POWERING AMERICA: EXAMINING THE STATE OF THE ELECTRIC INDUSTRY THROUGH MARKET PARTICIPANT PERSPECTIVES

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY

OF THE

COMMITTEE ON ENERGY AND COMMERCE

HOUSE OF REPRESENTATIVES

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POWERING AMERICA: EXAMINING THE STATE OF THE ELECTRIC INDUSTRY THROUGH MARKET PARTICIPANT PERSPECTIVES

TUESDAY, JULY 18, 2017

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENERGY,
COMMITTEE ON ENERGY AND COMMERCE,
Washington, DC.

The subcommittee met, pursuant to call, at 10:00 a.m., in room 2123 Rayburn House Office Building, Hon. Fred Upton (chairman of the subcommittee) presiding.

Present: Representatives Upton, Olson, Barton, Shimkus, Murphy, Latta, McKinley, Kinzinger, Griffith, Johnson, Long, Bucshon, Flores, Mullin, Hudson, Cramer, Walberg, Walden (ex officio), Rush, McNerney, Peters, Green, Castor, Sarbanes, Tonko, Loebsack, Schrader, Kennedy, Butterfield, and Pallone (ex officio).

Staff present: Elena Brennan, Legislative Clerk, Energy/Environment; Adam Buckalew, Professional Staff Member, Health; Karen Christian, General Counsel; Kelly Collins, Staff Assistant; Wyatt Ellertson, Research Associate, Energy/Environment; Adam Fromm, Director of Outreach and Coalitions; Tom Hassenboehler, Chief Counsel, Energy/Environment; A.T. Johnston, Senior Policy Advisor, Energy; Alex Miller, Video Production Aide and Press Assistant; Mark Ratner, Policy Coordinator; Annelise Rickert, Counsel, Energy; Dan Schneider, Press Secretary; Sam Spector, Policy Coordinator, Oversight and Investigations; Jason Stanek, Senior Counsel, Energy; Madeline Vey, Policy Coordinator, Digital Commerce and Consumer Protection; Priscilla Barbour, Minority Energy Fellow; Jeff Carroll, Minority Staff Director; David Cwiertny, Minority Energy/Environment Fellow; Rick Kessler, Minority Senior Advisor and Staff Director, Energy and Environment; Alexander Ratner, Minority Policy Analyst; and Tuley Wright, Minority Energy and Environment Policy Advisor.

OPENING STATEMENT OF HON. FRED UPTON, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF MICHIGAN

Mr. UPTON. It is my understanding that Mr. Rush is coming in the door, so we will now come to order at the subcommittee and the chair will recognize himself for an opening statement.

So I am certainly pleased to be here today to kick off this first of many hearings focused on America's electricity system. And as many in this room are aware, this committee has had an extensive history overseeing the nation's power sector. In fact, the namesake of this very building, Speaker Rayburn, worked as the chairman of the Energy and Commerce Committee to pass the Federal Power Act back in 1935, a law which continues to serve as the legal foundation of America's electricity system.

More recently, the committee was instrumental in the discussion and actions resulting in the creation of organized wholesale electricity markets and other power market reforms ensuring that rates continue to be just and reasonable. I can confidently say that this committee's efforts to oversee the nation's power sector must remain ongoing, as the ever-changing nature of the U.S. electricity system guarantees that there will always be new challenges to solve and new opportunities to seize.

With that in mind, I am excited to launch a new set of Energy and Commerce hearings today entitled Powering America series. This series of hearings is going to take a comprehensive look at recent developments and challenges in the way that we generate, transmit, and consume electricity in the U.S. and today's hearing will give us the opportunity to examine the state of the electric industry through the perspective of various market participants.

After hearing from each of these marketing participants this morning, we are going to be holding a second Powering America series hearing next week where we are going to be receiving testimony from each of the RTOs and ISOs who are responsible for operating America's regional wholesale electricity markets. It should also be said that in the coming months we are going to be announcing additional hearings in this series which will focus on more in-depth topics and issues related to the U.S. electricity system.

Joining us in today's discussion we have a full range of experts representing a wide range of stakeholders from across the electric sector and I would like to welcome them and thank them for being here.

As I am sure that each of our witnesses will attest to, the nation's electricity industry and system is undergoing a significant period of transformation. This transformation is affecting the composition of the country's electricity generation mix, the way that industry and regulators are approaching grid reliability, and how federal energy policies are interacting with state policies. Many of the recent developments and changes within the electricity sector are creating tremendous benefits for American consumers.

U.S. electricity prices are low, employment within the energy sector continues to rise, and advanced technologies are giving consumers more control over how they interact with the grid. And it is safe to say that the American electricity industry is a world leader and deserves more credit for the amazing work that they do.

With that being said, I know that the U.S. electricity system is not perfect nor will it ever be. The electricity industry is facing dynamic challenges in an uncertain future. The witnesses before us today have serious ideas on how electricity markets and energy policies can be improved, and this committee welcomes those ideas and is eager to engage in a meaningful discussion as to how we can strengthen the grid and how to provide greater value to consumers.

No one here is under the illusion that these issues will be understood and addressed in one or two hearings. The U.S. electricity system is the largest, most complex collection of machines and computers in the world and are influenced by a staggering number of stakeholders.

These electricity systems issue are complicated and in order to address them it will require an extended effort by this committee and by the Congress. Moreover, tackling these issues will require a bipartisan effort, which is why we have worked with our colleagues on both sides of the aisle in planning and conducting this hearing.

Reliable, affordable, clean energy is a vital component of every American's life. Going forward, we have got to strive to enhance the generation, delivery, and marketing of electricity in a way that continues to enrich the lives of all. And with that in mind, I look forward to the hearing and future hearings and would yield 5 minutes to the ranking member of the subcommittee, my friend from Illinois, Mr. Rush.

[The opening statement of Mr. Upton follows:]

PREPARED STATEMENT OF HON. FRED UPTON

Good morning. I am pleased to be here today to kick off this first of many hearings focused on America's electricity system. As many in this room are aware, this Committee has an extensive history overseeing the nation's power sector. In fact, the namesake of this very building, Speaker Sam Rayburn, worked as the Chairman of the Energy and Commerce Committee to pass the Federal Power Act in 1935, a law which continues to serve as the legal foundation of America's Electricity System. More recently, this Committee was instrumental in the discussion and actions resulting in the creation of organized wholesale electricity markets and other power marketing reforms, ensuring that rates continue to be "just and reasonable". I can confidently say, that this Committee's efforts to oversee the nation's power sector must remain ongoing as the ever-changing nature of the U.S. electricity system guarantees that there will always be new challenges to solve and new opportunities to seize.

With that in mind, I am excited to launch a new set of Energy and Commerce Committee hearings today, titled the "Powering America Series". This series of hearings will take a comprehensive look at recent developments and challenges in the way we generate, transmit, and consume electricity in the United States. Today's hearing will give us the opportunity to examine the state of the electric industry through the perspective of various market participants. After hearing from each of these market participants this morning, we will be holding a second "Powering America Series" hearing next week, where we will be receiving testimony from each of the RTOs and ISOs who are responsible for operating America's regional wholesale electricity markets. It should also be said that in the coming months, we will be announcing additional hearings in this series which will focus on more in-depth topics and issues related to the U.S. electricity system.

Joining us in today's discussion, we have a full panel of experts representing a wide range of stakeholders from across the electric sector and I would like to welcome them and thank them for being here. As I am sure each of our witnesses will attest to, the nation's electricity industry and system is undergoing a significant period of transformation. This transformation is affecting the composition of the country's electricity generation mix, the way industry and regulators are approaching grid reliability, and how Federal energy policies are interacting with State policies. Many of the recent developments and changes within the electricity sector are creating tremendous benefits for American consumers. U.S. electricity prices are low; employment within the energy sector continues to rise; and advanced technologies are giving consumers more control over how they interact with the grid. It is safe to say that the American electricity industry is a world leader and deserves more credit for the amazing work they do.

With that being said, I know that the U.S. electricity system is not perfect, nor will it ever be. The electricity industry is facing dynamic challenges and an uncertain future. The witnesses before us today have serious ideas on how electricity markets and energy policies can be improved. This Committee welcomes these ideas and is eager to engage in a meaningful discussion on how to strengthen the grid and how to provide greater value to American consumers.

No one here is under the illusion that these issues will be understood and addressed in one or two hearings. The U.S. electricity system is the largest, most-complex collection of machines and computers in the world and is influenced by a staggering number of stakeholders. These electricity system issues are complicated and in order to address them it will require an extended effort by this Committee, and by this Congress. Moreover, tackling these issues will require a bipartisan effort. Which is why we have worked with our colleagues on the other side of the aisle in planning and conducting this hearing.

Reliable, affordable, clean electricity is a vital component of every American's life. Going forward, we must strive to enhance the generation, delivery, and marketing of electricity in a way that continues to enrich the lives of all Americans. With this goal in mind, I look forward to this hearing and future hearings to come in this series.

OPENING STATEMENT OF HON. BOBBY L. RUSH, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF ILLINOIS

Mr. RUSH. I want to thank you, Mr. Chairman. Mr. Chairman, this hearing is important because it is examining the state of the electric industry through market participant perspectives.

Mr. Chairman, we know that the electricity grid of the 21st century will look significantly different than the grid of the last century, and rightfully so. Even as the Trump administration attempts to weaken federal environmental regulations and Congress fails to act in any meaningful way to address climate change, we see businesses, municipalities, states, and individual consumers step up their own campaigns to address this critical issue.

As consumers become more aware of their carbon footprint and how their behavior impacts their environment, they are also more demanding in terms of information, they are more demanding in terms of control over how energy is produced and consumed.

Indeed, Mr. Chairman, while many changes in our electric grid are spurred by state and federal policy and marketing forces, it is important to understand that consumers are also driving many of the trends we see taking place in the electricity market. From an increase in smart meters such as the ones being installed throughout my home city of Chicago to smarter appliances, consumers want the tools to more responsibly use energy both as a way to save money and as a way to save the environment. Other current trends include greater demand for cleaner, renewable sources of energy to compete with the traditional fossil fuels as well as increase in distributed generation and demand response resources.

Mr. Chairman, the result of these trends, as a DOE draft report suggests, does not make the grid less reliable but rather the opposite. The DOE study indicates that having fuel diversity has in fact improved grid stability. I want to quote, Mr. Chairman, that very same report. "The power system is more reliable today due to better planning, market discipline, and better operating rules and standards," is the remarks from that report.

Mr. Chairman, with the federal government abdicating its responsibility in enacting comprehensive energy policy that addresses one of the world's most pressing challenges, it is even more vital that we provide the resources and guidance for states to take more of a permanent role in advancing smart and sustainable energy policies.

Congress should not stand in the way of states like my own, Illinois, Mr. Chairman, that choose to enact renewable energy portfolios that provide credit to reliable zero or zero-carbon baseload sources of energy, including nuclear power, but rather Congress should ensure that FERC has the necessary mechanisms to meet the challenges and take advantage of the opportunities found in today's electric grid.

By almost all accounts, Mr. Chairman, for the foreseeable future, the nation's energy mix will continue to include sources from all of the above portfolios including cleaner burning fossil fuels, nuclear, and renewables. So Mr. Chairman, we must make sure that regulators have the tools and have the authority that they need to effectively and efficiently manage this portfolio.

So Mr. Chairman, I look forward to engaging today's panel of distinguished industry insiders and hearing from them regarding the opportunities and the challenges that we face in terms of electric infrastructure. I want to thank you, Mr. Chairman. With that I yield back.

Mr. UPTON. Thank you. The chair now recognizes the chair of the full committee, the gentleman from Oregon, Mr. Walden, for 5 minutes for an opening statement.

OPENING STATEMENT OF HON. GREG WALDEN, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF OREGON

Mr. WALDEN. Thank you very much, Mr. Chairman. And welcome to all of our witnesses and guests today. Last fall, this subcommittee held a hearing where a distinguished panel of witnesses described the origins of the Federal Power Act and how it has withstood the test of time. That testimony provided us with an historical context of how the federal government regulates the electricity sector.

Having explored those historical perspectives, today we begin examining the current state of the electricity industry. As we embark on the Powering America series of hearings, I would also like to welcome our witnesses again who are leaders representing a diverse set of utilities and market participants. We greatly value your input and counsel.

American consumers have come to expect safe, reliable, and affordable supplies of power regardless of how they receive their electricity. My district in Oregon, we receive electricity from just about every source including renewables. We get coal, we get natural gas, we get hydro, we get solar, and we get wind. We also receive it from cooperatives and public utility districts and municipalities and IOUs. In fact, we have just about everything out there.

In all these situations though, we expect to have power when we flip the switch and we expect to be at 60 cycles and 120 or 240 or whatever, but we expect it to work, and yet we know it is becoming more and more complex to provide that energy especially as we integrate and go up and down the grid.

New market participants offering advanced technologies and innovative services are changing the face of the industry faster than many have expected and that pace of change will only increase over time. At the same time, wholesale electricity prices are at near record lows around the United States.

While this is largely a result of cheap and plentiful natural gas supplies, the emergence of renewable resources are also affecting the composition of power being generated as well as market-clearing prices. As a result, in regions with competitive markets that dispatch generation based solely on lowest cost, we are seeing that some traditional baseload units, such as nuclear and coal-fired plants, cannot compete because they are too expensive to operate within their markets, causing some plants to retire before the end of their useful life.

While on its face low electricity prices are a boon for consumers and businesses, we are now hearing from some segments of the industry that the loss of nuclear and coal units from the generation fleet could have longer term impacts on grid reliability. While this is an issue that the DOE is examining in its baseload study, this is also an issue that this committee is exploring. Additionally, recent proposals by states to advance certain public policies in the organized electricity markets have added yet another layer of complexity to an already complicated system.

So my hope is that there is a path forward to achieve these state policies while also maintaining the integrity of the wholesale markets. I recognize this is not an easy task. Next week, we will continue our examination of the electricity system with executives from the RTOs and the ISOs who operate the transmission systems, but today I am interested in hearing directly from market participants regarding their experiences working in the electric sector and their thoughts on areas of potential improvement.

I would note that our panel includes representatives that participate in both the non-restructured markets as well as all seven organized markets. So, as Chairman Upton noted, today is just the first in our Powering America series of hearings examining this industry.

So I look forward to learning more about the state of the vital industry and hearing your thoughts regarding what, if any, reforms could help to achieve greater efficiencies, reliability, and competition in the wholesale markets while also continuing to deliver value to customers. As I have said previously, at the end of the day, our goal is to serve the interests of consumers and I look forward to your ideas to further that mission.

And I will say at the outset, we have another subcommittee hearing going on, on 340B hospital issues, so I have to pop up to that one as well, but with that I would yield the balance of my time to the chairman of the Environment Subcommittee, Mr. Shimkus.

[The prepared statement of Mr. Walden follows:]

PREPARED STATEMENT OF HON. GREG WALDEN

Last fall this subcommittee held a hearing where a distinguished panel of witnesses described the origins of the Federal Power Act and how it has withstood the test of time. That testimony provided us with a historical context of how the federal government regulates the electricity sector. Having explored those historical perspectives, today we will be examining the current state of the electricity industry. As we embark on this "Powering America" series of hearings, I'd like to welcome today's witnesses who are leaders representing a diverse set of utilities and markets participants.

American consumers have come to expect safe, reliable, and affordable supplies of power—regardless of how they receive their electricity. In my district, residents in central and eastern Oregon receive their electricity from small cooperatives, which are often the only provider in vast rural areas in Oregon. In other areas, like in southern Oregon or my hometown of Hood River, consumers rely on large investor-owned utilities to supply their electricity. In both situations, Americans now expect their power on demand. However, producing and delivering electricity from a power plant to our homes and businesses is becoming increasingly complex. New market participants offering advanced technologies and innovative services are changing the face of the industry faster than many have expected, and that pace of change will only increase with time.

At the same time, wholesale electricity prices are at near record lows around the country. While this is largely a result of cheap and plentiful natural gas supplies, the emergence of renewable resources are also affecting the composition of the power being generated as well as the market clearing prices. As a result, in regions with competitive markets that dispatch generation based solely on lowest-cost, we are seeing that some traditional "baseload" units, such as nuclear and coalfired plants, cannot compete because they are too expensive to operate within their markets, causing some plants to retire before the end of their useful life.

While on its face, low electricity prices are a boon for consumers and businesses, we are now hearing from some segments of the industry that the loss of nuclear and coal units from the generation fleet could have longer-term impacts on grid reliability. While this is an issue that the DOE is examining in its "Baseload Study," this is also an issue that the committee will be exploring.

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As Chairman Upton noted, today is just the first in our "Powering America" series of hearings examining the electricity industry. I look forward to learning more about the current state of this vital industry and hearing your thoughts regarding what, if any, reforms could help to achieve greater efficiencies, reliability, and competition in the wholesale markets, while also continuing to deliver value to consumers. As I've said previously, at the end of the day, our goal is to serve the best interests of consumers and I look forward to your ideas to further that mission.

Mr. SHIMKUS. Thank you, Mr. Chairman, and I will be brief. First of all, I want to welcome Joe for being on the panel, former committee staff. That shows you how old I am and how old you are starting to look there.

Secondly, for my colleagues on both sides, we are soliciting co-sponsors for our nuclear waste bill, the one we passed out of the full committee, 49–4. We are going to keep gathering names for the next 2 weeks, so check with your staff and make sure you get on that bill and I would appreciate it.

With that, Mr. Chairman, I yield back. Oh, H.R. 3053 is the bill number. Thank you, Mr. Chairman.

Mr. UPTON. As a co-sponsor of that bill I am glad to see that that is the case. And I would yield to the ranking member of the full committee, the gentleman from New Jersey, for an opening statement, Mr. Pallone.

OPENING STATEMENT OF HON. FRANK PALLONE, JR., A REPRESENTATIVE IN CONGRESS FROM THE STATE OF NEW JERSEY

Mr. PALLONE. Thank you, Mr. Chairman. And thanks for holding the hearing to provide us with a market participant perspective in our system of electricity regulation. Today's hearing picks up on the issue that you started to focus on last Congress, Mr. Chairman, with our insightful hearing on the Federal Power Act.

Like that hearing, today's hearing was developed in partnership between you and Chairman Walden and me and Ranking Member Rush, and this set up to be a completely non-partisan hearing with the goal of providing us important background for future decisions. I also want to welcome our witnesses, particularly Tammy Linde from New Jersey's PSEG, and I would like to welcome back to the committee a former counsel to the subcommittee and FERC chair, Joe Kelliher.

As I said previously, while our attention to electricity issues has been sporadic since the passage of the Energy Policy Act of 2005, there was a time when it seemed like this committee held hearings on the electric sector almost weekly. Now, developments in the electricity sector and the regional markets, both promising and concerning, require us to return again to a serious assessment of the state of the electric sector and how it is regulated.

Technology has dramatically transformed the possibilities for cost effectively generating and efficiently delivering electric energy to homes, businesses, and manufacturing facilities from a variety of sources. Distributed generation both fossil- and renewable-based along with improving storage options, smart meters, microgrids, and other technologies, have altered the possibilities for effectively and economically ensuring reliability.

These technologies have also called into question the most basic tenets of rate making and have challenged the longstanding financial model for utilities. These are enormous and complex matters that require careful examination by this committee. At the end of the day, we may decide that we need to make changes to the Federal Power Act or we may conclude that we should make no changes and continue to allow developments in the states and the courts to drive policy.

It is critical that our committee, at a minimum, take the time we need to examine these matters so that we arrive at decisions that are informed by fact and that serve the interests of our districts, our states, and the nation as a whole.

And at this time I would like to yield the balance of my time to Mr. McNerney.

[The prepared statement of Mr. Pallone follows:]

PREPARED STATEMENT OF HON. FRANK PALLONE, JR.

Thank you for holding today's hearing to provide us with a market participant perspective on our system of electricity regulation.

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Thank you, I yield back.

Mr. MCNERNEY. Well, I thank the ranking member, and I thank the chair for holding this hearing. I want to welcome the witnesses, in particular Mr. Schleimer from Calpine.

The electric grid has long provided Americans with reliable and affordable power upon which our economy depends. Today we see big changes though in our electric grid such as the challenge of reducing carbon emissions, distributed generation, cyber and physical threats, as well as rapidly developing technology.

Our nation depends on laws and regulations that encourages and allows utility companies to adapt and thrive. I look at this series of hearings as an opportunity to be informed in our legislative process which should be both bipartisan and productive, so I thank the witnesses and I yield back to the ranking member.

Mr. PALLONE. And I yield back also, Mr. Chairman.

Mr. UPTON. The gentleman yields back. With that we are ready to hear the testimony and do our normal Q & A. Thank you, panel, for being here.

And we are going to start with the senior guy, the guy who spent a lot of hours here, a lot of weeks and months, so over the years, Joe Kelliher. Joe, welcome back. Thank you.

It is a new mic so you have got to push the button, still.

STATEMENTS OF JOSEPH T. KELLIHER, EXECUTIVE VICE PRESIDENT, FEDERAL REGULATORY AFFAIRS, NEXTERA ENERGY, INC.; LISA G. MCALISTER, SENIOR VICE PRESIDENT AND GENERAL COUNSEL FOR REGULATORY AFFAIRS, AMERICAN MUNICIPAL POWER, INC.; STEVEN SCHLEIMER, SENIOR VICE PRESIDENT OF GOVERNMENT & REGULATORY AFFAIRS, CALPINE; JACKSON REASOR, CHIEF EXECUTIVE OFFICER, OLD DOMINION ELECTRIC COOPERATIVE; TAMARA LINDE, EXECUTIVE VICE PRESIDENT AND GENERAL COUNSEL, PUBLIC SERVICE ENTERPRISE GROUP, INC.; KENNETH D. SCHISLER, VICE PRESIDENT OF REGULATORY AND GOVERNMENT AFFAIRS, ENERNOC; AND ALEX GLENN, SENIOR VICE PRESIDENT OF STATE AND FEDERAL REGULATORY LEGAL SUPPORT, DUKE ENERGY

STATEMENT OF JOSEPH T. KELLIHER

Mr. KELLIHER. Mr. Chairman, Mr. Upton, Mr. Rush, members of the subcommittee, I appreciate the opportunity to testify today on the state of the U.S. electricity industry. My name is Joe Kelliher.

I am Executive Vice President for Federal Regulatory Affairs for NextEra Energy.

NextEra Energy is one of the largest generators in the United States. We have nearly 40,000 megawatts in the United States and Canada, and of the larger generators, NextEra has perhaps the most diverse electricity supply. We are also one of the relatively few numbers of truly national electricity companies. We operate in every regional power market in the United States and I offer the perspective of a competitor in those markets as well as the perspective of a former energy regulator. I was chairman of FERC for a number of years and a commissioner at FERC and a former counsel of this committee.

Since the 1980s and 1990s, the federal government has promoted competition in the wholesale power markets in order to lower rates to customers based on the belief that competitive markets provide greater efficiencies than traditional cost-of-service rate regulation and the goal of competition policy is lowering cost and shifting risk from customers to competitors.

The U.S. electricity industry, as members have noted in opening comments, is undergoing a major transition. The market fundamentals driving this transition include a dramatic increase in U.S. natural gas production, the resulting sharp and sustained decline in natural gas prices, significant declines in wholesale power prices, lower than expected electricity demand, and improvements in the efficiency and cost of new wind and solar generation.

Low wholesale power prices have led to sizable retirement of inefficient and uneconomic older coal and natural gas generation facilities, some retirement of uneconomic nuclear units, and large additions of modern, efficient natural gas and renewable energy generation. As a result, the U.S. electricity supply today has changed significantly and is now more diverse than our electricity supply has ever been up to this point.

These changes have been so significant as to raise concerns about whether these generation retirements are being driven by market fundamentals or by federal and state policy and whether the retirement of uneconomic generation poses a threat to electric system reliability. The evidence strongly suggests that the primary factor driving retirements has been market fundamentals not regulatory policy, and there is no evidence to suggest that the retirement of uneconomic generation poses a threat to electric reliability.

A number of states have proposed programs designed to prevent the retirement of uneconomic generation for a mix of policy rationales. To be clear, the market failure addressed by these state programs is low wholesale power prices, and the solution to this problem is to raise prices charged by a select few which would tend to suppress the prices for everyone else and discourage the entry of new, more efficient generation.

These proposals shift risk away from competitors back to consumers which is contrary to a central goal of competition policy itself. These state programs are controversial and they have been challenged in both federal and state courts. Some have been overturned, one was recently upheld, and other challenges remain pending. Because these state programs threaten the integrity of wholesale power markets, FERC is presented with some hard decisions on how to balance respect for state policy choices with its legal duty to assure just and reasonable prices.

This balancing though necessarily involves placing a lesser priority on efficiency and low cost, and in my view FERC has a legal duty to protect market integrity.

I believe our electricity markets are working well and are workably competitive. U.S. electricity markets are undergoing a major transition driven by market fundamentals, the result of low natural gas produced by the shale gas revolution combined with increased efficiency, low demand, and low wholesale power prices. This transition has been marked by major changes in our electricity supply mix. We are seeing tremendous diversity in technology change. This transition is likely to continue, producing an increasingly diverse and more reliable electricity supply.

As someone who bears the scars of the California crisis of 2000–2001, I admit that it feels strange to testify at a congressional hearing on the problem of low wholesale power prices and possible solutions to that problem. And I have to wonder if wholesale power prices were much higher we might not be having this hearing or we would have a completely different focus.

But that is just a point that we should keep the consumers in mind as we discuss these issues. While it is painful for many competitors, the transition of electricity markets has delivered significant benefits to consumers in the form of lower prices, and we have to accept the fact that while low wholesale prices can be painful for the owners of uneconomic generation facilities they are ultimately good for consumers and great for America.

And with that, I thank you for inviting me, and I look forward to questions.

[The prepared statement of Joseph T. Kelliher follows:]

Testimony of Joseph T. Kelliher

Executive Vice President – NextEra Energy, Inc.

Before the Subcommittee on Energy

Committee on Energy and Commerce

U.S. House of Representatives

"Powering America: Examining the State of the Electric Industry through Market Participant Perspectives"

July 18, 2017

Introduction

Mr. Chairman, Members of the Subcommittee, I appreciate the opportunity to testify today and offer my perspective on competitive wholesale power markets and the challenges facing those markets. I applaud the Subcommittee for its attention to this subject. I offer the perspective of a former Chairman of the Federal Energy Regulatory Commission (FERC), Executive Vice President of NextEra Energy, Inc., and a former Counsel of this Committee who was responsible for electricity issues. I appear today on behalf of NextEra Energy, one of the largest electric generators in the U.S., the third largest investor in American infrastructure, behind only AT&T and Verizon, and one of the very few electric energy companies that operates in every regional power market in the country.

NextEra Energy is a leading clean energy company with consolidated revenues of approximately $16.2 billion, approximately 45,900 megawatts of generating capacity, and approximately 14,700 employees in 30 states and Canada. Headquartered in Juno Beach, Florida, NextEra Energy's principal subsidiaries are Florida Power & Light Company, which serves approximately 4.9 million customer accounts in Florida and is one of the largest rate-regulated electric utilities in the United States, and NextEra Energy Resources, LLC, which, together with its affiliated entities, is one of the nation's largest natural gas generators and the world's largest generator of renewable energy from the wind and sun. Through its subsidiaries, NextEra Energy generates clean, emissions-free electricity from eight nuclear power units in Florida, New Hampshire, Iowa and Wisconsin.

U.S. Electricity Markets

There are two basic electricity markets in the United States, wholesale markets regulated by the Federal Energy Regulatory Commission (FERC) and retail markets subject to state jurisdiction and regulation by state public utility commissions. There are two types of wholesale power markets, organized markets administered by regional transmission organizations (RTO) and independent system operators (ISO), and bilateral markets governed by bilateral power purchase contracts between generators and utilities. Roughly two-thirds of U.S. electricity consumption occurs in the RTO and ISO markets, while bilateral markets are concentrated in the southeast and non-California West.

Of course, wholesale and retail markets interact with each other, and the legal and jurisdictional boundaries between these markets are not always clear. Because of that inter-relationship there has always been some tension between federal and state electric regulation, but my experience is that both federal and state regulators work very hard to respect each other's responsibilities in a manner that minimizes conflict.

Wholesale Competition

Wholesale markets are competitive, both in the organized RTO and ISO markets and bilateral markets. Competition policy has its roots in policy decisions made by FERC in the 1980s and 1990s, relying on authority granted to it by Congress in 1935. FERC promoted competition in wholesale power markets in order to lower rates to customers, in the belief that competitive markets provide greater efficiencies than traditional cost-based rate regulation. FERC believed competition would lower costs and shift risk from customers to competitors.

FERC encouraged competition by authorizing wholesale power sellers to charge market-based rates instead of cost-based rates. It further encouraged competition by requiring open access to the transmission grid, preventing grid owners from discriminating against competing wholesale sellers.

While wholesale markets are competitive, they are not deregulated. That is, wholesale sellers are subject to a panoply of market rules, as well as anti-manipulation rules issued under authority granted by Congress in the Energy Policy Act of 2005. In other words, wholesale markets are governed by both competition and regulation, a form of hybrid competition.

FERC understands that while competition may lower costs and deliver customer benefits, it will not always be kind to competitors. From the beginning, FERC recognized that competition will penalize sellers that are inefficient or have higher cost generation facilities. In short, competition policy does not necessarily benefit all competitors, and the exit of high cost generators is a necessary feature of competitive wholesale power markets.

State of U.S. Electricity Industry

The U.S. electricity industry is undergoing a fundamental transition. The market fundamentals driving this transition include a dramatic increase in U.S. natural gas production, the resulting sharp and sustained decline in natural gas prices, significant declines in wholesale power prices, displacement and retirement of inefficient coal, natural gas and oil-fired generation, lower than anticipated electricity demand, the addition of modern, efficient natural gas generation, and improvements in the efficiency and cost of new wind and solar generation. Contributing to these market forces are federal and state policies encouraging renewables, and stricter controls on emissions from fossil generation facilities.

Of these factors, the most important by far have been low natural gas prices in concert with the addition of highly efficient new gas generation. When combined with lower demand growth, the result is low wholesale power prices, rendering generation from older, inefficient facilities uneconomic. Importantly, the sharp decline in natural gas prices changed the longstanding relationship between coal and gas generation, making gas generation significantly lower cost than coal for the first time – that is the real game changer.

There has been sizeable retirement of inefficient and uneconomic older coal and natural gas generation facilities, some retirement of uneconomic nuclear units, and large additions of modern, efficient natural gas and renewable energy generation. As a result, the U.S. electricity supply mix has changed significantly over a relatively short period, and there is now more diversity in U.S. electricity supply than ever before. The coal share of our electricity supply mix declined from 47% in 2005 to 31% in 2016, the natural gas share rose from 22% to 33% over the same period, and wind and solar now account for 7% of our supply. Overall, the mix of U.S. electric generation facilities is younger, more efficient, more varied in size and technology, and more flexible than ever before.

These changes have been so significant to have raised concerns about whether generation retirements are being driven by market fundamentals or by federal or state policy, and whether the retirement of uneconomic generation poses a threat to electric system reliability. The evidence strongly suggests that the primary factor driving retirements has been market fundamentals, not regulatory policy, and there is no evidence to suggest the retirement of uneconomic generation poses a threat to electric reliability. Because the transition is driven by market fundamentals, it can be expected to continue.

While there are concerns in some quarters that future retirements may result in a loss of electricity supply diversity, the reality is the ongoing transition is likely to result in even greater diversity through the addition of electricity storage and distributed resources.

The retirement of inefficient and uneconomic generation is a natural aspect of a competitive market, and the exit of uncompetitive assets produces consumer benefits. Given the outlook for U.S. natural gas supply and prices and continued improvements in wind and solar efficiency and cost, the pressure for uneconomic facilities to exit may not relax.

Wholesale competition policy played a role in this transition. Lowering costs was the primary goal of competition policy and competition has helped maximize the benefits of the shale gas revolution. Competition policy also successfully shifts risk away from customers to market participants, and competitive markets facilitate deployment of new technologies.

Challenges Facing Competitive Wholesale Markets

While wholesale markets are working to drive down prices and to drive out inefficiencies, there are some who argue there is systemic "market failure" that must be corrected. Some critics who allege market failure fault competitive markets for not achieving goals these markets were never designed to meet in the first place. Markets were not designed to encourage diversity, retain uneconomic facilities, or achieve environmental goals – they were designed to result in an efficient outcome for consumers – they were designed to result in lower power costs and shift risks from consumers to competitors.

Though competitive markets are working, they face a number of challenges. The organized RTO and ISO markets are governed by complex market rules, and critics focus on that complexity, but complexity alone is not a sign of market failure. These markets are dynamic, so

RTOs and ISOs must continuously consider the need for market rule improvements intended to produce the correct outcomes, an aspect of their duty to protect market integrity. To the same end, FERC directs RTOs and ISOs to reform their rules from time to time.

There is always some tension between federal and state electric regulation. States have long had responsibility for integrated resource planning of electric generation in their states, particularly in states with vertically integrated utilities. As a general matter, FERC respects state policy decisions when they pose little harm to wholesale markets. But proposals by some states to prevent the exit of uneconomic generation not needed for electric reliability threaten the integrity of wholesale markets. States have different rationales for these programs.

To be clear, the fundamental "market failure" addressed by these proposals is low wholesale power prices, but low prices by themselves cannot be considered market failure if driven by market fundamentals, as they appear to be. The "solution" to the "problem" of low prices is to raise prices charged by a select few, which would tend to suppress prices for everyone else, discouraging the entry of new, more efficient economic generation.

In the end, these types of proposals shift risk away from generators back to customers, contrary to a primary goal of competition policy. In effect, the owners of uneconomic generation facilities get a safe haven from the risk of competitive markets.

As you can imagine, these state programs and proposals are controversial. They have been challenged in the courts, and some have been preempted by federal law or otherwise found unlawful. Currently, there are legal challenges pending in federal and state courts. Because of the tendency of these programs to suppress wholesale power prices, FERC is presented with difficult decisions on how to balance respect for state policy choices with its duty to protect market integrity and assure just and reasonable prices. It remains to be seen how FERC will balance these important interests.

Conclusion

In conclusion, I believe our electricity markets are working well and are workably competitive. U.S. electricity markets are undergoing a fundamental transition driven primarily by economics, the result of low cost natural gas produced by the shale gas revolution combined with increased energy efficiency, lower demand growth, and low wholesale power prices. The transition has been marked by an increase in new, more efficient natural gas generation, a significant increase in ever-lower cost wind and solar generation, and the retirement of inefficient, uneconomic generation. This transition is likely to continue, producing an increasingly diverse and more reliable electricity supply. We should keep the consumer in mind. While painful for many competitors, this transition has delivered significant benefits to the consumers in the form of lower prices. We have to accept the fact that, while low wholesale prices can be painful for the owners of uneconomic generation facilities, they are ultimately good for consumers and great for America.

Mr. UPTON. Thank you very much.

Next, we are joined by Lisa McAlister, Senior VP and General Counsel for Regulatory Affairs at American Municipal Power, Inc. Welcome.

STATEMENT OF LISA G. MCALISTER

Ms. MCALISTER. Thank you and good morning, Chairman Upton, Vice Chairman Olson, Ranking Member Rush and distinguished members of the subcommittee. My name is Lisa McAlister, and I am the Senior Vice President and General Counsel for Regulatory Affairs for American Municipal Power.

AMP is a nonprofit wholesale power supplier and service provider for 135 members across nine states with the majority of AMP's members in the PJM region. AMP is one of the largest public power, joint action organizations in the country and has generating facilities and/or members located in the districts of the following subcommittee members: Congressmen Griffith, Johnson, Latta, McKinley, Shimkus, and Walberg.

At the outset I want to make clear that AMP supports competitive electric markets. They offer opportunities for our members to serve their customers at the lower cost. AMP also strongly supports reliability, but as a member-focused organization we work hard to ensure that the benefits of regulatory changes made to improve reliability justify the costs to consumers. While the energy portion of wholesale bills is the most substantial portion, capacity and transmission are quickly becoming more significant and growing.

AMP has serious concerns about PJM's capacity construct and also the growing transmission costs. My written testimony provides more details and examples of the challenges that AMP and our members have faced in these areas. PJM's current administrative capacity construct called the reliability pricing model, or RPM, is not a market in any meaningful sense. Rather, RPM is a complex, rules-driven, administrative mechanism for pricing and procuring capacity that relies on distinctly non-market features.

PJM's capacity construct requires constant modifications to achieve the desired outcomes and is becoming increasingly complicated bringing increased volatility and so much rules churn that long-term planning is extremely difficult. We are moving away from markets.

One alternative solution is for local utilities known as load serving entities, or LSEs, to satisfy most or all of their capacity needs through bilateral arrangements in a real marketplace where there are willing buyers and sellers and they negotiate arrangements to meet their needs. Under an approach like this, each local utility or LSE would secure capacity to meet its peak load obligation plus a predetermined reserve margin bilaterally on a long-term portfolio basis. The RTOs would still have a significant role in determining the peak load obligations, identifying constraints on the system, and conducting a residual action. And this alternative has numerous advantages over the current capacity constructs including fewer moving parts and administrative judgments, harmonization between states and local policies, avoidance of jurisdictional disputes, and also flexibility for both states and generators.

It is important also for us to touch on transmission. Nationally, transmission costs have increased dramatically. For example, in four of AMP members' transmission zones, annual revenue requirements have increased by a range of 99 to 214 percent from 2009 through 2016. AMP understands that there are many drivers increasing transmission costs and AMP's members are willing to pay their fair share of the cost. But AMP has to work very hard to make sure these costs lead to the most cost effective and efficient grid expansion.

The transmission planning process must be open and transparent, must provide equitable treatment, and take into account the changing resource mix and configuration of the future, rather than a piecemeal replacement of the grid of the past. While it is essential for developers to earn a fair return on their investment, these rates should reflect current economic conditions and risks.

AMP supports Congress playing a more active role and encouraging FERC to refocus on its statutory mandate to ensure just and reasonable rates. Enhanced congressional oversight is critical to ensure that FERC is responsive to the real needs of customers.

Congress can be helpful by insisting that keeping costs to consumers as low as possible is a central part of the RTO mission; reiterating that load serving entities have a right to make generation choices that are not subject to rejection by the RTOs or FERC; insisting that resource adequacy constructs must accommodate state and public policy decisions; ensuring that RTO governing boards are representative, open, transparent, and independent from RTO management; requiring RTOs to demonstrate how the proposed market changes benefit customers; directing FERC and the RTOs to develop robust and consistent transmission planning criteria; and encouraging FERC to ensure that return on equity rates for transmission investments reflect current economic conditions and risk levels.

Thank you for the opportunity to appear before you today, and I would be happy to answer questions.

[The prepared statement of Lisa G. McAlister follows:]

U.S. House Subcommittee on Energy

Hearing on Powering America: Examining the State of the Electric Industry Through Market Participant Perspectives

July 18, 2017

Written Testimony of
Lisa G. McAlister
Senior Vice President and General Counsel of Regulatory Affairs,
American Municipal Power, Inc. (AMP)

Summary Points:

- American Municipal Power, Inc. (AMP) is the non-profit wholesale power supplier and service provider for 135 member municipal electric systems across nine states – with a majority of AMP's members being load-serving entities within the PJM region.
- AMP supports competitive markets, reliability and affordability but believes that the current capacity constructs in PJM are flawed and need a comprehensive review (in conjunction with the energy and ancillary services markets) of the cumulative impacts of PJM's overall market design on consumers.
- PJM's current capacity construct is a complex rules-driven administrative mechanism for pricing and procuring capacity that relies on distinctly non-market features. Over time, PJM's capacity construct has become less flexible and is incapable of accommodating state and public policy decisions.
- It is time to consider alternatives to the current capacity construct and AMP supports the broader use of bilateral contracting for load-serving entities, like AMP, to satisfy most or all of their capacity needs.
- AMP supports appropriate transmission infrastructure build-out to replace aging infrastructure. However, there needs to be more transparent transmission planning, equitable treatment, better oversight to ensure the most cost-effective and efficient grid expansion, and rates of return that reflect current economic conditions and risks.
- We support Congressional oversight and commend this Subcommittee for taking up these important matters.

Good morning, Chairman Upton, Vice Chairman Olson, Ranking Member Rush and distinguished members of the Subcommittee. My name is Lisa McAlister and I'm the Senior Vice President and General Counsel for Regulatory Affairs of American Municipal Power, Inc. (AMP). I'm pleased to have the opportunity to appear before you this morning to discuss the state of the electric markets in the Eastern Regional Transmission Organizations (RTOs) and my focus will be on the PJM Interconnection, LLC (PJM).

AMP has a unique vantage point on the state of the wholesale energy and capacity markets, the transmission planning that PJM oversees, and the impact of these policies on electric consumers. AMP is the non-profit wholesale power supplier and service provider for 135 member municipal electric systems across nine states – with a majority of AMP's members being load-serving entities (LSEs) within the PJM region. We are an active participant in the PJM stakeholder process and an active litigant in many of the administrative cases before the Federal Energy Regulatory Commission (FERC) that address the myriad changes to the PJM markets. AMP commends the Subcommittee for holding this hearing and appreciates the opportunity to share its perspective, and looks forward to discussing these matters further during the hearing.

The electric industry has experienced a number of changes throughout the past few decades – principally driven by regulatory actions. However, a discussion of the state of the electric industry must recognize that technology developments will be the principal driver to the changes confronting our industry going forward – be those grid modernization, customer-sited generation, shale gas, energy storage or cyber. While my remarks today will not focus on those technologies, AMP recognizes those drivers and we're working with our member municipal electric systems to ensure they have the tools needed to be prepared to meet their customer needs.

AMP is a member-focused organization and our members are customer-focused–therefore, the lens through which we view the impact of market changes is to ensure that the benefits of regulatory changes to improve reliability justify the costs to consumers.

I. Background

As you know, in the 1990s, the government decided to restructure the electricity industry, breaking vertically integrated utilities into generation and wires businesses and introducing competition in the generation sector. As the competitive market for generation began to emerge, it became clear that an impartial "traffic cop" with the authority to enforce grid reliability and operate the electric grid in a nondiscriminatory basis was needed to mitigate market power resulting from continued vertical integration of investor-owned utilities. FERC's landmark Orders 888, 889 and 2000 created independent system operators (ISOs), which have since become known also as regional transmission organizations (RTOs). Additional reforms by FERC and Congress continued the progress towards electricity market restructuring. With that progress came evolution of the RTOs and the development of RTO-run centralized wholesale markets.

Specifically, PJM began using locational marginal pricing (LMP) to set prices for energy purchases and sales in the PJM market and to price transmission congestion costs in 1997. FERC's basis for approving this market design was that LMP would send the proper price signals as to where generators should locate on the system, and where new transmission facilities should be constructed to relieve substantial and continuing congestion. But over time, it became evident that PJM's LMP energy market was not sending these signals—or at least that these signals were not being adequately responded to by market participants, chiefly generators and transmission owners. Electric generation owners in particular claimed that the existence of the $1,000 price cap prevented them from earning sufficient revenues to permit them to make the necessary investments. The "missing money problem" was repeatedly cited as justification for providing a separate locational capacity revenue stream for generation owners separate from energy market revenues. Accordingly, PJM developed its administrative capacity construct, called the Reliability Pricing Model (RPM). Again, the justification for RPM came down to the lack of a requirement for a long-term forward commitment for capacity as an obstacle to capacity resources being able to project an adequate revenue stream going forward. Consequently, PJM argued that the then-current, energy-only construct did not provide meaningful price signals to capacity resources of the true value of the level of reliability that they provide to the system.

In spite of the combined revenue that generators can obtain from the energy market and RPM capacity construct, as well as PJM's various ancillary services markets, the capacity constructs in particular have rapidly morphed beyond their intended purpose and require constant modifications to achieve desired outcomes. The capacity constructs are becoming increasingly complicated, bringing increased volatility and so much "rules churn" that any long-term planning and coordination is extremely difficult. For example, PJM's most recent changes add performance requirements that are overly restrictive and unnecessary. Further, what used to be an administrative construct to recover "missing money" is becoming a major source of revenue – and consumer costs – for many units. We are moving away from markets.

Due to market volatility and the constant rules churn, AMP embarked on a generation asset development effort a number of years ago to reduce its market exposure. As a result, today AMP has assets of more than $6.7 billion, including coal, gas and hydropower projects. Although AMP does own generation assets, AMP and its members remain net short on generation capacity and rely on market purchases to meet load obligations. Further, because AMP members are transmission-dependent and AMP does not own transmission, we rely on PJM and the transmission owners to plan and build and provide nondiscriminatory access to the transmission system to get our generation to our load.

II. Capacity Constructs

On May 1st and 2nd of this year, FERC held a technical conference to discuss the role of state policies in shaping the quantity and composition of resources needed to cost-effectively meet future reliability and operational needs in the Eastern RTOs and ISOs. The conference was a forum where FERC and the participants, including AMP, had a policy-level conversation about whether centralized capacity constructs are sufficiently flexible and robust to integrate state policies, while also satisfying reliability goals and meeting the needs of market participants and electric consumers in the face of an evolving resource mix.

Let me be clear at the outset: AMP supports competitive markets. Truly competitive markets are important to public power because they offer opportunities for our members to serve their customers at a lower cost. But, PJM's current administrative capacity adequacy construct is not a market in any meaningful sense. Rather, RPM is a complex rules-driven administrative mechanism for pricing and procuring capacity—one that relies on such distinctly non-market features as an artificial demand curve, price caps and minimum offer price requirements, and obstacles to competition from certain types of resources. And while the purpose of a true market is to arrive at the most efficient utilization of economic resources, RPM's acknowledged goal is to provide a stream of revenues to suppliers to make up for "missing money." RPM is a "market" in name only, and, as time has gone on, fewer and fewer PJM market participants use that term to describe it.

Another factor that sets RPM apart from a normal market is that RPM's rules are in constant flux. During the ten years RPM has been in effect, PJM has been in a near-constant state of developing, filing or defending some new set of RPM rules, some of which fundamentally changed the nature of RPM. In fact, since 2010, there have been 27 significant filings made to modify RPM. According to PJM, the 2016 Base Residual Auction (BRA) was the first BRA with no rule changes from the prior year. While PJM may view each set of rule changes as necessary to address some unforeseen events or to provide market design improvements, the constant "rules churn" that is RPM has a number of negative impacts. The ongoing accumulation of rules and patches to rules, for example, has produced an unduly complicated mechanism; at this point, in fact, RPM's complex web of rules, exceptions, and exceptions to exceptions is such as to confound many market participants while, at the same time, providing a cloak for gaming behavior by others. Furthermore, the ever-changing nature of RPM's rules makes long-term resource planning and coordination next to impossible. These dysfunctional attributes are manifest in the fact that, even after more than a decade of operation and countless tweaks and patches, RPM still falls woefully short in terms of its ability to:

- ensure reasonable, transparent and stable capacity prices;
- incent required levels of electric infrastructure development;
- promote fuel diversity (PJM has grown heavily dependent on natural gas generation); or
- provide any assurance that in the long term sufficient resources will be built to meet the region's reliability needs.

During FERC's September 25, 2013 Technical Conference on Centralized Capacity Constructs, PJM delivered a report on RPM's goals and its claimed successes in several areas, including that of bringing forth the right capacity investments in the right locations. Yet, less than a year later, PJM believed it necessary to propose a fundamental overhaul of RPM in the form of its Capacity Performance (CP) proposal. Touted as a response to the polar vortex of early 2014, CP was rich in features that were uniquely disruptive and burdensome for stakeholders, such as unreasonable operational performance requirements, a paradigm shift for seasonal resource participation, penalties disconnected from the value of performance at the time and with the potential to exceed capacity revenue, and a near complete unwinding of the market mitigation rules governing offer caps, to name a few. Rather than seeking to meet the challenge of extreme demands by adding flexibility to PJM's capacity construct, CP instead adopted an inflexible product definition that discourages fuel and technology diversity by imposing strict performance requirements which disregard the fact that, even among the most well-managed units, there will be variations in forced outage rates, fuel supply arrangements, ramping rates and minimum load levels, and environmental restrictions, among other things. And because CP imposes unduly discriminatory restrictions and requirements on the use of renewable and demand response resources, a whole family of resources that historically provided significant value to the region now are greatly hampered in the value they can bring. For example, as a result of feedback and strategic direction from our members and their customers, AMP made decisions to develop four new hydroelectric facilities totaling over 300 MW at an investment cost of nearly $3 billion. Those local decisions were reached in furtherance of a power supply strategy that incorporates long-lived (80-100 year) emission-free resources to avoid market volatility, and were pursued irrespective of RPM price signals or its three-year look-ahead. However, as a result of the move to CP, AMP cannot get full value for its hydroelectric infrastructure as they cannot guarantee 24/7/365 operation. This is the case because AMP cannot control the river flows and cannot practically back up the hydroelectric plants with an alternative generation resource. In making PJM's capacity construct less flexible, CP also has made it less capable of integrating the diversity of resources that may be an element of implementing important state policies.

Another example of the unreasonable effect of CP on AMP specifically has been to put AMP at risk of not being able to use its coal resource in one RTO (MISO) to serve its load in another RTO (PJM). With FERC's acquiescence, and against AMP's protests, FirstEnergy and Duke Energy withdrew from MISO to participate in PJM. A sizable number of AMP's members are served from the transmission facilities owned by FirstEnergy and Duke, so prior to those companies' RTO "realignment," a considerable portion of AMP's member load was located within MISO. That was the situation that existed when AMP negotiated the purchase of its 368 MW share of the Prairie State Generating Campus (Prairie State). When FirstEnergy and Duke moved into PJM, however, the interconnected AMP members were compelled as a practical matter to move into PJM, as well. Consequently, AMP found itself in the situation in which Prairie

State and other supply resources remained within MISO while most of its load was located in PJM. That outcome was one over which AMP had no control and it is the situation that continues to this day. However, today PJM's new CP rules require all capacity resources physically located outside of PJM to pseudo-tie into PJM to qualify as capacity resources. Thus, in order to utilize Prairie State for its intended purpose — namely, providing long-term power supply service to AMP's members in an economical and reliable manner (and not to take advantage of more advantageous market conditions in one RTO or the other), AMP is required to use a pseudo-tie arrangement to offer AMP's Prairie State share into PJM's capacity auctions. However, the pseudo-ties are currently under attack from competitive generators and other RTOs, among others. If AMP's use of that pseudo-tie becomes burdened to the point that it is rendered uneconomic, AMP's members would be deprived of the intended benefits of a resource in which AMP has invested significant capital and resources to serve its members.

More recently, PJM has faced another development it seems to view as a challenge to RPM—namely, the efforts by some states and LSEs to take a direct role in guiding the resource mix in order to implement state policies. These efforts have taken the form of legislatively required affiliate power purchase agreements (Ohio) that some market participants have opposed as "out of market threats" to RPM. FERC's questions in the April 13 Notice of Technical Conference suggest that it, too, has concerns about the impacts that policy-implementing payments to capacity resources may have on current RTO capacity constructs. An effort to distinguish between state actions that are "inside" versus "outside" the market would be misplaced, however, especially if the purpose of the distinction is to insulate the current capacity constructs from the "outside" influence of state policies. The reality is that, today, there already are factors at work that could be portrayed as "out of market" subsidies or advantages, such as state or local tax incentives, differing access to certain financing methods or vehicles, and variations in the cost of financing. Each of these factors ultimately has its roots in a particular state or local policy that may have differing effects across the spectrum of market participants and resources. Given this history, it is reasonable to expect that state and local governments, who are closer to and likely to take their cues from ultimate consumers, will continue in their efforts to guide asset decisions toward those that comport with relevant policies (as well as their long-term planning goals) regardless of the short-term and volatile signals produced by RPM and for reasons unrelated to the administrative determination of net Cost of New Entry (CONE) or Energy and Ancillary Services offsets. In a true market, nothing is truly "out of market."

AMP and its members, for example, retain the obligation to serve customers and, thus, AMP makes long-term strategic decisions, like whether to add distributed generation or deploy Advanced Metering Infrastructure, based upon the feedback and direction of our members and their customers. AMP is not alone; each state has valid environmental, political and policy goals that factor in a plethora of local and state considerations beyond the ability of a mechanistic administrative construct to accommodate. Consumers, and by extension their elected officials, are the parties best positioned to assign value to externalities in resource decision making. Self-supply is at the very core of public power's organizational model, and AMP's existence. An administrative construct that fails to accommodate those choices (because it can't) will always be "missing money."

PJM needs a resource adequacy construct that is robust enough to withstand the effect of external events without the need to adopt another set of complex rule changes in response to each event. There are alternatives to the current centralized capacity constructs that, in concert with the energy and ancillary services markets and shortage pricing, would be more resilient to external events. Simpler, more robust alternatives to RPM and centralized capacity constructs exist.

One such alternative is for LSEs to satisfy most or all of their capacity needs through bilateral arrangements, in a real marketplace where willing buyers and willing sellers negotiate arrangements tailored to meet the parties' individual wants and needs (*e.g.,* as to contract term, fuel type and resource flexibility, location on the grid, and financial terms), with a capacity auction available to satisfy any residual needs. Under such an approach, the RTO would retain its role of developing and specifying resource adequacy requirements for its footprint and Local Distribution Companies (LDCs) of concern. Each LSE, LDC or other Relevant Electric Retail Rate Authority (RERRA) would be responsible for securing capacity to meet its peak load obligation plus a predetermined reserve margin and would face significant penalties for failing to do so. LSEs, LDCs and RERRAs could procure resources bilaterally on a long-term portfolio basis in compliance with their respective resource adequacy requirements. The RTO could then conduct a residual auction to accommodate LSEs and supply that did not enter into long-term arrangements. This alternative has numerous advantages over current capacity constructs, including the following:

- **Fewer Moving Parts and Administrative Judgments**. Because the primary procurement construct is decentralized and bilateral, it eliminates the onerous stakeholder processes, disputes and subsequent litigation over discrete features of mandatory capacity constructs.

- **Harmonization with State and Local Public Resource Policies**. This proposal appropriately honors state and local resource portfolio and public policy choices, and does not bias market rules toward or against specific resource types.

- **Avoidance of Jurisdictional Disputes**. By appropriately involving state and local authorities in the resource adequacy, constrained zone mitigation and market power issues, this alternative sidesteps controversy over respective limits of state and federal jurisdiction in the capacity market area created by recent court decisions.

- **Flexibility for Individual States**. This proposal provides each individual state within an RTO region with the flexibility to address resource adequacy issues for its retail customers that may result from the state's prior decisions regarding retail access. An RTO-administered, centralized voluntary capacity market still would be available to satisfy residual needs.

- **Improved Product Differentiation and Resource Performance**. Bilateral contracting and other customized arrangements to procure electric resources enables the development of tailored products and services that will meet specific needs rather than relying solely on generic, lowest common denominator-type capacity products. For example, resources with desirable characteristics, such as those with dual fuel capability or firm gas transportation contracts that allow for certainty during winter peaks, could be appropriately valued and supported without complex and costly performance penalties.

- **Choice of Business Models for Merchant Generators**. This proposal provides merchant generators and resource suppliers a choice as well: they can enter into individualized bilateral supply arrangements with LSEs, rely on sales into the residual capacity auction (and/or the energy and ancillary services markets) to obtain their revenues, or pursue any combination of these approaches.

In evaluating the viability of the bilateral contracting model, we believe the benchmark should be the value bilateral contracting would bring to market efficiency and reliability and its amenability to implementing varying state policies, rather than its implications for existing centralized capacity constructs. Moreover, in considering this alternative to centralized capacity constructs, the policy concerns that might lead LSEs, states or local regulatory bodies to favor local generation over distant generation; newer, more efficient resources over older, less efficient ones; lower-emitting resources over higher-emitting resources, *etc.*, are legitimate concerns deserving of recognition and weight, and, second, policymakers will continue pursuing policies at the direction of their constituents. Market rules imposed by RTOs to protect administratively derived prices under centralized capacity procurement constructs should not erect barriers to meeting such policy goals. And, it bears noting, these prices, developed as they are in isolation from local consumer input, will be wrong. Capacity is not fungible and not all MWs of capacity are created equal. Consumers are in a better position to determine the value of a particular fuel or resource. Long-term contracts support legitimate public policy and should be encouraged, rather than being considered "out-of-market" subsidies. RTO market rules that effectively penalize long-term contracting and self-supply should be reformed.

As a second-tier alternative, and a minimum step to reform the capacity construct, public power systems' unfettered ability to self-supply their own loads with their own resources at their own costs should be restored. Although the original settlement that created PJM's capacity construct guaranteed that capacity resources of public power LSEs and other self-supply entities, like AMP, would clear, over time the PJM rules have changed and have stripped away guaranteed clearing for self-supply. This has resulted from modification of the minimum offer price rules (MOPR) that were deemed necessary to mitigate buyer-side market power. Buyer-side market power, also known as monopsony power, is defined as the power of a buyer facing many sellers and little to no competition from other buyers. *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 84 (3d Cir. 2014). The MOPR in PJM, in its original form, had a basis in economic theory: it targeted a limited set of new or uprated resources (new gas-fired resources) but did not apply to new nuclear, coal, hydroelectric, renewable, or energy storage resources, because these resources cannot be developed on a timeframe and at a size that could allow the exercise of buyer-side market power. The PJM MOPR has always been applied only to new entrants into the capacity market. It properly does not include existing resources as existing units have sunk costs that new units do not have. Initially, public power entities were exempted from MOPRs in PJM on the basis that they have no incentive to attempt to manipulate the market through below market offers. This is true because public power's business model effectively prohibits anything other than legitimate self-supply as they are non-profit entities whose purpose is to secure long-term supply arrangements at the lowest possible cost and they use tax-advantaged and tax-exempt financing to do that. There are real obligations that come with using such financing, including: 1) a prohibition on both the municipal LSE and any participants in a project financed with tax-advantaged obligations against using the project for anything other than the governmental purposes of the municipal LSE or project participant; and, 2) a prohibition against the municipal LSE or any project participant using their interest in the project for any activities that constitute a "private use" for the entire term the obligations remain outstanding. If a public power entity fails to comply with the requirements, the tax status of obligations issued by the municipal LSEs could be jeopardized and result in significant economic harm. In other words, the federal tax requirements on tax-advantaged obligations that are critical to the longstanding business models of public power entities serve as effective barriers against such entities building generation as merchant generation, market manipulation, or anything other than legitimate self-supply. Nonetheless, due to pressure from competitive generators, the MOPR rules were modified to include self-supply entities.

Most recently, on July 7, 2017, the U.S. Court of Appeals for the District of Columbia Circuit vacated and remanded back to FERC prior orders that accepted PJM's revisions to the MOPR in PJM's capacity auction rules with respect to several aspects of a PJM-proposed rate structure: the self-supply exemption, the competitive entry exemption, unit-specific review, and the mitigation period, on the basis that FERC exceeded the limits of its Federal Power Act Section 205 authority by suggesting modifications to PJM's proposal, which PJM accepted.

As a result of this decision, self-supply entities are squarely at risk of having to pay twice to satisfy the same capacity obligation - once for the resource procured outside of PJM's resource adequacy construct and a second time to procure through RPM to replace self-supply that failed to clear the auction. The decision also does nothing to promote consumer welfare as any blanket proposal that replaces lower cost offers with higher, administratively determined offers has more to do with maintaining existing seller-side market power than tailoring a real solution to a real problem.

It is worth noting also that there have been a number of calls, mostly from merchant generators, for FERC and/or RTOs to expand the application of MOPR to existing units in addition to new gas-fired units. AMP strongly believes that applying MOPR to existing units defies rational economic theory; takes more of the auction process behind closed doors as PJM and the Independent Market Monitor determine units' costs; and, introduces unwarranted uncertainty as generation resources could no longer know whether they will clear the market or not, resulting in the unintended consequence of severely damaging the bilateral market.

Finally, the consumer impacts of market reform alternatives must not be ignored. Market participants wishing to protect their economic interests dominate FERC adjudicative dockets and RTO stakeholder processes. In these fora, the interests of "load"—retail consumers and those charged with protecting them—often are drowned out by the self-interested concerns of larger and better-financed participants.

III. Energy Markets

Of the two wholesale electricity markets, the energy markets are better able to value or select additional attributes than the capacity constructs. As a result of FERC's last technical conference on this subject in the fall of 2013, FERC has done an admirable job in trying to improve price formation. This is the right track. And, while there are new technologies with different operating parameters and capabilities we need to address (distributed resources, energy storage), we must not lose sight of improving our current price formation processes regarding transparency of operator decisions, modeling all known constraints, and more accurate price formation rules during periods of transmission congestion and volatile fuel prices.

Improved energy market rules will be essential to address the rapidly changing technological demographic of intermittent resources with a zero energy cost. New energy products will be needed to allow RTOs to properly dispatch and balance the system, even at high levels of penetration by intermittent resources. For that reason, new energy products also must incentivize the retention of sufficient non-variable resources to ensure load continues to be served when intermittent resources are not generating.

IV. Transmission

AMP would be remiss to not touch on the third largest (and growing) component of wholesale electric bills: transmission. Nationally, transmission costs have increased drastically. According to the Edison Electric Institute's (EEI) December 2016 Transmission Projects at a Glance, increases in year-over-year total transmission investment by EEI's members reached approximately $20.1 billion in 2015 and are expected to increase through 2017 to a peak of approximately $22.5 billion in 2017. The Brattle Group, in a 2015 presentation to a JP Morgan Investor Conference, demonstrated these costs have been increasing exponentially since 1995. The build-out trend is expected to continue at a rate of $5 to $10 billion annually as infrastructure built in the 1960's reaches the end of its life and is replaced. According to Navigant, global spending on large-scale transmission system infrastructure for renewable energy integration is expected to grow from $36.7 billion in 2016 to $46.7 billion in 2025.

Locally, AMP's members have experienced similar increases over the past eight years. In four of AMP members' transmission zones, annual revenue requirements have increased by a range of 99 percent to 214 percent from 2009 through 2016.

AMP's members are willing to pay their share of costs, but must work to make sure these costs lead to the most cost-effective and efficient grid expansion. The transmission grid must be planned for the future, rather than piecemeal replacement of the grid of the past. The transmission planning process must be open and transparent, must provide equitable treatment, and take into account the changing resource mix and configuration of the future. This can be accomplished by a number of steps.

More robust planning processes for transparency and replicability are required. In PJM, since 2005, almost $19B in projects have been proposed absent transparent criteria and models that stakeholders can review and comment on prior to the plans being finalized, despite the fact that the transmission owners have turned over the planning and operation of their facilities to PJM. These supplemental projects are not needed to address any established NERC, PJM or even individual transmission owner criteria.

In addition to a lack of consistent planning criteria among transmission owners, different planning criteria and processes between different organized markets (RTOs/ISOs) hinder inter-regional projects from being built. The interregional planning process needs to move away from compartmentalized and multiple threshold evaluations and evaluate interregional projects based on their combined benefits across all regions.

In 2016, AMP and other public power organizations in PJM sponsored a new stakeholder effort to address the PJM Transmission Owners' use of Supplemental Projects to replace aging transmission infrastructure. This effort was placed on a hiatus when FERC issued a show cause order (EL16-71) with the concern that the PJM planning process is not providing stakeholders with the opportunity for early and meaningful input and participation in the transmission planning process, as required by Order No. 890. The stakeholders agreed to put their effort on hold to enable PJM and the Transmission Owners to prepare their responses to this order. With the subsequent lack of a FERC quorum, this hiatus was extended until just this month when AMP led a group of stakeholders to ensure efforts started back again. The PJM Transmission Owners have consistently opposed formation of this group and its returning to work.

More robust planning models that account for changing grid drivers are also required. We need better models via improved software to generate a common model that can accurately include all known system constraints. New drivers that must be considered include distributed intermittent renewables, smart grid/micro grid opportunities, aging transmission facilities, generation retirements and future environmental requirements. These drivers could reduce the need for transmission investments and failure to consider these factors could result in unnecessary investments and higher electric rates. The U.S. Department of Energy (DOE) and FERC must continue their focus in this area and fully engage the industry in this endeavor.

While it is essential for developers to earn a fair rate of return on their investments in transmission infrastructure, these rates should reflect current economic conditions and risks, and not have the unintended consequence of encouraging building or over-building for the sake of revenue generation. Return on Equity (ROE) rates must reflect current economic conditions and additional incentives must be awarded judiciously to reflect actual levels of risk.

V. Conclusion

AMP supports Congress playing a more active role in encouraging FERC to refocus on its statutory mandate to ensure "just and reasonable" rates for customers in a meaningful way, and to examine whether net customer benefits exist for the multitude of RTO market mechanisms deployed, proposed and on the horizon in the Eastern RTOs.

Enhanced congressional oversight is critical to ensure that FERC is responsive to the real needs of consumers. Congress can be helpful by:

- Insisting that keeping costs to consumers as low as possible be a central part of the RTO mission, in addition to promoting electric system reliability;

- Reiterating that LSEs, through their obligation to serve their customers, have a right to make generation resource decisions that are not subject to rejection by the RTO or FERC;

- Insisting that resource adequacy constructs have the flexibility and capability to accommodate state and public policy decisions;

- Ensuring that RTO governing boards are truly representative and open, transparent stakeholder boards (i.e., meaning they reflect all load-serving entities and hold open meetings);

- Ensure that RTO governing boards are independent from RTO management and act solely in the interest of the RTO, are free from conflicts that compromise judgment and are able to take positions in opposition to management;

- Requiring RTOs to demonstrate that proposed market changes benefit consumers (i.e., stop the creation of new markets and products for the sake of creating markets and products);

- Requiring FERC to consider real-world outcomes in its decision-making (including balancing consumer, financial, environmental and other impacts);

- Directing FERC and the RTOs to develop robust and consistent planning criteria among transmission owners and RTOs; and,

- Encouraging FERC to ensure that ROE rates for transmission investments reflect current economic conditions and actual risk levels for the investments.

In closing, I want to stress that AMP supports both competitive markets and transmission infrastructure build-out. However, the current capacity constructs are not competitive markets. They can and should be simplified to ensure they are achieving the policy goals for which they were designed: ensure resource adequacy; balance the numerous goals of safety, resource adequacy, consumer affordability, environmental sustainability, and financial stability to provide less price volatility to consumers; be consistent with the needs of wholesale customers and consumer preferences (and operate within the constraints) as reflected through applicable state environmental programs and all other jurisdictional policy objectives; accommodate all types of business platforms (merchant or competitive entries, investor owned utilities, and public power self-supply); facilitate trade to include bilateral contracting and not have market rules that restrict the use of available capacity; and produce just and reasonable rates.

In order to ensure that the right transmission is getting built at just and reasonable rates, transmission infrastructure must be designed and built in accordance with FERC direction and principles of coordination, openness, transparency, information exchange and comparability. Customers and transmission-dependent utilities like AMP and our members must have the ability to ensure that planned facilities are indeed necessary and economical and must have a meaningful opportunity for review and input after reviewing the transmission owners' transparent criteria, assumptions and models.

Thank you again for the opportunity to appear before you today; I would be happy to respond to any questions.

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Mr. UPTON. Thank you. Thanks very much.

Next, we are joined by Steven Schleimer, senior VP of Government & Regulatory Affairs at Calpine. Welcome, nice to see you.

STATEMENT OF STEVEN SCHLEIMER

Mr. SCHLEIMER. Good morning, Chairman Upton, Ranking Member Rush, and members of the subcommittee. Thank you for inviting me to testify today. Calpine is not a regulated utility receiving a guaranteed payment from customers. Rather, we compete head to head with other suppliers to sell power directly to wholesale and retail customers in the competitive markets across the country.

We have 26,000 megawatts of mostly natural gas-fired combined cycles and that is enough to power 25 to 30 million homes. We also own the Geysers plant in California which is the largest geothermal facility in the United States.

The first key takeaway I would like to impress upon you is that the competitive markets and particularly in the East Coast and Texas have been phenomenally successful. Over the last decade, there has been over 50,000 megawatts of new generation either committed or entering operations, representing $70 to $80 billion of new investment.

At the same time, as has been noted, wholesale prices are at historic lows, commissions rates are down significantly as well. The reserve margin, which is a measure of grid reliability, is significantly higher in each of these regions as well. All of this is clearly a win for consumers and the environment.

However, due to various policy goals and pressure from nuclear and coal generators, state policy makers have been increasingly intervening in competitive markets to bail out or subsidize specific plants. Examples include the New York and Illinois ZEC program along with current attempts to create subsidies in Ohio and Connecticut and nascent attempts in Pennsylvania and New Jersey, which were expected. If left unchecked, these efforts threaten the continued viability of competition in these regions. Investors are simply not going to invest in new infrastructure if they believe their direct competitors will receive out of market subsidy payments.

So now we get to the second key takeaway I would like to impress upon you, the half-in/half-out hybrid market where the state relies on the competitive market for some resource needs but then target subsidies to select power plants does not work. Once the subsidies start, competitive investment stops.

And how do we know that? We have seen exactly this result in California which decided to move away from competition and toward this hybrid half in/half out model more than a decade ago. And now new investment only occurs with long-term contracts from utilities and their captive customers. This is not necessarily a bad thing, that is just a policy decision California made.

In addition, a growing problem is that virtually all the existing generation left over from the competitive era is barely covering its costs or is losing money, yet some of these resources are absolutely critical for keeping the lights on in specific locations, for example in the San Francisco Bay Area. If one of these remaining competitive units suffers a major mechanical breakdown, it is unclear whether any investment would make sense without a guaranteed long-term payment from the utilities or the customers just to bring the unit back.

So the lesson learned from California is that half in/half out of competitive electricity markets doesn't work. Once the subsidies and bailouts really take hold it kills the competitive part. Investment dries up and long-term ratepayer guarantees are required to fund any new infrastructure or even to maintain existing infrastructure. Subsidies beget subsidies would beget more subsidies. So this is exactly what we are concerned about happening in the eastern market if we do not address the targeted subsidy issue now.

The good news is that both PJM and ISO in New England are actively engaged on these issues and have developed innovative proposals that are intended to allow a state to meet its public policy goals, but act as a firewall to protect the integrity of the wholesale competitive market. Both proposals have significant promise and may well result in workable solutions.

So let me just wrap up by reiterating that competitive wholesale markets have produced phenomenal results for benefits for consumers. On the one hand, investment is up and reliability is up. On the other hand, prices are down and emissions rates are down. So these achievements, however, are in jeopardy due to the desire to subsidize or bail out certain generation units.

The half in/half out competitive market model is unsustainable if you move towards the hybrid, so a coordinated effort is needed between all the states, FERC, and system operators to develop solutions that allows the states to pursue their public policy goals but is done in a way that allows the impact of that to be firewalled off from the rest of the wholesale market. Thank you.

[The prepared statement of Steven Schleimer follows:]

Statement of Steven Schleimer
Senior Vice President, Government and Regulatory Affairs, Calpine Corporation
Before the U.S. House of Representatives Committee on Energy and Commerce
Subcommittee on Energy
Hearing on "Powering America: Examining the State of the Electric Industry through Market Participant Perspectives"

July 18, 2017

Good morning Chairman Upton, Ranking Member Rush and members of the Subcommittee. Thank you for inviting me to testify today on the topic of "Powering America: Examining the State of the Electric Industry through Market Participant Perspectives." My name is Steven Schleimer and I serve as the Senior Vice President of Government and Regulatory Affairs of Calpine Corporation ("Calpine").

The most important message I can deliver today is that the deregulated markets are working and there is no action needed from you. This is not to say that the markets are perfect, but FERC and the ISOs have the tools they need to fine tune them. But, more about that later. First, let me introduce Calpine, which is an independent power producer ("IPP") that owns more than 26,000 megawatts (MW) of generation capacity from 80 power plants across the country, and we sell wholesale electricity in most of the regional markets, as well as directly to retail customers in 25 states. Calpine's Geysers plant in California is the largest geothermal power generating facility in the United States, which allows us to sell more renewable power than anyone else in the state. Importantly, Geysers is a dependable renewable resource that generates 24 hours per day, 365 days per year. In addition, within the United States, Calpine is the largest operator of combined heat and power facilities, the largest consumer of natural gas in the electricity sector, and through our affiliated companies is one of the largest suppliers of electricity to retail (end use) customers. We are not a regulated utility receiving a guaranteed return. Rather, we compete against other generators and retail suppliers to sell power directly to wholesale and retail customers. So the economics of supply and demand are fundamental to our business.

As a result of our generation and retail customer portfolio, Calpine is actively involved in virtually all the regional competitive markets, with a focus on PJM and ISO-NE (hereinafter referred to as "East Coast Markets"), CAISO, and ERCOT. Our public policy advocacy in these regions rests on two fundamental principles: reliance on markets to provide the most efficient outcomes as well as environmental stewardship. In fact, despite our size, Calpine's fleet is environmentally the cleanest among the major players in America's IPP sector.

My two key messages today are: First, the competitive electric sector, in particular the East Coast Markets and Texas are successful and functioning well. Significant new resource investment is occurring at a pace that is creating an increasingly reliable system, wholesale prices are generally at historic lows, and environmental emissions are down. These new resource investments are being made due to the game-changing discovery of shale natural gas, the existence of a competitive market with clearly defined rules, and a commitment by the stakeholders to seeing the market function.

Second, the East Coast Markets are now facing serious challenges. Due to various goals and pressure from incumbent generators, state policymakers have been increasing their efforts to pick winners and losers through out-of-market mandates and subsidies in their respective states. If left unchecked, these state efforts threaten the continued viability of competition in these regions. A "hybrid" market, where a state relies in part on the competitive wholesale electricity market to meet its resource needs, but also retains the right to select and subsidize preferred generation resource types to meet certain public policy goals, does not work and destroys all new competitive investment. Investors are simply not going to put their money into new infrastructure if they believe their direct competitors will receive out-of-market subsidies. A coordinated effort between all the stakeholders, particularly between the states and FERC, is needed to develop solutions that allow states to achieve their policy goals while at the same time protecting the wholesale market. The good news is efforts are already underway in those regions to address the issue.

Before going deeper into the specific issues, let me first note that the competitive electricity markets across the country are different from each other because of varying resource mixes, market structures, and policy goals. As a result, the defining issues in the East Coast Markets are different than the issues in California, which are different than those in Texas. For this reason, I will spend the rest of my time focusing on each region individually, starting with the East Coast.

The East Coast Competitive Markets Have Been Overwhelmingly Successful Thus Far, but There Are Storm Clouds Brewing On the Horizon

By any measure, the results produced by the East Coast Markets have been a benefit to consumer's pocketbooks, to the environment, as well as to the maintenance of a reliable grid. The market-driven competitive electric sector is on a transitional path from one supported by older, less efficient, and more costly power plants to one support by newer more efficient, less expensive, and cleaner natural gas plants. For the Base Residual Auctions in PJM's capacity market occurring between 2010-2015, approximately 24,000 MW of new generation were cleared and committed, of which 87 percent were natural gas resources.[1] This represents tens of billions of dollars of new investment in the region, including a new plant Calpine brought online in Delaware a few years ago, and another one currently under construction in Pennsylvania. Concurrent with the expansion

[1] http://www.pjm.com/~/media/library/reports-notices/special-reports/20160505-resource-investment-in-competitive-markets-paper.ashx

of natural gas fired generation capacity, there is also a significant amount of pipeline infrastructure occurring in the Northeastern US. For example, since 2014, almost 4 Billion Cubic Feet ("Bcf") of new pipeline capacity has been built to export Pennsylvania gas to other states, representing investment of more than $2 Billion. Almost 6 Bcf more is expected to be built between now and 2021, calling for investment of another $3.5 Billion.[2]

In PJM, wholesale prices today are lower in real terms than they were in 2000. Emissions are down significantly as well: Between 2005 and 2015, on a pounds of emissions per MWh basis, CO_2 emissions have decreased by 21%, NOx emissions decreased by 70%, and SO2 emissions decreased by 81%.[3] At the same time, the grid has become more fuel diverse, not less as some claim. In 2005, coal and nuclear represented 55% and 34% of PJM generation, respectively, with natural gas at only 5.3%. In 2015, the system was more well balanced and diverse, with coal and nuclear each at about 35% market share, and natural gas at approximately 23%.[4] Finally, PJM's market enjoys a reserve margin, which is a measure of grid reliability, that is significantly higher than its target.

Similarly, in ISO-NE, wholesale prices dropped 52 percent between 2006 and 2016, and are at historic lows since the current competitive market was established.[5] Since 2001, regional generator air emissions are down as the region shifted away from burning coal and oil to natural gas with NO_x falling by 68 percent, SO_2 by 95 percent, and CO_2 by 24 percent.[6] The investment in 15,000 MW of new generation, of which 87 percent is natural gas, has been largely responsible

[2] Calpine Company Analysis. FERC aggregated reports. https://www.ferc.gov/industries/gas/indus-act/pipelines/approved-projects.asp
[3] http://kleinmanenergy.upenn.edu/paper/electricity-competition
[4] Id.
[5] https://www.iso-ne.com/static-assets/documents/2017/02/20170227_pr_2016_price_release.pdf
[6] https://www.iso-ne.com/static-assets/documents/2017/02/2017_reo.pdf

for this significant long-term reduction.[7] ISO-NE's market also enjoys a reserve margin which is significantly higher than its target.

However, as I noted earlier, due to various goals and pressure from incumbent generators, state policymakers have been increasing their efforts to impact the generation mix in their respective states. Specific examples include the New York and Illinois "Zero Emissions Credit" programs, along with recent attempts to create subsidies for targeted generation units in Ohio and Connecticut. In New England, Massachusetts has established aggressive renewable mandates, calling for the utilities in the region to issue requests for proposals from certain types of preferred resources such as Canadian hydro and offshore wind, and to enter into long-term contracts with those resources if authorized by the state regulator. If executed, these contracts will obligate New England consumers to spend billions of dollars on high priced renewable generation outside of the competitive market structure. While these policy goals may be well intended, they nevertheless are having a significant, negative impact on the East Coast Markets. If not addressed, out-of-market subsidies will undermine competition, investment will dry up, and these states will be back in the business of mandating when, where, and what type of new generation will be built through long-term ratepayer guarantees, which is exactly the structure we moved away from several decades ago.

In a very helpful move, FERC recently held a technical conference to provide a forum for interested parties to participate and share views on ways to address the impact of state polices on the wholesale markets operated by PJM, ISO-NE, as well as NYISO. While many participants agreed that recent state actions are threatening the viability of the East Coast Markets, there was little agreement on the appropriate path forward to address these actions. Calpine's view is that

[7] https://www.iso-ne.com/about/key-stats/resource-mix

FERC and the RTOs must create new market rules that allow a state to meet its public policy goals, but at the same time protects the integrity of the wholesale market. The good news is that the regional organizations are actively engaged on these issues and have developed market proposals that would allow state policy intervention and competitive wholesale markets to exist side by side. Both proposals have significant promise and may well result in workable solutions.

Now I will move on to discuss the California electricity market.

California Has Moved Away From a Competitive Wholesale Market Model, and the Key Issue is How to Compensate Competitive Generators Needed for Ongoing Reliability

In 1998, California opened its wholesale and retail electricity markets, which prompted significant investment in generation by competitive suppliers. However, as a result of the state's energy crisis in 2000/2001, as well as the desire to significantly decarbonize the grid, the state moved back to a more centrally planned electricity system in the mid-2000's. On the one hand, this initiative has been highly successful in bringing resources online -- since that time over 10,000 MW of conventional gas fired generation has been built, in addition to another approximately 20,000 MW of renewables.[8] The state currently has a reserve margin more than twice needed to meet its target. The downside is that all this investment is supported by mandate-driven long-term contracting programs. These long-term contracting practices have decimated the competitive market, and competitive suppliers (who are still dependent on the market for their revenue) are no longer willing to make any investment without a guaranteed payment. In addition, since the policies that bring about this substantial investment are divorced from competitive wholesale markets, it has led to the paradox that while retail rates are amongst the highest in the country as a

[8]http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/Q4_2016_RPS_Report_to_the_Legislature_FINAL.pdf

result of these contracting mandates, wholesale prices are so low that the economic viability of the remaining generation that is dependent on competitive wholesale markets (generally existing conventional generation resources acquired or built when the market was competitive) is increasingly threatened.

To put the issues in context relative to Calpine, in its February 2016 earnings call, Calpine presented a graphic which showed that the approximately 3,500 MW of currently uncontracted, gas-fired CCGT generation it owns in California produces approximately $20 million of free cash flow per year.[9] While $20 million may sound like a lot, keep in mind this is relative to an unrecovered investment representing several billion dollars, so is actually a very small amount. If one of these units suffers a major mechanical breakdown, it is unclear whether anything beyond a nominal investment would make sense to bring the unit back into service.

To be clear, unlike what other companies are pursuing in the Eastern markets, Calpine is not seeking a bailout for these resources. In fact, we have already removed one 578 MW facility from service, and are scheduled to remove two other peaking facilities at the end of the year. Interestingly, the facility Calpine already removed from service was the Sutter Energy Center, an efficient combined cycle natural gas fired facility that was the first power plant to come online during the summer of 2001, helping to ease California's energy crisis. So, while competitive resources are struggling to cover their costs, current CAISO analyses indicate that some of them are absolutely critical for maintaining reliability in specific locations. We are urging state policymakers to identify which of those resources are needed to maintain reliability, and to apply existing mechanisms in the California ISO tariff that provides sufficient compensation to ensure the ongoing viability of this critical infrastructure.

[9] http://s2.q4cdn.com/871785789/files/doc_presentations/2016/CPN-4Q15-Earnings-Presentation.pdf

Finally, I will cover the Texas electricity market.

Texas' Market is Fundamentally Working Well, but Some Improvements are Needed

Over the last 5 years, wholesale electricity prices have declined by over 13 percent in Texas, and are at historic lows.[10] Emissions are down significantly as well. Between 2010 and 2016, on a pounds of emissions per MWh basis, CO_2 emissions have decreased by nearly 5 percent, NO_x emissions have decreased by 24 percent, and SO_2 emissions are down nearly 40 percent.[11] Between 2012 and 2016, Texas' competitive wholesale market spurred the construction of more than 14,000 MW of new generation, consisting of both wind and natural gas fired resources.[12]

Unlike the East Coast Markets, Texas does not have a capacity market, which is a structure in which the grid operator compensates generators for being available to provide power at some point in the future. This mechanism creates a forward price that signals to competitive generators when and where to invest. Instead, Texas relies on spot energy prices alone to signal the need for generation investment. While Calpine believes that a capacity market is a much more efficient and reliable structure over the longer term, Texas decided a couple of years ago to stay with its current energy-only design. We are confident this decision will be revisited at some point in the future. In the meantime, however, the Texas Public Utilities Commission recently opened a proceeding to examine improvements to the energy market structure, and we are hopeful changes can be made to make the market even more efficient and beneficial for consumers.

[10] https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-ERCOT-State-of-the-Market-Report.pdf
[11] http://www.ercot.com/mktinfo/retail/electric
[12] May 2017 CDR Report

Conclusion

Competitive wholesale markets have produced phenomenal benefits for consumers. Thousands of megawatts of new generation have been built, thus ensuring reliability, and old, inefficient generation has retired. Wholesale prices have decreased dramatically over the last 10 years, and investors, rather than ratepayers, are bearing the economic risk for the success or failure of generation facilities. The markets have done exactly what they were intended to do. These achievements, however, are in jeopardy. Due to state policymaker actions to subsidize certain generation, competition is being threatened. A hybrid model, where the states subsidize some generation but leave the remaining generation to rely on the market for their revenue, is unsustainable. A coordinated effort is needed between all the states, FERC, and market participants to develop solutions that allow states to pursue their policy goals while also protecting the wholesale markets. Such an effort will require leadership and a commitment to competitive markets, but if we have both, we will be able to develop solutions that ensure the continued viability of these markets.

Mr. UPTON. Thank you.

Next, we are joined by Jackson Reasor, CEO of Old Dominion Electric. Thank you and welcome.

STATEMENT OF JACKSON REASOR

Mr. REASOR. Chairman Upton, Ranking Member Rush, and members of the Energy Subcommittee, my name is Jack Reasor. I am president and CEO of Old Dominion Electric Cooperative in Glen Allen, Virginia. Old Dominion is pleased that the Energy Subcommittee is holding this hearing and that we have been invited to present our perspective as a wholesale market participant. And I must say, Mr. Chairman, I am very proud and pleased to find myself literally in the center of this presentation.

Old Dominion is a not-for-profit power electric cooperative that owns and operates electric generation facilities to provide capacity and energy to 11 electric distribution cooperatives throughout Virginia, Maryland, and Delaware. Old Dominion's members provide retail service to end-use consumers and as a result Old Dominion has an obligation to serve its consumer owners.

All of Old Dominion's members are located within the PJM interconnection. In addition, Old Dominion is a network transmission customer of PJM as well as a PJM transmission owner. As mentioned earlier, we have an obligation to serve our consumer members. That means we have to ensure there is enough electricity to meet their current and future needs.

As a participant in PJM, we also have to pay PJM for our share of PJM's cost in procuring capacity to ensure that there is enough electricity to satisfy their future energy needs. Unfortunately, our experience with PJM's capacity procurement policies has been mixed at best, and let me explain why.

PJM originally established that we could satisfy the obligation to procure capacity by building generation sources or using bilateral contracts to obtain capacity at competitive market prices. In other words, we could self-supply the capacity obligation. If additional capacity was needed, PJM would procure that capacity and allocate the cost to us and the other members and participants within PJM.

The self-supply, the first option and the PJM procured capacity second option, worked well for us. Unfortunately, PJM changed the rules and FERC approved the changes. Now our self-supplied capacity might fail to satisfy PJM's capacity market requirements. As a result, we might be required to obtain all of our capacity from PJM and pay those associated costs. We could be forced to pay twice for capacity, the significant investments and costs associated with our self-supplied capacity, plus our share of PJM's capacity costs.

We believe that federal policy should ensure that long-term investments in generation are honored and encouraged. Specifically, we should be allowed to self-supply the capacity procurement obligation as a first option and then turn to PJM's administered capacity in energy markets as a second option. Federal policy should also focus on reliable wholesale service at just and reasonable rates to provide the right price signals needed for new generation resource development. It would be a mistake for PJM to artificially inflate capacity prices above competitive just and reasonable levels.

In addition, federal policies should foster stability in market designs. The change in PJM's administered capacity market from its original function as a second choice option, a residual market to a mandatory market that threatens our first choice option has introduced unnecessary uncertainty which makes long-term planning very difficult.

Finally, federal policy should ensure that choices of generation resources are encouraged. PJM's administered capacity market is not a substitute of the wholesale market where we can determine the amount, the kind, and the location of generation resources we need to meet our consumers' and customers' needs.

Nothing in the law prevents FERC from adopting these needed federal policies. Therefore, at this time we do not believe there is a need for Congress to enact new legislation giving FERC additional authority or duties. However, the Energy and Commerce Committee should continue to use its oversight function and to monitor the manner in which the wholesale market operates.

Thank you, Mr. Chairman. I look forward to answering any questions.

[The prepared statement of Jackson Reasor follows:]

Testimony of Jackson Reasor

President and CEO - Old Dominion Electric Cooperative

Before the Subcommittee on Energy

Committee on Energy and Commerce

U.S. House of Representatives

"Powering America: Examining the State of Electric Industry through Market Participant Perspectives"

July 18, 2017

Summary of Statement of Jackson E. Reasor
President and CEO
Old Dominion Electric Cooperative

- Old Dominion is a not-for-profit power supply electric cooperative that owns and operates electric generation facilities that it uses, together with long-term wholesale contracts, to "self-supply" power to its members. Old Dominion supports competition in wholesale electric markets and the ability to self-supply when we determine this is the best long-term resource option.
- PJM's wholesale energy markets are working reasonably well. Plentiful natural gas supplies and improved generation technology have driven down wholesale energy prices.
- Repeated and significant changes to PJM's capacity procurement model have raised costs and undermined the ability of load-serving entities to self-supply power.
- Federal policies should focus on reliable wholesale service at just and reasonable rates for consumers.
- Federal policies should honor and encourage long-term investments in generation by load-serving entities like Old Dominion. Consumers will fare better if competitive wholesale power markets allow load-serving entities to first self-supply the generation capacity they need, by building it or purchasing it in voluntary long-term bilateral contracts, and then turning to the RTO centralized capacity and energy markets for their residual needs.
- Federal policy should ensure that load-serving entities are able to develop the portfolio of generation resources that they believe best meets their needs, based on their economic and non-economic criteria.
- FERC and the RTOs are beginning to address needed reform to these federal policies. Congress should monitor this process, but it does not need to amend the Federal Power Act at this time.

My name is Jack Reasor. I am President and CEO of Old Dominion Electric Cooperative in Glen Allen, Virginia. Old Dominion is pleased that the Energy Subcommittee is holding this hearing and that it has been invited to present its perspective as a wholesale market participant.

Old Dominion is a not-for-profit power supply electric cooperative, organized and existing under the laws of Virginia. Old Dominion provides capacity and energy to eleven electric distribution cooperatives in Virginia, Maryland, and Delaware ("Members"). Our Members provide retail electric service to end-use consumers. Old Dominion and its Members have obligations to serve their consumer-owners. In the taxonomy of wholesale market participants, Old Dominion is a "load-serving entity."

Old Dominion also owns and operates electric generation facilities that it uses to supply power to its Members. This business model, whereby a load-serving entity like an electric cooperative also owns generation used to serve its consumer-owners, is sometimes referred to in the industry as "self-supply."

All of our Members are located within the PJM Interconnection, a large regional transmission organization (RTO). Old Dominion is a network transmission customer of PJM as well as a PJM Transmission Owner. Unlike most electric cooperatives, however, Old Dominion is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC).

Old Dominion has long supported federal policies to promote greater competition in wholesale electric markets. Old Dominion and other electric cooperatives were among the early proponents of unbundled transmission service on the interstate grid. Old Dominion supported FERC's Order No. 888, which mandated unbundled, open-access transmission service in 1996. Old Dominion welcomed the conversion of PJM into a regional transmission organization (RTO) with a single control area and single tariff, because that would ensure more economical, non-discriminatory transmission service over the entire PJM region and thus provide more wholesale supply alternatives for load-serving entities.

In short, we support vigorous competition in wholesale electricity markets. We want wholesale suppliers to compete for our business, and we want the ability to "self-supply" when we determine this resource option is the best long-run alternative. Such competition within the wholesale market is good for our Members, and good for the consumer-owners they serve.

Old Dominion's Perspectives on Current Wholesale Electricity Markets

In general, the wholesale energy and ancillary-services markets in PJM are working reasonably well for Old Dominion and its member cooperatives. The plentiful and inexpensive supplies of natural gas that have resulted from technical advances in shale gas drilling techniques, coupled with the high efficiency of modern combined-cycle gas generating units, have driven down wholesale electric energy prices. And while the resulting lower wholesale electric prices may be causing financial hardship for some participants in the industry, this is how competitive markets should work. While the PJM energy and ancillary-services markets are working well, they are not perfect. We support efforts by PJM and FERC to examine ways to improve their efficiency during certain periods. Nonetheless, we should be steadfast by allowing these competitive markets to work as designed by permitting them to send the proper signals for market exits where appropriate.

On the other hand, Old Dominion's experience with PJM's capacity procurement mechanism, the Reliability Pricing Model, or "RPM," has been mixed at best. This is not a market in the usual sense of that word: PJM does not provide an opportunity for willing buyers and sellers to enter into voluntary capacity transactions, by which load-serving entities could procure the capacity to meet their capacity obligations at competitive market prices. Instead, RPM is a complex administrative construct through which PJM procures capacity to ensure regional grid reliability on a centralized basis. PJM allocates the resulting costs to load-serving entities like Old Dominion.

FERC initially approved RPM as a residual procurement mechanism for PJM to ensure resource adequacy at the least cost. FERC stated that "after [load-serving entities] have had the opportunity to procure capacity on their own, it is reasonable for PJM to procure capacity in an open auction at a time when further delay in procurement could jeopardize reliability." But it added, "This, however, should be a last resort."[1]

The RPM annual capacity auction is still called the "Base Residual Auction." But over time, repeated and significant design changes have made RPM more complex and costly and have undermined the ability of load-serving entities to use their resources to meet their capacity obligations.

In the ten years since RPM was put in place, it has undergone continuous revisions. According to PJM, during the period from 2010 to 2016, there were 24 significant filings at FERC to revise RPM, and the 2016 Base Residual Auction was the first such auction with no rule changes from the prior year.[2] But that is small comfort, because in that prior year, FERC approved a complete overhaul of RPM into its current form, "Capacity Performance," which imposes onerous performance requirements on capacity resources. These performance requirements are simply impossible for some resources to meet and result in costly non-performance penalties.[3]

Several RPM revisions have involved its Minimum Offer Price Rule, or "MOPR." This rule is intended to mitigate buyer-side market power that would lower the auction clearing price below an administratively determined competitive price floor. In its original form, the MOPR guaranteed that a load-serving entity's self-supplied capacity resource would clear the auction

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[1] *PJM Interconnection, LLC*, 117 FERC ¶ 61,331 at P 71 (2006).

[2] http://www.pjm.com/~/media/committees-groups/committees/mrc/20160825/20160825-item-07-pjm-capacity-problem-statement.ashx

[3] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (2015), *order on reh'g and compliance*, 155 FERC ¶ 61,157 (2016), *aff'd sub nom. Advanced Energy Mgt. Alliance v. FERC*, No. 16-1234 (D.C. Cir. June 20, 2017).

and the load-serving entity would receive auction revenues at the clearing price—even if the MOPR prevented that self-supplied capacity from setting the clearing price. In 2011, however, FERC approved rule changes that eliminated the guaranteed clearing for self-supplied resources.[4] This meant that a load-serving entity's self-supplied capacity might not clear the auction, and the load-serving entity could end up paying twice for capacity—its self-supplied capacity *plus* its share of PJM's capacity costs under RPM.

In 2013, FERC approved further revisions to the MOPR, including a new, albeit imperfect, self-supply exemption.[5] But earlier this month—over four years later—a federal court vacated and remanded FERC's approval of this new self-supply exemption as well as other MOPR revisions.[6] This ruling puts a cloud over the results of the Base Residual Auctions and leaves the MOPR rules for the 2018 Base Residual Auction in limbo until FERC issues an order on remand.

Given the constant churn of revisions to RPM, and particularly the MOPR, load-serving entities like Old Dominion are finding it increasingly difficult to make their own long-term procurement plans and to integrate them with RPM.

Principles for Federal Policies on Wholesale Electricity Markets

From its experience as an active market participant in PJM, Old Dominion has concluded that federal policy governing wholesale electricity markets should reflect several key principles. Old Dominion respectfully presents these principles to the subcommittee for its consideration.

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[4] *PJM Interconnection, LLC,* 135 FERC ¶ 61,022, *order on reh'g,* 137 FERC ¶ 61,145 (2011), *order on reh'g,* 138 FERC ¶ 61,194 (2012), *aff'd sub nom. N.J. Bd. of Pub. Utils. v. FERC,* 744 F.3d 74 (3d Cir. 2014).

[5] *PJM Interconnection, LLC,* 143 FERC ¶ 61,090 (2013), *order on reh'g and compliance,* 153 FERC ¶ 61,066 (2015), *vacated and remanded sub nom. NRG Power Mktg. LLC v. FERC,* No. 15-1452 (D.C. Cir. July 7, 2017).

[6] *NRG Power Marketing, LLC v. FERC,* No. 15-1452 (D.C. Cir. July 7, 2017).

1. ***Federal policies should focus on reliable wholesale service at just and reasonable rates for consumers.***

The bedrock requirement of the Federal Power Act is that wholesale electric rates should be just and reasonable.[7] Old Dominion believes that federal policy should focus on ensuring that wholesale electricity markets are effective in providing reliable service at just and reasonable rates. If wholesale markets achieve this objective, load-serving entities like Old Dominion will be able to meet their service obligations to consumers in the most economical manner.

A focus on just and reasonable wholesale rates will necessarily involve providing the right price signals needed for new generation resource development. Competitive wholesale electricity markets provide efficient price signals for market entry and exit.

Until now, PJM's MOPR has only been applied to capacity bids by *new* capacity resources. Recent proposals to apply the MOPR to *existing* generation resources would greatly exacerbate the problems facing load-serving entities seeking to use self-supplied capacity. Moreover, extending the MOPR to existing resources would also transform it from a mechanism to prevent the exercise of buyer market power into an all-purpose mechanism for artificially propping up capacity prices above competitive, just and reasonable levels.[8]

2. ***Federal policies should ensure that load-serving entities' long-term investments in generation are honored and encouraged.***

The key federal policy objective should be to ensure that long-term investments in generation resources by load-serving entities are honored and encouraged. Electric power generation and transmission is a capital-intensive business. These assets are costly and have long operating lives. Planning horizons are long. Accordingly, Old Dominion invests in or procures

[7] 16 U.S.C. § 824d(a).

[8] *See, e.g.*, Protest and Request for Rejection or, in the Alternative, Request for Suspension and Further Procedures of the PJM Load Group, *PJM Power Providers Group v. PJM Interconnection,* FERC Docket No. EL11-20-000 *et al.* (filed Mar. 4, 2011).

resources with a view to meet its long-term service obligations to its consumer-owners in a reliable and economic manner.

In our view, consumers will fare better if competitive wholesale power markets allow load-serving entities to meet their capacity obligations by first building generation resources or procuring them through voluntary long-term bilateral contracts, and then turning to RTO-administered capacity and energy markets for their residual needs. For this reason, it is important that RPM be restored to its proper and original role as a residual procurement mechanism—one that is subordinate to load-serving entities' long-term investment or procurement of resources to self-supply their capacity obligations.

3. Federal policies should foster stability in market designs.

Restoring RPM to its original residual function would help achieve another important goal—stability of wholesale market designs. The history of RPM's many revisions is a cautionary tale. These revisions moved RPM away from its original residual function, but they also introduced unnecessary uncertainty for all market participants. This uncertainty makes long-range planning and procurement difficult. Wholesale markets will have to be adapted to changing market forces, technologies, and state policies. But the fundamental aspects of wholesale market designs should not be in a constant state of flux as they have been over the last decade in PJM. Changes to a residual capacity market would be much less disruptive, however, since long-term investments and procurement would ensure greater market stability, which is their purpose.

4. Federal policies should ensure that load-serving entities' choices of generation resources are honored and encouraged.

Federal policy should ensure that load-serving entities are able to develop the portfolio of generation resources that they believe best meets their needs, based on their economic and non-economic criteria. Load-serving entities should be free to choose the mix of generation (and non-generation) technologies that meet their specific needs.

Centralized capacity markets like RPM will never be able to replicate this complex decision-making process. Currently the centralized capacity markets price one generator attribute, which is capacity. It may be possible to price other attributes, such as carbon emissions, but trying to price multiple state policies soon becomes unworkably complex and inevitably controversial. And centralized capacity markets will never become an adequate substitute for a true wholesale market where individual load-serving entities determine the amount, the kind, and the location of the generation resources they need to reliably and economically meet their service obligations.

Federal policy should ensure that load-serving entities can achieve the resource diversity they need. Resource diversity is the primary responsibility of the states. Load-serving entities are the primary implementers of state policies. Wholesale electricity markets should not impede state resource policies or load-serving entity resource investments or procurement decisions. Instead they should provide a non-discriminatory, competitive wholesale market for all types of resources.

Old Dominion's Conclusions and Recommendations

Fortunately, the RTOs and FERC are beginning to respond to these salient facts. Market forces, technological advances, changing consumer preferences, and changing state policies are forcing changes to the organized wholesale markets in PJM and the other eastern RTOs. FERC held a technical conference on this subject on May 1 and 2, 2017.[9] Old Dominion participated in

[9] State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C., FERC Docket No. AD17-11-000.

this technical conference and has filed post-technical conference comments making these same points.[10]

Old Dominion appreciates the attention the Energy Subcommittee is giving to these important wholesale market issues and the opportunity to present our perspectives. At this time, however, we do not believe there is a need for Congress to intervene by amending the Federal Power Act to give FERC additional authority or additional duties.

The Federal Power Act has proven to be a flexible statute over its 80 years of existence. It appears RTOs, including PJM, are beginning to address the emerging issues of accommodating state policies in wholesale markets, and this process is requiring them to take a close look at basic issues of market design. Hopefully FERC will also be able to address these issues. Old Dominion believes that there is no one-size-fits-all solution to the many issues now being discussed in different states and regions. We believe FERC and Congress should allow for regional flexibility in fashioning new policies that meet the basic principles outlined above.

Above all, Old Dominion believes that Congress should keep load-serving entities and their state and local regulators in the driver seat on resource acquisition to power America.

[10] See Pre-Conference Statement of Michael Cocco, FERC Docket No. AD-17-11-000 (Apr. 25, 2015); Initial Comments of Old Dominion Electric Cooperative, FERC Docket No. AD17-11-000 (June 22, 2015). The transcript of the conference and all pre-conference written statements are available at https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=8663&CalType=%20&CalendarID=116&Date=5/1/2017&View=Listview.

Mr. UPTON. Thank you very much.

Tamara Linde, who is the exec VP and general counsel for Public Service Enterprise Group, Inc., thank you and welcome.

STATEMENT OF TAMARA LINDE

Ms. LINDE. Good morning, Mr. Chairman and Ranking Member. Thank you for having me here and thank you to Congressman Pallone for the kind words. My name is Tamara Linde and I am executive vice president and general counsel for Public Service Enterprise Group, or PSEG.

Thank you for the opportunity to present PSEG's views on a critical issue facing the electric industry and, by extension, the nation's electricity customers. The issue is the urgent need to assure fuel diversity and resiliency in the nation's electric generation resource mix and to correct a flaw in the wholesale market design that is leading to premature retirement of nuclear baseload generation in our region.

Let me take a moment to describe PSEG. We are a large diversified energy company headquartered in New Jersey. We employ approximately 13,000 people and our New Jersey utility serves around 2.2 million electric customers and 1.8 million gas customers across the state. When people talk about an all-of-the-above energy portfolio, PSEG is that example.

Our generation fleet consists of nuclear, natural gas, coal, solar, and even some hydro. However, while most of our plants now operate in competitive markets, most were built as part of a state-regulated utility before wholesale markets were created. Nuclear baseload is at risk because the wholesale market has a flaw and does not value fuel diversity. In fact, markets were never designed to value fuel diversity because they didn't need to.

Diversity in generation resources was the status quo when markets were initially designed. The market was designed to drive another important objective which is to deliver the lowest cost resource needed to meet demand. For years, while different fuel costs were roughly comparable, markets could drive towards the lowest cost without sacrificing fuel security and diversity. Now the shale gas revolution has brought opportunity, but it has also revealed this serious market design flaw.

Today, after more than 30 years of operation, the 3,500 megawatt Salem and Hope Creek Nuclear Generating Stations in New Jersey turned a dramatic corner last year and they failed to earn enough to cover their cost of capital. While we have not announced their closure, we have made it clear that they are on an unsustainable path.

Absent a change or intervention, these baseload resources will permanently close. In fact, the timeframe for many at-risk plants is so short that states are moving forward to address the problem before it is too late. We believe that it is our duty to have honest discussions with leadership in New Jersey to ensure that the stakes are clearly understood and that the state is given an opportunity to take action if it chooses to.

We believe that state action may be critical if these resources are to survive. We believe that these actions can be done in a way that does not undermine the integrity of the wholesale market and can serve as a bridge until a regional or federal solution takes hold. Ultimately, we do see potential for a market solution. Fuel diversity has a value and the loss of fuel diversity has a cost. This needs to be factored into the wholesale design.

Mr. Chairman, this committee has presided over many fights within the electric industry over which fuel is better, which fuel is subsidized, and which business or regulatory model is best. We understand that you must look beyond winners and losers in the industry and focus on customers, communities, and the nation as a whole.

These closures will impact the reliability and resiliency of our electric system, our economy, our competitiveness, our environment, and even our national security. Nuclear energy contributes 10 billion in federal taxes and 2.2 billion in state taxes each year. Our global leadership on nuclear energy drives the adoption of U.S. nuclear safety and security standards across the world. A vibrant American nuclear industry supports the nuclear supply chain and provides the workforce necessary for the defense nuclear industry.

On a more basic level, it is never a good idea to have all of your eggs in one basket. That is true for retirement savings and it is equally true for the life-giving electric supply our customers depend on. In the past few years, our region has seen a polar vortex, Superstorm Sandy, a derecho, an earthquake, and a freak October snowstorm. Add to this the prospect for a physical or cyber intrusion or a fuel supply interruption and it is clear that the customer interest is better served by not being overly reliant on one fuel source.

Again I want to thank the subcommittee for inviting me today, and I will be happy to answer any questions.

[The prepared statement of Tamara Linde follows:]

Tamara Linde, Executive Vice President and General Counsel
Public Service Enterprise Group

Subcommittee on Energy
Committee on Energy and Commerce
U.S. House of Representatives

"Powering America: Examining the State of the Electric Industry through Market Participant Perspectives

July 18, 2017

Good morning Chairman Upton, Ranking Member Rush, and members of the subcommittee. My name is Tamara Linde, and I am the Executive Vice President and General Counsel of Public Service Enterprise Group (PSEG). Thank you for the opportunity to present PSEG's views on a critical issue facing the electric industry -- and by extension, our customers. That issue is the urgent need to preserve the diversity and resiliency of the nation's electric generation resource mix, and in particular, the need to address current flaws in the market design that threaten the viability of nuclear baseload generation.

In the Mid-Atlantic region where PSEG primarily operates, large baseload nuclear plants that fueled the economy for decades and are a critical part of the energy infrastructure are quickly becoming uneconomic as a result of a wholesale energy market design that fails to adequately value their attributes. The fact is that several nuclear plants in the United States have already shut down prematurely and owners of other plants have announced their plans to retire. Absent a change or an intervention in the very near future, reliable, much needed baseload resources that do not contribute to air emissions will permanently close, with implications far beyond any single corporate boardroom.

Before I elaborate on what is driving this predicament and what might be done to ensure that our electric system remains reliable and resilient for the long term, let me introduce my company. PSEG is a large, diversified energy company headquartered in Newark, New Jersey, and is among the largest electric companies in the United States. Our subsidiary Public Service Electric and Gas Company (PSE&G) owns and operates electric and natural gas distribution and transmission facilities and serves approximately 2.2 million electric customers and 1.8 million gas customers in New Jersey, many of whom reside in the state's most densely populated urban areas.

Another of our subsidiaries, PSEG Power, owns and operates approximately 11,000 megawatts of electric generation and sells the output from those generation facilities into the regional market known as PJM Interconnection, LLC (PJM), as well as wholesale electricity markets in New England and New York. PSEG maintains a diverse and well-balanced portfolio of electric power generation resources to meet customers' needs, including nuclear, natural gas, coal, and solar generation. While we currently are building three new natural gas plants in three states, it is worth noting that PSEG planned and built its diverse generation portfolio across many decades, and many of the facilities were built prior to the advent of competitive wholesale electricity markets. Thus, our belief in the importance of fuel diversity to our customers stretches back to the earliest days of our company.

To return to the problems facing nuclear, the 3,500 megawatt Salem and Hope Creek nuclear generating stations in southern New Jersey sit on the nation's second largest nuclear site and produce about 45 percent of the electricity in New Jersey. After more than 30 years of operation, PSEG's nuclear plants are not earning enough to cover their cost of capital. While we have not announced their closure, we have made it clear they are on an unsustainable path.

It may be surprising for Committee members to learn that large baseload nuclear plants in such a well-populated part of the country could be struggling financially. In fact, given the favorable location and size of these units, the fact that they *are* in economic peril may serve as a barometer for the severity of the crisis facing the entire nation's nuclear fleet, and the urgency facing policymakers who believe, as we do, that our country has something to lose with the erosion of fuel diversity and resiliency that would result from the premature closure of baseload generation, nuclear plants in particular.

While the economic stress facing PSEG's nuclear plants has a host of aggravating factors including significant additional regulatory costs imposed on nuclear plant operators by the Nuclear Regulatory Commission over the past 15 years, the proliferation of non-dispatchable renewable and demand-side resources enabled through federal and state tax policy, renewable portfolio standards and other regulatory treatments such as net-metering, the primary driver is a wholesale electricity market design that fails to adequately value and compensate these plants.

As for why this is the case, it may be instructive to examine how these markets have evolved over time. PSEG has a broad perspective on the evolution of electric wholesale markets administered by Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) in the northeast. PSEG has operated in these markets since their inception in the 1990s and has been among the original handful of vertically integrated utility companies in PJM to champion the movement towards competition in its market. We have steadfastly supported the markets to date and actively participated in the regulatory and stakeholder processes to improve the markets because of the benefits that competition has brought in lowering prices, increasing innovation, and protecting customers. Market forces have driven investment in new more efficient generating resources and the retirement of older less efficient generating plants. Markets have also driven nuclear operators like PSEG to maximize output from nuclear units, making them more competitive and more efficient.

Notwithstanding these benefits, the wholesale market design problem we face now is rooted in the historical focus on driving efficiency gains without regard to important factors required for the long term reliability of the electricity grid, especially fuel diversity and resiliency. This is because competitive markets evolved around a diverse set of existing generation resources. In other words, markets weren't designed to drive to fuel diversity as an outcome, because fuel diversity in the generation fleet was always presumed.

Fuel diversity in electric generation was a reasonable expectation in the world prior to the shale gas revolution. Just as the discovery of near unlimited quantities of accessible natural gas has prompted a fundamental re-evalution of our nation's ability to move from energy independence to energy dominance, we must also examine the impact of this revolutionary development on electricity markets, and make the design changes needed to ensure we avoid the irreversible loss of critical infrastructure, including nuclear resources.

Because time is of the essence for the Salem and Hope Creek stations, in New Jersey we have begun to discuss with policymakers what is at stake if PSEG's nuclear plants close their doors, including the fact that air emissions will increase and the cost of building alternative replacement resources will be higher than the cost of preserving the existing plants. The economic impact facts are also compelling, with hundreds of millions of dollars contributed to the state economy, including 1,600 full time jobs at our plants, and a $30 million contribution to the local tax base. But far and away the most critical concern we have put before state policymakers is the need to ensure the resiliency of electric supply against all manner of unforeseen contingencies. If PSEG's nuclear plants were to close, the overwhelming majority of remaining generation in New Jersey would be natural gas. Whether it's a polar vortex, a cyber intrusion, a fuel supply interruption or another event we can't imagine today, the utility mantra has always been to have an additional line of defense to deal with unexpected events. It's in our DNA to strive to build a system where we are not overly reliant on any single facility – or any single fuel source – to ensure the availability of the life-giving commodity our customers rely on.

The North American Electric Reliability Corporation sums it up by saying that "having a portion of a resource fleet with high reliability characteristics, such as low forced and maintenance outage rates and low exposure to fuel supply chain issues, is one of the most fundamental necessities of a reliable Bulk Power System."[1] Nuclear generation covers all of these bases.

Mr. Chairman, the challenges facing PSEG's nuclear plants are not unique. States such as Illinois and New York have already acted to prevent premature losses, and others such as Ohio, Connecticut and Pennsylvania are considering how they can take steps to prevent the premature closure of critical baseload generation. These efforts all take different forms, but what they have in common is the sense of urgency with which they are being pursued. Indeed, given the time constraints facing many of these at-risk plants, and given the absence of timely and effective action at the wholesale market level, state action emerges in many cases as the only viable option in the short term. We believe state actions can be taken in a way that do not disrupt the operation of the competitive markets, but can be a bridge until regional or federal solutions take hold. Accordingly we urge the Committee in its deliberation on Federal Power Act reform to respect the lawful ability of states to act to retain these critical assets.

In addition, Mr. Chairman, you have done much to encourage FERC to maintain its focus on ensuring that the true price of electricity is accurately reflected in the market in order to

[1] Synopsis of NERC Reliability Assessments at page 4, May 9, 2017.

support sustained investment, otherwise known as price formation. We applaud you for these efforts, and when the FERC returns to a quorum under new leadership we believe it will be important for the Commission to tackle this issue with even greater urgency. We look forward to working with you and other like-minded members of the Committee to continue to emphasize this as a priority.

Longer term, but equally important is broader reform of the way generation resources are valued and priced in the market. We have been encouraged by recent dialogues with regional grid operators that suggest the magnitude and urgency of the problem is beginning to bring the attention it deserves. FERC should require the RTOs to undertake these reforms immediately to ensure that the system is able to provide the diversity of resources needed to respond to the vast array of changing conditions, and ensure the bulk power system is not just reliable but resilient. More specifically, we need to address energy market design, which currently drives supply in a way that disadvantages certain resources such as baseload generation.

Finally Mr. Chairman, it bears mentioning that you have brought a diverse panel of stakeholders together for this hearing, with varying perspectives and priorities. Over the years this Committee has seen a variety of debates within the electric sector over preferred business models, fuel types, regulatory constructs and other issues. At the end of the day, we understand that you are obligated to look beyond winners and losers among us to find the right solutions for the customers and communities you represent, and for the country as a whole.

We believe that the potential loss of a sizeable percentage of the nation's nuclear fleet raises issues well beyond the scope of an individual company or even a specific state. For starters, nuclear energy and the technology behind it is one of the great American innovation stories. We should give careful consideration to the implications on our global competitiveness and our STEM pipeline of losing this primacy.

Second, these plants have literally been the engines behind local and regional economic growth for decades, not just for the electrons they generate but also for the hundreds of thousands of well-paying, high-quality jobs, and the funding for schools and police stations and local businesses in communities across the country. Nationwide nuclear energy contributes $10 billion in federal taxes and $2.2 billion in state taxes each year.

Finally, our nuclear regulatory and operational framework is the envy of the world, and for very good reason. It is in our fundamental national security interest to ensure that this remains the case. After all, our global leadership drives the adoption of U.S. nuclear safety and security standards elsewhere in the world. Similarly, it is in the clear interest of our national defense to ensure that our civilian reactors, and the supply chain they support, remains robust. It is time to think of the U.S. nuclear supply chain as critical infrastructure, just as we regard our national highway system, electric grid and drinking water infrastructure.

I thank you for the opportunity to share the views of my company this morning, and I would be glad to answering any questions you may have.

Mr. UPTON. Thank you.

Next, Kenneth Schisler, VP of Regulatory and Government Affairs from EnerNOC, welcome.

STATEMENT OF KENNETH D. SCHISLER

Mr. SCHISLER. Thank you, Mr. Chairman and members of the committee, for this opportunity to testify. My employer, EnerNOC, is an incredible American innovation success story. We were among a small group of technology startups right after the turn of the century that pioneered digital applications in U.S. electricity markets, and these innovations today are in commercial operation and are indeed a vital part of the American economy.

We do several innovative things at EnerNOC, but today I am here to talk about our primary business line and that is known as Demand Response. Demand Response is a homegrown American technology. It is an innovation that found success here first and has quickly spread throughout the developed and developing world.

The purpose of Demand Response is to engage customers, users, and users of electricity to manage consumption of electricity at critical periods when the electricity grid is under stress, to serve as a balancing resource on the grid, or to respond to signals when prices are high. Demand Response empowers energy users to become more flexible with their consumption and to monetize that flexibility providing grid services.

Companies like EnerNOC are known as aggregators. We aggregate the Demand Response capability of thousands of customers and manage them as a portfolio of resources in order to participate in electricity markets. Demand Response resources are dispatchable in a manner similar to traditional generation resources that receive and respond to dispatch signals from utilities and grid operators. In fact, most often Demand Response is actually treated on the supply side of the market, which sounds a bit like a non sequitur but it does work.

We operate in several FERC jurisdictional markets in the U.S. as well as several programs under the jurisdiction of state utility regulators. Demand Response enjoys broad bipartisan support. In fact, Chairman Kelliher seated at the end of the table, as chairman of FERC, issued the seminal order that enabled this latent capability of customers to improve the power grid through Demand Response and his legacy was carried forward by his successor Chairman Wellinghoff.

Demand Response is a win-win. It is unequivocally a win-win for the U.S. economy. We contribute to the U.S. energy resource diversity and security supply. It gives system operators one additional useful tool to reliably operate the nation's electricity grid, the users of electricity. Demand Response has been credited as helping to prevent many major grid emergencies, many major grid emergencies in recent years including many of those my colleague acknowledged, the polar vortex, wildfires in California, and many others.

Customers who participate in Demand Response receive compensation for participation. We pay customers from the market revenues that we receive by bidding their resources again in this portfolio into the wholesale markets. These customer payments of course bring down their total cost of energy which makes them more competitive in the U.S. and global economy.

Demand Response is a domestic energy resource, by definition, supporting energy independence. Our fuel source, if you will, is leveraging the flexibility of our customers to manage their demand for the benefit of the grid. Demand Response receives no subsidies, no special tax treatment under the federal tax code. It does not negatively impact the federal budget and does not require any subsidies from states or ratepayers in order to participate because it is cost effective on its own.

Demand Response improves efficiency of the grid and brings down energy costs for all consumers. In fact, in the PJM region Demand Response participation reduced wholesale market costs by nearly $10 billion in the current delivery year alone, and this is according to a report prepared by the PJM Independent Market Monitor. These benefits are going to increase as new technologies such as energy storage are increasingly adopted as part of a Demand Response strategy.

From a federal policy standpoint, the only prerequisite for Demand Response to thrive is to have nondiscriminatory, open access in wholesale electricity markets and that those markets remain competitive without pricing distortions. We have come a long way in open access, in part thanks to Chairman Kelliher's order. We still have some progress to make.

As far as healthy competitive markets, we are pleased that FERC has recently sought comments on how to maintain competitive markets while respecting the rights of states to create their own energy policies. It is vital that we get this right.

In conclusion, Demand Response is a homegrown U.S. technology. Companies like EnerNOC have revolutionized and created tremendous value in U.S. energy markets and we are now exporting that technology all over the world. Our only ask here today is that you continue to recognize Demand Response and its importance to the national energy strategy. Thank you.

[The prepared statement of Kenneth D. Schisler follows:]

Testimony of Kenneth D. Schisler, Vice President of Regulatory Affairs, EnerNOC, Inc., before the House Committee on Energy and Commerce, Subcommittee on Energy, Mr. Upton, Chairman, July 18, 2017, "Powering America: Examining the State of the Electric Industry through Market Participant Perspectives.

Summary of Testimony: Demand Response in electricity markets is a 21st Century American innovation that has improved the U.S. electricity system and is being exported all over the world. Demand Response involves coordinated management of consumer demand in a portfolio by market agents known as "Aggregators" who are market participants in electricity markets, usually bidding as a supply side resource competing against generation. Demand Response contributes to energy independence and energy security because it is a domestic resource and provides an additional valuable tool for system operators to manage the grid. Demand Response participation lowers the cost of energy in the market and allows participant to receive direct compensation for making their load management capability a grid resource. Demand Response increases reliability and market efficiency, and makes American businesses more competitive. Demand Response requires no taxpayer or ratepayer subsidies or tax breaks to be successful. Demand Response requires only that it have open and non-discriminatory access to compete in power markets and that power markets are truly competitive without pricing distortions.

Thank you Mr. Chairman and Committee Members for the opportunity to testify today.

My employer EnerNOC is an incredible American innovation success story. We were among a small group of U.S. startups right after the turn of the century that pioneered digital applications electricity markets and these innovations are now in commercial operation and are a vital part of the American economy.

While we do several things at EnerNOC, I'm here today to discuss our primary business, known as Demand Response. Demand Response is a homegrown American technology innovation that found success here first, and has quickly spread throughout the developed and developing world.

The purpose of Demand Response is to engage customers to manage consumption of electricity at critical periods when the electricity grid is under stress, to serve as a grid balancing resource, or to respond to signals during times of high prices. Demand Response empowers energy users to become more flexible with their consumption, and to monetize that flexibility providing grid services.

Companies like EnerNOC are known as "Aggregators." We aggregate the Demand Response capability of thousands of customers and manage them as a portfolio in order to participate in electricity markets. Demand Response resources are dispatchable in a similar manner to traditional generation resources that receive and respond to dispatch signals from utilities and grid operators. In fact, Demand Response is most often treated in markets as a supply-side resource, which sounds a bit like a *non sequitur*.

We operate in several FERC jurisdictional markets in the U.S. as well as some programs under the jurisdiction of the state utility regulators. Demand Response enjoys broad bipartisan support from policy makers and regulators. The Energy Policy Acts of 2005 and 2007 spurred adoption of policies that have helped leverage the latent capability of customers to improve the power grid through Demand Response.

Demand Response is a win-win that is unequivocally good for the U.S. economy.

- We contribute to energy resource diversity and security of supply in the U.S. power system. It gives system operators an additional useful tool to reliably operate our nation's electric grid. Demand Response has been credited as helping to prevent several major grid emergencies in recent years. These include the Polar Vortex in the Eastern U.S. in 2014, and many others at various times of the year.

- Customers who participate in Demand Response receive compensation for participation. We pay customers out of the market revenues we earn by bidding their Demand Response into the wholesale markets. These customer payments reduce total energy spend and make American businesses more competitive in the U.S. and global economy.
- Demand Response is a domestic energy resource supporting energy independence. Our "fuel source," if you will, is our customer's flexibility to manage demand.
- Demand Response receives no subsidies or special tax treatment under the federal tax code. It does not negatively impact the federal budget and does not require ratepayer subsidies because it is cost-effective on its own.
- Demand Response improves the efficiency of the grid and brings down energy costs for all consumers. In fact, in the PJM region of the Eastern U.S., Demand Response participation reduced wholesale market costs by nearly $10 Billion dollars in the current delivery year alone, according to a report prepared by the PJM market monitor.

These benefits will increase as resources such as energy storage are increasingly adopted as part of a demand response strategy.

From a federal policy standpoint, the only prerequisite for Demand Response to thrive is to have non-discriminatory open access in wholesale electricity markets and that those markets remain competitive without pricing distortions. We have come along way on open access and removing market barriers to Demand Response in the last decade, but we still have more progress we can make. As far as healthy competitive markets, we are pleased the FERC recently sought comments on how to maintain competitive markets while respecting the rights of states to create their own energy policy. It is vital that we get this right.

In conclusion, Demand Response is a homegrown U.S. technology. Companies like EnerNOC have revolutionized and created tremendous value in U.S. energy markets and now we are exporting this technology all over the world. Our only ask here today is that you continue to recognize Demand Response and its importance to our national energy strategy.

Mr. UPTON. Thank you.

Last, we are joined by Mr. Glenn, senior VP of State and Federal Regulatory Legal Support for Duke Energy, and I welcome you and nice to see you.

STATEMENT OF ALEX GLENN

Mr. GLENN. As owners and operators of wind farms in Massachusetts, Rhode Island, Pennsylvania, Kansas, Oklahoma, Wisconsin, Wyoming, Colorado, Texas, solar farms in California, Arizona, Texas, North Carolina, Florida and New Jersey, and battery storage projects in Ohio and one of the nation's largest in Texas with one of our wind farms and in addition to integrated electric utilities across seven states, we touch customers across the country every single day.

So to give you a context, Duke Energy is one of the largest energy holding companies in the United States. We have about $130 billion in assets and we reinvest in our communities $10 billion a year, annually, on our electric grid and our gas infrastructure, and we provide service to electric and gas customers that represent roughly about nine percent of the nation's population.

So I would like to use my time today to talk about actions that will greatly benefit our customers, unleash innovation, and spur economic growth. Specifically, I want to address permitting, renewables policy, cybersecurity, and then too on FERC nominations and tax reform.

Duke Energy plans to invest about $35 billion in addition to that $10 billion a year, $35 billion a year over the next 10 years to modernize our system. This transition is underpinned in part by natural gas infrastructure, much of which requires federal permitting. Too often we see overlapping and conflicting regulatory requirements which result in higher costs to our customers.

Bottom line, most permitting regulations impose no timeframes within which an agency has to act. And without a reasonable what I call a shot clock for decisions, delays put many vital projects at risk of completion. So just as our energy system needs to be modernized, so too do our policies. They need to be modernized to reflect today's markets and encourage innovation.

As a representative mentioned, the pace of change is increasing and so is that complexity, but our regulatory paradigm isn't. An example of this is PURPA. Today, renewable energy is booming, the cost of renewable energy technologies have dropped, and independent power producers are prolific and well financed. Many PURPA contracts though are significantly above the market cost of power and that is costing our customers money, so updating PURPA to reflect current market and technology needs will enable utilities to serve our customers at a lower cost.

Cyber, so hand in hand with critical infrastructure investment is the need to protect it. Protecting our infrastructure from cyberattacks is a top priority of Duke Energy. The electric industry is the only industry critical infrastructure, with mandatory enforceable cybersecurity standards. So Congress could aid our efforts, amending the SAFETY Act to expressly include cyberattacks so that in the event of such an attack we can focus on what we need to do, right, which is get the lights back on and get our economies back running.

Now we can make policy but we also need regulators to implement that policy, so that is where FERC nominations come in. As members of this committee are well aware, FERC has been without a quorum since February which has prevented action on crucial energy infrastructure projects. The president has now nominated three candidates, two of whom are awaiting votes before the full Senate and Duke Energy would urge this committee to do whatever it can to encourage your Senate colleagues to take up these nominees as quickly as possible so that a quorum can be established.

Finally, tax reform, although I understand tax reform falls outside the jurisdiction of this committee I mention it because you all have a deep understanding and are experts in our business and you understand that our industry is unique. Our rates and our returns on capital are set and regulated by state regulators. So because our electricity bills reflect our cost of service, including after-tax cost of capital, we need to preserve interest deductibility.

So our industry, as a number of the members have mentioned here today and our panelists have said, is undergoing remarkable transformation. We at Duke Energy stand ready to meet those challenges and those opportunities to power our economy to improve the quality of lives of the customers that we serve every day. Thank you.

[The prepared statement of Alex Glenn follows:]

Statement of Alex Glenn

Senior Vice President, State and Federal Regulatory Legal Support
Duke Energy Corporation

Before the
Committee on Energy and Commerce
Subcommittee on Energy
U.S. House of Representatives

On "Powering America: Examining the State of the Electric Industry through Market Participant Perspectives"

July 18, 2017

Good morning, Chairman Upton, Ranking Member Rush and members of the subcommittee. My name is Alex Glenn, and I serve as Senior Vice President, State and Federal Regulatory Legal Support for Duke Energy Corporation.

I appreciate the opportunity to provide the subcommittee with the perspective of an integrated electric utility, and our view on how we can best serve customers and enhance the economies of the communities we serve. Broadly, there are five areas where action will greatly benefit the customers we serve. First, establish a reasonable "shot clock" for actions on permit applications, as many critical infrastructure projects face unnecessary and costly delays. Second, retain the federal income tax deduction for interest expense, which helps to keep electricity rates as low as possible for customers. Third, update the Public Utility Regulatory Policies Act (PURPA) to enable utilities to serve customers at the lowest cost. Fourth, move forward on the Federal Energy Regulatory Commission (FERC) Commissioner nominees as soon as possible. And lastly, enhance cybersecurity by amending the Safety Act to expressly include cyberattacks, and improve the process to obtain a security clearance so that we can increase the information sharing capabilities between public and private entities. These five actions alone would provide substantial – and immediate – value to customers.

To put my comments in context, it may be helpful to the subcommittee to know more about Duke Energy. Duke Energy is one of the largest energy holding companies in the United States, with over $130 billion in assets. We are a driver of the economies of the states in which we operate, investing, on average, $10 billion annually in our energy infrastructure to provide safe, affordable, highly reliable and increasingly clean energy to the people and businesses we serve. Our 30,000 employees take great pride in the work we do 24/7/365, our ranking as the safest utility in the industry, as well that we work to keep our rates low relative to national averages. We provide electric and natural gas service to 25 million people – roughly 9 percent of the nation's population – and tens of thousands of business, small and large, across seven states. Our Commercial Renewable Energy business unit operates a large and growing portfolio of solar and wind renewable facilities in 14 states across the United States. We are one of the top five renewable energy companies in the country, having invested more than $5 billion in renewables over the last decade.

While the challenges faced by regulated electric utilities like Duke Energy are different than those faced by some of the other members of the panel, we all share the responsibility of keeping the lights on for the millions of people and businesses who rely on us every day.

The regulatory and legislative decisions made at the state and federal level have significant impacts on the lives of our customers, employees, and the many communities in which we serve. With this in mind, I would like to offer a few thoughts on the challenges before us, and the opportunities for unleashing innovation and economic growth.

Infrastructure

Investments in a strong and resilient energy system are critical to the nation's security, economy and cleaner energy future. In many ways, the energy grid is the lifeline of our economy and our way of life. To ensure we are able to continue delivering reliable, affordable, and increasingly clean energy that powers our economy – and which our customers demand – we need to make significant investments in modernizing our energy system, making it smarter, and more resilient to natural occurrences and premeditated physical attacks and cyberattacks. This is particularly important as our economy becomes increasingly dependent upon technology.

The regulated electric utility industry is one of the nation's most capital-intensive, investing more than $100 billion annually in critical infrastructure. Duke Energy operates the largest energy grid in the country, with more than 300,000 miles of transmission and distribution lines to power our communities and the lives of our customers. Over and above the $10 billion in annual investments we make to maintain the day-to-day functioning of the grid, we plan to invest another $25 billion over the next 10 years to modernize our system and build a smarter energy future.

This transition is underpinned by natural gas infrastructure, much of which requires federal permitting. There remain challenges, particularly the siting and permitting of these vital infrastructure projects to strengthen the power grid. Too often, there are overlapping and conflicting requirements that result in higher costs for our customers. Most permitting regulations impose no time frame for agency action, and without a "shot clock" for decisions, delays put many vital projects at risk of completion. The larger the infrastructure projects, which are often measured in hundreds of millions of dollars and sometimes multibillion dollars, delays and uncertainty can affect the cost of capital and overall project costs ultimately borne by our customers. The relicensing of our Catawba-Wateree Hydro project is a good example. We submitted our application for a new license in 2006, two years before expiration as required by law, and it took more than nine years for the federal government to complete its review.

Tax reform

Hand and hand with critical infrastructure investment is tax reform. These investments are necessary to ensure that customers have safe, reliable and affordable energy, but they also create a significant source of high-quality jobs and generate local tax revenues in communities across the country. While I understand that tax reform falls outside the jurisdiction of this committee, it is worth noting here because members of this committee understand that our rates and returns on capital investments are highly regulated, unlike that of other businesses, making our industry unique. Our distinction from other businesses is evident in our need to preserve interest deductibility since our customers' electricity bills reflect our cost of service, including after-tax cost of capital. We work hard to achieve the lowest cost of capital, and the federal income tax deduction for interest expense helps to keep electricity rates as low as possible.

Unlike other industries, regulated utilities do not benefit from forgoing interest deductibility for immediate expensing. We understand why 100 percent expensing could stimulate most industries and potentially spur economic growth, but our need to preserve interest deductibility is tied to keeping rates low for our customers and continuing our significant capital investments across the Southeast and the Midwest.

Duke Energy supports the goals of comprehensive tax reform and we want to partner with you to be the energy company that will power the economic growth and expansion throughout the country that will result from a transformation of the tax code.

PURPA Reform

Just as our energy system needs to be modernized, policies should also be modernized to reflect how the electricity sector has changed and encourage innovation without burdening customers with unnecessary costs. An example of this is the Public Utility Regulatory Policies Act, or PURPA. Enacted in 1978, PURPA was intended to encourage increased system reliability and the deployment of more energy-efficient and renewable energy production by independent power producers at a time when the United States was greatly reliant on imported fuel oil. In the years since PURPA was enacted, electricity markets have significantly changed. Independent power producers are prolific, well-financed and capitalized entities. And many PURPA contracts are significantly above the market cost of electricity, which has resulted in customers paying more for electricity than they would without such contracts.

Today, renewable energy is booming and the costs of renewable technologies have dropped dramatically. State-of-the-art combined-cycle natural gas generation has increased in efficiency to surpass the operating efficiencies of cogeneration facilities. The substantial growth in renewable energy due to federal and state incentives and policies has made many of the requirements of PURPA unnecessary. Accordingly, the original principles and the needs-based application of PURPA have been overtaken by dramatic advances in the energy marketplace. With these market changes, and the widespread deployment of PURPA facilities, utilities are experiencing operational challenges and higher costs due to PURPA's mandatory must-take purchase obligation. Updating PURPA to reflect market and technology trends will enable utilities to serve customers at the lowest cost possible.

FERC

I would like to address briefly the current situation at the Federal Energy Regulatory Commission (FERC). As members of this committee are well aware, FERC has been without a quorum since February, which has prevented action on crucial energy infrastructure projects, including new natural gas pipelines and other important rate and policy matters. The electric and natural gas industries depend strongly on a well-functioning FERC. Many of you recognized the seriousness of this issue in letters sent to the president in February and March of this year urging quick action on FERC nominations. In those letters, committee members and leadership acknowledged the importance of FERC continuing its "important regulatory oversight responsibilities to ensure American consumers have access to reliable energy."

The president has now nominated four candidates, two of whom are awaiting votes before the full Senate. Duke Energy is increasingly concerned about the lack of a quorum at FERC and strongly urges this committee to do whatever it can to encourage its Senate colleagues to take up these FERC nominations as quickly as possible.

Cybersecurity

We are well aware of the recent reports of cyber intrusions into the energy sector and certain nuclear facilities. Protecting our infrastructure, operations and customer, shareholder and employee information is a top priority for Duke Energy. When it comes to cyberthreats and potential breaches at Duke Energy, we work diligently to stay ahead of the game, using a "multilayered" defense approach to keep our energy grid secure.

We also work closely with industry and government partners. We have in place strong reporting requirements and partnerships to prevent and respond to threats. In fact, the electric sector and nuclear sector are the only critical infrastructure sectors with mandatory and enforceable cybersecurity standards. Extensive measures to safeguard our business and operational networks are necessary to prevent those with malicious intent from penetrating our systems, and to ensure we can respond appropriately to any security events.

There are areas Congress can examine to offer immediate improvements:

First is an examination of third-party liability protections by amending the Safety Act to expressly include cyberattacks (with no separate DHS declaration of an act of terror) – so that in the event of such an attack, utilities can focus on: 1) getting the lights back on, 2) rebuilding infrastructures and systems to keep the lights on and prevent more harm, and 3) enabling first responders to more effectively and efficiently do their critical work – instead of facing the crippling effects of protracted lawsuits in multiple jurisdictions.

The second area is improving the process to obtain a security clearance so that we can improve upon the information sharing capabilities between public and private entities. We have a number of individuals seeking clearances, and reducing the complexity of extending confidential information to private industry will strengthen and increase information sharing.

Workforce Transformation

As my remarks today have underscored, the energy sector is going through a significant transformation, and the needs and expectations of our customers and communities are evolving. We are modernizing our grid over the next decade and with that we will need a qualified workforce to meet these demands as we also address the challenges of a changing workforce.

About 30 percent of current Duke Energy employees are eligible for retirement today and we anticipate 52 percent of these employees to leave the company over the next six years. We anticipate nearly 9 percent of our employees will be leaving through retirement and other reasons by 2021. We determined that both the changing nature of our business and the scale of our large investments in grid modernization are creating a gap in the skills needed to continue to drive our business.

We are working with the Center for Energy Workforce Development to advance the awareness of jobs in the energy sector. We are also creating partnerships to advance workforce readiness to address the current and anticipated skills shortage that we face. Public policy impacting the regulated utilities' workforce training programs must also accurately reflect the changing industry needs. Reigniting interest in vocational jobs is a key focus for us. Working with secondary educational institutions to create curricula and funding for vocational training will help accelerate the development and employability of future workers. We are also focused on bringing veterans into our workforce. By the end of 2017 we expect about 15% of our incoming workforce to be veterans, and last year 50% of our lineworker hires were veterans. 65% of veterans pass the pre-employment aptitude test required for lineworkers – 17 points above the national average.

Finally, I would like to compliment the committee on its recent action on used nuclear fuel. While outside the jurisdiction of this subcommittee, the strong bipartisan vote in favor of Rep. Shimkus' bill shows the ability of this committee and its members to show leadership and bipartisanship in an effort to address a long-standing problem. Our customers have waited a long time to get what they have paid for, and we appreciate your efforts on their behalf.

The pace and complexity of change facing our industry today is unparalleled since the battle between AC and DC power in the 1880s. We, as an industry, stand ready to meet these challenges while continuing to provide safe, reliable, affordable and increasingly clean energy to power our economy and improve the quality of the lives of the customers we serve every day.

Again, thank you for the opportunity to be here today and I look forward to your questions.

Mr. UPTON. Well, thank you all. And at this point we will reach our 5 minutes of Q & A by members of the committee. Thank you very much for your testimony, and I would like to hit a couple of things in my 5 minutes if I can. One is to talk briefly about baseload closures. We see a lot of that all across the country, but I first want to just focus a little bit on the cybersecurity.

As we visit different installations, whether they be in our districts or states or even around the country, often we are hearing that the internet connections of each of those facilities is independent as not, you know, it is hard to penetrate. It is not attached to a larger network. Yet at the same time, we read and we have had some briefings particularly about state-sponsored attacks that are trying to get in, whether it is a water system, whether it is a utility, recently some nuclear facilities in the last couple weeks.

What is it that we can do to make sure that in fact that does not happen? What additional tools do we need to put into the toolbox, whether it be FERC, whether it be the Homeland Security and others, to make sure that in fact that does not happen?

And Mr. Glenn, you referenced that just briefly in your testimony, but give us some ideas on where we need to proceed—and I don't know if you have looked at our bill H.R. 3050, Enhancing State Energy Security Planning and Emergency Preparedness, but that is moving with strong bipartisan support. It came through this committee and will be on the floor very soon.

Mr. GLENN. Thank you, Mr. Chairman. And thank you for that bill. I think that is a very, very good start. And I think there is a couple of things. One is, we are the only industry with mandatory enforceable standards, so FERC and NERC, a delegation of FERC, have specifically prescribed standards that we must meet. How we meet those standards is a defense-in-depth way of meeting that.

So there is a couple things. One is, I think, streamlining the process by which our background checks for some of our employees can be done so that we can work more closely with other government agencies and heads of those agencies. I think that would be one thing that we could do that would be supportive. And we would be happy to work offline on certain other things that I think we can do.

Mr. UPTON. I just want to assure you—other ideas, other members of the panel, are there additional steps that we should take? It is important that we get a quorum on FERC. I think we have all been frustrated with the lack of the quorum. I hope the Senate acts before they adjourn for sure before their August break.

Let me talk a little bit about the baseload closures. So again we see this. In Michigan we have got a number of coal facilities that are beyond their use and they announced that they were closing. We have got issues on nuclear facilities around the country and for different reasons. We know that natural gas, we know that reliable, renewable energy costs have come down dramatically.

A number of states like Michigan have actually imposed a new standard in terms of a minimum requirement and it is a good thing for all of us that support all of the above. But it does take a while to get that replacement piece on, whether it is a new gas facility or whatever it might be. We all care about diversity, but at the bottom line of course is, I think every one of you mentioned, the cost to the consumer of that kilowatt that goes to their home and to their business.

So how do we balance all of that in terms of looking at the future and the 21st century energy needs that we have? Ms. Linde, you talked a little bit about that and it seems like New Jersey has done a really good job.

Ms. LINDE. Well, thank you. Fuel diversity is really important and we are concerned that at the wholesale market level the market design did not take that into consideration. So we do see that as something that needs to be addressed, but we recognize it can't be addressed quickly.

So we have states as was commented on by several of the other panelists that have nuclear plants that are suffering that are taking action and doing so as a bridge to a federal solution, it is important that we don't lose assets that have a long life ahead of them and that are providing a low-cost energy to our customers every day.

And I comment on that it is low cost because it is important to realize that, while nuclear plants are suffering financially because they are not being fully valued in the market, we believe it would be more expensive for our customers in New Jersey if they were to be retired and replaced with something else. So we believe it is less expensive for customers to keep these nuclear plants in operation and to keep them through the rest of their permit life, which goes on quite far into the future.

Our three nuclear plants in New Jersey have licenses that go out until 2046, and each of the three plants have different license terms but they have long lives ahead of them and they are important for fuel diversity and important for the cost of energy in the State of New Jersey.

Mr. UPTON. My time is expired, but let me, just a quick comment, maybe Mr. Schleimer and then Mr. Kelliher and then we will move on.

Mr. SCHLEIMER. Just really quickly, not necessarily sure I agree that the nuclear plants aren't being fully valued. PJM went through a process to revamp its capacity market to value reliability even more than it had been previously.

But putting that aside, I think we generally do agree that to the extent that there are issues like fuel diversity or other attributes like ramp rates and start-up times and shutdown times, et cetera, that aren't being valued, that that is something perfectly fine and acceptable and great for PJM and FERC and the other markets to look at expanding what the value of the different services are.

Mr. UPTON. Mr. Kelliher?

Mr. KELLIHER. Just very quick. We are really not at a point where we are losing diversity. I agree that the competitive markets are not designed to achieve diversity, but they have achieved it inadvertently almost. With the competitive markets focused completely on efficiency and cost that has resulted in the retirement of the uneconomic units, but in their place has come in very modern, advanced natural gas facilities, solar, and wind. And that result is we have more diversity in our electricity supply today than ever before, so there is not really a diversity crisis that we need to act on.

And the concept of baseload is becoming less useful over time. It used to be baseload unit was a unit that was cheaper to run. It also tended to have, it was operationally inflexible. But the principle characteristic, it was cheaper than everything else so you ran that first. That has switched. It used to be that coal was cheaper than natural gas. That is no longer the case. That is why gas is displacing coal.

It is not policy, it used to be that the most inefficient coal plant could produce electricity cheaper than the most efficient natural gas facility, but the fuel prices have switched to the point where that doesn't happen and it probably won't ever be restored.

Mr. UPTON. Thank you. The chair would recognize the ranking member of the subcommittee, Mr. Rush.

Mr. RUSH. Well, thank you, Mr. Chairman.

Ms. Linde, there are many energy consumers who believe that climate change is real and must be addressed and that includes the overwhelming majority of respected scientists and climatologists, the majority of the American people, and the leaders of every country in the world except Nicaragua, Syria, and our own illustrious president, Mr. Trump.

To address this issue especially in absence of federal action, many states have developed renewable energy portfolios, including Illinois, as I mentioned in my earlier statement, with the objective of reducing carbon emissions. In your opinion, would states like Illinois and others who have the objective of reducing carbon emissions be able to hit their targets without nuclear power, and why is it important that nuclear plants be valued appropriately as safe, reliable, zero-carbon sources of energy?

Ms. LINDE. Thank you. And you bring up another very important attribute of nuclear power. Nuclear power does not emit carbon and it is air emission free, so it is very important for an environmental policy considering reducing carbon or not increasing the amount of carbon.

I want to comment on something that Joe Kelliher said. We do have different opinions on the urgency of this situation, and Illinois is one of those states who saw the urgency and the need to take action so nuclear plants wouldn't shut down. In New Jersey, our nuclear plants that operate in New Jersey are a large percentage of the energy supply. If they shut down we will most likely move to predominantly natural gas as the single fuel source with some limited renewables.

New Jersey, like Illinois, has a renewable portfolio standard and has made significant steps to increase renewables in the state, and my company has been developing a lot of solar in the state as well. And we believe that is important. The important message I want to leave with you today is that these nuclear plants play a role in fuel diversity, they play an important role in keeping prices down, and they play an important environmental role and they need to be maintained for the future and they are at risk.

Mr. RUSH. Diversity, how important is fuel diversity in ensuring a reliable and resilient grid?

Ms. LINDE. I could comment on that. NERC issued a study this year that highlighted the importance of fuel diversity to a resilient grid. I think that report that was issued, I believe, in March of this year, does spell out the importance of fuel diversity to resiliency and the ability of a system, an electric grid system, to respond to a variety of different situations whether weather or physical or cyberattacks.

So we think that fuel diversity as NERC indicated is critical to resiliency and long-term reliability.

Mr. RUSH. Mr. Schisler, I only have a few more seconds here, but in your written testimony you state that from a federal policy viewpoint the only prerequisite for Demand Response to thrive is to have nondiscriminatory, open access in wholesale electricity market and that those markets remain competitive without pricing distortions.

Moving forward, are you confident that FERC will enact policies that will maintain competitive markets while respecting the rights of states to create their own energy policy?

Mr. SCHISLER. When the FERC gets a quorum we will hope that that will be the case. I do know that the RTOs and ISOs that you will be hearing from next week are taking this issue very seriously. We certainly don't want to stand in the way of states enacting their own energy policies, creating their own energy destiny, but market participants like EnerNOC, like independent power producers, rely upon market revenues and those prices are very important to sending long-term investment signals and that is why they have to be—fair, competitive wholesale markets have to be sacrosanct.

So, FERC has enjoyed a long history, regardless of leadership, of trying to trend toward making wholesale markets more competitive and I certainly hope that will continue, but that really does need to be the guiding principle.

Mr. UPTON. Thank you.

Mr. Olson?

Mr. OLSON. I thank the chair for holding this important hearing and welcome to our seven witnesses. It should be no surprise to anybody in this room, but my home State of Texas rode down a different trail in terms of our electric grid. Ninety percent is fully competitive, run by a group called ERCOT. Two cities, San Antonio and Austin, control their local grids. The Panhandle of West Texas and East Texas has their grids. They are interlocked.

Like other states, our source of power is changing rapidly, we are shifting from coal power to natural gas power fairly quickly. We have two nuclear reactors, nuclear sites, no more coming. That is it. We are number one for wind, number one in America with a rapidly growing solar industry.

My question is for you, Mr. Schleimer of Calpine. Your company has operations all across the country, many of those in Texas. As you mentioned in your opening statement, you said of ERCOT saying they are, "phenomenal." What does that mean and could our markets learn from the Texas example? Could they be phenomenal as well?

Mr. SCHLEIMER. Thank you, Mr. Vice Chairman.

So yes, Texas indeed did choose a different path. They have almost completely gone complete competition on both the wholesale and the retail side. And I would say that you know so far the distinguishing characteristic that you find in Texas versus some of the other markets is so far there hasn't been as much temptation to intervene in the competitive markets.

And so in fact over the last 5 or 6 years or so you have seen 14- or 15,000 megawatts of new resource being built, both natural gas but a tremendous amount of renewable resources. And those renewable resources actually were not done under long-term contracts with utilities, but really based on confidence in the market.

We do have some concerns about the structure of the ERCOT market just like some of the—it is very different. The U.S. regional markets each have their own concerns associated with them because of different policy drivers and dynamics and all that. But I would say so far, Texas is, their market remains probably the most competitive market with confidence in the rules going forward.

Mr. OLSON. And how do investment decisions in markets like ERCOT that are competitive or like the Mid-Atlantic differ from those in more traditional regions? Could a company build a new power plant in Texas with the same sorts of return on investment like they can in Georgia, for example, any competition issues there?

Mr. SCHLEIMER. So a company like ours really builds off of what the future market looks like and what our expectations of the future market looks like. So in regions where there is a known set of rules and we are confident in the set of rules and we can look out, obviously we are going to be wrong about what the future looks like, but at least we have, if we think we have a fair shot of getting our money back.

In other regions of the country that haven't deregulated or are still vertically integrated where the utilities still dominate, we will only make those investments over with the long-term contract or with the long-term ratepayer guarantee.

Mr. OLSON. Thank you.

Ms. McAlister, ma'am, a new source of energy like wind and solar only means something if we can get those to market. In Texas we have what is called competitive renewable energy zones, CREZ zones, to get resources all across the state. As plants continue to close and energy sources shift, new lines will be needed.

Can you share thoughts about the state of new transmission construction? Is the process working? Is it transparent enough? Are there bureaucratic roadblocks? What improvements can be made?

Ms. MCALISTER. I can speak to the PJM area where most of our customers are sited and where we have most of our resources. And I think that FERC has orders in place, Order 890, that allow it to provide infrastructure through an open and transparent process and we think that PJM is doing a pretty good job with the long-term transmission planning for those lines that are needed for reliability.

But what we are very concerned about is a different category of transmission and that is called supplemental transmission. Those are projects that are not needed for reliability and essentially the transmission owners make those calls whether those lines are needed or not and they really don't have the same transparency and open process as what the baseline transmission projects have. And so I think probably the best way to balance grid reliability is to make sure that the transmission process whether it is for baseline or supplemental is for it to be open and transparent and for those Order 890 obligations to apply to all types of transmission projects.

Mr. OLSON. Thank you. And on behalf of the best team in baseball, the best record, the Houston Astros, I yield back.

Mr. UPTON. Just wait, the Tigers are on a roll.

The chair would recognize the gentleman from California, Mr. McNerney.

Mr. MCNERNEY. Yes, what about basketball? At any rate, gentlemen.

Ms. Linde, do you believe that the RTOs and ISOs could charge a carbon adder and dispatch in order to adapt to state carbon reduction policies?

Ms. LINDE. I want to make sure I understand your question. Do I think they should or——

Mr. MCNERNEY. Could they do that successfully, what effect would it have on the market?

Ms. LINDE. I think the answer is it depends. If the price that is added to the market for the carbon adder is an appropriate price, then yes, it would make a significant difference and it would enable both renewable generation and nuclear generation, their environmental attributes to be valued in the market.

I caution, however, though, it is important that the details are appropriate because we have something else in the region of East Coast where it is called the Regional Greenhouse Gas Initiative and it was an effort by a group of states to add a carbon value and it was too low of a carbon value.

And in New Jersey we have a gubernatorial election coming up this year and both candidates have said that they will rejoin RGGI. And I want to be clear to explain that that will not be enough to address the nuclear challenge because the price on carbon is just far too low.

Mr. MCNERNEY. Thank you.

Mr. Glenn, how would increased transmission benefit both clean energy development and customers, and what are the biggest challenges to increasing transmission?

Mr. GLENN. The biggest challenges that we face in increasing transmission is the siting, frankly, and that can be at a state level. Also if we look at other projects across the nation that go through several states, the permitting process, the eminent domain process, those are our biggest challenges in getting projects on time, on budget, and getting renewable energy resources that have very, very low energy costs to markets in which we serve.

Mr. MCNERNEY. So in your opinion that would benefit the customers and the market to have increased transmission?

Mr. GLENN. Yes.

Mr. MCNERNEY. Thank you.

Mr. Schisler, I have been to a distributed generation facility and it is a very interesting process. There is a boom in distributed energy resources, renewables, policies of the Demand Response be brought up, and these are coming up pretty quickly.

Do you believe that the states have been able to make policies looking toward long-term effects or have they had to be more reactive? In other words, are states implementing policies proactively or are they being reactive to this technology?

Mr. SCHISLER. I think it has come so quick that they are forced to be more reactive. The changing landscape is almost occurring almost at a geometric rate when you look at the cost of storage has come down, the cost of renewables has come down. We are seeing vehicle-to-grid technologies and what is that going to do? Have we reached peak demand?

Utilities face a degree of radical uncertainty in their planning paradigm that they have never had to encounter throughout the history of distributed electricity service. And I don't know that any utility or any state commission has really wrapped their arms around what does integrated resource planning look like in the future. There is a lot to do in terms of thinking about how do we actually embrace the opportunity with these new technologies while addressing this radical uncertainty and still delivering safe, affordable, clean energy to consumers.

Mr. MCNERNEY. I agree.

Mr. Schleimer, I believe that you recommended a firewall between subsidized and nonsubsidized generation. Is that the correct interpretation?

Mr. SCHLEIMER. Yes, sir.

Mr. MCNERNEY. So could you describe what that firewall means? What would that look like?

Mr. SCHLEIMER. Sure. And there is a lot of different variations of this, but it basically boils down to running the capacity market two times. You run the capacity market once for competitive generators that are not receiving subsidies and that is basically the price that they get and so it retains the competitive market price and aspect to it, then you run the capacity market again and the subsidized units or the units that are getting out of market contracts get the prices out of that second run.

And so, instead of the subsidization deteriorating prices for the entire market, you are basically keeping the competitive market prices as they were assuming you didn't have the subsidization coming in. And like I said, there is a handful of different variations of that but that is the basic structure.

Mr. MCNERNEY. Thank you, Mr. Chairman.

Mr. UPTON. Mr. Walden?

Mr. WALDEN. Thank you very much, Mr. Chairman. And thanks again to our panelists and to the members for participating in this important hearing.

There seems to be some consensus among all the energy stakeholders that the electricity industry is undergoing a period of significant transformation, I don't think anybody denies that. And if just quickly we could go one end to the other, from your individual perspectives what do you think are the main drivers of that change that are transforming the industry? What are the main drivers? Is it consumers? Is it consumer demand, is it state laws, what is it that is from your perspective driving it?

Mr. KELLIHER. Low natural gas prices, lower than expected demand for electricity, and the sharply declining cost of renewables both wind and solar.

Mr. WALDEN. All right.

Ms. MCALISTER. I would agree it is basic market forces with the low natural gas, but I think it is also consumers demanding more and wanting different choices in their supply needs.

Mr. SCHLEIMER. I would agree with that list, cheap gas and wind and solar prices coming down. But I would also add that a significant driver is cheap money. I mean there is a lot of private investment occurring in the mid-Atlantic and the Northeast and elsewhere just because, you know, borrowing money is cheap and investors are looking for a place to put their dollars.

Mr. WALDEN. Get a return. Yes, all right.

Mr. REASOR. Technology.

Mr. WALDEN. Expand on that.

Mr. REASOR. What is brought as lower gas prices, technology, changes in the technologies of how we get that gas.

Mr. WALDEN. Fracking.

Mr. REASOR. So I would suggest technology has had the largest impact and going forward in at least the foreseeable future new technologies will continue to have the greatest impact.

Mr. WALDEN. All right.

Ms. LINDE. It is a very good question. And the most significant impacts that I see are from technology impacting the ability to get lower cost gas and that exposing the design flaw that I commented on in the wholesale market and also states. States are really driving towards policies that are encouraging and enabling investment in renewables and without that I don't think we would see the level of renewable investment that we have at least in my area of the country.

Mr. WALDEN. OK. All right.

Mr. SCHISLER. I would say technology. Technology has created an unprecedented democratization of the grid by users of electricity. They can now use energy in different ways and interact with electricity markets and interact with electricity suppliers in ways that were not possible even a decade ago and that is going to continue.

Mr. WALDEN. All right.

Mr. GLENN. June 19th, 2007, the introduction of the iPhone. That has completely changed our business and our business model. Customers want convenience, choice, and control over how they use and how they reduce our energy. I completely agree with Mr. Schisler. That combined with energy storage are the two things that have transformed our industry.

Mr. WALDEN. All right, thank you.

Mr. Kelliher, you testified that competition has been good for consumers as the markets have delivered benefits in the form of lower prices. And while competition in the electricity markets always intended to weed out high cost or inefficient generators, we now have states favoring policies that would potentially retain older, less economically competitive generation for a number of different reasons such as zero-emission benefits, job retention, tax base preservation. So were the wholesale electricity markets, were they ever intended to incorporate these state and local policies, can they and should they? And then I have one other question if we have time.

Mr. KELLIHER. To me, sir?

Mr. WALDEN. Yes.

Mr. KELLIHER. They don't and some critics of competition policy fault them for not delivering things they were never intended to deliver, which I think is a little unfair. But your other question is, well, can they? That is what RTOs are looking at right now and FERC is looking at right now. Is there a way to accommodate, accept state public policy choices with minimal harm to the markets?

And harm to the markets is going to occur either in the form of suppressed prices or the exit of economic generation in lieu of uneconomic generation, so I think there is no way to completely protect the market. It is either going to hurt price or force the retirement of economic units.

Mr. WALDEN. Well, and as you know, I think it is next week, Mr. Chairman, you are going to have the hearing on RTOs and ISOs and look at all of that side of this as well. Our goal is to make sure we stay ahead of the dynamic changes in the electricity market so that the grid works, so you get electricity where you need it when you need it. And obviously we have security issues that we will get into here and other places, but adequacy is a big part of that and the time to build out to make sure we have got the ability to transmit the power where we need it is something this committee is very concerned about as well.

My time has expired, Mr. Chairman. Thank you again. And to our panelists, thank you very much for your participation.

Mr. UPTON. Thank you.

Mr. Peters?

Mr. PETERS. Thank you, Mr. Chairman. I want to follow up on the Chairman's questions. But before I let it get away, Ms. Linde, what was the price that RGGI charged that you said was too low?

Ms. LINDE. I am not sure if I have it right here, but it is in the—oh, it is $2.67 per ton of carbon.

Mr. PETERS. OK, thank you.

Ms. LINDE. As compared to much higher numbers that are——

Mr. PETERS. Thirty to forty is other. So my question had to do of just putting aside some very important issues for the minute which is cybersecurity, which we talked about, putting aside the pricing in the markets, we have seen a phenomenon of this distributed generation. You say it is sometimes driven by consumers who want solar panels on their rooves, sometimes it is driven by state policies. I am concerned. What I hear about is that that creates an issue for delivering electricity, to making sure that when you turn on the lights from a systems point of view that they will come on.

And Mr. Schisler, I think you said something like we haven't started planning for that. What would that plan look like? What kind of concerns would you like to raise for us to consider as we see these technologies get deployed?

Mr. SCHISLER. So I think we are talking about two slightly different things. One is sort of a long-term planning paradigm, where do we need to transition and what transmission resources and what types of resources are we going to need? Are we going to need ramping resources or baseload, how much of it? That is more of a long view question that regulators have to face.

It is a fact that we know more today, both grid operators and distribution utilities today know what is happening downstream at the grid than they ever have in the past. We have better outage management response times. We have better information at what is happening at customer sites. And that is, I think that is where there has been innovation on that side. Not just innovation on the consumer side, it has been innovation on the utility side that has made the grid more resilient and I think some of the investments that made in recent years in grid resiliency in response to some of the storms have helped do that.

But ultimately I think there is like a real-time component to managing real-time operations and then there is the long-term view.

Mr. PETERS. Is that something that the private sector is going to handle or is that something that governments need to be involved in?

Mr. SCHISLER. Clearly, the real-time operations, I believe, is largely a utility function. So it is the distribution utility and it is the wholesale market and that is a regulated function.

Mr. PETERS. Anyone else have a comment on that?

Mr. GLENN. Congressman, Alex Glenn. Just to piggyback on what Mr. Schisler said, I think, two things. One is, as we invest that $35 billion in the grid it is going to make it smarter. It is going to deploy new technologies, but it is also going to use data analytics. So the last four people that we have hired at our company have been Ph.D.s in data analytics.

And I think those two things combined are going to help significantly the business that Mr. Schisler is in as well as the ability of customers and the ability of distributed generation to propagate across our systems in a way that is smartly done. And that is going to be the critical aspect of that.

Mr. PETERS. And I think it has got to be a partnership. So we, in San Diego, I think STG needs that 40 percent renewable now, and I don't—that is obviously not rooftop, but that is pretty good. But I think that now there is a clamoring among consumers to do more rooftop and community choice aggregation and all these things. We can't get so far out in front of it that we are not talking to the utilities about making sure that the grid is reliable from a supply standpoint.

And so maybe, Ms. Linde, if you had a question or a comment on that I think it is really important to have that conversation and to be in partnership.

Ms. LINDE. Thank you. And I agree with Mr. Schisler that Demand Response is a really critical component of our overall system. We want customers to respond to the cost and not use power and identify what price they are willing to not use the power. But when customers want power, when their rooftop solar is not working because the sun is not out, the utilities are the ones who have to be able to meet that demand.

And it is not just having enough as far as numbers, it is having the right mix, the right mix that can respond at the right time in the right combination. And the NERC report that came out this March addresses that and it identifies all of the different characteristics of different types of supply and how they work together. And it is important that we have experts and transmission planners and generation planners looking at making sure that when the flip, you know, someone flips the switch and they want their power that the right mix is standing behind it and ready and able to respond.

Mr. PETERS. Right. We want to do that in my perspective in a way that moves us toward renewables, but we have to do that together.

So thank you, Mr. Chairman.

Mr. UPTON. Mr. Shimkus?

Mr. SHIMKUS. Thank you, Mr. Chairman. It is great to have the panel. I think the bigger question now is do we get to the process of rewriting the Federal Power Act, really, last codified in 1935. We had testimony last year that said well, it was so vague that FERC was able to run and help create these regional markets.

And isn't the constitutional debate of what is interstate commerce and if you excite an electron and it is going across state boundaries that caused the question even maybe the federal regulation of the interstate commerce, which would be the transmission portion, and states' involvement is still in the distribution.

So I think that is the bigger question, because we are trying to—and I am not afraid to be involved in that debate, because as was quoted by Mr. Schisler, we have democratized this electricity use to the individual. And the iPhone was, Mr. Glenn, you used the iPhone as an example. So, and Joe was here when we did competition, when we used to have state regulated markets and we moved to the regions.

But I want to spend my time—and the RTOs will be here next week, but the people who have complaints about the RTOs will not be here next week. And so I really want to focus on two comments that are really the same, Mr. Reasor and Ms. McAlister—Mr. Reasor, you have a beef with PJM and you are wholly contained, OK, you are the rural cooperative, a different model evolved over time and some would say obviously it is a not-for-profit entity.

So briefly can you say, what is your beef? Because then I am going to go to Ms. McAlister—at least Illinois Municipal Electric Association has a beef because they are in two RTOs which causes problems. So first of all, what beef do you have with PJM because you are wholly contained, and then I am going to move to Ms. McAlister to explain the separation.

Mr. REASOR. Thank you, Congressman. Our big issue is the ability and having the first option that we can self-supply.

Mr. SHIMKUS. And you said that about 15 times in your opening statement.

Mr. REASOR. I did. I hope you remember that.

Mr. SHIMKUS. So what do you mean by self-supply?

Mr. REASOR. We are a load serving entity. That is what makes us a little bit different than some other parties.

Mr. SHIMKUS. So you are owners and the Federal Power Act gives you the authority, in fact it is in the statute that you can self-supply.

Mr. REASOR. Basically that is what we would argue.

Mr. SHIMKUS. Under 217(b).

Mr. REASOR. That is correct. Because we are a load serving entity we have an obligation to meet the needs of the consumers that own us, which we would suggest, I realize it is a different model, but we would suggest is the ideal model of a nonprofit entity that the consumer owns and that is where they get their electricity.

We should have the opportunity to self-supply that load to——

Mr. SHIMKUS. You should have the opportunity, it is in the statute.

Mr. REASOR. Well, but PJM in the way that——

Mr. SHIMKUS. Well, that is my point.

Mr. REASOR. Yes. And as you said, I have a little bit of a beef with PJM. However, I would say to you that when PJM started their first option for us to meet their capacity obligations, which are legitimate, was that we could look first to our self-supply.

Mr. SHIMKUS. OK, let me go to Ms. McAlister. I am running out of time. Because I hope, we haven't scheduled this out but I hope you know where I am going with this question.

Ms. MCALISTER. I think I do. And thank you for the question and just a quick point. We are also in two RTOs and we also serve load in non-RTO areas, so we have kind of got the whole scheme of things. So we have got the same kind of beef that Old Dominion has and, really, the crux of the problem from our perspective is that the capacity market and PJM over time has evolved and become overly complex.

It also reduces the amount of resources, the types of resources that can participate because they no longer meet the definition of a capacity resource and it has just become so unduly complicated that it makes long-term planning for entities like us very difficult. And we are at risk with what is called the minimum offer price rule which is essentially a floor price that is administratively set by PJM that makes——

Mr. SHIMKUS. And let me hold you because my time is running out and I want to get this point out——

Ms. MCALISTER. Yes.

Mr. SHIMKUS [continuing]. Is that so in Illinois we have PJM and we have MISO. Most of our generation is in the south from our Illinois municipal or even our co-ops. They should by federal law be able to provide to part of their ownership up to the PJM. But because of these regions, part of that load is sold to PJM who sells it back into their market at a premium versus the original clearing price in MISO, which means that those people who are owners of the generation can't get the real price of the generation.

And I think that needs to be looked at and I yield back, thank you.

Ms. MCALISTER. Do I get to respond?

Mr. UPTON. The gentleman's time has expired.

Mr. Green?

Mr. GREEN. Thank you, Mr. Chairman. I want to welcome our panel and thank the chair and the ranking member for calling it.

I was just kind of reminiscing because I have been on the Energy subcommittee and I look back in 2001 and '02 when we had so many different problems that are—in the day we have some problems that we can actually deal with, back then it was almost intractable. But again coming from Texas we don't want anybody messing with us and we will fix our own problems through our regulatory commission. So we have a different problem today, obviously availability and cost and that is affecting everyone.

Mr. Kelliher, you touched on how significant changes in the breakdown of our nation's electricity markets have led to questions about the driving force behind the retirement of certain types of electricity generation, market fundamentals or policy on the state or federal level. You stated the preponderance of the evidence suggests that market factors are the primary driving force behind the retirement of uneconomic generation methods.

Can you elaborate on the evidence you reference when stating that the market forces rather than a regulatory process has been the primary driving force behind the retirement, and again both your experience on this committee as a staff member but also in the industry.

Mr. KELLIHER. There have been arguments from time to time that negative pricing by wind is causing retirements of nuclear and coal plants, and there is pretty, I think very persuasive evidence that that is not true. There is PJM analysis that shows that first of all, negative pricing is when you bid below zero, but wind projects do bid negative from time to time, so do nuclear plants, so do hydro projects. So negative pricing is not something that is particular to wind projects.

But if you look at, well, when does negative pricing by wind projects set the market price in one of the RTOs, PJM analysis shows that it occurs 0.1 percent of the time, so that is 1 hour out of every 1,000 hours. I think it is hard to say that therefore that wind is the villain.

Mr. GREEN. Right, they are not driving the train.

Mr. KELLIHER. Right. And then even in Texas, your State of Texas where there is much more wind penetration in Texas than in PJM, negative pricing by wind projects in Texas occurs less than one percent of ours. So I think that shows that federal policies that encourage wind development are not causing those retirements.

And then the coal plant retirements, that is driven by in most cases just pure cost factors. As I said earlier, an uneconomic, an inefficient coal project used to be able to deliver power cheaper than the most efficient gas project. Those fuels have reversed themselves and now efficient gas projects will always be able to produce cheaper than even more efficient coal projects.

So I think coal retirements are really driven primarily by economics, not by environmental regulation. There are some that environmental regulation has been the tipping point where the cost of complying with new requirements, arguably, is the tipping point for some coal projects.

Mr. GREEN. Thank you.

Mr. Chairman, well, again I have welcomed Calpine to Texas over the last 15 or 20 years, and I joked at one ribbon cutting for a cogen facility in our district and said, when are you going to change your name to Texpine because so much of your investments are in Texas? But I appreciate you being part of our market. My Californians love that.

I am pleased that you discussed committed method of the energy market in Texas spurring increased investment and renewal in natural gas resources. You mentioned how these investments not only lead to lower prices for consumers but also increase in the electrical system reliability and decrease emission rates.

And let me point out in your statement where you talk about the Texas market, over the last 5 years electricity prices declined by over 13 percent in Texas and historic lows. Emissions are down also. Between 2010 and '16, the emissions per million kilowatt CO_2s were down 5 percent, NO_x emission and CO_2, SO_2 emissions were down. NO_x was down 24 percent and SO_2 were down 40 percent.

I can't remember in my history of being an elected official, whether it be in the Texas in the legislature or here, I have seen that kind of result in the electricity market. Can you share any other information outside of what your testimony was?

Mr. SCHLEIMER. Well, that has really been driven by, like we talked about earlier, the low gas price environment and a tremendous amount of investment that has been spurred in the Texas market in both highly efficient natural gas-fired combined cycles as well as, as you know there is a tremendous amount of wind in West Texas and that has largely displaced a lot of the coal and old steam facilities that the utilities used. Those coal plants in Texas, a lot of them are in financial difficulties now as a result of the change-out in the technologies.

Mr. GREEN. Well, Mr. Chairman, thank you for calling the hearing. Again, thank all our witnesses, because again it is good for us to look at where we are today as compared to where we were 5, 10, even 15, 20 years ago. Thank you.

Mr. UPTON. The chair would recognize in perfect segue the gentleman from Texas, Mr. Barton.

Mr. BARTON. Thank you, Mr. Chairman, and I will be brief. I have to go to a lunch meeting.

This is an important hearing, but I don't think it will make the front pages. There is a probably a better probability of the latest Trump tweet being on the front page tomorrow than anything we discover here.

But this is an important hearing, Mr. Chairman, because of a small thing called reliability. I will tell you what reliability is. I went out to my car this morning to attend Chairman Walden's breakfast meeting with the subcommittee chairman. When I turned the key nothing happened. I had no reliability. As it turns out my alternator had conked out. It worked yesterday, but it didn't work this morning. By the same token, when the people that are putting this hearing together, the staff getting ready for the hearing, when they came in this morning they turned the switch, the lights came on.

Our electric grid has got about 100 percent reliability. But that is not a given that it will always be so, and as we retire more and more plants and more and more of our generation is from renewables, there is nothing wrong with renewables except sometimes the wind doesn't blow and of course sometimes there is no sunshine. Water power is pretty much there all the time.

So we need to really think about better ways to continue to maintain and if possible improve reliability. One of the ideas that has been circulating is this idea of using artificial intelligence. Of course I know most people think that is what the Congress has is artificial intelligence, but this is a different definition.

So I would like the panel to comment on if they think that this concept of artificial intelligence can be used to more predict where the demand is going to be and help allocate the supply to the demand so that we maintain as close as possibly 100 percent reliability, so any comments from anybody about artificial intelligence used in the electricity grid? It is not a trick question.

Mr. GLENN. Congressman Barton, this is Alex Glenn from Duke Energy. I think that is going to be your next significant plateau then in technology improvements.

Mr. BARTON. So you think it can be used?

Mr. GLENN. I think it can be used and I think it ultimately will be used, the question is how and when. And I think what you are going to see is baby steps to look at it. And you might see it in call centers first, so that there is artificial intelligence in all of our call centers, and you may see that ramped up in different aspects.

Mr. BARTON. Is your company working on——

Mr. GLENN. We are working on that now to do that. So I think as you see technology and the pace and rapidity of that technology improvements you are going to see that continue to be more ubiquitous as the years progress.

Mr. BARTON. That is a nice word, ubiquitous. I will look that up. Sounds good though.

Yes, ma'am?

Ms. LINDE. I would also add at PSEG we are constantly adding new technology to a variety of our generation facilities, to project what piece of equipment in that generation facility might have a fault. We just actually upgraded some of our technology to have more predictive information, because the lights need to be on when people flip the switch. So our focus is making sure that our facilities, there are no surprises.

Also in understanding the transmission system, there is greater and greater intelligence being added to the transmission system to tell us information before it becomes a problem. And I agree with Mr. Glenn that I think we are going to be seeing more and more of this and utilities are paying attention. The industry is paying attention to this.

We also have to manage cost, so it is a balance between adding the right amount of technology but not doing it in a way that burdens customers if there is not a tremendous value. So it constantly has to be weighed to make sure we are putting the right intelligence into the——

Mr. BARTON. My time is about to expire. Is there anybody that doesn't think artificial intelligence is an option as we try to maintain reliability?

Mr. REASOR. Congressman, I would just say that I am not going to say it isn't. I think it is important for these reasons that have been stated to help us better understand where the needs are and the equipment and technology. But remember, the old non-artificial intelligence tells you that for good reliability you have to have the generation and you have to have the transmission to get it there.

The artificial intelligence maybe can tell us where it is lacking and maybe can tell us what equipment is failing, but it doesn't generate electricity. And ultimately for real reliability, true reliability you have to have the generation and you have to have the transmission to get it there.

Mr. BARTON. I eat a lot of health food but I also eat a lot of meat and potatoes, so I understand. With that I yield back, Mr. Chairman.

Mr. OLSON. [Presiding.] The gentleman yields back. The chair calls upon the gentlelady from Florida, Ms. Castor, for 5 minutes.

Ms. CASTOR. Thank you, Mr. Chairman. And thank you to all the witnesses that are here today. Congress doesn't do a very good job thinking decades ahead and planning ahead, it is always the next budget battle or the next bill on the horizon.

But coming from Florida, I am very attuned to the rising costs for consumers and all of us due to the changing climate, a/c bills and flood insurance, and Mr. Glenn knows in our neck of the woods, beach renourishment to keep our tourism economy going, what we have to do with property taxes to retrofit a lot of water and waste water infrastructure, property insurance.

So it seems to me we have reached a point where the old business model of selling electricity needs some updating and some places in the country are doing that better than others. The old business model was sell as much power and generate as much as possible to make your profit build plants and there are incentives for that.

But that doesn't really match up with what we need to do to promote a better mix. Yes, the baseload and reliability are fundamental, but we have got to do a better job in planning for the future and incentivizing the demand response, energy efficiency, conservation, and the transition to renewables.

Tell me what is working best out there across the country when it comes to those kind of incentives for you all, what you all believe can be the answer. Now realizing that we have had a change and the Clean Power Plan isn't going to be pushing everyone in all of the states, but what is working? What are the best incentives for our utilities to help us with the future?

Ms. MCALISTER. Thank you for the question. I think largely what you are talking about the shifts in resources are really being driven by consumer demand. And part of what we think would be a good incentive is allowing those resources to actually participate in the market without restrictions and be on par with some of the other types of supply, so that——

Ms. CASTOR. What do you mean?

Ms. MCALISTER. Well, for example, in the PJM capacity construct it has become more rigid and it has become less flexible and it doesn't incorporate some of the renewables because they can't operate 24/7 the way that some of the old coal-fired units can participate.

Ms. CASTOR. Is there a particular state or region in the country that is doing that better than others? Is there something specific you can point to?

Ms. MCALISTER. I know at AMP in the Midwest we are at 21 percent renewable resources, which for a Midwest utility is rather high, and that is because we are responsive to the consumer demands. We are a member——

Ms. CASTOR. Is it consumer demand or has the states set energy efficiency goals, conservation goals, or renewable goals?

Ms. MCALISTER. For us it is not the state because we are not regulated by the states, we are locally regulated. So it is the consumer driving the demand.

Ms. CASTOR. Mr. Peters and I were comparing notes. What did you say the San Diego area or—what is it?

Mr. PETERS. Forty.

Ms. CASTOR. With renewable, based on renewable power. And what is the state of California?

Mr. PETERS. Thirty-three.

Ms. CASTOR. Thirty-three. And that is because—will you be my witness, because the state has set those goals.

Mr. PETERS. Well, certainly it is partly because the state has set renewable goals and it is partly because I think the consumers are clamoring for it as well.

Mr. SCHISLER. I would say one thing that is working well is many states—California, Texas, and actually there is too many probably to list now—are doing a good job of getting customer data to customers through their smart grid investments and that is empowering customers and opening up newer and more efficient ways to use energy. So that is one example of what is working well and should be replicated elsewhere.

Ms. CASTOR. I guess there was some discussion of cell phones earlier, and this, the Millennial generation they are ready, and I do hear too the consumers are clamoring for more control now. Person-to-person maybe that doesn't make a dent, but you empower consumers and work with your industrial users over time and use technology and it kind of highlights the need for greater infrastructure investment if we could ever get the Congress in a bipartisan way to move on to energy or to infrastructure investments.

And I know, Mr. Glenn, you talked about this. We have got to make sure that energy resiliency and that we do an infrastructure bill it isn't just the bricks and mortar for transportation. It is very important, but it has got to be our energy future to help us control the costs that I see on the horizon decades ahead.

So thank you, Mr. Chairman. I have run out of time, I yield back.

Mr. OLSON. The gentlelady yields back. The chair calls upon the gentleman from West Virginia, Mr. McKinley, for 5 minutes.

Mr. MCKINLEY. Thank you, Mr. Chairman.

When we put two issues on the table, both the grid reliability and the greenhouse gases and climate change or all those combined, it is hard to extract good policy, good public policy and how we might be able to address that because there are consequences involved with those decisions and how that works out.

For me in West Virginia it is different than it is in California or Texas or elsewhere, is we have seen the impact of the regulatory impact over the last 8 years. Example, in West Virginia we used to have just in 2008, we had the second lowest utility bills in the country for industrial consumption, now we are 26th because our coal-fired power plants many of them were shut down or they were required to upgrade their facilities to such a level.

Now in conjunction with that at that same time, we had the seventh best rate of unemployment in the country, now West Virginia is 49th. So there are consequences to these. We have got to understand when we debate these issues we are all sensitive that there are consequences with it. And I don't understand yet, I have not been able to find a good response back for the coal miners across this country, but particularly in West Virginia, what did they do to cause this? Why is it they are losing their jobs? Why are there bankruptcies involving them? We have got to be more sensitive to the individuals when we set policy here that they are going to lose their jobs.

So Ms. Linde, if I could ask you a question. If we leveled the playing field and got rid of these tax subsidies that sweep all across our utilities could the traditional baseload power generators be better able to compete?

Ms. LINDE. Thank you. The PSEG is not, certainly is not encouraging the extension of those credits, but I also want to be clear that the existence of those credits are not what is causing our nuclear plants to be at risk. It is an aggravating factor perhaps but certainly not the main driver. The main driver is that there are fuel diversity and there are environmental attributes which some people also value are not being valued right now in the marketplace.

Mr. MCKINLEY. And that is why I wanted to get to that point, because you mentioned that several times, your main driver. So my question to you would be, you talked about the main driver or the economic stress on base plants and you mentioned nuclear in particular, because I think that is a solid baseload provider as is coal, is that the market fails to adequately value and compensate baseload.

Ms. LINDE. It does. There is——

Mr. MCKINLEY. So shouldn't we do something about that? Shouldn't we—again, my next—is in the market value, reliability, and resiliency, but we are not.

Ms. LINDE. We are not currently in the competitive marketplace. And it is not because there is an intention not to do it, it is just the market wasn't designed to do it. And we are pointing that out that—and for policy makers to make decisions. And we are pointing it out to you today, and we hope that the policy direction given to FERC is that fuel diversity and resiliency is important and we hope that that direction will cause changes and fill that gap in the market.

But we are also pointing it out to New Jersey, because states have an important role here. Some states like Illinois and New York have already taken action. They are not waiting because once these plants shut down they are gone forever. They are closed permanently, and we don't think that is good public policy.

So our ask is to recognize that these plants without a change either from the state or the federal government or some change in the price of natural gas which is certainly outside all of our control, that without some change these plants, we will see a shutdown, a continued and regular shutdown of these plants until it is too late and we shouldn't let that happen without deciding that we want——

Mr. MCKINLEY. And if I could, rather than allow this to go back up to 30,000 feet, what are specifics? Can you provide me or this committee some specifics of how we might be able to address the reliability and value that in our cost base?

Ms. LINDE. Absolutely. And we can do that separately outside of this committee, but FERC has been looking at this issue. The DOE as was commented before is working on a report. I think both of those places, FERC through their proceeding and the DOE through their report, those are vehicles to identify fuel diversity and resiliency as an important public policy because it is a choice that is going to be made.

Mr. MCKINLEY. Thank you. I yield back my time.

Mr. OLSON. The gentleman's time has expired. The chair calls upon the gentleman from New York, Mr. Tonko, for 5 minutes.

Mr. TONKO. Thank you, Mr. Chair. There has been some talk about that diversity that assists the whole equation here. And while I am sure there are differing views on how it should be done, do witnesses agree that it is important to maintain a diverse fuel supply for the sake of reliability? Maybe go across the board starting to our left here.

Mr. KELLIHER. In general, yes, but we have diversity now not because it was a goal, it is a byproduct of building the next increment of supply is looking for the technology that is lowest cost at the time and these tend to be long-lived facilities, so it is not as if in 1960 we had a certain electricity supply pie we planned to. I would say in general, yes.

Mr. TONKO. OK.

Mr. KELLIHER. In general, yes.

Mr. TONKO. If we would just go across the board and just give us a specific yes or no. Thank you.

Ms. MCALISTER. Yes. Grid reliability is crucial and fuel diversity is one aspect of that.

Mr. TONKO. OK.

Mr. SCHLEIMER. I would agree with that that fuel diversity is crucial but it is not single dimensional. You can't say one fuel, you looked at one fuel versus another and it is more fuel diverse. You have to look at flexibility, startup times, shutdown times, ability to integrate renewables, so there is eight or nine dimensions to fuel diversity, but absolutely.

Mr. TONKO. OK.

Mr. REASOR. Diversity is always good. You just have to be careful that you don't start regulating and controlling diversity and create winners and losers. That is a very risky slope to go down.

Mr. TONKO. Ms. Linde?

Ms. LINDE. I think you know my answer that fuel diversity is important.

Mr. TONKO. We heard you.

Ms. LINDE. And it can be a public policy without creating winners and losers. A fuel diversity doesn't mean nuclear for everyone. In some places nuclear doesn't exist. In New Jersey, fuel diversity means nuclear continues at least for the life of the licenses that they have.

Mr. TONKO. Thank you.

Mr. Schisler?

Mr. SCHISLER. Of course fuel diversity is good, but I do worry that we go down a path of sort of central planning and picking winners and losers which is ultimately going to lead to inefficiency. So fuel diversity is good, but I think we need to use market forces to achieve it as far as possible.

Mr. TONKO. OK.

And Mr. Glenn?

Mr. GLENN. Yes.

Mr. TONKO. OK, thank you very much.

Ms. McAlister, do you believe the RTO operated markets have provided the proper signals for a diverse array of electricity resources?

Ms. MCALISTER. I do not. That is really not what they were designed for as we have talked about a number of times. They were really designed for least-cost dispatch and that is what they are achieving, but they are not providing incentives for diverse fuel sources.

Mr. TONKO. And again across the board, what would the reaction be to that about the RTOs?

Mr. KELLIHER. They were not designed to achieve a certain level of fuel diversity, no.

Mr. TONKO. Mr. Schleimer?

Mr. SCHLEIMER. PJM actually looked at fuel diversity in a report they released a couple months ago and they found that fuel diversity, I think Mr. Kelliher referred to this already, is actually increasing in PJM, not decreasing.

Mr. TONKO. Thank you.

Mr. Reasor?

Mr. REASOR. Again, that wasn't their design.

Ms. LINDE. Yes, I agree. It was not their design.

Mr. SCHISLER. It was not their primary design, no.

Mr. TONKO. And Mr. Glenn?

Mr. GLENN. Yes.

Mr. TONKO. OK. And obviously state policy decisions can affect the fuel supply. Should state policies seek to promote or maintain fuel diversity anyone?

Mr. GLENN. Yes.

Mr. TONKO. Ms. Linde or Mr. Glenn?

Mr. GLENN. Yes, just to put it in perspective, one dollar for MMBTU increase in the price of natural gas for our customers in Florida will increase a fuel bill by $200 million. So if you think about that, fuel diversity and overall diversity in your generation planning is critically important.

Mr. TONKO. And Ms. Linde, I believe you wanted to respond?

Ms. LINDE. Yes. I do believe that states have a role in fuel diversity. Ideally, it should be handled on a regional or a federal basis because electricity markets are interconnected, but states have a legitimate role and the courts have been supporting that.

Mr. TONKO. Should the states give preference to reach environmental goals?

Ms. LINDE. Our view at PSEG is that it depends on the state. States, that is a local issue. Some states have renewable portfolio standards, others do not, and it is up to the constituents in those states to decide what they believe is most important. Ultimately, we have to do what is right for the customers and for our nation, and a state is going to respect what their customers and their citizens want.

Mr. TONKO. I believe my time is up, so Mr. Chair, I yield back.

Mr. OLSON. The gentleman's time has expired. The chairman calls upon the gentleman from the Commonwealth of Virginia, Mr. Griffith, for 5 minutes.

Mr. GRIFFITH. Thank you very much. I appreciate the chairman from Texas recognizing Virginia and do appreciate being with you all. I apologize that I have been in another committee hearing for part of the time, so I apologize in advance if I go over some previous territory.

I will say based on the opening statements and so forth that I recognize that we need fuel diversity, but I also recognize that I have some differing opinions with some of the members of the panel because while market forces certainly have played a role, the regulatory scheme in relationship to whether or not a utility continues to use an existing, or what was then an existing, coal-fired power plant has clearly been affected by regulation as well.

And some of those, because of the cost to their ratepayers, would have continued to use some of those coal-fired power plants for some time in the future if—and I believe it will be a low-cost natural gas supply for a number of years in the future—as they went to replace those facilities they would have replaced them probably with some mixture including a higher amount of natural gas, but it was artificially moved forward, in my opinion, by regulation. So I do disagree there.

I do think though that we should let the market work it out, trying to keep a diversity including coal because coal still accounts for 30 percent of our power source and that if we eliminated subsidies in the marketplace for all of the different potentials that coal would be in a much better position to play a role in that marketplace.

OK, so I got all that off my chest and I do believe that coal is going to need to be important when we look at high usage periods, because you may be able to build a lot of pipelines but you can't build enough pipelines to handle all the aspects of a polar vortex. And yet you can put coal in the back 40 and have it there ready to go in cases of emergency and when things don't work out quite the way, which is why in the eastern part of Virginia they just allowed two coal-fired power plants to fire back up because they haven't gotten the other supply there yet and they have got a transmission problem, so we are going to have to go back to coal in a place where it had already been eliminated.

So that being said, let me move on. I am going to call you Senator Reasor because that is how I knew you originally. It is good to see you. We talked earlier today. But Mr. Reasor and I, Senator Reasor and I served at one point in time in our past in the Virginia legislature, he in the Senate and I in the House. It is good to have you here today.

Having missed some of it, I have got a question for you but I am also going to give you an opportunity right now, is there anything that you haven't had an opportunity to speak on that you desire to speak on here today?

Mr. REASOR. I think I am good, Congressman.

Mr. GRIFFITH. All right.

Mr. REASOR. I appreciate the opportunity.

Mr. GRIFFITH. All right, so my question deals with procuring capacity is necessary for a healthy wholesale market. As a PJM member, I understand you may be unable to self-supply the capacity that is required. Is this true and how would you resolve the situation? And I am really curious how the self-supply issue got turned on its head. But you can talk about that some more.

Mr. REASOR. Thank you, Congressman, for the opportunity and you are exactly right. And I would go back to basically just saying this. PJM under their original structure did allow utilities like us who are load serving entities to have the opportunity to first look to our self-supply, and then if there was not enough capacity within PJM they would obtain that capacity and we would pay those costs as members of PJM. That worked fine. We liked that situation, we thought it worked well.

We are not sure—well, we have some ideas as to why the changes were made because other parties and participants within PJM saw the markets differently and wanted to kind of move the system around a little bit and so they convinced PJM that they should maybe do away with the idea of looking first to self-supply, but look first to the capacity markets that PJM instituted.

Now I will say that after a period of time we were able to reach a compromise and they made some exceptions to that rule that did allow us to look first to our self-supply and as long as that was in place that worked, but the courts have now said that may not be exactly because of a FERC ruling the way it will be allowed, so we are a little concerned about the future.

Mr. GRIFFITH. And would I be correct, and I am going to need a yes or no on this one because I am running out of time, but would I be correct if that makes it more difficult for you all to look for, say, investments in the coal fields where you might put a closed-loop hydro project inside of a coal mine that policy makes it more difficult for you to even consider that, doesn't it?

Mr. REASOR. It makes it more difficult for future planning and long-term planning and a facility like that would have to fit that category.

Mr. GRIFFITH. I appreciate it.

Ms. McAlister, real quick. Public power utilities like the city of Salem and the town of Richlands are governed by their city councils. How is the role of these elected officials and local decision making respected within the capacity construct, and you have got 10 seconds. Oh, you can get a little more, got a little more.

Ms. MCALISTER. Thank you. I don't think it is in particular, because the construct as we have talked about was designed to do least-cost dispatch and it is not conducive with local decision making.

Mr. GRIFFITH. I appreciate that.

And thank you for the extra time, Mr. Chairman, I yield back.

Mr. OLSON. The gentleman's time has expired. The chair calls upon the gentleman from Ohio, Mr. Johnson, for 5 minutes.

Mr. JOHNSON. Well, thank you, Mr. Chairman.

And Ms. McAlister, thank you for being here today. As a public power producer owning generating units throughout my home state of Ohio and a few hydro sources as well along the Ohio River adjacent to my district, I have appreciated your thoughts and insights today.

In your testimony you state that we must not lose sight of improving our current price formation processes regarding transparency of operator decisions, modeling, all known constraints, and more accurate price formation rules during periods of transmission congestion and volatile fuel prices. Can you elaborate just a little bit and explain what modeling all known constraints might entail?

Ms. MCALISTER. Thank you, Congressman Johnson. What we are really getting at there is that there actions that can be taken on the energy market and we have focused today on the capacity construct that we think needs a lot of work, but there is also work to be done on the energy market side of it. And FERC has been taking proactive actions to improve price formation through a series of technical conferences and we are very supportive of those actions and think that there is still more to be done as far as modeling and ensuring that during times of constraints we are getting the best least-cost energy.

Mr. JOHNSON. OK, all right. You talked about churning of RTO rules. How frequent are these rules changed and what is the impact of this churning that you describe?

Ms. MCALISTER. Well, since 2010, in PJM there have been 27 significant changes that were filed at FERC that fundamentally have changed the nature of PJM's capacity construct. And the effect of those is that the construct has become increasingly complex and it also doesn't ensure transparent or stable prices and it makes long-term planning very difficult.

So we think that it is time to acknowledge the capacity construct as designed might not be cutting it and we need to go back and do a comprehensive evaluation of whether we need to change.

Mr. JOHNSON. OK, all right. Thank you, one more. You also mentioned in your testimony that "new energy products must also incentivize the retention of sufficient nonvariable resources to ensure load continues to be served at all times." Can you elaborate on this? What would that entail?

Ms. MCALISTER. Well, what we were talking about there is in PJM with the recent capacity performance changes the definition of what a capacity resource changed and in order to qualify as a capacity resource you have to be available 24/7/365. And what that does is it negatively impacts intermittent and renewable resources.

And so one idea that we have is through bilateral contracting it would value those resources on par with some of the other resources that do meet the capacity performance definition.

Mr. JOHNSON. Let me make sure I understood this. So you would say that alternative sources that are not necessarily available 24/7/365 would be evaluated on the same basis as other sources, or is it the opposite of that?

Ms. MCALISTER. No, no. Well, I think what we would do is if you allow bilateral contracting to have broader use then those customers that value those attributes pay what they think it is worth. And then the other resources, for example, coal, the customers that value coal resources would pay through bilateral contracts the value of what they see coal being worth.

Not exactly on par, I mean they have different values. Some can't, if the wind isn't blowing it doesn't operate. So I am not saying that they are equivalent as resources, just that they should be allowed to be valued by the customers who want those particular attributes.

Mr. JOHNSON. OK, all right.

Mr. Glenn, you mentioned most permitting regulations do not impose a timeframe for agency action. Can you elaborate on the reasonable shot clock for decisions that you mentioned in a project delay your company is facing?

Mr. GLENN. Thank you. To give you a little context, we had a hydro——

Mr. JOHNSON. You have about 25 seconds.

Mr. GLENN. We had a hydro relicensing matter. It started, we filed our application 2 years before the license was to be issued pursuant to the law. That was in 2005, I believe. 9 years later we receive that permit, so to me that is not a reasonable shot clock. It has to be something less than that and obviously it is a balance. But we need to have some type of deadlines imposed.

Mr. JOHNSON. OK. All right, well, thank you.

Mr. Chairman, I yield back.

Mr. WALBERG [presiding]. I thank the gentleman and now I am pleased to recognize the fully repaired and recuperating gentleman from Missouri, a man we respect and glad to have you back with us, Mr. Long.

Mr. LONG. Thank you, Mr. Chairman.

And Mr. Glenn, you state in your testimony that the original principles and the needs-based application of PURPA have been overtaken by dramatic advances in the energy marketplace and many of the requirements of PURPA are unnecessary. Can you expand on why market changes have made much of PURPA unnecessary?

Mr. GLENN. Yes. I would use North Carolina as a good example of this, so when we look at 7 years ago, North Carolina had——

Mr. LONG. You might want to stay on your mic. I know you can't see me through them, but it is fine. You are not missing much.

Mr. GLENN. So 7 years ago we had 20 megawatts of solar capacity in North Carolina. Today we have 2,000 megawatts and it is largely due to PURPA-mandated contracts that we have to take and pay for those contracts even though we may not need those resources. We have another 5,000 megawatts in the queue.

To put that in perspective, that covers roughly three-quarters to almost the entire square footage of Washington, D.C. with solar panels and that comes at a cost to our customers. And we currently believe right now that contracts that we signed not 2 or 3 years ago are out of money and will be over the 10 to 15 years by about a billion dollars. That is a billion dollars that our customers are going to pay more than they otherwise would have.

Mr. LONG. So that kind of explains my next question, how you tell these experience and operational challenges due to PURPA, correct?

Mr. GLENN. The operational challenges are significant and they are becoming more and more significant because there are no ground rules on where those utilities are placed. It placed it where the cheapest land may be and so our system wasn't designed to handle a significant concentration, for example, of PURPA solar contracts in one area of our state. That is starting to have operational impacts on the way our system can handle that type of influx that comes online just like that and goes away with cloud cover or a thunderstorm just like that.

Mr. LONG. What are some of the recommendations for updating PURPA to reflect the changing marketplace you have?

Mr. GLENN. I think any updates to PURPA should be guided by, really, two principles and that is affordability to customers and reliability to the grid. And I think within that there are ways in which I think PURPA could be amended that will get at and really be a benefit to all of our customers.

Mr. LONG. OK. You also highlight the need to address workforce readiness giving the changing industry and new investments and grid modernization. Can you discuss Duke Energy's efforts to close this workforce skills gap?

Mr. GLENN. Yes. Right now we have roughly 30 percent of our employee base is retirement-eligible and so we are going to need to replace that workforce and with the grid modernization investments that we are making that is going to require a whole new cadre of employees to come online.

So what we are doing in our various states in which we operate is working with community colleges, working with technical schools, and working with universities to turn out more relay technicians, more qualified people who can do this type of work, more engineers.

So this is, for example, in North Carolina alone, this is going to be a jobs driver of our $13 billion investments just in that state alone, about 14,000 jobs a year. And those are good wage, good quality jobs. And so we are working with the university systems all throughout and the high school systems to get a qualified good workforce who live and work in those communities.

Mr. LONG. And so it is kind of a double whammy. You are losing 30 percent, 30 percent of your people are retirement-eligible and you are going to add a whole new section to your company.

Mr. GLENN. So we have got to replenish the old and we have got to infuse it with new employees as well.

Mr. LONG. And I appreciate your use of community colleges and such. I know they are very successful in my area. But what can you do to ensure workforce training programs reflect the changing industry needs?

Mr. GLENN. I think we have got to work hand in hand with our school systems, K–12 as well as high school as well as our community colleges in developing curriculums. And that is what we are doing, actually, in a lot of these community colleges is we develop curriculums. We find professors, so to speak, and we will donate money and resources, transformers, for example, that they can work on. So it needs to be hand in glove with, it is really a public-private partnership.

Mr. LONG. OK, thank you.

And I am out of time, Mr. Chairman. I yield back.

Mr. WALBERG. I thank the gentleman and I recognize myself for my 5 minutes of questioning now.

I certainly appreciate the hearing, the context of the hearing today, and I would like to thank the panelists for what you brought to the table, literally, for us this morning. Yesterday evening I saw a white paper by former FERC Commissioner Tony Clark that called for the reform of the outdated Public Utilities Regulatory Policies Act of 1978, otherwise known as PURPA, and I appreciate the gentleman from Missouri's questions on PURPA. It is an important issue I think we need to discuss today. I don't believe this committee has taken a comprehensive look at this policy since 2005, and I am very concerned about the negative impacts this law is having on Michigan ratepayers, my own included, and potentially on grid reliability.

Mr. Glenn, I appreciated your comments on PURPA and have a few questions for you as well. You stated in your testimony that PURPA's mandatory purchase obligation is directly increasing electricity prices for customers. Would you please elaborate further on this?

Mr. GLENN. Yes. As I responded to Congressman Long from Missouri, we are seeing in North Carolina alone about a billion dollar increase above what our customers otherwise would pay.

Mr. WALBERG. A billion.

Mr. GLENN. A billion. And that is just in 2,000 megawatts of contracts that have been signed to date. There is another 5,000 megawatts of these contracts that are in the queue that have not yet been built or signed. So this we see as a growing issue and that is just one state in which we operate in.

Mr. WALBERG. What are some other impacts PURPA mandatory purchase obligation is having on utilities' ability to plan and deliver the lowest cost, reliable energy to America's electricity customers?

Mr. GLENN. What we are seeing now is an increase in what we believe we will continue to see in the future are some reliability issues. For example, next year we project with all of the PURPA contracts that are coming online in North Carolina, for example, that we are going to have to dump power generated by some of our nuclear plants to other consumers of power or we are going to have to ramp down a nuclear plant. And a nuclear plant is not made——

Mr. WALBERG. To ramp down.

Mr. GLENN [continuing]. To cycle and to ramp-run. And so those are significant reliability issues and a nuclear plant is our lowest cost operating plant for our customers.

Mr. WALBERG. And this is because of outdated PURPA rules and standards?

Mr. GLENN. That is correct.

Mr. WALBERG. Are traditional baseload resources such as nuclear energy that can operate 24/7 as you mentioned being undermined in any other ways? This is important to me. We have Fermi in my districts. We have Fermi 3 licensing already in place, a lot of uncertainty how we move forward.

Mr. GLENN. And it places, you know, the dispatch ability of a nuclear plant that is a baseload that runs 24/7. So that has an adverse impact on our long-term ability to plan in how do we use and operate and maintain those resources.

Reliability and affordability and increasingly clean energy will always be our mission at our company and we will not compromise that at all. But we have to go in with open eyes at PURPA and really look at the facts and see what can be changed for the benefit of our customers.

Mr. WALBERG. Along that line then let me ask you, I have heard that developers are taking advantage of PURPA to force you utilities to purchase increasing amounts of electricity from them more so than originally required by law, more specifically, the one-mile rule. Could you explain this and the impacts it is having on the utility industry, the one-mile rule?

Mr. GLENN. The one-mile rule what we are seeing is developers in some of their projects are gaming the system where you can place your systems just beyond one mile of each other to get under the PURPA requirements. So I think it would be well served for the committee to just review on a fact basis what does this look like and how might it be addressed in the future so that customers aren't paying more than they should otherwise.

Mr. WALBERG. So the one-mile rule they are splitting up multiple parts of their grid responsibilities and capabilities to game the system?

Mr. GLENN. That is what it appears to be.

Mr. WALBERG. Appears to be, yes. OK. Well, I appreciate that information. I would also, in lieu of the fact we are waiting for—well, I would certainly yield to my friend from my own home district where I grew up in for additional questions.

Mr. RUSH. I want to thank you, Mr. Chairman.

Mr. Glenn, you said something that really kind of piqued my interest. Not that you said, but it is one thing. You were describing your job development approach at Duke Energy. Can you expound on that a little bit more and is that an approach that is shared by the industry in terms of utility companies, your approach in terms of job creation? I thought it was pretty invigorating.

Mr. GLENN. It is something that we have shared among our utility colleagues, but it is something that we have focused on in the last, particularly in the last 10 years as we have seen our workforce and the demographics of our workforce.

What we are also doing is, because we are in seven states in which we are vertically integrated electric utilities, our folks live and work and play and coach Little League in those communities and we want to represent and we want to be those communities and represent who they are and so that dictates how we hire as well.

And so we are very proud of the fact that we are—and our last, 13 percent of our last new hires have been veterans, for example, and 30 percent have been women. In a traditionally male-oriented industry, 30 percent of new hires is a phenomenal accomplishment, 31 percent minorities of all of our new hires through June of this year.

So we are taking a global approach not only K–12 and then in our community colleges with certain skill sectors, but we are making a concerted effort to try to broaden our pool of candidates who are coming in. And I think it helps that the energy industry right now is an incredibly dynamic and exciting place to be.

You know, maybe not everybody might think that but we hire people for careers and not jobs and then so that I think helps as well, so we are very proud of that fact.

Mr. RUSH. I certainly want to commend you and do for this approach and I think that this approach probably should be duplicated across the industry. Thank you.

Thank you, Mr. Chairman.

Mr. WALBERG. Reclaiming my time and I thank you. I thank the gentleman, and those are good points. These are good jobs we are talking about and they are worth affronting and getting people to understand that.

Now I am pleased to recognize the gentleman from Pennsylvania, the subcommittee chairman where I spent part of my morning, I am glad that you have made it back here. I recognize you, Mr. Murphy, for 5 minutes.

Mr. MURPHY. Thank you. Thank you, Mr. Chairman. I thank the panel and indulge me if I ask for some things you already answered. I have spent the last few hours delving into prescription drug costs and several organizations so we have to multitask and make these quantum leaps in our actions.

But I do want to ask about some jurisdictional boundaries. I was previously a state senator and so I am aware of a lot of things on those issues and also the wholesale and retail markets. But let's look at, do you think states and federal regulators are even on the same page sometimes, or are there some problems that occur when it comes to jurisdictional issues? Can anybody answer that for me, anybody have concerns?

Mr. KELLIHER. I am happy to start.

Mr. MURPHY. Thank you, Mr. Kelliher.

Mr. KELLIHER. There is always some level of tension between federal and state electricity regulators and part from the structure of the industry and what the states and federal governments are regulating. It is different than, say, in the natural gas business where producers are not really regulated, the local gas utilities are regulated only by the states and then the pipelines are regulated only by FERC.

In the electric industry you have a lot of vertical integration and parts of a vertical integrated utility's activities are regulated by the state, parts are regulated by FERC, and then the line is not clear. It is the point where there have been three Supreme Court decisions in the last 2 years trying to mark the line.

And this is, the core acts have been enacted in 1935, so since 1935 there is still not perfect clarity on the jurisdictional lines between the federal and state to the point where the Supreme Court had to parse through that three times.

Mr. MURPHY. Do they share the same goals or are they different kind of goals when it even comes to such things as providing assistance to economically struggle generation, generating units? Do they have the same goals, federal, state?

Mr. KELLIHER. They have different legal duties. I mean FERC regulates the wholesale power markets and its basic duty is to assure that prices are just and reasonable. Well, what does that mean? It means they have to be high enough to support continued investment in the generation that is needed to meet customers' needs but not so high that they reflect market power abuse.

But sometimes it can mean high prices. When natural gas prices were high, wholesale power prices were high. Those wholesale power prices weren't bad because they were driven by high natural gas prices. So the price can be high and still just and reasonable, whereas the state utility it is charged with retail rates and in some cases states have maintained vertically integrated utilities. So you go through the classic cost of service regulation and what costs are prudent and not prudent.

In other cases, states have broken up their utilities and required them to divest so the utility is a pure wires entity and they are buying power, typically relying on some kind of RTO market and the state role there is different. The vertically integrated state role, they are involved in resource adequacy and what is the supply mix of each regulated utility.

A state role in a competitive market is different. It is, is there enough megawatts, is there enough capacity to meet their needs? So sometimes those duties clash, but I think many times they don't.

Mr. MURPHY. Does anybody else want to weigh in on that issue? Yes, Ms. Linde?

Ms. LINDE. I agree with the description that Mr. Kelliher provided about the legal structure, but to respond to your question about are their goals the same, I think the fundamental goals, from my experience, have been the same. The regulators that I deal with at the state level, and I have been at PSEG for 27 years so I have dealt with a lot of different regulators at the state level and at the federal level, their fundamental goal is to make sure that the power is there when needed and it is a reasonable price. That is a very commonly shared goal among state regulators and federal regulators.

How to address different policy initiatives, sometimes there is a difference because there is a difference in timing on when the state has a particular initiative. We have seen a lot of states develop renewable portfolio standards to encourage development of renewables, and now we are seeing some states like New York and Illinois and some others take action to preserve baseload generating units.

The dialogue is occurring at the federal level and there is a dialogue about what is causing that premature retirement of baseload. PSEG believes that it is driven by a market flaw. And that dialogue needs to continue to occur because right now we have the federally regulated market that is not valuing fuel diversity and that lack of recognition of fuel diversity is causing a premature retirement of nuclear and some other baseload units and states reacting much more quickly in some cases as a bridge until the federal government and the federal regulators can solve that problem. So sometimes there are timing differences.

Mr. MURPHY. I appreciate that.

Mr. Chairman, I reflect back on some of the fuel crises and energy crises we had in the 1970s and we were going to make all these great changes to the markets and we tried them for a while and then dropped them suddenly.

So the issue of diversity is incredibly important because the sun sets, the wind dies. We lose coal plants. We can go for a surge for a while with natural gas and then we see prices go up in that and then companies say, OK, we have to raise the price now, but we also need natural gas to export for chemicals and lots of other things there.

So diversity is the way to go then to make the market more competitive, so thank you very much, Mr. Chairman.

Mr. WALBERG. I thank the gentleman. Seeing there are no further members wishing to ask questions, I would like to thank our witnesses again for being here today and going through this process. You are very helpful to us.

Pursuant to committee rules, I remind members that they have 10 business days to submit additional questions for the record, and I ask that witnesses submit their response within 10 business days upon receipt of the questions.

Without objection, the subcommittee stands adjourned.

[Whereupon, at 12:37 p.m., the subcommittee was adjourned.]

[Material submitted for inclusion in the record follows:]

GREG WALDEN, OREGON
CHAIRMAN

FRANK PALLONE, JR., NEW JERSEY
RANKING MEMBER

ONE HUNDRED FIFTEENTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON ENERGY AND COMMERCE
2125 RAYBURN HOUSE OFFICE BUILDING
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Majority (202) 225-2927
Minority (202) 225-3641

August 4, 2017

The Honorable Joseph T. Kelliher
Executive Vice President
Next Era Energy, Inc.
801 Pennsylvania Avenue, N.W.; Suite 220
Washington, DC 20004

Dear Mr. Kelliher:

Thank you for appearing before the Subcommittee on Energy on Tuesday, July 18, 2017, to testify at the hearing entitled "Powering America: Examining the State of the Electric Industry through Market Participant Perspectives."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

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Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment

Questions from The Honorable Fred Upton

1. Over the last decade, emissions from the power sector have been declining. What role has organized electricity markets played in declining emissions?

   Organized markets have played an important role in reducing emissions from the power sector over the last decade. The primary focus of organized markets is assuring adequate electricity supply at the lowest reasonable cost, and the structure of these markets places a relentless pressure on cost. That pressure manifests itself through the deployment of newer, more efficient generation facilities and the retirement of inefficient generation. Since inefficient generation facilities require more fuel and produce more emissions to generate the same electrical output as efficient facilities, the retirement of inefficient generation for economic reasons has the effect of also lowering emissions. Most of the inefficient generation that has retired in the organized markets has been older coal and natural gas generation with high emissions levels, and has been replaced by more efficient natural gas generation and renewable generation with lower or no emissions. While these same economic pressures exist outside of the organized markets, the transparent price signals within the organized markets has led competitive generators to retire older, inefficient resources more quickly. Although the object of organized markets is not lowering emissions, these markets are ultimately responsible for much of the emissions reductions that have occurred in their regions over the past ten years. Of course, other factors have played an important role in reducing emissions, including the steep decline in natural gas prices, lower demand for electricity, environmental requirements, and customer preferences for clean energy.

   a. Do you expect emissions from the power sector to continue to decline into the future?

      I expect emissions from the power sector will continue to decline as the U.S. electricity supply mix evolves to rely more heavily on wind and solar power, modern, efficient natural gas generation, and storage technologies. The transformation of the generation fleet is occurring primarily for economic reasons, with lower-cost natural gas and renewable generation displacing older, less efficient generation with higher emissions. This trend is expected to continue for years to come given the continuation of low natural prices and the on-going decline in the cost of wind and solar generation.

GREG WALDEN, OREGON
CHAIRMAN

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Minority (202) 225–3641

August 4, 2017

Ms. Lisa McAlister
Senior Vice President and
General Counsel for Regulatory Affairs
American Municipal Power, Inc.
1111 Schrock Road
Columbus, OH 43229

Dear Ms. McAlister:

Thank you for appearing before the Subcommittee on Energy on Tuesday, July 18, 2017, to testify at the hearing entitled "Powering America: Examining the State of the Electric Industry through Market Participant Perspectives."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

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Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment

AMP
PUBLIC POWER PARTNERS

August 18, 2017

Elena Brennan, Legislative Clerk
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, DC 20515

Dear Ms. Brennan:

Enclosed are responses to additional Member questions for the record of the July 18, 2017 hearing entitled "Powering America: Examining the State of the Electric Industry through Market Participant Perspectives." As requested, an electronic copy of these responses has also been emailed to your attention. We appreciate the opportunity to offer these additional responses, and to participate in the hearing.

On Behalf of the Members,

Lisa G. McAlister
Sr. Vice President and General Counsel for Regulatory Affairs

4846-9649-8509, v. 1

U.S. House Subcommittee on Energy
Hearing on Powering America: Examining the State of the Electric Industry Through Market Participant Perspectives
July 18, 2017

Responses to the Additional Questions for the Record by
Lisa G. McAlister
Senior Vice President and General Counsel of Regulatory Affairs, American Municipal Power, Inc. (AMP)

We reiterate our apprecation to the subcommittee leadership and members for the opportunity to testify, and appreciate the opportunity to augment the comments in our written and oral testimony by responding to these questions.

In response to the Honorable Chairman Upton's question:

1. In your written testimony, you mentioned the lack of consistent transmission planning between markets. How can the planning process move towards more consistency and better value inter-regional projects?

The interregional planning process must move towards more consistency and must better value inter-regional projects. Moving away from compartmentalized and multiple threshold evaluations and requiring the RTOs to coordinate modeling, planning and other cross-border functions would get closer to achieving those goals. Lack of effective inter-regional transmission planning has put AMP at risk of not being able to economically use its share of its coal-fired plant to serve AMP's load.

AMP is directly involved in the dysfunction between PJM and MISO regarding varying and duplicative obligations on generating resources that seek to serve load located in an adjacent RTO. Unfortunately, AMP has been drawn into this matter in spite of protests and through no fault of its own but, rather with the Federal Energy Regulatory Commission's (FERC) acquiescence, the actions of large transmission owners have placed AMP in the position of having a significant portion of its owned resources located in MISO while the great majority of its load is located in PJM. This unenviable situation resulted directly from the decisions by American Transmission Systems, Incorporated (ATSI) and Duke Energy Ohio/Duke Energy Kentucky (Duke) to withdraw from MISO and participate in PJM. A sizable number of AMP's members take service from the transmission facilities owned by ATSI and Duke, so prior to those companies' RTO "realignment," a considerable portion of AMP's member load was located within MISO. That was the situation that existed when AMP negotiated the purchase of its approximately 368 MW share of the coal-fired Prairie State Generating Campus (Prairie State) located in Illinois, within MISO's footprint. When ATSI and Duke moved into PJM, however, the interconnected AMP members were compelled as a practical matter to move into PJM, as well. Consequently, AMP found itself in the situation in which Prairie State and other supply resources remained within MISO[1] while after the migration most of its load was located in PJM. That outcome was one over which AMP had no control — as the Commission has found, "ATSI and Duke, and not their transmission customers, decided to withdraw from MISO"[2] — and it is the situation that continues to this day.

In order for AMP to utilize Prairie State for its intended purpose - providing long-term power supply service to AMP's members in an economical and reliable manner - AMP is required to utilize a pseudo-tie from MISO to PJM. A pseudo-tied generation

[1] It is worth noting that AMP also has two hydropower plants that are physically located in MISO's footprint that were developed prior to the time FirstEnergy and Duke migrated to MISO that remain stranded in MISO as AMP is unable to cost effectively obtain transmission from MISO to PJM to serve AMP's load that was moved into PJM as a result of the transmission owner decisions. And, even if AMP was able to obtain the firm transmission service, it would still have the risk and uncertainty associated with the pseudo-tie rules as discussed further below.

[2] *Midwest Indep. Transmission. System Operator, Inc.*, 153 FERC ¶ 61,101 at P 170 (2015); *see also Midwest Indep. Transmission. System Operator, Inc.*, 138 FERC ¶ 61,140 at P 65 (2012).

resource is one physically located in one RTO, but treated electrically as being in another balancing authority area. When a generator is pseudo-tied out of MISO, its "telemetered reading or value . . . is updated in real time and used as a tie line flow in the Area Control Error equation but . . . no physical tie or energy metering actually exists." In other words, generating facilities, like Prairie State, that are pseudo-tied out of MISO to PJM do not reside within the MISO Balancing Authority Area, do not participate in MISO's markets, and MISO loses functional control of the unit.

AMP's decision to pseudo-tie Prairie State into PJM was not made to take advantage of more advantageous market conditions in one RTO or the other; rather, it was a step that was necessary to utilize Prairie State to provide long-term power supply service to AMP's members that were moved into PJM. To serve its PJM load, AMP is required by PJM's FERC-approved tariff to pseudo-tie.

AMP's pseudo-tie became effective on June 1, 2016. Shortly thereafter, it became evident to AMP that the RTOs were both charging AMP for congestion over the same facilities. In other words, PJM would charge AMP for congestion on a transmission facility and MISO would also charge AMP for congestion on that same transmission facility. After an inability to achieve an informal resolution of this issue, AMP filed a complaint at FERC requesting that the RTOs stop duplicative congestion charges and refund AMP for the duplicative charges that had already been collected. The RTOs have acknowledged the double-charging issue as well as independently recognizing various problems that were not resolved for generation pseudo-tied from MISO to PJM prior to implementation of the pseudo-ties. Specifically, the RTOs identified problems associated with grid reliability and adequate modeling (such as coordinated congestion management and the potential need by MISO to commit or de-commit a pseudo-tied resource that it does not control in order to maintain its transmission system within thermal and voltage operating limits); market inefficiencies in MISO caused by the dispatch of pseudo-tied generation; and pseudo-tied units that retire or suspend operations without adequate notice to MISO and both RTOs charging congestion and administrative costs.

While the RTOs have been slowly working this issue through its Joint Operating process since the last quarter of last year, they have not come up with a solution, keep pushing the date by which they estimate a solution can be achieved, refuse to address the issue of refunding pseudo-tied generators for the duplicative charges already collected, and take up valuable stakeholder time developing new pseudo-tie agreements that do not address the current problems. AMP has detailed the lack of progress in a response to an RTO status update filed at FERC that is attached hereto.

In sum, from AMP's perspective, it appears that the RTOs have undertaken a long-running effort to restrict the use of external capacity resources located in one RTO to serve load in the other RTO by burdening the use of the pseudo-tie to the point that it is rendered uneconomic. If AMP's use of Prairie State to serve its PJM load becomes burdened to the point of being uneconomic, AMP's members would be deprived of the intended benefits of a resource in which AMP has invested significantly and in which the revenues derived from any alternative use almost certainly would not cover its members' PJM capacity costs. This stranding of new generation runs contrary to FERC's own long-running effort to remove artificial transactional barriers between RTOs (and especially between MISO and PJM). Burdening pseudo-tie arrangements with additional and overlapping requirements and costs predictably will impede the use of that mechanism, which, in turn — also predictably — will reduce competition in the capacity and energy markets. Competition from external resources, which is one of the few forces that exert downward pressure on prices in PJM's capacity auctions, has and will suffer as a result. Consumers will suffer the higher prices that necessarily will follow an impairment of competition.

PJM and MISO have been working on implementation of a Joint and Common Market since 2004. The goal of the Joint and Common Market is to achieve all the benefits of a combined market across the footprint that includes both PJM and MISO and that meets the needs of all customers and stakeholders on a non-discriminatory basis using the electric power grid in the two RTO's regions. The RTOs have acknowledged that these benefits will be gained by examining the different rules by which the two RTOs operate as individual entities and evolving to coordinate market operations and ensure there are no impediments to trade in either, both, or between the markets. The RTOs stated that modifications to their respective operations, tools and processes would be developed through an open stakeholder process designed to benefit participants regardless of which RTO they belong to, or if they are in both. As demonstrated through the pseudo-tie example, more work is required for the inter-regional planning process to be more consistent and better value interregional projects.

In response to the Honorable Chairman Upton's question:

2. **Your testimony mentioned the need for the transmission planning process to provide equitable treatment. Could you offer further examples of discriminatory treatment that has occurred in transmission planning and your thoughts to make the process fairer?**

Today there is a bifurcated process that works for effectively advancing broadly-supported transmission projects undertaken for system reliability, but provides scant review to "supplemental projects" that are rapidly driving up transmission costs.

AMP agrees that grid reliability is crucial. PJM, through its Regional Transmission Expansion Planning process, over a 15-year horizon identifies transmission constraints and other reliability concerns and develops transmission solutions to mitigate those identified reliability criteria violations (these are called baseline projects).

However, there is a second category of transmission projects called supplemental projects that are not required for compliance with NERC, PJM or even the Transmission Owners' system reliability, operational performance or economic criteria, and are not state public policy projects. Rather, supplemental projects are mostly replacing aging infrastructure or hardening the grid for added resilience. These supplemental projects are made based upon the determination of transmission owners, are not approved by PJM or states (with the exception of a siting process in some states) and are drastically increasing in the amount spent on supplemental projects. Specifically, out of approximately $30 billion in transmission projects in PJM since 2005, almost $19 billion has been for supplemental projects that have been proposed absent transparent criteria and models that stakeholders can review and comment on prior to the plans being finalized, despite the fact that the transmission owners have turned over the planning and operation of their facilities to PJM. While supplemental projects are supposed to be subject to the same open and transparent process as baseline projects, this is not the case.

The best way to balance grid reliability and concerns about discriminatory treatment between baseline and supplemental projects, as well as transmission rate increases is to ensure that all stakeholders have an opportunity for early and meaningful input and participation in the transmission planning process; that transmission owners have transparent, and to the extent possible, consistent criteria and models; and ensure that Return on Equity (ROE) rates reflect current economic conditions and additional incentives are awarded judiciously to reflect actual levels of risk. This could be achieved by subjecting supplemental projects to the same rigorous process as baseline projects.

Respectfully submitted,

Lisa G. McAlister
Senior Vice President & General Counsel for Regulatory Affairs
American Municipal Power, Inc.
1111 Schrock Road, Suite 100
Columbus, OH 43229
(614) 540-1111
lmcalister@amppartners.org

4812-3479-6109, v. 5

GREG WALDEN, OREGON
CHAIRMAN

FRANK PALLONE, JR., NEW JERSEY
RANKING MEMBER

ONE HUNDRED FIFTEENTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON ENERGY AND COMMERCE

2125 RAYBURN HOUSE OFFICE BUILDING
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Majority (202) 225–2927
Minority (202) 225–3641

August 4, 2017

Mr. Steven Schleimer
Senior Vice President
Calpine Corporation
717 Texas Street; Suite 1000
Houston, TX 77002

Dear Mr. Schleimer:

Thank you for appearing before the Subcommittee on Energy on Tuesday, July 18, 2017, to testify at the hearing entitled "Powering America: Examining the State of the Electric Industry through Market Participant Perspectives."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

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Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment

U.S. House of Representatives Committee on Energy and Commerce
Subcommittee on Energy
Hearing on "Powering America: Examining the State of the Electric Industry through Market Participant Perspectives"

Question for the Record for Steven Schleimer , Senior Vice President, Government and Regulatory Affairs, Calpine Corporation

The Honorable Fred Upton

Q. In contrast to some of your fellow witnesses, you defend your support of the capacity markets by citing to the recent investment of tens of billions of dollars in new generation. Can you elaborate on why you believe state subsidies and a "hybrid" market would destroy future competitive investment?

A. As I stated in my testimony, the competitive markets have been successful and continue to function quite well, attracting needed investments and reducing wholesale electricity prices. The trend towards providing out-of-market subsidies to certain resources is moving the markets away from a true competitive model to a "hybrid" model with states deciding which generation resources will be utilized rather than the market. Further, the subsidized resources then directly compete in the market, suppressing prices for other market participants. Investors are not likely to fund new, more efficient and economic generation resources if they face unfair competition in the markets and in turn, are potentially unable to recover their investment costs due to low revenues from depressed market prices.

GREG WALDEN, OREGON
CHAIRMAN

FRANK PALLONE, JR., NEW JERSEY
RANKING MEMBER

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WASHINGTON, DC 20515–6115
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August 4, 2017

Mr. Jackson E. Reasor
President and CEO
Old Dominion Electric Cooperative
4201 Dominion Boulevard
Glen Allen, VA 23060

Dear Mr. Reasor:

Thank you for appearing before the Subcommittee on Energy on Tuesday, July 18, 2017, to testify at the hearing entitled "Powering America: Examining the State of the Electric Industry through Market Participant Perspectives."

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Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment

U.S. House of Representatives
Committee on Energy and Commerce
Subcommittee on Energy

Powering America: A Review of the Operation and Effectiveness of the Nation's Wholesale Electricity Markets

Response to Additional Questions for the Record of Jackson E. Reasor

The Honorable Fred Upton

1. **As a Load Serving Entity (LSE), what obstacles do you face from wholesale power markets in planning your own self-supplied capacity procurements?**

Old Dominion Electric Cooperative is a not-for-profit power-supply electric cooperative, which provides capacity and energy to its members, eleven electric distribution cooperatives in Virginia, Maryland, and Delaware. These eleven distribution cooperatives provide retail electric service to their members, end-use consumers. As the question recognizes, Old Dominion is a Load Serving Entity (LSE).

Old Dominion's members are interconnected to the transmission grid operated by the PJM Interconnection, a Regional Transmission Organization (RTO) regulated by the Federal Energy Regulatory Commission (FERC). Old Dominion welcomed PJM's conversion twenty years ago into an RTO with a single control area and a single transmission tariff, and PJM's later expansion into Virginia, because this would provide more economical, non-discriminatory transmission service to Old Dominion's members and more wholesale power-supply alternatives to Old Dominion.

I believe that public policy should encourage long-term investments in capacity resources by LSEs. This is of particular concern for electric cooperative and municipal electric utilities. Cooperative utility LSEs like Old Dominion operate under long-standing business models as not-for-profit entities responsible for meeting their rural electric cooperative customers' power supply needs in a safe, reliable and economic manner. Electric power generation assets are costly and have long operating lives. Consequently, LSEs have long planning horizons. Old Dominion invests in or procures capacity resources with a view to meet its long-term service obligations to its consumer-owners in a reliable and economic manner. Old Dominion develops a diverse portfolio of capacity resources (including generation and other technologies) that it determines best meets its members' needs, based on economic and non-economic criteria.

In my view, Old Dominion's members and the consumers they serve will fare better if competitive wholesale power markets allow LSEs to meet their capacity obligations first by building generation resources or procuring them through voluntary long-term bilateral contracts, and then by turning to RTO-administered capacity markets for residual needs.

That is how PJM originally operated its centralized capacity procurement mechanism, the "Reliability Pricing Model" or "RPM." In 2006, FERC approved RPM as a residual capacity procurement mechanism for PJM to ensure resource adequacy at the least cost: "[W]e conclude that, after LSEs have had the opportunity to procure capacity on their own, it is reasonable for

PJM to procure capacity in an open auction at a time when further delay in procurement could jeopardize reliability. This, however, should be a last resort."[1] In fact, RPM's annual capacity auction was called—and still is called—the "Base Residual Auction."[2]

But over time, repeated and significant design changes have made RPM more complex and costly. In the ten years since RPM was put in place, it has undergone nearly continuous revisions. According to PJM, from 2010 to 2016, there were 24 significant filings at FERC to revise RPM, and the 2016 Base Residual Auction was the first such auction with no rule changes from the prior year.[3] These frequent changes have created obstacles for Old Dominion and other LSEs to plan and use their self-supplied resources to meet their capacity obligations. While Old Dominion is building its Wildcat Point Natural Gas Plant in Cecil County, Maryland, as a self-supplied generating resource under PJM's current tariff rules, those tariff rules have needlessly complicated Old Dominion's resource planning and added to its regulatory risks. In addition, a recent court decision requires FERC to reconsider the very rule that Old Dominion relied on in constructing this plant.

An important obstacle that RPM creates for LSEs planning to use self-supplied capacity arises from RPM's "Minimum Offer Price Rule." This rule imposes a floor on the prices that most new gas-fired generators can offer in PJM's capacity auctions. FERC approved this rule in 2006 because of a theoretical risk that net buyers of capacity could exercise monopsony power to lower PJM's capacity auction prices below PJM-determined competitive levels.[4]

As originally written, this tariff rule guaranteed that an LSEs' self-supplied capacity resource would "clear" in RPM's auctions—i.e., would be accepted as a capacity resource by PJM regardless of the LSE's offer price—even if the Minimum Offer Price Rule prevented the resource's offer price from lowering the auction-clearing price. But in 2011, FERC approved a PJM tariff change that eliminated this "guaranteed clearing" language.[5] The guaranteed clearing of self-supply is critical for LSEs. If self-supplied capacity does not clear RPM's auction, the LSE pays for capacity twice—once for the investment in its own capacity, then a second time to pay PJM's costs of procuring the same amount of capacity. But if its self-supplied capacity clears the auction, the LSE receives auction revenues from PJM for its self-supplied capacity that offset the (identical) costs the LSE must pay PJM for that amount of capacity procured in PJM's auction. Guaranteed clearing enables an LSE's self-supplied capacity to be a price hedge against volatile PJM capacity auction prices and allows LSEs to use their investments as intended.

After guaranteed clearing was eliminated, in 2012, PJM stakeholders, including public power and rural electric cooperatives, agreed to a limited "Self-Supply Exemption" from the Minimum Offer Price Rule, which FERC approved along with other changes to RPM in a 2013

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[1] *PJM Interconnection, LLC*, 115 FERC ¶ 61,079 at P 71, *order on reh'g*, 117 FERC ¶ 61,331 (2006).

[2] http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-base-residual-auction-faqs.ashx?la=en

[3] http://www.pjm.com/~/media/committees-groups/committees/mrc/20160825/20160825-item-07-pjm-capacity-problem-statement.ashx

[4] *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 104 (2006).

[5] *PJM Interconnection, LLC*, 135 FERC ¶ 61,022 at PP 183–184, 191–197, *reh'g denied*, 137 FERC ¶ 61,145 (2011), *reh'g denied*, 138 FERC ¶ 61,194 (2012), *pet. for review dismissed as moot in pertinent part sub nom. N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74 (3d Cir. 2014).

order.[6] The Self-Supply Exemption requires that the LSE meet "net-short/net-long" thresholds, meaning the exemption is available only to LSEs that have neither too much nor too little supply of capacity relative to their customers' load. However, the Self-Supply Exemption does not guarantee the clearing of such self-supplied capacity; it merely allows the qualifying self-supply to be offered at a price below the otherwise applicable floor on offer prices.

The Self-Supply Exemption became available in PJM's 2013 capacity auction. Old Dominion was able to use this Self-Supply Exemption when it offered its planned Wildcat Point Natural Gas Plant in PJM's Base Residual Auction in May 2014 for the delivery year 2017-2018. As a direct consequence of the Self-Supply Exemption, the Wildcat Point plant cleared the auction reducing Old Dominion's capacity purchases from the PJM market by approximately $50 million

However, on July 7, 2017, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated several of FERC's 2013 changes to RPM rules, including the addition of the Self-Supply Exemption, and remanded them to FERC for reconsideration.[7] The court's ruling puts a cloud over RPM results since the 2013 auction, including the 2014 auction in which Old Dominion's capacity from the Wildcat Point plant had cleared, thereby avoiding an incremental capacity purchase expense of approximately $50 million. The ruling also casts doubt on the continued viability of the current Self-Supply Exemption. Old Dominion does not know what FERC will do on remand with respect to the Self-Supply Exemption or other remanded provisions of RPM.

At the Subcommittee on Energy's July 26, 2017, hearing on "Powering America: A Review of the Operation and Effectiveness of the Nation's Wholesale Electricity Markets," the prepared written statement of PJM's witness Craig Glazer, Vice President for Government Policy, attempted to assuage concern over self-supply. The statement maintains that "public power entities have been availing themselves of their ability to self-supply and have been building new generation in PJM as a result." The statement then lists "recent" generation additions as apparent examples.

However, of the 21 generation units listed by PJM, Old Dominion's Wildcat Point Natural Gas Plant is the only unit that benefited from PJM's current Self-Supply Exemption—and a court has now directed FERC to reconsider that exemption. One unit was built before PJM removed the guaranteed-clearing language in 2011.[8] Three other units used a "unit-specific exemption" in 2011 and 2012 before PJM added the Self-Supply Exemption in 2013.[9] The other listed units were not subject to the Minimum Offer Price Rule, either because they were placed in service before PJM instituted RPM in 2007 or because they use a technology, such as hydropower, that does not subject them to the Minimum Offer Price Rule.

In particular, the other Old Dominion plants that PJM lists in its written statement were not built "as a result" of RPM's self-supply rules. Old Dominion built its Rock Springs Natural

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[6] *PJM Interconnection, LLC*, 143 FERC ¶ 61,090 (2013), *reh'g denied*, 153 FERC ¶ 61,066 (2015), *vacated and remanded sub nom. NRG Power Mktg. LLC v. FERC*, No. 15-1452 (D.C. Cir. July 7, 2017).

[7] *NRG Power Mktg., LLC, v. FERC*, No. 15-1452 (D.C. Cir. July 7, 2017).

[8] Down Natural Gas Power Plant (Vineland [NJ] Municipal Electric Utility).

[9] Beasley Power Station Units 1 and 2 (Delaware Municipal Electric Cooperative) [referred to as "Smyrna Natural Gas 1–2" in PJM's written statement]; Clayville Natural Gas Unit 1 (Vineland Municipal Electric Utility).

Gas Units 1 and 2, and its Louisa Natural Gas Units 1 through 5 in 2003—before PJM instituted RPM in 2007. In addition, the Louisa plants are in Virginia and were built before the utilities in Virginia were in PJM. Thus, PJM's implicit suggestion that these plants were built "as a result" of PJM's self-supply rules is simply wrong.

Furthermore, PJM's written statement asserts that the D.C. Circuit "did not overturn the specific agreed-to arrangement that PJM and its stakeholders worked out with public power utilities." It is not clear what PJM means by this claim. In fact, the court's opinion clearly states:

> We grant the petitions for review and vacate FERC's Orders with respect to unit-specific review, the competitive entry exemption, *the self-supply exemption*, and the mitigation period. We remand the matter to FERC.[10]

Given the constant churn of revisions to RPM, LSEs like Old Dominion face continued threats to their long-standing business models to adopt long-term procurement plans and integrate them with RPM. The current RPM rules, with a Self-Supply Exemption that is now uncertain, needlessly interfere with LSE resource planning and decisions and increase costs to consumers. As FERC itself has acknowledged, the "purpose and function" of the Minimum Offer Price Rule "is not to unreasonably impede the efforts" of utilities like Old Dominion that are "choosing to procure or build capacity under long-standing business models."[11]

a. Are there any potential alterations to PJM's Reliability Pricing Model that would ensure LSEs are able to self-supply their capacity obligations while balancing PJM's need to ensure regional grid reliability?

To ensure LSEs are able to self-supply their capacity obligations, while still balancing PJM's need to ensure regional grid reliability, RPM's Base Residual Auction should be restored to its proper and original role as a residual procurement mechanism—one that is subordinate to LSEs' long-term investment or procurement of resources to self-supply their share of PJM's capacity obligations.

As stated above, in my view, Old Dominion's members and the consumers they serve would fare better if competitive wholesale power markets were to allow LSEs to meet their capacity obligations by first building generation resources or procuring them through voluntary long-term bilateral contracts, and then turning to RTO-administered capacity markets for any residual capacity needs. Among other things, this approach would enable LSEs to develop the diverse portfolio of capacity resources (including generation and other technologies) that they believe best meets their needs, based on economic and non-economic criteria. Centralized capacity auctions like RPM cannot effectively replace LSE resource planning, which involves many considerations beyond the lowest cost for a single year three years in the future.

This would require, at a minimum, that PJM return to its pre-2011 approach of guaranteed clearing of LSE self-supplied capacity in RPM's auctions. In other words, RPM rules should guarantee that LSE self-supplied capacity clears the auction and the LSE receives auction revenues at the clearing price—even if PJM keeps a Minimum Offer Price Rule that prevents this

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[10] *Id.*, slip opinion at 16 (emphasis added).

[11] *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145 (2011) at P 208.

self-supplied capacity from setting an auction-clearing price below the price floor. Returning to the guaranteed-clearing provisions which were included in RPM's initial rules would be clearly superior to retaining the current, limited Self-Supply Exemption.

2. As both a transmission owner and transmission customer in the PJM market, how effective are existing cost allocation methodologies when planning transmission infrastructure?

Transmission planning and cost allocation for transmission facilities are an important issue in PJM. Old Dominion believes that several principles should govern transmission planning and cost allocation.

First, transmission planning for high-voltage transmission facilities for all forms of affordable generation should focus on the needs of LSEs and should result from an open, coordinated and transparent transmission planning process, as required by FERC.[12] Section 217(b)(4) of the Federal Power Act, which Congress added in 2005, requires that LSEs' needs drive the planning process:

> The Commission shall exercise the authority of the Commission under this chapter in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.[13]

Transmission planning should focus on the needs of the system in order to ensure that LSEs can serve their load in a reliable, safe and cost-effective manner. Such planning should take into account current needs as well as a reasonable forecast (e.g., 20+ years), since transmission assets can have useful lives of several decades, if planned correctly. Transmission planning should not be dictated by cost allocation. Instead, once the transmission solution is identified, then the costs should be allocated in a manner that is at least roughly commensurate with the benefits received.

I note that in PJM, Old Dominion and others have concerns that not all transmission planning is conducted in an open, coordinated and transparent manner. In some instances, individual Transmission Owners determine the need for transmission facilities based on their own unpublished guidelines as opposed to PJM criteria or the reliability criteria of the Electric Reliability Organization. These projects, referred to as "Supplemental Projects", are not subject to the same level of PJM Board or PJM Staff scrutiny or evaluation as are other projects included in PJM's Regional Transmission Expansion Plan. Therefore, customers are subject to paying for costly transmission facilities that may or may not be needed at the scope or the time they are constructed.

[12] *See Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[13] 16 U.S.C. § 824*q*(b)(4).

There are other concerns regarding Supplemental Projects. Local planning for Supplemental Projects in the various subregions in PJM has sometimes fallen short of the open, transparent and coordinated process required by FERC. In addition, PJM has failed to provide necessary consistency in planning for Supplemental Projects in the subregions. FERC has initiated an outstanding inquiry into PJM's local planning practices, and ODEC has recommended specific revisions to improve local transmission planning in PJM.[14] Consistency in all transmission planning in the PJM region should help to facilitate needed transmission while at the same time protecting customers from costs for which they do not derive sufficient benefit.

Planning regions should determine the benefits to be considered in allocating costs of high-voltage transmission facilities. Absent regional agreement, costs should be allocated among those entities that benefit both initially and over time and take transmission service from the transmission providers imposing the charge. Benefits should be tangible and non-trivial and related to the reliability and economic delivery of power. Benefits should also be at least roughly commensurate with allocated costs.

For the most part, the existing cost allocation methodologies in PJM are effective from the perspectives of allocating costs to the beneficiaries and not impeding development of necessary transmission facilities. In PJM, the costs of high voltage transmission facilities included in PJM's Regional Transmission Expansion Plan, characterized as Required Transmission Enhancements, and the lower voltage facilities needed to support them, are allocated 50 percent on a region-wide "postage stamp" basis according to load-ratio shares. The remaining 50 percent of costs are allocated based on a solution-based distribution factor method.[15] These cost allocations are updated each year by PJM on behalf of the PJM Transmission Owners. Lower voltage facilities, which are deemed Required Transmission Enhancements, are cost allocated 100 percent based on the solution-based distribution factor cost allocation method.[16]

There are two problems with the PJM transmission cost allocation methodology, from the perspective of a transmission customer paying the costs. First, the PJM beneficiary analysis is a snapshot in time. Transmission facilities are long-lived assets and their costs are recovered over many years. PJM's economic cost allocation methodology does not take into account changes which may occur over time in factors which might change the beneficiaries of a project, such as the physical characteristics of the system or the profile of the loads being served. This can result in a cost-beneficiary allocation which becomes unjust and unreasonable over time.

Second, while the solution-based distribution factor analysis produces just and reasonable cost allocation for the vast majority of projects approved through PJM's regional planning process, it is not well suited for allocating costs of transmission system upgrades that are not required to address thermal or voltage-based criteria violations. For such projects, PJM should consider alternative cost allocation methodologies in order to ensure that those entities that pay

[14] *Monongahela Power Company, et al.*, 156 FERC ¶ 61,134 (2016), *reh'g dismissed*, 157 FERC ¶ 61,178 (2016); *see also* Response of Old Dominion Electric Cooperative to Order to Show Cause, FERC Docket No. EL16-71-000 (filed Oct. 25, 2016).

[15] PJM Open Access Transmission Tariff, Schedule 12.

[16] *Id.*

for the facilities receive benefits that are roughly commensurate with the costs paid. In addition, these allocations should be updated on a regular basis.

An example of the transmission system upgrade situation is a project in the PJM region referred to as "Artificial Island." The Artificial Island project involves construction of a new 230-kV transmission line under the Delaware River and certain other facilities in order to address a specific system stability issue and related generation operation issues in an area in Southern New Jersey where certain nuclear generating units are located.[17] After Old Dominion and others complained over the unreasonable cost allocation for the project, the PJM Board of Directors decided to re-study the project and analyze project beneficiaries from alternate perspectives to find a reasonable cost allocation.[18] The proceeding before FERC has not yet been resolved, but PJM has developed alternative analyses based on the stability benefits provided by the transmission solution. There should be flexibility in cost allocation so that unique circumstances such as the Artificial Island project can be accommodated to ensure that costs are allocated roughly commensurate with benefits received.

[17] *See Order Denying Complaint and Accepting Cost Allocation Report*, 155 FERC ¶ 61,090 (2016); *reh'g pending*.

[18] *See* PJM's Informational Filing submitted in FERC Docket Nos. ER15-2563-000, *et al.*, on April 12, 2017.

GREG WALDEN, OREGON
CHAIRMAN

FRANK PALLONE, JR., NEW JERSEY
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ONE HUNDRED FIFTEENTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON ENERGY AND COMMERCE

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August 4, 2017

Ms. Tamara Linde
Executive Vice President and General Counsel
Public Service Enterprise Group, Inc.
80 Park Plaza
Newark, NJ 07102

Dear Ms. Linde:

Thank you for appearing before the Subcommittee on Energy on Tuesday, July 18, 2017, to testify at the hearing entitled "Powering America: Examining the State of the Electric Industry through Market Participant Perspectives."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Friday, August 18, 2017. Your responses should be mailed to Elena Brennan, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, DC 20515 and e-mailed in Word format to Elena.Brennan@mail.house.gov.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment

The Honorable Fred Upton

Q: In your testimony, you call attention to markets that disadvantage certain resources or fuel types. As nuclear resources struggle to compete in wholesale markets, do you feel there's room to monetize resource attributes, through the price formation process?

Linde Response:

Mr. Chairman, yes, there is room to monetize resource attributes in wholesale markets and FERC has the capability to do so. As my earlier testimony stated, fuel diversity is an important aspect of a reliable electric system yet our wholesale markets were not designed to ensure fuel diversity. Our electricity system is now faced with the premature loss of resources such as nuclear power plants that are relied on day in and day out to provide reliable, low-cost and air emission free electricity. These resources are at risk because our wholesale markets were not designed to value these assets or fuel diversity. The solution is a simple one - wholesale markets need to value these resources by monetizing their attributes and recognizing the importance of fuel diversity, fuel security and resilience. I outline below the procedural steps that FERC can and should take to ensure that our wholesale electricity markets properly value these important attributes. I note however that the necessary changes to wholesale market designs will take time that many baseload generators do not have. As a result, it is crucial to recognize that state solutions may be necessary to bridge the time until wholesale market designs can be modified so that valuable attributes of these resources are adequately recognized.

Actions FERC should take to ensure fuel diversity and resilience:

First, FERC should issue an "Order to Show Cause" under Federal Power Act section 206. FERC should find that the current RTO/ISO tariffs may be unjust and unreasonable because they fail to ensure diversity, fuel security and resilience. In response, the RTO/ISO would either (1) submit to FERC proposed changes to their tariffs to address this gap or (2) provide an explanation as to how their current tariffs ensure fuel diversity, security and resilience. FERC would then review the submittals and determine if they were indeed adequate to ensure fuel diversity, fuel security and resilience.

Alternatively, FERC has a pending docket (AD17-11) regarding the integration of public policy objectives into the wholesale markets in the Northeast. The FERC could utilize this docket to direct the RTOs/ISOs in the Northeast to submit reports within 60-days that explain what steps their regions are taking and could take to ensure that fuel diversity, security and resiliency are maintained over the long-term. After the RTOs/ISOs submit the reports, FERC could then use the same section 206 procedure to direct the RTOs/ISOs to make market design changes.

Additionally, over the past several years, you and this committee have done much to encourage FERC to maintain its focus on ensuring that the true price of electricity is accurately reflected in the market, otherwise known as price formation. Now that FERC has a quorum I encourage you to continue pressing this issue front and center with the new FERC commissioners and consider using these price formation efforts as a vehicle for monetizing important generation attributes.

FERC has been working to implement these reforms to wholesale energy market design for the purpose of ensuring that wholesale energy prices more accurately reflect the cost and value of serving customers' electricity needs. To date, FERC has directed reforms that seek to improve transparency in the manner in which RTOs/ISOs commit generation resources to serve customers, allow generation resources to update their offers on an hourly basis so that they reflect updated system conditions, and expand the class of resources that are eligible to set energy clearing prices. PSEG has been a strong advocate of these price formation reforms. FERC's energy pricing reforms are a work in progress and much work still needs to be done. FERC's ongoing efforts in this area are also capable of serving as a vehicle to properly monetize resource attributes and support fuel diversity. For example, PJM recently developed several white papers including one titled *Pricing Reform: Refining Locational Marginal Price (LMP) Formation* to recognize the contribution of all resources, including large, inflexible units (often referred to as "baseload" resources) in serving load in a given interval. This paper dated June 15, 2017 offers a proposal that is intended to recognize the contribution that generation resources provide to the system, including baseload resources, by correcting how baseload units are able to set energy prices in the market. While this proposal is not a complete solution to the challenges facing baseload resources, it is a step in the right direction and should be part of a FERC directive to PJM in the form of an Order to Show Cause.

There are also potential legislative solutions to build off of the work from your leadership and of this Committee. Congress could take action to amend the Federal Power Act to require fuel diversity, security and resiliency. This amendment would provide clarity that these attributes are of value to Congress and the policy of the United States.

GREG WALDEN, OREGON
CHAIRMAN

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RANKING MEMBER

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August 4, 2017

Mr. Ken Schisler
Vice President of Regulatory and Government Affairs
EnerNOC
One Marina Park Drive; Suite 400
Boston, MA 02210

Dear Mr. Schisler:

Thank you for appearing before the Subcommittee on Energy on Tuesday, July 18, 2017, to testify at the hearing entitled "Powering America: Examining the State of the Electric Industry through Market Participant Perspectives."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

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Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment

Responses of Kenneth D. Schisler to Member Questions from the July 18, 2017, Subcommittee on Energy Hearing, "Powering America: Examining the State of the Electric Industry through Market Participant Perspectives"

Responses to the Honorable Fred Upton, Chairman, Subcommittee on Energy

1. **Last year, your company and the demand response industry had a very big win before the Supreme Court. The landmark ruling in FERC v. EPSA preserved FERC's jurisdction over demand response in the wholesale electricity markets and also upheld the principle that demand response resources should be compensated at the same price as generators.**

    a. **In the wake of the Court's decision and the regulatory certainty it provided, what's been the the effect on the demand response industry? Have you seen additional opportunities for demand response participation.**

The Supreme Court decision helped stabilize the industry and ensured that over 10,000 MW of demand response participating in FERC jurisdictional wholesale markets would continue to be able to participate. This was a big win. However, the win here was primarily a preservation of the *status quo ante*, rather than the creation of significant new opportunities. The Supreme Court reviewed a D.C. Circuit decision that eliminated demand response from FERC jurisdiction, which decision greatly destabilized the industry and upended a decade of effort building DR capabilities in FERC-jurisdictional wholesale market.

The decision also affirmed a FERC regulation for determining compensation for demand response participating in wholesale energy markets, following a period in which several of the FERC-jurisdictional wholesale markets had developed several different ways to compensate demand response in energy markets. This part of the decision was favorable for the demand response industry, but the impact has been limited thus far for a variety of reasons. First, energy prices have been relatively low since the Supreme Court decision in much of the United States, making it more attractive for customers to consume energy rather than participate in demand response. Second, prior to the decision, demand response participation in energy markets had been, in comparison to capacity markets and reliability-based demand response products, relatively small. Economic demand response was virtually non-existent during the litigation because of the potential for refunds if the D.C. Circuit decision had been upheld. With the legal uncertainty removed, economic demand response should be a growth opportunity.

The Supreme Court decision has stimulated additional investment in demand response and new advanced energy technologies. It is important to understand that principle underlying the decision didn't just impact demand response, but other distributed energy resources (DER) such as energy storage, vehicle to grid technologies, and others. If customers were prohibited from participating directly or through aggregators in FERC jurisdicitonal markets, it would have negatively impacted the commercialization of a variety of new energy technologies and innovation in distributed energy resources. The recent acquisition of EnerNOC by the Enel Group, one of the largest electricity companies in the world, is a clear example of the optimism for the future of DERs, including demand response, in the U.S. and around the world.

With the Supreme Court decision, technological advances in dynamic management of customer demand, and the declining costs of energy storage, there is now the potential to unleash broader participation from customers in wholesale markets, including energy and ancillary markets where participation has been limited. Still, three critical elements are necessary to achieve this potential:

1. A Non-discriminatory market design that recognizes the attributes of Distributed Energy Resources without creating unnecessary barriers to entry across all FERC-jurisdictional markets.
2. State regulators and utilities in the Midcontinent Indpendent System Operator (MISO) and Southwest Power Pool (SPP) markets seeking broader collaboration with third party technology and services providers, and leveraging the capabilities and private capital of non-utility agents working with or through utilities to develop demand response potential.
3. A constructive regulatory and market platform in the California Independent System Operator (CAISO) territory.

On item 2 above, FERC Order 719 allowed state regulatory authorities to prohibit end-use customers from participating in wholesale markets either directly or through third-party demand response providers. With the exception of Illinois, every state in the MISO footprint chose to enact this prohibition. While many utilities offer interruptible tariffs to their customers that can be used to offset wholesale capacity requirements, few utilities offer customers' demand response resources into the wholesale energy and ancillary markets. Participation in these markets typically requires a higher degree of technology and risk tolerance than what is found in utility interruptible programs. Moreover, traditional state regulatory structures do not stimulate efficient levels of investment in demand response by utilities.

In order to achieve efficient levels demand response participation in MISO, active collaboration is needed between state regulators, utilities, and third party DER/DR aggregators. This can be achieved in a manner consistent with the vertically integrated nature of Midwest states. It should be acknowledged that recently several Midwest states have demonstrated leadership and are actively considering how to stimulate broader distributed energy resource participation, including third parties working through or in conjuction with utilities.

With respect to Item 3 above, while California permits wholesale demand response participation, significant demand response investment and potential remains sidelined in CAISO due to significant uncertainty with regard to the management by CAISO of demand response participation. Despite its large size and good fundamentals for demand response, a number of barriers and unpredictable and disordered decision-making is a concern that has resulted in CAISO having a woefully underdeveloped market potential for demand response.

In your testimony, you noted that demand response resources reduced wholesale market costs by nearly $10 billion dollars in PJM for the current delivery year. Can you explain how demand response accomplished such a significant reduction?

a. **Were these savings realized in the energy markets, capacity markets, or both markets? Are these savings net of payments to demand response resources?**

This figure comes from a report from the PJM Independent Market Monitor, with a citation provided below, and is specific to capacity market savings. The quote from Page 6 of the report is:

"The inclusion of sell offers for Demand Resources and Energy Efficiency resources had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2017/2018 RPM Base Residual Auction were $7,512,229,630. If there were no offers for DR or EE in the 2017/2018 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been $16,859,658,203, an increase of $9,347,428,573, or 124.4 percent, compared to the actual results."[1] We are not aware of any publically available figures on energy and ancillary market savings, and since the current delivery year is still in progress, it would not be possible to calculate savings over the entire time period.

The driver for the large savings is most likely a result of willingness from demand response resources to provide capacity at a more competitive cost than certain generation assets. If demand response had not participated in the auction, supply would have been lower, and the clearing price for PJM capacity would have been substantially higher.

[1] Monitoring Analytics. Analysis of the 2017/2018 RPM Base Residual Auction. The Independent Market Monitor for PJM. October 6, 2014

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August 4, 2017

Mr. Alex Glenn
Senior Vice President
Duke Energy Corporation
550 South Tryon Street
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Dear Mr. Glenn:

Thank you for appearing before the Subcommittee on Energy on Tuesday, July 18, 2017, to testify at the hearing entitled "Powering America: Examining the State of the Electric Industry through Market Participant Perspectives."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Friday, August 18, 2017. Your responses should be mailed to Elena Brennan, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, DC 20515 and e-mailed in Word format to Elena.Brennan@mail.house.gov.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment

The Honorable Fred Upton
Chairman, Subcommittee on Energy
2125 Rayburn House Office Building
Washington, D.C. 20515

The Honorable Bobby Rush
Ranking Member, Subcommittee on Energy
2125 Rayburn House Office Building
Washington, D.C. 20515

August 17, 2017

Dear Chairman Upton and Ranking Member Rush:

Thank you for inviting me to appear before the Subcommittee on Energy on Tuesday, July 18, 2017 to testify at the hearing entitled "Powering America: Examining the State of the Electric Industry through Market Participant Perspectives."

Per your request, I have attached my responses to the questions for the record prior to the August 18, 2017 deadline.

Please let me know if you have any questions or would like additional information.

Sincerely,

Alex Glenn
SVP State & Fed Regulatory Legal Support
Duke Energy

The Honorable Fred Upton

Question:

1. You testified that it may be time to update PURPA as a result of the changes in the market, notably substantial growth in renewable energy due to federal and state incentives and policies. Can you describe what circumstances are causing utilities to pay above-market costs for electricity under a PURPA contract?

    a. Do you have an example of how much more ratepayers are paying because of PURPA contracts?

    b. Do you have specific suggestions on how PURPA should be revised?

2. You testified that Qualifying Facilities (QFs) under PURPA contract at higher costs due to mandatory purchase obligations set out in law. However, the power they sell to the wholesale markets play an important role in fuel diversity and resiliency – do those added benefits to the grid outweigh slightly higher costs?

    a. How could avoided-cost calculations be changed to better integrate QFs into wholesale markets at more cost-effective price points?

Response:

1. The circumstances that are causing utilities to pay above-market costs for electricity under a PURPA contract are two-fold: 1) the interpretation of "incremental cost" (PURPA Section 210) has diverged from both wholesale market price and cost-based pricing in a number of jurisdictions and 2) neither the 1978 PURPA statute nor the 2005 PURPA amendments anticipated that there would be material costs associated with integrating large amounts of PURPA power into electric systems and thus, PURPA statute is silent on who bears the costs associated with integrating variable, intermittent energy deliveries from PURPA facilities into the electric system. As a result, utilities and utility customers bear those costs.

    "Incremental Cost" has diverged from actual cost
    Interpretation of PURPA Section 210, at both the FERC and state commission level, has led to a situation in which the "incremental cost" or "avoided cost rate" that a utility must offer to a PURPA facility for its energy can be markedly higher than the utility's cost-based price and/or the wholesale energy price available in a market today.

    While there are a number of examples of how "incremental cost" has diverged from actual energy prices across the nation, a well-documented example is in North Carolina, where the utility is required to offer to a PURPA facility a price that includes a capacity payment, *even when the utility has demonstrated that it does not have a new generation capacity need.* (When a utility does not have a need for new energy generation capacity, the value of new capacity is zero.)

    As a result of this divergence from actual energy prices, in North Carolina, the utility must offer a rate of approximately $50 per megawatt-hour to a PURPA facility when, in actuality, the value should be approximately $35 per megawatt-hour (a price that reflects a $35 value of energy and a $0 value of capacity). The effect of this $15 difference becomes very material when amplified by the hundreds of thousands of megawatt-hours per year that some utilities must buy from PURPA facilities.

To better align "incremental cost" with market prices, we recommend a simple remedy: Congress should specify, in a PURPA modernization amendment, "no such rule prescribed under PURPA Section 210 (a) shall provide for a rate which exceeds the lower of actual cost-based or wholesale market prices available to the electric utility (as indicated by market clearing prices, prices set through an RFP process, short contract prices, published indices, or other such indicia)."

PURPA fails to address integration cost

The second reason why some utilities have been forced to pay above-market costs for electricity under a PURPA contract is because there is no requirement that the PURPA facility (i.e., the solar or wind generator) bear any of the cost for integrating its variable, intermittent energy deliveries into the electric system operator.

As more and more PURPA solar and wind facilities deliver energy, the cost of integration has become a material burden to utility customers in a number of regions of the country. At significant levels of wind and/or solar penetration, an electric system operator will dispatch its generation and operate its transmission facilities differently – often in a more costly manner – to accommodate the weather-dependent deliveries of wind solar facilities.

The National Renewable Energy Laboratory estimates that solar and wind integration cost range from $1.00 per megawatt-hour to $7.00 per megawatt-hour, depending on amount of PURPA capacity, the type of renewable energy, and the size and capabilities of the electric system operator who must take the PURPA power. Amplified across hundreds of thousands of megawatt-hours from PURPA solar facilities and millions of megawatt-hours from PURPA wind facilities, the aggregate cost of integration becomes material.

An example of a situation where the utility and the utility customers are bearing the cost of integrating large volumes of solar energy is in Eastern North Carolina, where Duke Energy expects that the amount of PURPA solar capacity delivering energy at certain hours of the day during the spring and the fall, will be so high that we, Duke Energy, will be in a situation where we actually have to "dump" some amount of baseload nuclear power. That means that Duke Energy must find a neighbor utility that can accommodate that excess power and, most likely, pay him to take the excess power that Duke Energy must get rid of in order to maintain line voltages within NERC standards.

You may ask, so why not just turn off the nuclear power when the PURPA solar is delivering at such high volumes? The option of "turning off" baseload coal or nuclear is actually very costly and even dangerous, as these plants are not designed to be turned off/on daily. In addition, turning off a unit is unadvisable due to the fact that solar output varies with weather conditions. For example, if a large front of thunderstorms travels through eastern North Carolina, we can expect almost 2,000 megawatts of PURPA solar capacity (enough solar to cover 10,000 acres or 15 square miles) to cease production within seconds as the storm clouds gather and obstruct the sun. In such a situation, "turning off" baseload is not advisable because baseload energy and capacity may be necessary to serve customers when PURPA power ceases.

As a result of the nature of the PURPA must-take power, the amount of PURPA power, and the characteristics of the incumbent electric system operator, the utility consumer will likely pay two or even three times for energy: once for the nuclear power (which cannot be ramped on and off), again for the mandatory purchase of solar power, and once again for the cost of paying a neighboring utility to take excess power so that the system can safely and reliably accommodate the solar power.

To remedy this situation, Congress should amend PURPA Section 210 (b) to include the following phrase: "The rules prescribed...shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase ... *(3) shall obligate the QF to operationally integrate its facility with the electric system operator.*"

a. The mandatory purchase obligation, whereby a utility must buy power from PURPA facilities at specific purchase prices, for a specific term, has a measurable impact on the prices our consumers pay for electricity. Key to understanding the impact of PURPA is to recognize that when an electric utility purchases power from a PURPA facility like a solar generator or a wind generator, those costs are actually borne by the utility's consumer, in the same manner in which the cost of natural gas fuel is passed on to the customer, without mark-up.

   As for overpayment, Duke Energy calculated the degree to which its North Carolina customers were overpaying for PURPA purchase at the end of 2016. At that time, Duke Energy had an estimated 1,600 megawatts of solar interconnected to and selling back to Duke Energy. We estimated that the aggregate cost of the rates for purchase offered to PURPA facilities, extrapolated over the expected output of the facilities and across the term of the purchase agreement (12-14 years) was $2.9 billion. If the Duke Energy had not been required to offer payment for capacity when the utility's capacity need was zero, or if the utility had not been required to offer long-term, fixed price rates to PURPA facilities, and if these contracts were valued at the utility's wholesale price today, these contracts, in aggregate would have cost the utility customer base just $1.9 billion. Thus, delta between the actual wholesale price and the PURPA price, over the course of the PURPA long-term contracts, in aggregate, comes to more than $1 billion.

   For reference, sixty percent of all PURPA solar projects nationwide are in North Carolina. In 2010, North Carolina had just 20 megawatts of solar installed; enough solar to cover about one hundred acres. Today, in North Carolina, there are more than 2,000 megawatts of solar power in operation; the equivalent of 10,000 acres or 15 square miles of solar panels. Bloomberg News actually called the North Carolina a PURPA "gold rush" given the number of investors flocking to fund solar farms in North Carolina. In addition, there remain more than 5000 megawatts of PURPA facility solar awaiting interconnection; that is the equivalent of an additional five nuclear reactors' worth of solar capacity awaiting interconnection.

b. Please refer to my response to Question 1.

2. No, the added benefits of fuel diversity and "resiliency" do not justify the slightly higher prices we are obligated to offer PURPA facilities. Electric utilities constantly assess and compare the cost-effectiveness of generation resources like solar, wind, natural gas, nuclear, and coal. These calculations take into account costs and benefits of

environmental attributes as well as the long-term price of various fuels. As a result of these calculations and a tremendous amount of due diligence, Duke Energy now owns and operates a fleet of nearly 250 megawatts of solar power within our regulated utility companies. This is the amount of solar that state regulatory bodies have deemed "prudent" thus far.

The utility's ability to pay for higher cost resources is extremely limited. Utilities must prove that those resources are absolutely essential in order to meet reliability requirements, environmental requirements, and/or customer demand. While solar PV and wind are non-emitting resources with zero fuel cost, they remain weather dependent and are not reliable, dispatchable peaking resources that can be built to meet summer afternoon peaks or winter morning peaks.

As for resiliency, in order for a solar facility to supply electricity during a grid outage to a critical facility like a Red Cross evacuation site or fire station, the solar PV system would have to be designed with resiliency in mind from the beginning. That is, the solar would be combined with other technologies, such as energy storage, switches that safely isolate the circuit between the solar facility and the fire station from the rest of the grid during an outage, and additional equipment to control the flow and quality of the electricity. Today, this additional energy storage, control, and switching equipment is very expensive.

The vast majority of solar PV systems as installed today in the United States are technically incapable of providing consumer power during a grid outage; when the grid is in an outage, the solar PV systems are required to automatically shut off in accordance with IEEE 1547* protocols intended to protect the safety of utility line workers. (If solar power were to deliver energy back to the grid during an outage, that would endanger the lives of utility line workers.)

*The Energy Policy Act of 2005 established IEEE 1547 as the national standard for the interconnection of distributed generation resources [solar] in the United States of America.

a. There is a simple way to better integrate QFs into wholesale markets at more cost-effective price points: Congress should specify, in a PURPA modernization amendment, "no such rule prescribed under PURPA Section 210 (a) shall provide for a rate which exceeds the lower of actual cost-based or wholesale market prices available to the electric utility (as indicated by market clearing prices, prices set through an RFP process, short contract prices, published indices, or other such indicia)." Such an amendment will prompt FERC rule-making that will enable integration of QFs into wholesale markets at more cost-effective price points.

The Honorable Richard Hudson

<u>Question:</u>

1. In your testimony, you discuss how the timely siting and permitting of vital infrastructure projects is critical to strengthen the power grid. You also mention how the lack of quorum at FERC is preventing action on these crucial infrastructure projects, including natural gas pipelines. One such project, the Atlantic Coast Pipeline, will provide clean-burning natural gas supplies to growing markets in Virginia and North Carolina. Pipeline

construction alone will create 17,000 new jobs and $2.7 billion in economic activity across the region, and once operating, the pipeline will save consumers an estimated $377 million a year on their energy costs. Additionally, the pipeline will generate $28 million in annual property tax revenue for local governments along the route. This pipeline is one that needs a FERC Commission issued Certificate Order by the end of September in order for the company to begin physical work on clearing the right of way for the pipeline in October. If these timelines aren't met it could significantly delay the in-service date of ACP. If that happens, what will that do to Virginia and North Carolina customers?

2. You flagged that the preservation of interest deductibility in tax reform is critical for electric utilities. Can you expand on what type of capital investments Duke Energy and other electric utilities make in the communities they serve and why that is tied to interest deductibility?

Response:

1. The Atlantic Coast Pipeline needs a FERC Commission issued Certificate Order by the end of September in order for the company to begin physical work on clearing the right of way for the pipeline in October. If these timelines are not met it could significantly delay the in service date of pipeline, potentially resulting in hundreds of millions of dollars in delay-related costs to Duke and constrained natural gas supply for our customers which could result in higher prices and inability to meet demand.

2. The electric power industry is the nation's most capital-intensive industry and invests more than $100 billion annually to build a smarter energy infrastructure and to transition to even cleaner generation sources. Electric companies are significant engines of growth across the U.S. economy.

   Just this year, Duke Energy announced a $13 billion, 10-year project to modernize the state's electric system. These upgrades will harden the system against storms and outages; make it safer and more resilient against cyber-attacks and physical threats; help expand renewable energy; generate jobs and stimulate economic growth. It will also give 7 million people in North Carolina more information to manage their energy use.

   Duke Energy's 10-year modernization plan for NC will result in:

   - Additional bill-lowering tools designed to help customers reduce their energy costs
   - An average of 13,900 jobs each year
   - $10.4 billion in salaries and wages
   - Almost $800 million in state taxes and $550 million in local taxes
   - A total economic output of $21.5 billion over the 10 years

   Capital investments such as this modernization plan rely heavily on the ability to deduct interest. This is due to the highly regulated nature of our businesses as independent state public utility commissions allow electric companies to recover their costs through the rates they charge their customers for electricity service. If electric companies are unable to deduct interest costs for infrastructure projects, they would pass the higher cost of capital on to their customers. Raising electricity prices has a disproportionate impact on lower-income customers and small businesses, and hurts the global competitiveness of energy-intensive industries in this country.

Eliminating the ability to deduct interest expense would have a dramatic impact on customers' electricity bills. Raising capital through equity is currently more expensive than raising capital through debt, and removing the deduction for interest expense will not change this fact. Allowing electric companies to continue deducting interest expense provides a "win-win" for the American economy.