S. HRG. 115–498

THE PERFORMANCE OF THE ELECTRIC POWER SYSTEM IN THE NORTHEAST AND MID-ATLANTIC DURING RECENT WINTER WEATHER EVENTS, INCLUDING THE BOMB CYCLONE

HEARING

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED FIFTEENTH CONGRESS

SECOND SESSION

JANUARY 23, 2018

Printed for the use of the
Committee on Energy and Natural Resources

Available via the World Wide Web: http://www.govinfo.gov

U.S. GOVERNMENT PUBLISHING OFFICE

28–695 WASHINGTON : 2019

COMMITTEE ON ENERGY AND NATURAL RESOURCES

LISA MURKOWSKI, Alaska, *Chairman*

JOHN BARRASSO, Wyoming
JAMES E. RISCH, Idaho
MIKE LEE, Utah
JEFF FLAKE, Arizona
STEVE DAINES, Montana
CORY GARDNER, Colorado
LAMAR ALEXANDER, Tennessee
JOHN HOEVEN, North Dakota
BILL CASSIDY, Louisiana
ROB PORTMAN, Ohio
SHELLEY MOORE CAPITO, West Virginia

MARIA CANTWELL, Washington
RON WYDEN, Oregon
BERNARD SANDERS, Vermont
DEBBIE STABENOW, Michigan
JOE MANCHIN III, West Virginia
MARTIN HEINRICH, New Mexico
MAZIE K. HIRONO, Hawaii
ANGUS S. KING, JR., Maine
TAMMY DUCKWORTH, Illinois
CATHERINE CORTEZ MASTO, Nevada
TINA SMITH, Minnesota

BRIAN HUGHES, *Staff Director*
PATRICK J. MCCORMICK III, *Chief Counsel*
ROBERT IVANAUSKAS, *FERC Detailee*
MARY LOUISE WAGNER, *Democratic Staff Director*
SAM E. FOWLER, *Democratic Chief Counsel*
SPENCER GRAY, *Democratic Professional Staff Member*

CONTENTS

OPENING STATEMENTS

WITNESSES

ALPHABETICAL LISTING AND APPENDIX MATERIAL SUBMITTED

THE PERFORMANCE OF THE ELECTRIC POWER SYSTEM IN THE NORTHEAST AND MID-ATLANTIC DURING RECENT WINTER WEATHER EVENTS, INCLUDING THE BOMB CYCLONE

TUESDAY, JANUARY 23, 2018

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

The Committee met, pursuant to notice, at 10:18 a.m. in Room SD–366, Dirksen Senate Office Building, Hon. Lisa Murkowski, Chairman of the Committee, presiding.

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

Senator BARRASSO [presiding]. We call this hearing to order. I want to welcome everyone here.

Senator Murkowski will be here shortly for this hearing that is titled, "Examining the Performance of the Electric Power System in the Northeast and Mid-Atlantic during recent winter weather events, including the Bomb Cyclone."

I would like to start by calling on the Ranking Member, Senator Cantwell, to give her opening statement.

STATEMENT OF HON. MARIA CANTWELL, U.S. SENATOR FROM WASHINGTON

Senator CANTWELL. Thank you, Chair Barrasso, and good morning to everyone. I am sure that Senator Murkowski will be here shortly.

As some people may know, a 7.9 magnitude earthquake hit off the coast of Alaska, impacting Kodiak and parts of the Pacific Northwest with tsunami warnings that were issued for activities that were expected. Those warnings for tsunami waves have been recalled, but no doubt, I am sure the Senator is dealing with lots of things this morning related to that and other issues.

I want to thank our witnesses, Chairman McIntyre and Mr. Walker, for being here. And I want to thank the staff here. We're glad we're back in operation. So we look forward to hearing from all our witnesses on the subject on the reliability of the grid and its performance.

Last year Secretary Perry and his staff reviewed the reliability of the electricity grid in the light of the changing fuel mix, and I was relieved when I saw the staff report in August which I thought

was fairly balanced. It carefully distinguished between the terms "reliability" and "resilience", and it described emerging techniques to integrate more renewable resources, including synthetic inertia and frequency response. It also recommended grid operators adopt resilience metrics that still needed to be developed.

Unfortunately, when Secretary Perry filed his report as a proposal to FERC, I was a little more alarmed. The proposal ignored the conclusion of the Department's own staff. It was a transparent attempt, in my opinion, to prop up the Administration's favorite kinds of energies which are getting outpaced in the marketplace.

There were many problems with this proposal. They never defined resilience. It picked a single attribute of power plants—fuel stored onsite—and it elevated it above all other factors. It promised full recovery for coal in some states that had chosen to follow a market model years ago. But the biggest problem was that it would hit consumers with billions of dollars of additional added costs to multiple, independent assessments.

Bailing out coal plants isn't just bad policy, it was a breathtaking raid on the consumer's pocketbooks.

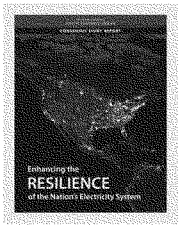
The PJM market monitor found that the Secretary's proposal could nearly double the cost of wholesale energy in the nation's largest electricity market. So I want to applaud Chairman McIntyre and the whole Commission for unanimously rejecting the Secretary's proposal. At the heart of that rejection, I believe, are consumers. I think the Commission wisely reviewed the Federal Power Act's just and reasonable standard for electricity rates and found that the Secretary had not met this burden of proving that the current rules are unjust and unreasonable. Consumers couldn't have asked for a better defense.

Given some of the troubling stories about coal interests and lobbying the Department, it has never been more important for FERC to maintain its tradition of independence.

I hope that Secretary's proposal hasn't given resilience a bad name. The difference between the grid's recovery from hurricanes in Florida and Texas versus Puerto Rico shows that resilience really does affect lives and quality of life. It deserves more attention.

So I am pleased that we have Allison Clements testifying today, along with our other witnesses. She serves on the National Academies Committee that wrote an excellent report last summer on grid resilience, and I would like to submit that report for the record.

[The information referred to follows:]



Enhancing the Resilience of the Nation's Electricity System

DETAILS

170 pages | 8.5 x 11 | PAPERBACK
ISBN 978-0-309-46307-2 | DOI 10.17226/24836

CONTRIBUTORS

Committee on Enhancing the Resilience of the Nation's Electric Power Transmission and Distribution System; Board on Energy and Environmental Systems; Division on Engineering and Physical Sciences; National Academies of Sciences, Engineering, and Medicine

Senator CANTWELL. It also has a series of concrete recommendations to Congress, to FERC and the Department of Energy that I hope we can explore today.

Again, Madam Chair, thanks to all the witnesses for being here and for calling this hearing.

STATEMENT OF HON. LISA MURKOWSKI, U.S. SENATOR FROM ALASKA

The CHAIRMAN [presiding]. Thank you, Senator Cantwell.

My apologies to our witnesses, as well as our Committee members. We have had a busy morning in Alaska this morning. I am told all is well, but I appreciate more than ever the value of things like the earthquake and tsunami early warning systems. It is important that they are there and that they were actually operating now that the government is back to order.

Last week I outlined the busy agenda that we will have this year. While we will maintain our focus on legislation and nominations, oversight is also a very critical part of our role. We are obligated to examine the performance of agencies under our jurisdiction. Today is an opportunity to gauge whether federal policy is helping or hindering improvements in energy system performance.

While it may not have been up to Alaska standards, the cold, snow and ice endured by many in the lower 48, especially along the Eastern Seaboard, was quite notable over the holidays and into the New Year. While the worst of it occurred over and on the shoulders of a holiday period and we didn't reach the extremes felt in the 2014 Polar Vortex, we did experience a so-called "Bomb Cyclone" event.

I understand that a Bomb Cyclone is a cyclone storm system in which the pressure drops precipitously in a short period of time. Apparently these happen relatively often off the northeast coast but this recent storm was a record-breaker with the largest pressure drop in a 24-hour period since 1976. As such, it presented a kind of informative stress test for the electric power system.

Now I have often said that federal law and policy must enable energy to be affordable, clean, diverse and secure. With this hearing, we return to a subject I have been following keenly since at least 2010 about how changes in the nation's electric grid and the mix of primary electricity sources are stressing system reliability and what federal changes may be necessary to address those stresses. The Secretary of Energy's Notice of Proposed Rulemaking (NOPR) issued in September and the recent FERC Order in response were focused on these same issues.

In 2014, following the Polar Vortex, we held a similar hearing to examine challenges to the electric system. I said then that we needed to redouble a properly scaled and continuously improving approach to grid reliability and security. I am pleased to see that today's testimony shows that there were many lessons learned from that extreme weather event.

For example, there now appears to be improved coordination between the electric and the gas systems. The RTOs and FERC have reformed market rules and improved business practices, NERC has updated its approaches and that is all good news. The bad news

is that we have not addressed the more difficult and fundamental challenges for electric and gas infrastructure.

For example, gas pipeline infrastructure remains too constrained. Broader policy changes are not sufficiently taking into account increasing risks that, in future years, system operators may have to turn to intentional service interruptions, otherwise known as "load shedding" or rolling blackouts or brownouts, to manage certain peak periods. One of our witnesses will speak about the situation in New England, which in some respects could serve as a harbinger of challenges in other parts of our nation.

We must ensure that our nation's natural gas supply, which is a boon to our economy and to our national security, can be reliably delivered to a changing marketplace.

At the same time, it is not clear what the reliability and economic impacts will be of a grid whose primary electricity resources are less diverse over time as baseload nuclear and coal units continue to retire.

Meeting all of these challenges, while also strengthening competition for the benefit of energy customers, should be a shared priority. After all, promoting competition has been a tenet of federal electricity policy that has enjoyed wide bipartisan support for more than two decades and should remain so.

This morning we will hear from leaders of two agencies under our jurisdiction, FERC and the Department of Energy. We will hear from the heads of three regulated entities with quasi-regulatory responsibilities, the North American Electricity Reliability Corporation, or NERC, and the two regional transmission organizations, PJM and ISO New England. We also have a member of a committee of the National Academies of Science, Engineering, and Medicine with us.

So I welcome each of you to the Committee this morning and look forward to your testimony. I would ask that you try to limit your testimony to about five minutes. Your full statements will be included as part of the record.

This morning we are joined by the Honorable Kevin McIntyre, who is the Chairman of the Federal Energy Regulatory Commission (FERC). This is the first time that you have appeared before the Committee in your capacity as Chairman. We welcome you.

The Honorable Bruce Walker is also with us as the Assistant Secretary for the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy (DOE). It is good to see you again, Bruce.

Mr. Charles Berardesco is the Interim President and the CEO for NERC, the North American Electric Reliability Corporation. We welcome you.

Ms. Allison Clements is the President of goodgrid LLC. Senator Cantwell has mentioned your contributions. We thank you.

Mr. Andrew Ott is the President and CEO for PJM Interconnection, L.L.C. Welcome.

Mr. Gordon van Welie is the President and CEO of ISO New England.

Welcome to each of you.

Chairman McIntyre, if you would like to begin with your comments this morning.

STATEMENT OF HON. KEVIN J. MCINTYRE, CHAIRMAN, FEDERAL ENERGY REGULATORY COMMISSION

Mr. MCINTYRE. Yes, Senator.

Chairman Murkowski, Ranking Member Cantwell and members of the Committee, thank you for the opportunity to appear before you today to discuss the performance of the electric system during the recent weather events.

I am honored to serve as the Chairman of the FERC. Our Commission takes seriously the responsibilities that Congress has entrusted to us concerning the reliability of the bulk power system (BPS) in this country.

We are still receiving and reviewing the data related to the performance of the bulk power system during the cold weather event that has taken place over the past month. Based on what we know to date, it appears that notwithstanding stress in several regions, overall, the bulk power system performed relatively well amid challenging circumstances. Looking forward, we must both learn from this experience and remain vigilant with respect to challenges to the reliability and resilience of the bulk power system.

The performance of the bulk power system during the 2014 winter event you referred to, now commonly known as the Polar Vortex, did provide useful context for understanding the performance of the bulk power system under the more recent winter events of the past month.

During the 2014 Polar Vortex, much of the U.S. experienced sustained and, at times extreme, cold weather. The challenges presented by these conditions and high electric demand were compounded by unplanned generator shutdowns of various fuel types. These combined circumstances tested grid reliability and power supplies and contributed to high electricity prices.

Drawing on that experience, FERC took numerous actions, as you have referenced, to address reliability and resource performance issues. For example, the Commission directed Regional Transmission Organizations and Independent System Operators, or RTOs and ISOs, as we usually call them, to report on fuel assurance issues, and the Commission revised its regulations to enhance coordination between the natural gas and the electric industries in light of the increasing use of natural gas as fuel for electric generation.

For certain regions, the Commission approved capacity market reforms that are intended to increase financial incentives for improved resource performance and to penalize non-performance or poor performance. The Commission also approved temporary winter reliability programs in New England.

Turning to the winter weather events of the past month, it is useful to consider the impact of the recent weather events on both the provision of service and the associated costs of that service. Importantly, there were no significant customer outages that resulted from failures of the bulk power system, generators or transmission lines. While there were no significant reliability problems during this recent cold weather event, wholesale energy prices were high, reflecting the stress on the system.

Higher wholesale energy prices that accurately reflect fuel costs and current system conditions can be beneficial sending important

signals that drive operational and investment decisions for both utilities and consumers. We also recognize that higher wholesale energy prices are ultimately borne by retail customers. And so, the Commission is attentive to the potential for behavior that takes advantage of extreme weather events.

Just as the Commission and the RTOs and the ISOs drew lessons from the Polar Vortex in 2014 and applied them in ways that better prepared us for this recent cold weather event, we will examine these more recent events very carefully and seek to learn from them.

I would like to emphasize a few points that the Commission made in an order issued a couple of weeks ago on the issue of resilience, more generally, referred to by Ranking Member Cantwell in her opening remarks.

On January 8th, the Commission responded to the Proposed Rule on grid reliability and resilience pricing submitted to the Commission by the Secretary of Energy, and we initiated a new proceeding to further explore resilience issues beginning with the RTOs and the ISOs. As we stated in our order, we appreciate the Secretary reinforcing the importance of the resilience of our bulk power system as an issue that warrants further attention and, as we said in our order, prompt attention.

The goals of our new proceeding are: First, to develop a common understanding among the Commission and industry and others as to what resilience of the bulk power system actually means and requires; second, to understand how each RTO and ISO assess resilience within its geographic footprint; and third, to use this information to evaluate whether additional Commission action regarding resilience is appropriate at this time.

The Commission directed each RTO and ISO to submit within 60 days of our order specific information regarding resilience of the bulk power system within those respective regions, and we invited the other interested entities to file reply comments within 30 days after the RTOs and ISOs submit their comments. We expect to review the additional material and promptly decide whether additional Commission action is warranted to address grid resilience.

In our January 8th order, the Commission also recognized that the concept of resilience necessarily involves issues that extend beyond our Commission's jurisdiction such as distribution system reliability and modernization. For that reason, we encouraged RTOs and ISOs and other interested entities to engage with state regulators and other stakeholders to address resilience at the distribution level and more broadly.

I assure you that the reliability and the resilience of the bulk power system will remain a priority of the FERC.

I look forward to answering your questions.

[The prepared statement of Mr. McIntyre follows:]

Testimony of Kevin J. McIntyre
Chairman, Federal Energy Regulatory Commission
Before the Committee on Energy and Natural Resources
United States Senate
January 23, 2018

Chairman Murkowski, Ranking Member Cantwell, and members of the Committee:

Thank you for the opportunity to appear before you today to discuss the performance of the electric system during recent winter weather events. I appreciate your attention to this important issue.

The recent cold weather event stretching from late December into early January tested the bulk power system and affected different regions in different ways. Although we are still receiving and reviewing data, it appears that, notwithstanding stress in several regions, overall the bulk power system performed relatively well. We have previously taken action to address known and anticipated challenges regarding reliability and resilience, and the recent cold weather event highlights the importance of both continued evaluation of the bulk power system and the need for the Commission to remain vigilant in addressing these issues.

The Polar Vortex of 2014

How the bulk power system performed during the winter event—now commonly referred to as the 2014 Polar Vortex—provides useful context for understanding how the bulk power system performed under the winter weather events of the past month. During the 2014 Polar Vortex, much of the United States experienced sustained and, at times, extreme cold weather. With temperatures 20 to 35 degrees below average in many areas, winter electric peak demand reached record highs in the regions served by several of the country's regional transmission organizations (RTO) and independent system operators (ISO), including the Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection, L.L.C. (PJM), New York Independent System Operator, Inc. (NYISO), and Southwest Power Pool, Inc. (SPP), with ISO New England Inc. (ISO-NE) experiencing a winter peak electric demand just below its record level. The extreme cold weather and corresponding increased demand challenged the electric system. These challenges were compounded by unplanned generator shutdowns, including those caused by mechanical failures related to temperatures falling below plants' design basis, poor winterization, and the stress of extended run times; frozen coal piles; natural gas interruptions; and fuel-oil delivery problems, including propane deliveries. These

combined circumstances tested grid reliability and power supplies, and contributed to high electricity prices.

At the same time, record high natural gas demand placed extreme stress on the U.S. natural gas system. In the Northeast, natural gas pipelines serving the region issued capacity constraint warnings and operational flow orders (OFOs), holding pipeline customers to scheduled flows and making it difficult for some natural gas to make it to market demand centers. Many storage facilities also issued restrictions on withdrawals. In the upper Midwest, an explosion on TransCanada's Mainline Line 1 lateral in Manitoba disrupted natural gas supplies to the Canadian and upper Midwest markets. The high natural gas demand and pipeline constraints translated to record high natural gas spot prices, spiking to $123/MMBtu in New York City against an average winter 2013-2014 price of $11.30/MMBtu; $120/MMBtu in Philadelphia against an average winter 2013-2014 price of $9.70/MMBtu; and over $50/MMBtu in the Midwest against an average winter 2013-2014 price of $7.44/MMBtu.

Electricity prices during the 2014 Polar Vortex reached $2,000/MWh for a number of hours in some regions. On-peak average real-time prices ran from $300-$700/MWh in PJM and MISO. High natural gas prices contributed to these electricity prices because natural gas was the marginal fuel for most electricity markets. Even these high prices, however, did not reflect the entire cost of the event. Some of the actions taken by RTOs and ISOs resulted in historically high out-of-market make-whole payments, or uplift payments, to reimburse generators for costs that were not covered through normal energy and ancillary service sales. During the event, the RTOs and ISOs declared emergency conditions on several occasions, and some implemented emergency procedures, including emergency demand response, voltage reduction, and emergency energy purchases. Ultimately, the bulk power system remained stable and generally performed reliably throughout the 2014 Polar Vortex; however, the event underscored the need for the Commission and industry to focus on market design enhancements, as well as improved gas-electric coordination.

Applying Lessons from the 2014 Polar Vortex

The Commission took numerous actions, both nationwide and with a region-specific focus, to address reliability and resource performance issues since the 2014 Polar Vortex.

Among its broader efforts, for example, the Commission examined fuel assurance, grid reliability, and generator performance issues that arose during the 2014 Polar Vortex, and it required RTOs/ISOs to report on their strategies to address market and system performance associated with fuel assurance issues. The Commission also has taken

action to respond to the increasing use of natural gas for electric generation, including revising its regulations (Order No. 809) to better coordinate the scheduling of transportation service on interstate natural gas pipelines with the scheduling practices of the wholesale natural gas and electric industries, and to provide additional scheduling flexibility to all shippers on interstate natural gas pipelines. The Commission also issued orders that facilitated improved communications between the RTOs/ISOs and natural gas pipelines. Situational awareness for the RTOs/ISOs is of particular importance during stressed system conditions, caused by, for example, increased demand for natural gas during a cold snap. Among other things, improved communications can provide RTOs/ISOs confidence that natural gas-fired resources will respond when called upon to provide energy. This confidence, in turn, mitigates the need to take costly actions that an RTO/ISO may otherwise feel compelled to take if a natural gas-fired generator does not respond as expected.

Additionally, the Commission initiated proceedings to evaluate price formation in the energy and ancillary services markets operated by RTOs/ISOs, with a focus, in part, on providing correct incentives for market participants to follow commitment and dispatch instructions, to make efficient investments in facilities and equipment, and to maintain reliability. As part of that effort, the Commission issued Order No. 831, requiring RTOs/ISOs to revise their existing offer caps to help ensure that energy prices reflect the cost to serve demand and that resources will not operate at a loss during extreme winter weather conditions when fuel supply can be tight.

As to region-specific efforts, the Commission approved significant capacity market reforms in both ISO-NE and PJM that are intended to provide greater financial incentives for improved resource performance and to impose penalties for non-performance. The Commission also has approved a series of temporary, short-term, out-of-market winter reliability programs in New England, which, among other things, provide financial incentives for resources to secure firm fuel in advance of the coldest months. And, even before issuing Order No. 831, in direct response to unprecedented spikes in fuel costs caused during the 2014 Polar Vortex, the Commission granted PJM, NYISO, and MISO temporary waivers of certain tariff provisions related to the offer price cap to allow qualifying resources to recover their full verified costs of providing energy under such extreme weather conditions. As recently as this month, due to the most recent cold weather event stretching from late December 2017 into January 2018, the Commission again granted NYISO and MISO temporary waivers of tariff provisions related to the offer cap, while noting that the impending implementation of Order No. 831 reforms should render such waivers unnecessary in the future.

The Cold Weather Event of December 2017-January 2018

In reviewing the performance of the electric system during the recent winter weather events, it is useful to consider the impact of the recent weather event on both the provision of service and the associated costs of that service.

We are still receiving information from the ISOs and the RTOs regarding the recent cold weather event. However, the bulk power system appears to have performed relatively well. There were no customer outages resulting from failures of the bulk power system, generators, or transmission lines. Overall peak load in the eastern market regions was slightly below levels during the 2014 Polar Vortex.

During this period, each region managed its system in different ways. In managing their systems, beginning on December 28 and continuing into early January, several regions issued Cold Weather Alerts to prepare for cold weather. In MISO, for example, a Cold Weather Alert directs generators to implement winterization plans for plants, ensure the availability of staff to operate plants if called on, double-check fuel supplies, and defer maintenance on generators and transmission lines, if possible. As the cold weather settled in and the risk to reliability increased, RTOs/ISOs issued Conservative Operations Notices and Watches. These notices suspend maintenance on generators and transmission facilities so that they may be available, if needed. These notices also permit out-of-market actions to relieve system constraints. On January 5, for example, all eastern market regions, the Tennessee Valley Authority, and parts of the Southeast had declared system alerts or conservative operations. As noted, while Commission staff is continuing to gather data regarding the types of actions taken during the recent cold weather event, these alerts and warnings are less severe than, and in fact are aimed at preventing, the kind of emergency actions taken during the 2014 Polar Vortex.

Throughout the cold weather event, the bulk transmission system operated reliably, with no loss of load due to transmission system failures. One notable event was the tripping on January 4 of one of the transmission lines connecting the Pilgrim nuclear station to the New England grid. The loss of this line required the plant operator to manually remove the plant from service. In PJM, gas supply issues caused outages at certain generation facilities, but mechanical problems and other factors caused significantly more outages across all types of generation facilities.

With limited exceptions, the RTOs/ISOs had sufficient reserves to ensure reliable operations. To place that statement in context, RTOs/ISOs hold generation in reserve to address unexpected contingencies like an unplanned generation outage. If an RTO/ISO gets to the point that it does not have enough resources in reserve, a reserve shortage

event is declared, and the reserve price is set administratively to reflect the fact that the system has a scarcity of resources needed to reliably serve load. During the recent cold weather event, only MISO and NYISO experienced reserve shortage events. As noted, we are still receiving data. Based on what we know, it appears MISO experienced a limited number of shortages between January 1 and January 5 and NYISO experienced a limited number of reserve shortages on January 5 and 7.

During the 2014 Polar Vortex, there were a large number of forced outages of generating stations due to failures in plant systems (boilers, electrical equipment, pumping equipment, and other components), fuel supply issues, and other factors. Initial data suggest that generator performance during the recent cold weather event improved when compared to the 2014 Polar Vortex. However, a definitive assessment cannot be made at this time.

While there were no significant reliability issues during this recent cold weather event, wholesale energy prices were high. Average energy prices in the eastern RTOs/ISOs were more than four times higher than the average energy price last winter. Looking at the period starting around December 28, 2017 through January 7, 2018, day-ahead energy prices

- at ISO-NE's internal hub prices averaged $177/MWh with a maximum price of $320/MWh,
- at PJM's Eastern Hub prices averaged $165/MWh with a maximum price of $375/MWh,
- in NYISO's Zone J (New York City) prices averaged $167/MWh with a maximum price of $315/MWh, and
- at the MISO Indiana Hub prices averaged $56/MWh with a maximum price of $158/MWh.

These figures compare to prices ranging from the low-$30s/MWh to low-$40s/MWh last winter.

We would expect competitive pressures supplemented by market power mitigation rules to lead to energy market prices that reflect the cost of fuel to generate energy and any shortage conditions. However, the Commission is attentive to the potential for behavior that takes advantage of extreme weather events. As part of its daily surveillance activities, Commission staff is reviewing market data to identify market outcomes during the most recent cold weather event that could be the result of manipulative behavior.

Given the expectation that energy market prices are consistent with fuel market fundamentals, I will provide some details about fuel markets during the cold weather

event. The cold weather that affected much of the Northeast and Midwest during the first week of January triggered a number of natural gas pipeline capacity constraints, resulting in record-setting natural gas price spikes. Trading for January 5—the peak day for spot prices—came near the end of a long succession of tight market conditions, during which total U.S. natural gas demand topped 100 Bcfd for 11 straight days in comparison to an average demand of 93.5 Bcfd in January of last year. Total U.S. natural gas demand averaged 127 Bcfd from December 25 to January 4.

In the Northeast, natural gas spot prices in New York peaked at $140/MMBtu on January 4 for flow on January 5, with two trades reported as high as $175/MMBtu. That same day, seven trading points in the Northeast and Mid-Atlantic cleared with volume-weighted average prices of greater than $100/MMBtu, while three others were above $75/MMBtu. New England was, in part, able to compensate for pipeline capacity constraints with cross-border supplies from Eastern Canada and Liquefied Natural Gas (LNG). The Canaport LNG import terminal received a 3.2 Bcf cargo from Trinidad and Tobago on January 3. Additionally, internationally-sourced LNG into the Everett LNG import terminal near Boston aided in serving the New England market. Everett received three cargoes totaling approximately 9 Bcf between December 29 and January 10, also sourced from Trinidad and Tobago. Finally, with regional heating oil prices hovering significantly below natural gas prices, around $13/MMBtu, in the Northeast and New England, it became economical for power plants to run on oil instead of natural gas. Of note, the New England region's reliance on oil-fired units during this period highlights the need to timely replenish oil inventories and carefully manage emission allowances.

In the Midwest, natural gas spot prices were elevated, but generally did not trade above $10/MMBtu. However, Northern Natural Ventura saw record natural gas prices on December 28, when Northern Border pipeline issued an OFO signaling tight conditions that resulted in an average price of $67/MMBtu, with some trades reported as high as $100/MMBtu. Pipelines in the Midwest had fewer capacity constraints than those in the Northeast, allowing greater access to supplies from multiple sources, including the nearby Appalachian Basin.

Finally, in the Southeast and Gulf Coast, prices at Henry Hub rose as high as $6.88/MMBtu from approximately $2.60/MMBtu before the cold snap. Although there were some operating constraints in the region, they were not as widespread as experienced in the Northeast.

Delivery limitations on pipelines traversing the Northeast and parts of the Midwest were prevalent in late December and early January, with several long-haul pipelines issuing system-wide restrictions. OFOs were declared on Algonquin, Dominion, Iroquois, Tennessee, and Texas Eastern pipelines in the Northeast, while other pipelines across the

grid warned shippers to remain in balance so as not to trigger restrictions. Most of the OFOs declared during the cold were lifted on or before January 9.

There are several key factors that made this most recent cold weather event less impactful to the U.S. pipeline system as a whole than during the 2014 Polar Vortex. Pipeline disruptions were less systematic and more regional in nature. Additionally, new pipeline connections provided markets near the Marcellus and Utica shale production areas better access to natural gas supplies. Increased storage withdrawals and timely use of LNG supplies also contributed to maintaining system stability.

In addition to the cost of energy generated to serve load, the cost of generation held in reserve can be an important component of the total cost borne by consumers. High prices for generation held in reserve indicates a stressed system because fewer resources are available to respond to unexpected contingencies. The frequency at which reserve prices increased to non-trivial levels during the recent cold weather event varied by region. Some of these differences are due to differences in the specific reserve market design each RTO/ISO uses. ISO-NE experienced reserve prices over $1/MWh for only 13 percent of hours. Reserve prices for resources that can respond within 10 minutes were greater than $1/MWh in 41 percent of hours in PJM, 39 percent of hours in NYISO and 72 percent of hours in the MISO. Commission staff is continuing to review these market outcomes to understand whether they are representative of actual differences in operational experience and to understand the degree to which the actions that RTOs/ISOs appropriately took to maintain reliability were reflected in market outcomes.

While higher wholesale energy prices are ultimately borne by retail customers, they send important signals to drive performance and investment. During moderate system conditions, many resources earn little to no revenue above their short-term variable costs and thus receive little revenue to offset the long-term fixed costs of building and maintaining the resource. In addition to capacity market revenue, the energy revenue earned during stressful conditions provides a means to recover a resource's fixed costs. Prices that accurately reflect fuel costs and system conditions also send signals that drive operational and investment decisions for both resources and consumers.

Looking Forward

Just as the Commission and the RTOs/ISOs drew lessons from the Polar Vortex of 2014 and applied them in ways that better prepared us for the recent cold weather event, we will examine these recent events carefully and seek to learn from them.

I also would like to emphasize several points that the Commission made in an order we issued on January 8 in response to the Proposed Rule on Grid Reliability and Resilience Pricing submitted to the Commission by the Secretary of Energy, and to initiate a new proceeding in Docket No. AD18-7-000.

First, in that order the Commission made clear that the resilience of the bulk power system will remain a priority of the Commission. The Commission recognizes that we must remain vigilant with respect to challenges to the resilience of the bulk power system, because affordable and reliable electricity is vital to the country's economic and national security. We appreciate the Secretary of Energy reinforcing the resilience of the bulk power system as an important issue that warrants further attention.

Second, in recent years, we have seen a variety of economic, environmental, and policy drivers that are changing the way electricity is procured and used. These changes present new opportunities and challenges regarding the reliability, affordability, environmental profile, and resilience of the electric system. In navigating these changes, the Commission's markets, transmission planning rules, and reliability standards should evolve as needed to address the bulk power system's continued reliability and resilience.

Third, to those ends, the Commission initiated a new proceeding to further explore resilience issues in the RTOs/ISOs. The goals of this new proceeding are: (1) to develop a common understanding among the Commission, industry, and others as to what resilience of the bulk power system means and requires; (2) to understand how each RTO/ISO assesses resilience in its geographic footprint; and (3) to use this information to evaluate whether additional Commission action regarding resilience is appropriate at this time. Therefore, the Commission directed each RTOs/ISOs to submit within 60 days of that order specific information regarding the resilience of the bulk power system in its region. We expect to review the additional material and promptly decide whether additional Commission action is warranted to address grid resilience.

Fourth, in announcing its initiative to further explore grid resilience, the Commission recognized that RTOs/ISOs are well suited to understand the needs of their respective regions and initially assess how to address resilience given the needs of their individual regions. Indeed, the report released last week by ISO-NE illustrates that type of thoughtful, forward-looking attention to resilience challenges. In addition, the concept of resilience necessarily involves issues that extend beyond the Commission's jurisdiction, such as distribution system reliability and modernization. For that reason, the January 8 order encourages RTOs/ ISOs and other interested entities to engage with state regulators and other stakeholders to address resilience at the distribution level.

I look forward to working with the Members of this Committee to promote the resilience of the bulk power system. I appreciate your attention to this important issue.

The CHAIRMAN. Thank you, Chairman McIntyre.

Assistant Secretary Walker, welcome.

STATEMENT OF HON. BRUCE J. WALKER, ASSISTANT SECRETARY, OFFICE OF ELECTRICITY DELIVERY AND ENERGY RELIABILITY, U.S. DEPARTMENT OF ENERGY

Mr. WALKER. Thank you.

Chairman Murkowski, Ranking Member Cantwell and distinguished members of the Committee, thank you for the opportunity to discuss the issue of grid resilience during the recent cold weather affecting the Northeast United States.

Just two months ago I testified before this Committee regarding the response and recovery efforts in Puerto Rico and the U.S. Virgin Islands. Secretary Perry and the Administration remain committed to supporting this restoration.

The topic of today's hearing is timely. The resilience and reliability of the energy sector are top priorities of the Secretary and a major focus of the Department of Energy. In fact, the first study requested by the Secretary was the Staff Report to the Secretary on Electricity Markets and Reliability.

The report examined the evolution of the wholesale electricity markets, the effect on grid reliability and resilience as it relates to wholesale energy and capacity markets compensating specific attributes and the connection between regulatory burdens and the retirement of baseload power plants. Many of the findings contained within the study were borne out in recent severe weather events across the nation.

The last several months have been quite demanding on the energy sector. From an extremely active hurricane season to the 2018 Deep Freeze, we have confronted challenges that tested the resilience and reliability of our energy infrastructure in different ways.

During the recent cold snap from late December 2017 to early January, the Northeast saw record low temperatures for several days; however, customer outages were minimal.

What was apparent during this weather event was the continued reliance on baseload generation and a diverse energy portfolio. Without action that recognizes the essential reliability services provided by a strategically diversified generation portfolio, we cannot guarantee the resilience of the electric grid. The grid's integrity is maintained by an abundant and diverse supply of fuel sources today, especially with onsite fuel capability; however, the real question is whether or not this diversity will be here tomorrow.

Resilience for our electric infrastructure has become more important than ever as major parts of our economy are now totally dependent on electricity. Even momentary disruptions in power quality can result in major economic losses.

At the same time, we are in the early stages of a large transformation of our electric supply system, with this process of change likely to continue for many years. Keeping the lights on during this transformation will require unprecedented coordination and collaboration amongst many parties. DOE is committed to work with FERC and regional RTOs and ISOs to achieve this mission.

Stakeholders are facing multiple, connected issues. With growing asset stress, the integration of increasing amounts of distributed

energy resources, growing consumer participation, dynamic markets, increasing cybersecurity and physical threats and the advent of the Internet of Things, the grid that sustained us for over a century must be designed to ensure reliability and resilience over the next century.

Today, the marketplace, rather than engineering principles focused on building and maintaining a resilient energy system, is driving the design of the system. However, it is clear we need an in-depth understanding of the resilience of our electricity and related infrastructure in order to know how best to either modify existing market structures and/or build new resiliency standards into the system.

To that end, I propose that DOE undertake a detailed analysis that integrates into a single, North American energy infrastructure model of the ongoing resilience planning efforts at the local, state and regional levels, including the interconnections between Canada and Mexico and also fills any gaps and harmonizes any inconsistencies in various efforts at those same levels.

I understand that we currently do not have funds appropriated for such a task, so I am taking this opportunity to make my position clear. I believe that building this resiliency model should be the top priority for DOE's Office of Electricity Delivery and Energy Reliability over the coming years as does the leadership of the Department of Energy.

To address challenges posed by events such as the recent cold snap as well as systemic energy infrastructure issues, it is critical for us to be proactive and cultivate an ecosystem of resilience, a network of producers, distributors, regulators, vendors and public partners, acting together to strengthen our ability to prepare, respond and recover.

DOE continues to partner with industry, federal agencies, states, local governments and other stakeholders to quickly identify threats, to develop in-depth strategies to mitigate those threats and rapidly respond to any disruptions.

Resilience is not a one-time activity but a habit. It is not something that cannot be done in 24 or 48 hours before an event and many events occur with little or no notice. Resilience is approaching our energy infrastructure with long-term planning in mind, understanding the future benefits resulting from investments made today.

In conclusion, today we are faced with various threats that continually become more frequent and impactful. The energy system that provides services throughout the nation are prime targets. Accordingly, we need to build upon the reliable system we have today, realized from the hard work of FERC and the RTOs and ISOs, to make them more resilient to stave the deleterious effects of these present and real threats. The near-term concern is that energy markets are significantly driving the investments being made in generation sources throughout the nation.

Indeed, most of these investments are primarily being made to address economic dispatch issues within specific regions. This has resulted in a significant reliance, in fact, perhaps an overreliance in some instances, on less costly fuel, in this case today, natural gas.

The lack of a comprehensive integrated process to drive appropriate investments to improve resiliency that take into account energy system interdependencies, critical infrastructure susceptibilities, essential reliability services as well as affordability, increases the risk of a compromised energy infrastructure and thus, the security of this nation.

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

[The prepared statement of Mr. Walker follows:]

Written Testimony of Assistant Secretary Bruce J. Walker

Office of Electricity Delivery and Energy Reliability

U.S. Department of Energy

Before the

U.S. Senate

Committee on Energy and Natural Resources

January 23, 2018

Introduction

Chairman Murkowski, Ranking Member Cantwell, and distinguished Members of the Committee, thank you for the opportunity to discuss the issue of grid resilience during the recent cold weather event affecting the Northeast United States. Just two months ago, I testified before this Committee regarding the response and recovery efforts in Puerto Rico and the U.S. Virgin Islands. Secretary Perry and the Administration remain committed to supporting this recovery.

The topic of today's hearing is timely. The resilience and reliability of the energy sector are top priorities of the Secretary and a major focus of the Department of Energy (DOE). In fact, the first study requested by the Secretary was the *Staff Report to the Secretary on Electricity Markets and Reliability* (Reliability Report). The report examined the evolution of wholesale electricity markets, the effect on grid reliability and resilience as it relates to wholesale energy and capacity markets compensating specific attributes, and the connection between regulatory burdens and the retirement of baseload power plants. Many of the findings contained within the study were borne out in recent severe weather events across the Nation.

2018 Deep Freeze

The last several months have been quite demanding of the energy sector. From an extremely active hurricane season to the 2018 Deep Freeze, we have confronted challenges that tested the resilience and reliability of our energy infrastructure in different ways. During the recent cold snap from late December 2017 to early January of this year, the Northeast saw record low temperatures for several days. However, customer outages were minimal.

What was apparent during this weather event was the continued reliance on baseload generation and a diverse energy portfolio. Without action that recognizes the essential reliability services provided by a strategically diversified generation portfolio, we cannot guarantee the resilience of the electric grid. The grid's integrity is maintained by an abundant and diverse supply of fuel sources today, especially with onsite fuel capability. However, the real question is whether or not this diversity will be here tomorrow.

The Need for Resilience

Resilience for our electricity infrastructure has become more important than ever as major parts of our economy are now totally dependent on electricity. Even momentary disruptions in power quality can result in major economic losses. At the same time, we are in the early stages of a large transformation of our electricity supply system, with this process of change likely to continue for many years. Keeping the lights on during this transformation will require unprecedented coordination and collaboration amongst many parties.

Stakeholders are facing multiple, connected issues. With growing asset stress, the integration of increasing amounts of distributed energy resources, growing consumer participation, dynamic markets, increasing cybersecurity and physical threats, and the advent of the Internet of Things, the grid that sustained us for over a century must be designed to ensure reliability and resilience over the next century.

Today, the marketplace—rather than electrical engineering principles focused on building and maintaining a resilient energy system—is driving the design of the system. However, it is clear we need an in-depth understanding of the resilience of our electricity and related infrastructure in order to know how best to either modify existing market structures or build new resiliency standards into the system.

To that end, I propose that DOE undertake a detailed analysis that: 1) integrates into a single North American energy infrastructure model of the ongoing resilience planning efforts at the local, state, and regional level, including interconnections that reach into Canada and Mexico, and 2) fills any gaps and harmonizes any inconsistencies in the various efforts at the local, state, and regional levels. I understand that we currently do not have funds appropriated for such a task, so I am taking this opportunity to make my position clear: I believe building this resilience model should be the top priority for DOE's Office of Electricity Delivery and Energy Reliability over the coming years.

To address challenges posed by events such as the recent cold snap as well as systemic energy infrastructure issues, it is critical for us to be proactive and cultivate an ecosystem of resilience: a network of producers, distributors, regulators, vendors, and public partners, acting together to strengthen our ability to prepare, respond, and recover. DOE continues to partner with industry, Federal agencies, states, local governments, and other stakeholders to quickly identify threats, develop in-depth strategies to mitigate those threats, and rapidly respond to any disruptions.

Resilience is not a one-time activity but rather a habit. It is not something that can be done in the 24 or 48 hours before an event, and many events occur with little or no notice. Resilience is approaching our energy infrastructure with long term planning in mind, understanding the future benefits resulting from investments made today.

Ongoing DOE Resilience Activities

Another way DOE is working toward a more resilient grid is through our Grid Modernization Initiative (GMI). Last fall, we announced awards of up to $32 million to DOE's National Laboratories to support early stage research and development of next-generation tools and technologies to further improve the resiliency of the Nation's critical energy infrastructure, including the electric grid and oil and natural gas infrastructure.

Seven Resilient Distribution Systems projects awarded through DOE's Grid Modernization Laboratory Consortium (GMLC) will develop and validate innovative approaches to enhance the resiliency of distribution systems – including microgrids – with emerging grid technologies at regional scale.

In addition to the Resilient Distribution Systems awards, DOE also announced last year the award of over $20 million to DOE's National Laboratories and partners to support critical early stage research and development of next-generation cybersecurity tools, technologies, as well as building capacity throughout the energy sector for day-to-day operations. The 20 projects supported by this funding are expected to have broad applicability to the U.S. energy delivery sector by meeting their needs in a cost-effective manner with a clear path for acceptance by asset owners and operators.

The Department conducts and participates in exercises to prepare and enhance resilience. Last year, we held the Clear Path V Table Top Exercise in Houston, TX to explore interdependencies between the energy sub-sectors – oil, natural gas, and electricity – and the communications sector. The exercise provided a forum for Federal, state, local, and industry stakeholders to openly discuss and identify solutions to issues impacting the Nation's energy infrastructure before, during, and after a disaster.

DOE also participated in the Grid Security Exercise IV (GridEx IV) hosted by NERC last November. The GridEx IV exercise was designed to simulate a cyber/physical attack on electric and other critical infrastructures across North America and to find ways to enhance grid resilience.

The frequency, scale, and sophistication of cyber threats have increased. Cyber incidents have the potential to interrupt energy services, damage highly specialized equipment, and threaten human health and safety. As a result, cybersecurity and resilience for energy systems have emerged as one of the Nation's most important security challenges. This work will require continued partnerships with public and private stakeholders.

Our Cybersecurity for Energy Delivery Systems (CEDS) Research and Development program aligns activities with Federal and private sector priorities, envisioning resilient energy delivery control systems designed, installed, operated, and maintained to survive a cyber incident while sustaining critical functions.

The CEDS program is designed to assist the energy sector asset owners by developing cybersecurity solutions for energy delivery systems through a focused research and development effort. DOE's Office of Electricity Delivery and Energy Reliability co-funds projects with industry partners to make advances in cybersecurity capabilities for energy delivery systems. These research partnerships are helping to detect, prevent, and mitigate the consequences of a cyber incident for our present and future energy delivery systems.

Conclusion

Threats to our Nation's energy infrastructure from a full spectrum of natural and manmade events will persist and DOE is working diligently to stay ahead of the curve. The solution is an ecosystem of resilience that works in partnership with state, local, tribal, territorial, regional, and industry stakeholders to help protect local communities through increased reliability and flexibility.

To accomplish this, we must accelerate information sharing to inform better local investment decisions, encourage innovation and the use of best practices to help raise the energy sector's security maturity, and strengthen local incident response and recovery capabilities, especially through participation in training programs and preparedness exercises. Additionally, DOE has an opportunity, if funded, to integrate local, state, and regional models into a North American resilience model.

Building an ecosystem of resilience is a shared endeavor, and keeping a focus on partnerships remains an imperative. DOE is committed to continue building on its years of coordinating with and fostering vital energy sector relationships with our Federal partners, as well as investing in technologies to enhance security and resilience in order to support industry efforts to respond to, and recover quickly from, all threats and hazards.

The CHAIRMAN. Thank you, Assistant Secretary, I appreciate your words.

Mr. WALKER. Thank you.

The CHAIRMAN. Mr. Berardesco, welcome.

STATEMENT OF CHARLES A. BERARDESCO, INTERIM PRESIDENT AND CHIEF EXECUTIVE OFFICER, NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Mr. BERARDESCO. Thank you.

Chairman Murkowski, Ranking Member Cantwell, members of the Committee, thank you for holding today's hearing. I'm the Interim President and CEO of NERC, the Electric Reliability Organization designated by FERC. In addition to developing and enforcing mandatory reliability standards for the bulk power system, NERC continually assesses reliability and monitors system operations, including in New England and the Mid-Atlantic.

My testimony covers four points: NERC's monitoring of the bulk power system and our work with stakeholders, industry and government; the performance of the system during the recent extreme cold weather; how NERC fosters a continuous learning environment to improve reliability; and recommendations based on NERC's reliability assessments.

For NERC, severe weather is, among other things, an opportunity to learn from events, to improve reliability for the future. Even when nothing bad happens, stress on the system points to reliability risks that should be addressed. NERC's bulk power system awareness group is our eyes and ears on the system and an important part of this process. On a daily basis, we continuously monitor operations on the grid working with NERC's regional entities, reliability coordinators, transmission operators and generators.

In conjunction with NERC's regional entities, we also analyze system disturbances that impact, or could impact, reliability. In turn, this information is shared with industry operators, FERC and DOE.

In short, these activities provide daily visibility into the system and actionable information to improve reliability.

During extreme weather events NERC operates on an elevated basis. Throughout the severe cold weather period, we held calls with NERC's regional entities in the affected areas and gathered information from the Reliability Coordinators, such as ISO New England and PJM, about concerns and issues associated with the impending storm. Multiple coordination calls were held daily with regional entities and FERC staff to understand fuel levels, natural gas availability and other factors such as fuel storage and replenishment plans as well as dual fuel capabilities.

During the extreme cold the primary challenge was reliably serving electricity demand during a period of near, and in some cases, record-setting winter lows. To manage the situation, Reliability Coordinators implemented conservative operations, emergency procedures and began heightened planning, communications and preparation.

Throughout, the bulk power system remained stable and reliable. A diverse generation mix with adequate flexibility and backup fuel

was key to meeting increased electricity demand, and all forms of generation contributed to serving load.

New England experienced, perhaps, the greatest stress to the system. The region experienced increased use of fuel oil for generation, due to high natural gas prices, combined with record-setting consumption of natural gas for heating and other uses. Resupply of depleted oil inventories was delayed due to a winter storm impacting New England.

Finally, the loss of the nuclear power station due to a transmission system outage removed 685 megawatts of baseload generation for several days. But again, throughout all of this, in New England and elsewhere, there was no loss of load due to BPS conditions.

Based on the information we reviewed to date, we are seeing improved performance this winter compared to past winters of similar or worse severity. In part, this is due to actions taken from the lessons of the 2014 Polar Vortex.

NERC's report analyzing the Polar Vortex underscores the need for thorough and sustained winter preparation, close coordination and communication between generator and system operators and reliable fuel supply.

NERC and the regions, in close coordination with industry stakeholders, conduct annual workshops and webinars concerning winter weather preparation, provide lessons learned and share good industry practices.

The regional entities are important to leveraging NERC's work with industry at the regional level. For example, the Reliability First Corporation, whose footprint includes the Mid-Atlantic region, conducted 18 onsite visits to generators since the Polar Vortex. These engagements are targeted at generating facilities that have experienced freezing or cold weather-related issues during prior winters and new generating facilities. This collaboration helped remedy winter challenges and share lessons learned, thereby contributing to improved performance.

While the recent extreme cold weather period was less severe than the 2014 Polar Vortex, observations from both events point to four recommendations that NERC makes in the recent reliability assessments. First, reliable and assured fuel supply is essential to electric reliability. In wholesale electricity markets NERC recommends that market operators develop additional rules or incentives to encourage increased fuel security, particularly during winter months. Policies should also promote reliable natural gas supply and transportation. Second, generator owners and operators should maintain and regularly test backup fuel operability. Third, regulation of oil-based fuel for backup generation raises a potential need for expeditious consideration of air permit waivers. And finally, during the extreme cold, a diverse generation mix, flexible fuel resources and backup fuel were key to meeting increased electricity demand.

Accordingly, NERC recommends policymakers and regulators should consider measures promoting fuel diversity and assurance.

Thank you for this opportunity and I look forward to your questions.

[The prepared statement of Mr. Berardesco follows:]

Testimony of Charles A. Berardesco, Interim President and Chief Executive Officer
North American Electric Reliability Corporation

Before the United States Senate Committee on Energy and Natural Resources
Washington, DC
"The Performance of the Electric Power System Under Certain Weather Conditions"

January 23, 2018

Introduction

Chairman Murkowski, Ranking Member Cantwell, members of the committee, I am Charles Berardesco, interim president and chief executive officer of the North American Electric Reliability Corporation ("NERC"). On behalf of NERC, I appreciate the opportunity to discuss the performance of the bulk power system[1] ("BPS") during the severe cold weather that gripped the eastern half of the United States and Canada over a two-week period in late 2017 and early 2018.

During the extreme cold, high electricity demand prompted activation of established procedures by industry to manage reliability risk and increased stress on the system. These procedures included conservative operations, cold weather alerts, and other special procedures to support continued reliable operation of the BPS. NERC, working closely with our Registered Entities[2] and federal partners monitors the BPS. Throughout this period, there were minimal observed impacts on the BPS. System stability was maintained; and the system operated reliably. Actions taken by NERC and Regional Entities[3] since the 2014 Polar Vortex contributed to reliability, underscoring the contributions of the Electric Reliability Organization Enterprise[4] ("ERO Enterprise") in promoting a continuous learning environment. As is the norm during extreme winter weather, cold temperatures did impact the system, thus highlighting the importance of a diverse and reliable fuel supply.

My testimony will discuss:

- How NERC's Bulk Power Situation Awareness ("BPSA") group monitors the BPS and works with stakeholders in industry and government.

[1] The "bulk power system" refers to facilities and control systems necessary for operating the interconnected electricity transmission network (generally 100kV and above), and the electric energy and services needed to maintain system reliability. It does not include facilities used in the local distribution of electric energy.
[2] "Registered Entities" refers to the more than 1,400 bulk power system owners, operators and users required to register with NERC and subject to mandatory reliability standards.
[3] The Regional Entities include Florida Reliability Coordinating Council, Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Reliability Corporation, Southwest Power Pool RE, Texas Reliability Entity, and Western Electricity Coordinating Council.
[4] The "ERO Enterprise" refers collectively to NERC and the eight Regional Entities which have delegation agreements with NERC to perform compliance functions and other activities.

- The performance of the BPS during the extreme cold and how system owners and operators navigated challenges during that period.
- How the ERO Enterprise supports a continuous learning environment for industry, regulators, and policymakers.
- How our observations underscore NERC's recommendations regarding fuel diversity and fuel supply.

About NERC

NERC is a private non-profit corporation that was certified in 2006 by the Federal Energy Regulatory Commission ("FERC") as the ERO under Section 215 of the Federal Power Act (16 U.S.C. §824o). With oversight by FERC, NERC develops and enforces reliability standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's Electricity Information Sharing and Analysis Center performs a critical role in real-time situational awareness and information sharing to protect the electricity industry's critical infrastructure against vulnerabilities. NERC has agreements with eight Regional Entities to which NERC delegates authority to perform certain functions. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. Our jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

NERC's Bulk Power System Awareness Group

NERC's Bulk Power System Awareness ("BPSA") group provides continuous monitoring of the BPS. During severe weather events, BPSA operates under an elevated status to closely monitor operating conditions. BPSA, in conjunction with the eight Regional Entities, collects and analyzes information across the 14 Reliability Coordinator ("RC") areas on system disturbances and other incidents that have, or could have, an impact on the BPS and disseminates this information to internal departments, Registered Entities, and governmental agencies. BPSA also monitors ongoing storms, natural disasters, and geopolitical events that may potentially impact or are currently impacting the BPS. The BPSA group also supports the development and publication of industry alerts and awareness products and facilitates information sharing among industry, Regions, and the government (U.S. Department of Energy, U.S. Department of Homeland Security, FERC) during crisis situations and major system disturbances.

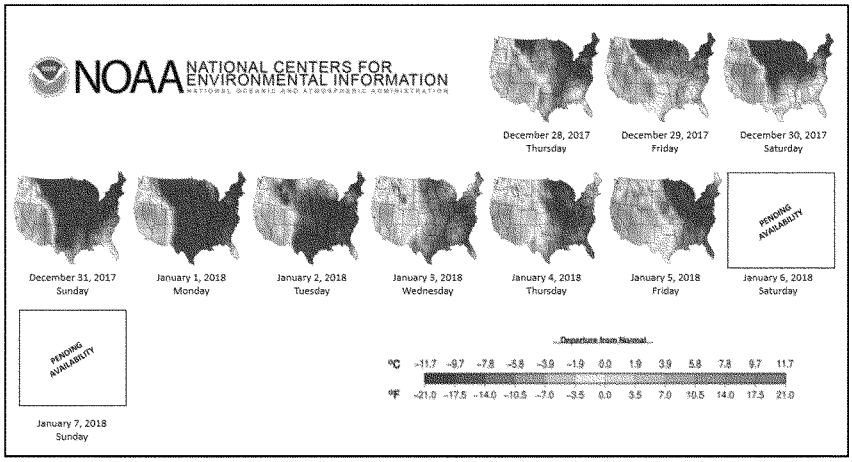
In short, BPSA is NERC's continuous "eyes and ears" on the system. During the recent severe cold weather, NERC BPSA held calls with its Regional Entities in the affected areas and gathered information from the Reliability Coordinators about concerns and issues associated with the impending storm. Multiple coordination calls were held daily with Regional Entities and FERC staff to further understand fuel levels, natural gas availability, and other factors such as fuel storage and replenishment plans, as well as dual fuel capabilities. This information was further shared with other government agencies and staffs. The NERC BPSA and affected Regional

Entities also conducted historical assessments, including high and low average temperature deviations and historical performance rates under similar weather conditions.

BPS Performance During the Extreme Cold Weather

The appendix details the performance of the BPS in eight Reliability Coordinator areas (including the Northeast and the Mid-Atlantic), load and fuel profiles, and measures implemented to manage the extreme weather. The following is a general overview of system performance and notable observations from system monitoring and analysis.

The BPS remained stable and reliable as a mass of extremely cold air moved into the eastern half of the United States, as far south as Texas and the Carolinas, during the last week of 2017 and first week of 2018. As the chart below indicates, temperatures ranged from 10° to 20° F or more below normal across most of the affected area from approximately December 28 through January 7. In contrast, the 2014 Polar Vortex saw widespread temperature departures 30° to 35° F below normal with widespread snow, ice, and freezing rain that drove a higher than desired rate of generation forced outages. [5]



There was no load loss due to BPS conditions or events during this most recent period of high loads and extreme cold. Reliability Coordinators in affected parts of the country implemented conservative operations and abnormal conditions emergency procedures and began heightened planning, communication and preparation as early as December 23. Although a nuclear power station in Massachusetts was forced offline due to a transmission system outage on January 4, overall, throughout the period, there were no significant events impacting the

[5] *See* Polar Vortex Review, NERC, September 2014.

transmission system, nor abnormally high generator forced outages. The primary challenge was reliably serving electricity demand during a period of near- and in some cases record-setting winter loads. A diverse generation mix with adequate flexibility and back-up fuel was key to meeting this increased electricity demand. All forms of generation contributed to serving load.

During the extreme cold weather, six Reliability Coordinators exceeded their forecasted 2017/18 winter peaks, some significantly so – Electric Reliability Council of Texas ("ERCOT") by 14.26%, Tennessee Valley Authority ("TVA") by 6.44%, and PJM Interconnection, L.L.C. ("PJM") by 4.38%. ERCOT also set a new all-time winter peak record, surpassing the previous record (which was set in January 2017) by over 3,200 MW.

While no records were set or peak forecasts exceeded, New England exhibited the greatest stress to the system. There, high natural gas prices combined with record setting consumption for heating and other non-power generation uses resulted in increased use of fuel oil for generation over the entire period. This increased consumption depleted inventories, the resupply of which was delayed in transportation due to the winter storm (reported in the media as the "bomb cyclone"). As mentioned, a nuclear power station in Massachusetts was forced offline due to a transmission system outage on January 4, removing 685 MW of baseload generation for several days. While reliability was maintained, this event further tightened the capacity situation across the New England ISO footprint until temperatures warmed, oil supplies were replenished, and the nuclear plant came back online on January 10.

Entities in the southeastern United States also experienced significantly stressed conditions, particularly in the VACAR South Reliability Coordinator footprint (most of North and South Carolina, and parts of surrounding states). These entities implemented a greater number and more significant emergency procedures than other areas, including use of a 5% system-wide voltage reduction to reduce loads during morning peak on January 2. While load shedding was not ultimately required, the portfolio of emergency procedures used by VACAR South RC were the closest to those employed during the 2014 Polar Vortex.

Overall BPS performance during the early 2018 cold weather events showed improvements over the past winters of similar or worse severity. In part, the improved performance observed so far reflects actions taken by stakeholders as a result of analysis, lessons learned, and implementation of recommendations from experiences in the 2011 Texas Cold Snap and the 2014 Polar Vortex. NERC and its stakeholder committees have worked with industry and the North American Generator Forum ("NAGF") to provide cold weather training materials that capture many of the lessons learned and share good industry practices in the mitigation of cold weather risks. In turn, the ERO Enterprise has used many of the resources in webinars, conferences, workshops, and outreach visits to educate industry about these risks. Many of these resources are shared publically on the NERC website[6].

[6] See *NERC's Cold Weather Training Materials*.

As recommended in the Polar Vortex Report, NERC and the Regional Entities continue to emphasize the need for thorough and sustained winter preparation to improve generation performance, as well as close coordination and communication between generator and system operators, particularly during peak winter demand periods. NERC and the regions, in close coordination with the NAGF, conduct annual workshops and webinars concerning winter weather preparation, and review each winter season or other extreme load periods for lessons learned or good industry practices to share across North America.

The Regional Entities are important to leveraging this work with industry at the regional level. For example, the ReliabilityFirst Corporation[7] ("RF") – whose footprint includes the Mid-Atlantic region – conducted 18 targeted on-site generating facility engagements since the Polar Vortex. These engagements are targeted at generating facilities that have experienced freezing or cold weather-related issues during prior winters, and new generating facilities. RF explains and discusses winter preparedness challenges with the entity; identifies and shares best practices; reviews the entity's winterization plan implementation records; and conducts walk-throughs of areas of the facilities susceptible to extreme weather challenges. RF utilizes cross-functional teams of experts to conduct these engagements (expertise in facility operations, maintenance, engineering, and planning). During the generating facility engagements, RF also verifies that the facilities have remedied previously identified winterization challenges. Such challenges have included issues with frozen valves and clogging of combustion turbine inlet filters with snow. In addition to these activities, RF conducts educational meetings and conference calls with entities within the RF region, biannual reliability workshops, reports on best practices, and consultation and information sharing with NERC. There have been improvements in cold weather performance each year in the RF footprint since the Polar Vortex, such as reduced outages and increased reserves.

In the Northeast, the Northeast Power Coordinating Council ("NPCC") routinely conducts operational coordination conference calls with Reliability Coordinators within the region. These calls provide a forum to communicate the status of current operating conditions, to facilitate the procurement of emergency condition assistance, and to enable sharing of information regarding potential threats to the system. In advance of and during the most recent winter storm and extreme cold weather, NPCC administered a number of pre-emergency preparedness calls to support programs that provided for additional system resiliency and security in the event of multiple contingencies during critical periods. Other Regional Entities have pursued activities similar to RF's and NPCC's in order to promote a strong learning environment with industry. Overall, in part due to the efforts of NERC and the Regional Entities, NERC's *2017 State of Reliability* report shows improvement in winter generator availability.[8]

---

[7] ReliabilityFirst Corporation footprint stretches from the eastern Great Lakes to the Eastern Seaboard and includes 13 states and the District of Columbia. See Regional Entity map here.
[8] *See* 2017 State of Reliability, NERC, June 2017.

NERC's Reliability Standards also require industry to prepare for and mitigate emergencies from extreme weather. In particular, Emergency Operations Standard-011-1 ("EOP-011-1") addresses the effects of operating emergencies by ensuring each Transmission Operator and Balancing Authority has developed operating plans to mitigate emergencies, and that those plans are coordinated within a Reliability Coordinator area. Among other factors, operating plans must include reliability impacts of extreme weather conditions.

Key Findings and Recommendations from NERC Assessments Related to the Cold Weather

During the extreme cold period, natural gas and oil-fired generation (in New England especially) were increasingly called upon to provide needed power. Increased reliance on natural gas and oil during severe weather conditions underscores the importance of recommendations in NERC's recent assessments.[9] In its long-term reliability assessments, NERC identifies how reliance on a single fuel increases vulnerabilities, particularly during extreme weather conditions. Against a backdrop of low natural gas prices and policies that promote increased natural gas generation, regions of the country have significantly increased dependence on natural gas over the past decade. Four of NERC's assessment areas now meet their peak electric demand with greater than 50 percent of that sourced from natural-gas-fired electric generation.[10]

Recognizing these trends, it is important to continue learning from extreme events to further enhance reliability for the future as we have learned from the 2014 Polar Vortex. During the Polar Vortex, extended periods of cold temperatures caused direct impacts on fuel availability, especially for natural-gas-fired generation. Higher-than-expected forced outages and common-mode failures were observed during the Polar Vortex due to the following: 1) natural gas interruptions (including supply injection), compressor outages, and one pipeline explosion, 2) oil delivery problems, 3) frozen well heads, 4) inability to procure natural gas, and 5) fuel oil gelling. Because natural gas provides "just-in-time" fuel and is not stored on site at generators, maintaining firm transportation and dual fuel capability can significantly reduce the risk of interruption, common-mode failure, and widespread fuel delivery impacts.

NERC's 2017/2018 Winter Reliability Assessment observes an increasing trend since 2012 of natural gas-fired generation outages during winter months.[11] These historical outages that resulted from fuel unavailability during the winter months underscore the need for fuel assurance and operational readiness during periods when reliance on natural gas can be critical.

While the recent extreme cold weather period was less severe than the 2014 Polar Vortex, observations from both events do point to a number of recommendations that NERC makes in recent assessments.

---

[9] *See* Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System, NERC, November 2017, *and* 2017 Long-Term Reliability Assessment, NERC, December 2017.
[10] *See* 2017 Long-Term Reliability Assessment (pg 15), NERC, December 2017.
[11] *See* 2017/2018 Winter Reliability Assessment (pg 13), NERC, November 2017.

Reliable Fuel Supply – Natural gas supply and transportation were highly reliable throughout the extreme cold period, yet reliable natural gas supply and transportation must remain a high priority. In the Northeast, for example, natural gas generation was unable to access natural gas due to the interruptible nature of the fuel transportation agreements with natural gas pipelines and the limited pipeline capacity available in the region. High natural gas prices also caused a shift away from natural gas and to fuel oil. New England is highly dependent on oil fuel to use as a back-up in the event of extreme weather impacting the amount of available natural gas. Inadequate fuel infrastructure, particularly natural gas infrastructure to serve the growing fleet of natural gas-fired power plants is a current and growing reliability risk.

NERC also recommends that in areas impacted by an increasing share of natural-gas-fired generation, transmission planners and operators should identify and report on potential reliability concerns due to natural gas generation with interruptible natural gas transportation and supplies. In wholesale electricity markets, market operators should develop additional rules or incentives to encourage increased fuel security, particularly during winter months.

Fuel Diversity – During the extreme cold, a diverse generation mix with adequate flexible fuel resources and back-up fuel was key to meeting increased electricity demand. All forms of generation contributed to serving load. The outage of the nuclear power station in Massachusetts exemplifies that even the most fuel secure generation resources can be forced out of service when the system needs it most. Accordingly, NERC recommends policymakers and regulators should consider measures promoting fuel diversity and supplemental fuel sources as they evaluate electric system plans, consistent with policy objectives. Additionally, regulators and policymakers should expedite licensing of new transmission and natural gas infrastructure to diversify and distribute risk.

Maintain and Regularly Test Backup Fuel Operability – Generator Owners and Operators of natural gas generation with dual fuel capability should maintain and regularly test operational capabilities and back-up fuel inventories. In the 2014 Polar Vortex, a significant amount of failed oil fuel startups occurred and thus forced units out of service, even those with ample oil backup inventories. A continued and persistent winterization effort should continue to ensure operational readiness. Oil tank replenishment must also be considered.

Expeditious Consideration of Air Permit Waivers – Dual fuel capability increases generation reliability. While oil fuel is an important backup fuel for electric reliability, the use of oil-based fuel is subject to various federal, state, and provincial laws and regulations that can impose limitations when power is most needed for reliability. While oil-fired generation units did not exceed permitted levels during the recent extreme cold period, the situation could become more acute if generators continue to rely on oil during the remaining winter months. When planning for severe weather, temporary air permit waivers may be needed from environmental agencies in advance of extreme winter weather to ensure operational readiness of the resources committed to providing capacity during the winter.

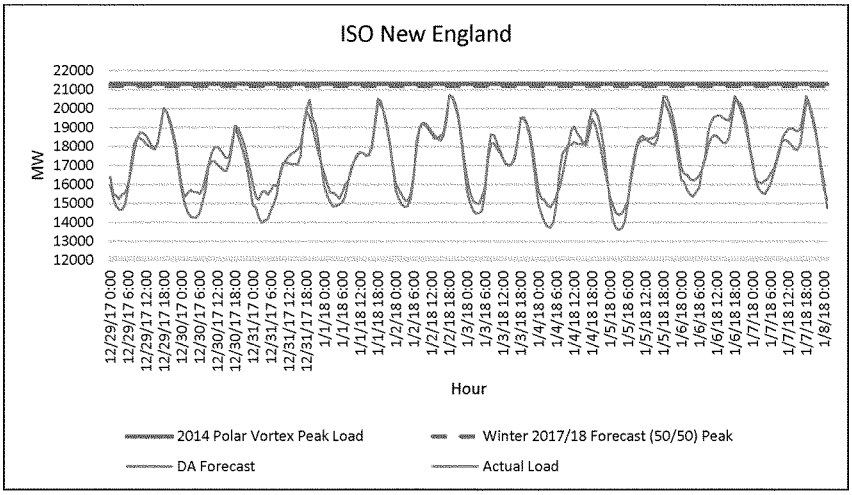
Conclusion

The BPS performed well as a mass of extremely cold air moved into the eastern half of the United States for a sustained period in late 2017 and early 2018. Throughout, NERC's BPSA group operated on elevated status to provide continuous monitoring of the system, working with other NERC departments, Regional Entities, industry and government stakeholders. NERC's analyses of cold weather events across North America, including the 2014 Polar Vortex, along with our ongoing reliability assessment work provide numerous recommendations and lessons learned. This work promotes a learning environment through follow-up and outreach by NERC, Regional Entities, and, most importantly, by the actions of NERC's Registered Entities. We have seen improvement and have also identified areas for further awareness and analysis. We continue to work with our partners at the U.S. Department of Energy and FERC to monitor these events and assure the reliability of North America's bulk power system.

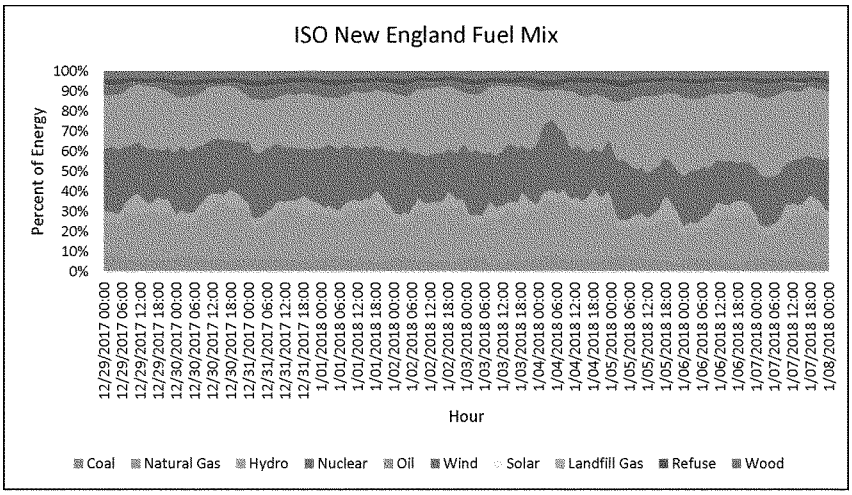
APPENDIX

For each of eight Reliability Coordinator areas during the cold weather period, the following provides additional detail on the performance of the BPS, fuel mix, and measures taken to assure reliability.

ISO New England



Data Sources:
Energy Information Administration US Electric System Operating Data
NERC Polar Vortex Review, 2014
NERC 2017/18 Winter Reliability Assessment



Data Sources:
ISO New England Dispatch Fuel Mix
Power Systems Update: New England grid operations through recent bitter cold weather and preparation for winter storm

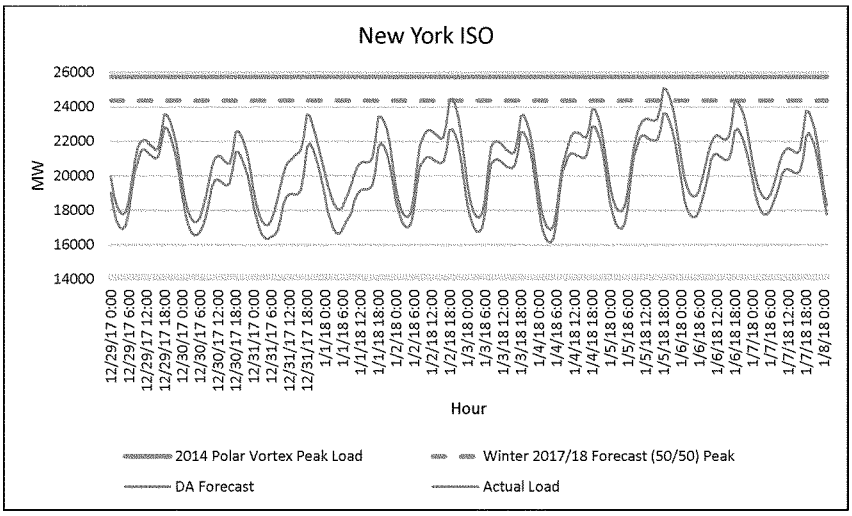
ISO New England observed a peak load of 20,663 MW for hour ending 6:00 PM EST on January 5, at which time they were importing 3,186 MW or 15.4% of their demand. Loads came in between 93.35% and 111.51% of day-ahead hourly forecasts during the period. For comparison, the highest observed load during the 2014 Polar Vortex was 21,300 MW and the forecasted (50/50) peak load for winter 2017/18 is 21,197 MW. ISO-NE did not exceed their seasonal peak forecast or set any peak new load records during the period. ISO-NE implemented their Master/Local Control Center #2 procedures and declared two Cold Weather Watches during this period. These emergency procedures were used as precautionary measures consistent with ISO-NE procedures and practice, and were expected measures given the circumstances.

During the period, ISO NEW England's fuel mix used increasing proportions of fuel oil, and a relatively consistent but higher than normal proportion of coal. Media reporting and initial analysis suggests that this was driven at least in part by economic considerations, as the price of natural gas rose and remained higher than normal due to heavy natural gas consumption for heating and other non-power production uses. Increased use of fuel oil since around December 25 led to onsite oil inventories at many facilities being depleted to uncomfortably low levels;

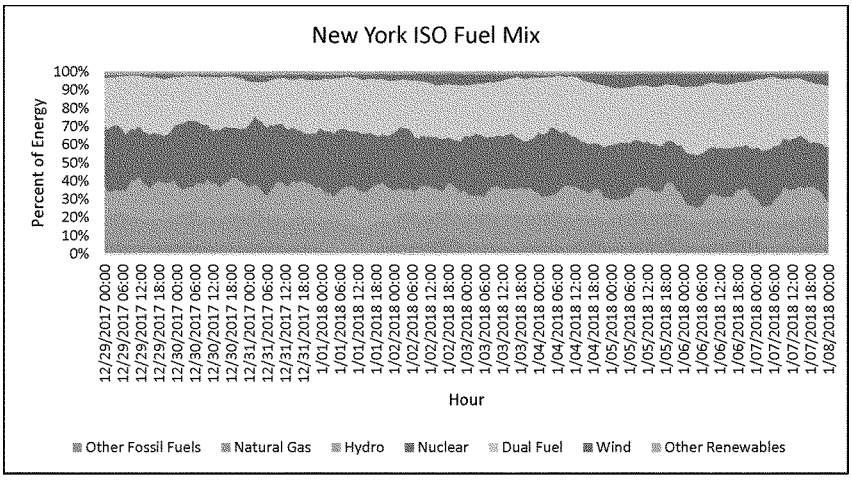
this was compounded by delays in planned resupply deliveries due to Winter Storm Grayson. Other oil-fired generation ran up against emissions limitations.

On Thursday afternoon, January 4, a nuclear generating station in Massachusetts was removed from service by operators subsequent to the loss of a transmission line connecting to the facility. The loss of approximately 685 MW of capacity through late on January 10 exacerbated the challenge of managing fuel availability. ISO-NE delayed the operations of certain resources for later hours or days, operating some facilities out of the economic order of merit in order to ensure adequate generation availability throughout the period.

New York ISO



Data Sources:
Energy Information Administration US Electric System Operating Data
NERC Polar Vortex Review, 2014
NERC 2017/18 Winter Reliability Assessment

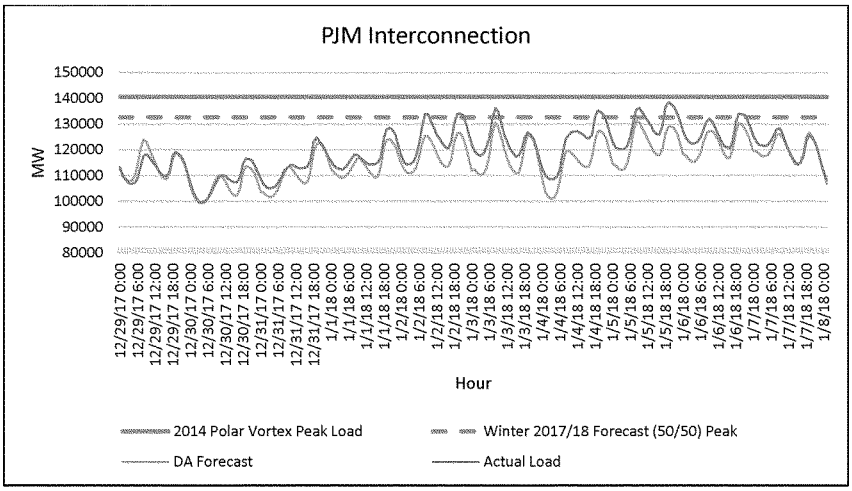


Data Source:
NYISO Data Graphs and Fuel Mix Chart (historical)

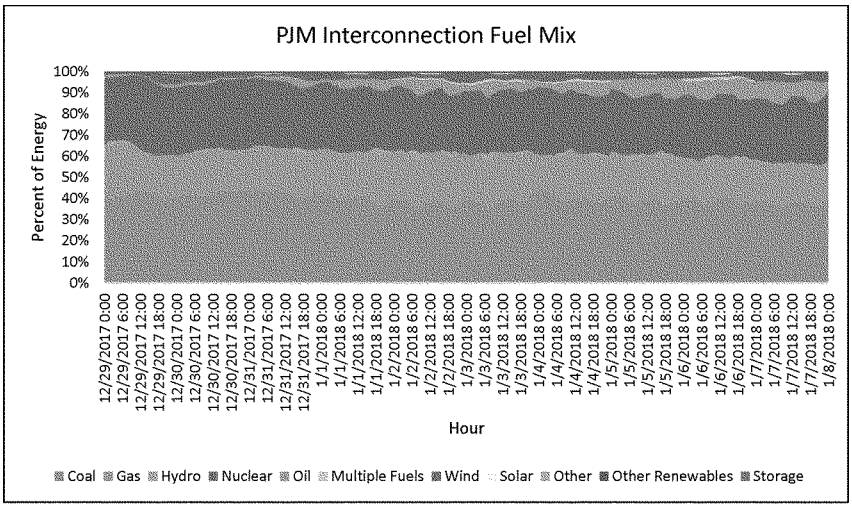
New York ISO observed a peak load of 25,081 MW for hour ending 6:00 PM EST on January 5, at which time they were importing 1,414 MW or 5.6% of their demand. Loads came in between 101.49% and 112.52% of day-ahead hourly forecasts during the period. For comparison, the highest observed load during the 2014 Polar Vortex was 25,738 MW and the forecasted (50/50) peak load for winter 2017/18 is 24,365 MW. NYISO exceeded their forecasted seasonal peak by 2.94% but did not set any new record peak loads during this period. NYISO did not implement any emergency procedures directly related to cold weather, high loads, or capacity positions.

New York ISO's fuel mix during the period appears to be within normal ranges for high load winter scenarios, noting a significant and increasing proportion of dual-fuel capable units running throughout the period. One generation facility reported a fuel supply emergency due to delayed rail shipments of coal, but this did not cause an adverse impact to the bulk power system. Initial analysis of generator performance showed good availability and no significant trends of weather-related outages.

PJM Interconnection



Data Sources:
Energy Information Administration US Electric System Operating Data
NERC Polar Vortex Review, 2014
NERC 2017/18 Winter Reliability Assessment



Data Source:
PJM Data Miner 2 Generation by Fuel Type

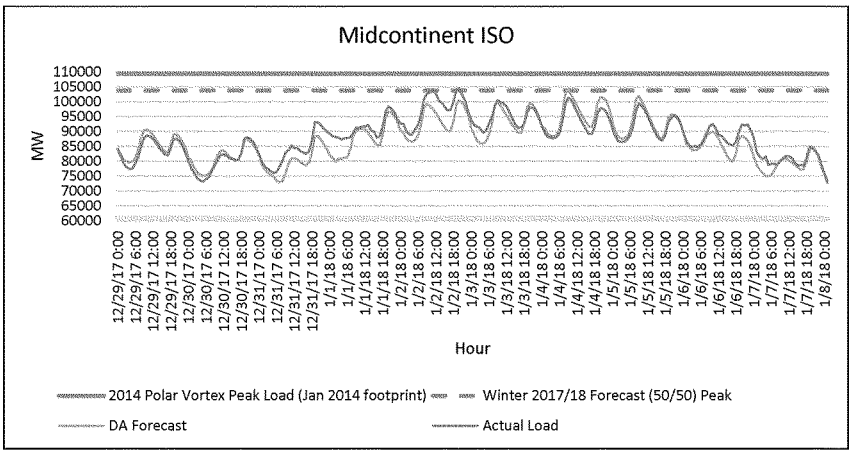
PJM Interconnection observed a peak load of 138,465 MW for hour ending 7:00 PM EST on January 6, at which time they were importing 323 MW or 0.2% of their demand. Loads came in between 95.96% and 110.65% of day-ahead hourly forecasts during the period. For comparison, the highest observed load during the 2014 Polar Vortex was 140,510 MW and the forecasted (50/50) peak load for winter 2017/18 is 132,652 MW. PJM exceeded their forecasted seasonal peak by 4.38% but did not set any new record peak loads during this period. Three of the top ten highest winter peaks occurred during this period, including the fourth highest winter peak.

PJM declared two Cold Weather Alerts during the period, adjusting the affected areas as the deepest cold passed across the RTO footprint. On January 4 and 5, PJM implemented their Heavy Load Voltage Schedule emergency procedures, which involve member companies taking actions on the distribution and sub-transmission systems that will support voltage at extra high voltage (EHV, generally 345kV and above) and increase reactive power reserves on the bulk power system. This emergency procedure is typically implemented during protracted periods of high loads driven by extreme heat or cold, and while its use is not a signal of particular concern it does indicate elevated stress on the transmission system and reactive power resources.

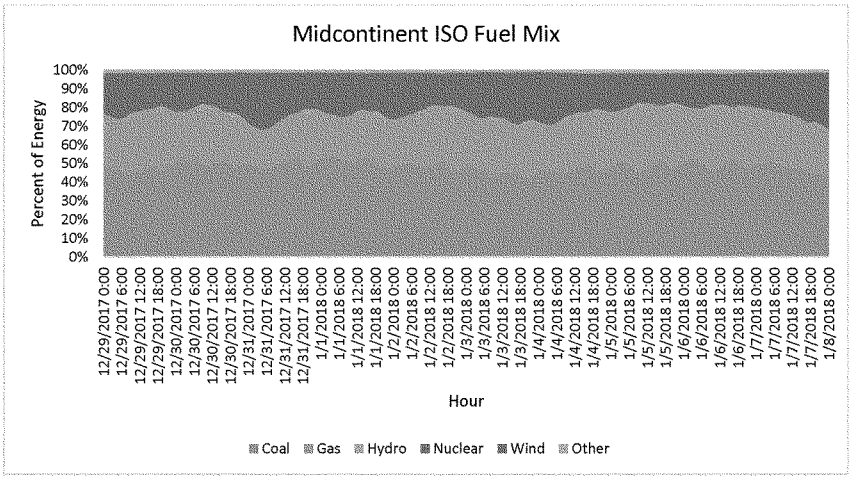
PJM Interconnection's fuel mix during the period appears to be within normal ranges for high load winter scenarios. The proportion of fuel oil used increased throughout the period but

remained a fairly small fraction of overall generation. Initial analysis of generator performance showed good availability and no significant trends of weather-related outages.

Midcontinent ISO



Data Sources:
Energy Information Administration US Electric System Operating Data
NERC Polar Vortex Review, 2014
NERC 2017/18 Winter Reliability Assessment



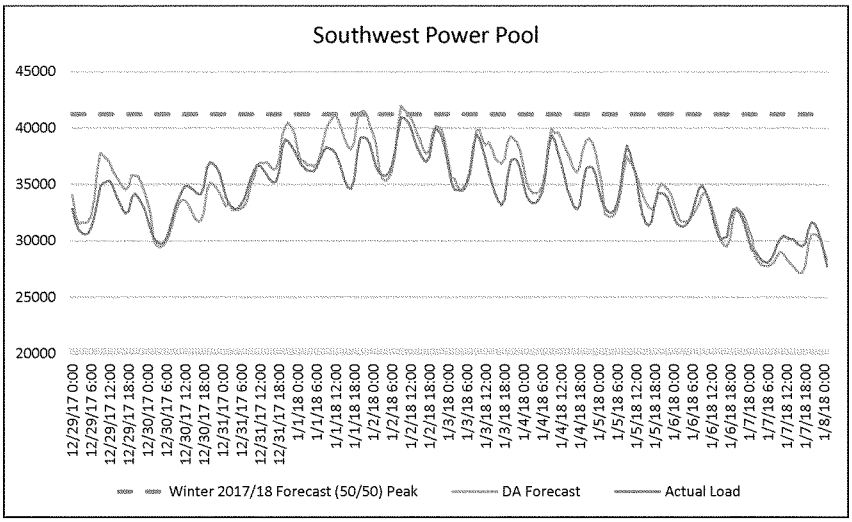
Data Source: MISO Energy Market Reports – Sub-regional Generation Fuel Mix

Midcontinent ISO (MISO) observed a peak load of 104,367 MW for hour ending 7:00 PM CST on January 3, at which time they were exporting 2,930 MW. Loads came in between 94.20% and 110.38% of day-ahead hourly forecasts during the period. For comparison, the forecasted (50/50) peak load for winter 2017/18 is 103,731 MW. During the 2014 Polar Vortex the highest observed load was 109,307 MW, but that figure included approximately 5,000 MW of peak demand (from WAPA Upper Great Plains, Basin Electric Power Cooperative, and Heartland Consumers Power District) that transitioned out of from MISO to SPP in 2015. MISO exceeded their forecasted seasonal peak by 0.61% but did not set any new record peak loads during this period. Duke Energy Indiana set a new all-time winter peak record of 7,281 MW for hour ending 9:00 AM CST on January 2.

MISO implemented their Conservative Operations procedures and declared a Cold Weather Alert for varying parts of the ISO footprint during this period. These emergency procedures were used as precautionary measures consistent with MISO procedures and practice, and were expected measures given the circumstances.

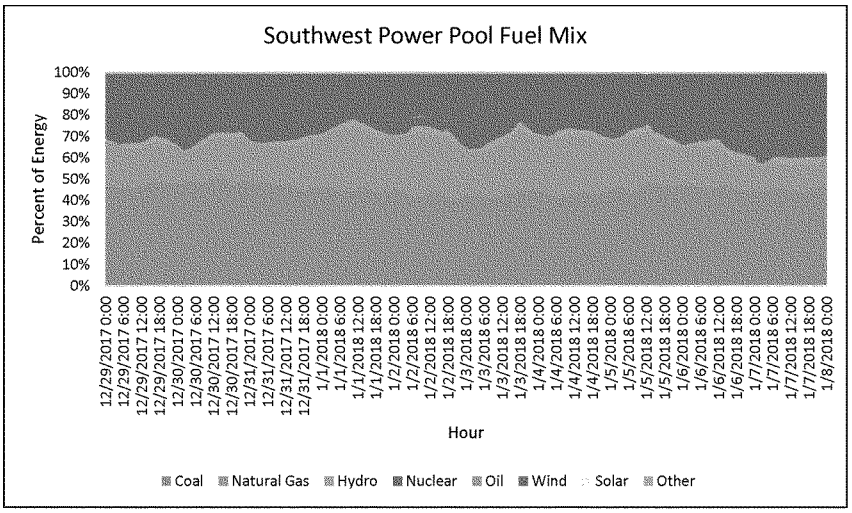
Midcontinent ISO's fuel mix during the period appears to be within normal ranges for high load winter scenarios. Initial analysis of generator performance showed good availability and no significant trends of weather-related outages.

Southwest Power Pool



Data Sources:

Energy Information Administration US Electric System Operating Data
SPP Integrated Marketplace MTLF vs. Actual (to backfill missing EIA-930 data)
NERC Polar Vortex Review, 2014
NERC 2017/18 Winter Reliability Assessment



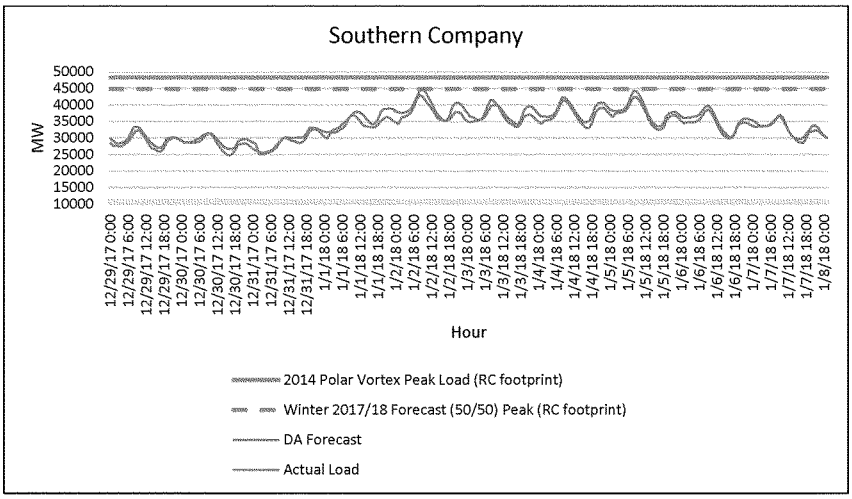
Data Source:
SPP Integrated Marketplace Hourly Generation Capacity by Fuel Type

Southwest Power Pool (SPP) observed a peak load of 40,920 MW for hour ending 7:00 PM CST on January 2, at which time they were exporting 860 MW. Loads came in between 89.95% and 121.07% of day-ahead hourly forecasts during the period. During the 2014 Polar Vortex the highest observed load was 36,602 MW, but that figure did not include approximately 5,000 MW of peak demand (from WAPA Upper Great Plains, Basin Electric Power Cooperative, and Heartland Consumers Power District) that transitioned from MISO into SPP in 2015. SPP did not exceed any seasonal forecast or record peak loads during this period.

SPP declared a Cold Weather Alert for the RTO footprint during this period but did not implement any emergency procedures directly related to high loads or capacity positions.

Southwest Power Pool's fuel mix during the period appears to be within normal ranges for high load winter scenarios. Initial analysis of generator performance showed good availability and no significant trends of weather-related outages.

Southern Company and Southeastern Reliability Coordinator



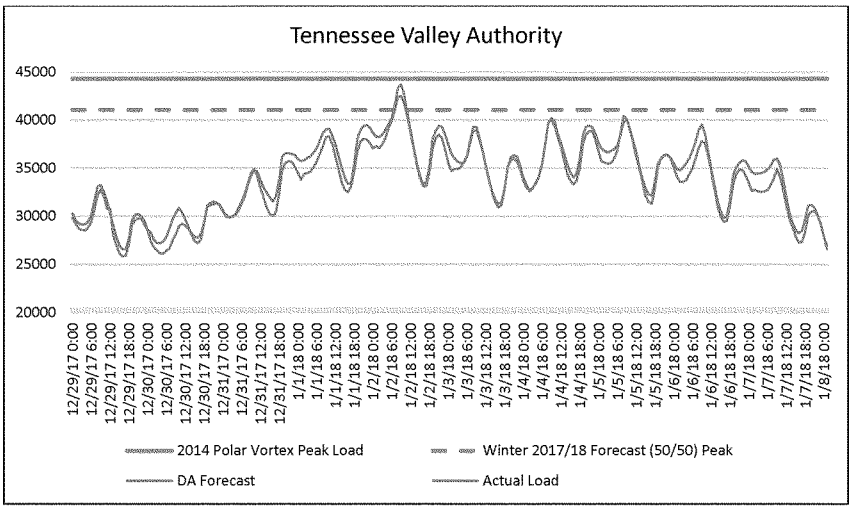
Data Sources:
Energy Information Administration US Electric System Operating Data
NERC Polar Vortex Review, 2014
NERC 2017/18 Winter Reliability Assessment

Southern Company (the Balancing Authority Area, not the larger Southeastern Reliability Coordinator footprint) observed a peak load of 44,656 MW for hour ending 9:00 AM EST on January 2, at which time they were importing 2,504 MW or 5.6% of their demand. Loads came in between 92.30% and 110.55% of day-ahead hourly forecasts during the period. For comparison, for the larger Southeastern Reliability Coordinator footprint (which includes the loads from PowerSouth Energy Cooperative, Alabama Electric Cooperative, and Southeastern Power Administration Balancing Authority Areas) the highest load observed during the 2014 Polar Vortex was 48,279 MW, and the forecasted (50/50) peak load for winter 2017/18 is 44,805 MW.

Southeastern RC implemented their Conservative Operations Watch emergency procedures as precautionary measures consistent with internal procedures and past practice. This was an expected measure given the circumstances. Southeastern RC declared an Energy Emergency Alert 1 (EEA-1) for the Alabama Electric Cooperative Balancing Authority (AEC BA) for 6½ hours on the morning of January 2; an EEA-1 is an emergency procedure used to communicate between operators that for a Balancing Authority, all available generation is committed to serve

load and meet operating reserve requirements, and that BA is concerned about sustaining adequate contingency reserves in the near future. No further emergency procedures were required to maintain adequate generation resources.

Tennessee Valley Authority



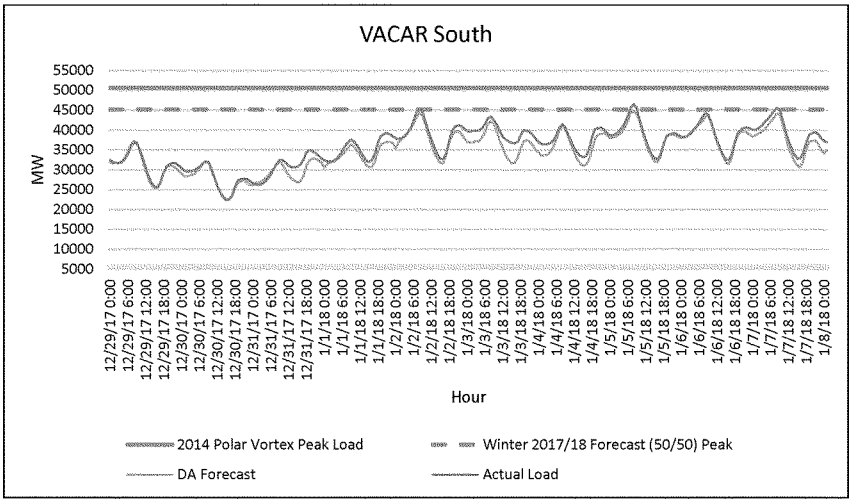
Data Sources:
Energy Information Administration US Electric System Operating Data
NERC Polar Vortex Review, 2014
NERC 2017/18 Winter Reliability Assessment

Tennessee Valley Authority (TVA) (the larger Reliability Coordinator footprint, including TVA, Louisville Gas & Electric/Kentucky Utilities, and Associated Electric Cooperative Balancing Authority Areas) observed a peak load of 43,696 MW for hour ending 9:00 AM CST on January 2, at which time they were importing 2,869 MW or 6.57% of their demand. Loads came in between 92.67% and 106.48% of day-ahead hourly forecasts during the period. For comparison, the highest observed load during the 2014 Polar Vortex was 44,285 MW and the forecasted (50/50) peak load for winter 2017/18 is 41,051 MW. TVA exceeded their forecasted seasonal peak by 6.44% but did not set any new record peak loads during this period.

TVA implemented their Conservative Operations Watch emergency procedures for the Reliability Coordinator footprint as a precautionary measure consistent with internal

procedures and past practice. As a tool to manage heavy loads, TVA issued a Power Supply Alert and implemented selected initial measures of its Emergency Load Curtailment Plan emergency procedure. This included making public appeals for voluntary load reductions for all customers in the RC footprint, from the evening of January 1 through January 5. TVA RC declared an Energy Emergency Alert 1 (EEA-1) for the TVA BA footprint for seven hours on the morning of January 2.

VACAR South Reliability Coordinator



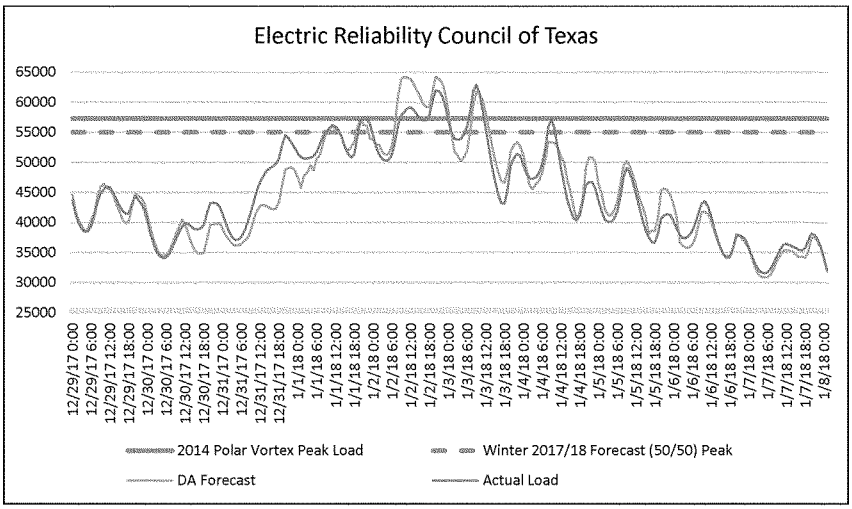
Data Sources:
Energy Information Administration US Electric System Operating Data
NERC Polar Vortex Review, 2014
NERC 2017/18 Winter Reliability Assessment

VACAR South Reliability Coordinator footprint (including Duke Energy Carolinas, Duke Energy Progress, South Carolina Electric & Gas Company, and South Carolina Public Service Authority (Santee Cooper) Balancing Authority Areas) observed a peak load of 46,495 MW for hour ending 8:00 AM EST on January 5, at which time they were importing 2,039 MW or 4.39% of their demand. Loads came in between 97.24% and 116.26% of day-ahead hourly forecasts during the period. For comparison, the highest observed load during the 2014 Polar Vortex was 50,659 MW and the forecasted (50/50) peak load for winter 2017/18 is 45,189 MW. VACAR South exceeded their forecasted seasonal peak by 2.89% but did not set any new record peak

loads during this period. Duke Energy Carolinas set a new all-time peak load (21,163 MW for hour ending 8:00 AM on January 5) and South Carolina Electric & Gas set a new all-time electricity usage record (103,700 MWh on January 3).

VACAR South RC implemented their Conservative Operations Watch emergency procedures as precautionary measures consistent with internal procedures and past practice. This was an expected measure given the circumstances. The most significant stress to the bulk power system was on the morning of January 2, which saw EEA-1 declarations for the Duke Energy Progress (CPLE and CPLW), Duke Energy Carolinas (DUK), Santee Cooper (SC), and South Carolina Electric & Gas (SCEG) BAs. A 5% voltage reduction was implemented across the Duke Energy Progress Balancing Authorities to reduce consumption through the morning peak load period. Concurrent with the voltage reduction VACAR South declared an Energy Emergency Alert 2 (EEA-2) for Duke Energy Progress, indicating that the Balancing Authorities were no longer able to provide its expected energy requirements and has implemented its Operating Plan(s) to mitigate Emergencies, but is still able to maintain minimum Contingency Reserve requirements in real time. South Carolina Electric & Gas made public appeals for voluntary load reduction on the morning of January 2, lasting until January 7. VACAR South also declared EEA-1s for the Santee Cooper BA over morning peak hours on January 4, 5, and 6. January 7 was also a challenging morning, seeing EEA-1 declarations for Duke Energy Progress, Duke Energy Carolinas, and Santee Cooper BAs, with Duke Energy Progress and Santee Cooper being elevated to EEA-2 for a period of time.

Electric Reliability Council of Texas



Data Sources:
Energy Information Administration US Electric System Operating Data
NERC Polar Vortex Review, 2014
NERC 2017/18 Winter Reliability Assessment

Electric Reliability Council of Texas (ERCOT) observed a peak load of 62,855 MW for hour ending 8:00 AM CST on January 3, at which time they were importing 73 MW across the DC ties, or 0.12% of their demand. Loads came in between 89.71% and 117.56% of day-ahead hourly forecasts during the period. For comparison, the highest observed load during the 2014 Polar Vortex was 57,277 MW and the forecasted (50/50) peak load for winter 2017/18 is 55,033 MW. ERCOT exceeded their forecasted seasonal peak by 14.26%, and set a new record winter peak, exceeding the previous peak of 59,650 MW (set hour ending 9:00 AM on January 6, 2017) during several hours on January 2 and 3. CPS Energy also set a new all-time peak demand record of 4,300 MW for hour ending 8:00 AM CST on January 3.

ERCOT issued an Operating Condition Notice for potentially extreme cold weather from January 1-4, consistent with ISO protocols and practice. This was an expected measure given the circumstances. A number of units tripped during the period, but there was no adverse impact to reliability as available reserves remained well above required levels. AEP Texas issued public appeals for energy conservation for customers impacted by distribution system outages in the Laredo and Rio Grande Valley areas, to help relieve challenges due to cold load pickup during distribution outage restoration. This was not related to any BPS conditions, but did receive

significant regional media coverage as some of the customer outages were protracted or multiple outages.

The CHAIRMAN. Thank you, Mr. Berardesco.

Ms. Clements, welcome.

STATEMENT OF ALLISON CLEMENTS, PRESIDENT, GOODGRID LLC

Ms. CLEMENTS. Thank you. Good morning.

Thank you and good morning, Chairwoman Murkowski, Ranking Member Cantwell and distinguished members of the Committee.

I am President of goodgrid, a firm that specializes in energy policy and law. In 2016 to 2017, I served on the National Academies of Sciences, Engineering, and Medicine Committee that produced this consensus report, "Enhancing the Resilience of the Nation's Electricity System." While I will talk about the report's findings, the views I express today are my own, not the Committee's.

The national dialogue about resilience comes at a critical moment. The National Academies Report notes that the U.S. electricity grid is increasingly vulnerable to the risk of cyber and physical attack and the increased frequency and duration of hurricanes, blizzards, floods and other extreme weather events caused by climate change.

The hurricanes you mentioned, Senator Cantwell, in your remarks, provide the most vivid examples of the health and safety impacts that prolonged electricity outages can have on our population, especially our already most vulnerable communities.

Natural disasters reportedly caused $306 billion in 2017, making it, by far, the most expensive natural disaster year on record.

As the FERC most recently defined it, resilience is "the ability to withstand and reduce the magnitude and/or duration of a disruptive event." Importantly, resilience is, at its core, a transmission and distribution system concept and not one that is specifically focused on power generation types. We must distinguish between resilience and reliability, as you mentioned. Grid reliability is ensuring that enough generation and transmission exists to satisfy all customers' electricity needs and avoiding blackouts if a line or a plant goes down.

While implementing reliability rules is certainly complex, the concept itself is relatively straightforward and amenable to standards for measuring its sufficiency. Resilience, separately, has emerged with this massive new risk brought on by the threat of attack and by the impacts of climate change.

Although the unpredictable nature of the threats, like from this mornings canceled tsunami warning, making, defining and developing resiliency metrics is difficult; however, existing NERC and regional standards for reliability do actually also provide some resiliency benefit.

The recent winter conditions provide three takeaways to inform your resilience-related policy thinking.

First, the transmission system is reliable. We've already heard this. Incorporating lessons learned from the 2014 Polar Vortex, RTOs reliably managed unexpected outages during the Bomb Cyclone, like the manual shutdown of the Pilgrim Nuclear Plant in ISO New England. Before we rush to establish resilience rules for the transmission system, we should determine what markets, planning and operations protocols already due in terms of supporting

resilience and whether additional metrics are necessary. The National Academies Report cautions about the difficulties of creating cost-effective and non-redundant rules for unpredictable and varied resilience needs. This Committee can support the efforts that Chairman McIntyre described at FERC on the resilience front.

Second, efforts to ensure resilience should focus on protecting vulnerable communities and ensuring access to hospitals, fire stations and other critical services. Despite the bulk system reliability in the last month, 80,000 homes and businesses had little comfort when they lost power during the Bomb Cyclone. To tackle end-use resilience needs where people are affected, we depend on resilience planning and emergency preparedness at the local and state level. Proactive Congressional support outlined in the National Academies Report, especially via public-private partnerships, can go a long way in supporting this planning and improving resilience.

Third, renewable energy and distributed energy resources are critical components of a reliable grid. The Bomb Cyclone and the 2014 Polar Vortex affirmed wind power's role as a critical cold weather reliability resource. Wind power performed well above its allotted capacity values and did not go offline, helping to avoid, generally, helping to avoid price spikes and other blackouts.

Distributed energy resources, especially customers getting paid to reduce their power use, can provide significant contributions to extreme weather reliability as well.

This was demonstrated during the Polar Vortex in PJM where nearly 3,000 megawatts of voluntary demand reduction played a key reliability role. Unfortunately, current ISO New England and PJM rules do not provide incentives for economic reductions under these conditions in demand and did not facilitate significant economic demand response this month, to my understanding.

These takeaways affirm the value of competitive wholesale markets and FERC's long tradition of technology-neutral support for these markets.

With the DOE's proposed NOPR behind us, this Committee should be wary of other supposed in-market proposals, intended to sustain specific types of power generation.

At this critical moment and through smart resilience policy, this Committee has a strong opportunity to support a clean, reliable and affordable energy future.

Thank you.

[The prepared statement of Ms. Clements follows:]

Prepared Statement of Allison Clements
President, goodgrid LLC
Before the U.S. Senate Committee on Energy and Natural Resources
January 23, 2018

Good morning Chairwoman Murkowski, Ranking Member Cantwell, and distinguished Members of the Committee. Thank you for the opportunity to speak today. My name is Allison Clements and I am president of goodgrid, a firm specializing in energy law and policy. In 2016, I served on a National Academies of Sciences, Engineering, and Medicine committee that produced a consensus report, "*Enhancing the Resilience of the Nation's Electricity System*." While I will talk about the report's findings, the views I express today are my own and do not represent the committee.

The national dialogue about resilience comes at a critical moment. The U.S. electricity system is the backbone of an increasingly electrified and fast-paced economy. The National Academies Report notes that the U.S. electricity grid is vulnerable to the risk of cyber and physical attack and increasingly severe weather events expected as the climate changes and hurricanes, blizzards, floods and other extreme weather events increase in intensity and frequency. Recent hurricanes in the Southeast and Puerto Rico provide the most vivid examples of the health and safety impacts prolonged electricity outages can have on our population, especially on our already most vulnerable communities. These hurricanes and other natural disasters reportedly caused $306 billion in damage last year, making 2017 the costliest natural disaster year on record by a significant margin.

As the Federal Energy Regulatory Commission (FERC) most recently defined it, resilience is "*[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events*" on the electric grid, including management and recovery from such events.

I would provide two footnotes. First, resilience is a transmission and distribution system concept, not one that focuses on specific power generation types. Second, resilience occurs at distinct levels of the electrical system, from interconnection-wide down to end-use where real people actually experience the impact.

We must be disciplined to distinguish between the related but separate concepts of *resilience* and *reliability*. Grid reliability involves two aspects: ensuring enough generation and transmission exists to satisfy all customers' electricity demand at all times, and that the transmission system keeps operating without blackouts when any particular transmission line or power plant fails. While implementing rules, procedures, and processes to ensure reliability is complex, the concept itself is relatively straightforward and amenable to standards measuring its sufficiency.

Our focus on resilience, separately, has emerged with the massive new risk brought on by climate change and the threat of attack. Although the unpredictable nature of the threats makes defining and developing resiliency metrics difficult, existing North American Electric Corporation (NERC) and regional reliability standards and practices do provide resiliency value.

The recent winter conditions in the Northeast and Mid-Atlantic provide a ready case study to examine what resilience means for our country's transmission and distribution systems. I offer three takeaways to inform your resilience-related policy efforts.

First, the transmission system is reliable and resilience is improving. Incorporating lessons learned from the 2014 Polar Vortex, regional transmission organizations reliably managed unexpected generation and transmission outages during the bomb cyclone and prolonged cold, like the manual shut down of the Pilgrim Nuclear Plant in ISO-NE resulting from the failure of a transmission line supplying the plant power.

Before we rush to establish resilience rules for the transmission system, we should do more work to determine what infrastructure, operating and communication protocols support resilience and whether additional metrics are necessary. The National Academies Report cautions about the difficulties of creating cost-effective and non-redundant rules for something as unpredictable and varied as resilience needs. FERC's new docket requiring the regional transmission organizations to report on resilience can play an important role and Congress can support this effort.

Second, efforts to ensure resilience should focus on protecting vulnerable communities and ensuring access to hospitals, fire stations and other critical services. Success in maintaining transmission reliability likely provided little comfort to the 80,000 homes and businesses across the East Coast that lost power during the prolonged cold. Distribution and substation failure are at least partially to blame. To tackle end-use resilience needs, we depend on resilience planning and emergency preparedness at the local and state level. Congress should support local and state planning for these disruptions. Proactive support outlined in the National Academies Report, especially via public-private partnerships, can go a long way to improve resilience and mitigate damage.

Third, renewable energy and distributed energy resources are critical components of a reliable grid. The extreme cold and bomb cyclone affirmed wind power's role as a critical cold-weather reliability resource; a role demonstrated earlier during the 2014 Polar Vortex when wind power performed well above its allotted capacity value, helping to avoid price spikes and outages. Renewable energy contributes to reliability thanks to improved forecasting, transmission planning processes, market rules and improvements in wind, solar and distributed resource technology.

Distributed energy resources, especially demand response or customers getting paid to reduce their power use, can provide significant contributions to extreme weather reliability. At one point during the Polar Vortex, voluntary participants provided nearly 3,000 MW in demand reduction, playing a key role in avoiding reliability issues. Unfortunately, current ISO-NE and PJM rules for demand response to not provide incentives for economic reductions in demand and, as I understand it, did not facilitate significant demand response participation last month.

FERC should ensure that all NERC and regional reliability standards, practices and protocols do not discriminate against the ability of renewable energy and distributed energy resources to contribute and be compensated for their full reliability value. To do otherwise not only risks violating the Federal Power Act but leaves value and customer benefits unrealized. This

Committee should encourage FERC to finalize its outstanding proposed rule that breaks down remaining barriers to both storage and distributed energy resource participation in all wholesale markets.

These takeaways affirm the value of competitive wholesale markets and the Commission's ability to continue its long tradition of technology-neutral support for competitive electricity markets. FERC's decision to reject DOE's proposed resilience rule rebuffs the idea that the "baseload" nature of older, inflexible fossil-fueled and nuclear units arms them with any particular resilience or reliability value. This Committee should be wary of other supposed in- or out-of-market proposals, including some underway in the Northeastern regional transmission organizations, intended to sustain income for specific types of power generation in contravention of FERC's technology-neutral obligation and traditional approach.

Through continuing support for competitive markets without preference, this Committee and Congress can support a cleaner, more reliable and more affordable energy future.

The CHAIRMAN. Thank you, Ms. Clements.

Mr. Ott, welcome to the Committee.

STATEMENT OF ANDREW L. OTT, PRESIDENT & CEO, PJM INTERCONNECTION, L.L.C.

Mr. OTT. Thank you, Chair Murkowski and Ranking Member Cantwell and other members of the Committee. I appreciate the opportunity to testify in front of you today about PJM's experience during the recent cold snap from December 27th to January 7th. I wish to offer, also, our perspective on activities we need to engage in in the future to ensure that our nation's electric infrastructure remains reliable and resilient and the supply of electricity is actually met efficiently, fairly and cost-effectively.

As I note in my testimony, we are a FERC-regulated, regional transmission organization serving all or parts of 13 states plus the District of Columbia. We have a population of 65 million people. So obviously, the reliability of the grid is job one for us.

During recent cold weather, we've experienced three of our top ten winter peak demand days of all time. Overall, the grid and the generation fleet performed very well. We had very sustained high performance throughout the cold snap.

This cold snap was actually prolonged as compared to the Polar Vortex which was much shorter, more deeper cold. This cold snap was much more prolonged, and we depended on that prolonged improved performance.

With the support of FERC, we had instituted reforms in our capacity market regarding pay for performance based on the lessons learned from the Polar Vortex, as the Chairman had indicated. And we did see significantly improved performance during this cold weather event.

All resource types, coal-fired generation, gas-fired generation, nuclear generation, renewable generation, all performed better in this cold weather event than what we saw during the Polar Vortex and certainly we see that improvement was based on our lessons learned, improvements in investment back into those resources to see that they perform well.

While I can assure you that the grid is reliable today, our work is not done. We certainly cannot become complacent. We need to look at certain initiatives to undertake, and certainly PJM has been undertaking those initiatives to look at the resilience of the grid and how we are going to improve the robustness and resilience of the grid into the future.

We look at this from three perspectives: we have to plan the grid with an eye toward resilience, go beyond the traditional criteria; we need to operate the grid looking at the increased risks and increased threats that we see; and also, look at recovery of the grid should something happen we need to be able to bounce back quickly. So, those are the types of things we look at.

I want to also bring to this Committee's attention some of the broader initiatives we'll be actually working in partnership with the new FERC Chairman as we go through the process of the docket that they opened, as he had mentioned.

One of the most important things that we have been focused on is how does our market, electricity market, actually compensate for resources that are providing reliability services?

And we have proposed key reforms and have engaged in discussion about key reforms on what we call price formation, and I want to spend a little bit of time explaining what that means for this Committee and for FERC as a whole.

Just to be clear, the generating units we call upon to serve our customers and produce electricity get paid. They recover their offers and their costs and certainly are not uncompensated.

But at times what we find is the total cost of operation of those units to provide the reliable power in each day, they don't necessarily get those monies in the market. Sometimes the market price doesn't reflect the fact that they're online and running; therefore, we have to compensate them through what we call an "out-of-market" payment. To put it in perspective, in this recent cold snap normally the out-of-market payments are about $500,000 a day for us, which is a very small number compared to the total cost of electricity. In the cold snap, we saw that increase fairly dramatically to $4 million, sometimes $6 million a day.

What that shows is, so we are running those units to provide reliability to the grid, but the fact that they're running isn't reflected in the power price, the price of electricity. They get paid, but they aren't seeing it in the price. Therefore, when they go to sell their electricity forward in the market, so they're going to sell it for next month or next year, they're selling it at a discount that's not reflecting the fact that they were on to serve customers reliably in that cold snap.

So, that's the issue we have to address. That's the issue that all resources will benefit from whether it be coal-fired resources, gas-fired resources, nuclear, renewable, demand response, alternative technologies. If we get the price right, all of these resources will see the dollar value of the reliability that they're proposing, and that's what we want to engage in, is that conversation.

What we really need, because there's so many things that we need to address, we need to put time discipline. We're looking for FERC, and certainly we'll work with FERC, to put time discipline on these discussions to address these in a timely manner.

I thank you very much. I look forward to questions.

[The prepared statement of Mr. Ott follows:]

United States Senate

Committee on Energy and Natural Resources

Testimony of Andrew L. Ott, President & CEO
PJM Interconnection, L.L.C.

"Examining the Performance of the Electric Power Systems Under Certain Weather Conditions"

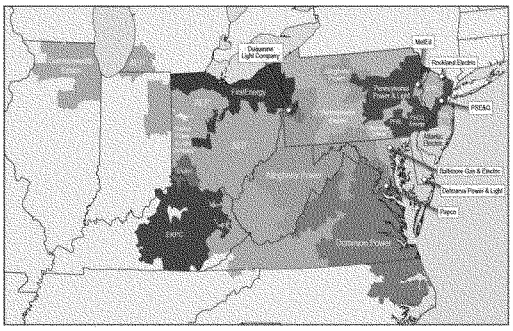
January 23, 2018

As the CEO of the largest electric grid in North America and the largest competitive wholesale electricity market in the world, I am pleased to have the opportunity to testify today on PJM's real-time experience during the recent incidence of prolonged cold weather from December 27, 2017, to January 7, 2018. I also wish to offer our perspectives on the state of the electric grid in the PJM footprint, as well as what PJM believes will be needed in the future to ensure that our nation's need for a reliable and resilient supply of electricity is met efficiently, fairly and cost-effectively. These recommendations address both reforms already underway in PJM as well as larger policy issues that will require consideration by FERC, DOE and other policymakers.

PJM is the independent Regional Transmission Organization covering all or parts of 13 states and the District of Columbia, in an area with a population of more than 65 million. Our role is three-fold:

1. To ensure the reliability of the grid
2. To operate robust competitive wholesale electricity markets that both attract needed investment and yield just and reasonable rates for customers
3. To plan for the expansion and evolution of the power grid in the region we serve

Figure 1. PJM Service Territory and Key Statistics



Key Statistics	
Member companies	1,000+
Millions of people served	65
Peak load in megawatts	165,492
MW of generating capacity	176,569
Miles of transmission lines	82,546
2016 GWh of annual energy	792,314
Generation sources	1,304
Square miles of territory	243,417
States served	13 + DC

We are appreciative of the work of this Committee and its excellent Staff on both sides of the aisle. I personally, along with my Staff, have met on many occasions with Members and Majority and Minority Staff and appreciate your keen interest and helpful interaction with PJM over the years. We also appreciate the support we have received from FERC and DOE, both of which have been keenly focused on ensuring a reliable grid at rates that are just and reasonable to consumers.

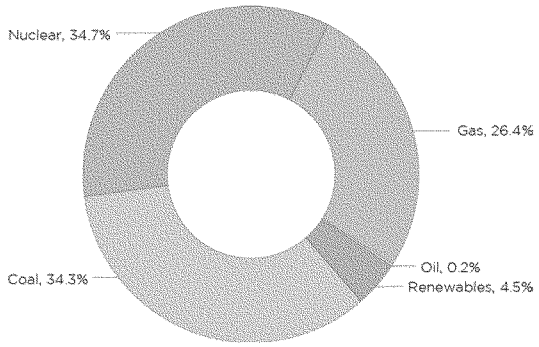
At PJM, we have a very diverse footprint. That footprint includes net-exporting states like Pennsylvania, West Virginia and Kentucky, with their rich resources in coal and natural gas, as well as net-consuming states such as Maryland and New Jersey that have aggressively embraced renewable resources to meet their future needs. Notably, the energy markets have provided benefits to each state in our region, be they states with surplus energy to sell to the rest of the grid or net-consuming states, which depend on the large regional market to ensure that customers have choices in their sourcing of electric generation.

State of the PJM Grid

My testimony will address both the state of the grid today as well as the policy and operational reforms we will need in the future as the grid changes.

The PJM grid today is both reliable and diverse. In terms of energy production, our generation fleet is almost evenly split between coal, natural gas and nuclear resources, with ever-growing penetration of renewable generation and healthy levels of demand response and energy efficiency.

Figure 2. 2016 Fuel Mix (Energy)

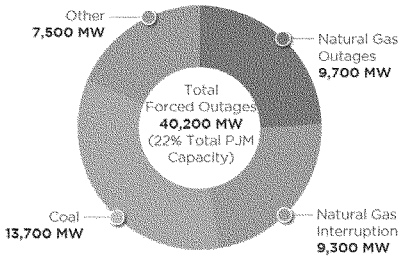


Looking Back: The 2014 Polar Vortex

At PJM, the reliability of the bulk power system is job number one, and we are committed to using all of the sophisticated market, operational and planning tools at our disposal to ensure that the grid remains reliable going forward. The performance of our assets, especially during the recent cold snap, indicates that the grid remains reliable today. As a reference point, I will illustrate how we have progressed from the time of the Polar Vortex in 2014 to today.

The Polar Vortex of 2014 was characterized by multiple days of below-zero temperatures through much of our footprint. I need to be clear, even at the height of the Polar Vortex, we were not facing imminent blackouts. However, the performance of the generation fleet was not where it needed to be at that time to meet system conditions. We saw a significant number of plant outages across the board from generation of all types. This is illustrated in Figure 3, which shows "forced outages" on the peak energy demand hour of the Polar Vortex.

Figure 3. 2014 Polar Vortex Forced Outages – January 7, 2014 Evening Peak (7 p.m.)

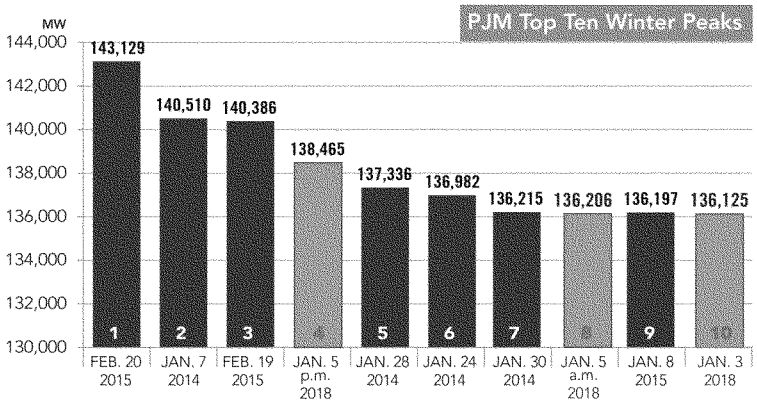


With FERC's support, we were able to implement key reforms by instituting a performance-based incentive and penalty system, which was designed to ensure that generators are available when required.

The December-January Cold Snap

During the recent cold snap from December 27, 2017, to January 7, 2018, we experienced three of our top 10 winter peak demand days of all time (Figure 4). Overall, the grid and the generation fleet performed well. Even during peak demand, PJM had an abundance of reserves and capacity.

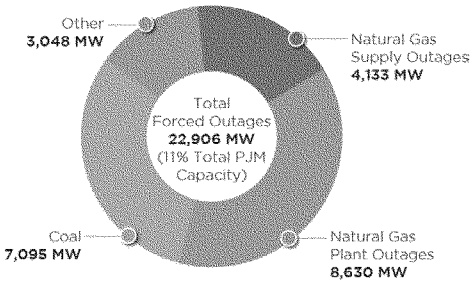
Figure 4. Top Ten PJM Winter Peaks



I want to address what the preliminary data reveals as to unplanned generator outages (what the industry refers to as "forced outages"). Before presenting the data, the term "forced outages" needs to be put into context. Generating units of all types are complex machines. They operate under stressed conditions during extreme temperatures and, by definition, these complex machines have parts that can fail. These mechanical failures in many cases are transitory –the mechanical failure is often promptly repaired so that the generator can quickly return to service.

We have generating reserves available precisely because generators can experience forced outages during stressed conditions (i.e., additional generation beyond the specific demand at any given point in time). Preliminary data (Figure 5) shows that overall forced outages during the peak demand hour of the recent cold snap were about half what they were during the Polar Vortex.

Figure 5. 2018 Cold Snap Forced Outages – January 6, 2018 Morning Peak (9 a.m.)

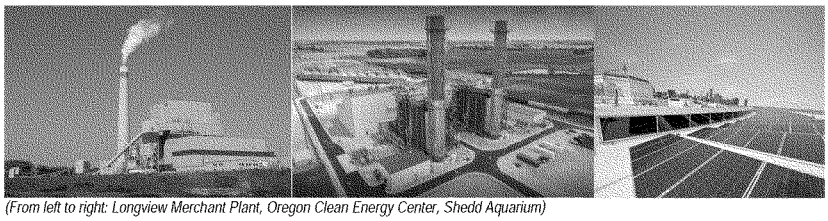


In most respects, the recent cold snap was much milder than the Polar Vortex – the temperatures were not as low, the wind chill was much less, and the demand for electricity was lower, in part due to the cold snap occurring during a holiday week. On the flip side, the cold snap did last for much longer, which led to some degrading of generator performance over time.

In short, there are many factors that drove improved performance, including enhancements PJM and its member companies have put in place in the years since the Polar Vortex, such as deployment of more efficient generation resources, increased investment in existing resources, improved performance incentives, enhanced winterization measures and increased gas-electric coordination.

As a result of our capacity and Energy Markets, we have seen significant new entry of a variety of fuel types. We have seen almost 40,000 MW of new generation since the inception of the capacity market. These include a diverse mix of new resources including new highly efficient natural gas units such as those being developed in Ohio; the Longview merchant coal plant in West Virginia; and innovative energy storage and demand response technologies such as deployed at the Shedd Aquarium in downtown Chicago. Although we have seen over 20,000 MW of coal retirements, the average age of the coal units that have retired was over 50 years. In short, the markets have helped to incent new efficient generation of all fuel types and help to retain existing generation needed to serve electric needs of customers in our footprint.

Figure 6. Efficient Types of Generation



(From left to right: Longview Merchant Plant, Oregon Clean Energy Center, Shedd Aquarium)

However, this is a time for all of us to be proactive. We need to ensure a strong 21st-century grid and to look forward to address issues that are just on the horizon. I outline those below.

Key Ingredients: The Recipe for Going Forward

Although I can assure you that the grid is reliable today and that we have many tools at our disposal to continue to ensure overall bulk electric system reliability, our work is not done and we cannot become complacent. Rather, we have been keenly focused on key initiatives to ensure not just a reliable grid, but a resilient grid, and to ensure that we are properly valuing those resources that are providing the grid with key reliability and resilience attributes.

There is often confusion as to how the terms "resilience" and "reliability" relate to each other. Reliability of the bulk power system is a very specific term focused on ensuring the delivery of service to end-use customers. The Congress, in the Energy Policy Act of 2005, defined reliable operation of the electric grid as:

"(O)perating the elements of the bulk-power system within equipment and electric system thermal, voltage and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

The operative words in this definition involve operating the system "*within equipment and electric system thermal, voltage and stability limits.*" PJM works to meet this definition in our operations every day and has systems in place to ensure this level of reliability.

By contrast, we view grid resilience as a different concept, focusing more on keeping the grid functioning, no matter what the cause of the event, and planning, operating and ensuring grid restoration should such an extreme event occur. We used to worry about equipment failure, now we have to worry about hacking, terrorist attacks, even intentional interference. Those concerns lead us beyond reliability and into resilience.

As an analogy, think of an automobile: There are basic safety standards in place today that are designed to protect the driver when he or she is operating the vehicle at certain speeds and under certain predictable and recurring conditions. We do not require that cars be designed to protect the driver from any risk no matter how severe. Yet the electric grid, which is so critical to our national economy, needs to plan for, operate through, and quickly recover from events, no matter how severe. That has been our focus, and we appreciate that this has become a targeted focus at the federal level.

We believe there are a number of initiatives that can be undertaken in this area. Many, such as establishing protocols around reserve levels, conservative operations, planning and system restoration are actively underway in PJM, in consultation with our states and stakeholders. But there are certain broader policy areas that I wanted to bring to the Committee's attention and that we may address in our comments to FERC. These potential initiatives include:

1. **Bringing Gas-Electric Coordination to the Next Level.** As natural gas becomes a more dominant fuel in the PJM footprint, our dependence on the natural gas pipeline infrastructure has grown significantly. In the past, the region PJM serves was primarily coal dependent. The customers of the natural gas pipeline system in our footprint were almost exclusively local gas utilities and large industrial customers who used natural gas in their industrial processes. During that time, the principal demand on the pipeline system was heating load in the winter. By contrast, today's customers of the natural gas pipeline system include natural gas-fired electric generators whose demand for natural gas fluctuates by time of day rather than simply by season, as was the case with gas utilities serving customers for home or commercial heating.

   The level of communication and coordination between our operators and the operators of the natural gas pipeline system is much improved, and it is an activity on which we expend considerable effort. But in our view, it is time to bring the coordination between these two industries to the next level. To reach this next

level we believe it is important that FERC, DOE, and, in some cases, this Committee look into some key dichotomies in the regulation of these vital infrastructures.

For instance, the electric industry is subject to mandatory physical and cybersecurity standards determined and enforced ultimately by FERC. The natural gas pipeline industry is subject to different, high-level voluntary guidelines in these areas issued by the Transportation Security Administration augmented with yet a different level of regulation by the Pipeline and Hazardous Materials Safety Administration. I say this not to impugn work that the pipelines have done in this area but to point out that the two industries face vastly different compliance obligations, particularly in the area of cybersecurity. By definition, these dichotomies will inevitably hinder an optimal integrated and coordinated approach to common threats from both physical and cyberattack. Whether or not we need to change the regulatory structures around physical and cybersecurity between these two industries is an issue I will leave for you as policymakers. But I'd be remiss if I didn't point out the differences and how those differences can challenge all of us in reaching the next level of gas-electric coordination.

2. **Balancing the Need for Transparency With the Need to Protect Critical Infrastructure**. Although a hallmark of RTO operations and our planning process has been transparency, in the future, we believe a balance needs to be struck in this area. On the one hand, transparency in detailing to stakeholders the need for particular grid improvements is very important, and on the other, we do not want to inadvertently publicly release highly sensitive information about vulnerabilities on the grid.

   To date, the regulators and the RTOs have addressed this issue through labeling highly sensitive grid information as Critical Electric Infrastructure Information (CEII). But the CEII rules utilized at FERC and at the state level are designed around a "right to know" approach, with some verification of the bona fides of the requestor. Yet, the federal government doesn't approach classified information this way. Rather, that system is based on the provision of access based on a demonstrated "need to know." It may be time to consider evolving our release of a limited set of highly sensitive infrastructure information from a "right to know" to a "need to know" basis. We think this can be accomplished in a manner that also allows the opportunity at the appropriate time for customers and the public to examine (and potentially challenge) the costs of any grid upgrade through the regulatory process. But for this balance to be workable, we will need direction from FERC — as much of its regulatory regime to date has, understandably, been driven by moving toward greater transparency without a corresponding focus on tightening rules around CEII.

3. **Properly Valuing the Reliability Attributes of Generation Resources**. Focusing on physical infrastructure is clearly important, for the reasons I outlined above. But without a compensation system that properly values the attributes that any particular resource brings to the grid, we will inevitably frustrate many of these other initiatives and fail to properly attract the capital this capital-intensive industry needs to make some of these critical investments, particularly those needed to ensure a resilient generation fleet.

   Specifically, we have proposed key reforms in how we compensate generating units that are needed to serve the demand for electricity. Today, we operate under a set of rules written in a vastly different time that limit the ability of certain generating units to set prices in a given hour. These units are still compensated for their costs to operate, but because they are not able to set clearing prices, those clearing prices are artificially lower than they should be in those hours. This has a price-suppressive effect on all generating units, including nuclear and coal generation, as well as natural gas and renewable generation. Price formation reforms in this area were specifically recommended by the DOE in its comprehensive August 2017 analysis. This type of reform, along with reforms to pricing during certain times when we are approaching temporary shortage conditions, would, in our view, go a long way toward properly compensating *all* generation needed to serve demand.

We understand that we carry the burden to justify these pricing changes to FERC, our regulator. We have begun a stakeholder process on this issue. But to avoid the potential for delay, we feel it would be helpful for the Commission to impose some process timelines around this debate, at least at the stakeholder level, so these issues can get to the regulator and not languish. We all respond better when we have some realistic deadline in front of us. It is for this reason that we have continued to seek a deadline from the Commission for the filing of price formation reforms that each region of the nation feels it needs to address its unique challenges. We continue to believe that resolving these kinds of pricing issues is as important to ensuring a resilient fleet as are some of the more operational and infrastructure-focused reforms I outlined above.

The recent cold snap has demonstrated this need very clearly. We pay what we call "out-of-market payments" to generators for their costs to run when we call on them for reliability purposes. These costs are not currently reflected in PJM's energy pricing. While out-of-market payments have improved since the Polar Vortex (approximately $16 million per day) we still saw significant payments during the recent event (approximately $4 million per day). By contrast, on a typical day, out-of-market payments may be approximately $400,000 to $500,000. This further demonstrates the need to improve pricing for those generators that we must run for reliability but also need to be paid out-of-market payments.

Conclusion

Steven Covey, in his book "The 7 Habits of Highly Successful People" reminds us that:

"The main thing is to keep the main thing, the main thing."

At PJM, I am pleased to report that we have laser-like focus on issues associated with reliability, resilience and proper pricing of the generation and demand response resources that are needed to keep the lights on for the 65 million Americans that depend on us. I have outlined above some very specific recommendations that we have raised with FERC and DOE and are considering raising again as part of suggesting a proposed path forward for the Commission on these important issues. We value our close working relationship with this Committee on both sides of the aisle in this process. Accordingly, I reaffirm PJM's commitment to be a resource that can bring to the table independent unbiased information and recommendations for policy initiatives in these important areas in order to ensure that we can evolve the grid to meet the nation's growing demand for a resilient electric grid at just and reasonable rates.

The CHAIRMAN. Thank you, Mr. Ott.

Mr. van Welie?

STATEMENT OF GORDON VAN WELIE, PRESIDENT & CHIEF EXECUTIVE OFFICER, ISO NEW ENGLAND

Mr. VAN WELIE. Good morning, Chairman Murkowski, Ranking Member Cantwell, members of the Committee. Thank you so much for the opportunity to appear before you this morning.

In 2013, I appeared before this Committee to highlight a growing concern in New England which was that we were becoming more dependent on natural gas-fired power generation without the region making the investment in the natural gas infrastructure to supply the fuel to those generators. And since that time, we've continued to express our concern over the lack of secure fuel arrangements in the region.

We also highlighted the possibility that both wholesale energy prices and emissions would rise when extreme weather results in natural gas pipeline constraints.

In late December and early January, we experienced the impacts of the current fuel constraints as bitter cold temperatures drove an increase in demand for natural gas in the region. We've known for several years that when it gets cold the region does not have sufficient gas infrastructure to meet demand for both home heating and power generation.

Constrained pipelines resulted in substantially higher natural gas prices causing gas to be priced out of the market. As a result, the bulk of the replacement energy was provided by burning oil, either through steam generators burning oil or by dual fuel units switching from gas to oil.

These circumstances raise reliability challenges. First, the high burn rate for oil-fired generators rapidly diminishes oil inventory which inevitably needs to be replaced. And however, in a snow or an ice event, replenishment can be difficult or even impossible. Second, emission regulations limit the run time of oil-fired generators. Finally, both the fuel constraints and the rapid depletion of the oil inventory dramatically increased the potential of reliability consequences of a large transmission or generator outage during an extended cold weather event.

These circumstances caused us to rejoice the operation of a number of the oil-fired generators and commit other resources into the market in order to manage the fuel inventory through the tail end of that extreme weather event.

So far this winter, we've been fortunate not to experience any major contingencies that we could not handle and the bulk power system has operated reliably. That said, we know that winter is far from over and we will continue to carefully monitor regional fuel availability. Regardless of the outcome of the remainder of the winter, I believe the last few weeks validate our concerns and underscore the importance of a study that we released last week.

In late 2016, we embarked on a study that we call, the Operational Fuel Security Analysis, to improve the region's understanding of the reliability risks stemming from the lack of fuel security.

Our recent experience leads us to the conclusion that no new incremental gas infrastructure will be built to serve power generation; therefore, the study does not assume the build out of additional gas supply infrastructure for power generation.

We examined 23 different scenarios to analyze whether or not fuel would be available to meet demand and to assess the operational risk that materialized, in particular, with the retirement of non-gas-fired resources or the outages of critical resources in infrastructure on the system. The analysis saw that energy shortfalls due to inadequate fuel would occur with almost every future fuel mix scenario requiring frequent use of emergency actions, including load shedding to protect grid reliability.

So the ISO will discuss the results of this analysis with stakeholders, policymakers and regulators in the region throughout 2018 to understand the level of fuel security risk and hopefully determine what level of risk the region and the grid operator should accept.

It will be costly to remedy these fuel security challenges; however, the alternative is negative impacts on system reliability, chronic price spikes during cold weather, higher emissions when it's more economic to burn oil than natural gas and the possibility of further interventions by the ISO into the market to delay the retirement of critical resources.

Wholesale markets and the transformation of New England's bulk power system have resulted in significant economic and environmental benefits to the region; however, the fuel security difficulties are real and they are significant.

If we're able to meet these challenges I think it will result in a more reliable, efficient and clean power grid benefiting the entire region.

I appreciate your Committee's focus on this important matter and look forward to any questions that you might have.

[The prepared statement of Mr. van Welie follows:]

TESTIMONY OF GORDON VAN WELIE
PRESIDENT & CHIEF EXECUTIVE OFFICER, ISO NEW ENGLAND

BEFORE THE US SENATE COMMITTEE ON ENERGY & NATURAL RESOURCES

FULL COMMITTEE HEARING TO EXAMINE THE PERFORMANCE OF THE ELECTRIC POWER SYSTEM UNDER CERTAIN WEATHER CONDITIONS

TUESDAY, JANUARY 23, 2018

Chairman Murkowski, Ranking Member Cantwell, and members of the committee, thank you for the opportunity to appear before you this morning.

My name is Gordon van Welie, and I am the president and chief executive officer of ISO New England (ISO-NE).

In 2013, I appeared before this committee to highlight a growing reliability concern in New England. In my remarks, I outlined a significant change to the region's fuel mix – specifically, that New England was becoming more reliant on natural gas for power generation without making a subsequent investment in natural gas supply infrastructure. I noted that "for power-grid reliability to be maintained, we must increase levels of fuel availability within the region, either through more secure gas pipeline arrangements, gas storage or additional dual fuel capability." Since that time, ISO-NE has continued to express our ongoing concern over the lack of secure fuel arrangements for the region's generators.[1] ISO-NE has also highlighted the possibility that both wholesale energy prices and emissions will rise when extreme weather results in natural gas pipeline constraints – driving up the price of natural gas (and wholesale energy) and forcing New England to rely on oil- and coal-fired generation for multi-day (or multi-week) periods.

As I will discuss later in my testimony, ISO-NE recently released an extensive study, known as the Operational Fuel Security Analysis (OFSA), which underscores that fuel-security risk—the possibility that power plants won't have or be able to get the fuel they need to run, particularly in winter—is the foremost challenge to a reliable power grid in New England.

The study reviews possible operational scenarios in New England for the winter 2024/2025 and quantifies the amount of time the region will be short of operating reserves as well as when load-shedding will be needed to keep the bulk power system in balance. I will expand on the purpose and structure of the study later in my testimony, but the headline is that New England's limited fuel infrastructure will eventually cause severe reliability issues if fuel security is not addressed. Suffice to say the severity of many of the results underscores the tremendous importance of improving fuel security arrangements in New England and the potential consequences for failing to act.

[1] I reiterated these concerns in my most recent Congressional testimony before the House Energy Subcommittee on July 26, 2017.

Recent Cold Weather Operations

In late December and early January we experienced the impacts of the current fuel supply constraints. Bitter cold temperatures drove an increase in demand for natural gas. However, we've known for several years that when it gets cold New England does not have sufficient natural gas supply infrastructure to meet demand for both home heating and power generation. Constrained pipelines resulted in substantially higher natural gas prices[2] which led to much older and less efficient oil- and coal-fired power plants running "in merit." This means it is less expensive to run those plants than to dispatch natural gas generators (an extremely unusual occurrence most weeks of the year). We also witnessed dual-fuel power plants switch over to burn oil during periods when the price of natural gas exceeded the price of oil.

These circumstances raise reliability challenges. First, a high burn rate for oil-fired generators diminishes oil inventory which inevitably needs to be replaced. However, during a snow or ice event, replenishment can be difficult (or impossible). Second, emissions regulations limit the run-time of oil-fired generators. While we weathered a stretch of extremely cold weather and a blizzard, we remain concerned about resupply of these resources during the remainder of the winter season and are in close coordination with state and federal officials about the challenges of ensuring adequate oil supplies to the region. Finally, given the fuel constraints, the rapid depletion of the oil inventory, and the reality that resupply was several days away during the peak of the cold weather period, our biggest operating concern was that we would experience a large, multi-day system contingency during this period or that oil-fired generators would run out of fuel before they could be resupplied.

This caused us to reduce the operation of a number of the oil-fired resources and commit additional resources in the market in the last few days of the cold weather period in order to manage the remaining oil inventories.

Overall, the bulk power system in New England has operated reliably thus far this winter and we were fortunate to not experience any major contingencies that we could not manage. So far, ISO-NE has not made voluntary appeals for conservation, nor have we entered into operating procedures consequent to a depletion of reserves. Efficient wholesale energy markets have sent critical price signals to encourage generators to be available during critical periods and have reflected the relative value of fuels within the region. That said, we know well that winter is far from over and we will continue to carefully monitor regional fuel availability.

Short- and Long-term Planning is Essential

Prior to the winter 2013/2014, ISO-NE initiated a short-term program to address fuel adequacy concerns during the winter season. That winter, we enacted the first of the region's Winter Reliability Programs (WRP) as an interim measure to mitigate seasonal reliability risk and enhance reliable grid operations.[3] Although the Winter Reliability Program has evolved slightly since its initial structure, the

---

[2] In several instances over the last few years, pipeline constraints have led to New England having the most expensive spot natural gas prices in the world (as we experienced during this recent cold snap).
[3] These programs were developed through New England's stakeholder process and were approved by our regulator, the Federal Energy Regulatory Commission.

goal has remained the same: To create a financial incentive for the physical procurement of oil within the region prior to December 1, to secure firm contracts for liquefied natural gas (LNG), and the creation of a winter-specific active demand-response program. These programs have proven enormously valuable. For instance, this year's WRP procured roughly three million barrels of oil eligible for compensation under the program – inventory that played a substantial role in reliable grid operations during the recent cold weather period. However, these initiatives were designed on a stop-gap, temporary basis until more permanent, market-based improvements could be implemented.

While we have made several improvements to wholesale markets over the last few years to strengthen reliability, perhaps the most notable long-term modification is a change within our Forward Capacity Market (FCM) known as "Pay for Performance." This approach more closely aligns the capacity payment a resource receives with its performance during critical periods. If a capacity resource over-performs relative to its obligation, it receives a higher capacity payment; consequently, underperforming will result in lower revenue for a capacity resource.[4] These changes were designed in 2013, approved by the Federal Energy Regulatory Commission (FERC) in 2014 and first included in capacity obligations awarded through Forward Capacity Auction #9 (FCA) conducted in February 2015. These new performance incentives will take effect in the capacity commitment period beginning on June 1, 2018. While we are hopeful these changes will provide a strong incentive for more secure fuel arrangements, we are always ready to identify and propose additional ways that wholesale markets can be modified to improve grid reliability.[5]

To that end, since the initial design of Pay for Performance was discussed and filed, we have closely observed the permitting and siting of dual-fuel resources in the region, the performance of the generation fleet and fuel supply chain during cold weather periods, and the evolution of state policies to determine whether our initial assumptions in 2013 were correct. Much has changed since 2013, and our observations over the past several years cause us to question whether additional changes to the market design, or further actions by regional policymakers, may be necessary to ensure reliable system operations in the future. One of the objectives of the OFSA is to stimulate discussion with regional stakeholders and policymakers as to the degree of operational risk the region is willing to accept, and whether additional changes to the market design may be necessary to address the fuel security risks identified in the study.

The committee may also be interested in changes we recently proposed to integrate an anticipated influx of renewable energy (backed by public-policy driven long-term contracts) into the FCM. Currently, new renewable energy projects will only be developed if supported by long-term, state-backed contracts that provide above-market revenues. As a result, they will likely have difficulty clearing in a capacity auction due to a rule that protects competitive pricing in the auction. The Competitive Auctions with Sponsored Policy Resources (CASPR) proposal we recently filed with FERC would create an opportunity (and financial incentive) for older resources obtaining a Capacity Supply Obligation to transfer those obligations to new renewable resources and subsequently retire. We believe CASPR provides a market-based signal for less efficient units to leave the system in an orderly manner while allowing states to further their public policy goals.

---

[4] ISO New England does not dictate how a resource makes arrangements to be available during these periods.
[5] Outside of market changes, ISO-NE has also done extensive work improving communication and coordination with natural gas pipeline operators.

While this is a positive step toward accommodating policy-driven resources in the wholesale markets, it may exacerbate the fuel-security challenge if certain non-natural gas fired generation were to retire before the region has addressed the fuel infrastructure constraints highlighted in the Operational Fuel Security Analysis.

New England's Fuel Mix Transition Continues

In 2000, oil- and coal-fired resources combined to produce 40% of New England's electricity while natural gas produced 15%. However, natural gas now produces roughly half of the region's electricity while on an annual basis oil and coal combine for well under 10%. While we continue to rely on these older resources under extreme weather conditions, they are retiring from our market. [6] In addition, within a four and a half year period we will have seen the retirement of two nuclear plants (the Vermont Yankee and Pilgrim Nuclear Power Stations), leaving New England with two nuclear power stations – the 2,100 MW Millstone Power Station in Connecticut (comprising two generators) and the 1,200 MW Seabrook Station nuclear plant in New Hampshire. It is important to note that the future of the Millstone Power Station is uncertain as the asset owner and the state continue discussions about whether to allow Millstone to participate in state procurements for clean energy.

All six New England states are members of the Regional Greenhouse Gas Initiative and each state is striving to meet individual renewable portfolio standards along with (statutory or aspirational) economy-wide carbon reduction goals. These goals will lead to further constraints on burning fossil fuels in the region during the same time as the region adds more renewable energy to the system. And, although the timing is uncertain, we expect to see a higher demand for clean wholesale energy as a number of the states seek to electrify their transportation and heating sectors. We have seen – and will continue to see – tremendous change in our fuel mix driven both by market economics and regional and state public policy needs.

Fuel-Security Analysis Indicates Need for Further Action

As I mentioned earlier, for some time ISO-NE has been publicly discussing the need for additional fuel supply infrastructure or measures that will significantly reduce the need for wholesale electricity production or natural gas supply during peak periods.[7] Despite several attempts on a regional and individual state basis to find innovative ways to finance new natural gas pipeline investment, ISO-NE does not see that investment materializing in the near future. While measures to reduce wholesale demand have steadily increased, and prior investments in energy efficiency continue to yield tremendous benefits, they are not growing swiftly enough to relieve the constraints. In addition, the region has made significant investments in solar/photovoltaic (PV) resources, particularly at the distribution level. However, while these PV resources can reduce the strain on the electric grid and

[6] ISO-NE has already approved a retirement bid for the 383 MW coal-fired unit at Bridgeport Harbor Station for the upcoming Forward Capacity Auction #12 (February 5, 2018). The unit was one of three coal-fired facilities that took on a capacity obligation in FCA #11.

[7] This could take many forms, including new natural gas pipelines, the creation of a "virtual" pipeline including firm LNG contracts, investing in natural gas storage, interregional transmission lines with firm delivery agreements for renewable energy, or measures that will reduce the demand for natural gas and/or electricity produced by natural gas.

offset the need for fossil fuels, their contribution is limited during the winter – particularly during and after winter snow storms.

In late 2016 we embarked on an Operational Fuel Security Analysis,[8] which we released on January 17, to improve the region's understanding of reliability risks and inform the subsequent stakeholder discussions. The study does not assume the build-out of any new natural gas supply infrastructure.[9] It looks at 23 scenarios to analyze whether enough fuel would be available to meet demand and to understand the operational risks without additional gas import capabilities. The scenarios we chose are not intended to predict the future system, but rather seek to illustrate the range of potential risks that could confront the power system if fuel and energy are constrained during winter.

The OFSA found that energy shortfalls *due to inadequate fuel* would occur with almost every fuel-mix scenario in winter 2024/2025, requiring frequent use of emergency actions to protect the grid. The study results suggest that New England could be headed for significant levels of emergency actions, particularly during major fuel or resource outages.

Emergency actions that would be visible to the public range from requests for voluntary energy conservation to involuntary load-shedding (rolling blackouts directed by ISO-NE, but carried out by local utilities, affecting blocks of customers). This outcome is forecasted in 19 of the 23 scenarios. Of course, while ISO-NE tried to model a representative range of scenarios in order to distil risk trends, we readily acknowledge that we cannot predict the future and therefore we are prepared to produce additional scenarios, based on feedback from our stakeholders, which will further refine the study. The study's findings suggest six major conclusions:

- Outages: The region is vulnerable to the season-long outage of any of several major energy facilities.
    - These include a compressor station on a major natural gas pipeline (cutting off fuel to generators with a combined capacity of 7,000 MW); the Millstone Nuclear Power Station; the Canaport LNG facility in New Brunswick, Canada; and the Distrigas LNG facility in Massachusetts.
- Stored fuels: Power system reliability is heavily dependent on LNG and electricity imports; more dual-fuel capability is also a key reliability factor, but permitting for construction and emissions is difficult.
- Logistics: The timely availability of fuel is critical, highlighting the importance of fuel-delivery logistics.
- Risk trends: All but four scenarios result in fuel shortages requiring load-shedding, indicating the trends affecting New England's power system may intensify the region's fuel-security risk.
- Renewables: More renewable resources can help lessen the region's fuel-security risk but are likely to drive oil- and coal-fired generation retirements, requiring high LNG imports to counteract the loss of stored fuels.

[8] The OFSA is not an economic study and thus does not consider fuel costs or prices.
[9] It is important to note that ISO New England has no mechanism or authority to invest in, or direct investment in, natural gas supply infrastructure or any fuel infrastructure. The process that leads to reliability-based investments in New England's electric transmission system is fundamentally different than investments in natural gas pipelines which rely on firm, long-term contracts with natural gas customers to get built.

- Positive outcomes: Higher levels of LNG, imports, and renewables can minimize system stress and maintain reliability; *to attain these higher levels, delivery assurances for LNG and electricity imports, as well as transmission expansion, will be needed.*

It will be costly to remedy these fuel-security challenges – whether the region chooses to invest in renewable energy (and related transmission), fuel infrastructure with long-term contracts, or further measures to reduce demand for wholesale electricity and natural gas.

The alternative is negative impacts on system reliability, chronic price spikes during cold weather, higher emissions when it's more economic to burn oil than natural gas, and the possibility of further interventions by ISO-NE in the wholesale electricity market to try to delay critical resources from retiring. It is important to note that while ISO-NE has the authority (subject to final approval from FERC) to enter into reliability agreements to delay the retirement of generators to avoid overloading the transmission system, we currently do not have the authority to delay retirements due to fuel security risks. In order to do this, we would have to seek approval for appropriate tariff changes from FERC. Furthermore, as experience has shown, generation owners may choose to retire their assets regardless of the offer of a reliability agreement.

We are also mindful that new state-level emissions regulations will be even more restrictive by the winter of 2024/25 – impacting ISO-NE's ability to operate certain generators. Due to the lack of historical data and the inability to predict when selected generators will be affected, this constraint was not modeled in the OFSA. Looking forward, we think that it is important to holistically understand the future of reliable operations in a fuel- and emission-constrained power system environment. The tool we created to produce the OFSA will provide us with a starting point to understand future power system dynamics and we used it for the first time in operations during the cold weather period in early January 2018. We intend to update the tool as power system constraints change and use it as a means to dynamically quantify the regional fuel security risks.

ISO-NE will discuss the results of this operational fuel-security analysis with stakeholders, regulators, and policymakers throughout 2018. A key question to be addressed will be the level of fuel-security risk that New England is willing to accept. As the system operator mandated to maintain a reliable power system, ISO-NE must conduct its own assessment of the level of risk to reliable operations. A primary consideration will be ISO-NE's responsibility, as a regional reliability coordinator, to operate the region's power system in a way that maintains the reliability of the region while meeting our responsibilities to the entire Eastern Interconnection.

US Department of Energy's Proposed Resiliency Rule and FERC's Docket on Resiliency

Prior to the implementation of long-term solutions for the region's fuel-security challenges, ISO-NE will respond to FERC's recent action requiring reports on factors impacting resiliency in New England.

As many of you know, this directive from FERC comes after the Commission declined to adopt the 2017 US Department of Energy Notice of Proposed Rulemaking directing cost-of-service payments to certain generation assets. ISO-NE opposed adoption of the NOPR as harmful to the competitive markets that have yielded reliability, economic, and environmental benefits to New England and that it *would*

not have addressed the fuel-security issues specific to our region.[10] The recent release of the OFSA should provide valuable guideposts for ISO-NE's eventual response to FERC's resilience proceeding.

Conclusion

The transformation of New England's bulk power system over the last decade has resulted in tremendous benefits for the region in the form of generally lower wholesale electricity prices, a cleaner-burning fleet of resources, and increases in overall electric grid reliability.

However, we now face challenges that do not lend themselves to easy solutions. As we have seen recently, the fuel-security difficulties are real and they are significant. Until they are addressed, cold weather will continue to drive substantial increases in the price of natural gas (as well as wholesale energy) and emissions and create regional reliability challenges. Aided with the findings of the Operational Fuel Security Analysis, we anticipate the fuel-security challenges will require further action by ISO-NE and New England stakeholders. Despite these challenges, I am eager to engage in regional stakeholder discussions on the findings of the study and to work together to find appropriate solutions. If we are able to meet these challenges, it will result in a more reliable, efficient, and clean power grid benefitting the entire region.

I appreciate the committee's focus on this important issue and I hope you will be in touch with any further questions.

Thank you.

[10] ISO New England joined the ISO/RTO Council in its opposition as well.

The CHAIRMAN. Thank you, Mr. van Welie, we appreciate it. We appreciate the testimony of each of you this morning.

Senator Manchin has indicated he has a pressing matter somewhere else and he asked very politely, so I am going to yield my time. You may take the first round of questions.

Senator MANCHIN. I begged.

[Laughter.]

Senator MANCHIN. I begged.

I want to thank Chairman Murkowski. Thank you so much and my dear friend, Ranking Member Cantwell, for allowing me to have this opportunity, but also for this hearing.

Full disclaimer: West Virginia, as you know, has been a heavy-lifting state for a long time. We are very blessed and very pleased to be able to provide the energy the country has needed, starting way back when—for building, making the steel to build the ships that defend our country. So we are very proud of the energy part that we play in this great nation.

With that, I think you all know that I am an all-in energy portfolio and the State of West Virginia is too, even though coal has been a dominant factor now that the Marcellus shale has come on so strong and Utica and even Rogersville. We have been blessed, and we're going to be able to help the country for many years to come.

With that, as you know, I have been vocal about ensuring the reliability and resilience of our grid for some years, particularly since the Polar Vortex of 2014, which you all alluded to, and also the recent cold snap, the cold period that we hit.

I supported the recent Department of Energy grid study and its subsequent proposal by FERC rulemaking. I have been asking questions about reliability and resilience in this Committee for some time and will continue to do so, particularly because we continue to see coal and nuclear plants going offline.

We know the market forces that are at play. But over the most recent deep freeze of the Bomb Cyclone, as many are calling it, the grid performed well. I think you all recognize that, and I applaud each of you in your role, particularly you, Mr. Ott, in staying vigilant to make sure West Virginia homes stayed warm and the lights stayed on, since PJM is over West Virginia.

I want to stress three points. We need to stay vigilant because coal-fired power performed well during the latest cold snap, yet many plants are fighting to survive. We need to better protect consumers from the shock and hardship of high electric bills when these events happen. West Virginia bills, as my colleague, Senator Capito will tell you, have risen exorbitantly in a very short period of time through no fault of its own. And I continue to be concerned that without criteria or standards for resilience it is truly hard to know whether our grid is actually resilient or not.

So, for those people who believe that we can do without fossil completely, I want us all to be completely honest and accurate with them. We cannot. Maybe that day will come in the future. It's not here. And for what period of time and how soon that will happen, I don't know.

I want to make sure we can provide what this country needs immediately and now and continue to do so for the time that it is going to be called upon.

If I can start with you, Mr. McIntyre, and go down the line and ask one question. What would this country have done without the backup of coal-fired plants in the Polar Vortex and also this last Bomb Cyclone, if you will? And what critical position would it have put our country in, if any, so we can put that to rest and find out how we can stabilize and keep coal vibrant so it is there for that resilience that we need and the dependability this country needs?

Mr. MCINTYRE. Thank you for the question, Senator.

Coal did, as you heard from a couple of our witnesses here——

Senator MANCHIN. Sure.

Mr. MCINTYRE. ——perform well alongside other——

Senator MANCHIN. I guess the question I am asking, would the system have been able to be flexible enough to provide the energy we needed during these periods of time?

Mr. MCINTYRE. I think in this recent weather event, we wouldn't have seen any widespread outages absent coal. That said, coal was the key contributor. It wasn't exempt from operational problems. There were some issues, as I understand it, with frozen coal piles in certain sites and so on. But it was, no question, the key contributor.

I share your overall view that all-of-the-above needs to be our philosophy of the different types of resources.

Senator MANCHIN. Coal needs to have a place in this energy mix.

Mr. MCINTYRE. Absolutely.

Senator MANCHIN. Okay.

Mr. Walker?

Mr. WALKER. Yes, sir, thank you for the question.

So, you said something that I just want to—there's a little bit of a nuance. It's whether or not we could or should survive without the coal.

And I think——

Senator MANCHIN. There are some people that think that we should.

Mr. WALKER. Right.

And I think it's very important to point out——

Senator MANCHIN. I think they're wrong.

Mr. WALKER. ——that the evolution of the electric grid has inextricably tied together the vast energy systems throughout the United States—coal, natural gas, oil, insomuch as what we've done is we've put ourselves in a position where we now have more infrastructure to have to protect to ensure the safe and reliable distribution of bulk power.

And so, you know, coal did play an important part here. And on average, it presented and provided 38 percent of the load during this event.

So——

Senator MANCHIN. Do you think that 38 percent, if it was not available, we would have had serious problems?

Mr. WALKER. The markets would have met the need with just simply much higher resources, but the point I'm trying to make, and perhaps not well, is that when we start relying on those other

resources, things like natural gas and things like oil, we also increase our exposure because now the critical infrastructure in this country is not the coal sitting at a plant or a nuclear facility where I've got the nuclear fuel there. I've got to rely on thousands of miles of pipeline or transportation systems to get oil to locations.

So the challenge to manage this, particularly in facing the threats we have today with, mostly, physical and cybersecurity, really, really should give us pause to step back and think about the diversity mix and whether or not we could ever get rid of oil. I think the better question for us is should we get rid of oil because it does—or coal, rather.

Senator MANCHIN. Yes, I am not worried about oil.

Mr. WALKER. Because each one of those has certain unique characteristics that are very important.

And I apologize for that.

On page 86 of the staff report there's a chart that defines the different values of different types of generation add. And it's really, I think, what we have an opportunity going forward with and I look forward to working with FERC and the respective RTOs, is really finding that optimal mix that gives us the diversity for the resiliency and also minimizes our exposure from the cyber and physical threats that we face today.

Senator MANCHIN. Madam Chair, I know my time is up. Can I just ask Mr. Walker—Mr. Ott, with PJM, he's responsible for delivering the 56 million, I think, was it 56 million?

The CHAIRMAN. You are pressing your luck here this morning.

[Laughter.]

Mr. Ott, if you could reply, please.

Senator MANCHIN. Mr. Ott?

Mr. OTT. I'll make it very short.

The reality is, again, for this past event, 45,000 megawatts of the electricity that we delivered which is 40 percent or more, was coal-fired. We could not have served customers without the coal-fired resources. That's the reality.

The point is, are the prices reflecting the fact that those resources are running? My answer is no, it's not. We need to fix that. We clearly need it for now. The question is how does it transition?

Clearly some coal plants don't run. They never run. They don't produce electricity. They're just hanging on. They should go.

The ones that are running and online every day to serve customers should be reflected in the price. So, we need those. Some can go. Some have to stay.

Senator MANCHIN. Thank you all.

Thank you, Madam Chairman, for being so considerate and kind.

The CHAIRMAN. It is a new day.

Senator Cantwell.

Senator CANTWELL. Thank you, Madam Chair.

Mr. Walker, obviously you've heard some of the recommendations on resiliency. Which one of those ideas in the report stand out to you as good things to implement?

Mr. WALKER. I think the position that FERC is taking in re-establishing what was previously the NOPR, in bringing the RTOs and the ISOs together to evaluate that the resiliency on their respective systems will provide an excellent baseline. And I've had

the opportunity to meet with Mr. van Welie and go over his New England report and looked at the work that was done by PJM with the Polar Vortex.

Those are two fantastic baseline analyses that will enable FERC, DOE, the RTOs and the ISOs to move forward with really having a fundamental understanding of where the interdependencies are on the system so that we can actually build a better and more resilient system informed by where the actual risk is and not the markets.

Senator CANTWELL. Well, I appreciate your comments about, first of all, compromised infrastructure and cybersecurity. I mean, given the Quadrennial Energy Review, that is where it said we should be spending our attention.

And I'm reminded of this debate we had in this Committee in 2015 about just that very issue, where oil and coal were competing for rail supremacy, and left upper Midwest utilities without the ability to serve their customers, simply because of congestion. So the dynamic is changing.

And so I appreciate Ms. Clements' reports and the recommendations of those reports because you are citing the changing nature of economics and the challenges that then deliver to the utilities and to those who regulate the utilities.

And that is why, Chairman McIntyre, I am so glad that you guys resisted what I thought was undue political pressure on the NOPR to try to force a bailout.

I know that last week, Commissioner Chatterjee filed an ex parte notice about First Energy, a coal plant transfer. I think that was the right thing for him to do. But the news was troubling to me because it said to me that there were those who were trying to influence FERC on a political aspect as opposed to the thorny economic issues that are at stake here.

What do you plan to continue to do to make sure that FERC is an independent agency? I will just give a little context—when ENRON manipulated the energy markets, I don't think anybody in my state really understood who or what FERC was. But after that, I guarantee you, it has become a household word because they know it is those that protect them from being gouged unfairly on energy prices, something so important to the economy of the Northwest.

Mr. MCINTYRE. Yes, well, thank you for the question, Senator.

The independence of FERC as an agency, as a federal agency, is essential to, first of all, it's that way by design, statutorily in its construction.

And it's very important to me, personally, as I stated here in my confirmation hearing. I intend to do my utmost to ensure that it lives up to that independence.

In this particular instance, I am delighted that we had a five to nothing vote reflected in our January 8 order. As you know, that reflects a bipartisan commission, three Republicans, two Democrats. And I'm just so pleased that we were able to see, kind of, a common path forward in terms of pursuing this very important issue of resilience.

Senator CANTWELL. So, you will make sure that politics stays out of it?

Mr. MCINTYRE. Thus far, honestly, it hasn't been a problem. I have not personally felt any undue influence into any efforts to affect my decision-making.

Senator CANTWELL. Great.

Mr. MCINTYRE. And I would expect that to continue.

Senator CANTWELL. Great, thank you.

Ms. Clements, what about the Northeast and getting more supply? A lot of attention has been focused on increasing natural gas. What are some of the other options? I certainly understand the value of supply, but what do you think are some of the other solutions for the region for reliance and resilience?

Ms. CLEMENTS. Thank you for the question, Senator.

I think there is a couple of realities that we have to start with when we answer that question.

And one is that this transition toward a different resource mix, one that has low marginal cost, free fuel from the sun and the wind as a predominant choice on parts of communities, on the parts of companies, on the parts of citizens, is already underway. It's already happening.

And what the grid operators have always done as the energy mix has transitioned over time from back in the 50s all the way up until today, is manage that transition very well. And so the idea that this new set of resources coming on can't be reliable is a false place to start.

And then the last reality, to inform. The answer to your question is that fuel diversity is one aspect of a resilient grid and of a reliable grid. It's not the only aspect.

So when you're looking at the Fuel Security Report that just got released from New England, it is a great input into what is the standard regional planning practices for Regional Transmission Organizations and Integrated System Operators. It's a set. It's a piece. It showed 23 different scenarios. The assumptions that are included in the report have yet to be vetted through the stakeholder process, and certainly there's views by different stakeholders on whether or not those are the correct assumptions. But the report doesn't look at energy efficiency, the cheapest, most effective resource at protecting both resilience and reliability.

Senator CANTWELL. Thank you.

Ms. CLEMENTS. It doesn't look at energy storage or any of those other options.

Senator CANTWELL. Thank you.

Thank you, Madam Chair.

The CHAIRMAN. Thank you, Senator Cantwell.

Senator Barrasso.

Senator BARRASSO. Thank you very much, Madam Chairman.

Mr. McIntyre, Wyoming is the nation's leading coal and uranium producing state. The industries are responsible for thousands of Wyoming jobs, billions in state and local government revenues. Coal and uranium also play a critical role in the electric grid reliability and resilience.

During this recent cold snap, coal-fired and nuclear power generation resources were critical to meeting the electricity demand during the most extreme conditions. I am concerned about both the

economic impact and the electric reliability impact of the continued retirement of these vital resources across the country.

As FERC deals with this grid resiliency question, is the Commission going to evaluate pricing of reliability and resiliency in terms of the attributes of coal and nuclear resources? How do you plan to look at that?

Mr. MCINTYRE. Thank you for the question, Senator.

I don't think we're doing a complete job if we don't take that into account. And so, we've been fairly broad in the range of the questions that we have put to the boots on the ground here which are the RTOs and ISOs. And we need them to give us their best-informed views on, not only the operational aspects of keeping the lights on, as we say, but also what is needed from a market standpoint since they run the organized markets and the respective footprints as well. What is needed in a market sense to ensure that resources that are indeed contributing resilience benefits to our grid are properly compensated.

Senator BARRASSO. Alright.

Now following up on that, both for Mr. van Welie and I'll ask you, Mr. Ott, to weigh in as well. Data from the Department of Energy shows that New England was heavily reliant on baseload coal and nuclear generation during this recent cold snap. Specifically, the data shows that at the peak of the cold snap, coal-fired generation accounted for 7 percent of the dispatch to capacity despite being only 2.6 percent of installed capacity in the region, so, really called upon to perform. Additionally, nuclear generation accounted for 23 percent of dispatched capacity despite being only 12 percent of the installed capacity.

Isn't it fair to conclude that when your region needed power the most, it was the reliable coal and nuclear power plants that were necessary to keep the lights on?

Mr. VAN WELIE. Well, I think coal and oil definitely, coal and nuclear definitely, contributed.

I think the prospect for coal in New England is limited. There are two coal-fired power stations left on the system, one of which will retire fairly soon. We have four nuclear reactors, one of which will retire soon. And you know, what was surprising to us was 35 percent of the energy was coming from oil burned in the region, and many of those oil units are 40 years old.

So, I think the issue for us in New England is that we are definitely transitioning to a different power system as the region strives to decarbonize. By definition, we have to reduce the amount of fossil fuel burnt in the region.

The question is, you know, what's the game plan looking forward in terms of to do so reliably. And the idea behind the study is to demonstrate the consequences of doing nothing, in the first instance, which we think are severe and to lay out for policymakers the various paths forward.

I think we're looking forward to engaging a conversation on how best to orchestrate that transition.

Senator BARRASSO. Okay.

Mr. Ott, would you like to add anything about PJM's experience?

Mr. OTT. Yes, sir.

Certainly from PJM's experience, of course, we have a much bigger proportion of our total resource mix being coal and nuclear. And in fact, during this recent cold weather event, obviously, more than half of the total supply was coal and nuclear. And certainly, let me be clear, we couldn't survive without gas. We couldn't survive without coal. We couldn't survive without nuclear. We need them all, in the moment. And I think the key, what we're focused on is, the key is each of these bring to the table reliability characteristics. Each of these were online when we needed them.

The point was, as I had made in my opening comments, the pricing doesn't always reflect that, therefore, when they go sell their energy forward the fact they were on for reliability during the cold weather isn't reflected in the forward price. That's unfair. It puts them at a disadvantage and we need to fix it.

And I think, really, this debate over there are certain coal plants, frankly, that are old and don't run much and didn't run during this period. Those need to retire. The ones that are online running every day, we need to keep them, and that's the reality.

Senator BARRASSO. Are there some specific actions that you might recommend that FERC take to ensure that baseload coal and nuclear generation resources are paid for the value that they bring to the grid?

Mr. OTT. Yes, certainly. We've discussed that with FERC and certainly we'll continue the discussion with the Chairman as part of this new docket. And really it focuses on the energy price formation that we just discussed in saying we really need to take a hard look at that.

FERC had already looked at fast-start pricing and the phenomena I'm describing here, the fast-start pricing won't affect that. We need to look at the pricing related to these types of events where it's not the resources that flexible and moving around, it's the ones that are online and serving customers that we need to address.

Senator BARRASSO. Thank you.

Thank you, Madam Chairman.

The CHAIRMAN. Thank you, Senator Barrasso.

Senator Smith.

Senator SMITH. Thank you, Madam Chair, for organizing this very important hearing and I very much appreciated reading your testimony, though I am sorry I missed your comments here today.

It is apropos because Minnesota is, this morning, digging out from a major snow event. And in Minnesota that means a lot of snow, not a little bit of snow. And so it is uppermost on my mind about the impact of dangerous weather events on the resilience of the whole community. I really appreciate how important this is to all come together.

Last week, we heard in this Committee from the International Energy Agency Director, Dr. Birol, about renewable energy and how renewable energy, like wind and solar, is going to be the lowest cost new generation around the world within maybe the next 10 years, and how energy storage costs are dropping as well.

So I would be very interested in hearing from this panel about how you think these changes will affect the reliability and the resilience of the grid. It seems to me that diversifying would con-

tribute to that, but I would be very interested to know what your perspectives are on this.

Really anybody.

Mr. MCINTYRE. I'll jump in briefly first, Senator.

And I say again, welcome to Washington.

[Laughter.]

Renewable generation is already, clearly, in the column of success story. It gets better every year, and it is contributing reliably to the satisfaction of our nation's electricity needs today. And I expect that trend to continue. It performs well during harsh weather, as we heard, including improved performance of wind resources in cold weather conditions.

That said, it's still the case that it presents operational challenges in that the wind isn't always blowing and the sun isn't always shining. So, that presents some realities to it.

I think that energy storage which your question referenced also will be something that will advance the ball significantly toward addressing that. It's not so much today, at least in my view, a compensation issue, as a technological one. We need the technology to take that next big step. But with that, I think the picture of that side of the industry is good already and improving.

Senator SMITH. Yes, please go ahead.

Mr. WALKER. Senator, thank you for the comment.

I would note that the diversity that you speak to, I think, does in fact add to the capability to provide resilient power.

And I think, in particular, the integration of the renewables provides strategic use of those resources to meet certain demands and certain requirements to certain areas that they really can have a tremendous level of capability.

That being said, storage, as I noted in my confirmation hearing, I consider it the Holy Grail of the electric system. And that being said, it is one of the top five goals in my specific department to focus in on really moving grid megawatt scale storage forward so that we can integrate that as a resource and help enable some of the integration of renewables and other resources to be really key parts of our resilient grid.

Senator SMITH. Thank you.

Maybe I could just follow up with Ms. Clements on this? What role do you see energy efficiency, and you also have talked some about demand response, play in resilience? In Minnesota, we've had some success weatherizing homes, for example, to lower energy consumption and take some of the pressure off the grid. I would be interested in hearing your thoughts on that.

Ms. CLEMENTS. Thanks for the question, Senator.

Energy efficiency is the most underrated resource we have. It's the cheapest, by far. We've been talking about it for a long time. So perhaps it's not as exciting and new, but the potential is still high.

And a different National Academy's report suggests on the order of magnitude of 25 to 30 percent, economy-wide potential reductions are available still.

In the states that have pursued as a policy matter all cost-effective energy efficiency, they are taking down decreases in total demand at the level of three percent a year.

Together with other distributed energy resources, like demand response, which PJM has provided as high as in some years, 12,000 megawatts of resources, meaning that's 12,000 megawatts of power plants you don't need in certain instances and are really exciting.

I think three things about distributed energy resources, in addition to bringing down these numbers of megawatts. They provide the flexibility, the resource flexibility, to integrate the high penetrations of this lowest cost renewable energy potential that you describe. And they can provide the flexibility. And finally, they are a great resilience resource. If you think about the storage during Hurricane Sandy when microgrids were able to island themselves and continue to provide power at hospitals and at fire stations. That's a real opportunity on the resilience side.

So, I think that the potential is just tremendous and that's where we should start.

Senator SMITH. Thank you very much.

The CHAIRMAN. Thank you, Senator Smith.

Senator Capito.

Senator CAPITO. Thank you, Madam Chair.

I thank the panel. This is, obviously, of great interest to me being the other Senator from West Virginia and coal, obviously, a very important part of our, not just our economy, but as Senator Manchin said, very proud of the history of energy production that we have had in our state. We also have the Marcellus shale development which is very exciting.

Just a quick question. Mr. Ott, Mr. van—if I say your name, van Welie? Did I get it right?

Mr. VAN WELIE. Perfect, thank you.

Senator CAPITO. Okay.

Mr. Ott, he mentioned how many retiring nuclear and coal plants are going to be in his area. What is that figure for PJM until 2020 say?

Mr. OTT. Yes, as far as PJM, we do have one nuclear station, a 620 megawatt nuclear station, that's scheduled to retire coming up before 2020.

As far as coal plants, we've experienced 20,000 megawatts of coal plants retiring previously.

Senator CAPITO. Right.

Mr. OTT. For the next few years we're looking, probably, in the 4,000 range of announced. Certainly, there could be more go.

Senator CAPITO. Which is 17 different units. Is that—that is what I have here.

Mr. OTT. Yes, in that realm.

But again, some of them have not formally announced. Some have formally announced. There are some that are having concerns financially, but as far as formally announcing, it's a little bit less than that.

Senator CAPITO. So, let me continue with you.

At peak load during the cold snap, natural gas generators provided only 48 percent of what you had predicted, and coal overtook that. Is that correct? Could you talk about that a little bit?

Mr. OTT. Yes, certainly.

In PJM, what we saw was the coal during the recent cold snap, we saw more coal production than normal. I think it was an eco-

nomic displacement. In other words, the gas prices went up, therefore, the gas units dispatched down, coal came on at a higher level. So, certainly we saw a lot more coal production, coal-fired production, if you will, than we normally would in that cold snap.

Senator CAPITO. Chairman McIntyre, can you help me with this?

The pricing of natural gas spot prices spiked up to an all-time high during this time, maybe 60 times their normal price. Do you know that, Chairman?

Mr. MCINTYRE. I don't know if it was an all-time high. I know that we did experience significant price increases. And as I mentioned earlier, that's the kind of thing that can, in a broad sense, be helpful. It's important that we have market signals that reflect shortages, including in this case, short-term spikes in demand.

Senator CAPITO. Right.

Mr. MCINTYRE. It sends proper signals both to providers of the resource and to consumers.

Senator CAPITO. Mr. van Welie, do you want to make some more comments?

Mr. VAN WELIE. Well, to affirm what you just said, the prices got up in the $100 range. So, if you look at it when the pipes aren't constrained, in the $2 to $3 range from an——

Senator CAPITO. Well, that gets me to another issue that we have, sort of, talked around but certainly in the New England area the accessibility to natural gas and the permitting with pipelines. I mean, we are having difficultly, even the State of West Virginia sometimes, permitting our pipelines.

The Chairwoman can speak about this as well. New England does not seem to have the appetite to permit the pipeline, so I read in the Financial Times that says that gas from Russia, Arctic is going to warm homes in Boston and there is LNG coming from Russia. We have a natural resource in my home state and region we would love to be selling our natural gas in this country, into the Northeast. So, how do you respond to that?

Mr. VAN WELIE. Well, I think the first problem in New England is to find a customer for the gas pipeline. So I think the structural issue is that there's no customer prepared to sign the long-term contract to have the pipeline built.

The second issue is once you have a customer, then you have to confront the siting issue. And I'd say there's a siting problem both in New England and in New York.

For us to move the gas from the Marcellus shale into New England, you'd have to overcome those two obstacles.

I think the decision from a policy point of view for the region is do regional policymakers want to make those investments to relieve those constraints or do they live with the constraints and work around them?

And if you're going to work around the constraints, then you either have to turn to alternative fuels, like oil or LNG and then in that sense, the Jones Act doesn't make a lot of sense to me because we're importing LNG from faraway places when we're exporting it from terminals a few hundred miles south of us.

Senator CAPITO. So, with the Russian LNG that has come in, obviously they already have a customer that is purchasing this be-

cause the supplies got so low during the Bomb Cyclone. Is that correct?

Mr. VAN WELIE. Yeah. So what happens is the dynamic is when the LNG inventory of the gas supply drops, you know, below certain levels, customers in the gas markets, local distribution companies, for example, will start calling for spot gas supplies.

Senator CAPITO. Right.

Mr. VAN WELIE. And so, you get contracting happening in the world markets for LNG.

Senator CAPITO. Interesting to me from another perspective is while that is occurring the Russian gas coming here, we have two cargo vessels with LNG from our southern ports or Louisiana shipping into Europe to try to help them meet their challenge.

I mean, if we are looking at an overall system here, from cost, from emissions and all kinds of things, that does not seem to make a whole lot of sense to me.

Mr. VAN WELIE. It doesn't make a lot of sense to me either.

Senator CAPITO. No.

Thank you.

The CHAIRMAN. And our job is to make sense of all of this.

[Laughter.]

Let's go to Senator King.

Senator KING. I hate to follow the admonition to make sense. It makes it difficult.

[Laughter.]

Mr. van Welie, I very much enjoyed seeing you. I remember meeting with you in 2013 about this very issue.

And first, Madam Chair, I love this panel. We should take them with us everywhere. You all have done a really good job of illustrating a lot of issues, important issues, in a brief time.

I do want to promote something for the audience and anybody interested in these issues, and it is an app called ISO to Go, produced by ISO. It gives you moment-to-moment prices all over New England, where the demand curve—by the way, Mr. van Welie, the demand is exceeding the forecast at this moment by about half a megawatt. You may want to call your office——

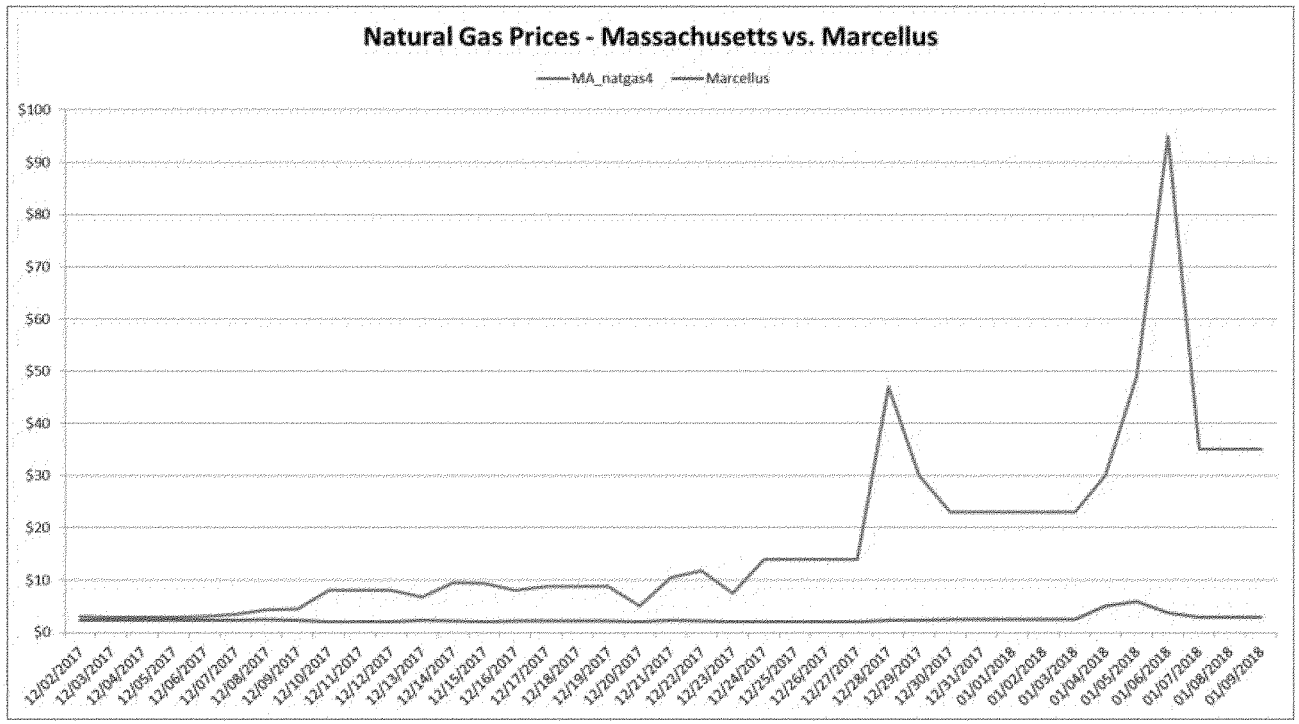
[Laughter.]

——when we finish here.

But it also gives where all the resources are—renewables, oil, gas, coal and nuclear. This is very, very useful. Thank you for this. It is incredibly helpful.

Now I want to put up some visuals, I learn visually, to what we have been talking about here today.

[The information referred to follows:]


Natural Gas Prices - Massachusetts vs. Marcellus
MA_natgas4
Marcellus
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
12/02/2017
12/03/2017
12/04/2017
12/05/2017
12/06/2017
12/07/2017
12/08/2017
12/09/2017
12/10/2017
12/11/2017
12/12/2017
12/13/2017
12/14/2017
12/15/2017
12/16/2017
12/17/2017
12/18/2017
12/19/2017
12/20/2017
12/21/2017
12/22/2017
12/23/2017
12/24/2017
12/25/2017
12/26/2017
12/27/2017
12/28/2017
12/29/2017
12/30/2017
12/31/2017
01/01/2018
01/02/2018
01/03/2018
01/04/2018
01/05/2018
01/06/2018
01/07/2018
01/08/2018
01/09/2018

Senator KING. The bottom red line on this chart is the Marcellus shale cost in the region, around in Pennsylvania going back to the beginning of December. The blue line is the cost in New England. What this tells us is it is not a natural gas price problem, it is a delivery problem. And that is what we have been talking about today. It is the infrastructure problem that we have been talking about.

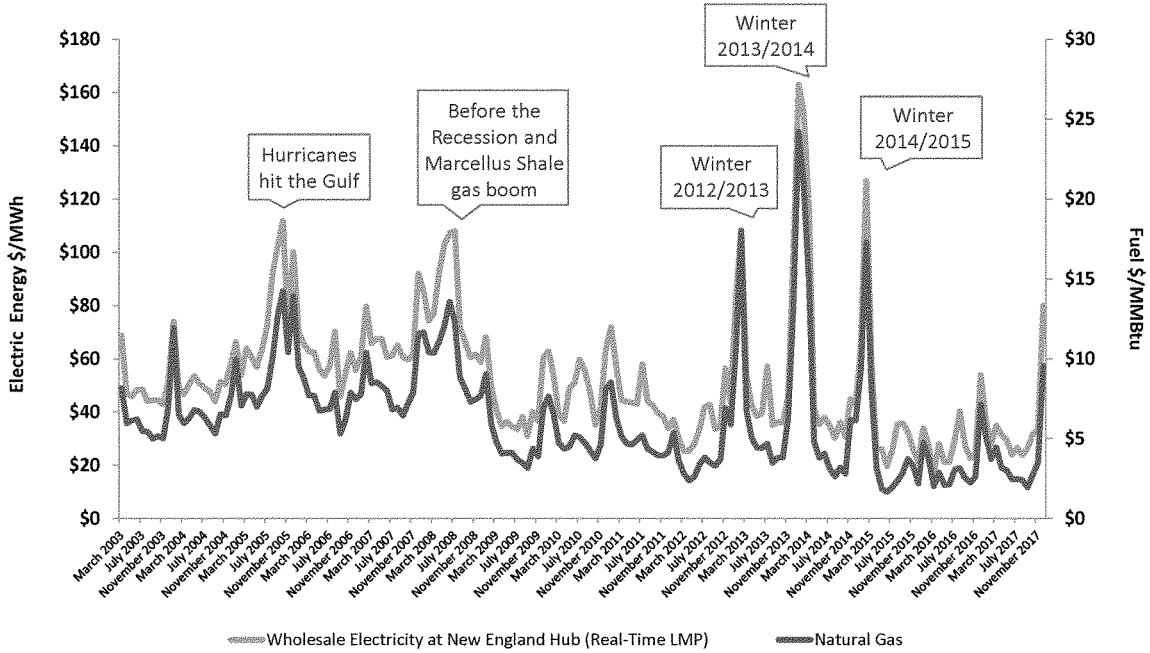
The problem with the infrastructure is, does anybody want to build a $2 or $3 billion pipeline to deal with this if it is not going to be necessary the rest of the year. And that is where we get into the tradeoffs between storage and LNG as an option and building the infrastructure. I just want to indicate how these things all interrelate.

The other piece is the relationship between what we just saw, which is natural gas prices and electricity—an absolute, almost entire, straightforward correlation, as you see.

[The information referred to follows:]

Natural Gas and Wholesale Electricity Prices Are Linked

Monthly average natural gas and wholesale electricity prices at the New England hub



Senator KING. This goes back 15 years.

Hurricanes hit the Gulf. Gas goes up. Electricity in New England goes up. Same thing over the winter of 2014, the Polar Vortex, and we're up in this area—I saw $32 a megawatt hour recently. So these things are all interrelated.

One of my favorite comments was from a friend of mine in Maine who said there is rarely a silver bullet, but there is often silver buckshot. That is what we are talking about here is a multiplicity of resources.

Ms. Clements, you talked about efficiency. The cheapest kilowatt hour is the one you never use. So we have efficiency opportunities. We've got renewables. We've got demand response. We've got storage. We've got infrastructure. We've got rate structure, Mr. McIntyre. We've got rate structure which will influence how we use power in terms of efficiency during the day.

I realize I am making a speech here. If you can find a question in here, you are welcome to it.

[Laughter.]

Mr. van Welie, talk to me about this, how we deal with this. Let's make it specific. Do we build a pipeline or do we do more storage?

Mr. VAN WELIE. So, I think it's going to come down to what policymakers decide to do. I think there's two parallel tracks in terms of this conversation in New England.

The one track that we're going to be the lead on is how do we make sure that the constraint is appropriately priced in the market because, to Chairman McIntyre's point, unless we price that constraint, we're not going to get the reliability that we seek. I think we learned some things over the past few weeks that make us think that we've still got a lot of work to do.

I think the separate and parallel discussion is how to relieve these constraints.

So to Ms. Clements' point, and I agree with you, energy efficiency is one tool in the toolbox.

Ms. Clements, you may have missed it in our analysis, but we take into account and project forward all the energy efficiency efforts that the states are making. And the New England states have made significant efforts. I think they lead the nation now in terms of energy efficiency.

But I think the evolution is occurring faster than what the states are doing with regard to these efficiency investments. And my fear, really, is that the retirements will happen more quickly than these investments will be made.

And the other thing, I look out——

Senator KING. One of the problems I see here is that gas is the cheapest capital cost, and yet you are taking the price risk. That is one of the tradeoffs, but the way our system is working now everyone is looking for low rates next year and the year after, but we do not have long-term, 15-year power purchase agreements that will support the capital investment necessary for some of the other options.

Mr. VAN WELIE. Yes, I think the peakiness of the demand for this fuel is the issue. And I think the—we're going to be stuck with this problem for a long time. Because if you think about where the re-

gion is going in the long run, we want to take carbon out of transportation and heating which means we're going to drive the demand for wholesale electricity up in the region. And so, over time we're going to have less utilization of the pipeline, but when you need it you're going to really need it in a big way. And you can offset some of that through electric storage, but our issue really is seasonal storage. So, I think the region needs to work through the various possibilities and understand what the cost benefit trade——

Senator KING. Again, you are talking about grid level storage, but it is hard to justify the cost of grid level storage if you only need it two weeks of the year. Correct?

Mr. VAN WELIE. Exactly. And grid level storage in terms of today's technologies are not very useful in a multi-day, multi-week event.

The CHAIRMAN. Thank you, Senator King.

Senator KING. Thank you.

The CHAIRMAN. Senator Daines.

Senator DAINES. Thank you, Chair Murkowski, Ranking Member Cantwell.

It seems like each winter and each summer when energy demands peak we are reminded of the importance of reliable and affordable energy.

I am from one of those northern states, Montana. We respect terms like Polar Vortex and Bomb Cyclones. Of course, in Montana, we call that January, but that is the way it goes.

[Laughter.]

The importance of keeping the supply on hand to keep the lights on and the infrastructure necessary to support that system and this winter has been no different.

This hearing is timely as my office is kicking off planning efforts for our Montana Energy Summit. We do this every couple years. It will be in Billings in May. We have invited FERC Chairman, Kevin McIntyre, to attend, Secretary Perry and others. We hope to have important conversations related to energy infrastructure and the jobs energy creates in our states, and we hope they can both attend.

As you have probably heard me say more than you want to, one critical piece of our energy infrastructure in Montana and across the Pacific Northwest is the Colstrip Power Plant. It supports about 750 direct jobs, generates enough power for about 1.7 million homes and businesses across Montana and the Pacific Northwest. Through heavy-handed regulations, litigation and some state policies, the future of this plant is actually at risk.

I was out there a couple years ago on a visit that is memorable to me. They were taking their boilers down for maintenance. It was July. I walked in and they were scrambling. The plant manager had been up since early, early morning, middle of the night, in July. And so, what's the problem? He says, well, here's the problem. He said, we have tremendous balanced energy portfolio in Montana. We are truly an all-of-the-above state. We are developing our renewables. We have great hydro resources. We have wind resources. But this high-pressure system moved into the Northwest. And when high-pressure systems move in, what happens? The tem-

perature goes up and the wind stops blowing, and because they had Colstrip down—one of the major units down for boiler maintenance—we were struggling to keep up with baseload at that moment because the wind stopped blowing.

We refer to wind as intermittent power, and it is not a critique of that renewable source of energy, but we still have to solve the storage issue with wind to make it a more reliable part of our energy portfolio.

I just came back from Taiwan last year. It was September. If you remember what happened in Taiwan in August, they lost electricity to about half the homes across Taiwan. It was a major outage. And why? Because they were too aggressively going forward on eliminating nuclear energy from their balanced portfolio. They had a plant that was ready to go, back in 2014, but it was battling some of the regulatory issues to get it up and running. With that peak load on a hot day in August, they lost their baseload.

I understand that while a lot of coal-fired generation has retired in recent years, New England had to rely on its existing coal and oil-fired generation for this winter event.

And as more states' energy mixes are changing toward more renewable generation due to policies and so forth, I remain convinced that we must find ways to keep a diverse, truly all-of-the-above, energy mix in this nation, especially during these peak times of load.

My question for Mr. Walker: In your experience, how important is it to keep a diverse energy portfolio at all times, but especially during peak load?

Mr. WALKER. Thank you for the question, Senator.

I believe it's extremely important. And it's not only during peak load, I think it's throughout the year.

You know, importantly, the diversity of the load provides the opportunity for us to build resiliency into the model.

With the threats we have today with cyber and physical security, which are very real. They're emerging. They're evolving. They're increasing. And the impact of these could be very significant in the country.

So as we look at the portfolio of generation sources that we have, the diversity component is extremely important. And as we work with the RTOs and with FERC to evaluate the proposal set forth by FERC, those are things that we will identify and look at.

I mentioned earlier on page 86 of the staff report, there's a diagram that illustrates the different capabilities of just different generation sources, things that provide for the baseload, the essential reliability services of each of the different types of generators.

As you look at this, it's like an optimization equation. When you look at all the different variables and you look at what the underlying goal is, which is to provide a safe, reliable and resilient grid, it's about optimizing the generation components that we have as well as the underlying systems that tie into those generation sources to be able to get and achieve the reliability and resilience we need to.

Senator DAINES. My last comment, and I know I am out of time.

My training was in engineering. And so, when I tell this quick little story about engineers it is not meant to be disparaging because I is one. I was in a debate one time about capacity—I was

running operations for Proctor and Gamble—and the variation and demand and so forth and need to be able to have capacity available to cover spikes. We believed it needed to be over here and the engineers were off in their ivory tower doing some calculations. Thankfully we had a senior executive that, kind of, was listening to this Hatfield/McCoy debate, and stepped back. He said, first of all, I always err on the side of the operation folks because they deal with reality. But number two, if an engineer were to design the amount of beds needed for a family of three, in terms of capacity, they would say you only need one bed for a family of three because on average, everybody sleeps eight hours a day.

[Laughter.]

It is something to think about as we relate to peak capacity.

Thank you.

The CHAIRMAN. Thank you, Senator Daines.

Senator Heinrich.

Senator HEINRICH. Senator Daines can get away with that because he is an engineer. Unfortunately, I am too. It is a curse and sometimes a blessing.

[Laughter.]

I wanted to start out and talk a little bit about that term, baseload power, because we hear a lot more of it today than we did 10 or 15 years ago. And I find that fascinating.

I grew up in a utility family where my dad was a lineman when I was young. He was the manager later. Those were the days when coal and nuclear and hydro were the only games in town.

But I bring that up because I think baseload, oftentimes today, is more of a political term than an engineering term. It tends to come up, oftentimes, at times when it is, sort of, code for trying to subsidize generation that is no longer competitive in the marketplace.

I would just point out that when those coal-fired generators go down, and oftentimes that is unplanned maintenance and it is not unusual, they are providing zero baseload megawatts to the grid. We need to find ways today to think about our grid and meet supply and demand together and know what the weather is going to be tomorrow and the next day so that we can match those things up from whatever generation sources we are using.

I want to go to Mr. Walker first because you said something to Senator Manchin, and I do not want to misquote you. I want to understand if I understood you correctly that inherently coal at a coal generation station is less exposed to the threats of physical or cyber threat to the grid than say, oil and gas pipelines.

The reason why I bring that up is because from my perspective once you use that coal to generate, you have to get it to the customer. You have to do that over transmission lines and then distribution lines. And it seems to me that all of these infrastructures are equally exposed to those threats.

You have the same SCADA systems at substations and relating to transmission and distribution on the electric grid that you would use in pipelines. You have the same physical threats to both of those distribution networks.

So, I do not see the difference in terms of exposure, in terms of critical infrastructure. Am I missing something?

Mr. WALKER. No, that's a fair question.

And I'll be—so what you heard me say, let me reiterate, is that what I do believe. And from, you know, the perspective that we're taking and I'm taking right now is DOE is focused on protecting critical national infrastructure. As FERC deals with the marketplace and we focus in on the resiliency, the capability that provides that safety and resilience in the grid.

If I have a stockpile of coal, in this sense it's at a location for a sufficient period of time, I'm not placing at risk the infrastructure as if it were natural gas.

So, if we take the——

Senator HEINRICH. What if that coal is too frozen or too wet to actually burn?

Mr. WALKER. And those are possibilities that were realized during the Polar Vortex.

Senator HEINRICH. Right.

Mr. WALKER. So, and I think through much of the work that was done after the Polar Vortex, provisions have been placed at the utilities and the generation plants that utilize things like coal to prevent, you know, through weatherization techniques and things like that.

Senator HEINRICH. So when I think of the Polar Vortex or even this latest Bomb Cyclone, if I am getting that term correct, the unsung hero that I think about that gets very little attention is actually demand response.

I would be curious to hear from the folks at PJM and ISO New England, how important is demand response at this point in these sorts of events? And has a market been fully implemented and are there federal policies in place that assure that demand response is allowed to compete as effectively as possible in these kinds of events?

Mr. VAN WELIE. So, a market has been fully developed for demand response.

We speak of demand resources broadly in New England and I say they're two categories. The one is passive, demand resources like energy efficiency. And that's very well developed in New England because of all the state programs supporting that investment. The active demand response which is active reduction during system events and so forth. We have lower penetration in New England, but the market exists. I think the issue has been the economics. It's not competitive in the market relative to some of the other resources.

If you'd give me a minute I just wanted to reinforce something else you said as well. I think there's a policy conundrum here with regard to this discussion between fuel diversity and fuel security. I think the policy conundrum is that the term fuel diversity is at odds with the idea of a competitive wholesale market because it implies a central planning orchestration of the different resources on the system.

Whereas the market is what you're really trying to do is create a competitive construct where the most economic resources come forward to produce the reliability service which is why you don't hear us using the term fuel diversity. We use the term fuel security.

Senator HEINRICH. Right.

The CHAIRMAN. Thank you.

Senator Cassidy.

Senator CASSIDY. Thank you.

Gentlemen, I am going to refer to some testimony we actually had in June 2016 from a fellow, Jonathan Peress, who is the Director of Air Policy, Environmental Defense Fund. It was a very good hearing last time which I will now, kind of, raise questions from that.

Mr. McIntyre, seeing that there was this price spike in fuel cost. LNG was imported. It had a spot price going far higher in the Northeast. This gentleman last year said that there was actually a lot of unused capacity in our Northeast pipeline system and that FERC was working to add flexibility to the schedule and to better use that capacity.

One, do you agree with it? It is an assertion from two years ago, I guess, a year and a half ago. Do you agree with that assertion? And two, has FERC now worked to add flexibility in terms of delivering of gas?

Mr. MCINTYRE. I know that we have worked on reforms in the market structures and practices and schedules in the interrelationship between natural gas pipelines which we regulate and electric transmission which, of course, is critical to gain the power from where it's generated, to where it's consumed.

Senator CASSIDY. Now, I think, he was speaking of the gas and he said that at times only 54 percent of the capacity was used in the Polar Vortex, the event to which he was referring. I guess I am asking is that still an issue or has that been addressed specifically?

Mr. MCINTYRE. Well, we do have, as you heard, I think most——

Senator CASSIDY. I had to step out, I am sorry if I missed that.

Mr. MCINTYRE. No, it's quite alright.

But Mr. van Welie has presented the situation in New England and that is where, indeed, we have ongoing, long-term challenges in transportation infrastructure.

Senator CASSIDY. Is that related to lack of efficient use of current capacity? And I am sure it is not either/or. Or is it due to lack of capacity, sir?

Mr. VAN WELIE. In New England, it's really lack of capacity at this point.

Senator CASSIDY. Now, this gentleman, again, made the point and it was very provocative, that if you look at the lack of capacity it was only like two weeks out of the year in which there was lack of capacity. And his point, it is cheaper to pay high spot prices on those two weeks out of the year as opposed to pay for the infrastructure that would be underutilized for the remaining 50 weeks of the year.

Any thoughts about that?

Mr. VAN WELIE. Well, I think it depends on one's view of the cost and benefits of rolling blackouts, for example. So I think there's a point beyond which we will maintain the supply and demand balance by taking demand off the system.

So I think that's the tradeoff. I mean, one could look at it and say it's not worth making an investment in a pipeline infrastructure because we only use it a month a year, let's say, the incre-

mental capacity. But you have to weigh that against the other consequences as well.

I think what our study attempts to do is to show that we're very close to the edge in New England and we need to find a way of relieving this constraint, one way or another, either through investment in the pipeline infrastructure or continued investments in other sources of energy that will take the pressure off the gas pipeline and/or reducing demand on the systems. Those are the three avenues available to the region. I think they differ in implications with regard to cost.

Senator CASSIDY. So, importation of LNG would not be adequate for those two to four weeks a year in which you truly are constrained?

Mr. VAN WELIE. Well, I think imports of LNG, if you look at our study, we will become much more dependent than today on imports of LNG.

I think our market monitor has raised another question which is there are two suppliers of LNG into the region, one of which is in Boston, the other which is in New Brunswick, Canada. They are pivotal suppliers into the marketplace.

So one should expect to pay very high prices for natural gas when we have these constraints. And I think the policy tradeoff is do you want to pay these high prices on an episodic basis whenever it gets cold or do you want to soften those economics by investing in infrastructure that will relieve those constraints?

Senator CASSIDY. But again, this gentleman's point, I don't mean to belabor, but I think it is a critical question that pipelines are so expensive, particularly a green field investment, that it is actually cheaper to do the episodic high price than it is to do the infrastructure. Now, he is not here to make his point directly, but it sounds almost like you are disagreeing with that.

Mr. VAN WELIE. I think that the region needs to work through those cost benefit tradeoffs.

Senator CASSIDY. Okay. I yield back.

Thank you.

The CHAIRMAN. Thank you, Senator.

Senator Duckworth.

Senator DUCKWORTH. Thank you, Chairwoman Murkowski and thank you for convening this very important conversation.

Unfortunately, my two engineering colleagues are not here, but I just wanted to remind them that multiple people sharing the same bed in the United States Navy is called hot racking and there are young sailors, submariners, who are doing it right now in order to defend our nation. So, let's say a quiet prayer for them of thanks for what they are willing to put up with to keep us safe.

My question goes back to the work that states have been doing for renewable energy. Illinois, my home state, has made tremendous gains in this area. In addition to requiring 25 percent renewable energy by 2025, we also prioritize investments in jobs training programs that are focused on low income individuals to create thousands of clean energy jobs. These investments will help make our grid more reliable and more resilient, not less, while also creating jobs.

Ms. Clements, in your opinion, how will Illinois' renewable energy policies impact the power system in the context of extreme weather events?

Ms. CLEMENTS. Thank you, Senator.

I think the recent Illinois Energy Act is one of the great examples of the smart way that states are leaning into this energy transition and saying we are going to use American ingenuity to harness the resources that we have and to create economic opportunity and jobs from making the grid more resilient and reliable.

By increasing the diversity of the resources on the system, through increased wind and solar under the RPS standard in the law and through increasing energy efficiency, excuse me, it is increasing resource diversity. At this point, nationally, only about seven percent of the resource mix is non-hydro renewables.

And when you think about the characteristics, every kind of resource has a set of benefits and issues that we've just been talking about. And so, narrowing the conversation to just gas versus coal and LNG versus new pipelines is an overly narrow view of the opportunities.

The wholesale energy markets have done a good job of what they've intended to do which is to provide low-cost, reliable energy.

As the mix changes and as states like Illinois take these exciting actions, the markets are going to have to start valuing things like resource flexibility that the Illinois Act is going to bring in through new distributed energy resources. And that's exciting.

But when we're talking about price formation in the markets, let's not forget that we can't undervalue the benefits that the renewable energy resources and the distributed energy resources and energy efficient are also bringing to the table. So, when they're overperforming and providing extra services to the grid, they should also be getting paid for those services.

And so, I think Illinois along with Minnesota and Hawaii and New York and California are just showing the way that other states can look to as an example.

Senator DUCKWORTH. Thank you.

Can you speak a little bit to the cost of the renewables during extreme weather events and how they compare to other fuels?

Ms. CLEMENTS. Well, on a marginal cost basis, Senator, the beauty of renewables, of course, is that the wind and the sun are free. And so, they were able to help by, wind, specifically in the Polar Vortex and we're still getting the information from the Bomb Cyclone, but the, you know, what they served, the role that wind, in particular served, was to help avoid those price spikes or to mitigate some of those natural gas marginal cost price spikes by overperforming at low marginal cost.

Senator DUCKWORTH. Thank you.

In every tragedy there is some opportunity, and even though four months have passed since Hurricane Maria made landfall and clear evidence of the storm remain, the lack of electricity, running water, and reliable communications remain a central challenge to Puerto Rico as it struggles to return to semblance of life.

I am committed to developing and advancing policy that will enable the island to remain operational during the next superstorm. And so I would like to see in Puerto Rico some investments made

so that they are not put in the same place that they were in before Maria hit.

Ms. Clements, in your opinion, will policies that help stimulate solar and batteries be useful in this endeavor to better position them for the next storm? Because we know with global warming and every extreme event, they are going to get hit again.

Ms. CLEMENTS. Thanks for the question.

Absolutely. I mean, I think just as of yesterday, 32 percent of Puerto Rico's customers remained without power. So, that's all of October, November, December and now most of January.

And the government also announced that they're considering privatizing the utility. That might help, in and of itself, with creditworthiness of the offtakers and bringing in the expertise that can really provide that innovative, new model grid.

But anything that the Congress can do to provide those incentives, to help get that solar and get that energy storage online in Puerto Rico is critical and will facilitate a model that, per the National Academy recommendations, can serve as a best practice which then can be shared with other states and regions within the continental U.S.

Senator DUCKWORTH. Thank you, and I look forward to working with members of this Committee on securing legislation that will help us achieve these goals.

Thank you, Madam Chair.

The CHAIRMAN. Thank you, Senator Duckworth.

Senator Hoeven.

Senator HOEVEN. Thank you, Madam Chairman.

I have two questions for each of you, which relate to the Bomb Cyclone, but certainly to capacity and reliability.

One goes back to a question that Senator Daines was getting at and that is essentially how do we make sure that we have enough baseload power for those type of events, so we are ready for those type of events? So one, how do we make sure we have enough baseload power? And number two, how are we going to build the transmission and the pipelines to make sure that we have an adequate distribution system?

We are running into incredible difficulties building any type of pipeline for oil or gas and we are also running into the same kind of problems with transmission. So, it is actually, whether you are a fan of traditional or renewable energy, we are running into the problem of building enough infrastructure.

And I can cite examples to you, including most recently, the Dakota Access Pipeline in our state which now moves half a million barrels of oil a day to East Coast refineries that need our light, sweet crude. If they don't get it from us, they get it from Saudi Arabia. I would rather they get it from North Dakota.

So you could each take a swing at it. Those two issues, how do we make sure we have enough baseload power, how are we going to get people to support building this transmission we need to have the reliability we want? Chairman McIntyre, do you want to lead the effort here?

Mr. MCINTYRE. Why not?

Thank you, Senator, thank you for the question.

As to baseload, as was pointed out, it's a term that means different things to different people these days. I think of it as the big, large-scale power plants that are intentionally designed to, kind of, run 24/7, essentially. And that is changing as technology changes and the economics of the market change.

To answer your question, how do we ensure we have enough of it? I think we ensure we have the right market structures in place that compensate those resources, compensate them appropriately.

Second, you raised the question of the difficulty of getting sufficient new energy infrastructure built. I fully share that concern. It's unquestionably a problem. We have to look at ways to mend and improve our permitting processes so we can get over some of these obstacles.

Senator HOEVEN. Okay.

Mr. Walker.

Mr. WALKER. Thank you, Senator.

With regard to the baseload, one of the things I learned early on being an electrical engineer is we're not very creative. So, we name things for exactly what they do and baseload referred to basically the bottom of the stack, the economic stack and for what was going to meet the base requirements of load. And I think that, as the Chairman recognized, I think recognizing them from a market standpoint and placing value on things like the central reliability services as part of the economics will help drive that.

I think also, in recognizing and taking a different perspective and looking at it from a resiliency standpoint, there are values that will not be captured in the economic component that have value to the economic and national security of the United States. And I think those, in conjunction with the work that FERC does, need to be integrated together to help drive the investment.

And then, once we've identified those critical components that are both valuable to the market from an economic standpoint to drive costs down and valuable from a physical and cybersecurity perspective to ensure the national security, we blend those together to help work through the processes.

DOE works with the states and local, you know, components of the United States municipal governments to work through these issues, as does FERC. And I think, with the proper data, the proper analysis and the evaluation that really identifies the right locations, we'll work through the process and get them in.

Senator HOEVEN. I like your pin.

Mr. WALKER. Thank you. I got it from Northcom.

Senator HOEVEN. Yes, good job. Glad to see you wearing it.

Mr. WALKER. Thanks.

Senator HOEVEN. Charles? I am not going to take a swing at your last name there.

[Laughter.]

Mr. BERARDESCO. Thank you.

Senator HOEVEN. Do pronounce it for me though.

Mr. BERARDESCO. Berardesco.

Senator HOEVEN. Thank you.

Mr. BERARDESCO. So NERC has identified fuel diversity as being critical to the operation of the bulk power system in the long run.

We are in the middle of a significant transformation of our system, and having that fuel diversity is what's going to allow us to have the reliable operations.

And I tend to move away from terms like baseload or other kinds of adjectives and simply talk about that different generation provides different attributes and has different risks attached to it.

So the policymakers need to consider what's the appropriate mix of that kind of generation that's going to give you the best risk outcome, risk-based outcome, for operating your system in a local area.

But what's really important to us is we move to an environment where we are more and more thinking about renewables as part of our mix, is the stability of the bulk power system behind it. That system is critical in order for renewables to, in fact, be attractive to people because to the extent that there is no wind or no sun, you're drawing power from the grid. And so, having the grid operating reliably is critical to the success of renewables being inserted into our system.

And we need to really consider carefully what are the attributes that different generations provide to that stability of that system and making sure that everyone is fairly contributing to that stability of the system from each of the different generation portfolios.

I'm not much of an expert on transmission siting or incentives, but I will say just listening to the testimony here today, it seems obvious to me, if you're going to move, particularly in the case of gas generation, if you're going to move to more gas generation is being part of it, whether it's a bridge to a more renewable-based system or simply part of the basic power structure, you're going to need more capacity. I mean, we're hearing that testimony today. So, providing some types of incentives that get better capacity for gas, seems to me, a fairly important consideration for policymakers going forward.

Senator HOEVEN. Well, you have to get support for siting it.

Ms. Clements?

Ms. CLEMENTS. Thank you.

I go with the description of baseload as an operating characteristic, as a sum subset of power plants and that we are going to, as we move forward, we're able to move away from that particular characteristic as the primary goal.

However, the sheer number of megawatts that resources provide on the system is important and we've got lots of power, the country, across the country, planning reserve margins are very strong and so, from, in general, how do we have enough? There's already lots there.

Senator HOEVEN. So go to the infrastructure piece then?

If you have the power you have to get it to where you need it.

Ms. CLEMENTS. Absolutely. And I think this is an opportunity for the Committee to have real bipartisan work together on a well-designed policy to build out transmission lines to support the movement of wind from the windy places to the cities that need it and the sun from the sunny places. That development has to uphold environmental protections and it has to be done carefully, but it can be done well.

Senator HOEVEN. It has to uphold environmental protections, but you have to build it.

You cannot take 10 years to build a transmission line or a pipeline. You can get all kind of power, but it does not do you any good if it is not in the right place when you need it, right?

Mr. Ott?

Mr. OTT. Thank you. I'll be brief given the time.

Essentially, for the baseload resource, again, it's really the reliability characteristics you're looking for to run the power grid and making sure those are appropriately compensated, as the Chairman had indicated. And certainly, I think that we have a track record in the capacity markets that those have been effective in targeting performance of resources.

I think the Polar Vortex lessons learned was a success story. And certainly, I think we can do some things in the energy market to address some of the concerns I've raised.

As far as infrastructure, I do believe RTO regional planning processes have been successful in getting a lot of infrastructure built. Certainly, in PJM $20 billion worth of transmission investment in the past 15 years.

As far as gas pipeline infrastructure, I see that as an issue we do need to figure out a way to get the siting process for gas pipelines moving.

Senator HOEVEN. It has really changed from this battle between renewable or traditional to both have the commonality in this interest of actually getting approval for construction of this infrastructure. It should be working together.

Mr. OTT. Right, agreed.

Senator HOEVEN. Sir?

Mr. VAN WELIE. So I think baseload is rapidly becoming an obsolete term because I think, I think of baseload as what's producing energy with the minimum price, and I think that's changed over the years. We've come from a world where we had coal and nuclear and we're now with gas and renewables going forward.

I think if I look at the problem, I think we've got structures in place to ensure that we've got enough resource on the system. We've got structures in place through the transmission planning authorities that the RTOs have with FERC oversight to make sure that we can get transmission built.

I think siting is a problem. I think the big regulatory gap, the structural problem has only been restructured, the markets, 20 years ago. We didn't understand the dependency that would be created on the gas system. And so, we have a gas system where the business model is completely different from the electric system in the restructured markets. That leads to the situation where you don't have a customer for the incremental pipeline investments needed to serve the gas generation. So, I think that's a problem we're going to struggle with for a while.

Senator HOEVEN. I think that is right. It is a problem.

Madam Chairman, thank you for your indulgence. I apologize for going over my time, I appreciate it.

The CHAIRMAN. You went well over, but this is exactly what this Committee hearing was designed to dig into was these types of questions.

So——

Senator HOEVEN. When you say well, you mean qualitatively or quantitatively?

The CHAIRMAN. Both. Both.

[Laughter.]

It was good though. These are questions that, I think, are very important and the answers on the records are equally important.

So, well done, sir.

Senator Cortez Masto.

Senator CORTEZ MASTO. Thank you, and I appreciate that as well, the comments and the conversation we are having today is so important. Thank you to the Chairman as well.

Mr. McIntyre, it is good to see you again. Let me start with you.

When you were before the Committee for your nomination hearing, we briefly discussed integrating renewable energy into the power grid. In Nevada we actually have an Energy Bill of Rights that allows consumers to generate, export and store renewable energy on their property.

Mr. McIntyre, do you believe there are additional actions that FERC can take to allow distributed energy resources access to wholesale electricity markets?

Mr. MCINTYRE. There may well be, Senator.

Thank you for the question.

There is already a lot of work that has been undertaken within the Commission prior to my arrival, and we have a record of materials that have been submitted to address this very question. That is part of the work that remains before me, personally, and before the Commission as well. It's a very important issue and it's something that we're going to turn our attention to in due course.

Senator CORTEZ MASTO. I know in late 2016, FERC issued a Proposed Rule that would eliminate barriers to the participation of renewable energy and electric storage in the wholesale markets. What is the status of that effort?

Mr. MCINTYRE. And that's precisely the work that I was referring to.

Senator CORTEZ MASTO. That is what you are talking about. Is there a timeframe or do you have a sense of how——

Mr. MCINTYRE. It's something that we'll be turning to in the coming months. I don't have a specific calendar in mind for it.

Senator CORTEZ MASTO. Okay.

Mr. Berardesco, in your testimony you provide a number of key findings and recommendations on how to increase resiliency for cold weather, but I am curious if you have any recommendations for extreme heat. In Nevada, it can get up to 115 degrees in the summer.

Senator BERARDESCO. I don't, off the top of my head.

Senator CORTEZ MASTO. Okay.

[Laughter.]

Senator BERARDESCO. Thank you.

Senator CORTEZ MASTO. Thank you.

Ms. Clements, one of your recommendations on how to enhance resiliency efforts is to ensure that resilience efforts focus on protecting vulnerable communities. What exactly could be done to better protect vulnerable communities, and can you elaborate a little bit more on that?

Ms. CLEMENTS. Sure.

If you think about the—well, first of all, let's remember that there's a lot of institutions involved in protecting communities in the event that something very bad happens, like a hurricane or a drought or some other kind of storm. And critical services like hospitals and fire stations and police stations and shelters and food banks need support and to be able to figure out their plans for how they're going to respond in emergencies. Now remember, a lot of this is subject to state and local jurisdiction.

Senator CORTEZ MASTO. Right.

Ms. CLEMENTS. And so, what we recommend in the National Academy's report is that Congress provide funding and support and field disseminations and best practices so that we can try this. We can support the local communities who have to figure this out and then help to share that information and socialize those, excuse me, best practices by region and across the country.

Senator CORTEZ MASTO. Thank you.

Mr. Walker, I know my colleague from Illinois talked a little bit about this—Puerto Rico and the devastation there and the work that is being done to modernize their electric grid.

I just saw a report that notes that DOE's long-term plan for Puerto Rico is to begin with new microgrid power installations at three manufacturing sites on the island. Can you elaborate a little bit more on DOE's long-term plan?

Mr. WALKER. Sure.

We've—that project is actually not a DOE project.

Senator CORTEZ MASTO. Oh, it is not?

Mr. WALKER. It's a PRIDCO, which is the Puerto Rico Industrial Development Corporation, owns about 200 pieces of property on the island of Puerto Rico.

Senator CORTEZ MASTO. Okay.

Mr. WALKER. And as the Industrial Development Corporation they own the property and they lease it back, back to customers. So, customers like Johnson & Johnson, Honeywell.

And so, we've been working very closely with PRIDCO and their staff and the Puerto Rican government to give them technical expertise with regard to how to site these microgrids at various locations on the island in an effort to ensure better power quality for these bigger manufacturing customers and then and in an effort to reduce their energy costs to encourage them to stay on the island and further expand their employment opportunities for the people of Puerto Rico.

Senator CORTEZ MASTO. Anything else that you are doing? Long-term plans to address their energy needs there in Puerto Rico?

Mr. WALKER. Yes, we are working with all the stakeholders that put together plans and integrating them and distilling them down into one so it's a better document. And we're adding whatever technical capabilities we've got to do that.

Just yesterday, my team and I met with the TAC Committee, the Technical Advisory Committee that was put together by PREPA, to coordinate our efforts and, you know, walk through what our plan is moving forward.

Senator CORTEZ MASTO. Okay.

Thank you. Thank you, all.

The CHAIRMAN. Thank you, Senator.

Assistant Secretary Walker, thank you for your efforts with Puerto Rico and all that is going on there. I appreciated the opportunity that we had when we were over there to have that following conversation. Obviously, there remains a great deal more to be done, but I appreciate your ongoing efforts.

Several members have commented about the quality of the witnesses that we have had this morning and the discussion. One of the benefits of holding the gavel here is I get to stay for the full morning.

[Laughter.]

It has been as important and, I think, enlightening in certain areas as any hearing that we have had in a while. So I thank you for that.

I hear from most of you that okay, we are beyond the discussion about baseload power and how we define it. I forget which of you referred to the policy conundrum between diversity versus security. I think it is often very easy to say we need to have this diverse portfolio, but if the diversity does not give you the security of access to—you fail when it comes to your resiliency. You fail in terms of your ability to really meet the expectation there.

And so, I think it is important that as we talk about these very serious challenges that we see as you have a grid that is evolving and changing and aging and how we do a better job with the integration of all of this that we keep in mind this distinction between diversity and security and recognize that has to be part of our issue.

We have heard several colleagues state that we can have all the supply that we need, but if we cannot move it, it does not get us anywhere. I think Alaska is a poster child for that. We have extraordinary resources, but our challenge has always been moving that to the market.

I really do appreciate so much of what we have heard here today. You will notice that I have deferred my questions, holding them until the end so I do not have the clock running on me and I do not want to keep you all too long, but I do feel like I can bat cleanup here a little bit.

Let me begin with you, Chairman, and again, I appreciate all that you are doing within the Commission there.

I do not know if it is fair to ask you your personal opinion, but I will ask you your personal opinion about what you believe is the risk to the grid presented by the ongoing retirements that we are seeing in nuclear with coal retirements, and just for purposes of conversation here, if you have a scale of one to ten with ten being the most severe risk to the grid, where do you put us?

Mr. MCINTYRE. Thank you, Madam Chairman, for the question.

Quantification is an inherently tricky business and I feel so particularly here, but I can tell you conceptually that we're probably, clearly, at a five. I say that on the basis just of what we know today of the resilience challenges that have presented themselves in prior weather events and other circumstances.

And I say that because of the potential irreversibility of the situation of unit retirements and individual unit retirement of a par-

ticularly sizable plant is a serious matter to the grid, let alone an entire class, an entire class of power plants.

So, it's something that as of today, I'd say merits a five ranking on your scale, but I will have a better informed personal opinion after we have heard from the RTOs and ISOs about what specific needs they see and concerns they have in their respective——

The CHAIRMAN. Let me ask you about that because you, the FERC really has, kind of, kicked that to the RTOs and the ISOs to define what the concerns are with regards to resiliency. I guess the question is are they the best organizations to make that assessment or that determination? What about the EROs, the Electricity Reliability Organizations, whether it is NERC, its various regional entities? What about DOE? How do all the others factor into this? I think we recognize that the RTOs and the ISOs, they do not own the grid. You do have owners of the grid.

I understand why FERC moved forward as you did in rejecting the NOPR. And I understand, I think, where you are trying to go with gathering this assessment back, but does it need to be broader, I guess is my question, than just the RTOs and the ISOs?

Mr. MCINTYRE. I'm happy to say, Madam Chairman, it is broader.

The CHAIRMAN. Okay.

Mr. MCINTYRE. The most immediate and directed request was to the RTOs and ISOs to report back and answering some specific questions we put to them.

But we have invited broader stakeholder input. I'm happy to say we already have initiated outreach and had some good communications already with Mr. Walker's organization in the Department and with Mr. Berardesco's organization, NERC. And I would expect that to continue, in addition to hearing from other stakeholders as well.

So I do agree with your suggestion. It needs to be beyond just the RTOs and ISOs.

The CHAIRMAN. Well, I appreciate that and do feel that is an important part of any analysis that might move forward.

Assistant Secretary Walker, you spoke to cooperation and collaboration that needs to go on. I think you said it is going to take unprecedented cooperation and collaboration to keep the lights on or something to that effect.

Mr. WALKER. That's correct.

The CHAIRMAN. To that end then, with the resiliency model that you have indicated is a top priority for DOE, have you or your staff, have you reached out to FERC's reliability or security staff or been working with the RTOs on this? Tell me how you are going to do this——

Mr. WALKER. Sure, sure. It's a good question.

I do believe that it does and will take a significant amount of collaboration. Chairman McIntyre and I have already spoken about this with regard to this model. Yesterday, I had the opportunity to meet with Gordon down at the end of the table here with regard to the New England study. My team, back at DOE, has already reached out and gone through looking toward integrating all of the work that FERC's initiative will yield.

And so, we work pretty regularly within DOE with the ISOs and the RTOs and as well as through the Electricity Sector Coordinating Council, we reach back throughout the United States and with NERC, with all the partners that we've got there.

But in this case, it's even bigger than the electric side because it's really where the nexus to bring together the oil and natural gas component.

So presently we actually have two separate coordinating councils which we're looking to bring together under this rubric because of the interdependencies between oil, natural gas and the electric system. We've already laid out a schedule of all of those participants that we need to pull together to work with FERC, NERC and the regional RTOs in an effort to ensure that we get the best answer we can. And that's the essence and where this model comes from. Once we've got all of the information, we then can take the actual technical components of the system which we already have.

We've already started gathering that and that's part of the reason I was out at Northcom with my team last week is starting to define some of the resiliency work that's already been done in the United States at the Department of Defense and with the Army Corps. That's why there was a specific reason to be there.

So we've already started that initiative to gather all of the components that we've got around. In fact, yesterday I met with DOE security organization to identify work that's been done for resilience at our nuclear power plants and through our NNSA groups to be able to coordinate that and provide that information, effectively to FERC, as we progress this forward.

We're very much in lock step with this moving forward because it is so critically important to the national security components that we address day-to-day and we, obviously, can dovetail very well into the marketplace to solve a lot of these issues.

The CHAIRMAN. Well, that is good to know because this is exactly what we need. It is good to know that there are reports, there is analysis, but if we are not really coordinating and learning from other entities and what they have done or how they have advances, it is not as valuable, I think, as we would hope.

Let me ask another question of you, Chairman McIntyre, because there has been discussion about price formation and making sure that value is in place. I guess that the quick question is how prompt will FERC be when it says that it will act promptly if it sees a need to take action?

I raise this because FERC opened up its price formation dockets just after the Polar Vortex, a couple months into early 2014. That work still has not been completed on price formation.

I think what would be important to know is, given the reality of time that it takes, I mean, when you say that FERC is going to take prompt action, does this mean that it is technical conferences or staff memos and white papers? What can actually be expected?

I think we know that oftentimes this is complicated and lengthy, but we also speak frequently about this paralysis of analysis and the situation of this review, of ensuring reliability. I raised it eight years ago, maybe even longer now since I have raised these concerns, and we continue to see growing levels of retirements. I would hope that FERC recognizes that we need to move beyond

technical conferences and more white papers and that we actually need to see that action. Can you speak to what——

Mr. MCINTYRE. Yes, Madam Chair.

It's a very valid question and certainly when I was in the private sector I shared those occasional frustrations as well.

The CHAIRMAN. You were pushing everybody along.

[Laughter.]

Mr. MCINTYRE. But in terms of our January 8 order on our grid resilience initiative, there is a certain calendar spelled out there—60 days first for the RTOs and ISOs to get back to us with their responses to our specific questions, 30 days for stakeholder input thereafter. And then, yes, our commitment to prompt action thereafter. I cannot say now how much time will be involved in such a prompt action, because it will depend on the quality of the information which we get back which I expect to be very good in general.

But it's something where I have declared it and our order declares it to be a matter of priority for this Commission. Those are not words we utter very often, is a declared priority of the Commission now to get this right and to move with speed.

And I should say that in the meantime, we have stated as well in the very same order, that should any short-term concerns arise within a given RTO or with a given utility, we want to know about it immediately. We will not sit idly by if there is some sort of legitimate concern regarding reliability or resilience of the grid.

The CHAIRMAN. Well, I appreciate that.

I think that it helps that you have been on the other side and just very recently so that you know, not only of the need, but have been one who has been in the situation where you are urging the action. I think that will help on the inside as well.

I think given what members have covered throughout, I had many, many questions when I started and I think we received good information before the Committee, and so many of the questions I had have been answered.

But I recognize that this is a challenging space, most certainly. We see the challenges pronounced when we have weather events that push, kind of, the energy status quo that we might get pretty comfortable with. It is a reminder that we need to be vigilant in understanding, again, the security, the reliability, the resilience of our energy supply.

I mentioned just a few minutes ago that this hearing has probably been the most educational. It is right up there with the one that we had several weeks back when we had the head of the IEA here, Dr. Birol, who spoke about the energy trends internationally. He had four upheavals. I won't go through all of them, but his fourth upheaval was what is happening with electricity and how that whole sector is being impacted.

We have a lot of work to do, but this has been a very instructive and helpful hearing to all members, so I thank you for the time.

With that, we stand adjourned.

[Whereupon, at 12:32 p.m. the hearing was adjourned.]

APPENDIX MATERIAL SUBMITTED

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Kevin McIntyre

Questions from Chairman Lisa Murkowski

Question 1: While FERC stated that it intends to act "promptly" when it terminated its proceeding on DOE's proposed rule on resiliency, that docket is now closed, and the Commission has not established a timeline for taking action.

a. Can you assure this Committee that if you see a need for action on resiliency or reliability, you will promptly submit the matter to a vote by the Commission?

Answer: Yes. The Commission's January 8 order addressing DOE's proposed grid resilience rule not only terminated the rulemaking proceeding initiated by that proposal, but also initiated a new FERC proceeding to address resilience issues more broadly. In that January 8 order, the Commission directed the nation's regional transmission organizations (RTOs) and independent system operators (ISOs) to provide information to address grid resilience issues within their respective geographic areas, in addition to inviting input from other market participants and stakeholders. The Commission committed that it would review the material and decide promptly whether additional Commission action is warranted to address grid resilience. Our order also stated that if presented with a specific threat identified by an RTO or ISO, the Commission would promptly consider action to address the threat.

b. Given that FERC opened its price formation dockets shortly after the polar vortex in 2014, and FERC still hasn't completed its work on price formation, how will you avoid additional years of technical conferences, staff memos, white papers, and reviewing public comments?

Answer: The Commission's work on price formation has been ongoing and continues. The Commission initially identified a multitude of issues that potentially warrant Commission action under the broad umbrella of "price formation." Since that stage, the Commission has taken a number of concrete actions. In June 2016, the Commission issued a rulemaking order, Order No. 825, reforming the RTO/ISO processes governing the timing intervals for transaction settlements in the organized wholesale electricity markets, together with "shortage pricing." This order established important steps to address failures to compensate certain resources at prices that properly reflect the value of the services they provide to the system, thereby distorting price signals, and in certain instances, creating a disincentive for resources to respond to dispatch signals. Similarly, in November 2016, the Commission issued a final rule reforming the system of price caps applicable to offers to provide energy in RTO/ISO markets (Order No. 831). In December 2016, the Commission issued a notice of proposed rulemaking addressing the pricing of fast-start resources. After reviewing that record, the Commission in December 2017 elected to take more targeted action and opened three investigations into fast-start pricing practices in PJM Interconnection, L.L.C., Southwest Power Pool, Inc., and New York Independent System Operator, Inc. In January 2017, the Commission issued a notice of proposed rulemaking on uplift allocation and transparency. The Commission is reviewing the record in that proceeding. Thus, the

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Kevin McIntyre

Commission already has taken numerous actions on price formation matters, and our work on these important issues continues.

c. Given that certain market participants will not support changes to markets where they now have an advantage, do you believe that FERC will be able to act in the face of market pressures to avoid acting?

Answer: Yes. Commission action to ensure just and reasonable rates is not dependent on the support of market participants. Under section 206 of the Federal Power Act, the Commission has the power to act on its own motion to address unjust and unreasonable rates, terms and conditions. Moreover, the Commission can act on complaints alleging that rates, terms and conditions currently in effect are unjust and unreasonable, including complaints that RTOs/ISOs file to make changes to their own tariffs in the absence of full market participants' support. In each of these circumstances, the Commission acts on the record of the case, in which all interested parties may participate.

d. Given that FERC staff had already asked five pages of questions on the DOE NOPR prior to FERC's action on January 8, and given that FERC received hundreds of comments comprising thousands of pages of material on the DOE NOPR, do you believe that the public will be discouraged about the prospect of resubmitting their commentary and proposals on resiliency for a second round of comments?

Answer: No. Although the DOE proposed rule generated the submission of many documents to the Commission, the January 8 order initiated a new proceeding different from the DOE proposed rule and seeks information that the DOE proposed rule did not attempt to elicit. I expect that interested entities will have views on the new proceeding, including on the information that the RTOs/ISOs will submit, and the Commission will review that material thoroughly.

e. Given that I have been expressing my concerns for some eight years about the issue of ensuring reliability in the face of an increasing numbers of retirements, do you have a plan for moving FERC staff beyond any sympathy it may have for the managerial technique of "paralysis by analysis?"

Answer: Shortly after the issuance of the January 8 order, I directed FERC staff to start work on assessing any next steps we may consider to address the resilience of the bulk power system. The material that we directed the nation's RTOs and ISOs to provide will further inform that work. Although I cannot determine today what any specific next steps may be, this matter, as the Commission stated in the January 8 order, is a priority of the Commission, and we expect to determine any next steps promptly.

f. Based on your review of the comments and proposals already submitted in the DOE NOPR, what types of proposals do you believe that FERC should be considering?

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Kevin McIntyre

Answer: I do not want to prejudge any possible next steps – particularly before we have RTO/ISO submittals and additional stakeholder input requested by the January 8 order. However, I have instructed staff that everything should be on the table for the Commission's consideration.

g. Do you see a need for FERC action on resiliency or reliability in markets beyond the organized markets that were the subject of the DOE NOPR? If so, how should market participants in those regions inform FERC of their concerns?

Answer: Although FERC's January 8 order and its prescribed procedures focus on the RTO/ISO regions, as the DOE proposal had done as well, as a next step in our consideration of grid resilience I recognize that the concept of resilience necessarily involves issues, topics, and questions that extend well beyond the RTOs/ISOs and their respective geographic areas and members, such as to utilities that are not participants in organized markets, in addition to non-FERC-jurisdictional distribution systems. Therefore, in the January 8 order the Commission encouraged RTOs/ISOs and other interested entities to engage with state regulators and other stakeholders through Regional State Committees or other venues to address resilience at the distribution level. In addition, utilities outside of the organized markets are invited to raise their concerns and perspectives with the Commission as well.

Question 2: Now that FERC has rejected the DOE NOPR in its entirety, closing out that docket, the only remaining avenue for the Commission to consider grid resiliency seems to be the new docket opened by FERC where it is asking the RTOs and ISOs to submit their thoughts on resiliency. The public will then have an opportunity to reply.

a. While the RTOs and ISOs are certainly "on the ground" when it comes to resiliency in their regions, they are far from the only set of organizations with obligations over reliability or resiliency. Yet only the RTOs and ISOs have an opportunity to submit the initial set of materials. Does this mean that FERC is granting the RTOs and ISOs the opportunity to define our nation's concerns about resiliency? Do you believe that they are the organizations in the best position to independently assess the reliability of the grid?

Answer: The RTOs/ISOs are appropriate entities to start with to obtain information regarding the resilience of the bulk power grids that they operate. This is the premise from which the DOE proposal proceeded, and FERC's January 8 order reflects the same view. Each RTO and ISO is uniquely tasked with operation of the entire grid within its geographic region, and thus each has an understanding of that grid that may be better informed than would be feasible for other entities to possess. However, the Commission specifically solicited comments from other interested entities as well. The Commission will be guided by the entire record and will not rely on only one segment of the market to determine Commission policy or next steps.

b. Will you commit to careful consideration of the views of the Electric Reliability Organization (ERO) — NERC and its various regional entities — on reliability and resiliency?

Answer: Yes.

c. Since the RTOs and ISOs do not own the transmission grid, and they do not own generating plants, will you commit to careful consideration of the views of those companies that own the grid and its power plants? In particular, the owners of the transmission grid operate assets on the grid, which suggests that they would have special knowledge of transmission constraints and issues prior to that information becoming apparent across the RTO or ISO.

Answer: Yes.

d. Since consumers of energy pay for actions to address reliability or resiliency, will you commit to careful consideration of their views?

Answer: Yes.

e. Will you direct your staff to arrange a series of meetings between experts at DOE and the offices of Reliability and Energy Infrastructure Security at FERC on the topic of promptly addressing issues of reliability and resiliency?

Answer: Yes. FERC staff is working actively on this matter now, and this includes staff in the Commission's Office of Electric Reliability and Office of Energy Infrastructure Security.

Question 3: In December, 2017, FERC announced that it would review its policy statement on its process for the certification of gas pipelines. FERC's promise to review this policy, which was issued in 1999, appears to be supported by a report issued by Sue Tierney in November 2017. In the press release associated with this announcement, you apparently supported this review as part of a pledge that you made during Senate confirmation to take a fresh look at all aspects of FERC's work.

a. To whom did you make this pledge?

Answer: During the confirmation process, I indicated in my responses to several questions for the record (QFR) that I believe that the Commission should, from time to time, review its existing policies and procedures to ensure they are functioning effectively and efficiently. *See, e.g.,* my responses to the following QFRs: Senator Cantwell QFRs 4, 7, and 10; Senator Wyden QFR 6; Senator Hoeven QFR 4; and Senator Cassidy QFR 1.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Kevin McIntyre

b. Did you make a pledge about the 1999 policy statement? To whom?

Answer: See my response to Senator Wyden's QFR 6. ("The currently effective formal policy governing this determination of pipeline need was adopted by the Commission in 1999. If confirmed, I commit that I will base my decision-making and actions on careful review of the applicable law as applied to the situation at hand. I also believe that agencies periodically should review their policies to ensure they are effective, and if confirmed I will give these important issues concerning pipeline need the careful attention they deserve and will work to ensure that the Commission's review process considers all relevant issues."). *See also* my response to your question 3(a).

c. Have you considered how this review will impact the willingness of investors to make needed investments into American pipeline projects, as compared to other available investments worldwide? What are your thoughts?

Answer: I appreciate that the review of any of our policies and procedures may generate questions among segments of the energy industry, including among investors. I also believe that good government requires a review of our policies from time to time, especially as here, where our policy was last reviewed nearly 20 years ago and the affected markets have undergone profound changes in the meantime, and I expect our review to be conducted in a manner that is appropriately inclusive of all perspectives, including investors'.

d. Is this review by FERC more important than its review of security concerns on existing pipelines, especially if a series of pipeline assets are attacked in a region that depends heavily on natural gas? Specifically, will you allocate more staff to reconsidering the 1999 policy statement than you allocate to existing security on pipelines?

Answer: Primary authority over natural gas pipeline security resides with the Transportation Security Administration (TSA). I will continue to offer any assistance that FERC may be able to usefully provide to the TSA in its work on this issue. FERC also carefully considers security issues when exercising our certification and rate-making authority with respect to natural gas pipelines, including safety and security provisions related to pipeline routing and other factors, where appropriate. In addition, the Commission and TSA have developed a joint, voluntary assessment program to conduct in-depth cybersecurity reviews of natural gas pipeline entities. Further, the Commission works with Federal and State partners, such as the Department of Homeland Security, the DOE, the Federal Bureau of Investigation, and state public utility commissions, to share security information and best practices.

Question 4: In assessing the organized markets, have you considered the need for both entry and exit in a well-functioning marketplace? Notwithstanding the vital contributions of wind, solar, hydro, oil, and other resources to our markets, what are your thoughts on a market design that is structured so that nuclear and coal plants do not have a realistic opportunity for new entry, but do have opportunities to permanently exit during periods of low natural gas prices? Should

markets be designed to eventually "ratchet" out all nuclear and coal, so that the natural gas industry ultimately gains a virtual monopoly on fuel supply to the electricity markets?

Answer: Efficient entry and exit price signals are a key element of well-functioning markets. All technologies, regardless of fuel-type, should be able to compete on a level playing field to provide energy, ancillary services, and capacity, where they are technically capable of doing so. New nuclear and coal plants have an opportunity to compete against existing resources and other new resources to enter the market and provide wholesale services. Today, those wholesale services are designed to meet identified bulk power system needs. As I noted in my written testimony, the Commission's market rules should evolve as needed to address the bulk power system's continued reliability and resilience given changes in the way electricity is generated, procured and used. To that end, the Commission initiated a new proceeding to further explore resilience issues. I expect that the Commission will review the additional material and promptly decide whether additional Commission action is warranted to address grid resilience.

Questions from Ranking Member Maria Cantwell

Questions: On January 12, Commissioner Chatterjee filed a notice of an *ex parte* communication with an attorney for FirstEnergy. This notice indicated that in a phone call with Commissioner Chatterjee, the attorney expressed his concern about a forthcoming order that was adverse to his client's interests and his preference for the Commission to set the issue for hearing instead. As you and I discussed during the Committee hearing on January 23, I find this incident troubling.

Do you plan to investigate whether and how nonpublic information may have been shared with this attorney or others before the Commission's final order in docket no. EC17-88-000?

What other steps, if any, do you plan to take to avoid a potential recurrence of nonpublic information being shared with members of the public?

Answer: FERC's independence, impartiality and integrity are essential to the Commission and its proper functioning. These principles include assurance of the protection of non-public information and our decisionmaking processes. The Commission's regulations prohibiting off-the-record (ex parte) communications in contested proceedings ensure that those outside the Commission do not have preferential access to Commission decisionmakers or to non-public information in such proceedings. I take those regulations seriously, as do my fellow Commissioners and the Commission's staff. Following the issuance of the January 12 ex parte notice you reference, I directed the Commission's General Counsel to confer with our Designated Agency Ethics Official to review the content and procedural requirements of our ethics training, which already is mandatory for current employees on an annual basis and for new employees as they are hired, to confirm the thoroughness of our coverage of these important subjects.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Kevin McIntyre

Question from Senator Debbie Stabenow

Question: In Michigan, more than 300,000 households use propane as a primary heating fuel, more than any other state in the country. During the polar vortex of 2014, many of these householders experienced significant price spikes in propane costs. In some cases, prices for propane more than doubled.

Could you tell me what FERC and the Department of Energy can do – in partnership with MISO – to ensure suppliers secure more propane before winter? It is my understanding that ISO New England instituted similar actions following the 2014 polar vortex.

Answer: FERC has no direct jurisdiction over the price of propane. The Interstate Commerce Act (ICA) does provide the Commission with jurisdiction over the rates, terms and conditions of tariffs pursuant to which FERC-jurisdictional oil pipelines ship products such as propane, but we have no role in setting prices in the propane commodity market. We stay apprised of propane supply issues primarily through regular contact with governmental entities at the state and federal level who are directly involved with issues of propane supply and demand. Consistent with Section 15(13) under the ICA, pipelines are not permitted to disclose to the Commission product shipments, including when and where propane is shipped. The Commission's role in 2014, after an emergency propane shortage was brought to our attention, was limited to using emergency powers under the ICA to direct a single pipeline to prioritize propane transportation service for approximately two weeks. The Commission's jurisdiction does not empower it to mandate that propane suppliers secure any particular propane volume.

Prior to the 2014 Polar Vortex, the Commission accepted ISO New England Inc.'s 2013-2014 Winter Reliability Program, which paid selected oil and dual-fuel generators to fill their oil tanks for the winter period, paid selected dual-fuel generators to successfully demonstrate their fuel-switching capability prior to the winter, and procured additional demand response service. However, because propane is not used as a fuel source for electric generators to provide wholesale services, the Winter Reliability Program did not extend to measures intended to secure sufficient propane supplies. The Midcontinent Independent System Operator, Inc. (MISO) monitors the status of natural gas pipelines related to generator availability, but it does not monitor the status of propane availability, as such availability is not related to the operation of the MISO system.

Questions from Senator Joe Manchin III

Question 1: In 2014, Congress called for an independent assessment and a comprehensive study on the resilience and reliability of the electric transmission and distribution system. The National Academy of Science published its report on Enhancing the Resilience of the Electric System in 2017. The Report contains specific recommendations directed to DOE, including a recommendation that DOE should partner directly with the North American Electric Reliability

Corporation (NERC) to implement resilience metrics in the utility setting. Further, it's my understanding that NERC has established standards for grid reliability but not for grid resilience.

To your knowledge, has an independent study ever been undertaken to evaluate individual generation resources based on a comprehensive set of resilience factors including geography, weather, transmission infrastructure, and ancillary capabilities?

Answer: To my knowledge, no such comprehensive resilience study has been performed. However, NERC has performed event analysis for extreme seasonal weather such as its "Polar Vortex Review" in September 2014. Regional transmission organizations and independent system operators (RTOs/ISOs) also perform various transmission and ancillary service planning and operations studies, as well as studies of seasonal weather and other extreme events. It is my hope that the Commission's pending proceeding on the resilience of our grid will elicit studies by RTOs/ISOs on the factors you cite.

Question 2: Since there are no standards for resilience, would you support having NERC develop resilience standards? How long do you think that would take?

Answer: While resilience is not covered explicitly by the existing reliability standards, NERC has indicated that "resilience is reflected throughout NERC's programs.... NERC has a family of emergency preparedness and operations standards covering such topics as blackstart capability, system restoration coordination, and geomagnetic disturbance operations."

As noted in the Commission's January 8 order on the Department of Energy (DOE) Proposed Rule and initiating new proceeding in Docket No. AD18-7-000 to address resilience issues, FERC's markets, transmission planning rules, and reliability standards should evolve as needed to address the bulk power system's continued reliability and resilience. Resilience of the bulk power system will remain a priority of the Commission, and we expect to review submitted material and promptly decide whether further Commission action on this issue is warranted. If the Commission determines that it is appropriate to pursue formal reliability standards as part of that action, then, based on the Commission's past experience in such situations, I believe that it could take anywhere from six months to up to two years to develop additional standards, although a proceeding of this complexity would likely trend toward the longer period.

Question 3: If DOE and NERC determined that certain generation resources were critical to system resilience, would you agree that those resources should be compensated for the resilience attributes they provide?

Answer: The Federal Power Act requires that the Commission give due weight to the technical expertise of NERC with respect to the content of proposed reliability standards or modifications to such standards, and the Commission would certainly consider the views of NERC on issues regarding electric system resilience. Similarly, the Commission would welcome input from DOE. The Commission also would consider carefully the views of RTOs/ISOs, generators,

customers, consumers, and other stakeholders on resilience attributes. Ultimately, any requirement of compensation must rest on a Commission determination that such compensation is just and reasonable.

Question 4: What specifically can we be doing here in Congress to ensure natural gas does not experience delivery problems and price spikes?

Answer: To the extent there are problems regarding natural gas delivery and price spikes, most appear to be limited to certain regions. Price spikes in the natural gas market are largely driven by economic fundamentals – high demand and limited supply into demand centers. Actions that encourage new pipeline capacity into constrained markets could mitigate natural gas commodity price spikes.

Congressional action addressing pipeline infrastructure may also help to address delivery problems and price spikes. As I stated at my September 7, 2017 Confirmation Hearing, efficient use of existing pipeline capacity and investment in new pipelines carries the potential to facilitate other investment and economic growth in the energy sector, benefiting the public.

Question 5: How much natural gas is supplied to electricity generators under interruptible vs firm gas delivery contracts?

Answer: Electric generators procure natural gas under a variety of arrangements, including firm transportation, interruptible transportation, and delivered product from marketers. Data obtained by the Commission via submittals of its Form No. 549D on gas transportation and storage arrangements show that electric generators held about 15 billion cubic feet per day (Bcf/d) of firm transportation capacity on interstate natural gas pipelines in 2016, the latest year for which we have such data. This amounts to approximately 55 percent of electric generators' average daily consumption in 2016 (27.4 Bcf/d). This figure does not account for delivery arrangements made through marketers who may also hold firm transportation. According to the Energy Information Administration's Form No. 923, in 2016, gas-fired generators reported that approximately 79 percent of either natural gas transportation or supply contracts were firm, with 21 percent reported as interruptible. Given the different public data sources available, it is reasonable to infer that the amount of natural gas being supplied under firm gas delivery contracts is somewhere in the range of 55 to 79 percent.

Question 6: Would the grid be more resilient if gas was delivered to electricity generators via firm contract?

Answer: It is difficult to determine the extent to which increased use of firm natural gas pipeline transportation contracting would result in improving grid resilience in a cost-effective manner. Delivery of natural gas to electric generators via firm contract may be an economic tool for improving grid resilience, in addition to addressing pipeline infrastructure needs and efficiently using existing pipeline capacity. The impacts of certain emergency events, such as

those that trigger force majeure, would not be addressed by an increased use of firm contracting. The Commission has initiated a new proceeding in Docket No. AD18-7-000 to further explore resilience issues. The goals of this proceeding are to develop a common understanding among the Commission, industry and others of what resilience of the bulk power system means and requires; to understand how each regional transmission organization and independent system operator assesses resilience in its geographic footprint; and to use this information to evaluate whether additional Commission action regarding resilience is appropriate.

Question 7: You provided us with an overview of the constraint issues that natural gas pipelines experienced during the cold snap. In West Virginia, there are several major pipelines being developed - including the Mountain Valley Pipeline and the Atlantic Coast Pipeline - that aim to reduce natural gas constraint and expand the markets for our region's abundant natural gas. In the Northwest, some pipeline customers were constrained making it difficult for some natural gas to make it to demand centers – a major reason for some of the very large price spikes we saw. You noted that there were record high spot prices including $123 in New York City, $120 in Philadelphia and over $50 in the Midwest. You noted there were two trades at $175 in New York. These wholesale energy prices are VERY high. You mentioned that last winter these prices ranged from the low $30s to the high $40s. Fairly soon after you assumed the chairmanship of FERC, you announced that the Commission would conduct a review of its 1999 policy statement on certification of interstate natural gas pipelines.

Do you expect this exercise will help ensure that the pipeline permitting process more readily addresses these areas of high demand and high constraint?

Answer: In announcing the Commission's plans to review the Policy Statement on Certification of New Interstate Natural Gas Pipeline Facilities (issued in 1999), I stated that I am approaching this topic with an open mind and want the staff and the Commission to take a fresh look at all aspects of the issue. Clearly, the industry has changed significantly since 1999, and we should constantly be examining our various processes and procedures to see if we can do better. The Commission's policy for certification of natural gas pipelines covers a broad array of concerns, including fostering competitive markets, protecting captive customers, and avoiding unnecessary environmental and community impacts. At the same time, the Commission strives to serve increasing demands for natural gas and to ensure that appropriate incentives are in place for the optimal level of construction and efficient customer choices. The Commission will invite the views of all stakeholders to ensure that it accurately and efficiently assesses the pipeline applications it receives.

Questions from Senator Martin Heinrich

Question 1: Chairman McIntyre, what is the status and likely timeline to complete the commission's pending NOPR on energy storage and distributed energy resource aggregation (RM16-23-000)? Does FERC have the technical information it needs to complete the pending rule-making on storage's participation in competitive markets?

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Kevin McIntyre

Answer: The Commission issued a Final Rule to remove barriers to the participation of electric storage resources in the capacity, energy, and ancillary service markets operated by Regional Transmission Organizations (RTO) and Independent System Operators (ISO) on February 15, 2018. The Commission concurrently announced that, while it continues to believe that removing barriers to distributed energy resource aggregations in the RTO/ISO markets is important, more information is needed with respect to those proposals. Therefore, Commission staff will hold a technical conference on April 10-11, 2018 to gather additional information to help the Commission determine what action to take on the distributed energy resource aggregation reforms.

Question 2: Chairman McIntyre, as Mr. Ott of PJM notes in his prepared testimony, the electric utility sector is the only critical infrastructure that has mandatory and enforceable standards for physical and cybersecurity. Given the current role of natural gas in power generation, what are your thoughts on the adequacy of current measures to protect interstate gas pipelines used for power generation?

Answer: The Commission currently possesses rate-making authority and certificate authority for interstate natural gas pipelines while the Transportation Security Administration (TSA) has primary authority over pipeline security. Congress and the TSA are in the best position to evaluate the adequacy of TSA's current natural gas pipeline security authority to determine whether natural gas pipelines should be subject to additional or mandatory security measures or standards.

Question 3: Investment in new power transmission lines can also help improve grid reliability and resilience. What are your thoughts on the commission's current approach to encouraging investment in transmission capacity to improve reliability in bulk-power markets?
Do you think the commission's Order 1000 has been effective in supporting regional planning and encouraging investment in new transmission?

Answer: Order No. 1000, implemented in 2011, brought marked change to the process by which facilities intended to address our nation's electric transmission needs are planned. Order No. 1000 implemented detailed requirements for organized regional transmission planning and interregional coordination, established a framework to address critical questions regarding how to allocate the costs of new transmission infrastructure projects selected for development through the transmission planning process, and eliminated presumptive development rights previously held by incumbent transmission providers (referred to as the federal "right of first refusal"). Recognizing that many in the industry expected Order No. 1000 to boost competitive investment in new transmission infrastructure, I am aware of criticisms that perhaps fewer new transmission projects have come to fruition than anticipated. The Commission has opened a proceeding, including holding a technical conference and inviting comments, to further examine issues related to regional transmission planning and competitive transmission development. I expect that the record in that proceeding will inform the need for further Commission action.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Kevin McIntyre

Question from Senator Mazie K. Hirono

Question: I, along with other members of the Armed Services Committee, have worked to focus the Department of Defense on improving the energy resilience of its installations. As the Massachusetts Institute of Technology's Lincoln Laboratory has concluded, the DOD can be important early adopter of solutions for the domestic grid that increase mission effectiveness and resilience. For example, Hawaii's Joint Base Pearl Harbor Hickam has been a leader in testing microgrid technologies and the integration of renewable power sources. I understand that FERC's new proceeding on resilience is focused on the input of regional transmission organizations and independent system operators, but do you plan to seek input from the Department of Defense for its views on resilience?

Answer: Yes, I will ensure that FERC staff working on this matter will reach out to the Department of Defense for its input. I am interested in hearing all views on this important issue.

Question from Senator Tina Smith

Question: During the polar vortex in 2014, power plants in Minnesota had dangerously low coal stockpiles due to rail delivery constraints. As a result, a number of coal power plants were idled. While this did not lead to any outages, it did drive up power prices in the region. What is the Federal Energy Regulatory Commission doing to make sure that similar issues do not arise in the future?

Answer: As I noted in my testimony, I am mindful that higher wholesale energy prices are ultimately borne by retail customers. Nonetheless, prices that accurately reflect fuel costs and system conditions, including instances when a meaningful amount of generation is unavailable, send signals that drive operational and investment decisions for both resources and consumers. In the case of the coal power plant outages you reference, I expect that accurate price signals will create incentives for generation owners to take appropriate action to mitigate the potential for a similar occurrence in the future.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Bruce Walker

QUESTIONS FROM CHAIRMAN MURKOWSKI

Q1. Has DOE made arrangement to provide the RTOs/ISOs and FERC with credible threat assessments to help analyze resilience and reliability issues? Will staff at DOE commit to a series of meetings between its subject matter experts and the offices of Reliability and Energy Infrastructure Security at FERC? Will staff at DOE commit to a series of meetings between its subject matter experts and the staff at NERC and the RTOs/ISOs?

A1. As a member of the NSC and Sector Specific Agency for the energy sector on cybersecurity, the Department of Energy (DOE) is the lead agency to assess and analyze credible threats to reliability and resilience issues facing the security of our Nation's grid. Much of this involves classified information. However, as a general practice we typically provide unclassified, valuable information, including threat information, to Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC), most frequently through NERC in its role managing the Electricity Subsector Information Sharing and Analysis Center (E-ISAC). The E-ISAC then shares that information through its established channels to the RTOs and ISOs. However, due to the constant nature of threats to our energy systems, we recently offered "read-ins" to all FERC commissioners.

Q2. The New England ISO recently issued a report about its "Operational Fuel-Security" last week that predicts, in one scenario, a likelihood of rolling black outs and season-long outages from the loss of nuclear generation. I presume this report is getting a lot of attention at DOE—does DOE have the resources to assist and evaluate these kind of assessments? Given that our nation can hardly tolerate this sort of vulnerability on its electric grid, will DOE be communicating its concerns to FERC? When and how?

A2. The recent New England ISO report has received much attention within DOE. The Department utilizes its congressionally designated authority to evaluate assessments like the New England ISO report and to provide additional analysis where appropriate.

The resilience and reliability of the energy sector are top priorities of Secretary Perry and a major focus of DOE. Taking action to recognize the essential reliability services that a strategically diversified generation portfolio provide, is essential in guaranteeing the

resilience of the electric grid. The grid's integrity is maintained by an abundant and diverse supply of fuel sources today, especially with onsite fuel capacity. The New England ISO report highlights the issue stating, "In the coming years as more oil, coal, and nuclear leave the system, keeping the lights on in New England will become an even more tenuous proposition."

DOE has taken the important step of beginning this discussion by submitting the Notice of Proposed Rulemaking for the Grid Resiliency Pricing Rule to FERC last fall. In response, FERC opened a new grid resiliency docket, ordering the RTOs and ISOs to submit reports on grid resiliency threats and market mechanisms to address those threats. DOE will continue to engage with FERC to ensure that adequate fuel-secure generation is maintained to keep the lights on in New England and across the nation.

Q3. In national defense, we have the nuclear triad, which may be costly, but which ensures that our nation has three diverse approaches to strategic defense. Does the diversity of the grid compare to the nuclear triad in that it may be more costly for our nation to maintain infrastructure on three major fuels, but it's a strategic advantage in the long run? That is, by having three fuels in our markets, we have something of an insurance policy against price spikes in any one fuel, and we have an insurance policy against failure in one type of fuel supply. What is your assessment on the need for three major sources of fuel?

A3. A reliable, resilient electric grid is powered by an "all of the above" mix of generation resources that, together, help mitigate disruptions and enable rapid response when disruptions occur. The grid's integrity is maintained by an abundant and diverse supply of fuel sources, especially with onsite fuel capability. This assessment was the result of our grid study conducted and issued last year and the premise of our NOPR to FERC proposing action be taken to ensure a diverse source of all fuels in our electricity markets.

Q4. In assessing the organized markets, have you considered the need for both entry and exit in a well-functioning marketplace? Notwithstanding the vital contributions of wind, solar, hydro, oil, and other resources to our markets, what are your thoughts on a market design that is structured so that nuclear and coal plants do not have a realistic opportunity for new entry, but do have opportunities to permanently exit during periods of low natural gas prices? Should markets be designed to eventually "ratchet" out all nuclear

and coal, so that the natural gas industry ultimately gains a virtual monopoly on fuel supply to the electricity markets?

A4. Throughout the 2018 Deep Freeze, the Northeast relied on baseload generation and a diverse energy portfolio. As noted previously, a reliable, resilient electric grid is powered by an "all of the above" mix of generation resources.

The marketplace is driving the design of the system. It is clear we need an in-depth understanding of the resilience of our electricity and related infrastructure in order to know how best to either modify existing market structures or build new resiliency standards into the system.

Coal and oil-fired units have played a significant role during the 2018 Deep Freeze, contributing nearly 15% more at peak to the generation mix in Eastern US ISOs than on an average winter demand day.

- Across the six ISOs, coal provided 55% of the incremental daily generation needed, or 764,000 out of 1,213,000 gigawatt-hours per day (GWh/d)
- Combined, fossil and nuclear energy plants provided 89% of electricity across all the ISOs, with 69% of the total coming from fossil energy plants (nearly all from traditional baseload sources)

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Bruce Walker

QUESTION FROM RANKING MEMBER CANTWELL

Q1. In your testimony you stated that building a resilience model is your top priority for the Office of Electricity Delivery and Energy Reliability. A consensus study report published last year by the National Academies of Sciences, Engineering, and Medicine ("Enhancing the Resilience of the Nation's Electricity System") recommended several new related authorities for the Department of Energy to enhance the grid's resilience. Do you see value in Congress creating additional authority, to the extent it is lacking under existing law, for the Department to carry out the following activities (excerpted from the recommendations collected in Chapter 7 of the Academies' final report)?

- (Overarching Recommendation 4) Oversee development of more reliable inventories of backup power needs and capabilities, including "stress testing" existing supply contracts for equipment and fuel supply.
- (Overarching Recommendation 5) Expand the Department's research, development, and demonstration activities related to grid resilience, including:
  - (Recommendation 4.1) A demonstration grant program for projects to improve regulator and utility confidence for innovative solutions;
  - (Recommendation 4.2) A demonstration program to explore the extent to which distributed energy resources could help prevent large-area outages;
  - (Recommendation 4.6) Research programs focused on the operation of degraded or damaged electricity systems;
  - (Recommendation 5.6) A demonstration program and training facility for future microgrids for operators to gain hands-on experience with islanding, operating, and restoring feeders;
  - (Recommendation 6.12) Development of a utility network simulator for use in cyber configuration and testing; and
  - (Recommendation 4.10) A demonstration program resulting in a prototypical cyber-physical-social control system architecture.
- (Overarching Recommendation 6) Jointly establish with the Department of Homeland Security a "visioning" process to systematically imagine and assess plausible large-area, long-duration grid disruptions that could have major adverse consequences.

A1. The FY 2019 Budget provides sufficient funding for the appropriate prioritized scope of activities for the Office of Electricity Delivery. For recommendation 4, the Department

will work with the Department of Homeland Security (DHS), Federal Emergency Management Administration (FEMA), Electricity Subsector Coordinating Council, and U.S. Army Corps of Engineers (USACE), to evaluate current temporary emergency power needs/requirements, and how to better assist state, local, tribal, and private industry emergency planners maximize their efforts to ensure greater resiliency when addressing their temporary power requirements.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Bruce Walker

QUESTIONS FROM SENATOR STABENOW

Q1. In Michigan, more than 300,000 households use propane as a primary heating fuel, more than any other state in the country. During the polar vortex of 2014, many of these householders experienced significant price spikes in propane costs. In some cases, prices for propane more than doubled.

Could you tell me what FERC and the Department of Energy can do – in partnership with MISO – to ensure suppliers secure more propane before winter? It is my understanding that ISO New England instituted similar actions following the 2014 polar vortex.

A1. Prices and the supply of propane to customers depend on market forces and are not regulated by Federal Energy Regulatory Commission (FERC) or the Department of Energy (DOE). Neither the ISO New England nor the Midcontinent Independent System Operator (MISO) have the jurisdiction to assist in propane residential heating market problems, as both have unrelated missions of operating wholesale electricity markets and assuring the reliability of the wholesale electric grid in their respective regions. To maintain electric grid reliability, ISO New England took steps in 2014, and continues to do so, to assure fuel oil availability for New England-based natural gas and fuel oil electric generators that are essential during cold spells, but not for fuel oil or propane used for residential heating.

As part of lessons learned with 2014's propane shortages, DOE's EIA expanded its State Heating Oil and Propane Program, a cooperative data collection effort between EIA and State Energy Offices that collects weekly residential heating oil and propane prices at a state level from October through March for dissemination to policymakers, industry analysts, and consumers. Associations, including the National Association of State Energy Officials and the National Gas Propane Association, hosted lessons learned meetings to identify steps to prevent shortages from happening in future years. Finally, DOE's OE continues to conduct regional exercises with states on their Energy Assurance Plans and how these plans can best prepare states to respond quickly in a crisis situation, such as the 2014 propane crisis.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Bruce Walker

QUESTIONS FROM SENATOR MANCHIN

Q1. In 2014, Congress called for an independent assessment and a comprehensive study on the resilience and reliability of the electric transmission and distribution system. The National Academy of Science published its report on Enhancing the Resilience of the Electric System in 2017. The Report contains specific recommendations directed to DOE, including a recommendation that DOE should partner directly with the North American Electric Reliability Corporation (NERC) to implement resilience metrics in the utility setting. Further, it's my understanding that NERC has established standards for grid reliability but not for grid resilience.

To your knowledge, has an independent study ever been undertaken to evaluate individual generation resources based on a comprehensive set of resilience factors including geography, weather, transmission infrastructure, and ancillary capabilities?

A1. We do not know of any such study. The closest may be *PJM's Evolving Resource Mix and System Reliability*, PJM Interconnection, March 30, 2017, which contains a table that compares individual generation resources against fuel assurance, flexibility, various ancillary services, and several other reliability and resilience-contributing attributes.[a]

Q2. Since there are no standards for resilience, would you support having NERC develop resilience standards? How long do you think that would take?

A2. Further analysis is needed to determine whether standards for resilience would be beneficial and necessary and if so, what they may look like and how they could be implemented.

Q3. If DOE and NERC determined that certain generation resources were critical to system resilience, would you agree that those resources should be compensated for the resilience attributes they provide?

[a] http://www.pjm.com/-/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: *The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone*
Questions for the Record Submitted to the Honorable Bruce Walker

A3. The Department of Energy (DOE)'s recent *Staff Report on Electric Markets and Reliability* recommended that "Pricing mechanisms or regulations should be fuel and technology neutral and centered on the reliability [or resilience] services provided."[a]

Q4. What specifically can we be doing here in Congress to ensure natural gas does not experience delivery problems and price spikes?

A4. In the Northeast, natural gas transmission constraints have caused price differentials to rise during periods of peak demand, typically during prolonged cold weather events. While in the past few years, construction of natural gas pipelines in other parts of the country have caused natural gas price differentials to decrease in those regions, the Northeast has seen price differentials increase.

Several high-profile pipeline projects proposed in the Northeast have highlighted the different regulatory authorities held by the Federal Energy Regulatory Commission and the states. Congress could, for instance, examine whether the provisions of Section 401 of the Clean Water Act are being implemented consistently by states and in accordance with the intent of Congress.

Q5. How much natural gas is supplied to electricity generators under interruptible vs firm gas delivery contracts?

A5. Background and Sources

- EIA's information on power plants is collected by two surveys, the EIA-923, "Power Plant Operations Report," and the EIA-860, "Annual Electric Generator Report." The data reviewed and presented here are 2016 preliminary information. This is the most recent calendar year for which complete data are available. Although the information is preliminary we do not expect any significant difference from the final 2016 data, which will be available in several weeks.

[a] https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf, page 126

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Bruce Walker

- The information presented is for the Electric Power Sector (EPS). This sector consists of the power plants whose primary business is to generate and sell electricity. We have excluded plants for whom power sales is a secondary function. These are typically industrial co-generators, such as facilities at refineries whose primary purpose is to produce steam for the refining process and generate electricity as a sideline.
- Data is collected from traditional regulated utilities (e.g., Southern Company and Independent Power Producers ("IPP"). It is important to note that the delivered price information collected from the IPPs is business sensitive and must be aggregated in public reports so that the values for any individual plant or company cannot be derived. Although the delivered price data for traditional utilities is public information, the need to protect the data for the IPP subset limits the level of detail EIA can publish.
- The data presented is for the lower 48 states. Transactions in Alaska were excluded as unrepresentative of the major U.S. natural gas market. There is no use of natural gas for power generation in Hawaii.
- A single power plant may have several generating units using different fuels. For example, one unit at a plant can burn coal and a second could burn natural gas. For the purpose of this analysis we categorized a power plant as a natural gas plant if it had at least one generating unit that reported natural gas as its primary fuel.
- Fuel receipts and prices are reported to EIA by the larger power plants that account for the bulk of fuel use for power generation. The many small power plants are not required to report this data.

Natural Gas Pricing, and Firm and Non-Firm Natural Gas

Delivered natural gas prices will generally include a price for the natural gas commodity (supply) and a price for transportation service. For any transaction both or either of these components can be firm or interruptible. The supply is entirely firm only if both the supply and the transportation is firm. The commodity price of the gas, even for multi-

year contracts, will usually be tied to a standard industry price index, such as the price of natural gas at Henry Hub, Louisiana.

In addition to a volumetric charge (i.e., dollars per million Btu (MMBtu)), firm supply or transportation may also include a demand charge (also referred to as a capacity charge or reservation fee). This is a fixed payment, generally monthly, to reserve a block of gas supply or transportation capacity.

The foregoing describes only the basics of natural gas pricing. Many other factors influence the price including fuel quality-related penalties and premiums; balancing charges (related to how much gas a buyer has taken off a pipeline system compared to the quantity of gas the buyer's supplier has injected into the pipeline); litigation settlement charges; prior-period adjustments; and in some cases fees paid to local natural gas distribution companies for final delivery of the gas. There are many other variations. For example, by paying a premium for "no-notice" service a gas buyer can reduce or eliminate balancing charges.

A related factor is the impact of financial hedging arrangements, such as natural gas utures contracts, used to limit price risks. These financial instruments have both a cost and an impact on the final effective price of the gas. EIA directs survey respondents to exclude the cost and price impact of hedging arrangements from reported prices, but the agency cannot ensure that these directions are always followed.

Because of all the factors influencing delivered natural gas prices and how those prices re reported to EIA, any single or small set of transactions may be unrepresentative of the overall market. When using the EIA data the best picture of the overall market comes from examining a large volume of transactions for multiple power plants.

Findings

To address the three questions, natural gas receipts by power plants in 2016 were divided into three categories:

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Bruce Walker

- Firm: Gas supply and transportation were both reported to EIA as firm.
- Mixed: Gas supply or transportation were reported to EIA as firm, but not both.
- Non-firm: Neither gas supply nor transportation were reported to EIA as firm.

The results are shown below in Tables 1 and 2:

- There were a total of 1,362 gas-burning power plants at the end of 2016.
- Of these, 670 were large enough to be required to report gas contract information to EIA. These plants accounted for almost 90% of gas-fired generating capacity.
- Of the 670 reporting plants:
    - 394 used only firm gas supply and transportation (59% of total U.S. gas-burning generating capacity)
    - 111 plants used at least some firm gas supply or transportation (13% of total U.S. gas-burning generating capacity)
    - 165 plants relied entirely on non-firm gas supply and transportation (17% of total U.S. gas-fired generating capacity)
- In 2016, the price difference between firm gas deliveries (supply and transportation were both firm) and non-firm gas deliveries (both supply and transportation were interruptible) was $0.30 per MMBtu. For the plants reporting gas receipts data, 75% of the total volume of gas delivered was entirely firm.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Bruce Walker

Table 1: Number of Natural Gas-Fired Plants and Generating Units, End-of-Year 2016

	Power Plants	Generating Units	Capacity (MW)	Percent of Total Capacity
1. Total number of gas-fired plants and units in the Electric Power Sector at the end of 2016 (Operable plants only, Alaska excluded)	1,362	4,786	435,691	100%
2. Of the total, the number of generating units and plants that reported natural gas receipts to EIA in 2016	670	2,999	389,537	89%
Of the plants reporting receipts:				
Those receiving only firm gas:	394	1,901	256,431	59%
Those Receiving only non-firm gas:	165	640	74,432	17%
Those receiving both firm and non-firm gas:	111	458	58,674	13%

Notes: Preliminary data for generating capacity reported on the EIA-860 survey and receipts reported on the EIA-923 survey. Data is for plants in the Electric Power Sector (excludes industrial and commercial generators). Alaska is excluded. Hawaii does not have gas-fired generators.

Source: Preliminary EIA-923 and EIA-860 data for 2016.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Bruce Walker

Table 2: Weighted-Average Natural Gas Prices Delivered to Gas-Fired Power Plants, 2016

	Price ($ per MMBtu)	Difference from Firm Price ($ per MMBtu)	Reported Volume (Trillions of Btus)	Percent of Total Volume
Average Delivered Price of Firm Gas (supply and transportation are firm)	2.96	0.00	6,559	75%
Average Price of Mixed Gas (supply or transportation are firm, but not both)	2.70	0.26	322	4%
Average Price of Non-Firm Gas (supply and transportation are both interruptible)	2.66	0.30	1,826	21%
Total or Weighted Average	2.89	0.07	8,706	100%

Notes: 2016 preliminary data for receipts reported on the EIA-923 survey for the plants and generating units included in Table 1, line 2. Data is for plants in the Electric Power Sector (excludes industrial and commercial generators). Alaska is excluded. Hawaii does not have gas-fired generators.

Source: Preliminary EIA-923 data for 2016.

Q6. Would the grid be more resilient if gas was delivered to electricity generators via firm contract?

A6. Yes, having contractual guarantees on the delivery of natural gas to an electricity generator leads to greater resilience, other things being equal. The use of firm contracts, or variants thereof, for delivery of natural gas to electric generation, is a common practice in some regions, particularly the Southeast and the West, but also parts of the Midwest, all where electric generation is still owned by vertically-integrated electric utilities. In contrast, for competitive reasons, electric generation owned by independent power

producers, which is common in the New England and PJM (in most of the states PJM serves) electricity markets, do not enter into such contracts.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Bruce Walker

QUESTION FROM SENATOR HIRONO

Q1. The Fourth National Climate Assessment released by 13 federal agencies in November 2017 concluded that human-induced climate change has contributed substantially to an increase in extreme storms. For example, human-induced climate change made the extremely active 2014 Hawaiian hurricane season substantially more likely. Since you were confirmed as Assistant Secretary last October, you have been dealing with the widespread and continuing power outages in Puerto Rico and the Virgin Islands as a result of powerful hurricanes. Do you agree with Ms. Clements that the federal government should support local and state resilience planning and emergency preparedness? If so, do you agree with me that it would be difficult to accomplish that objective while cutting the budget of the Office of Electricity Delivery and Energy Reliability by 42%, as the President proposed last year?

A1. The Department of Energy (DOE) supports local and state resilience planning and emergency preparedness. The Department recognizes that the response to energy sector incidents begins at the state, local, tribal, and territorial (SLTT) levels. As such, DOE routinely engages with state and local emergency management offices and energy assurance officials on a myriad of resilience and energy security initiatives that support their resilience planning efforts.

In February 2016, DOE signed an updated Agreement for Enhanced Federal and State Energy Emergency Coordination, Communications, and Information Sharing with the National Association of State Energy Officials (NASEO), the National Association of Regulatory Utility Commissioners (NARUC), the National Governors Association (NGA), and the National Emergency Management Association (NEMA). The updated agreement lays the groundwork for information sharing amongst SLTT governments around the country to promote energy resilience and accelerated response. As part of this agreement, DOE and state associations provide training and seminars for Energy Assurance Coordinators, and DOE and the states have developed information sharing protocols and processes to streamline response operations, which are tested through drills and exercises.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Bruce Walker

DOE also hosted the Liberty Eclipse Energy Assurance Exercise in December 2016 in Newport, RI, with nearly 100 exercise participants from 11 states, private industry, DHS, FEMA, DOD, DOE, and other interagency partners. During the exercise, participants confronted a fictitious cyber incident that cascaded into the physical sector and discussed the challenges of restoring electrical and fuel systems. The exercise resulted in greater awareness of challenges for cyber incident coordination with states and the need for updating state energy assurance plans. DOE plans to do additional exercises like Liberty Eclipse moving forward.

In 2017, OE worked with NASEO to provide technical assistance to twelve states to update their state energy assurance plans. Later this year DOE will be able to test our plans and information sharing at this year's Clear Path exercise, to be held either in or near Washington, DC, in May. Clear Path VI will build on the successful implementation of the second regionally-focused Clear Path exercise, which occurred during May 2017 and was cited by participants from multiple sectors as crucial to preparing for a nearly-identical real-world event only a few months later: Hurricane Harvey. Clear Path VI will also address the desire to conduct more issue-focused exercises that explore coordination between industry, state, and Federal partners in managing interdependencies within and between infrastructure sectors.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to the Honorable Bruce Walker

QUESTIONS FROM SENATOR SMITH

Q1. Previous extreme weather events such as Hurricanes Sandy and Harvey showed how microgrids are instrumental in keeping critical infrastructure online – and I think they are critical for enhancing overall grid resiliency. A recent report from the National Academy of Sciences calls for the Department of Energy to support demonstration and training facilities for future microgrids that will allow microgrid operators to gain hands-on experience with islanding, operating, and restoring feeders. I think this is an idea worthy of consideration. How do you envision the DOE's role in supporting the deployment of microgrids around the country?

A1. Research activities under the Resilient Distribution Systems program focus on the development of innovative technologies, tools, and techniques to modernize the distribution portion of the electric delivery system. Results from the research in Advanced Distribution Management Systems (ADMS), microgrids, and Dynamic Controls and Communications (DC&C) will enable industry to strengthen the resilience of electrical infrastructure against adverse effects of future extreme weather phenomena and other unforeseen natural and man-made occurrences.

Q2. I understand you have spent a considerable amount of time in Puerto Rico in last few months working to restore the power grid. Do you feel that additional microgrids would have assisted in more quickly restoring power to the island's critical infrastructure?

A2. While microgrids can be helpful in some contexts, it is not clear whether the existence of microgrids prior to the storm would have better enabled the restoration of power. .

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: *The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone*
Questions for the Record Submitted to Mr. Charles Berardesco

Questions from Chairman Lisa Murkowski

Question 1: Your testimony highlights the importance of a diverse and reliable fuel supply. However, you also note that four of NERC's assessment areas are now more than 50 percent reliant on natural gas-fired electric generation to meet their peak electric demand.

a. **How does reliance on a single fuel source like natural gas increase vulnerabilities, particularly during an extreme weather event?**

Reliance on a single fuel source increases reliability risk and specifically the availability of resources, particularly during extreme weather when circumstances could limit or disrupt fuel supply. During the recent cold weather period in New England, for example, natural gas supply became constrained due to high demand for both home heating and power generation. As a result, natural gas prices surged in New England, prompting dual-fuel generators to switch to oil during this period. This dual-fuel capability was critical to reliably serving New England electricity customers during the cold snap. However, back-up fuel inventories are not limitless and typically only last 2 to 3 days. After that time, oil supplies will need to be replenished, presenting some logistical challenges during extreme weather conditions. Furthermore, environmental permits need to be considered as they generally limit oil-burning operation.

b. **How important is fuel security – making sure you have adequate resources available – to a reliable and resilient grid system?**

Fuel security – or fuel assurance – is one critical element of a reliable and resilient system. Reliable operation of the BPS requires a generation resource mix that includes facilities with fuel assurance and low sensitivity to fuel supply disruptions. Fuel diversity is another important dimension. A fuel diverse generation portfolio creates redundancies in available resources and is a means to fuel assurance. Fuel diversity also results in an electric grid that is less susceptible to disturbances and better capable of restoring service quickly after an event on the system.

Question 2: In assessing the long-term reliability of the organized markets, have you considered the need for both entry and exit in a well-functioning marketplace? Notwithstanding the vital contributions of wind, solar, hydro, oil, and other resources to our markets, what are your thoughts on the reliability impacts of a market design that is structured so that nuclear and coal plants do not have a realistic opportunity for new entry, but do have opportunities to permanently exit during periods of low natural gas prices? Would such a market design raise concerns about long-term reliability?

From NERC's perspective, these questions emphasize the need to understand the reliability implications of the changing resource mix, including among regulators and policymakers who

set market design. The market scenario described, whereby coal-fired and nuclear generators could retire and new entry by these generators is unlikely, increases challenges with maintaining fuel assurance.

The BPS resource mix is changing in fundamental ways. As some conventional generation from coal and nuclear retires, variable energy resources – especially wind and solar – are rapidly expanding and capturing a significant share of new capacity additions. The balancing resource tends to be natural gas-fired generation, in which fuel is not maintained on site and is transported "just-in-time." It is essential to understand the implications of these trends in order to maintain reliability under all expected conditions, including those conditions where natural gas facilities are unavailable due to maintenance, interrupted for electric power, or curtailed due to a disruption.

Conventional electric generating units provide frequency, inertia, and voltage support (notably termed by NERC as "essential reliability services") as a function of their large spinning synchronous generators and governor-controls. Power system operators use these essential reliability services to manage reliability under a variety of system conditions. These conventional units also have relatively high availability rates and on-site fuel. Variable energy resources can provide some essential reliability services, although costs and market rules may not fully recognize such capabilities.

In recent reliability assessments and in comments to FERC on the Grid Reliability and Resilience Pricing NOPR (Docket No. RM18-1-000), NERC recommends that policymakers continue to pursue policy initiatives that recognize the reliability attributes of all resources, including the need for and value of essential reliability services and fuel assurance.

Question 3: The New England ISO issued a report about its "Operational Fuel-Security" last week that predicts a likelihood of rolling black outs and season long outages from the loss of nuclear generation in one scenario. What is NERC's role in assessing such work done by an ISO? Is NERC planning to do its own assessment of ISO-New England?

NERC has no formal role in assessing studies performed by regional transmission operators such as ISO New England. NERC does have a statutory role to conduct reliability assessments of the interconnected bulk power system. As part of that process, NERC collects data and information from 21 assessment areas across North America to identify reliability issues and trends. For example, NERC's *Long-Term Reliability Assessment* (LTRA) provides a 10-year forward look for reliability in each of the 21 assessment areas.[1] In the ISO New England area, the 2017 LTRA

[1] *See* 2017 Long-Term Reliability Assessment, NERC, December 2017.

points to a need for adequate fuel availability for generators, especially during winter. This stems from the lack of firm natural gas supply and pipeline transportation contracts.[2]

In 2017, NERC conducted an assessment titled *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System*[3] which included an analysis of a major natural gas disruption in the New England area (among other areas). In the course of conducting the NERC assessment, NERC found that a disruption in the New England area could result in transmission-related deliverability challenges which would need to be evaluated further by the transmission planner (ISO-NE). In parallel, ISO-NE's study included a variety of scenarios under which a natural gas disruption would significantly impact New England's electric reliability. The study concurred and reaffirmed NERC's findings, and concluded, "In almost all future resource combinations, the power system was unable to meet electricity demand and maintain reliability without some degree of emergency actions."[4]

Question from Senator Debbie Stabenow

Question: Mr. Berardesco, according to the Energy Information Administration's 2017 energy outlook, 56 percent of all recoverable U.S. natural gas will be consumed by 2050 as a result of domestic demand and increased LNG exports. If we continue on a path of ever-increasing amounts of exports of U.S. LNG, I am concerned this will harm domestic manufacturers and ratepayers in Michigan and nationwide. In fact, industry analysts have indicated that abundant and affordable natural gas was a catalyst for $160 billion in new manufacturing investments in the U.S. since 2012. In Michigan, this translates into new jobs.

Is NERC looking at how increased LNG exports will affect electricity costs, particularly as more and more power plants are turning to natural gas as a fuel source?

Reliable and secure fuel supply is critical to supporting electric reliability. NERC evaluates natural gas availability as it relates to continued reliable operation of the Bulk Power System (BPS). While NERC is aware of the concern over the economic impact of LNG exports on natural gas markets, fuel costs are not typically evaluated in the normal course of NERC's technical reliability assessments. Our assessments to date have not identified reliability impacts related to LNG exports.

---

[2] *Ibid.*, 49.
[3] *See* Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System, NERC, November 2017.
[4] *See* Operational Fuel-Security Analysis, ISO-New England, January 2017, page 8.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: *The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone*
Questions for the Record Submitted to Mr. Charles Berardesco

Questions from Senator Joe Manchin III

Question 1: In 2014, Congress called for an independent assessment and a comprehensive study on the resilience and reliability of the electric transmission and distribution system. The National Academy of Science published its report on Enhancing the Resilience of the Electric System in 2017. The Report contains specific recommendations directed to DOE, including a recommendation that DOE should partner directly with the North American Electric Reliability Corporation (NERC) to implement resilience metrics in the utility setting. Further, it's my understanding that NERC has established standards for grid reliability but not for grid resilience.

To your knowledge, has an independent study ever been undertaken to evaluate individual generation resources based on a comprehensive set of resilience factors including geography, weather, transmission infrastructure, and ancillary capabilities?

In August 2017, DOE published the "Staff Report to the Secretary on Electricity Markets and Reliability." This report provides an assessment of the reliability and resilience of the electric grid and an overview of the evolution of electricity markets. In conducting this assessment, the report examines retirements of coal, nuclear, natural gas, and hydropower retirements. And as discussed in question 2 immediately below, NERC routinely evaluates generation resources and their contribution to reliability in our Reliability Assessments.

Question 2: Since there are no standards for resilience, would you support having NERC develop resilience standards? How long do you think that would take?

As an enhanced yardstick of reliability, resilience is reflected in NERC's mission and is expressed in numerous ways through mandatory reliability standards, work products, and continuous activities. Furthering this focus on resilience, NERC's Board of Trustees recently directed the development of a resilience framework with recommendations within NERC's jurisdiction. The framework and recommendations will be considered by the Board later this year.

NERC's mandatory reliability standards incorporate resilience in many ways, supporting such elements as robustness, resourcefulness, rapid recovery, and adaptability. For example, NERC's emergency preparedness and operations standards include planning requirements to operate the system reliably over a broad spectrum of conditions (TPL-001-4). Other examples include operating procedures and mitigation of solar storms (TPL-007-1 and EOP-010-1), blackstart requirements (EOP-005-2), event reporting requirements (EOP-004-3), system restoration coordination (EOP-006-2), and operating plans to mitigate emergencies (EOP-011-1).

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: *The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone*
Questions for the Record Submitted to Mr. Charles Berardesco

NERC's programs and activities recognize the need for resilience efforts to address low probability, but impactful events. For instance, resilience elements are incorporated into NERC's definition of the Adequate Level of Reliability[5] (ALR). ALR is used primarily to guide NERC reliability standards development, and also to assess reliability and identify gaps in data. ALR includes performance objectives addressing low probability disturbances, and coordinated and controlled restoration of the system after major system disturbances that result in blackouts and widespread outages.

Through our reliability assessments, NERC routinely evaluates generation resources and their contributions to reliability.[6] Individual generation unit data is submitted to NERC each year, and an assessment is performed to understand the aggregate impacts to the bulk power system as a result of new and retiring generation resources. NERC evaluates 21 different assessment areas across North America for resource and transmission adequacy. NERC measures the contribution of essential reliability services to actual reliability needs including system inertial response, frequency response, voltage and reactive support, and ramping capability. NERC routinely performs scenario and probabilistic analysis measuring the impact of extreme events, such as the disruption of major natural gas facilities, lower-than-expected variable energy contributions, and high-than-expected electricity demand due to extreme summer or winter conditions. NERC also published a report on severe impact resilience and has collaborated with FERC and regional entities on industry response and recovery plans.

As mentioned above, NERC's Board of Trustees recently requested that the Reliability Issues Steering Committee, an advisory committee that reports directly to the Board, provide a resilience framework for consideration by the Board. The elements of the proposed framework include:

1. Development of a common understanding and definition of the key elements of BPS resilience;
2. Understanding of how these key elements fit into the existing ERO framework; and
3. Evaluation of whether there is a need to undertake additional steps within the ERO framework to address these key elements of BPS resilience beyond what is already in place and underway in connection with ongoing ERO Enterprise operations, including work being undertaken by each of the NERC standing committees.

The Board has asked the RISC committee to continue moving forward on a resilience framework and present recommendations at the May 2018 meeting. In addition, NERC continues to monitor FERC's new proceeding concerning grid resilience in regional transmission organizations and independent system operators (Docket No. AD18-7-000).

---

[5] *See* Definition: Adequate Level of Reliability for the Bulk Electric System.
[6] *See* 2017 Long-Term Reliability Assessment, NERC, December 2017, *and* State of Reliability 2017, NERC, June 2017.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: *The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone*
Questions for the Record Submitted to Mr. Charles Berardesco

Question 3: If DOE and NERC determined that certain generation resources were critical to system resilience, would you agree that those resources should be compensated for the resilience attributes they provide?

Recognizing the reliability benefits provided by all generation should help ensure that the generation resource mix continues to evolve in a manner that avoids creating risk to reliability of the BPS. In comments submitted to FERC on the Grid Reliability and Resilience Pricing NOPR (Docket No. RM18-1-000), NERC recommends that DOE and FERC continue to pursue policies and market rules supporting reliability and resilience, consistent with their respective authorities.

Question from Senator Catherine Cortez Masto

Question 1: During questioning, Senator Cortez Masto noted winter weather preparedness initiatives discussed in Mr. Berardesco's testimony and asked about NERC and industry activities supporting preparedness for extreme hot weather. Mr. Berardesco stated he would provide this information in writing, which appears below.

From a generation perspective, impacts of extreme and prolonged hot weather include derating generator capabilities due to high temperatures affecting unit cooling performance needed for optimal power production. Generators located in warmer climates often remove some of the preparation performed for cold weather performance, as these cold weather preparations can affect cooling performance (e.g., exterior insulation, wind breaks, heaters, etc.). Water levels from exterior sources like cooling ponds are also monitored as lower summer water levels as well as higher water temperatures can effect generator cooling performance. Some generation plants have environmental limits on cooling ponds or other open water sources (e.g., lakes, rivers, and streams) which require the units to be forced offline if these limits are reached.

Much like winter preparedness, generators and transmission operators undertake initiatives to anticipate extreme hot weather contingencies commonly experienced during the summer months. For example, entities perform inspections and seasonal maintenance on equipment, clean radiators, check cooling systems, add cooling equipment, and test emergency operating procedures. They also conduct system operator seminars, black start drills, review summer load forecasts, equipment and line upgrades in preparation for increased load in accordance with planning studies.

Each year, NERC performs a Summer Reliability Assessment (SRA) to identify, assess, and report details about the reliability of the North American BPS and to make recommendations as

necessary. The SRA identifies potential summer resource deficiencies and operating reliability concerns, determines peak electricity demand and supply changes, and highlights unique regional challenges.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: *The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone*
Questions for the Record Submitted to Ms. Allison Clements

Responses in bold font

Questions from Chairman Lisa Murkowski

Question 1: You testified that regional reliability standards, practices and protocols should "not discriminate against the ability of renewable energy and distributed energy resources to contribute and be compensated for their full reliability value. To do otherwise not only risks violating the Federal Power Act but leaves value and customer benefits unrealized."

a. Please specify the entire "reliability value" for wind and solar resources in New England and PJM over the past few weeks, as well as distributed energy resources.

Wind and solar can contribute energy, frequency response, reactive support, and ramping and balancing, which are the Essential Reliability Services defined by The North American Electric Reliability Corporation (NERC). No resource can provide all of these services at all times. A well-functioning market allows all resources to contribute what they can when they are available. The point I intended to make in my testimony was that if utility-scale wind or solar power, or distributed energy resources, are prohibited from or limited in their provision of energy and grid services, then their full contribution to system reliability is not recognized or valued.

Specific to the bomb cyclone event, as noted in response to Question 2 below, wind energy output in particular performed well above average and many times greater than the grid operator planned and compensated for (as capacity) during the bomb cyclone's high demand periods, contributing to the avoidance of reliability issues. High levels of wind output helped to compensate for unexpected outages by other types of resources, with PJM noting that large numbers of coal and gas generators experienced unexpected outages during the event.[1] As noted next in Question (1)(b), existing capacity and to a lesser extent ancillary service markets undervalue the reliability contributions of wind power during the bomb cyclone.

b. Do you believe these resources are not being fully compensated for their reliability value?

Yes, they are not being fully compensated for their reliability value. Wind and solar generators are capable of "contributing to capacity and resource adequacy, maintaining local voltage and frequency performance, minimizing grid disturbances, providing grid balancing services, and creating a more flexible and diverse generation fleet."[2] Distributed

[1] *PJM Cold Snap Performance Dec. 28, 2017 to Jan. 7, 2018* at 16 (Feb. 28, 2018), http://www.pjm.com/-/media/library/reports-notices/weather-related/20180226-january-2018-cold-weather-event-report.ashx.
[2] G. Van Horn, P. Allen, K. Voellmann, M.J. Bradley & Associates, *Powering into the Future: Renewable Energy & Grid Reliability* (Feb. 15, 2017), https://www.mjbradley.com/reports/powering-future-renewable-energy-grid-reliability.

energy resources, similarly, can provide the fast responsiveness necessary to support a flexible and dynamic grid. It is worth reiterating that there are several aspects of system reliability. In my testimony, I meant that the transmission system requires certain types of grid services to operate reliably. Renewable energy resources and distributed energy resources can be undercompensated for their contributions to grid reliability based on existing market rules and the failure to evolve compensated grid services to support the country's rapidly changing resource mix.

First, as relates to the provision of existing energy, capacity and ancillary market (and non-market) services, some rules effectively prohibit participation by renewable energy resources and distributed energy resources or undervalue their contributions. Examples include: (1) PJM's capacity performance rules that make it difficult if not impossible for wind and solar resources and many demand response resources to provide capacity in line with their seasonal capabilities; (2) ISO-NE's recent 'CASPR' proposal, which would impose a minimum offer floor price on capacity market bids that remove renewable energy's zero marginal cost advantage and risk failure to clear renewables, thereby not acknowledging the capacity contributions they do in fact provide; (3) PJM's energy and capacity market rules that require distributed energy resources, including distribution level storage, to participate as either generation or demand response, the processes for which are each time consuming and only capture partial value that the distributed energy resources can provide, resulting in low participation by these resources; and (4) capacity factor determinations for wind and solar power that fail to account for seasonal variations or actual performance.

The example of PJM's capacity performance rules is instructive. PJM's revised capacity market rules focus on annual peak demand periods, which on a summer-peaking system like PJM prioritizes summer performance over winter performance. This penalizes resources like wind energy that have high value during winter periods, as demonstrated in the bomb cyclone and polar vortex wind output data discussed below. This systematically undervalues the contributions of renewable resources in particular, but also disadvantages many types of winter demand response resources that could make valuable contributions during winter peak periods.

To participate in PJM's capacity market, renewable resources are often forced to pair with other resources to avoid strict penalties that can be imposed for not meeting capacity performance obligations in all periods of the year. This inefficient pairing requirement harms wind, solar and demand response and highlights the failure to compensate resources for their contributions. PJM itself is responsible for coordinated dispatch throughout the year, which involves pairing changing sets of resources on the power system all the time. The fact then, that renewable resources must enter into contractual pairing arrangements to receive any value and are still typically only compensated at a fraction of their true value, indicates that the capacity market is failing to properly compensate and incentivize these resources.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: *The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone*
Questions for the Record Submitted to Ms. Allison Clements

PJM's capacity performance and other prohibitions and limitations derive from a set of market rules developed more than two decades ago, before hydraulic fracturing changed the game with abundant and low-cost natural gas, and before technology, political and market forces facilitated an exponential increase in renewable energy development. In some cases, market rules are simply outdated. In many cases (arguably including PJM's capacity performance reform), however, incumbent generating resources that are comparatively uneconomic to operate are fighting to impose rules that create value streams for certain resource types (e.g., coal and nuclear) while penalizing or harming the economics of lower marginal cost resources (e.g., wind, solar, natural gas and some distributed energy resources). In these and other examples, the full contributions of renewable energy resources go uncounted or are undervalued, resulting in less than full payment to the resources themselves and additional costs to customers who effectively pay twice for the procurement of additional (unnecessary) grid services that the renewable resources are already providing.

Second, the characteristics of grid services required to cost-effectively and reliably operate the transmission system are changing as the resource mix changes. The Federal Energy Regulatory Commission (FERC) established the existing slate of ancillary services, which includes generating reserves, in 1996 as part of Order 888, the landmark FERC rule that required all transmission-owning utilities to open their transmission lines to third-party generators. In 1996, the time the nation's generating mix imparted a different set of characteristics and impacts on operation of the transmission grid. As our country's electricity grid has evolved, these services have, largely, not changed to support that evolution.

It is not clear that an entire new set of "resilience standards" or "resilience services" are necessary to support the evolving resource mix. It is, however, important to ensure that the set of market services offered in each of the regions supports the grid's evolution to a flexible, fast responding and dynamic grid that is both reliable and resilient in the face of policies and market forces driving a new resource mix.[3]

b. To what potential Federal Power Act violation are you referring to?

The Federal Power Act requires FERC to ensure that the rates for wholesale sales of electricity are "just and reasonable" and not unduly discriminatory.[4] If rules are in place that prohibit or limit some given resource types from providing energy, capacity or ancillary services – resource types that may provide the service more cheaply and therefore reduce market clearing prices – then it is impossible to ensure wholesale rates are just and reasonable and satisfy the Federal Power Act. It is also impossible to ensure that wholesale

[3] R. Orvis and S. Aggarwal, *A Roadmap for Finding Flexibility in Wholesale Markets* (Oct. 2017), http://energyinnovation.org/wp-content/uploads/2017/10/A-Roadmap-For-Finding-Flexibility-In-Wholesale-Power-Markets.pdf.
[4] 16 U.S.C. §§ 824d, 824e.

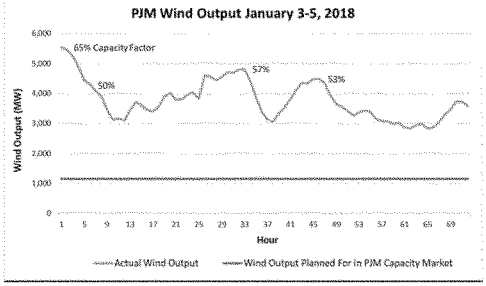
electricity sales are not unduly discriminatory if certain resource types are barred from providing them. The Supreme Court was clear about this FPA obligation in FERC v. Electric Power Supply Association.[5]

In addition, the failure to ensure that available resource adequacy and other ancillary services most cost-effectively support the changing resource mix, which includes high penetrations of variable renewable energy resources may mean inefficient and more expensive use of available grid services, again likely implicating the Federal Power Act's just and reasonable requirements.

Question 2: You note that "the extreme cold and bomb cyclone affirmed the wind power's role as a critical cold-weather reliability resource." While that news is certainly encouraging,

a. please elaborate with specific data.

"During the most challenging periods of the Bomb Cyclone, in PJM wind output was more than 40 percent above average, while in New England wind output was more than twice its normal level."[6] From January 3 to January 5, 2018, PJM's wind output (the gray line in the chart below) was consistently three to five times more than the level PJM plans for and compensates wind for in its capacity market (the blue line in the chart below).[7]



[5] *FERC v. Electric Power Supply Association*, 136 S. Ct. 760 (2016) ("*FERC v. EPSA*").
[6] M. Goggin, Grid Strategies LLC, *Fossil lab misses mark in cold weather "resilience" report*, http://sustainableferc.org/fossil-lab-misses-mark-in-cold-weather-resilience-report/
[7] The American Wind Energy Association (AWEA) provided this analysis at http://www.aweablog.org/wind-energy-perform-bomb-cyclone/. For purposes of capacity market participation, PJM generally assigns a capacity value to wind of 13% of nameplate capacity, yet during winter high demand periods wind consistently exceeds this level, as shown in the chart.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: *The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone*
Questions for the Record Submitted to Ms. Allison Clements

In New England, ISO-NE reported wind output of more than twice its normal level during some of the most challenging periods on January 5 and 6.[8]

Date	Total New England Generation (GWh)	Wind Output (% Above Average)
1/1/2018	355	71.7%
1/2/2018	381	43.5%
1/3/2018	350	-14.6%
1/4/2018	336	66.2%
1/5/2018	345	127.6%
1/6/2018	360	121.9%
1/7/2018	357	51.1%

In both regions, wind power was able to contribute to avoiding potential transmission system reliability issues by over-performing in the face of unplanned outages by other types of resources. Along with wind's performance during the 2014 polar vortex event and a similar cold snap in Texas in 2011, this data continues to demonstrate that renewable resources regularly over-perform in weather conditions that cause trouble for other resource types.[9] Because wind and solar photovoltaics are not dependent on fuel or cooling water deliveries, they are immune to many disruptions like drought, rail congestion, flooding, and others, that have affected coal, gas, and nuclear power plants.

c. Compared to the capacity of wind that could have theoretically been provided, how much wind was supplied to ISO-NE and PJM during the peaks in the recent cold snap?

All resources experience planned and unplanned outages, as well as changes in output level based on market conditions, that keep their output levels well below 100% of theoretical maximum output. A more relevant metric than theoretical ability is a resource's performance relative to the capacity value or accredited capacity that a grid operator plans for, and in regions with a capacity market, compensates resources for.

---

[8] Data provided at https://www.iso-ne.com/static-assets/documents/2018/01/2018_daygenbyfuel.xlsx, chart from AWEA, http://www.aweablog.org/wind-energy-perform-bomb-cyclone/.

[9] See data available at http://www.ercot.com/content/meetings/board/keydocs/2011/0214/Review_of_February_2,_2011_EEA_Event.pdf and https://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx; the Texas grid operator's statements regarding the relative performance of wind and other resources at https://www.texastribune.org/2011/02/04/an-interview-with-the-ceo-of-the-texas-grid/; and analysis of PJM wind performance during the polar vortex at http://awea.files.cms-plus.com/AWEA%20Cold%20Snap%20Report%20Final%20-%20January%202015.pdf.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: *The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone*
Questions for the Record Submitted to Ms. Allison Clements

As shown in the previous answer, during the bomb cyclone wind output was consistently 3-5 times higher than the capacity value that wind is credited for in the PJM capacity market, which is also the amount PJM uses for its capacity planning processes.

In contrast, PJM data confirm that during the bomb cyclone and polar vortex event, resources of all types, and particularly coal and gas generators, experienced unexpected failures.[10] In many cases these unexpected outage percentages for coal and gas were in the double digits, which while an improvement from the 2014 polar vortex event, is still higher than the amount the grid operator plans for and compensates.[11]

Question 3: You note that ISO-NE and PJM did not rely on demand response participation during the cold weather event but point to the current rules in those organized markets as failing to provide incentives. Please elaborate. What kinds of demand response actions do you believe are less costly than supplying energy during a severe cold weather event? Please provide the data to support your view that such demand response would be less costly (both prior to and after any subsidies are considered).

Demand response resources do participate in capacity markets in PJM and ISO-NE. However, the problem is that these markets do not efficiently compensate and incentivize these resources, particularly for winter peak demand periods, as discussed above related to PJM.

Some demand response resources, like aggregated pool pumps, have more demand to reduce in the summer than the winter. Other demand response resources, like aggregated heating systems, are available only during winter months. PJM's requirement that resources be available year-round has had the impact of reducing demand response resources bidding capacity into the market. Over the last seven years, demand response clearing in PJM's main annual capacity auction has declined by over 6,000 MW. Although phase in of capacity performance requirements is not the only reason for the decline in demand response participation, it is a significant factor in the reduction in demand response participation – capacity performance started to phase in for the 2018/2019 BRA and reached 100 percent capacity performance for the 2020/2021 BRA.[12] The following chart demonstrates the decline in demand response in the last seven years of the main capacity market auctions, or "BRAs":[13]

---

[10] *PJM Cold Snap Performance Dec. 28, 2017 to Jan. 7, 2018* at 15 (Feb. 28, 2018) http://www.pjm.com/-/media/library/reports-notices/weather-related/20180226-january-2018-cold-weather-event-report.ashx.
[11] *PJM Cold Snap Performance Dec. 28, 2017 to Jan. 7, 2018* at 21.
[12] During legal challenges over FERC's Order 745 leading up to the Supreme Court's decision in *FERC v. EPSA*, market uncertainty also contributed to reduced market participation. However, certainty provided by the decision did not lead to a corresponding increase in demand response resources in PJM.
[13] PJM, 2020/2021 RPM Base Residual Auction Results, http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: *The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone*
Questions for the Record Submitted to Ms. Allison Clements

Megawatts of Unforced Capacity Procured by Type from the 2014/2015 BRA to the 2020/2021 BRA

Delivery Year	New Generation	Generation Uprates	Imports	Demand Response	Energy Efficiency
2020/2021	2,389.3	434.5	3,997.2	7,820.4	1,710.2
2019/2020	5,373.6	155.6	3,875.9	10,348.0	1,515.1
2018/2019	2,954.3	587.6	4,687.9	11,084.4	1,246.5
2017/2018	5,927.4	339.9	4,525.5	10,974.8	1,338.9
2016/2017	4,281.6	1,181.3	7,462.7	12,408.1	1,117.3
2015/2016	4,898.9	447.4	3,935.3	14,832.8	922.5
2014/2015	415.5	341.1	3,016.5	14,118.4	822.1

*All MW Values are in UCAP Terms

It is well understood that participation by demand response resources in capacity and energy markets saves customers money. For example, in an analysis by PJM's market monitor of the 2019/2020 BRA (which took place in 2016), the inclusion of demand response and energy efficiency bids in the annual capacity market saved over $2 billion, or 30 percent of the total auction revenues for just one delivery year.[14] These savings do not take into account the MWs of peak power plant supply that are not necessary to build or maintain and pay for because of demand response impact on peak demand. In Texas, demand response, primarily from large industrial customers, efficiently provides many services to ERCOT's grid by curtailing demand in return for compensation.[15] These load resources clearly find their participation to be economically beneficial, as participation is voluntary. Demand response resources generally do not receive federal subsidies other than a guarantee that they can participate in the wholesale markets if they satisfy each market's respective participation requirements.

During specific weather events, demand response resources help to reduce demand and therefore price spikes during peak periods. ISO-NE and PJM, as well as NERC, noted the key role of demand response in avoiding black outs and price spikes during the 2014 polar vortex.[16] Finally, by contributing to avoided black outs during extreme weather events, demand response helps protect against health and safety impacts, as well as productivity costs, that may arise with prolonged outages.

Question 4: Given your testimony that global warming could result in more extreme weather, should ISO New England plan for weather that is less extreme in the future? Or more extreme?

ISO-NE should plan for an increasing number of extreme weather events. The question is what type of infrastructure can most cost-effectively provide the reliability and resilience that the region needs in light of this reality. Although I have concerns that ISO-NE's fuel security study, a draft of which Mr. Van Welie shared as part of his testimony, uses overly

[14] Monitoring Analytics, *Analysis of the 2019/2020 RPM Base Residual Auction* at 9 (Aug. 31, 2016), http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf.
[15] ERCOT, Load Resources, http://www.ercot.com/services/programs/load/laar/index.html.
[16] See e.g., NERC, *Grid Resiliency Demonstrated during January Polar Vortex*, https://www.nerc.com/news/Pages/Grid-Resiliency-Demonstrated-during-January-Polar-Vortex-.aspx.

conservative assumptions related to renewable energy and distributed energy resources, even with conservative assumptions, the analysis resulted in three of the four most reliable scenarios for the mid 2020s in New England being high renewables scenarios.[17]

Questions from Senator Ron Wyden

Questions: Ms. Clements, in September 2017, I introduced three bills (S.1874, S,1875 and S.1876) that would lower the cost of energy storage and promote technologies that would make the grid more flexible, such as demand response. In your testimony, you highlighted the role demand response played during the 2014 Polar Vortex, but you noted that demand response played a lesser role in the recent Bomb Cyclone because of current rules from the PJM and New England grid operators.

In your view, what policies should be enacted to ensure that demand response can contribute to the resiliency of grids during winter storms?

Policies at the utility, state and federal level can ensure that demand response is able to contribute to grid resiliency during winter storm conditions. At the federal level, FERC and Congress can act to make this happen.

First, FERC has the authority, and the obligation, to ensure that demand response resources are able to participate in all wholesale markets for which the resources are technically capable of providing services.

FERC has made some progress on this front. The Commission's recent Order 841, which intends to break down barriers to energy storage participation in wholesale markets, is an important step forward. The Commission's continuing consideration of breaking down barriers to aggregations of distributed energy resources, via a technical conference that will be held April 10-11, 2018, provides the basis for a similar order for distributed energy resource aggregations, which FERC should pursue and finalize.

Concerns around the boundaries between federal and state jurisdiction over demand response and other distributed energy resources continue to play out at FERC and in the states. The U.S. Supreme Court's decision in *FERC v. EPSA* made clear that FERC has authority over these resources when they are participating in wholesale markets, and the states retain traditional authority over these resources participation in distribution system programs via utility programs or state laws and regulations. FERC can continue to demonstrate this cooperative federalism approach in its decisions.

---

[17] ISO-NE, *Analysis of the 2019/2020 RPM* at 33 (Jan. 17, 2018), https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: *The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone*
Questions for the Record Submitted to Ms. Allison Clements

FERC should also consider the need to evolve Order 888's suite of required ancillary services to ensure they are the right set to value the flexibility services needed to ensure resiliency going forward. This is not to say that FERC needs to develop new "resiliency services," as it is not clear this is the case. It is only a suggestion that FERC consider how to ensure grid flexibility going forward.

Congress can support development of FERC-jurisdictional and state-jurisdictional demand response and other distributed energy resources by passing exactly the types of policies contained in your proposed S.1874, S.1875, and S.1876. S.1874 and S.1875, specifically, address the myriad of barriers and interfacing factors that impact distributed energy resource deployment. Policies like S.1876 can bring down energy storage costs faster than individual state efforts (although ongoing state efforts are making significant progress in this regard) and represent a critical step towards the flexible, dynamic and fast-acting grid our citizens, companies and economy deserve. One addition to these policy proposals would be to specifically dedicate funding to addressing the operational issues related to integrating high amounts of these resources onto the electricity grid with the intent of providing both distribution system and transmission system services. Transparency and coordination between distribution utilities and transmission system operators is critical to efficient and effective dispatch of demand response and other distributed energy resources in the manner that most cost-effectively serves grid needs. This necessary transparency and coordination requires continuing development and refinement of accessible technology platforms for which government research and development, as well as deployment, support is critical.

What impact would a higher penetration of demand response and energy storage have on the cost of electricity during a winter storm?

The impact would be very beneficial. Increased availability of demand response and energy storage is proven to reduce customer electricity costs. Electricity market prices for all MWh sold in the wholesale market are set based on the most expensive resource that must operate. During peak winter demand periods this is typically an oil-fired unit or a gas generator using natural gas that is priced many times higher than normal.

By reducing the need for those most expensive resources to operate and conserving scarce electricity (and the fuels used to produce it), demand response lowers the electricity market price for all consumers. Demand response effectively allows customers to determine the value they place on using electricity at that point in time, which is often lower than the price of electricity during peak demand periods. As a result, it is mutually beneficial to the customer and the system for the customer to be paid to reduce their electricity usage.

Demand response and energy storage also provide grid resilience and can reduce costs in many types of severe weather conditions, not just winter storms.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: *The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone*
Questions for the Record Submitted to Ms. Allison Clements

Questions from Senator Joe Manchin III

Question 1: In 2014, Congress called for an independent assessment and a comprehensive study on the resilience and reliability of the electric transmission and distribution system. The National Academy of Science published its report on Enhancing the Resilience of the Electric System in 2017. The Report contains specific recommendations directed to DOE, including a recommendation that DOE should partner directly with the North American Electric Reliability Corporation (NERC) to implement resilience metrics in the utility setting. Further, it's my understanding that NERC has established standards for grid reliability but not for grid resilience.

To your knowledge, has an independent study ever been undertaken to evaluate individual generation resources based on a comprehensive set of resilience factors including geography, weather, transmission infrastructure, and ancillary capabilities?

I had the honor of serving on the National Academies of Sciences (NAS) committee that wrote the *Enhancing the Resilience of the Electric System* report, alongside many impressive engineering and policy experts. The report did make recommendations that DOE partner with NERC to address grid resilience needs. The report recognized resilience as a transmission and distribution system concept, not one that focuses on specific power generation types. While most power outages are caused by distribution line outages, most long-duration, high impact events result from transmission system failures. The report noted that existing NERC reliability standards do provide some resilience value. The report also cautioned that there are significant difficulties in creating cost-effective and non-redundant standards for something as varied as resilience.

To my knowledge, there has not been an independent study of the type you describe. Should one be designed, it is important to keep the definition of resilience in mind. No single generation resource type is individually more resilient than another. FERC has affirmed the NAS report definition of resilience as a systems concept. In its recent establishment of the resilience docket, FERC defined the concept as: "[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."[18] Each generating unit interconnecting to a transmission or distribution line has some impact on system resilience under any set of circumstances, but the individual resilience of any generation source is only one input into a system's ability to recover from a disruptive event.

Question 2: Since there are no standards for resilience, would you support having NERC develop resilience standards? How long do you think that would take?

[18] As FERC noted, this definition is generally supported by previous resilience-focused initiatives, including by the National Academies, the National Infrastructure Advisory Council, Argonne National Laboratory, and the President's Council of Economic Advisers and DOE under the previous Administration.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: *The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone*
Questions for the Record Submitted to Ms. Allison Clements

As noted above and in my testimony, before engaging in a process to develop resilience standards, more work is necessary to determine what transmission infrastructure, operating and communication protocols, and technology already work to support resilience and whether additional metrics are necessary.

NERC's reliability standards already address resilience, as NERC itself recently explained.[19] There may be areas that could be improved such as incorporating High Impact Low Frequency extreme events in transmission planning standards, but in general there is no basis for resilience standards on generation beyond current reliability requirements.

One of the only opportunities that comes to mind would be requiring conventional generators to meet the voltage and frequency disturbance ride-through standards currently imposed on wind plants under FERC Order 661A. Since 2005, this rigorous standard has required wind plants to remain online during frequency and voltage disturbances, which are typically caused by the failure of a large conventional power plant or transmission line. Wind plants are able to provide this service thanks to their sophisticated power electronics and advanced controls, while efforts at NERC to impose a similar requirement on conventional generators under Standard PRC-024 were opposed on the grounds that many conventional generators could not meet that standard. Remaining online and not contributing to a potential cascading outage by not failing during a grid disturbance is a key aspect of resilience, so if there were an area to focus on it would be this. NERC's standards development process typically takes months to years, depending on the standard.

Question 3: If DOE and NERC determined that certain generation resources were critical to system resilience, would you agree that those resources should be compensated for the resilience attributes they provide?

No generator or class of generator is critical to system resilience. The power system is planned such that any individual generator can be lost and reserves are available to activate to back them up.

The Federal Power Act has proven wise, decade after decade, in remaining neutral as to the type of generating resources that make up the country's resource mix. From my perspective, the appropriate way to ensure system resilience is to first determine whether and where there are any gaps in existing reliability standards and planning protocols that implicate transmission system resilience. After that process, any missing grid resilience needs can be defined as necessary grid services, which then any capable generating

[19] P. Kure, *NERC Planning Committee Update* at 57-67 (March 6-7, 2018), https://www.nerc.com/comm/PC/Agenda%20Highlights%20and%20Minutes%202013/Draft_PC_Meeting_Presentations_March_6-7_2018_Jacksonville_FL.pdf.

resources should be able to compete to provide. I have several concerns with coming at the resilience issue from a specific resource-type perspective. First, payments based on generation type run counter to the definition of resilience, which is a distribution and transmission system concept. It is unlikely that any given utility-scale generating resource will be proven critical to resilience in a manner incremental to reliability-related compensation the units are already receiving. Second, technology will change and different types of generating resources will be able to perform differently over time. New technologies may emerge that were not contemplated when determining compensation rules. Locking in specific resource-type compensation ensures policy will not keep pace with technology and will ultimately prove a detriment to customers.

Question from Senator Mazie K. Hirono

Question: As you may know, Hawaii is already getting over 26 percent of its power from renewable resources. You stated in your testimony that renewable energy and distributed energy resources are critical to a reliable grid. Can you elaborate on the benefits that you see from renewable energy for increasing the reliability and resilience of power to serve our homes, schools, hospitals, and businesses?

Hawaii's ongoing work to transform its electricity sector is very impressive and will provide lessons learned for the rest of the country, especially around the effective optimization of distributed energy resources. As noted in the NAS resilience report, grid resilience exists at several levels – interconnection, region, state, utility, and end use. Improving resilience at the distribution and end-use level is critical to protecting people impacted by extreme weather events.

Utility-scale renewable energy and distributed energy resources are key components of this localized reliability and resilience. As noted above, utility-scale wind and solar resources avoid some of the fuel supply vulnerabilities like flooding and delivery failure that other resources face during extreme weather. Distributed energy resources provide the basis for microgrids, which the NAS report also highlights as important components of distribution and end-use resilience.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to Mr. Andrew Ott

Questions from Chairman Lisa Murkowski

Question 1: You sometimes refer to the potential need to take emergency measures during a severe cold weather event, including measures like rolling blackouts, or load shedding. While neither ISO-NE nor PJM needed to shed load in this most recent event, where is the trend going? What happens if we have another such event, or even a colder event, five years from now? What should we be doing now, so that we're ready in five years?

PJM's response focuses on two aspects to this question, namely:

- What mechanisms and checks and balances are in place today to address potential extreme weather events in the near future (i.e., over the next five years)?
- What additional actions are needed to address high impact low frequency events?

Mechanisms and Tools in Place to Address Stressed Conditions on the Grid from Extreme Weather Events – As a Regional Transmission Organization (RTO), PJM integrates its planning, operations and markets all to ensure reliability of the grid in response to extreme weather events and peak load conditions.

Starting with the planning process, PJM conducts a long-range Regional Transmission Expansion Planning (RTEP) process that identifies the changes and additions to the grid that are needed to ensure reliability. This process includes compliance with reliability standards promulgated by NERC and FERC pursuant to Section 215 of the Federal Power Act. The PJM planning process employs a 15-year planning horizon to identify and order major transmission investments and upgrades that will maintain grid reliability and improve economic efficiency. To date, net transmission investments authorized under PJM's Regional Transmission Expansion Plan (RTEP) since 2000 total is approximately $35.4 billion.

On the resource side, it should be noted that although PJM saw about 22,000 MW of coal units retire since 2010, the capacity market attracted more than 37,000 MW of new generation since 2007, of which more than 21,000 MW of new generation was placed in service between 2010 and 2017. This has resulted in a current PJM reserve margin of 29.1 percent, which is well above the targeted reserve margin of 16.6 percent for 2017 and 16.1 percent for 2018. Future capacity Base Residual Auctions through 2021 have yielded almost 50,000 MW of generation capacity additions, of which 80 percent is natural gas.

Since the implementation of the Reliability Pricing Model (RPM), PJM has implemented market rules changes and is currently working on additional changes to ensure system reliability in the future. In the August 2015 RPM capacity auction for the 2018/2019 Delivery Year, PJM implemented a set of market rules called Capacity Performance (CP). These rules were focused on improving resource performance during system emergencies by strengthening the penalty structure for non-performance. These rules were driven by poor generation performance during the 2014 Polar Vortex (22 percent forced outage rate) and have resulted in a material

improvement. In the most recent cold snap between December 2017 and mid-January 2018, the forced outage rate for generation resources dropped to 11–12 percent.

In short, PJM markets, operations and planning and the tariffed rules approved by FERC that govern each of these work together symbiotically to ensure that reliability of the grid is maintained and enhanced.

Additional Actions Needed to Address Potential Future Low Probability But High Impact Events – PJM is focused, as is FERC, on addressing "grid resilience issues," i.e., the ability to plan for, operate through and recover from a low-probability, high-impact event. PJM's efforts in this area range widely. They include efforts to enhance the planning process to address critical infrastructure; the creation of real-time gas pipeline system monitoring by PJM staff (in order to respond to a potential pipeline contingency by triggering additional reserves); and coordination with the U.S. Department of Defense, Argonne National Labs, FEMA and the states to enhance restoration of critical loads on the PJM system.

PJM does not believe that operating outside of the market to preserve a particular class or type of generation is needed at this time for reliability. The markets have been resilient in attracting new investment. In addition, a variety of tools exist as a backstop should specific generation be needed in a particular area.

Finally, there is a legitimate issue for discussion about dependence on one particular fuel. The region is blessed with the availability of multiple pipelines, natural gas storage supplies, rich resources of coal and availability of wind resources. However, in the PJM footprint, we have seen a significant number of new pipelines being developed as the PJM region sits on top of the Marcellus and Utica shale natural gas resources.

The combination of market signals, PJM's geographic location and FERC consideration of the various grid resilience initiatives, which PJM will be detailing in its March 9 comments to FERC, works to keep this region poised to continue to address both extreme weather events and high-impact, low-frequency events.

Question 2: How do options like demand response and energy efficiency fit into these extreme weather events? How much is the grid helped during winter peaks by these options?

In the PJM footprint, demand response (DR) has matured significantly in the last 10 years. It has transitioned from a legacy utility program to a resource that is integrated into the wholesale markets and leveraged to operate the grid. PJM is working to broaden the opportunities for electricity consumers to respond to wholesale prices and grid conditions. The ability to call on demand reductions gives system operators greater flexibility in managing the grid during challenging conditions.
Energy efficiency (EE) is considered a passive resource. It is compensated as a capacity resource based on the average continuous year-round load reduction provided by the EE installation.

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: *The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone*
Questions for the Record Submitted to Mr. Andrew Ott

Prior to the implementation of Capacity Performance (CP), demand response and energy efficiency were permitted to be seasonal resources that only had to perform to their stated capability during the summer period. This was based on the assumption that the primary risk for operational emergencies existed during the summer. The 2014 Polar Vortex changed how PJM perceived this risk and led to the conversion of products like demand response and energy efficiency to annual products as opposed to seasonal ones. This requirement will ensure that these resources are available to perform if PJM needs them during an emergency at any time during the year.

Effective 2018/19, capacity resources that do not alone, meet the requirements of a Capacity Performance product may combine their capabilities and offer as a single Aggregate Resource. This applies to intermittent resources, capacity storage resources, demand resources, energy efficiency resources and environmentally limited resources.

Although DR was only a summer product during the 2014 Polar Vortex, PJM deployed DR resources due to the severe operating conditions, and they provided a measurable benefit.[1] During the most recent cold snap, PJM did not reach severe enough emergency conditions to call on DR.

Approximately 60 MW of economic DR participated during the recent cold weather. It is estimated that approximately 5,400 MW of emergency DR was available during the recent cold weather; however, PJM did not need to utilize this emergency DR to manage the grid due to the significant reduction in generation forced-outage rates.

Question 3: In assessing the organized markets, have you considered the need for both entry and exit in a well-functioning marketplace? Notwithstanding the vital contributions of wind, solar, hydro, oil, and other resources to our markets, what are your thoughts on a market design that is structured so that nuclear and coal plants do not have a realistic opportunity for new entry, but do have opportunities to permanently exit during periods of low natural gas prices? Should markets be designed to eventually "ratchet" out all nuclear and coal, so that the natural gas industry ultimately gains a virtual monopoly on fuel supply to the electricity markets?

The changing resource mix is not unique to PJM. Over the last few years, the NERC Reliability Issues Steering Committee (RISC), as part of the ERO Reliability Risk Priorities RISC recommendations to the NERC Board of Trustees,[2] has identified changing resource mix as a high-priority focus area, assigning it a high risk profile.

[1] http://www.pjm.com/-/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx?la=en
[2] http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Reccommendations_Board_Approved_Nov_2016.pdf

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to Mr. Andrew Ott

PJM's markets are designed not to favor any one resource type over another. They are designed to allow the market signals to decide which resource types can meet system needs at the lowest cost and incentivize those efficient entry and exit decisions. However, giving the growing concern about over-dependency on natural gas, PJM performed a study and published a paper in 2017 titled "PJM's Evolving Resource Mix and System Reliability,"[3] which focused on resource diversity and how it affects reliability. In summary, that study indicated that PJM's generation fleet today is more diverse then it has ever been due to the growth of natural gas and that there is no immediate reliability concern with the current fleet or its foreseeable trajectory.

From PJM's perspective, the new entry prospects of nuclear and coal resources do not appear to be a market design issue, since there are challenges for new coal and nuclear resources in market and non-market areas across the country. These resources require more capital and a longer construction period and are the subject of more regulations (both safety and environmental).

PJM has raised issues associated with the proper setting of energy market clearing prices to ensure that market clearing prices reflect the costs of all resources that are serving demand. PJM has noted that in the recent cold snap, out-of-market uplift payments increased by at least a factor of 10 during the severe cold weather operations which indicates the operating costs of some generation that was needed to meet the electricity demand was not reflected in clearing prices.

Just to be clear, all of the resources that are serving load are compensated, in some cases through out-of-market "uplift" payments. But in some cases, such costs are not properly reflected in locational marginal prices, which could put these resources – and all other resources needed to meet demand – at a disadvantage because market prices are not reflecting the true cost to serve demand.

PJM has proposed energy market price formation reforms to address these issues, and we believe such reforms should be addressed in a timely manner. These reforms include both enhanced reserve pricing and energy price formation reforms. PJM has also flagged this issue for FERC consideration in the context of FERC's energy price formation efforts.

[3] http://www.pjm.com/-/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx?la=en

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to Mr. Andrew Ott

Questions from Senator Mike Lee

Question 1: What impact did the market reforms enacted in the wake of the 2014 polar vortex have on PJM's ability to ensure safe and reliable grid performance during the recent cold weather event?

While improved performance was seen during the most recent cold weather event, it's important to note that neither the temperatures nor customer demand reached the levels experienced in 2014 during the Polar Vortex. During the recent cold weather event, it was not necessary for PJM to invoke a performance assessment interval, a 72-hour maintenance recall or any transient shortage intervals because the system was performing well. However, the system was stressed, and there were some significant indicators of improved performance of generating resources since 2014.

In the August 2015 RPM capacity auction for the 2018/2019 delivery year, PJM implemented a set of market rules called Capacity Performance (CP). These rules were directly focused on improving resource performance during system emergencies by strengthening the penalty structure for non-performance. These rules were driven by poor generation performance during the 2014 Polar Vortex (22 percent forced outage rate) and have resulted in a material improvement. In the most recent cold snap, between December 2017 and mid-January 2018, the forced outage rate for generation resources dropped to 11–12 percent.

In addition to the implementation of CP, several other factors improved performance from the 2014 Polar Vortex. These include enhancements PJM and its member companies have put in place, such as deployment of more efficient generation resources, increased investment in existing resources, improved performance incentives, enhanced winterization measures and increased gas-electric coordination.

Question 2: How many of the coal and nuclear plants that PJM relied on during the recent cold spell are expected to retire over the next five years? How much capacity will those retirements represent?

There are 44 units representing a total of 8,072 MW of generation capacity currently scheduled to deactivate in PJM over the next five years. Of the 44 units scheduled to deactivate, 23 are coal units representing 4,885 MW and two are nuclear units totaling 1,410 MW of capacity. Of the 23 retiring coal units, 16 coal units representing 3,688 MW of capacity operated during a period of the recent cold snap. All of the 1,410 MW of retiring nuclear generation operated during the cold snap; however, one of the retiring nuclear units was on a partial forced outage for the later portion of the cold snap.

PJM analyzed the performance of retiring coal units as compared to non-retiring units during the recent cold snap, using preliminary forced outage data at various snapshots in time across the

cold snap duration that aligned with either high load peaks or a high amount of generator forced outages. The chart below shows that, using the forced outage reduction megawatt amounts as a percentage of both retiring coal installed capacity (ICAP) and non-retiring coal ICAP, non-retiring coal units had a lower percentage of forced outages during the recent cold snap.

Coal Forced Outages as a Percentage of ICAP Categorized by Retiring vs. Non-Retiring Units						
Date	**Jan. 3, 2018 Hour Ending 8**	**Jan. 4, 2018 Hour Ending 19**	**Jan. 5, 2018 Hour Ending 9**	**Jan. 5, 2018 Hour Ending 19**	**Jan. 6, 2018 Hour Ending 9**	**Jan. 7, 2018 Hour Ending 9**
Non-Retiring Coal	11.7%	8.0%	9.1%	8.5%	11.0%	10.7%
Retiring Coal	31.7%	16.0%	20.5%	23.2%	19.9%	19.8%
Forced Outage (All Gen)	8.2%	7.1%	8.6%	8.5%	11.7%	12.1%

PJM maintains an active list of pending generator deactivations on the PJM website[4] and does not see any challenge to reliability or fuel diversity from the announced retirements.

Questions from Senator Joe Manchin III

Question 1: Mr. Ott, I want to thank you for all you have done in working with my office and the Committee in advance of this important hearing. There are 17 PJM coal units – 4,266 MW – that are going to retire during the 2018 through 2020 period. The average age of those retiring units is 43 years and the average size is 249 megawatts. Nine of those units – totaling about 3,600 MW – are large enough that I would think that at least some of these were probably relied on during the "bomb cyclone". I know that on a unit by unit basis you all are still doing some post-event analysis.

Mr. Ott, have you identified which of these units performed during the deep freeze we just experienced?

There are 44 units representing a total of 8,072 MW of generation capacity currently scheduled to deactivate in PJM over the next five years. Of the 44 units scheduled to deactivate, 23 are coal units representing 4,885 MW and two are nuclear units totaling 1,410 MW of capacity. Of the 23 retiring coal units, 16 coal units representing 3,688 MW of capacity operated during a period of the recent cold snap. All of the 1,410 MW of retiring nuclear generation operated during the cold

[4] http://www.pjm.com/~/media/planning/gen-retire/pending-deactivation-requests-xls.ashx?la=en

snap; however, one of the retiring nuclear units was on a partial forced outage for the later portion of the cold snap.

PJM analyzed the performance of retiring coal units as compared to non-retiring units during the recent cold snap, using preliminary forced outage data at various snapshots in time across the cold snap duration that aligned with either high load peaks or a high amount of generator forced outages. The chart below shows that, using the forced outage reduction MW amounts as a percentage of both retiring coal installed capacity (ICAP) and non-retiring coal ICAP, non-retiring coal units had a lower percentage of forced outages during the recent cold snap.

Coal Forced Outages as a Percentage of ICAP Categorized by Retiring vs. Non-Retiring Units						
Date	**Jan. 3, 2018 Hour Ending 8**	**Jan. 4, 2018 Hour Ending 19**	**Jan. 5, 2018 Hour Ending 9**	**Jan. 5, 2018 Hour Ending 19**	**Jan. 6, 2018 Hour Ending 9**	**Jan. 7, 2018 Hour Ending 9**
Non-Retiring Coal	11.7%	8.0%	9.1%	8.5%	11.0%	10.7%
Retiring Coal	31.7%	16.0%	20.5%	23.2%	19.9%	19.8%
Forced Outage (All gen)	8.2%	7.1%	8.6%	8.5%	11.7%	12.1%

PJM maintains an active list of pending generator deactivations on the PJM website[5] and does not see any challenge to reliability or fuel diversity from the announced retirements.

During the bomb cyclone, would electricity prices have been higher without coal and nuclear generation? Do you know how much higher?

As stated in Andrew Ott's testimony to the Committee on Energy and Natural Resources, in terms of energy production, PJM's generation fleet is almost evenly split between coal, natural gas and nuclear resources, with ever-growing penetration of renewable generation and healthy levels of demand response and energy efficiency. This means that without coal and nuclear it would have been very difficult or impossible for PJM to serve all of the electricity demand during the bomb cyclone. However, it is also true that without natural gas-fired and oil-fired generation, it would have been equally difficult to serve the load because of the significant amount of power generation this part of the fleet contributes to meeting demand.

In the extremely unlikely scenario that all of the coal and nuclear generation was not available during the recent bomb cyclone, it is difficult to speculate how much higher electricity prices would have been because in such a scenario the electricity demand could not have been met.

[5] http://www.pjm.com/~/media/planning/gen-retire/pending-deactivation-requests-xls.ashx?la=en

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: *The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone*
Questions for the Record Submitted to Mr. Andrew Ott

However, we do not believe such a scenario could happen because PJM operations and planning processes ensure margins on the system are robust enough to operate through extreme weather scenarios. PJM's current reserve margin of 29.1 percent is well above PJM's targeted reserve margin of 16.6 percent for 2017 and 16.1 percent for 2018.

Question 2: In 2014, Congress called for an independent assessment and a comprehensive study on the resilience and reliability of the electric transmission and distribution system. The National Academy of Science published its report on Enhancing the Resilience of the Electric System in 2017. The Report contains specific recommendations directed to DOE, including a recommendation that DOE should partner directly with the North American Electric Reliability Corporation (NERC) to implement resilience metrics in the utility setting. Further, it's my understanding that NERC has established standards for grid reliability but not for grid resilience.

To your knowledge, has an independent study ever been undertaken to evaluate individual generation resources based on a comprehensive set of resilience factors including geography, weather, transmission infrastructure, and ancillary capabilities?

In 2017, PJM evaluated individual generation resources based on a comprehensive set of resilience factors. PJM conducted an independent analysis of the PJM footprint to include resource attributes and those attributes' contribution to promoting reliability and resilience with additional conclusions drawn about resilience and necessary next steps to better understand the impacts of particular resource mix portfolio.[6] To PJM's knowledge there has been no comprehensive study across the United States.

Question 3: Since there are no standards for resilience, would you support having NERC develop resilience standards? How long do you think that would take?

PJM supports a uniform definition and clear metrics for resilience; however, regarding national standards, NERC has indeed established standards that reach to resilience issues by addressing specific threats such as the Critical Infrastructure Protection (CIP) standard, CIP-014: Physical Security. The purpose of this standard is to "to identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection." Similarly, NERC Standard EOP-010: Geomagnetic Disturbance Operations establishes requirements to mitigate the effects of geomagnetic disturbance (GMD) events by implementing operating plans, processes and procedures, and TPL-001: Transmission System Planning Performance Requirements specifies

[6] http://www.pjm.com/-/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx?la=en

that transmission planners, such as PJM, establish system planning performance requirements that will result in reliable operations over a broad spectrum of system conditions and probable contingencies. PJM believes that not all threats to resilience are applicable nationally; rather, resilience issues can also be and are regionally oriented. NERC should endeavor to develop an overall resilience framework that includes assessing threats to resilience – those that are national in nature – and promoting a common definition.

NERC should be encouraged to contribute to the development of a set of resilience metrics that can be used to apply consistent approaches across the various regions of the nation.

There may also be an opportunity for NERC to continue to improve on the standards mentioned above. The NERC standard process is thorough but could potentially take years to develop new requirements.

Due to the increased importance of natural gas generation and gas-electric coordination, it is also important to look at the standards governing cyber and physical security for pipelines. The governing models for standards are vastly different between the bulk electric system and the pipelines. For the bulk electric system, detailed cyber and physical security standards (and penalties for non-compliance with these standards) are promulgated by NERC and approved by FERC. Pipeline cyber standards and physical security standards (beyond specific pipeline standards promulgated by PHMSA) are overseen by TSA and largely voluntary in nature. Although legislation would be needed to change this disparate paradigm, there is little reason why the approaches taken by TSA and FERC to these cross-industry topics need to be so diverse, and increased alignment between the two would improve coordination.

Question 4: If DOE and NERC determined that certain generation resources were critical to system resilience, would you agree that those resources should be compensated for the resilience attributes they provide?

PJM's market design already compensates units for a number of resilience services and products they provide. Ancillary services such as spinning reserve and voltage support are services PJM compensates for under its tariff. PJM is also in the process of addressing additional compensation and requirements for primary frequency support, dual-fuel requirements for black start service, and rules that will allow generators to recover costs for emergency operations where market rules do not provide cost recovery.

PJM has raised issues associated with the proper setting of energy market clearing prices to ensure that market clearing prices reflect the costs of all resources that are serving load. PJM has noted that in the recent cold snap, out-of-market uplift payments increased by at least a factor of 10 during the severe cold weather operationswhich indicates the operating costs of some generation that was needed to meet the electricity demand was not reflected in clearing prices. Just to be clear, all of the resources that are serving load are compensated, in some cases through

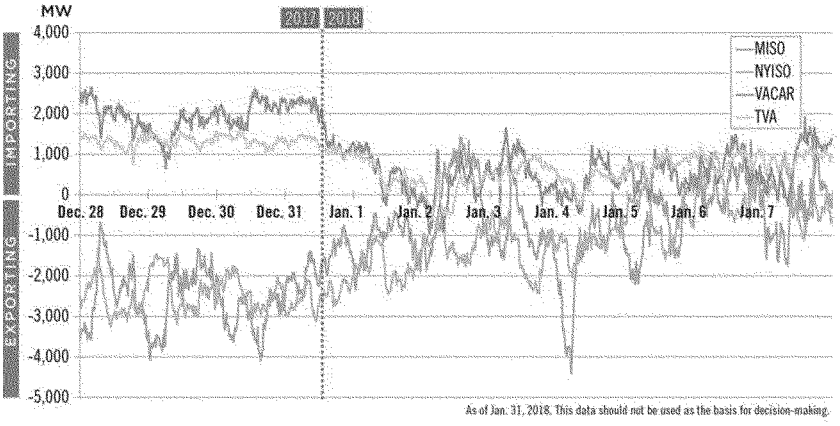
out-of-market "uplift" payments. But in some cases, such costs are not properly reflected in locational marginal prices, which could put these resources and all other resources needed to meet demand at a disadvantage because market prices are not reflecting the true cost to serve electricity demand. PJM has proposed energy market price formation reforms to address these issues and we believe such reforms should be addressed in a timely manner. These reforms include both enhanced reserve pricing and energy price formation reforms. PJM has also flagged this issue for FERC consideration in the context of FERC's energy price formation efforts.

Questions from Senator Tina Smith

Question 1: I understand that transmission played a key role in keeping up with high energy demand on the East Coast. PJM, for example, was reportedly importing power from MISO in the Midwest during the bomb cyclone. Do you feel that new transmission lines connecting the Midwest to the East Coast would be good for grid reliability and resilience?

As outlined below, power flowed from MISO to PJM in a number of hours during the recent cold weather snap. This power flow was as a result of economic decisions made by generators in the MISO region to sell into PJM as a result of higher prices during this period in the PJM region.

PJM Interchange, Dec. 28, 2017 to Jan. 7, 2018



U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: ***The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone***
Questions for the Record Submitted to Mr. Andrew Ott

Question 2: What are the obstacles to getting more transmission lines built? How can the federal government help facilitate more transmission projects in the future?

In general, PJM has been successful in getting more transmission lines built. To date, net transmission investments authorized under PJM's Regional Transmission Expansion Plan (RTEP) since 2000 total is approximately $35.4 billion.

With respect to getting more transmission built for resilience, Mr. Ott's written testimony regarding "balancing the need for transparency with the need to protect critical infrastructure" indicated that although a hallmark of RTO operations and PJM's planning process has been transparency, in the future, PJM believes a balance needs to be struck in this area. On the one hand, transparency in detailing to stakeholders the need for particular grid improvements is very important, and on the other, we do not want to inadvertently publicly release highly sensitive information about vulnerabilities on the grid.

To date, the regulators and the RTOs have addressed this issue through labeling highly sensitive grid information as Critical Electric Infrastructure Information (CEII). But the CEII rules utilized at FERC and at the state level are designed around a "right to know" approach, with some verification of the bona fides of the requestor. However, the federal government doesn't approach classified information this way. Rather, that system is based on the provision of access based on a demonstrated "need to know."

It may be time to consider evolving our release of a limited set of highly sensitive infrastructure information from a "right to know" to a "need to know" basis. PJM thinks this can be accomplished in a manner that also allows the opportunity at the appropriate time for customers and the public to examine (and potentially challenge) the costs of any grid upgrade through the regulatory process. But for this balance to be workable, PJM will need direction from FERC – as much of its regulatory regime to date has, understandably, been driven by moving toward greater transparency without a corresponding focus on tightening rules around CEII.

ISO new england

Gordon van Welie
President & Chief Executive Officer

February 20, 2018

The Honorable Lisa Murkowski
Chairman, U.S. Senate Committee on Energy & Natural Resources
304 Dirksen Senate Building
Washington, DC 20510

Dear Chairman Murkowski:

Thank you again for the opportunity to appear before the Energy & Natural Resources Committee on January 23, and the opportunity to respond to the questions below.

In addition to my answers, I have included a copy of ISO New England's recently-released *2018 Regional Electricity Outlook* (REO). The REO is one of the many ways ISO New England keeps stakeholders informed about the current state of the grid, issues affecting its future, and ISO actions to ensure a modern, reliable power system for New England.

Please be in touch with any further questions or if I can provide additional information.

Sincerely,

Gordon van Welie
President and Chief Executive Officer

cc: The Honorable Maria Cantwell, Ranking Member
The Honorable Bernard Sanders
The Honorable Angus King

U.S. Senate Committee on Energy and Natural Resources
January 23, 2018 Hearing: *The Performance of the Electric Power System in the Northeast and mid-Atlantic during recent Winter Weather Events, including the Bomb Cyclone*
Questions for the Record Submitted to Mr. Gordon van Welie

Questions from Chairman Lisa Murkowski

Question 1: *You sometimes refer to the potential need to take emergency measures during a severe cold weather event, including measures like rolling blackouts, or load shedding. While neither ISO-NE nor PJM needed to shed load in this most recent event, where is the trend going? What happens if we have another such event, or even a colder event, five years from now? What should we be doing now, so that we're ready in five years?*

Question 2: *How do options like demand response and energy efficiency fit into these extreme weather events? How much is the grid helped during winter peaks by these options?*

Question 3: *In assessing the organized markets, have you considered the need for both entry and exit in a well-functioning marketplace? Notwithstanding the vital contributions of wind, solar, hydro, oil, and other resources to our markets, what are your thoughts on a market design that is structured so that nuclear plants do not have a realistic opportunity for new entry, but do have opportunities to permanently exit during periods of low natural gas prices? Should markets be designed to eventually "ratchet" out all nuclear, so that the natural gas industry ultimately gains a virtual monopoly on fuel supply to the electricity markets?*

Question 4: *Why did ISO New England fail to model any new gas infrastructure in its recent report on Operational Fuel Security? What is the nature of the public's support or objection to new gas infrastructure in New England?*

Question 5: *In 2014, the Vermont Yankee nuclear plant was shut down. At that time, it represented an important part of New England's total electric generation. Given the large share of nuclear in the ISO New England fuel mix during much of the cold weather event these past few weeks, it seems that much of that energy would need to be replaced by gas (or oil when gas prices skyrocket) in the absence of nuclear power. This might be attractive to the profitability of gas and oil plants, but may be bad for carbon emissions, and bad for consumers. How does ISO New England address these competing priorities? What are the views of the regulators and consumer advocates in New England?*

Response:

I appreciate the opportunity to expand on my comments from the Committee's January 23 hearing. Since I appeared before your Committee, ISO New England has published its *2018 Regional Electricity Outlook* (REO).[1] The REO reinforces that the biggest challenges to the reliability of New England's electric grid are the lack of fuel infrastructure to supply the region's natural-gas-fired generators (combined with further emissions restrictions on oil-fired generation) and the reality that older oil and nuclear generators are becoming less economically competitive and may retire before the region has added sufficient new energy sources to replace them.

During the recent cold stretch that gripped New England from December 26, 2017, to January 7, 2018, constrained pipeline capacity resulted in substantially higher natural gas and wholesale electricity prices, leading to less expensive oil and coal power plants operating instead of the usually competitive natural-gas-fired generation. With oil-fired generation running hard, oil supplies at power plants around the region began to rapidly deplete over the two-week period, making system operations extremely challenging and significantly increasing the reliability risk to the system. In the coming years as more oil, coal, and nuclear leave the system, keeping the lights on in New England will become an even more tenuous proposition.

New England continues to see the retirement of a significant number of oil, coal, and nuclear power plants. While oil and coal plants may only run a fraction of the time throughout the year (combining to produce only 3% of New England's electricity in 2017), they are critical resources during periods when the price of natural gas exceeds the price of oil or coal or when there is no natural gas available for power generation. However, as oil, coal, and nuclear continue to retire it will make reliable grid operations even more challenging. As I mentioned at the January 23 hearing, investments need to be made to either alleviate the region's natural gas pipeline constraints or to work around the constraints through enhancements to natural gas infrastructure or the supply chains for liquefied natural gas and oil; relaxation of rules to allow easier permitting and operation of dual-fuel resources; investments in even more renewable energy and any transmission needed to deliver it; or further measures to significantly reduce demand on the power system or the gas system. Most likely, the solution for New England will be some combination of these. I am hopeful that ISO New England's recently-released Operational Fuel Security Analysis will bring additional clarity to New England's reliability challenges.

The ISO can continue to work on improving market incentives to stimulate the required investments, but ultimately it will be up to market participants and the states to determine which investments make the most sense for the region (given the cost and environmental tradeoffs that exist between the various options). One of the key market design questions facing the ISO and its stakeholders is how much reliability risk should be mitigated through the market. The states face an additional question, which is whether to allow the infrastructure constraints to persist (which will result in economic impacts in the energy markets when the fuel infrastructure becomes constrained), or whether they should act to relieve the fuel infrastructure constraints by utilizing some combination of the options discussed

[1] https://iso-ne.com/static-assets/documents/2018/02/2018_reo.pdf

above (which will require significant investments in infrastructure and/or the relaxation of certain environmental constraints). Depending on circumstances, the states may ultimately face a decision as to whether they support the retention of critical energy resources in the region, until such time as they have added sufficient replacement energy resources to allow these resources to retire. The Operational Fuel Security Analysis demonstrates that if overall fuel security is not addressed, the region will face a setback to future power system reliability and state efforts to transition to clean energy economy-wide, as well as increased energy costs. We are eager to continue regional discussions in the coming months on these critical topics.

Regarding your questions on nuclear, it is important to remember that ISO New England administers competitive wholesale markets that are fuel-neutral. While we recognize the contributions made by nuclear plants operating in the region, New England's wholesale markets are based on the economics of participating resources. New England's competitive markets have resulted in generally lower wholesale electricity prices, dramatic reductions in emissions, and meaningful reliability benefits.

As you may be aware, regulators and policymakers in Connecticut are reviewing issues related to the future of the Millstone nuclear power plant. It is one of the critical energy resources mentioned above. Millstone's importance to reliable grid operations is highlighted in the Operational Fuel Security Analysis, which notes that the loss of Millstone's 2,100 megawatts (MW) for the modeled period of time results in significant operational challenges. The owners of Millstone have not formally given notice to ISO New England that they are intending to exit the wholesale electricity markets. Should Millstone seek to retire, ISO New England will conduct a review of the retirement request and will work with our regulator, the Federal Energy Regulatory Commission, to assure that the region's electricity system remains reliable and resilient.

Energy efficiency and demand response resources play an important role in our wholesale markets and help to meet the reliability needs of the power system. New England states combine to invest over $1 billion annually in energy efficiency (which is treated as capacity in our markets) and we are seeing significant impacts on electricity demand due to these investments (we expect this trend to continue until the states start migrating the transportation and heating sectors towards grid-scale clean energy, which will likely increase the demand on the bulk power system). Active demand response programs play an important role as well and have performed well when called upon (typically during operating procedures performed during a capacity deficiency). Active demand response resources will soon be fully integrated into our daily energy markets.

You touch on a critical point about the Operational Fuel Security Analysis – the assumption by ISO New England that no further natural gas supply infrastructure is forthcoming (beyond incremental expansion already underway). We did not model additional natural gas infrastructure because we do not anticipate further development during the time period of the analysis. Several projects that had been proposed have been withdrawn and there continues to be strong local opposition to these types of investments in New England and neighboring regions. Furthermore, because of the restructuring of the industry and the incompatibility between the gas pipeline business model (which requires long term commitments) and the economic circumstances for merchant generators in the competitive wholesale

markets, merchant generators will not enter into the contracts to build new pipelines. The New England States tried to coordinate a commitment to sign up for new pipeline capacity, but that effort was hindered when the Massachusetts Supreme Judicial Court ruled that the MA Department of Public Utilities did not have the authority to charge electric ratepayers for the cost of natural gas pipeline capacity. While other states had authority to seek additional pipeline capacity, Massachusetts' involvement was critical to the proposed regional arrangement. In summary, the question of who will contract for new pipeline capacity has vexed the region for the past several years.

Questions from Senator Mike Lee

Question 1: *How did a lack of pipeline infrastructure affect the spot pricing issues and the need for fuel oil use in dual fuel units during the recent cold spell?*

Question 2: *Why did ISO-New England's Operational Fuel-Security Analysis assume that no additional natural gas pipeline capacity would be added within the study's timeframe?*

Response:

The lack of adequate natural gas supply infrastructure during the recent cold weather period resulted in significant price increases both in the price of natural gas and wholesale energy. New England experienced the highest natural gas prices in the country for a time during the cold snap. Constrained pipelines drove up prices – which in turn made oil- and coal-fired resources economic (an unusual occurrence in New England throughout most of the year). Through our markets, we became heavily reliant on oil-fired power plants and maintaining reliability was more challenging as those plants diminished their inventory or approached their annual emissions limits. Bottlenecks on the natural gas supply network result in higher prices, higher emissions, and increased reliability concerns.

Regarding ISO New England's decision to omit the possibility of additional natural gas supply infrastructure from the Operational Fuel Security Analysis, please see my answer to the Chairman above.

Questions from Senator Joe Manchin III

Question 1: *In 2014, Congress called for an independent assessment and a comprehensive study on the resilience and reliability of the electric transmission and distribution system. The National Academy of Science published its report on Enhancing the Resilience of the Electric System in 2017. The Report contains specific recommendations directed to DOE, including a recommendation that DOE should partner directly with the North American Electric Reliability Corporation (NERC) to implement resilience metrics in the utility setting. Further, it's my understanding that NERC has established standards for grid reliability but not for grid resilience.*

To your knowledge, has an independent study ever been undertaken to evaluate individual generation resources based on a comprehensive set of resilience factors including geography, weather, transmission infrastructure, and ancillary capabilities?

Question 2: *Since there are no standards for resilience, would you support having NERC develop resilience standards? How long do you think that would take?*

Question 3: *If DOE and NERC determined that certain generation resources were critical to system resilience, would you agree that those resources should be compensated for the resilience attributes they provide?*

Response:

I am not aware of an independent study with the comprehensive scope that you describe; however, NERC is in the midst of a bulk power system resilience effort, and ISO New England is actively engaged in that process.

Perhaps more immediately, on March 9, ISO New England will make a filing at the Federal Energy Regulatory Commission on electric grid resilience. As you know, following its rejection of the September 2017 U.S. Department of Energy Proposed Rulemaking on grid resilience, the Commission directed entities like ISO New England to report on identifying and addressing resilience-related issues.
In my submitted testimony and opening statement on January 23, I noted the importance of ISO New England's Operational Fuel Security Analysis and the role it plays in identifying major fuel-security challenges and that the subsequent regional dialogue will pay dividends in improving both electric grid reliability and resilience. Fuel security is not the region's only challenge to electric grid resilience; however, it is a challenge not specifically being addressed in other proceedings or discussions.

Questions from Senator Tina Smith

Question 1: *I understand that transmission played a key role in keeping up with high energy demand on the East Coast. PJM, for example, was reportedly importing power from MISO in the Midwest during the bomb cyclone. Do you feel that new transmission lines connecting the Midwest to the East Coast would be good for grid reliability and resilience?*

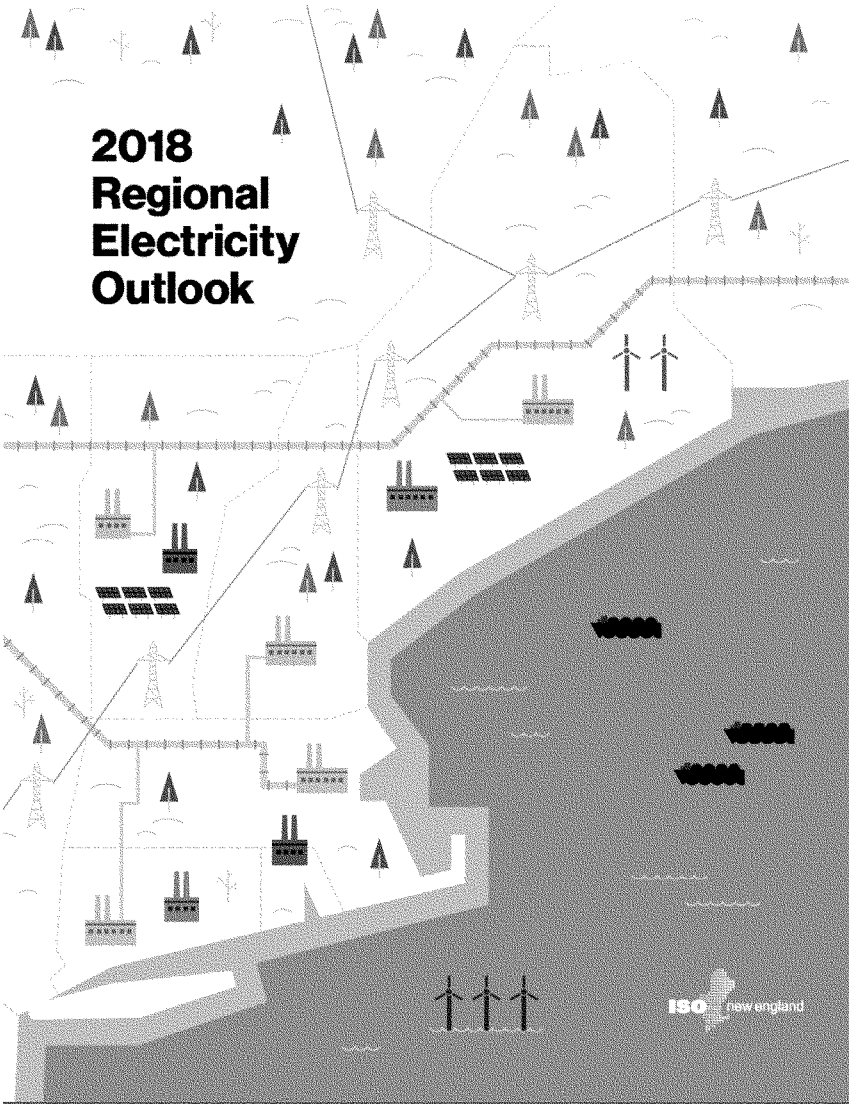
Question 2: *What are the obstacles to getting more transmission lines built? How can the federal government help facilitate more transmission projects in the future?*

Response:

Since 2003, New England has spent approximately $10 billion on reliability-based electric transmission, with another $2.3 billion in estimated future investment over the next few years. Prior to that investment, New England experienced meaningful amounts of transmission congestion and in 2005 was identified by the U.S. Department of Energy as a "Congestion Area of Concern." In 2009, that label was dropped, and New England now operates with very little congestion or "uplift" (payments to resources operating out of merit) and without any special reliability agreements.

Interregional transmission also provides reliability benefits and ISO New England participates in interregional planning with our neighboring system operators. Additional transmission will be necessary if the region seeks to build out substantial amounts of wind in northern New England and access greater levels of hydropower from Canada. Some of the New England states are currently evaluating options for additional transmission projects into the region.

In general, further transmission investments will be required to enable the shift to a cleaner power system, but that can be accomplished in the Northeast region and it does not require investments for transmission from the Midwest to the East Coast.



Complete PDF can be found at:
https://www.iso-ne.com/static-assets/documents/2018/02/2018_reo.pdf

○