. Accordingly, PJM recommends a more holistic regulatory framework for identifying and coordination of modeling of (1) pipeline contingencies in RTO planning and (2) real-time impacts of adverse pipeline events on BES operations.
- PJM requests an increased focus on restoration planning coordination between RTOs and pipelines as each entity has valuable information that can affect the other's timely restoration.
- PJM urges the Commission to encourage the development of additional pipeline services tailored to the flexibility needs of natural gas-fired generation so as to encourage appropriate tailoring and pricing of services beyond today's traditional firm/interruptible paradigm.
- PJM believes that much can be done both in the Commission's exercise of jurisdiction over RTOs as well as interstate pipelines to improve generation interconnection coordination with pipelines in order to better align interconnection activities and timelines and minimize potential issues associated with generation facilities located in areas on pipeline systems where reliability or resilience benefits may be sub-optimal.
- Finally, PJM believes that more action is needed to support the harmonization of cyber and physical security standards between the electric sector and the natural gas pipeline system. PJM recognizes that this matter spans beyond the Commission but also involves the Transportation Security Administration ("TSA") and Pipeline and Hazardous Materials Safety Administration ("PHMSA"), but believes that through greater inter-agency coordination, a base level of resilience to

physical and cyber-attacks can be achieved even while still respecting the different regulatory authorities of each agency.

- In addition, greater communication and coordination is needed with the local distribution companies ("LDCs") that supply wholesale generation, and the Commission should support such efforts including evaluating whether communication and coordination obligations should be imposed on LDCs that supply jurisdictional wholesale generation.[9]
- As noted below, PJM is moving forward on requiring dual fuel capability at all Black Start Units but urges, as the next step, coordination across the nation of a consistent means to determine Critical Restoration Units and the development of criteria to assure fuel capability to such Critical Restoration Units.[10]
- RTOs, as part of their restoration role, should be asked to demonstrate steps they are taking to improve coordination with other critical interdependent infrastructure systems *(e.g.*, telecommunications, water utilities) that (i) could be impacted through events of type discussed herein, or (ii) are themselves vulnerabilities that could contribute to, or amplify the impact of such events. Coordination between the Commission, the Federal Communications Commission ("FCC") and DHS would provide additional federal support for such efforts.

PJM stands ready to work with the Commission and its stakeholders on each of these potential initiatives, and appreciates the Commission's leadership in this important area.

III. COMMENTS

As the Commission indicated, at the most basic level, ensuring resilience requires determining which risks to the BES to protect against, and identifying the steps that are needed to ensure those risks are addressed.[11] The Grid Resilience Order, *inter alia*, asks three broad questions. First, how should resilience be defined?[12] Second, how do RTOs assess threats to resilience?[13] Third, how do RTOs mitigate threats to resilience?[14] PJM's responses to the

[9] One possible manner of imposing obligations on LDCs might be as customers of interstate pipeline tariffs.

[10] PJM is focusing efforts on the second tier of generation used in restoration, commonly referred to as critical load units, and referred to herein as Critical Restoration Units.

[11] Grid Resilience Order at P 24.

[12] *Id.* at P 23.

[13] *Id.* at P 25.

[14] *Id.* at P 27.

AMERICAN PUBLIC POWER ASSOCIATION
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Statement for the Record

Of the American Public Power Association to

The Senate Committee on Energy and Natural Resources for

The Hearing on Reliability, Resiliency, and Affordability of Electric Service

March 11, 2021

The American Public Power Association (APPA) writes today to thank the committee for its consideration of the reliability, resiliency, and affordability of electric service. APPA is the voice of not-for-profit, community-owned utilities that power more than 2,000 towns and cities nationwide. The association represents public power utilities before the federal government to protect the interests of the more than 49 million people and 2.6 million businesses that public power utilities serve, and the 93,000 people that public power utilities employ.

Nationwide on average, public power utility customers enjoy lower average bills and higher reliability than customers served by other electric power utilities.[1] Changes in the resource mix of electric power generation, a growing population, more frequent extreme weather events, aging infrastructure, and a sprawling electric power grid pose challenges that must be addressed. [2]

These challenges are coming more frequently and coming throughout the year. Nine of the world's 10 warmest years on record have occurred since 2005, according to scientists from NOAA's National Centers for Environmental Information.[3] Conversely, during the same 15-year period there were winter-related presidentially declared major disasters or emergencies in every year except one.[4]

Most recently, Winter Storm Uri contributed to blanketing nearly three quarters of the lower 48 states in snow, submerged much of the country in record breaking air temperatures, and resulted in emergency designations in Texas, Louisiana, and Oklahoma. This snow brought challenges, but more significant was the record-breaking arctic cold that came with it. For example, during the storm, Dallas suffered through its coldest three-day stretch on record.

[1] Am. Pub. Power Ass'n, 2017-2018 Public Power Directory & Statistical Report 48 (2017); Press Release, U.S. Energy Info. Admin., Average Frequency and Duration of Electric Distribution Outages Vary by States (April 5, 2018), https://www.eia.gov/todayinenergy/detail.php?id=35652.

[2] The bulk power grid alone includes more than 240,000 miles of high-voltage power lines (230 kilovolts and greater). By comparison, the entire European Union has just 191,000 miles of such lines.

[3] https://www.noaa.gov/news/2019-was-2nd-hottest-year-on-record-for-earth-say-noaa-nasa.

[4] https://www.fema.gov/disasters/disaster-declarations.

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For electric utilities, including not-for-profit public power utilities, Winter Storm Uri and the arctic blast accompanying it posed three significant challenges.

- First, the cold weather drove high demand for natural gas and electricity to heat homes and businesses;

- Second, electric power generation in many cases was constrained; and

- Third, wholesale natural gas prices and, in turn, wholesale electric prices soared in regions controlled by the Electric Reliability Council of Texas (ERCOT), the Southwest Power Pool (SPP), and the Midcontinent Independent System Operator (MISO), but even effected prices in states in the Southwest and as far west as California.

Regarding constrained generation, much of the reduced power generation capacity was due to issues related to natural gas. North American Reliability Corporation President and CEO Jim Robb has observed that the dependence of electricity on natural gas from a reliability perspective cannot be understated. Events during Winter Storm Uri prove that point. However, it is also worth noting that almost every electric power source experienced some challenges at some point during ythe storm. Natural gas wells and pipelines froze; but wind turbines also froze and there was not much wind blowing in any case; some coal piles froze; at least one nuclear power plant tripped off in Texas due to the effects of extreme cold on the non-nuclear side of the plant; power plants themselves faced freezing; and while solar is not a major part of the energy mix in Texas, it was unavailable at night and in some cases during the day because of the lack of sun or snow/freeze on solar panels.

Throughout the storm, public power utilities worked to ensure power supply for their customers and to limit disruptions when they were forced by circumstances. Utilities sequestered crews in power plants and call centers. Staff did extensive outreach to commercial customers to ask for reductions in demand and so reserve more power for critical and residential customers. Some plant personnel even worked by hand with shovels to free coal frozen in train cars. And, where snow and ice caused damage to distribution systems, utilities brought in outside crews to help restore service.

Now that public power utilities have weathered the actual storm, APPA's top priority is to make sure impacted utilities and their customers have the resources they need to handle the financial aftermath. APPA is still assessing the effect of the storm on its members and their customers. It is evident though that a many factors could lead to widely disparate effects. First, it is worth noting that public power's customers really *are* the utility. A public power utility has no shareholders or equity investors, so any impact will eventually be borne by customers. Second, the effects of the storm vary widely among public power utilities, depending on their resource mix and position in the marketplace, but particularly related to available gas supply and the price of natural gas. Some members of the public power community have reported spending a significant percentage of their annual revenues in just one week. This is particularly true of joint action agencies, which are consortia of public power utilities formed to provide power and other services to public power utilities. That includes on natural gas as fuel and on wholesale power purchases. Other public power utilities appear to have emerged without significant negative effect. For APPA, a key concern is that utility customers are not saddled—possibly for years—with the excessive costs of sustained natural gas and wholesale electric price spikes.

The work this committee is undertaking to determine what occurred last month, along with investigations by the Federal Energy Regulatory Commission and the affected states, is essential to developing policies to prevent similar events from occurring in the future. We believe these investigations will include as a key takeaway the importance of a robust and diverse generation resource mix. In fact, while some have already allowed their preconceived notions to lead them to conclusions about what and who is to blame, we believe that one of the most important lessons likely to be learned is that each of these resources has strengths and weaknesses. Conversely, overreliance on a single resource type can lead to catastrophic price increases, and more importantly, risk to life and property.

Likewise, as we look to apply lessons learned this winter to our broader goals of reliability, resiliency, and affordability, APPA would urge against a rush to judgement. For example, in response to previous winter storms, some have sought to pass federal legislation to require mandatory capacity markets and "performance requirements" in all regional transmission organization regions. These new rules ostensibly were intended to increase resiliency but would have served to limit state flexibility in developing a resource mix and would have increased costs to consumers by billions of dollars annually. And, again, as noted above, almost every electric power source experienced some challenges at some point during Winter Storm Uri even in locations where capacity was available. Supply was the issue, and, as such mandatory capacity markets and performance requirements would not have changed the outcome. As a result, APPA encourages a thoughtful and measured approach to determining whether or not the events caused by Winter Storm Uri and other extreme weather events necessitate changes in the various markets and reliability regions.

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