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KEEPING THE LIGHTS ON: EXAMINING THE STATE OF REGIONAL GRID RELIABILITY

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY

OF THE

COMMITTEE ON ENERGY AND COMMERCE

HOUSE OF REPRESENTATIVES

ONE HUNDRED NINETEENTH CONGRESS

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KEEPING THE LIGHTS ON: EXAMINING THE STATE OF REGIONAL GRID RELIABILITY

TUESDAY, MARCH 25, 2025

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

The subcommittee met, pursuant to call, at 10:14 a.m., in the John D. Dingell Room 2123, Rayburn House Office Building, Hon. Robert E. Latta (chairman of the subcommittee) presiding.

Members present: Representatives Latta, Weber, Palmer, Allen, Balderson, Pfluger, Harshbarger, Miller-Meeks, James, Bentz, Fry, Lee, Langworthy, Rulli, Evans, Goldman, Fedorchak, Guthrie (ex officio), Castor (subcommittee ranking member), Peters, Menendez, McClellan, DeGette, Matsui, Tonko, Veasey, Schrier, Fletcher, Auchincloss, and Pallone (ex officio).

Also present: Representatives Carter of Georgia and Joyce.

Staff present: Ansley Boylan, Director of Operations; Jessica Donlon, General Counsel; Andrew Furman, Professional Staff Member; Sydney Greene, Director of Finance and Logistics; Emily Hale, Staff Assistant; Megan Jackson, Staff Director; Mary Martin, Chief Counsel; Joel Miller, Chief Counsel; Ben Mullaney, Press Secretary; Jake Riith, Staff Assistant; Jackson Rudden, Staff Assistant; Chris Sarley, Member Services/Stakeholder Director; Emma Schultheis, Clerk; Peter Spencer, Senior Professional Staff Member; Kaley Stidham, Press Assistant; Matt VanHyfte, Communications Director; Rasheedah Blackwood, Minority Intern; Waverly Gordon, Minority Deputy Staff Director and General Counsel; Tiffany Guarascio, Minority Staff Director; Perry Hamilton, Minority Member Services and Outreach Manager; Kristopher Pittard, Minority Professional Staff Member; Emma Roehrig, Minority Staff Assistant; Kylea Rogers, Minority Policy Analyst.

Mr. LATTA. Well, good morning. The Subcommittee on Energy will now come to order.

And the Chair recognizes himself for 5 minutes for an opening statement.

OPENING STATEMENT OF HON. ROBERT E. LATTA, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF OHIO

Welcome to today's hearing, "Keeping the Lights On: Examining the State of Regional Grid Reliability." Today, we will continue the subcommittee's work to address the ongoing electric reliability crisis facing our Nation.

The witnesses before us are each of the regional grid operators and ERCOT, who collectively cover two-thirds of the country. These organizations are charged with overseeing reliability to their State or region, administering markets for the sale and purchase of electricity products, and coordinating transmission development.

While each grid operator functions in a similar manner, they all take unique approaches to addressing the regional and demographic differences of communities and their footprints. But no matter where in the country they serve, they are confronting the challenges facing our power sector.

It is no secret that our country is in the midst of a reliability crisis, and it could not come at a worse time. The North American Electric Reliability Corporation, NERC, recently stated that 52 gigawatts of generation will retire in the next 4 years. To put this into context, that is the rough equivalent of 40 nuclear plants or 500 square miles of solar panels.

While dangerous amounts of baseload generation are leaving the grid, we are facing historic levels of demand entering the system and interconnection queues that are backlogged with intermittent resources and battery storage facilities. We know that renewables are not a one-on-one replacement for dispatchable baseload power that is essential to reliability and provides spinning reserves needed to stabilize the system through fluctuations.

It is not clear that the pace at which baseload generation is coming online will bridge the gap of retiring supply and meet increasing demands over the next few short years.

As we are well aware, these new demands are largely driven by developments in artificial intelligence and domestic manufacturing. Achieving a leadership position in the development of AI and reshoring domestic manufacturing is not a pipe dream to strive for, it is a national security imperative that could shape America's future in the global economy.

Regional grid operators before us today are on the front lines of the reliability crisis, and this is a new era of historic electricity demand.

When operating correctly, electricity markets should allow clear market signals to drive investment into new generation, efficient interconnection of new resources should address increasing demand, and coordinated transmission planning should bring needed electricity supplies to growing load centers.

However, these organizations and electricity markets do not operate in a vacuum. Excessive Federal overreach, like the Clean Power Plan 2.0, drove significant premature retirements of baseload power and discouraged long-term investment into baseload generation sources. Significant subsidies for intermittent generation undermine the economies of baseload or on-demand dispatchable generation resources that are essential to keeping the lights on.

These grid operators are also tasked with the difficult job of maintaining reliability and resource adequacy as States implement restrictive policies designed to attack fossil resources. Because the interconnected nature of much of our bulk power system, the decisions of one State to drive out baseload power inherently impact the reliability of our neighboring States.

All these problems are compounded by systematic permitting challenges that make it nearly impossible to develop new infrastructure in large parts of our country. Markets cannot build where governments do not let them do. We need to address these challenges through a pragmatic whole-of-government approach that recognizes the benefits of different source—of fuel sources, the limitation of others, and prioritizes energy expansion.

There is a value to ensuring a diverse resource mix, but it is important to recognize that not all electrons should be treated equally. The variability of intermittent resources like wind and solar innately require backup generation during inclement weather conditions and where battery storage facilities are operationally restricted. Often it is during these periods of inclement weather when we need electricity the most to protect the health and safety of our communities.

I look forward to today's discussion regarding the ongoing reliability crisis and the important steps regional grid operators are taking to correct market inefficiencies to keep the lights on for all Americans.

[The prepared statement of Mr. Latta follows:]

Chairman Robert E. Latta
Opening Statement—Subcommittee on Energy
"Keeping the Lights On: Examining the State of Regional Grid Reliability"
March 25, 2025

As prepared for delivery

Welcome to today's hearing "Keeping the Lights on: Examining the State of Regional Grid Reliability."

Today, we will continue this subcommittee's work to address the ongoing electric reliability crisis facing our nation.

The witnesses before us are each of the regional grid operators, and ERCOT, who collectively cover 2/3 of our country.

These organizations are charged with overseeing reliability of their state or region, administering markets for the sale and purchase of electricity products, and coordinating transmission development.

While each grid operator functions in a similar manner, they all take unique approaches to addressing the regional and demographic differences of communities in their footprints.

But no matter where in the country they serve, they are all confronting the challenges facing our power sector.

It's no secret that our country is in the midst of a reliability crisis, and it could not come at a worse time.

The North American Electric Reliability Corporation, or NERC, recently stated that 52 GW of generation will retire in the next 4 years.

To put this into context, that is the rough equivalent of 40 nuclear plants or 500 square miles of solar panels.
While dangerous amounts of baseload generation are leaving the grid, we're witnessing historic levels of demand entering the system and interconnection queues that are backlogged with intermittent resources and battery storage facilities.

We know that renewables are not a one-for-one replacement for dispatchable, baseload power that is essential to reliability and provides spinning reserves needed to stabilize the system through fluctuations.

It is not clear that the pace at which baseload generation is coming online will bridge the gap of retiring supply ***and*** meet increasing demands over the next few short years.

As we are all well aware, these new demands are largely driven by developments in artificial intelligence and domestic manufacturing.

Achieving a leadership position in the development of AI and reshoring domestic manufacturing is not a pipe dream to strive for – it is a national security imperative that could shape America's place in the future global economy.

Regional grid operators before us today are on the front lines of the reliability crisis and this new era of historic electricity demand.

When operating correctly, electricity markets should allow clear market signals to drive investment into new generation, efficient interconnection of new resources should address increasing demand, and coordinated transmission planning should bring needed electricity supplies to growing load centers.

However, these organizations and their electricity markets do not operate in a vacuum.

Excessive federal overreach, like the Clean Power Plan 2.0, drove significant premature retirements of baseload power and discouraged long-term investment into baseload generation sources.

Significant subsidies for intermittent generation undermine the economics of baseload, or on-demand, dispatchable, generation resources that are essential to keeping the lights on.
These grid operators are also tasked with the difficult job of maintaining reliability and resource adequacy as States implement restrictive policies designed to attack fossil resources.

Because of the interconnected nature of much of our bulk power system, the decisions of one State to drive out baseload power inherently impact the reliability of neighboring states.

All of these problems are compounded by systemic permitting challenges that make it nearly impossible to develop new infrastructure in large parts of our country.

Markets cannot build what governments do not let them.

We need to address these challenges through a pragmatic whole of government approach that recognizes the benefits of different fuel sources, the limitation of others, and prioritizes energy ***expansion***.

There is value to ensuring a diverse resource mix, but it is important to recognize that not all electrons should be treated equally.

The variability of intermittent sources like wind and solar innately require back up generation during inclement weather conditions and where battery storage facilities are operationally restricted.

Often it is during these periods of inclement weather when we need electricity the most to protect the health and safety of our communities.

I look forward to today's discussion regarding the ongoing reliability crisis and the important steps regional grid operators are taking to correct market inefficiencies to keep the lights on for all Americans.

Thank you and I yield back the balance of my time.

Mr. LATTA. And with that, I yield back the balance of my time and at this time recognize the gentlelady from Florida, the ranking member of the subcommittee, 5 minutes for an opening statement.

OPENING STATEMENT OF HON. KATHY CASTOR, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF FLORIDA

Ms. CASTOR. Well, thank you, Chairman Latta. And welcome to our witnesses today. And I want to thank you and everyone working to keep America's power system as modern and as efficient, affordable, and reliable as it can be, from the linemen who were restoring power after the devastating hurricane season in my neck of the woods to folks dealing with wildfires, extreme events, and just now the new calls for huge new sources of energy and capacity across the country.

A resilient and reliable electric grid that utilizes the cleanest resources possible is vital to all Americans. And decade after decade, we have modernized energy sources in the grid, and we must continue to do so.

And while I am pleased that we are focused on strengthening the grid, the hearing ignores the damage being done by the Trump administration and Elon Musk to reliable, affordable energy, including the investments under the infrastructure law and the Clean Energy Climate Resilience Law, the IRA.

Since I started thinking about this hearing, I have had the lyrics from "Wicked," that great dance number, stuck in my head, "Dancing Through Life": "We are dancing through life, no need to tough it when you can slough it off as you do."

For example, the early Trump shutdown of grants and loans halted electricity and grid projects, causing chaos and additional costs for co-ops and power producers and, ultimately, consumers. Then you have the illegal layoffs of energy experts in various agencies, the illegal firings of the Department of Energy Inspector General, and the disruption of electricity trade between Canada and the U.S. It is all leading to higher cost for American consumers.

For instance, the U.S. imposed a 10 percent tariff on Canadian electricity imports. And Ontario retaliated with a 25 percent surcharge in electricity exports to Michigan, New York, and Minnesota. And although Ontario suspended the surcharge, the tariffs have strained the integrated power grid shared by the two countries. This interconnected system has historically provided reliability and cost benefits, but tariffs now are threatening its efficiency.

So I urge colleagues to stand up to this chaos that is fueling higher costs and uncertainties. It has weakened our ability to strengthen the grid.

And as Republicans hammer out their tax giveaways to billionaires, that should not come at the expense of grid infrastructure investments and clean energy tax credits for solar, wind, nuclear, and pollution reduction.

One analysis predicts that repealing the clean energy tax credits would increase annual energy costs for each U.S. household. It would cost us about 800,000 jobs and decrease our GDP.

Solar wind and battery storage are the cheapest and cleanest ways to add energy supply to the grid now. They are driving down

energy costs now. RTOs, ISOs, and FERC are making progress on interconnection queues, and Congress should help them. Because we understand there are over 2,000 gigawatts of energy and storage waiting in line. That is equivalent to about one billion homes at peak demand.

Also, there are many commonsense, practical policy solutions to help our grid connect more resources and strengthen the grid. My bicameral Advancing GETs Act is a great example. The bill would encourage FERC to implement shared savings, incentives that promote the deployment of grid-enhancing technologies—that is the cheapest way to supercharge our power grid—and would allow utilities to earn a profit for saving money and save consumers billions on their electricity bills every year.

Similarly, the Expediting Generator Interconnection Procedures Act would make commonsense reforms to the outdated, sluggish process that we use to bring energy of all kinds onto the grid. We could promote the use of automation and standardization studies, ensuring that grid upgrade costs are fairly allocated to customers who benefit from the interconnection of new resources.

The energy affordability crisis we are grappling with today requires real forward-looking policy solutions. It requires a politically independent and well-staffed FERC, and it requires a consistent commitment to energy policy, one that keeps Americans safe, helps us compete with our foreign adversaries, and continues to deliver investments in jobs across America.

Thank you, Mr. Chairman. I yield back.

[The prepared statement of Ms. Castor follows:]

Committee on Energy and Commerce

Opening Statement as Prepared for Delivery
of
Subcommittee on Energy
Ranking Member Kathy Castor

Hearing on "Keeping the Lights On: Examining the State of Regional Grid Reliability"

March 25, 2025

I find it absurd that the majority has called a hearing on this important topic of strengthening our electric system, while at the same time, they stand idly by as Elon Musk and the Trump Administration take a sledgehammer to Department of Energy initiatives that strengthen and modernize the grid. The Administration has spent its first few weeks mired in illegal shutdowns of DOE grants, loans and partnerships that make energy safe, reliable and affordable. That includes the illegal firings of the DOE IG tasked with rooting out waste, fraud, and abuse and the scientists who protect our nuclear enterprise.

Meanwhile, the Administration and House Republicans have offered nothing to help hardworking Americans tackle the cost of living including electric bills. In fact, consumers are losing confidence as Republicans instead focus on tax breaks for the wealthy and well-connected and handouts to Big Oil and Gas.

Beware - Canada and Mexico are all major makers of electrical grid components like transformers, circuit breakers and switchgears, which are needed to upgrade our growing grid. Trump's tariffs will make these upgrades more expensive and take even longer, not to mention the direct cost increases that tariffs on electricity will have on northern states.

As part of the Bipartisan Infrastructure Law, DOE was administering a $10.5 billion Grid Resilience and Innovation Partnerships (GRIP) to enhance grid flexibility and improve the resilience of the power system against extreme weather.

One GRIP project was a battery installation at an Iron Mountain data center in Virginia that was meant to test the potential to store clean power for backup and grid-support uses. On his first day in office, the President illegally froze that project, as well as $103 million dollars in grid funding that should be helping my neighbors in Florida.

Growing America's leadership in artificial intelligence requires access to more energy – we will see a doubling of data center electricity capacity by 2030 from projects already under construction. A 1-gigawatt data center would be the single largest energy load in the United States today – and we're planning to build dozens of them.

To support data centers and broader electricity growth, the U.S. Energy Information Association forecasts the U.S. will build 63 GW of new utility-scale capacity this year – 94% of which is zero-carbon.

Gas will not magically solve this challenge. Even for those who decide they want to build new gas plants, if they make that decision today, the plant won't come online before 2030. Next generation

technologies like advanced geothermal and nuclear power, while incredibly promising, are at least several years away. And here's a fact check of the speech last night: He misleadingly said Biden's administration had "closed more than 100 power plants." According to the Department of Energy, the number of utility-scale electric power plants actually increased by 2,187 during the Biden Administration. (Coal- and petroleum-powered plants decreased, because they don't make economic sense.)

Solar, wind, and batteries are the least expensive, cleanest and fastest ways to add energy to the grid now. They're driving down energy costs now. If we want to lower the cost of energy and we want more reliable energy, then we should be making it easier to build solar, wind and batteries wherever it makes sense to do so. That's why its raising huge red flags that the Trump Administration is unceremoniously halting these grid and power projects.

If Republicans were willing to stand up for the innovative work to modernize the grid that is happening right now, then there are real policies we could work on together.

The real barriers to getting new power online – for data centers, large-scale manufacturing, or just everyday American families – is the limited capacity and disjointedness of our power grid. We need to build more transmission to enable more generation and get more out of our existing grid infrastructure.

My bicameral Advancing GETs Act is a great example of this. The bill would direct FERC to implement shared savings incentives that promote the deployment of grid-enhancing technologies. That could unlock hundreds of gigawatts of clean energy stuck in interconnection queues.

We can also expand the use of new tools, like virtual power plants, which can help manage flexible electricity loads. We should also examine state level proposals that ensure that the costs of serving large loads are paid by the that companies that are vastly increasing load growth, and not shifted to consumers.

The United States faces two options. We can choose to double down on outdated, fossil fuel driven strategies that are more expensive, that are slower to interconnect, and are big polluters. Or we can choose the other option, advancing real policies that deliver cheaper, cleaner, faster power that could benefit everyone.

I yield back.

Mr. LATTA. Thank you. The gentlelady yields back.

And the Chair now recognizes the gentleman from Kentucky, the chairman of the Energy and Commerce Committee, for 5 minutes for his opening statement.

OPENING STATEMENT OF HON. BRETT GUTHRIE, A REPRESENTATIVE IN CONGRESS FROM THE COMMONWEALTH OF KENTUCKY

Mr. GUTHRIE. Thank you, Chairman Latta, and thank you for the recognition. Thank you for all of our witnesses being here. There's a lot of sayings that—I don't see my friend from Michigan in here on our committee this morning, but her husband, a lot of sayings are attributed to Chairman Dingell over looking at the globe and say, "That is the jurisdiction of Energy and Commerce." Another one is, he always said, if it—for our jurisdiction—"If it moves, it is energy. If it is not moving, it is commerce." So that is our jurisdiction.

So I use the Dingell corollary. It takes energy to move commerce, and for us to be successful to turn—somebody said the other day that AI turns energy into intelligence. And so it is vitally important that we as a country get together and figure out how we are going to beat China, and it is by having affordable, reliable delivery of electric power.

And the complicated question of how to deliver that power effectively is compounded by the tremendous increase in demand projected over coming years for specific purposes like AI, and broader increases in consumer demand. I know we have met slower energy growth over the last generation and also more efficiency, which is absolutely part of it is to be more efficient, but now we are seeing a rising in demand. And so we have to ensure affordable, reliable delivery of power to meet our needs, and the tremendous amount of energy it is going to require for the utility grid.

So here in Congress we must identify and understand the forces impacting the ability of engineers to plan and operate this system for better or for worse. And we must address the commonsense policy reforms that will allow utilities and operators to do their work cost-effectively.

Over the past decade, certain Federal and State policies have made it more difficult for operators to keep the lights on. The threats of the Biden administration's electricity policy was to shut down baseload coal and limit natural gas generation with onerous new rules and regulations. During this time, many States also established policies to transition away from fossil generation that is essential for maintaining grid reliability. Momentum behind this so-called transition continues just as a generational increase in power demand is emerging.

Consider how new demand growth is clashing with the residual Biden-Harris policies today. In December, the North American Electric Reliability Corporation, NERC, projected peak power demand to grow by 151 gigawatts—151 gigawatts over the next 10 years. Over the same period, NERC reports expected retirements of dispatchable generation which is needed for reliability to be as much as 115 gigawatts. This gap between retirements and growth in demand alone accounts over 240 gigawatts or an equivalent

amount of power needed to support 195 million homes over an entire year.

Ensuring the availability of reliable power will require stopping and reversing retirements of dispatchable resources and building out new natural gas generation and eventually nuclear and other reliable sources. Yet the vast amount of the new generation that is aligned today to connect the grid is intermittent wind and solar, which cannot be relied upon when you need it the most.

As a result, half of the Nation is at risk of power shortfalls over the next 10 years—think about it, half the Nation. For all the benefits of all-the-above resource policies, the current path that incentivizes a massive renewable build is putting the electric system out of balance and dramatically increasing risk.

Today we will talk to the grid operators that are caught at the center of the clash between failing policies and strong economic demand affecting our Nation's generation mix. They must deal with the consequences, so understanding the challenges you face and how you plan to meet the growing demand is essential for our work.

Last week the Secretary of Energy noted that the existential security implications of our race with China on AI and other advanced technologies, a focus on meeting the China challenges and with the DeepSeek, that should wake us up that we are challenging China. We can't always expect to be on top if we don't focus on being on top. So that raise—should raise serious questions about what is necessary to clear the way in permitting and regulatory policy, which will enable tremendous energy and power growth in the coming years.

Recognize we have to be—we have to be focused on making sure we do everything in the right way and in a sustainable way as much as we can possible. But we have to fully appreciate the scale of the pace of change coming because of the AI, the data centers, and the demand. As well with Microsoft. Microsoft data—not all, but some Microsoft data centers can use as much power as the city of Seattle. That puts it into perspective.

I look forward to this discussion. I will yield back.

[The prepared statement of Mr. Guthrie follows:]

Chairman Brett Guthrie
Opening Statement—Subcommittee on Energy
"Keeping the Lights On: Examining the State of Regional Grid Reliability."
March 25, 2025

As prepared for delivery

Thank you, Chairman Latta, and thank you to our witnesses for being here today.

We all agree that the affordable, reliable delivery of electric power is essential for a strong and secure American economy and to fortify our competition with China.

The complicated question of how to deliver power effectively is compounded by the tremendous increase in demand projected over coming years, both for specific purposes like AI data centers and broader increases in consumer demand.

Ensuring affordable, reliable delivery of power to meet the needs in our communities requires tremendous amounts of planning and oversight by the engineers and operators of the electric system—from utilities to the regional grid operators joining us this morning.

Here in Congress, we must identify and understand the forces impacting the ability of engineers to plan and operate this system—for better or worse.

And we must address the commonsense policy reforms that will allow utilities and operators to do their work cost-effectively.

Over the past decade, certain federal and state policies have made it more difficult for operators to keep the lights on.

The thrust of the Biden Administration's electricity policy was to shut down baseload coal and limit natural gas generation with onerous rules and regulations.

During this time, many states also established policies to transition away from fossil generation that is essential for maintaining grid reliability.

Momentum behind this so-called "transition" continues, just as a generational increase in power demand is emerging.

Consider how new demand growth is clashing with residual Biden-Harris policies today.

In December, the North American Electric Reliability Corporation – NERC – projected peak power demand to grow by 151 gigawatts over the next ten years.

Over this same period, NERC reports expected retirements of dispatchable generation, which is needed for reliability, to be as much as 115 gigawatts.

This gap between retirements and growth in demand in the United States alone amounts to over 240 gigawatts, or an equivalent amount of power needed to support over 195 million homes for an entire year.

Ensuring the availability of reliable power will require stopping and reversing retirements of dispatchable resources and building out new natural gas generation, and eventually nuclear and other reliable sources.

Yet the vast amount of the new generation that is in line today to connect to the grid is intermittent wind and solar, which cannot be relied upon to be there when you need it the most.

As a result, half the nation is at risk of power short falls over the next ten years.

For all the benefits of all-of-the-above resource policies, the current path that incentivizes a massive renewable build out is putting the electric system out-of-balance and dramatically increasing risk.

Today, we will talk to the grid operators that are caught at the center of the clash between failing policies and strong economic demand affecting our nation's generation mix.

They must deal with the consequences, so understanding the challenges they face and how they plan to meet growing demand is essential for our work.

Last week, the Secretary of Energy noted the existential security implications of our race with China on AI and other advanced technologies.

A focus on meeting the China challenge raises serious questions about what is really necessary to clear the way in permitting and in regulatory policy, which will enable tremendous energy and power growth in the coming years.

We can start by recognizing that we are only going meet this challenge if we fully appreciate the scale and pace of change that will be necessary to ensure a reliable system in the future.

With that, I yield back.

Mr. LATTA. Thank you. The gentleman yields back.

The Chair now recognizes the gentleman from New Jersey, the ranking member of the full committee, for 5 minutes for an opening statement.

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

Mr. PALLONE. Thank you, Chairman Latta.

For the third time this Congress, we have had an important hearing focusing on the reliability and affordability of electricity in this country. And for the third time, my Republican colleagues are going to purposely ignore the fact they are attempting to repeal the single biggest incentive to build electricity capacity in this country, and that is the Inflation Reduction Act. Repealing billions of dollars in technology-neutral funding for all types of new energy is not the way to address the increasing need for energy.

It also ignores the fact that the Trump administration is freezing Federal funding and trying to rescind grants for grid reliability projects that the grid operators sitting before us today have said are vital to addressing increasing energy demand. It also ignores the fact that President Trump is attempting to put tariffs on electricity imports from Canada, which could seriously drive up energy costs for people in the Midwest and the Northeast.

It is time that we recognize that the chaotic and constantly changing policies of Trump and Elon Musk are the single greatest threat right now to grid reliability.

Just last week, yet another study came out, this time from Energy Innovation, showing that repealing the Inflation Reduction Act would increase American families' power bills. Republicans are talking about the importance of affordability, but their actions don't match their words.

Despite continued Republican attacks on our grid's reliability and affordability, today's hearing is still important. Regional grid operators play a critical role in keeping the lights on for our customers. And 27 years ago, FERC Order 888 brought competition to electricity markets around the country. Since that time, the competition encouraged by these markets has broadly lowered wholesale energy prices and made the grid cleaner, all while ensuring reliability.

But that is not guaranteed. And I am worried that some of the rules of the road that govern regional transmission organization could start to harm consumers.

Last year, partially as a result of poor market design, capacity prices in the PJM region exploded from $29 to $270 per megawatt day. And these price increases aren't abstract. They are directly responsible for roughly $25 per month increase in New Jersey power bills that my constituents will start feeling this June.

So, Mr. Asthana, I want to be clear: This is completely unacceptable. PJM's years of dragging its feet on reforming its capacity markets and interconnection queue are finally coming home to roost, but it is my constituents who are stuck paying the bill. PJM has demonstrated a complete inability to connect resources to the grid in a timely fashion. And I recognize that PJM has taken a

number of steps in the last few years to rectify this, but frankly it is too little, too late.

The years of inaction have already taken their toll. A recent report found that, if PJM had implemented proactive transmission planning and simplified interconnection processes years ago, it could have avoided half of these costs. And I am frustrated that PJM is touting its progress in connecting more energy with its grid when it still has not fully complied with FERC's requirements under Order 2023. Meanwhile, PJM is spending my constituents' rate paper dollars—ratepayer dollars, I should say—suing for over—Order 2023, creating further uncertainty for potential developers of power plants.

And, Mr. Asthana—I hope I am pronouncing it right—your organization simply must get its act together. I appreciate that PJM has introduced some short-term tweaks to its market and is working together with States, including New Jersey, to find a pathway to protect ratepayers, but this all should have been figured out years ago.

And as we continue this discussion today, it is important we recognize that, in this time of increased demand for electricity, families are increasingly at risk of their power bills becoming unaffordable. Grid operators and, frankly, FERC must remember that they have a legal obligation to ensure that their policies are just and reasonable, and anything else does a disservice to the American people who depend on you.

And with that, Mr. Chairman, I will yield back.

[The prepared statement of Mr. Pallone follows:]

Committee on Energy and Commerce

Opening Statement as Prepared for Delivery
of
Full Committee Ranking Member Frank Pallone, Jr.

Hearing on "Keeping the Lights On: Examining the State of Regional Grid Reliability"

March 25, 2025

For the third time this Congress, we're having an important hearing focusing on the reliability and affordability of electricity in this country. And for the third time, my Republican colleagues are going to purposefully ignore the fact they're attempting to repeal the single biggest incentive to build electricity capacity in this country – the Inflation Reduction Act.

Repealing billions of dollars in technology neutral funding for all types of new energy is not the way you address the increasing need for energy.

It also ignores the fact that the Trump Administration is freezing federal funding and trying to rescind grants for grid reliability projects that the grid operators sitting before us today have said are vital to addressing increasing energy demand. It also ignores the fact that President Trump is attempting to put tariffs on electricity imports from Canada, which could seriously drive-up energy costs for people in the Midwest and Northeast.

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Just last week, yet another study came out – this time from Energy Innovation – showing that repealing the Inflation Reduction Act would increase American families' power bills. Republicans are talking about the importance of affordability, but their actions don't match their words.

Despite continued Republican attacks on our grid's reliability and affordability, today's hearing is important. Regional grid operators play a critical role in keeping the lights on for their customers. Twenty-seven years ago, FERC Order 888 brought competition to electricity markets around the country. Since that time, the competition encouraged by these markets has broadly lowered wholesale energy prices and made the grid cleaner, all while ensuring reliability.

But that's not guaranteed, and I'm worried that some of the rules of the road that govern Regional Transmission Organizations could start to harm consumers. Last year, partially as a result of poor market design, capacity prices in the PJM region exploded from $29 to $270 per megawatt-day. These price increases aren't abstract – they are directly responsible for a roughly $25 per month increase in New Jersey power bills that my constituents will start feeling in June.

Mr. Asthana, I want to be clear: this is completely unacceptable. PJM's years of dragging its feet on reforming its capacity markets and interconnection queue are finally coming home to roost, but it's my constituents who are stuck paying the bill. PJM has demonstrated a complete inability to connect resources to the grid in a timely fashion. I recognize that PJM has taken a number of steps in the last few years to rectify this, but frankly it's too little, too late – the years of inaction have already taken their toll. A recent report found that if PJM had implemented proactive transmission planning and simplified interconnection processes years ago, it could have avoided half of these costs.

And I'm frustrated that PJM is touting its progress in connecting more energy to its grid when it still has not fully complied with FERC's requirements under Order 2023. Meanwhile, PJM is spending my constituents' ratepayer dollars suing FERC over Order 2023 – creating further uncertainty for potential developers of power plants. Mr. Asthana, your organization simply must get its act together. I appreciate that PJM has introduced some short-term tweaks to its market, and is working together with states, including New Jersey, to find a pathway to protect ratepayers. But this all should have been figured out years ago.

As we continue this discussion today, it's important we recognize that in this time of increased demand for electricity, families are increasingly at risk of their power bills becoming unaffordable. Grid operators – and, frankly, FERC – must remember that they have a legal obligation to ensure that their policies are just and reasonable. Anything else does a disservice to the American people who depend on you.

I yield back.

Mr. LATTA. Thank you very much. The gentleman yields back the balance of his time. And this now concludes Member opening statements.

The Chair reminds Members that, pursuant to committee rules, all Members' opening statements will be made part of the record.

We want to thank all of our witnesses for being with us today and taking time to testify before the subcommittee. Each witness will have the opportunity to give an opening statement followed by a round of questions from the Members.

Our witnesses today are Manu Asthana, the president and CEO of PJM Interconnection, LLC; Mr. Gordon van Welie, president and CEO of Independent Service Operator of New England; Ms. Jennifer Curran, the senior vice president for planning and operations at Midcontinent Independent Service Operator; Mr. Richard Dewey, president and CEO of New York Independent System Operator; Mr. Lanny Nickell, the chief operating officer of Southwest Power Pool; Mr. Elliot Mainzer, the president and CEO of California Independent System Operator; and Mr. Pablo Vegas, the president and CEO of the Electric Reliability Council of Texas, ERCOT.

Again, we appreciate all of our witnesses for being with us today. And before we get started, just a quick reminder about our light system in front of you. You will have 5 minutes to give an opening statement. At 4 minutes, you will get a yellow light, meaning you have 1 minute remaining. Red light signifies your time is up. So if you please wrap up when you see the red light come on.

Also, just pull the mike up close to you as you are speaking.

And at this time, we will begin with our witnesses that are before us today. Mr. Asthana, you have 5 minutes to give an opening statement. Thanks again for being with us today.

STATEMENTS OF MANU ASTHANA, PRESIDENT AND CHIEF EXECUTIVE OFFICER, PJM INTERCONNECTION; GORDON VAN WELIE, PRESIDENT AND CHIEF EXECUTIVE OFFICER, ISO NEW ENGLAND; JENNIFER CURRAN, SENIOR VICE PRESIDENT, PLANNING AND OPERATIONS, MIDCONTINENT INDEPENDENT SYSTEM OPERATOR; RICHARD DEWEY, PRESIDENT AND CHIEF EXECUTIVE OFFICER, NEW YORK INDEPENDENT SYSTEM OPERATOR; LANNY NICKELL, EXECUTIVE VICE PRESIDENT, CHIEF OPERATING OFFICER, SOUTHWEST POWER POOL; ELLIOT MAINZER, PRESIDENT AND CHIEF EXECUTIVE OFFICER, CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION; AND PABLO VEGAS, PRESIDENT AND CHIEF EXECUTIVE OFFICER, ELECTRIC RELIABILITY COUNCIL OF TEXAS

STATEMENT OF MANU ASTHANA

Mr. ASTHANA. Yes. Chairman Latta, Ranking Member Castor, Chairman Guthrie, Ranking Member Pallone, and members of the subcommittee, good morning. My name is Manu Asthana. I am the CEO of PJM Interconnection. PJM works to ensure the reliable flow of power to 67 million people across 13 States and DC. We serve about one in five Americans.

We are fully regulated by the FERC. As you know, FERC plays a critical leadership role in our industry. And the value of having a fully staffed, well-functioning Federal regulator, particularly at this time, cannot be understated.

We don't have a profit motive. Our core mission is grid reliability. Our work, along with that of our member companies, has ensured a strong and stable grid for almost a century since our founding in 1927.

More recently, however, we have seen three notable trends I wanted to share with you that concern us. First, dispatchable thermal generation is retiring, often driven by Federal or State policy.

Second, most of our interconnection queue is made up of intermittent renewable generation. And I want to be clear: These generators play an important role on the grid, and we want them—we want them to come online, but they are not a one-for-one substitute for the machines that they are replacing.

And finally, third, electrical demand is growing, driven primarily by data center load growth. Less supply, more demand: It adds up to increased reliability risk and higher prices. And we are seeing this across large parts of our country. This is not just a PJM phenomenon.

Our industry has been working hard on solutions. Specifically, in PJM, amongst other things, we have reformed our generator interconnection process. We had a queue of about 200,000 megawatts of generation. We have whittled that down to 67,000 megawatts, an incredible amount of progress, with another 50,000 megawatts through the queue ready to go. And, actually, parts of it have started to construct, and some has already come online. We have opened new pathways for generators to connect to the grid, and we have implemented reforms to our market rules.

And the good news is these initiatives are having an impact. I am happy to report several generators have withdrawn their retirement decisions. We have a shuttered nuclear power plant that has announced its return and is working hard to come back.

Pennsylvania's former largest coal plant is being studied to come back to life as a gas generator. Demand response providers are looking for ways to bring more supply onto the system, and developers are working hard to bring their projects to market. In fact, just last week, one of the new pathways to interconnection that I talked about resulted in 27,000—almost 27,000 megawatts of new generation applying to interconnect to PJM, which is very exciting.

But our work is not done. It still takes roughly 18 months to build a data center. Takes 5 years-plus to build a power plant. And global supply chains for grid components like transformers and turbines are backlogged.

The stakes are high, and we remain committed to the task at hand. In our opinion, we have six key areas of focus for the industry looking forward, and I wanted to share them with you.

First, we must keep the supply that we have today. More retirements are going to make it much harder for us to serve this load growth. Second, we must try to bring back what we can from retirement, whether in its current form or repowered form with a different fuel, or using those sites for different generators. Third, we need to connect new generators rapidly, and that includes upgrades

of existing generators. Fourth, we need to harness demand flexibility, which I think is a real hidden opportunity. Fifth, we do need siting and permitting reforms for generation and transmission, and we could use help with that. And, finally, more investment in natural gas infrastructure is needed to support power generation flexibility.

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

[The prepared statement of Mr. Asthana follows:]



U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON ENERGY & COMMERCE, SUBCOMMITTEE ON ENERGY

Testimony of Manu Asthana
President and CEO, PJM Interconnection

March 25, 2025

For Public Use

Introduction

Chairman Latta, Ranking Member Castor, Chairman Guthrie, Ranking Member Pallone and Members of the Subcommittee:

Thank you for the opportunity to participate in today's hearing to provide additional detail on a number of recent actions taken by PJM to help preserve electric grid reliability during a period of heavy forecasted demand growth. My name is Manu Asthana, and I serve as President of CEO of PJM Interconnection.

Based in Valley Forge, Pennsylvania, PJM ensures the reliable flow of power to 67 million customers in all or parts of 13 states and the District of Columbia. PJM has no profit motive, as it effectively functions as a not-for-profit entity that is fully regulated by the Federal Energy Regulatory Commission (FERC).

We liken our role to that of an air traffic controller, but for the electric grid. We don't own the high-voltage transmission lines that carry electricity where it is needed most, but we direct and balance the flow of that power throughout our footprint and to neighboring regions when they need it.

In addition to managing reliable operations, PJM also plans necessary enhancements to the grid to ensure reliability into the future and operates electricity markets within its region to competitively procure capacity and to efficiently dispatch resources to meet electricity demand, or load, in real time. The purpose of these electricity markets is to cost-effectively reinforce reliable grid operations.

Earlier this month, PJM's Sr. Vice President of Governmental and Member Services, Asim Z. Haque, provided testimony to this committee outlining PJM and its role while describing a number of concerning industry issues we have been voicing in recent years.

I will not reiterate every point that my colleague shared but will focus on:

- The significant new demand forecasted to enter the system, due primarily to data center proliferation but also due to expansion of the electric vehicle market, electrification of building heating systems and growth in U.S. manufacturing
- Solution-oriented actions PJM has undertaken to help bring new supply to the system and to continue to appropriately reflect supply/demand fundamentals in our market

We look forward to our continued work with this Committee and members on both sides of the aisle, and thank you for your attention and collaboration as we address these issues constructively and proactively. In addition, we appreciate the strong leadership provided by our regulator, the Federal Energy Regulatory Commission, as we move forward as an industry.

Testimony

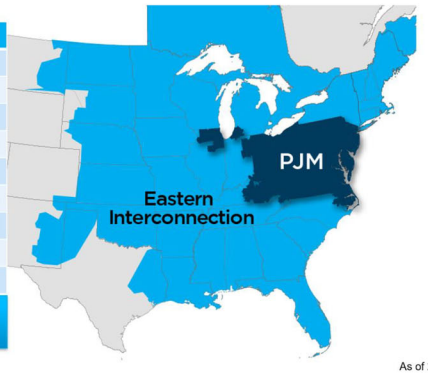
PJM and Its Role

PJM's footprint encompasses all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and Washington, D.C., as shown in **Figure 1.** As such, we are responsible for ensuring reliable and efficient delivery of electricity over the bulk electric system to one-fifth of the nation. We are fuel and technology neutral in carrying out this function, valuing resources using different fuels and technologies based on their reliability value and cost-effectiveness.

Figure 1. PJM Service Territory

Key Statistics	
Member companies	1,110
Millions of people served	67+
Peak load in megawatts	165,563
Megawatts of generating capacity	182,036
Miles of transmission lines (BES)	88,333
Gigawatt hours of annual energy	800,004
Generation sources	1,486
Square miles of territory	369,054
States served	13 + DC

- 27% of generation in Eastern Interconnection
- 24% of load in Eastern Interconnection



As of 2/2025

PJM's Operations, Markets & System Planning Have Supported Strong System Performance Over a Long History

Founded in 1927, PJM is an independent, federally regulated organization charged with undertaking three core functions:

- Real-time operation of the bulk power grid
- Market operations to ensure the most cost-effective and efficient procurement and dispatch of resources to meet customer demand
- Planning the expansion of the electric transmission system to meet future customer needs

Each of these functions operates in tandem to ensure the reliable and economically efficient delivery of electricity to the 67 million Americans we serve, not just today, but in the future.

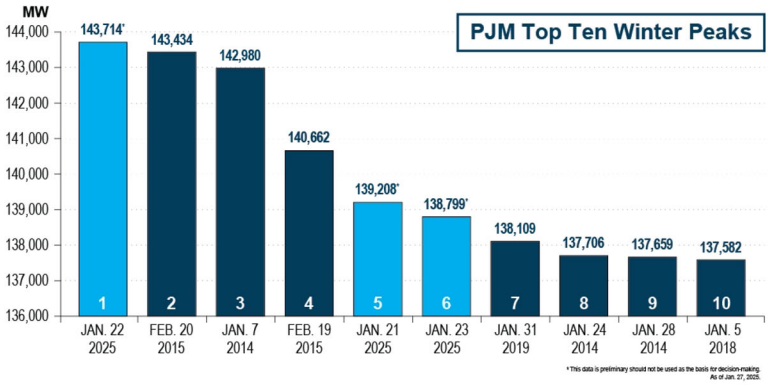
PJM's markets exist to reinforce grid reliability by ensuring that market signals work in tandem with regional reliability requirements and the standards promulgated by the North American Electric Reliability Corporation (NERC). For example, our capacity market is designed to procure resources available to meet projected peak demand and other contingencies ahead of time. Through our Day-Ahead and Real-Time energy markets, we economically dispatch the most cost-effective resources to meet the hour-by-hour demand for electricity within the physical limitations of the transmission system.

In addition, based on economics and needs, in any given hour, PJM facilitates the export or import of power to and from our interconnected neighboring systems, including: those systems to our south, such as Duke Energy in the Carolinas and the Tennessee Valley Authority; the Midcontinent Independent System Operator (MISO) to our west; and the New York Independent System Operator to our north.

Our strong interconnected ties with our neighbors have allowed us to facilitate exports to our neighbors in MISO, TVA, Duke Energy-Carolinas and the Southwest Power Pool (SPP) during tight conditions. On Feb. 21, when some of our neighbors were experiencing record electricity demand, we were exporting approximately 14,000 MW of power.

On Jan. 22, PJM itself reached a preliminary record for winter demand approaching 145,000 MW, also while supporting neighboring systems on all fronts. See **Figure 2** below. At the same time, end-use customers within the PJM region benefit from lower-cost supplies of electricity from our neighbors during other times of the year. These strong ties (which we refer to as "interregional transfer capability") help to support reliable and cost-effective operations throughout the entire Eastern Interconnection and our participation in the Eastern Interconnection also enables us to import energy from our neighbors when our system is stressed.

Figure 2. PJM Top Ten Hourly Winter Peaks

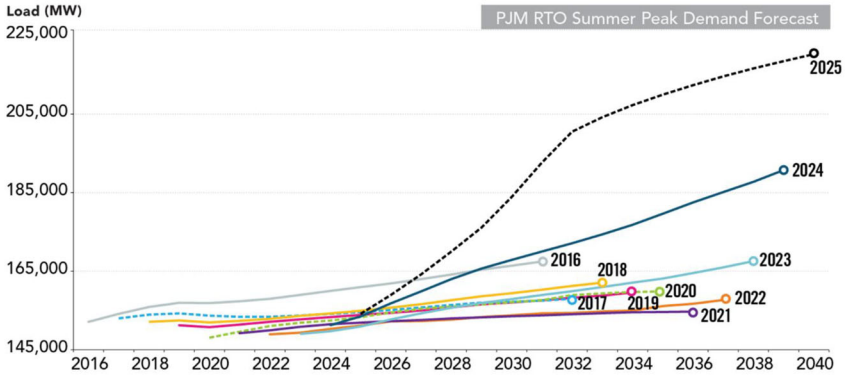


Recent Trends Have Increased Resource Adequacy Risk

PJM has analytically studied and will continue to study the impacts of the quickly changing energy landscape. Based on our analysis, we have observed several trends that, when taken together, create a growing resource adequacy concern. These trends are not limited to PJM's region – they are impacting a significant part of our country.

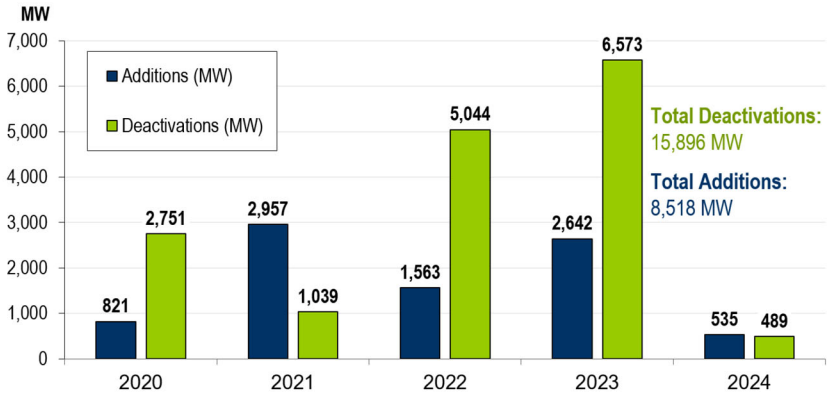
- The rate of electricity demand is anticipated to increase significantly in the future due to the development of large data centers in the PJM service area, shown in **Figure 3**. There have also been increases in demand coming from the electrification of the transportation and heating sectors and from industrial growth. After more than a decade of mostly flat demand growth, these developments are welcome because they represent economic development. PJM is focused on ways to serve this growing demand reliably.

Figure 3. PJM 15-Year Summer Peak Demand Forecast



- Additionally, the pace of retirements of existing dispatchable fossil-based resources, largely due to state and federal policies, is clearly outpacing the rate of construction of new resources, shown in **Figure 4**.

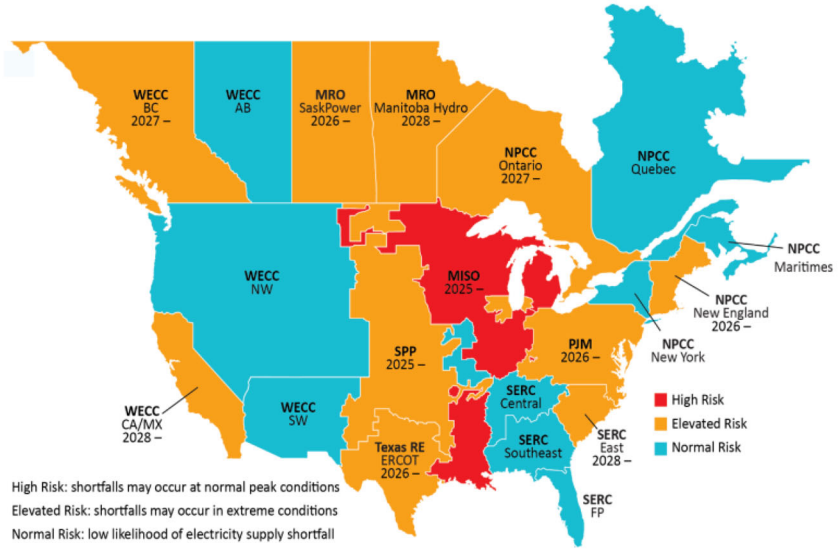
Figure 4. Deactivations and Additions – Estimated Unforced Capacity MW (Based on 2026/2027 BRA ELCC Class Averages)



- Our interconnection queues are composed primarily of intermittent renewable resources that have different operating characteristics than the generation they are replacing. Given these differences, one unit of nameplate capacity of retiring generation requires multiple units of replacement capacity. Longer duration batteries and potentially other technologies could change this equation in the future if they can become more cost-effective and be deployed at scale.

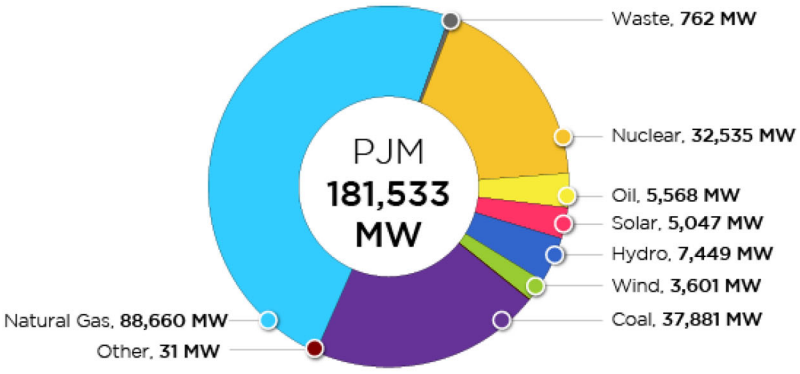
The North American Electric Reliability Corporation (NERC) recently determined in its annual assessment that mounting resource adequacy shortfalls now have the potential to affect two-thirds of the country during peak or extreme system conditions. See **Figure 5** below. NERC's independent analysis also found that while a clear understanding of many challenges facing the industry is needed to address the problem, the risks to reliability are also influenced by government policies, regulations, consumer preferences and economic factors.

Figure 5. NERC 2024 Long-Term Reliability Assessment



Fortunately, PJM has had a diversified portfolio of generation assets that have capably served to maintain grid reliability for many years, as noted in **Figure 6** below. This portfolio has been undergoing significant transition in recent years. Dispatchable generators, i.e., those generators that can quickly respond to directions from PJM operators regardless of weather, are retiring at a rapid, date-certain pace, largely due to state and federal policies. Although today the category of dispatchable generators largely refers to fossil-fuel-based resources, longer-duration batteries and potentially other technologies could also serve in this role in the future to the extent they can become more cost-effective and be deployed at scale.

Figure 6. PJM Existing Installed Capacity Mix (Capacity Interconnection Rights – as of Dec. 31, 2024)



Notably, PJM is resource agnostic and works to facilitate the entry of all resources onto the system. As demand increases, PJM will need not only a substantial amount of this mostly renewable generation currently seeking interconnection, but also additional dispatchable supply to meet our forecasted demand increases in future years.

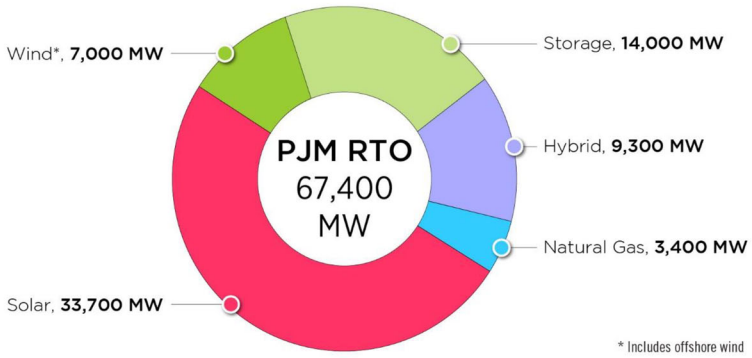
PJM and Our Members Have Taken Significant Actions To Mitigate This Risk

PJM identified this growing resource adequacy risk more than two years ago with the publication of our Energy Transition in PJM: Resource Retirements, Replacements & Risks study (PDF) and has been focused on actions to mitigate the risk. These actions include:

Significant Interconnection Process Reform: With overwhelming stakeholder support and the approval of PJM's proposal by FERC in 2022, PJM launched significant reforms that moved the interconnection process from a "first-come, first-served" system of queue management to a "first-ready, first-served" system with progress payments and milestones designed to weed out speculative projects. A current snapshot of PJM's queued capacity by fuel type is included below (**Figure 7**).

- That transition started in July 2023 and is expected to be completed next year. Currently, approximately 50 GW of generation is through the queue with completed studies, approximately 18 GW is being processed to move to the final study phase for completion this year, and an additional ~50 GW will be through the queue by late 2026. At that point, PJM's transition to our new interconnection queue process will be complete, and new projects will be studied in 1–2 years in the normal course.

Figure 7. PJM Queued Capacity (Nameplate) by Fuel Type ("Active" Projects Currently Under Study in the PJM Queue as of March 21, 2025)



Reliability Resource Initiative – A queue opened for new, shovel-ready resources that can come online quickly and that most effectively contribute to reliability.

Capacity Interconnection Rights Transfer – A reform package endorsed by PJM stakeholders and currently pending review by FERC that would facilitate an expedited interconnection process for a replacement resource seeking to use the capacity interconnection rights of a deactivating resource. Effectively, this means that a new generation resource can swap in for a deactivating generation resource at the same or similar location and, as a result, would not need to go through the generation interconnection queue (e.g., coal plant retirement and gas conversion or renewables swapping in).

Surplus Interconnection Service – This work aims to streamline the use of the unused portion of interconnection service for a facility that cannot or does not operate continuously, every hour of every day, year-round (e.g., adding battery storage to a renewable site).

Significant Investment in Interconnection Tools & Automation:

- **NextGen** – A PJM planning tool designed to further streamline the generation interconnection process by providing a comprehensive and efficient interface to track projects from application to construction.
- **Queue Scope** – Allows users to visually evaluate the potential impacts of new generation on the power grid. Integrated with the PJM system map, users can visualize how a generator impacts congestion on lines, as well as the potential transmission upgrades that would be needed to interconnect a project.
- **Queue Destination** – this helps planners build models, process generator deliverability results and automate cost allocation and reports.
- **PowerTemplate** – an automation tool that assists in the drafting of generation interconnection agreements and other legal documents.
- **InfraTrack** – a resource for managing project milestones, task tracking and invoice cost allocation.

Capacity Market Reforms To Ensure Market Prices Accurately Reflect Supply – Demand Conditions:

- **Must-Offer Requirements** – Reforms meant to more accurately reflect the actual quantity of existing generation capacity resources, while continuing to safeguard against the potential exercise of market power that may be exerted by the withholding of such resources. The changes should result in additional resources being offered in PJM's upcoming capacity auction.
- **Reliability Must-Run Resources and Cost of New (Generation) Entry** – Reforms designed to recognize the capacity contribution of qualifying Reliability Must-Run units that may be expected to perform during capacity emergencies for the 2026/2027 and 2027/2028 Delivery Years. Reliability Must-Run units are generators that are asked to remain operating for a limited time beyond their intended retirement date to maintain system reliability.

These Actions Are Having an Impact

Collectively, the various proposals and reforms that PJM have pursued are making a difference as they are rolled out and implemented. When our queue reforms were implemented in the middle of 2023, PJM had approximately 253 GW of projects under study. That number has decreased substantially and will continue to decrease with remaining projects processed through the queue by next year. Meanwhile, newly approved programs, including PJM's Resource Reliability Initiative and Surplus Interconnection Service can also serve to add needed generating capacity and transmission capacity on the system.

In fact, PJM's Reliability Resource Initiative has attracted 94 completed applications (47 for uprates to existing facilities and 47 for new generation) totaling 19.9 GW of unforced capacity and 26.6 GW of nameplate capacity. PJM will now use a FERC-approved rating process to select up to 50 projects to provide a one-time influx of reliable generation that is needed to meet demand over the next decade as PJM continues to integrate intermittent resources like wind and solar onto the grid.

Additionally, since the beginning of last year, 1,100 MW of existing generation chose to remain as supply resources in PJM after previously submitting a notice to retire. With tightening supply conditions, we encourage all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability. Moreover, PJM also supports efforts to redevelop new units or restart existing units at the sites of former generating facilities. Examples include the proposal to convert the former coal-fired Homer City Generating Station in Pennsylvania to a new natural gas-fired facility. Similarly, a proposal to reactivate the former Three Mile Island Nuclear Generating Station (Unit 1) in Pennsylvania will contribute more than 800 new megawatts to the grid at a period when demand for electricity is projected to increase dramatically.

Recommended Ongoing Areas of Focus

Looking forward, PJM has identified a number of key areas of focus that will be important to support system reliability and resource adequacy:

1. Keep the resources we have online – We need existing generation to remain in place in support of reliability while we continue to integrate new resources on to our system.
2. Retirement reversals – We have seen a good deal of action on this front in recent months, and we are hopeful that this trend will continue given our market reforms.
3. Continue to automate the interconnection process using new tools with a focus on moving projects to construction and operation more quickly; in the near term, expand the addition of "shovel-ready" projects through the Reliability Resource Initiative.
4. Increase opportunities for demand flexibility, including potentially by finding more ways to access backup generation on site at large loads when the grid needs it most.
5. A continued focus on siting and permitting reforms to expedite the construction of new generation and transmission infrastructure.
6. Support additional investment in natural gas infrastructure (e.g., pipeline infrastructure) to enable more flexible operations of existing and new gas generators.

I thank you for the opportunity to present my testimony today. I look forward to your questions.

Mr. LATTA. Well, thank you very much for your opening statement.

Mr. van Welie, you are now recognized for 5 minutes for your opening statement.

STATEMENT OF GORDON VAN WELIE

Mr. VAN WELIE. Good morning, Chairman Latta, Ranking Member Castor, Chairman Guthrie, Ranking Member Pallone, and members of the subcommittee. Thank you for the opportunity to appear here today.

Like other regions, New England's electric system is undergoing an energy transition. Historically, power system planning has focused on having enough resources. We refer to this as resource adequacy. However, as we transition to more weather-dependent resources, one of the biggest challenges facing New England is making sure that there is sufficient energy in the system to meet expected electricity growth.

The wholesale markets run by ISO New England effectively price supply-and-demand conditions, providing important signals to developers when investment is needed. However, the wholesale markets alone cannot assure resource adequacy. State and Federal policies also play a key role in achieving regional resource adequacy.

While the wholesale markets operate on shorter timeframes, the States have the ability to structure longer-term commitments, through various hedging strategies, to incentivize to develop the sufficient resources to meet the resource adequacy standard that is priced in our capacity market. Moreover, the States have the ability to address barriers to entry for resources participating in wholesale electricity markets. These longer-term commitments can also protect consumers against price volatility in both the energy and the capacity markets.

In short, the ISO and the New England States have a joint and complementary role in achieving resource adequacy. Furthermore, investor confidence in the wholesale markets is dependent on a supportive policy and regulatory framework at both the State and the Federal level.

As a region, New England has made progress in evolving the market design to align with the resources that are coming forward. We are implementing new approaches to plan the transmission system to meet the States' policy objectives, and we have new tools to help us better quantify our reliability risks in a rapidly changing power system across the region.

Incentivized by State policies, the region has invested heavily in energy efficiency and behind-the-meter solar resources, which have effectively reduced demand for electricity from the grid operated by us in New England. These investments, coupled with relatively little interest from data centers and other AI-driven activities, has meant that New England has thus far not seen the rapid growth in consumer demand forecasted in other regions.

The reliability and market outlook for the near term is favorable, though potential challenges lie ahead. Our latest 10-year forecast projects regional electricity consumption will increase by about 17 percent over the next decade. It remains to be seen whether that

load growth will outpace the net effect of generator retirements and new supply coming online.

It is difficult to build new grid-scale energy infrastructure in New England. And recent developments give us cause for concern about the region staying on pace with maintaining resource and energy adequacy as load grows. This may have implications towards the end of this decade.

Due to recent Federal executive actions, New England is facing new uncertainty about the timing of offshore wind development, which has been planned as a major new domestic source of energy for our region.

As of January, battery storage and wind resources make up the largest proposals in our interconnection queue at 47 percent and 45 percent, respectively. There are currently no other categories of resources proposed at that scale. And this could have implications in both the near and the short term.

The current deliberations about new tariffs on imports have the potential to affect not only the price of electricity in New England but also the availability of power to New England from our long-standing electricity trading partners in eastern Canada. This could also have implications in both the near and the long term.

As demand grows for electricity in New England, the region will need new resources to meet resource adequacy needs, and it will be critical to ensure that we have a supportive policy and regulatory framework in place to allow for the entry of those resources.

Thank you.

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

GORDON VAN WELIE, PRESIDENT & CEO, ISO NEW ENGLAND

BEFORE THE HOUSE ENERGY & COMMERCE COMMITTEE

SUBCOMMITTEE ON ENERGY

TUESDAY, MARCH 25, 2025

Chairman Latta, Ranking Member Castor, Chairman Guthrie, Ranking Member Pallone, and Members of this Subcommittee, thank you for the opportunity to appear before you today.

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

About ISO New England

ISO New England is the independent, not-for-profit corporation responsible for operating a competitive wholesale electricity market across the six New England states and we plan the transmission system to ensure that it can meet the future demand for electricity in the region. Our job is to reliably plan and operate the power system to meet reliability standards set by the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC).

Focus of this testimony

My testimony will briefly describe New England's current energy situation and the outlook for the changing resource mix, the growth of electricity demand, and the impacts for reliability and the wholesale markets.

Resource adequacy is a big challenge for grid operators

Like many other parts of the country, New England's electric power system is undergoing an energy transition. Historically, power system planning has focused on having enough resources; this is referred to as "resource adequacy." However, as we transition to more weather-dependent resources, one of the

biggest challenges facing ISO New England is making sure there is sufficient *energy* in the system to meet expected electricity growth.

As we navigate this rapidly changing landscape, ISO New England remains committed to working with policymakers like yourselves, the Federal Energy Regulatory Commission (FERC), the New England states, and our stakeholders to ensure a reliable grid today and into the future.

Important roles for ISO New England and the states in ensuring resource adequacy

The wholesale markets administered by ISO New England are effective at pricing supply and demand conditions in both the energy and capacity markets, and this provides important signals to developers when investment is needed. However, the wholesale markets alone cannot ensure resource adequacy. The states also play key roles in achieving regional resource adequacy.

ISO New England, under the jurisdiction of the FERC, has responsibility for major aspects of designing the markets and planning the transmission system. We plan the transmission system for the long term, but our wholesale markets are essentially short-term "spot" markets. The states, in comparison, have the ability to structure longer term commitments (through various hedging strategies) to protect consumers against undue price volatility in both the energy and capacity markets, and to incent the development of sufficient resources to meet the resource adequacy standard that is priced in the capacity market. Moreover, the states have the ability to address barriers to entry for resources participating in wholesale electricity markets.

In short, the ISO and the states play a joint and complementary role in ensuring resource adequacy. Finally, it is vitally important that there is collaborative support from both federal and state regulators for New England's chosen resource adequacy construct, i.e., the capacity market. This is fundamental to ensuring regulatory certainty for investors in the market.

Our changing resource mix

Over the past 20 years, New England has seen a dramatic shift in our region's energy mix as oil and coal generators have been replaced by natural gas-fired generation. Those impacts can be seen in our energy mix today. On an annual basis, more than 50 percent of New England's electricity is generated using natural gas and only a fraction of a percent using oil and coal. This trend can flip in cold weather, however.

Particular challenges for New England in the winter

During extended periods of cold weather in New England, the gas pipelines are not capable of serving the coincident peak demand for gas from heating customers and power generation. The physical constraints on the gas pipeline infrastructure drive gas prices higher, resulting in the region shifting from using pipeline gas to oil and liquified natural gas (LNG). Moreover, due to the limitations imposed by the Jones Act, the region is unable to import LNG from domestic sources and instead relies on shipments from outside the United States, which are priced at global LNG prices. These factors are significant contributors to the region's vulnerability to high natural gas prices and wholesale electricity prices in the winter.

Regional benefits of state incentives for energy efficiency and solar

Incentivized by state policies, the region has also invested heavily in energy efficiency and behind-the-meter solar resources, which have effectively reduced demand for electricity from the grid operated by ISO New England. These investments, coupled with relatively little interest from large loads from data centers and other AI-driven activities, has meant New England has thus far not seen the rapid growth in consumer demand seen in other regions.

New England states continue to pursue a transition to non-carbon emitting resources

The New England states are contracting for, or incentivizing, the development of large amounts of non-carbon emitting resources. Their objective is to decarbonize the power system and power the transportation and heating sectors of the economy with electricity. In particular, the states are incentivizing the development of wind and solar to reshape our region's energy mix, and batteries to store surplus wind and solar energy and help displace fossil fuels during periods when wind and solar cannot produce.

The states have centered much of these efforts around offshore wind, as it is the largest source of carbon-free energy potential in the region. New England has long been challenged by our location at the end of the energy pipeline, but the states have sought to take advantage of the vast offshore wind potential that is right at our doorstep. Offshore wind resources can be a strong and steady source of energy that is injected directly into major load centers in New England, and their production profile during the winter is helpful for offsetting the effects of the constraints on the gas pipeline system.

Forecast for load growth

As I mentioned previously, state investments in energy efficiency and behind-the-meter solar have slowed demand growth in New England over the past decade. We do, however, expect this to change as policies aimed at electrifying the heating and transportation sectors take effect.

Our latest 10-year forecast projects regional electricity consumption will increase by about 17% over the next decade, driven primarily by the states' policies supporting electrification of heating systems and transportation.

Need for a robust transmission system

To support the states' policy goals and address demand growth, our region will also need a robust transmission system capable of integrating renewable resources and moving the electrical energy to New England's consumers.

During my last appearance before this subcommittee in 2023, I spoke to the findings of the ISO's 2050 Transmission Study, which offered an overview of the regional transmission system investment needed into the middle of the century to ensure reliability. Since then, the ISO has been working with the New England States and our stakeholders to issue a first-of-its-kind regional solicitation under the region's new longer-term transmission planning (LTTP) process.

In December, the New England States Committee on Electricity's (NESCOE) put forth the requirements for the Request for Proposal (RFP), guided by the ISO's 2050 Transmission Study findings, which are focused on relieving future transmission bottlenecks between northern and southern New England. This month, ISO New England posted a draft of the 2025 Longer-Term Transmission Planning RFP for stakeholder comment.

This longer-term transmission planning effort is an example of the ongoing partnership between the ISO and the New England states to ensure a reliable power system for our region.

New resources under development

As the market administrator, ISO New England does not plan the resource mix or contract for new resources. We do not pick or choose resources. The markets are open to all resources that can provide the services we need for a reliable system. However, states have the ability under the Federal Power Act to select specific resources and shape the overall energy mix.

As I mentioned, the New England states have identified offshore wind as a major resource that can be developed in our region and they have made major commitments to developing wind resource and the land-based infrastructure and human resources to support the offshore wind industry.

The ISO's generator interconnection queue reflects the impact that state policies are having on the future energy mix.

As of January, battery storage and wind resources make up the largest proposals in the interconnection queue (at 47% and 45% respectively). Grid-scale solar is a relatively small, but growing, component of new generation proposals (at 8%).

While the interconnection queue is an indicator of developer interest, not all projects that enter the queue are completed. Recently, project developers have announced delays to development of major wind farms off the coast of Massachusetts and Rhode Island. There are currently no other categories of resources proposed at that scale.

Key projects: market reforms and new modeling tools

As the region's power system continues to evolve, ISO New England has initiated several key projects to enhance the functions of our markets and our ability to conduct risk assessments, both of which will help to strengthen the reliability of New England's grid.

In February 2024, we announced reforms to our capacity market to transition from procuring an annual capacity product on a three-year forward basis to procuring capacity on a seasonal basis and closer to the timeframe when it will be needed. As part of these reforms, ISO New England has also initiated a resource capacity accreditation project to better reflect each resource's contribution to system reliability during stressed grid conditions. These enhancements will help ensure that resource operating characteristics and seasonal capabilities are more accurately accounted for in our markets.

ISO New England has also created a Probabilistic Energy Adequacy Tool (PEAT) to evaluate the operational impacts of extreme weather events. As I previously testified, the ISO worked with the Electric Power Research Institute (EPRI) to conduct a probabilistic energy adequacy study for New England that provides a framework to assess risks associated with extreme weather events. The study tool provides an early warning system to inform the region on the magnitude of these risks and provides a basis for developing solutions. Using this tool, we have been working with regional stakeholders to establish a Regional Energy Shortfall Threshold (REST) that determines the acceptable level of reliability risk. Once established, we can evaluate if meeting the REST requires the development of specific regional solutions, which could range from market designs to infrastructure investments to dynamic retail pricing and price responsiveness by end-use consumers.

When I testified before this subcommittee in September 2023, I shared the risk assessment that we developed for our region using PEAT. While there are some new variables, much of that analysis holds true to this day.

Results of probability assessments

The short-term risks are manageable, but there are greater risks in the longer term. The biggest long-term risk would be if the region could not maintain sufficient resource or energy adequacy to meet growing demand for electricity. These longer-term risks could be caused by the rate of electrification outpacing the addition of new resources, existing generators retiring prematurely, or the imposition of additional constraints on the operation of existing generators fueled by oil or gas.

Factors that could affect reliability risks

Significant constraints on existing resources and barriers to entry for new resources, as well as rapid acceleration in load growth (from electrification, AI, or other sources), could elevate reliability risks in

our region. While New England currently has a modest amount of surplus generation, the situation could become untenable if generators were to retire prematurely, or if electricity demand were to grow much more rapidly than the pace at which new resources come online.

New England has been counting on offshore wind as a major new source of energy and our studies have shown substantial reliability benefits of offshore wind, primarily because it delays or displaces the consumption of gas and oil so that it will be more available in the subset of high demand periods when the wind does not blow. (When a proposed resource has a signed contract or is a winner in a state-sponsored RFP, our practice is to include it in the resource base case for our studies.) The region has two offshore wind projects nearing their in-service dates. However, for a variety of reasons, additional offshore wind development in New England is facing new challenges and could potentially be delayed. If the large amount of offshore wind that has been contracted for by the states is significantly delayed or ultimately does not materialize, the region would need to assess the potential impacts and determine what other options might be needed to meet resource adequacy needs in the future.

I also mentioned how federal and state policies have historically impacted our regional energy mix.

Over the past few weeks, we have seen firsthand the impact that shifts in federal policy can have on our region. In January, the Trump Administration announced it was suspending federal offshore wind leases and permitting pending an environmental and economic review of those projects. In February, the Trump Administration announced an across-the-board 25% tariff on Canadian imports, with a lower 10% tariff for energy resources. Based on legal precedent, we do not believe the tariffs placed on Canadian imports apply to electricity, but uncertainty remains about whether that is the case.

Potential impact of new tariffs on imports

New England has historically been a net importer of electricity via interconnections with neighboring power systems in New York, Quebec, and New Brunswick. Since 2020, net imports into New England have supplied between 9% and 21% of our electricity needs. A new transmission tie into New England from Quebec, known as the New England Clean Energy Connect (NECEC), is under construction and would allow the region to import an additional 1,200 MW of hydropower from Canada. While the applicability of potential new import tariffs to electricity remains unclear, we anticipate that if tariffs were implemented on Canadian electricity there would be an impact on wholesale prices. The extent of the impact would depend on several factors, including the level of imports, whether those resources are setting market prices, and the terms of any long-term contracts. If the electricity were to stop flowing from Canada, it could present reliability problems depending on the time of year, demand levels and resource mix on the New England system.

Conclusion

As a region, New England has made progress in evolving the market design to align with the resources that are coming forward. We are implementing new approaches to plan the transmission system to meet the states' policy objectives. And we have new tools to help us better quantify reliability risks in a rapidly changing power system. The reliability and market outlook for the near term is generally favorable. Nevertheless, other serious challenges lie ahead.

It remains to be seen whether load growth will outpace the net effects of generator retirements and new supply coming online. This will have implications for the end of the decade.

Due to recent federal executive actions, New England is facing new uncertainty about the prospects for offshore wind, long viewed as an abundant, domestic source of energy for our region. This could have implications in both the near and long term.

The current deliberations about new tariffs on imports have the potential to affect not only the price of electricity in New England, but also the availability of power to New England from our long-standing electricity trading partners in Eastern Canada. This could have implications in both the near and long term.

As demand for electricity in New England grows, the region will need new resources to meet resource adequacy needs. It will be critical to ensure that we have a policy and regulatory framework in place that will allow for the entry of those resources.

Thank you.

SUMMARY OF ISO-NE TESTIMONY

- The ISO projects the region will have adequate resources in the near term, but we have concerns about the end of the decade due to the uncertainty around load growth and resource retirements and the entry of new resources.
    - The region, and the ISO, are counting on the addition of large quantities of offshore wind to maintain resource and energy adequacy. If the large amount of offshore wind that has been contracted for by the states is significantly delayed or ultimately does not materialize, the region would need to assess the potential impacts and determine what other options might be needed to meet resource adequacy needs in the future.
    - Our latest 10-year forecast projects regional electricity consumption will increase by about 17% over the next decade, driven primarily by the states' policies supporting the electrification of heating systems and transportation.
- The ISO and the states have a joint and complementary role to play in achieving resource adequacy:
    - The ISO needs to design and implement effective market designs to produce efficient pricing/incentives to retain and develop resources and ensure that the transmission system is robust (including implementing interconnection queue reforms).
    - The states, in comparison, can structure longer term commitments (through various hedging strategies) to protect consumers against undue price volatility in both the energy and capacity markets, and to incent the development of sufficient resources to meet the resource adequacy standard that is priced in the capacity market. Moreover, the states can address barriers to entry for resources participating in wholesale electricity markets.
- The ISO is working on reforms to the capacity market and has implemented a sophisticated set of tools to monitor resource and energy adequacy, so that the region has forewarning of resource and energy adequacy risks as the system involves. This will serve to inform the market and the states on these risks.
- The ISO is working on a longer-term transmission planning effort with the New England states focused on relieving future transmission bottlenecks between northern and southern New England. This is an example of the ongoing partnership between the ISO and the New England states to ensure a reliable power system for our region.
- Tariffs on imports will likely raise prices (in some form) and if Canadian imports were to be completely curtailed that could create bigger concerns for reliability.

Mr. LATTA. Well, thank you very much for your statement.

And, Ms. Curran, you are recognized for 5 minutes for your opening statement.

STATEMENT OF JENNIFER CURRAN

Ms. CURRAN. Thank you.

Good morning, Chair Latta, Ranking Member Castor, Chairman Guthrie, Ranking Member Pallone, and members of the subcommittee. I am Jennifer Curran, vice president of operations and planning for the Midcontinent Independent System Operator, or MISO, as we are more commonly known. It is a pleasure to be here today as you consider the state of regional grid reliability and its impact on our Nation. I hope MISO's experiences and insights will be helpful as you continue your work on this.

MISO serves over 45 million customers in a territory that spans all or part of 15 States. We created in 2024 alone $5 billion in value for the region. That in turn has an impact on cost for consumers in the region.

Unlike some other RTOs, in MISO our utilities and load-serving entities are the ones with the responsibility for resource adequacy. We work closely with them to ensure that there is an accurate picture of the evolving and current resource risks that exist, so that as they make their investment decisions they can be better informed.

We are fuel-source and policy neutral in MISO. That means we do not advocate, prefer, or favor any kind of fuel type or electric policy. Instead, we work to implement State and Federal policies and the goals and objectives of our members. That doesn't mean, of course, that we are disinterested observers. Reliability of the bulk electric system is our mission, and that is the topic today.

And as we consider the energy landscape, I think we have already talked about a number of the factors, and MISO is no different. We see rapid retirement of existing resources, significant growth of noncarbon-emitting resources, many of which do not have the same attributes in terms of duration of operation as those retiring resources, and, of course, load growth driven not just by data centers but also the reshoring of manufacturing into the U.S.

We have been following and working to get ahead of these issues for a number of years through an initiative we call the Reliability Imperative. Over the last several years, we have made a number of changes, including instituting changes to how we accredit generation resources. That is how we determine how they will perform during those most high-risk hours and gives us all a more accurate picture of the resource adequacy picture.

We are updating our markets, things like market pricing signals to ensure that we are sending the right signal to incent generation output during the times of the tightest operating conditions.

Over the past few years, we have approved over $30 billion of new regional transmission lines that will substantially improve electric transfer capability across the region and ensure electric reliability and the associated economic growth.

We, like others, have instituted a number of improvements to the generator interconnection queue process to hasten the approval of generation. And we are currently seeking approval at FERC for

something we call the Expedited Resource Addition Study. That study is a temporary framework to provide an ability to expedite certain new-generation projects that are desperately needed to meet resource adequacy and reliability risks.

But much more work remains to be done. One of the easiest approaches is to slow down the retirement of the existing resources. We need to keep as many of the resources as we have online until adequate replacements are in place to ensure that we are able to continue to provide customers 24 hours a day, 7 days a week, 365 days a year.

But that doesn't mean we can slow down investment in new infrastructure. We need to continue at a very rapid pace the development of new-generation resources of all types to serve that growing electricity need, and we need to ensure that we are investing in the transmission assets that are needed to deliver that energy to where it is needed.

Finally, we need to continue to work on process reforms to ensure that our markets and planning processes enable the changes to meet the changes we need in the future. Things like the Expedited Resource Adequacy Study that I mentioned, things like ensuring that we have the right accreditation for demand side and other resources, the addition of market products and the like are all going to be important to our future.

MISO's extensive analytical work and operational experience make it clear that no single electric-generating resource type, transmission line, new technology, or process change is going to solve all of our problems on its own. It is a multifaceted problem that is going to take a coordinated approach that leverages all of these tools.

I appreciate your attention to these vital issues, and I look forward to working with Congress and Federal and State regulators to ensure a reliable electric system.

[The prepared statement of Ms. Curran follows:]

Testimony of Jennifer Curran

Senior Vice President, Planning and Operations

Midcontinent Independent System Operator, Inc. (MISO)

Before the House Committee on Energy and Commerce,
Subcommittee on Energy

" Keeping the Lights On: Examining the State of
Regional Grid Reliability."

March 25, 2025

Executive Summary

Today, several factors produce rising electricity resource adequacy and reliability concerns across the country, creating a complex policy landscape:

- Growing electric demand from continued electrification, a resurgence in manufacturing, and energy-hungry data centers to support artificial intelligence.
- The accelerated early retirement of existing electric generation.
- The growing preference for low or no carbon emission resources that often do not have the 24/7 availability, flexibility, and duration attributes of the power plants they are replacing.
- More frequent occurrences of extreme weather, particularly winter storms affecting large areas of the country, are creating challenging operating conditions.

For several years, MISO has been taking action through its ongoing Reliability Imperative initiative to help address these growing challenges. For example:

- Electric resource accreditation reforms to better identify a resource's ability to perform during hours of highest risk and updated real-time pricing signals to better incentivize availability during tight operating conditions.
- Over $30 billion in new transmission lines to substantially improve electric transfer capabilities and ensure electric reliability and associated economic growth.
- Improvements to the generator interconnection queue process to expedite the approval of new electric generation on the system.

More work remains to be done to ensure that our nation's bulk electric system remains reliable:

- Let reliability needs help inform the pace of retirement of existing electric generating resources, ensuring they aren't retired before adequate new electric generation is available.
- Continue developing new electric generation resources and transmission projects at a rapid pace; mitigate the regulatory, supply chain, and other challenges that hinder development.
- Leverage an approach that includes a mixture of present and new thermal resources as well as solar, wind, storage, emerging technologies, and transmission to achieve reliability.
- Support reforms, like MISO's Expedited Resource Adequacy Study and Demand Response and Emergency Resource reforms, that enhance the utilization of existing resources.

Introduction

Good morning Committee Chairman Guthrie, Ranking Member Pallone, Subcommittee Chairman Latta and Ranking Member Castor, and members of the Subcommittee. I am Jennifer Curran, Senior Vice President of Planning and Operations for the Midcontinent Independent System Operator (MISO). It is a pleasure to be here today as you consider the state of regional grid reliability and its impact on our nation. I hope MISO's insights and experience will be useful to your work of shaping U.S. energy policy.

MISO Overview

Before I share MISO's insights on some of the challenges facing our nation's bulk electric system and MISO's work to stay a step ahead of these challenges, I would like to provide a brief overview of MISO and our work.

MISO is a 501(c)(4) not-for-profit social welfare organization with an obligation to act in the public interest. MISO is responsible for ensuring the reliability of the high-voltage electric transmission system to deliver low-cost wholesale energy to consumers. The Federal Energy Regulatory Commission's (FERC) Order 2000 established Regional Transmission Organizations (RTOs), like MISO, to be independent entities that plan and operate the electric grid on a regional basis to maintain reliability and maximize efficiency. MISO was the first Independent System Operator to be recognized as an RTO, receiving FERC approval in 2001.

The wholesale electricity markets MISO manages are the largest in North America in terms of geographical scope, serving about 45 million people across all or parts of 15 states, stretching from the Canadian border to the Gulf Coast. The pricing rules in the MISO market are designed to reinforce the reliable operations of the bulk electric system. MISO's energy markets are also among the largest in the world, with more than 550 market participants and $40 billion in annual gross market charges. MISO also serves as the reliability coordinator for the Canadian province of Manitoba.

Currently, the MISO market region contains about 77,000 miles of high-voltage transmission lines and 203 gigawatts of electric generating capacity. MISO does not own any of these assets. Instead, with the consent of our 223 members and in accordance with our FERC-regulated tariff, MISO exercises functional control over the region's transmission and generation resources with the aim of utilizing them to ensure reliability in the most cost-effective manner possible. MISO has a robust and strong stakeholder process that allows asset owners, state regulators, load-serving entities, and end-use customers to provide input and guidance to MISO on a regular and ongoing basis.

The MISO region predominantly consists of vertically integrated utilities with responsibility for providing adequate electric generation to meet needed load for their area and states having jurisdiction over electric resource adequacy decisions. This is distinct from many other RTOs, which rely more heavily on competitive markets to shape electric resource adequacy needs. MISO works with the states, utilizing its regional perspectives and insights, to ensure they have an understanding of evolving system needs and conditions.

MISO puts a priority on maintaining our independence from individual market participants. We are fuel source and policy neutral, meaning we do not favor, prefer, or advocate any particular fuel or policy outcome. That doesn't mean, however, that we are disinterested observers. Our mission is to ensure the continued reliability of the bulk electric system.

MISO also creates significant value for the region, which is quantified in the MISO Value Proposition study. Our work to maintain reliability, administer wholesale markets and conduct transmission planning on a regional scale generates substantial benefits. In 2024 alone MISO created approximately $5.1 billion in savings for the region, and over $50 billion since 2007. Ultimately, this results in lower costs to consumers.

Electric System Challenges

Electricity plays a vital role in the lives of all Americans, and its importance is continuously growing. To ensure that our nation's bulk electric system remains reliable in our ever-changing world, it is important to recognize and stay ahead of the challenges and trends that could impact

electricity. Today, the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth.

Driven by a combination of state and federal policies and consumer demand for carbon free energy, the MISO region is experiencing a rapid growth of wind and solar energy accompanied by the retirement of many coal and natural gas power plants. While weather-dependent resources like solar and wind are being added in large numbers and provide many benefits, including lower electricity production costs than natural gas or coal and lack of carbon emissions, they typically do not provide the 24/7 availability, flexibility, and duration attributes of the retiring power plants they are replacing. For example, MISO has experienced 11 wind droughts – extended periods of time with extremely low wind output – since 2020, including one lasting 40 consecutive hours. Similarly, solar output is dramatically reduced in overcast or cloudy weather conditions, as often occur in winter storms, and output is virtually zero in the overnight hours.

In order to understand potential impacts of a changing generation mix, MISO compiles our individual member plans and state policies. MISO then uses this information to develop a range of expected outcomes we call Future Planning Scenarios. MISO's Future Planning Scenarios estimate that while the total amount of installed electric generation will increase significantly over the next 20 years due to the rapid growth of wind and solar, the actual amount of electricity available to the system during critical hours could decline by about 32 GW due to the operational characteristics of these new resources. Emerging technologies with the needed characteristics, such as longer-duration battery storage and small modular nuclear reactors, hold great promise in the future but are likely years away from grid-scale viability.

We must also recognize that the existing electric transmission infrastructure is inadequate to meet future needs. It cannot carry the amount of energy that will be needed in future years, nor does it provide the connectivity to move energy from increasingly widespread generation fleets to population centers. It is notable too that approving and building new high-voltage transmission lines is a complex and lengthy process.

MISO's region, like most of the country, is also experiencing changing weather patterns, including more frequent occurrences of extreme weather, particularly winter storms affecting large areas of the country. These extreme weather events create challenging operating conditions, with high demand for electricity sometimes accompanied by reduced solar or wind output and, in some instances, challenges with adequate fuel supplies for natural gas and coal power plants. This highlights the need for a diverse electric generation fleet and a robust transmission system to move energy over long distances.

Finally, demand for electricity is growing at an accelerated pace. Over the last few decades, we have experienced growth in electrification through electronic devices, smart home products, and electric vehicles, but minimal growth in electric demand, largely due to increasing energy efficiency. Looking ahead, however, we expect much stronger growth from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence. In fact, based on the current trajectory, electric load in the MISO region is projected to grow by approximately 60% over the next 20 years, threatening to outpace new electric resource additions if urgent action isn't taken.

This combination of factors significantly increases operational challenges, uncertainty, and reliability risks to the electric grid. This, in turn, creates significant economic and security risks for our nation. If electricity production and delivery from all sources cannot keep up with growing demand, then the planned growth of manufacturing, artificial intelligence, and data centers cannot occur. A timely and coordinated approach is necessary if we are to continue meeting the nation's need for reliable and low-cost electricity.

Opportunities and Work-in-Progress

MISO continuously works with its members and states to gain a more accurate understanding of future electricity needs and timelines. Two of our most important tools are the Futures Planning Scenarios, which are MISO projections capturing a range of potential system conditions over a 20-year horizon, and the annual Organization of MISO States and MISO survey, a voluntary survey of generation owners to assess available resource capacity to serve the projected load over the next five years. These regularly updated studies provide the basis for long-term transmission

planning efforts and help inform the electric resource planning decisions, which are the purview of the states and utilities in the MISO region.

MISO's extensive analysis and operational experience make it clear that no single electric generating resource, transmission line, process improvement, emerging technology, or other solutions will solve all our challenges. Addressing our nation's future electricity needs requires a multi-faceted and coordinated approach that leverages all of these tools.

Improving existing market and operations processes and tools is a cost-effective and timely way to improve reliability in an efficient manner. Over the last few years MISO instituted, with FERC approval, electric resource accreditation reforms to better identify their ability to perform during hours of highest risk, and recently submitted a filing to update its shortage pricing to better incentivize electric resource availability during tight operating conditions. Looking ahead, MISO is currently working with its stakeholders to update the framework governing the usage of Demand Response and Emergency Resources to improve the ability of those existing entities to support system reliability during challenging operating conditions.

Other efforts include working to maximize electric flows on existing transmission lines, which can be enabled by utilizing certain grid-enhancing technologies, like advanced line ratings, that provide more accurate real-time data on the amount of electricity that can safely be transmitted without overheating a power line.

A substantial amount of new electric generation is also needed to help meet future electricity needs. While MISO supports the work of developers to continue accelerating the advancement of solar, wind, and emerging technologies, there is also a need to maintain existing and add new natural gas resources to provide flexibility and duration characteristics, thus serving as a reliability insurance policy for periods when electric demand is high and weather conditions aren't conducive to adequate solar and wind output. A growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them. This can be addressed by letting local reliability requirements determine the pace of retirement of existing power plants. Having

the right mix of resources on the system means that we don't have to choose between decarbonization and reliability.

To ensure the necessary generation is there when needed, MISO is also working to improve the efficiency and timeliness of approving new electric generator interconnections. Currently, MISO's generator interconnection queue faces a significant backlog, with over 1,600 projects totaling over 296 GW of installed capacity currently under review. For comparison, MISO's region currently has less than 1,500 generating units and peak electric load in 2024 was 122 GW. While history has shown that not all projects submitted into the queue will be built, they all must be studied for potential system impact. Currently, queue cycles are taking three to four years, as a dramatic growth in the number of project requests in recent years has exponentially increased the difficulty of the detailed studies that must be conducted. MISO has instituted several reforms to speed up the queue cycles, including a cap on the number of projects that can enter the queue in a given cycle, and is working on several technology enhancements and process improvements to eventually get to a one-year queue cycle. In the interim, an Expedited Resource Addition Study process was recently submitted for FERC for consideration. If approved, this process would provide a temporary framework, sunsetting by the end of 2028, for the accelerated study of electric generation projects that are required to address urgent resource adequacy and reliability needs. A second challenge is the long timeline required for approved electric generation projects to be built and connected to the system. Currently, the MISO region has over 53 GW of projects that have been approved but are not yet operational, and project developers have indicated that more than half of those are delayed, often due to regulatory hurdles, supply chain challenges, and labor shortages.

As electric demand grows and electric generation shifts from large power plants to more dispersed solar and wind facilities, there is also a need for significant expansion of high-voltage transmission lines. To that end, over the last several years MISO has approved over $30 billion in new transmission lines through its Long-Range Transmission Planning efforts, with more expected in the coming years. These projects are projected to have a benefit-to-cost ratio of approximately 2.6 to 1 and will substantially improve electric transfer capabilities and enable the electric reliability and associated economic growth being planned across the nation.

Interregional collaboration with neighboring grid operators – including SPP, PJM, and TVA – is also a vital tool for meeting demand for electricity. MISO and our neighbors have various operating agreements and communications protocols in place to help support one another, as feasible, for both economic and reliability purposes. Additionally, MISO and SPP have collaborated on a Joint Targeted Interconnection Queue that includes five transmission projects along the shared border that is expected to enable 28 GW of new electric generation, providing reliability and economic benefits to both regions.

Looking Ahead

The operational challenges and reliability risks of the MISO region are largely mirrored across the country. To address them, we need to take several important steps to turn around the decline in available energy and to expedite the construction of new electric generation and the transmission lines necessary to move necessary energy from where it is produced to where it is needed. Specifically:

- A strong, working Federal Energy Regulatory Commission is vital to furthering policies and supporting reforms necessary to ensure a stable and reliable electric system.

- Ensure that states and utilities have the information they need to make prudent electric resource decisions to support resource adequacy.

- Let reliability needs help inform the pace of retirement of existing electric generating resources, ensuring they aren't retired before adequate new electric generation is available.

- Continue developing new resources at a rapid pace. Streamline the approval of new electric generation and transmission projects, and work to mitigate the regulatory, supply chain, and workforce challenges that can hinder development of these projects.

- Leverage an "all of the above" approach that includes a mixture of solar, wind, natural gas, storage, emerging technologies, and transmission to achieve reliability.

- Support reforms, like MISO's Expedited Resource Adequacy Study and Demand Response and Emergency Resource reforms, that enable the more effective and efficient utilization of existing resources and capabilities.

- Continue to support and encourage interregional collaboration on future transmission needs and operational protocols that maximize the use of the existing system.

Mr. LATTA. Well, thank you for your opening statement.

And, Mr. Dewey, you are recognized for 5 minutes for your opening statement.

STATEMENT OF RICHARD DEWEY

Mr. DEWEY. Thank you, Mr. Chairman.

On behalf of the NYISO, I would like to thank Chairman Latta, Vice Chairman Weber, Ranking Member Castor, and Ranking Member Pallone, subcommittee members, staff, and all for the invitation to discuss the state of grid reliability with you today.

My name is Rich Dewey. I am the president and CEO and a 25-year veteran of the New York ISO. My full statement has been filed with your offices, but I want to share a couple of key points with you at the start here.

For the past 25 years, New York ISO has operated the New York State power system to the strongest reliability criteria in the Nation. In addition to standards enforced by the North American Electric Reliability Corporation, or NERC, we comply with standards by the NPCC, or the Northeast Power Coordinating Council, as well as the New York State Reliability Council, which is specific to New York.

We are champions of the essential role that the power grid plays in preserving the health and safety of New Yorkers, empowering our modern economy. It is our number-one priority. In addition or in filling this role, we perform essential planning studies that are continuously monitored to ensure reliability. And we administer wholesale electricity markets that allow for the most efficient scheduling and solutions to meet the reliability needs for consumers, which is a critical piece.

In New York State today—primarily driven by public policy, and like many other parts of the country—the power system is rapidly transitioning to a cleaner supply resources. This transition presents significant challenges because firm dispatchable generation, primarily powered by fossil fuels, is being replaced by intermittent wind and solar and storage resources that are dependent on the weather.

At the same time, demand is growing significantly due to the electrification of the economy and welcome economic development and manufacturing. More than twice as much legacy generation has been retired in recent years as the entry of this new supply.

In my filed comments and these remarks, I am going to highlight how our planning processes and how our markets position us to tackle these challenges.

From a planning perspective, we have a comprehensive reliability planning process that examines the future in three ways: We do a 20-year scenario-based analysis to show options of how the power system could transform over the next 20 years; we have detailed reliability studies that look for potential reliability violations over a 10-year horizon; and on a quarterly basis we do short-term assessments to allow us to rapidly react to changing conditions.

In short, we are continuously studying the reliability of the grid and are prepared to take actions when it is necessary.

Our most recent reliability study which looks at the 10-year horizon identifies reliability violations as early as 2033. Acceleration of

load growth or unplanned generator retirements could accelerate these deficiencies. Our report also highlighted the increased reliance on electricity in winter, the heightened severity of winter reliability events, the uncertainty of fuel supply, as well as the reliance on a rapidly aging generation fleet.

In order to satisfy load growth projections necessary to meet these economic factors, more generation and transmission assets are needed.

From a markets perspective, our wholesale electricity markets play a crucial role in delivering reliable outcomes and at the least production costs. Properly designed markets ensure pricing signals, attract necessary new resources to the right location, incentivize needed performance response from existing resources, and shift investment risk from consumers.

The NYISO markets optimize schedules to supply resources to maximize value to consumers, performance from suppliers, and provide the right attributes for reliability. Recent innovative market products at the NYISO encourage dynamic scheduling of reserves, encourage flexibility of load through demand response, and signal entry of distributed energy resources and energy storage that will improve the flexibility of the system. This flexibility will be crucial to manage the intermittency inherent in the grid of the future and are important components of the market.

I want to thank you for the opportunity to share these thoughts with you. I look forward to your questions and future dialogue.

Thank you.

[The prepared statement of Mr. Dewey follows:]

Draft Pre-Hearing Statement

STATEMENT OF RICHARD DEWEY

PRESIDENT AND CHIEF EXECUTIVE OFFICER

NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.

Before the

U.S. House of Representatives

Committee on Energy and Commerce

Subcommittee on Energy

"Keeping the Lights On: Examining the State of Regional Grid Reliability"

March 25, 2025

On behalf of the NYISO, I would like to thank the House Subcommittee on Energy Chairman Robert E. Latta, Vice Chairman Randy Weber, Ranking Member Kathy Castor, Subcommittee members, and staff, for your invitation to discuss the state of grid reliability and the important roles that Independent System Operators and Regional Transmission Operators play in providing reliable and cost effective electricity to consumers.

My name is Richard Dewey, President and Chief Executive Officer of the New York Independent System Operator, Inc. (“NYISO”) and I am pleased to be with you today to discuss our work maintaining power system reliability and competitive electric markets for New York.

I joined the NYISO in 2000. In my previous roles within the organization, I led the System Planning, Information Technology, and Market Structures organizations. I hold a Bachelor of Science in Electrical and Computer Engineering from Clarkson University, a Master of Science in Computer Engineering from Syracuse University, and I am a graduate of Harvard Business School’s General Management Program.

The NYISO is an independent, not-for-profit organization that began operation in 1999. We are regulated by the Federal Energy Regulatory Commission (“FERC”) under the Federal Power Act. The NYISO is responsible for operating the bulk electricity grid in New York, administering competitive wholesale electricity markets, and conducting comprehensive long-term planning for the electric power system. The NYISO, its directors, and its employees are prohibited from taking any financial interest in its market participants or the outcomes of the energy markets it oversees. The NYISO is obligated to provide open, non-discriminatory access to the electric system. We maintain a balanced, unbiased perspective on generation, transmission and demand-side resources.

For 25 years, the NYISO has operated the New York power system to the strongest reliability standards in the nation. We operate the bulk electric system in New York under standards enforced by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the New York State Reliability Council. The grid operated by the NYISO is interconnected with systems operated by ISO-New England, PJM Interconnection, the Ontario Independent Electric System Operator, and Hydro Quebec.

At the NYISO, we are champions of the essential role the grid provides in preserving the health and safety of all New Yorkers, as well as being the backbone of our economy. Since the NYISO's inception in 1999, preserving electric system reliability has been our top priority in the face of great change, whether it be societal, policy-based, or more frequent extreme weather. As older resources retire and new resources transform the way the system responds, this commitment remains.

The power system in New York, and in many parts of the country, is experiencing an unprecedented transition. New York's public policies are increasingly prioritizing clean energy production and a rapid transition away from fossil fuels. It is imperative that during this time of rapid change we maintain adequate supply necessary to meet growing consumer demand for electricity.

Competitive electric markets continue be the most powerful vehicle available to speed investment in the grid. During a time of rising interest rates, supply chain constraints, and economic uncertainty, competitive electric markets continue to provide superior cost efficiency and strong investment signals while shifting that investment risk away from the consumer.

As residents and businesses across New York become more dependent on electricity to power their lives and livelihoods, the expectation for reliable electricity will also continue to grow. And as the pace and scale of the state's energy transition accelerates, the collective efforts of all stakeholders must align. A careful and collaborative approach is critical.

To manage the challenges associated with the clean energy transition, we must keep a careful watch on how the electric system itself is reacting and responding to this change. The power system is experiencing a growing imbalance between the number of new generating facilities entering service and the retirement of traditional fossil-based resources that have powered the grid for the last several decades. Reliability of the system is showing strains under a mix of changing conditions and new pressures. Balancing the needs of grid reliability with the growing amount of weather-dependent generation and policy requirements for a just transition requires careful attention to system data and information.

The NYISO Reliability Planning Process

The NYISO evaluates the reliability implications of changes in available supply and transmission, along with projected demand, on a regular basis, conducting a variety of studies that help determine if reliability could be at risk in the future. Our Reliability Needs Assessment (RNA)

and Comprehensive Reliability Plan (CRP) and quarterly Short-Term Assessment of Reliability (STAR) analyses regularly assess the state of change on the grid and determine what new resources and transmission upgrades may be needed to maintain reliability. These reports allow the NYISO to rapidly evaluate the state of change on the grid and identify resource capability needed to maintain reliability.

The NYISO released the 2024-2034 RNA in November 2024. The report, issued biennially, highlights growing risks to electric system reliability, including projected increases in peak demand due to electrification of the transportation and building sectors; additional generator deactivations; delayed implementation of planned infrastructure projects; and extreme weather.

The 2024-2034 RNA finds that if demand on the grid grows at a rate greater than the buildout of new generation and transmission, reliability deficiencies could arise within the RNA's ten-year planning period. It also details how the advance of new technology and economic development is compounding the complexity of maintaining reliability and the combination of near-term growth in demand from data centers, semiconductor fabrication, and new manufacturing facilities highlights the challenges for grid planning over the next several years.

The RNA also shows that the early stages of the transition of the supply mix, driven by public policies, are resulting in the retirement of fossil fuel generation faster than renewable resources are entering service. This trend has led to concerns over declining reliability margins across the state — an important element for grid reliability. Since the enactment of the state's Climate Leadership and Community Protection Act, more than twice the capacity of generation has deactivated than has been added to the system. Should this trend continue, the RNA warns that additional reliability needs may be identified, both statewide and for localities. The RNA also evaluates the potential for additional retirements of gas-fueled resources in New York City, driven by state policies, that could also result in additional reliability needs without additional resources to replace them.

The potential risks and resource needs identified in the RNA may be resolved by new capacity resources coming into service, construction of additional transmission facilities, increased energy efficiency, integration of distributed energy resources (DERs) and/or growth in demand response participation.

The RNA also emphasizes the need for additional transmission infrastructure to move renewable electricity from where we expect it will be sited to where it will be needed to serve demand. Building more generation to meet growing demand alone will be inadequate to meet the needs of a modern grid — we also need to move that electricity readily around the state as consumer demand dictates. While the RNA points out the challenge with electrifying homes, buildings, and the transportation sector, adding large, new energy-intensive load will require investments in major transmission infrastructure to keep the grid safe and reliable.

The RNA also examines challenges to grid reliability of the expected transition from a summer peaking system to a winter peaking system. The assessment finds that projected increases in demand, as discussed above, pose risks to summertime reliability in the near term, which transitions to wintertime risks in the long term. A winter peaking system introduces new reliability concerns, particularly around fuel availability for gas-fired generators. The ability of the New York generation fleet to serve the increased winter demand will be more challenging if faced with a natural gas shortage. Based on a recent assessment of New York's fuel and energy security, the RNA states the following: "The NYISO will need to rely significantly on dual-fuel generation resources to support winter system reliability into the next decade and changes to the resource mix may complicate system operations during multi-day cold snap conditions. The frequency and severity of projected potential loss of load events grow over the modeling time horizon as the generation mix evolves and the demand for electricity increases."

Additionally, the RNA identifies that the increased frequency of extreme weather events poses risks to reliability. The report underscores that New York is not immune from such extreme weather, which could lead to greater electrical demand and more forced generator outages than previously accounted for in the NYISO's baseline forecasts. In consideration of these risk factors, the New York grid may be deficient in future years such that the transmission system could not fully serve the demand. Planning for the more extreme system conditions of heatwaves and cold snaps is currently beyond established design criteria.

The Critical Role of the NYISO's Wholesale Market Design Supporting Grid Reliability

Wholesale electricity markets must serve to both attract new supply while retaining existing resources. For the past 25 years, competitive wholesale electricity markets in New York have supported the reliable, efficient operation of the grid. Furthermore, as investors look for opportunities to develop new resources to supply the grid, electricity markets ensure that the risk of those investments remain entirely on the developer an investor, rather than on ratepayers and taxpayers. An added benefit of wholesale electricity markets is that competition among resources rewards economic efficiency. Historically, this has resulted in cleaner and more efficient supply coming onto the grid and displacing older, less efficient supply.

Wholesale electricity markets use price signals to attract and retain enough supply in the most beneficial locations on the system to provide needed reliability services. Market-based price signals are transparent and stimulate necessary infrastructure investment to meet renewable and decarbonization goals, energy conservation, and demand response. Effectively designed markets incent the most beneficial reliability attributes and have effective performance characteristics to ensure consumers only pay for the services that drive reliable outcomes.

Today's grid consists largely of dispatchable resources that respond quickly to system needs. To ensure markets continue to attract the investment necessary for the grid of the future, we are taking numerous steps to evolve and enhance market designs.

For example, we are working with stakeholders to identify the emerging winter risks and determine what market changes may be needed to compensate suppliers for meeting these needs.

We also are working on market enhancements addressing dynamic reserves to balance intermittency. Operating reserves ensure sufficient supply to meet changing conditions in real-time, such as unplanned generator or transmission outages. Historically this need was solved by identifying fixed, system-wide reserve requirements. As renewable capacity grows and supply to the grid is more susceptible to changing weather conditions, establishing dynamic reserve requirements will support renewable energy integration by more accurately accounting for uncertainty and procuring this additional reserve at the lowest cost to consumers.

Finally, we are working on advanced storage modeling to coordinate the growing fleet of storage resources and improve tools for grid operators to manage capabilities so that these resources are deployed at the most effective times to meet New York's reliability needs.

The NYISO's Mission and Dedication

The NYISO's nearly 650 employees share a common mission: maintain grid reliability, deliver electricity at the least cost through our wholesale markets, plan for an effective and efficient transition to a clean energy grid, and serve as an independent and authoritative source of information for policymakers, regulators, investors, stakeholders, market participants, and the public.

Every minute, every hour, every day, highly skilled grid operators support reliability and resilience. Through sophisticated modeling and expertise, NYISO grid planners support reliability and enable record levels of new transmission and supply development. The NYISO's innovative wholesale market design continues to lead the way in supporting consumer affordability by aligning reliability with cost efficiency. Balancing the transition in the mix of supply through effective planning that identifies and mitigates reliability risks, supports needed transmission investment to access supply, and more efficiently coordinates interconnection of new supply is at the forefront of the NYISO's work.

The NYISO's role as an independent, authoritative source of information is essential. As we move towards a zero-emissions grid, it is critical to understand how the growth of intermittent resources and risks stemming from extreme weather, both in the summer and winter, will impact the ability to maintain reliability of the New York electric system.

As policymakers seek widespread change in how energy is produced and consumed, the NYISO is providing critical data and information on the reliability implications of current and new policies. The NYISO will continue to actively engage with stakeholders and policymakers on the path to a reliable and lower emissions grid for New York. The NYISO's leadership in developing innovative market design enhancements demonstrates our focus on innovation. The expertise of our grid operations is unrivaled, and the importance of the skilled and authoritative system

planning work done by the NYISO demonstrates the value of our independence. That success also demonstrates our ability to work across all sectors and interested parties to build consensus that supports reliability, consumer interests, public policy and new technologies that will help build the grid of the future.

Thank you for the opportunity to engage with the sub-committee today, and I look forward to further discussion and collaboration on these important issues going forward.

Mr. LATTA. Well, thank you very much for your opening statement.

And, Mr. Nickell, you are now recognized for 5 minutes for your opening statement.

STATEMENT OF LANNY NICKELL

Mr. NICKELL. Well, good morning. Chairman Latta, Vice Chairman Weber, Ranking Member Castor, Ranking Member Pallone, and members of the subcommittee, thank you for the opportunity to speak to you this morning about grid reliability.

I am Lanny Nickell. I am currently executive vice president and chief operating officer of Southwest Power Pool, and I am the incoming CEO as of April 1. We are a regional grid operator, serving 18 million people across 14 States in the central part of our country. We are responsible simply for keeping the lights on today and in the future.

Our industry is at an inflection point as it experiences a rate of change I have not previously seen in my 32-plus-year career. Over the last decade, the transition and resource mix and demand growth has drastically increased operational complexity and has almost exponentially increased risk of having to interrupt electric service due to insufficient supply.

We have already witnessed significant growth in both our summer and winter peak demands. Our current summer peak was 10 percent higher than the highest peak set 2 years earlier. And this winter we set a winter peak that was 2.5 percent higher than the previous winter record demand.

Electricity use in our region grew about 25 percent over the last 10 years. This growth in demand is expected to continue in unprecedented fashion as we are forecasting peak demand to be as much as 50 percent higher over the next 10 years, mostly driven by the AI data center boom.

As consumption has grown, we have also witnessed a rapid shift from a more steady source of dispatchable generation to a more intermittent renewable heavy generation mix. In other words, many aging coal and gas plants have been retired and replaced with wind generation in our region, shrinking the firm capacity margin that we have long depended on for reliability. This growing imbalance between the rising demand and a less dispatchable, more intermittent resource mix lies at the heart of what we have referred to as our generational challenge.

Without a collective set of corrective actions, we will struggle to keep up with future needs, and our risk of not being able to continuously supply electric service to consumers will be at an all-time high.

On our end, in SPP we have been acting to increase regional requirements for excess capacity, and we are urging generators to stay online until sufficient replacement capacity is ready. We are working feverishly to accelerate our study processes for generator interconnections, and we have recently approved a transmission expansion plan requiring over five times the transmission investment of our previous largest project portfolio. We need significantly more generation and more transmission to meet the growing demands,

and we need it to be interconnected much quicker than we have historically seen.

We will also need more of the generation being interconnected to be dispatchable so that it is available when needed to offset the variability of intermittent weather-dependent generation. Simply put, we need a lot more steel in the ground, and time is short. Meeting this challenge will require everyone's cooperation. We have to work together.

For example, we need a fully functioning FERC so that they can continue their good work ensuring reliability, permitting infrastructure, and supporting competitive energy markets.

Additionally, utilities can bring generation and transmission. RTOs can work together to lead and envision this future that we are all depending on.

We all have to do our part to safeguard the grid so that the life-enhancing and life-sustaining product of power can continue to be provided as affordably as possible. I am confident that we can meet this challenge, but we cannot do it alone. We need your help.

Thank you, and I look forward to your questions.

[The prepared statement of Mr. Nickell follows:]

Testimony of Lanny Nickell

Executive Vice President, Chief Operating Officer

Southwest Power Pool, Inc.

Before the House Energy & Commerce Subcommittee on Energy

"Keeping the Lights On: Examining the State of Regional Grid Reliability"

Tuesday, March 25, 2025

Chairman Latta, Vice Chairman Weber, Ranking Member Castor, and members of the Subcommittee, thank you for the opportunity to speak about grid reliability.

My name is Lanny Nickell. I am Southwest Power Pool's (SPP) Executive Vice President and Chief Operating Officer, and incoming President and CEO effective April 1. As a regional transmission organization (RTO), SPP coordinates grid operations across a 14-state area in the central United States and is responsible for ensuring the reliable, economic delivery of wholesale electricity to utilities serving more than 18 million people in our region. We oversee the generation and delivery of electric power for our member utilities, study and direct needed enhancements to the region's bulk transmission network, and operate a wholesale electricity market that enables delivery of some of the most affordable wholesale energy in the country. I appreciate the chance to discuss the state of our grid and our generational challenge to meet an unprecedented growing demand for electricity with an evolving mix of energy sources.

Our industry is at a pivotal moment—having experienced the transition from historically centralized, controllable coal and natural gas generation toward decentralized, renewable-heavy resources. This rapid shift has increased operational complexity and significantly amplified reliability risks.

The demand for electricity in our region has increased faster than we had previously projected. SPP set our latest record peak for instantaneous demand in August 2023: around 56 gigawatts (GW), equivalent to the output of more than 50 Hoover Dams. That was roughly 10% higher than the peak set two years earlier. This growth isn't limited to summer. On February 20, 2025, we experienced a record winter peak of approximately 48 GW, about 2.5% higher than our prior winter peak. And it's not only that demand peaks are getting higher; overall electricity usage is increasing

too. Between 2014 and 2024, the annual electricity consumption in our region grew by roughly 25%. This increase has been driven by a number of factors, including economic expansion, conversion of gas to electric heating, harsh weather conditions, and an emerging proliferation of datacenters that require immense power.

Seasonal risks are no longer confined to summer months; winter electricity demand has surged dramatically, reinforcing our need for increased reserve margins and dispatchable generation. Recent reliability challenges, such as those experienced during Winter Storm Uri, demonstrate vividly why a diversified and robust generation mix is indispensable to grid resilience.

One of these drivers – the rise of advanced computing and artificial intelligence (AI) – deserves special mention. AI and high-performance computing are fueling a new wave of data centers that consume immense amounts of electricity. Our region's affordable and reliable power has already attracted interest from companies looking to build these energy-intensive facilities within SPP's footprint. Serving these emerging large loads will require us to strategically plan and aggressively expand our grid – ensuring we have sufficient generation and reinforcing transmission to deliver power where it's needed. It is also critical to maintain energy security for these digital infrastructure hubs, meaning a resilient, uninterrupted supply of electricity. By proactively meeting AI-driven demand through streamlined development of new resources and infrastructure, we can preserve reliability and help the United States maintain a competitive edge in the global digital economy.

SPP forecasts that peak demand over the next ten years could be as much as 50% higher than today's levels. Dispatchable power plant retirements due to age or environmental limits have been occurring and are expected to continue to occur, steadily reducing the amount of firm capacity

available to serve customers. These retirements have tightened our supply margins and almost exponentially increased reliability risks. Compounding the challenge, the majority of new generation that has been added in our region over the last several years has been intermittent wind. In other words, a large amount of around-the-clock generation was retired and largely replaced with weather-dependent resources.

This imbalance between rising demand and a changing resource mix is central to the challenge our industry and nation face. In 2024, SPP produced a comprehensive report on this subject titled "Our Generational Challenge." Its conclusion is that, without significant and collaborative action, grid operators like SPP will find it increasingly difficult to keep pace with consumers' future electricity needs. Notably, SPP's report also suggested measures to mitigate the reliability gap – for example, setting higher planning reserve margins (a step we have since taken) and incentivizing key generators to remain in operation longer until replacement resources can be put in place.

Among our peers across the nation, SPP has been a leader in navigating America's wind energy boom. Wind capacity in the SPP region has increased 30× over the last two decades, and we've seen as much as 90% of our region's demand for electricity supplied by wind power. Thanks in part to an abundant supply of renewable resources, SPP enjoys the lowest wholesale electricity prices of any region in the country.

An abundance of wind generation, however, also brings challenges, because it's a variable resource – meaning we can't control its availability. Instead, we react to varying wind generation output as weather conditions change. On February 27, changing wind speeds caused wind generation to plunge by 12,000 MW in just two hours. To meet the continuing demand for electricity, we had to rapidly increase the output of the dispatchable generation available during that time, primarily

natural gas generation. If dispatchable generation had not been available, we would have been forced to interrupt electricity consumption within the region. This real-world event underscores how variability stresses the system, especially during high-load periods, and we need increased dispatchable baseload generation in our footprint to ensure the lights stay on.

The nation's transmission infrastructure is simply not ready for this accelerating future. Even SPP's latest transmission expansion plan (published in October 2024) called for more than five times the investment of any prior plan—underscoring the massive scale of infrastructure needed to reliably meet rapidly growing electricity demand.

To maintain reliability amid these challenges, SPP and our member utilities have prioritized improving policies to ensure resource adequacy – the ample, reliable provision of generating capacity needed to meet peak demand with sufficient reserve or excess capacity that can be deployed as needed. Every utility providing electric service in our region must maintain access to an amount of reserve capacity that exceeds their expected peak demand. We call this a planning reserve margin. Driven by the almost exponentially increasing reliability risks we are facing and lessons learned from recent weather events, SPP's stakeholders and board have recently increased our planning reserve margin requirements. Beginning with the summer season of 2023, we increased summer reserve requirements from 12% to 15%. In other words, to ensure a safe amount of "headroom," utilities must have the ability to produce 15% more energy than their forecasts suggest they'll need during a summer peak. That requirement is expected to increase to 16% for the summer season of 2026 and 17% for the summer season of 2029. Last year, we set a new winter-season reserve target of 36% effective beginning in 2026 which will increase to 38% effective in 2029. This helps us mitigate unplanned transmission and generation outages, sudden changes in weather conditions, and other risks. It also signals that new investment in reliable

capacity is needed, so that our nation always has a safety net in terms of immediately available electricity. While smaller margins are less costly to maintain, they allow less room for error, increasing the risk of emergencies.

The good news is that we have a robust pipeline of new resources eager to come online. SPP has more than 100 GW of generation projects interested in connecting to our grid – almost twice our peak demand as of today, with over a third of those projects consisting of battery storage and gas generation, which will help offset the variable nature of the renewable generation we have today. If even a fraction of these projects gets built, and if we can construct the needed transmission to support them, they'll greatly improve our resource adequacy.

SPP's generation interconnection study queue, like most of the nation's, has been backlogged for years for a number of reasons. Likewise, transmission builders often face permitting, supply chain, and other challenges that further slow construction. SPP is working to streamline our processes, and we expect to clear our backlog by the end of this year. In the meantime, there remains a pressing need for new transmission lines to deliver energy from where it's produced to the growing load centers where it's needed. Our members have invested more than $12 billion in transmission over the past decade (with another $7 billion approved late last year), but more is needed to meet this generational challenge. Efficiently harnessing new resources – and replacing retiring plants – to meet future demand at low cost requires proactive planning and regulatory support.

We are on track to implement process improvements by the end of 2025 that will allow us to achieve a 12-month turnaround of new generator interconnection requests, allowing needed generation resources to reach operation faster and mitigate near-term reliability gaps. Further, SPP and its load-serving members are taking steps to ensure we maintain sufficient dispatchable

capacity through this transition. Many utilities in our footprint are investing in new on-demand generation and keeping existing plants available as long as needed. For example, Omaha Public Power District (OPPD) in Nebraska recently announced plans to add 900 MW of fast-start natural gas generation by 2030 to help meet rising demand reliably. Other SPP utilities have similar plans for new gas-fired power stations or upgrades, and some are extending the operation of critical coal and gas units to avoid near-term shortfalls. In addition, our members continue to expand demand response capabilities and explore emerging technologies like grid-scale batteries to supplement firm capacity. SPP is further evaluating market incentives to encourage adequate dispatchable resources and working closely with state regulators on coordinated resource planning. These joint efforts will help offset the retirement of older assets and provide the around-the-clock power needed to back up our growing renewable fleet.

We are also pursuing significant efforts to reimagine transmission planning policies—improving cost-sharing mechanisms, streamlining approval processes and allowing expedited access to generating resources needed to meet increasing reserve margin requirements. These policy changes are essential to accelerate construction of critical infrastructure, ensuring the grid meets growing electricity needs swiftly and economically.

SPP's system is reaching new heights of demand and integration of a diverse portfolio of generating resources. This is an exciting time of innovation and opportunity in our industry, but also one that truly tests our infrastructure planning and operating strategies. I want to emphasize that reliability is – and will remain – our top priority. We are taking steps such as boosting reserves, improving market tools, adding new generation, and advocating for appropriate grid expansion to

ensure we continue to keep the lights on at all times. Decisions made today will determine whether we succeed in providing reliable, affordable, and sustainable power for the next generation.

To make these urgent and transformational changes, our industry has a critical need for collaboration and consensus from utilities, regulators, policymakers, other Regional Transmission Organizations, and consumers. Utilities can upgrade aging infrastructure and bring new transmission and generation to the grid. State regulatory commissions can develop responsible cost allocation and resource adequacy policies and support prudent investments in infrastructure expansion. The Federal Energy Regulatory Commission (FERC) is critical in permitting infrastructure and acting decisively and in a timely manner on filings meant to ensure reliability and effective energy markets. Policymakers can enact laws that promote reliability while balancing affordability and environmental goals; they can also support collaboration across multi-state regions. RTOs can work together to provide visionary leadership in our regions while working across our boundaries to collaborate on interregional projects and improve grid resilience. Consumers can stay informed and support utilities' efforts to build infrastructure needed to provide reliable and affordable electric service. They can participate in demand response and energy efficiency programs and voluntarily reduce consumption during emergencies.

SPP's call to action is for all these parties to work together to assure adequate generation and transmission is being planned for the future. I am confident we can meet this challenge, but SPP can't do it alone. Thank you, and I look forward to your questions.

Mr. LATTA. Well, thank you very much for your statement.

And, Mr. Mainzer, you are recognized for 5 minutes for your opening statement.

STATEMENT OF ELLIOT MAINZER

Mr. MAINZER. Chairman Latta, Ranking Member Castor, Chairman Guthrie, Ranking Member Pallone, and members of the subcommittee, thank you for the opportunity to testify today. My name is Elliot Mainzer. I serve as president and CEO of the California Independent System Operator Corporation, commonly referred to as the CAISO.

The CAISO is a nonprofit public benefit corporation that does not own any generation or transmission assets. We play a number of key roles to ensure the grid is reliable, including transmission planning, overseeing interconnection of new resources, operation of electricity markets, and providing reliability coordinator services to entities across the Western interconnection. We do not operate a centralized capacity market but work with State and municipal entities to ensure adequate procurement and deployment of generation and storage resources.

Like other regions of the country, California has faced extreme weather and other challenges. But the CAISO and our State partners have made major advances in reliability in recent years due to commonsense approaches to expanding energy supply, efficiently interconnecting new resources, and proactively planning for transmission upgrades. New resources are coming online at a rapid pace.

Since 2020, over 24 gigawatts of new generation capacity has been added to the CAISO grid, including approximately 7 gigawatts last year. This new capacity includes over 11 gigawatts of battery storage. The CAISO relies on these new resources as well as a diverse generation mix that includes solar, wind, geothermal, bio gas, hydro, natural gas, and nuclear generation to maintain reliability. During the next 5 years, we expect resource growth to continue to be comprised largely of battery storage, solar, and wind resources.

At the CAISO, we work to ensure safe and reliable service to our electricity customers through collaboration with California State agencies and other local regulatory authorities.

The CAISO, the California Public Utilities Commission, and the California Energy Commission have entered into a memorandum of understanding to help synchronize load forecasting, power and transmission planning, interconnection queueing, and procurement of new resources. This enhanced coordination has been essential to onboarding the thousands of megawatts of new generating capacity and battery energy storage that have come online in recent years and will continue to guide our approach to ensuring reliability and resource adequacy in California.

The reliability of our grid has also been advanced by thoughtful and timely oversight by FERC. Last year, FERC approved a comprehensive set of interconnection queue reforms, resulting from an extensive CAISO stakeholder process that was anchored in our approach to coordinated planning. Based on our implementation so

far, we have observed a significant reduction in projects clogging our interconnection study process.

The CAISO's most recent transmission plan included 26 new projects at an estimated cost of $6.1 billion to support over 85 gigawatts of new resources by 2035. We are also actively engaged in several interregional transmission projects that will access clean energy resources identified in the CPUC's resource planning efforts that will also help deliver new generating resources and support reliability for utilities in other States.

Electrification of transportation and buildings has been the primary driver of load growth today within the CAISO's footprint. The CEC's latest demand forecast shows a 33 percent growth in peak demand over the next 10 years and a 45 percent growth in peak demand over the next 15.

Currently, there is about 1 gigawatt of data center load connected to the CAISO system. The CEC projects an increase in data center loads over the next 15 years with a sharp increase projected to start around the 2028 timeframe. The CAISO is working diligently to serve emerging large electric loads within our footprint, including major transmission enhancements to the transmission system in the Silicon Valley.

Reliability in the West is further enhanced by the success of the CAISO's Western Energy Imbalance Market, which has been in operation since 2014. Optimizing supply and demand in 15-minute and 5-minute intervals, the Western Energy Imbalance Market today spans 22 market participants in 10 States and leverages the significant transmission connectivity and resource diversity across parts of the West, which is particularly valuable during extreme weather events.

We are now working to extend a new day-ahead market platform to others in the West. Fully approved by FERC in 2024, the Extended Day Ahead Market will expand the ability to optimize supply and demand in the day-ahead timeframe, which will further enhance market efficiency and reliability and reduce cost to the ratepayers of participating utilities.

The CAISO recognizes that our work continues in order to maintain the pace of new resource development to meet growing electric demands and State policy goals. We remain focused on implementing our coordinated planning and interconnection processes in extending our market service offerings to other entities across the West.

We look forward to further engaging with the Federal Government to ensure reliability and cost savings for electricity consumers.

Thank you again for the opportunity to be here this morning, and that concludes my testimony.

[The prepared statement of Mr. Mainzer follows:]

Testimony of Elliot Mainzer, President and Chief Executive Officer,

California Independent System Operator Corporation,

Keeping the Lights On: Examining the State of Regional Grid Reliability

Subcommittee on Energy, Committee on Energy and Commerce,

United States House of Representatives

March 25, 2025

Executive Summary

Like other regions of the country, California has faced extreme weather and other challenges, but the California Independent System Operator (CAISO) and our key partners have made major advances in reliability in recent years due to common sense approaches to expanding energy supply, efficiently interconnecting new resources, and proactively planning for transmission upgrades. New resources are coming online at a rapid pace. Since 2020 over 24 GW of new generation capacity has been added to the CAISO grid, including approximately 7 GW last year. This new capacity includes over 11 GW of battery storage. Based on the CAISO's implementation so far of its new interconnection reforms, there has been a material reduction in projects clogging the CAISO interconnection study process. The CAISO's 2023-2024 Transmission Plan included 26 new projects costing $6.1 billion to support 85 GW of capacity by 2035. Reliability is further enhanced in the West by the operation of the Western Energy Imbalance Market (WEIM), which allows over 22 participating entities to rely on a broad geographic footprint of transmission and generation resources to improve reliability and reduce costs. Working in a state driven process, the CAISO partners with regulators, utilities, developers and other stakeholders to advance reliability and affordability for electricity consumers. Through these partnerships we have realized mutual economic and reliability benefits from planning and operational coordination. The CAISO recognizes that our work continues in order to maintain the pace of new resource development to meet growing electric demands and state policy goals. The CAISO remains focused on implementing its coordinated forward planning process with state agencies and looks forward to further engagement with the federal government to ensure reliability and cost savings.

Written Statement

Chairman Latta, Ranking Member Castor, Chairman Guthrie, Ranking Member Pallone, and Members of the Subcommittee, thank you for the opportunity to testify today. My name is Elliot Mainzer. I serve as President and Chief Executive Officer of the California Independent System Operator Corporation, commonly referred to as the CAISO. For the last 25 years, I have served in various roles working to achieve reliable and affordable energy by supporting innovation and creativity in generation development, transmission planning, market design and regional collaboration. I joined the CAISO in September 2020, after an 18-year career at the Bonneville Power Administration (BPA), including seven years as Administrator and CEO.

The CAISO is a nonprofit public benefit corporation and does not own any generation or transmission lines. We do play a number of key roles to ensure the grid is reliable, including transmission planning, overseeing interconnection of new resources, operation of electricity markets, and providing Reliability Coordinator services to 42 entities operating in the Western Interconnection. Unlike other ISOs/RTOs, we do not operate a centralized capacity market but work with the state and municipal entities to ensure adequate procurement and deployment of generation and storage resources.

Reliability

Like other regions of the country, California has faced extreme weather and other challenges, but the CAISO and our partners have made major advances in reliability in recent years due to common sense approaches to expanding energy supply, efficiently interconnecting

new resources, and proactively planning for transmission upgrades. New resources are coming online at a rapid pace.

Since 2020 over 24 GW of new generation capacity has been added to the CAISO grid, including approximately 7 GW last year. This new capacity includes over 11 GW of battery storage. The CAISO relies on these new resources, as well as a diverse generation mix that includes solar, wind, geothermal, biogas, hydro, storage, natural gas, and nuclear generation. As reflected in figure 1, during the next five years, we expect resource growth to continue to be comprised largely of battery storage, solar, and wind resources.

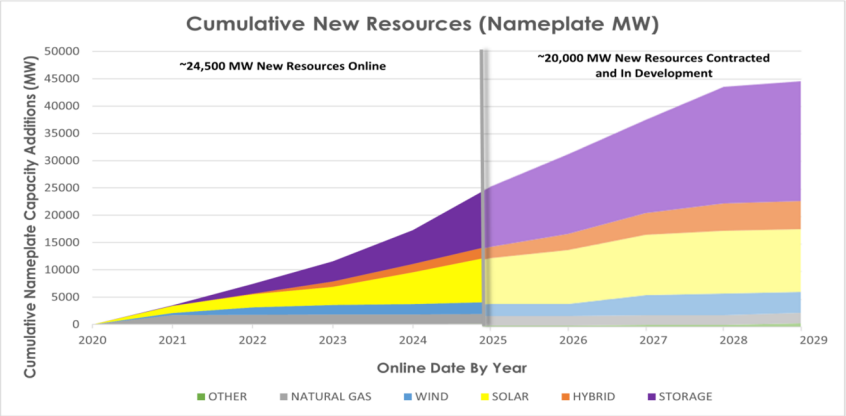


Figure 1. Cumulative new resource additions and projected new resource additions as tracked and reported by the California Public Utilities Commission (CPUC).

The reliability of our grid is also advanced by thoughtful and timely oversight by FERC. Last year, FERC approved a comprehensive set of interconnection reforms resulting from an extensive CAISO stakeholder process. These reforms will help projects aligned with state and local resource plans and located in areas with transmission availability to proceed through the

CAISO interconnection queue. Based on our implementation so far, we have observed a material reduction in projects clogging our interconnection study process.

The CAISO's 2023-2024 Transmission Plan included 26 new projects at an estimated cost of $6.1 billion to support load growth of over 85 GW by 2035. Figure 2 reflects recent transmission developments in the Western United States. These transmission projects will support resources identified in the California Public Utilities Commission's resource planning efforts and increase reliability and foster economic development in the West. Two of these projects, TransWest Express and SunZia, are seeking to participate under the CAISO's novel Subscriber Participating Transmission Owner model to connect out of state resources to the CAISO. Our coordination with adjacent states, utilities, and developers provides a new path to support development across the region.

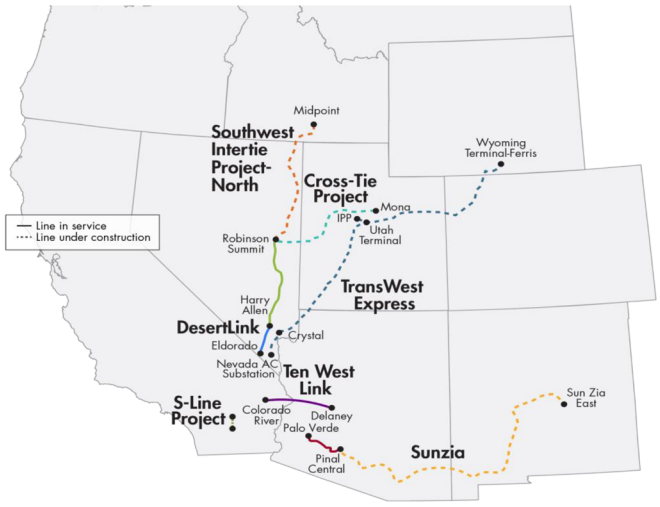


Figure 2. Multi-state transmission projects that deliver west-wide benefits and enhance resilience.

Reliability in the West is further enhanced by the success of the CAISO's Western Energy Imbalance Market (WEIM), which has been in operation since 2014, and optimizes supply in real-time for every fifteen minute interval and then again for every five minute interval across the Western footprint. Enhanced reliability across the region has been achieved because of the large foot print of 22 market participants in ten states. In addition, approximately $7 billion in cost savings have been achieved for electricity customers.

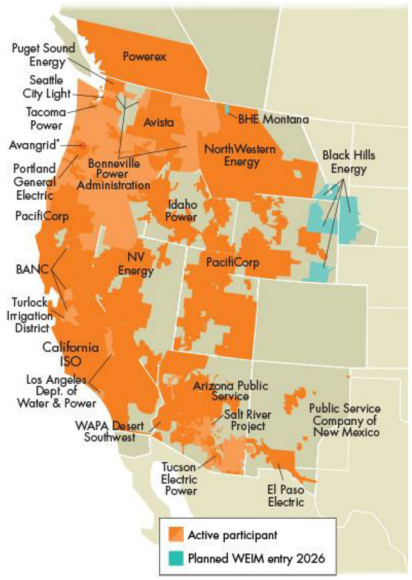


Figure 3. Balancing authorities either currently participating in the Western Energy Imbalance Market or planning to do so.

We are now working to extend our day-ahead market platform to others in the West. Fully approved by the FERC in 2024, the Extended Day Ahead Market will expand the ability to optimize supply and demand in the day-ahead timeframe which will enhance market efficiency and reliability and reduce costs to ratepayers across the West.

State-Driven Process

The CAISO collaborates with California's state agencies and other local regulatory authorities to ensure safe and reliable service to electricity customers. The CAISO, the California Public Utilities Commission (CPUC), and the California Energy Commission (CEC) entered into a memorandum of understanding to improve coordination and to enhance resource and transmission planning to achieve state reliability and policy needs. The CAISO manages the transmission planning and generator interconnection processes, which carefully account for the inputs provided by CEC's demand forecast, the CPUC's integrated resource planning, and additional inputs from non-CPUC jurisdictional local regulatory authorities. All of these processes have a minimum 10 to 15-year horizon, with the CAISO also providing transmission assessments 20 years into the future.

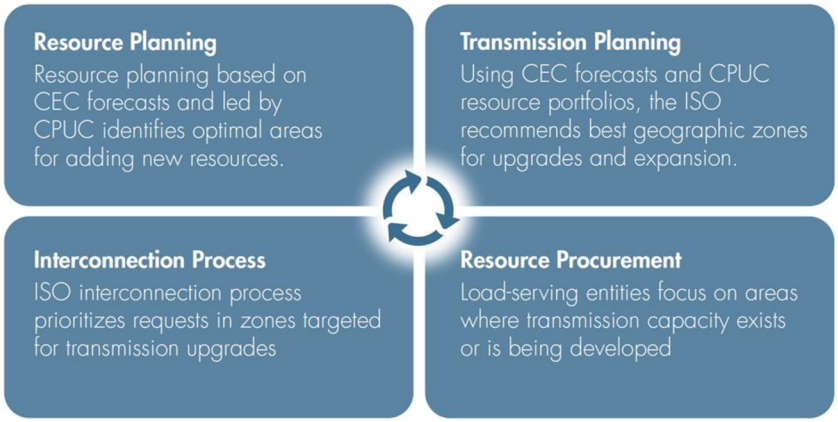


Figure 4. The collaborative process identified in the Memorandum of Understanding signed by the CAISO, the California Public Utilities Commission, and the California Energy Commission.

This coordination has facilitated the addition of thousands of megawatts of new generating capacity and battery energy storage. The CAISO now has over 11 GW of energy storage, one fifth of CAISO's demand, nearly all of which has interconnected in the last few years through the CAISO's interconnection process.

Large Load Growth

Electrification of transportation and buildings has been the primary driver of load growth to date within the CAISO's footprint. The CEC's latest demand forecast shows a 33% growth in peak demand over the next 10 years, and a 45% growth in peak demand over the next 15 years. As the home of Silicon Valley, the CAISO is working diligently to serve emerging large electric loads within our footprint, including major enhancements to the transmission system in Silicon Valley. Currently, there is about 1 GW of data center loads connected to the CAISO system. The CEC projects an increase in data center loads over the next 15 years, with a sharp increase projected to start around the 2028 timeframe. The CEC projects data center load to increase by 2.3 GW by 2030, and 3.3 GW by 2035. In addition to onboarding thousands of megawatts of new generating capacity, the CAISO is also working with our partners in government and industry to increase the role of flexible loads and virtual power plants in supporting reliability within our market footprint, including the potential of securing flexibility services from data centers themselves.

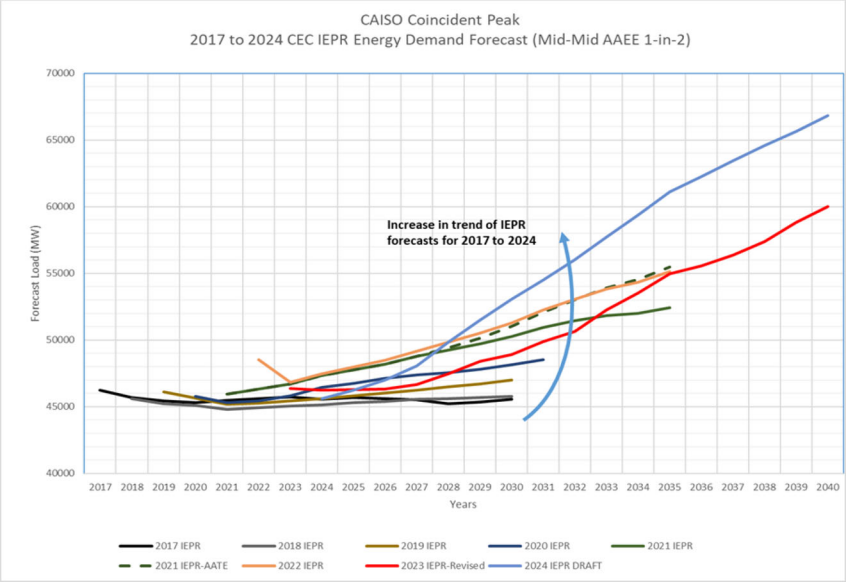


Figure 5. Acceleration of load growth projections from year to year based on the California Energy Commissio n's Integrated Energy Policy Report (IEPR).

Looking Forward

The CAISO recognizes that our work continues in order to maintain the pace of new resource development to meet growing electric demands and state policy goals. The CAISO remains focused on implementing its coordinated forward planning process with state energy agencies and looks forward to further engagement with the federal government to ensure reliability and cost savings for electricity consumers.

Mr. LATTA. And thank you very much for your opening statement.

And, Mr. Vegas, you are recognized for 5 minutes for your opening statement.

STATEMENT OF PABLO VEGAS

Mr. VEGAS. Chairman Latta, Ranking Member Castor, Chairman Guthrie, Ranking Member Pallone, and Vice Chairman Weber, and members of the subcommittee, it is an honor to be here representing the Electric Reliability Council of Texas—or ERCOT, as we are referred to—where we manage the flow of electricity to over 27 million Texans.

Texas continues to experience unprecedented economic and population growth, driving electricity demands to record levels each year. At the same time, the energy mix that powers Texas is evolving rapidly, with intermittent resources and battery storage playing an ever-increasing role in system operations. This transition presents opportunities but also real challenges that require planning and investments to ensure system reliability.

Today, I want to share how ERCOT is managing this shift while keeping reliability at the forefront, the lessons that we have learned from recent weather events, and why ensuring a balance and resilient power supply remains essential for the future.

In the summer of 2023, ERCOT set a new all-time peak demand record of 85,508 megawatts. Last month, we set a new winter peak demand record of 80,525 megawatts, a demand level that is normally seen and experienced in the summer.

This isn't just about a growing population. Texas has become a magnet for industries that require increasing amounts of electricity, from semiconductor plants to data centers, broad industrial growth, and large-scale industrial electrification in the Permian Basin.

Today, wind and solar make up 42 percent of our installed generation capacity. Both of those represent the most installed capacity in the United States, with thousands of megawatts being added each year.

Battery storage, which was just emerging a few years ago, is playing a critical role in balancing supply and demand during tight grid conditions, and it is acting as a growing bridge asset during critical hours.

From an operations perspective, solar generation helps to meet peak afternoon demand, and batteries provide rapid response to system fluctuations with their growing presence in the ancillary services market.

Wind and solar power are variable by nature, meaning that their output is not always available when it is needed most. Batteries help significantly, but current storage technology is still limited in duration, in our market typically 1 to 2 hours, meaning that it cannot fully replace the need for traditional, long-duration dispatchable generation.

Natural gas, coal, and nuclear power still supply 65 percent of the delivered energy on the ERCOT grid in 2024. Those long-duration dispatchable resources remain the backbone of reliability, providing critical generation around the clock.

We are seeing an uptick in the generation interconnection queue from gas generation, and efforts that have been spearheaded by the Texas legislature, such as the Texas Energy Fund, are providing incentives for dispatchable power plant development.

We cannot lose sight of a fundamental reality: A reliable grid must have a balanced mix of generation resources, especially with the all-of-the-above approach we see in the ERCOT power region.

Additionally, flexible demand is becoming a more critical component of reliable operations, and we are exploring ways to best leverage that potential in the face of a significant forecast of demand growth ahead of us.

Immediately following Winter Storm Uri, the Texas legislature put in place a set of weatherization standards during the 2021 legislative session. And to date, ERCOT has conducted over 3,300 inspections of generation resources and transmission facilities. The weatherization program inspects facilities for various preparation measures intended to reasonably ensure sustained operation at weather-zone-specific cold and hot conditions. And new programs such as the Firm Fuel Supply Service is available to ensure reliability during winter events in the event of a fuel curtailment for gas generation resources.

This combination of efforts has shown to be beneficial over the last several winter seasons, where the performance held to the standard that Texans have come to expect from their grid.

As we look to the future, ERCOT remains focused on ensuring that Texas has a grid capable of supporting its continued growth and economic success. That means encouraging investment in dispatchable generation, expanding and modernizing transmission infrastructure, leveraging demand-side solutions and new technologies, and enhancing grid security and resilience.

The ERCOT grid is not alone at being at an inflection point. We are balancing record-breaking demand growth with a rapidly evolving generation mix, all while ensuring that we are focused on reliability for millions of Texans. It is a challenge, but it is also an opportunity to build a smarter, stronger, and more resilient grid that can continue to support Texas and the United States for generations to come.

I appreciate the opportunity to testify today, and I look forward to your questions.

[The prepared statement of Mr. Vegas follows:]

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Testimony of Mr. Pablo Vegas

President and Chief Executive Officer

Electric Reliability Council of Texas, Inc.

Before the United States House of Representatives

Committee on Energy and Commerce

Subcommittee on Energy

"Keeping the Lights On: Examining the State of Regional Grid Reliability"

March 25, 2025



Summary of Statement

- Texas is experiencing unprecedented economic and population growth, leading to record-breaking electricity demand.
- In 2023, ERCOT set a summer peak demand record of 85,508 MW and, last month, a winter peak demand record of 80,525 MW—a demand level typically seen in summer.
- Broad industrial growth, including semiconductor plants, data centers, and large-scale electrification in the Permian Basin, is a major driver of rising demand.
- Wind and solar now make up 42% of ERCOT's installed generation capacity, the largest in the U.S., with continued expansion.
- Battery storage is playing a growing role, particularly in balancing supply and demand during tight conditions, but current technology is generally limited to 1-2 hours of duration.
- Dispatchable generation (natural gas, coal, nuclear) still provides 65% of ERCOT's delivered energy, ensuring grid reliability.
- The Texas Energy Fund and an uptick in natural gas project proposals signal investment in dispatchable generation.
- Since 2021, ERCOT has conducted 3,362 inspections of generation resources and transmission facilities to enforce weatherization standards.
- Programs like the Firm Fuel Supply Service provide backup fuel options to improve winter reliability.
- These measures have improved ERCOT's winter performance, ensuring consistent reliability in recent seasons.
- Maintaining a balanced generation mix is essential, leveraging renewables, storage, and dispatchable resources.
- Flexible demand solutions will play a critical role in managing continued demand growth.
- Expanding and modernizing transmission infrastructure and incorporating new grid technologies are priorities.
- Grid security and resilience must remain a key focus.

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Testimony of Mr. Pablo Vegas

Chairman Latta, Ranking Member Castor, Chairman Guthrie, Ranking Member Pallone and Members of the Subcommittee. It is an honor to be here representing the Electric Reliability Council of Texas (ERCOT), where we manage the flow of electricity to over 27 million Texans.

Texas continues to experience unprecedented economic and population growth, driving electricity demand to record-breaking levels.

At the same time, the energy mix that powers Texas is evolving rapidly, with intermittent Resources and battery storage playing an ever-increasing role in system operations. This transition presents opportunities—but also real challenges—that require planning and investments to ensure system reliability.

Today, I want to share how ERCOT is managing this shift while keeping reliability at the forefront, what lessons we've learned from recent weather events, and why ensuring a balanced and resilient power supply remains essential for the future.

In the summer of 2023, ERCOT set a new all-time peak demand record of 85,508 MW. Last month, we set a new Winter Peak Demand record of 80,525 MW, a demand level normally experienced in the summer.

This isn't just about a growing population. Texas has become a magnet for industries that require increasing amounts of electricity, from semiconductor plants to data centers, broad industrial growth and large-scale industrial electrification in the Permian Basin.

Today, wind and solar make up 42% of our installed generation capacity, both representing the most installed capacity in the US, with thousands of megawatts being added each year. Battery storage, which was just emerging a few years ago, is playing a critical role in balancing supply and demand during tight grid conditions, acting as a growing bridge-asset during those hours.

From an operations perspective, solar generation helps meet peak afternoon demand, and batteries provide rapid responses to system fluctuations with their growing presence in the Ancillary Services market.

Wind and solar power are variable by nature, meaning that their output isn't always available when it's needed most. Batteries help, but current storage technology is still limited in duration, in our market typically 1 to 2 hours, meaning it can't fully replace the need for traditional long duration dispatchable generation.

Natural gas, coal, and nuclear power still supplied 65% of the *delivered* energy on the ERCOT grid in 2024. These long duration dispatchable resources remain the backbone of reliability, providing critical generation around the clock.

We are seeing an uptick in the generation interconnection queue from gas generation, and efforts spearheaded by the Texas Legislature, such as the Texas Energy Fund, are providing incentives for dispatchable power plant development.

We cannot lose sight of a fundamental reality: a reliable grid must have a balanced mix of generation resources, especially with the "all of the above" approach we see in the ERCOT power region.

Additionally, flexible demand is becoming a more critical component of reliable operations, and we are exploring ways to best leverage that potential in the face of the significant forecasted demand growth ahead.

Now, after Winter Storm Uri, the Texas Legislature put in place a set of Weatherization Standards during the 2021 Legislative Session, and to-date ERCOT has conducted 3,362 inspections of generation resources and transmission facilities. The weatherization program inspects facilities for various preparation measures intended to reasonably ensure sustained operation at weather zone-specific cold and hot conditions, and new programs such as the *Firm Fuel Supply Service* are available to ensure reliability during winter events in the event of fuel curtailments for gas generation resources.

This combination of efforts has shown to be beneficial over the last several winter seasons, where the performance held to the standard that Texans have come to expect from their grid.

As we look to the future, ERCOT remains focused on ensuring that Texas has a grid capable of supporting its continued growth and economic success. That means:

- **Encouraging investment in dispatchable generation**
- **Expanding and modernizing transmission infrastructure**
- **Leveraging demand-side solutions and new technologies**
- **Enhancing grid security and resilience**

The ERCOT grid is not alone in being at an inflection point. We are balancing record-breaking demand growth with a rapidly evolving generation mix, all while ensuring that we are focused on reliability for millions of Texans.

It's a challenge, but it's also an opportunity—to build a smarter, stronger, and more resilient grid that can continue to support Texas and the United States for generations to come. I appreciate the opportunity to testify today, and I look forward to your questions.



United States House of Representatives
Committee on Energy and Commerce
Subcommittee on Energy

Supplementary Materials

Pablo Vegas
President and Chief Executive Officer
Electric Reliability Council of Texas, Inc.

March 25, 2025

ERCOT Facts



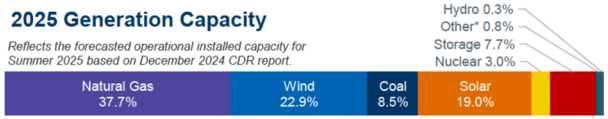
85,508 MW
Record peak demand (August 10, 2023)

103,105+ MW
Expected capacity for summer 2025 peak demand (December 2024 CDR)

$3.8 billion
Transmission projects endorsed in 2024

2025 Generation Capacity

Reflects the forecasted operational installed capacity for Summer 2025 based on December 2024 CDR report.



The sum of the percentages may not equal 100% dues to rounding.
**Other includes biomass-fired units and DC tie capacity.*

2024 Energy Use



** Other includes hydro, petroleum coke (pet coke), biomass, landfill gas, distillate fuel oil, net DC-tie and Block Load Transfer important/exports and an adjustment for wholesale storage load.*

1 MW of electricity is enough to serve about 250 residential customers during ERCOT peak hours.

40,006 MW
Wind
of installed wind capacity as of March 2025, the most of any state in the nation

28,550 MW
Generation Record (March 3, 2025)

69.15 %
Penetration Record (April 10, 2022)

32,316 MW
Solar
of utility-scale installed solar capacity as of March 2025

25,041 MW
Generation Record (March 10, 2025)

54.23 %
Penetration Record (March 1, 2025)

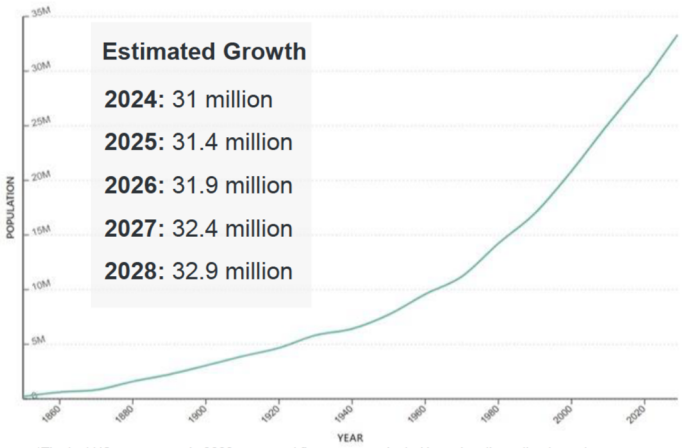
~76 % (~36,966 MW)
Preliminary **Wind + Solar** Penetration Record (March 1, 2025)

13,417 MW
Energy Storage
of installed energy storage capacity as of March 2025

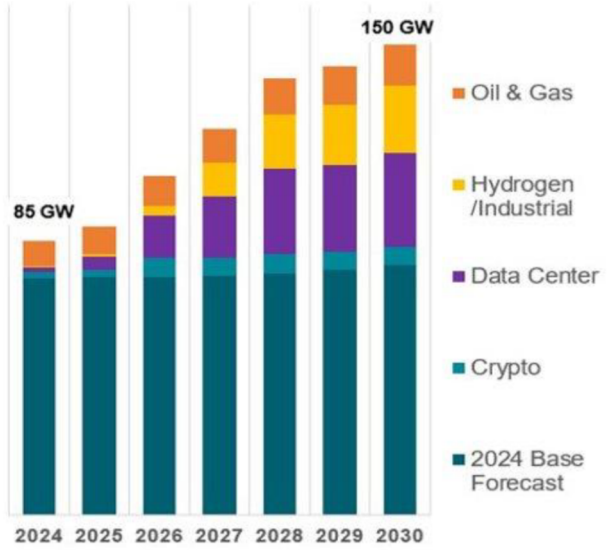
4,963 MW
Energy storage generation Record (March 10, 2025)

Load Side – What is Happening?

Texas Population 2023
30,500,280*



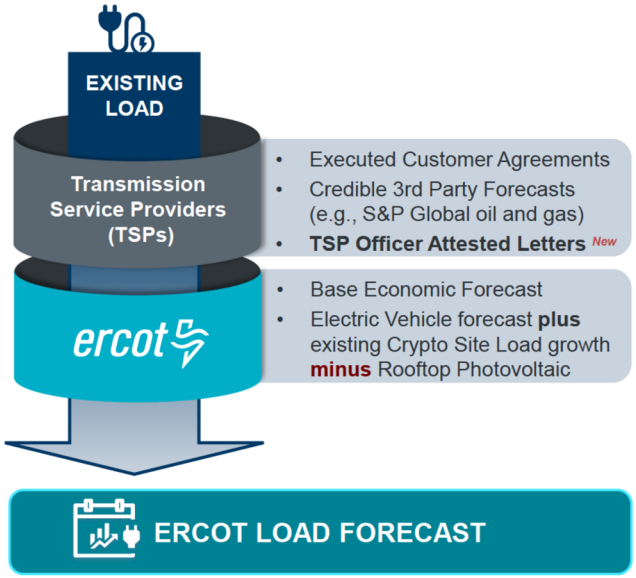
*The last US census was in 2020 so current figures are projected based on the estimates only.



** HB5066 - ERCOT has limited ability to verify Transmission Service Provider (TSP) officer attested load

Key Takeaway: Forecasted load growth is significant.

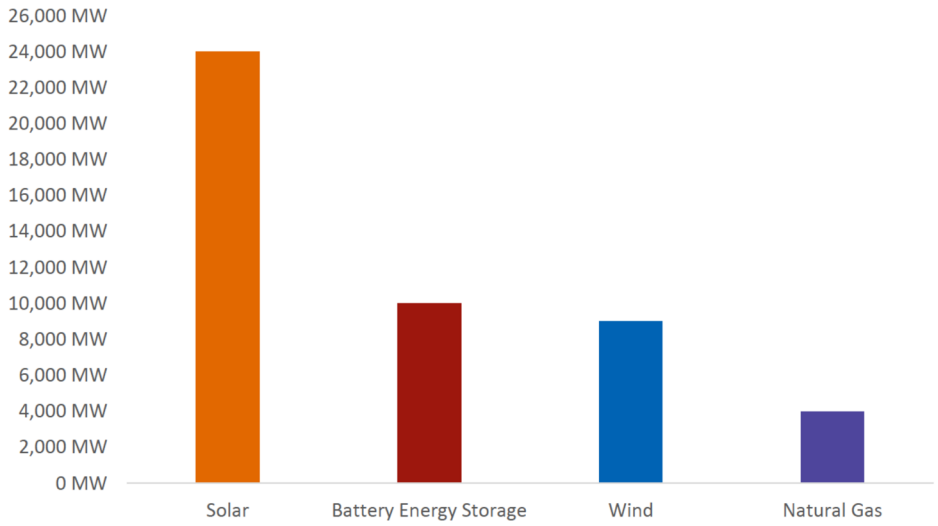
HB5066 Load Forecasting Process



Key Takeaways:

- The most impactful difference between the HB5066 process and ERCOT's previous Load forecasting process is that ERCOT must accept TSP Officer Attested Letters as reasonable.
- ERCOT has limited data to be able to verify Loads provided in TSP's Officer Attested load category.

New Generation by Resource Type: January 2021 through March 2025



Dispatchable Thermal Generation

(2009-2024) only 1,700 MW of net new dispatchable thermal generation added.

- 23,083 MW added
- 21,354 MW retired

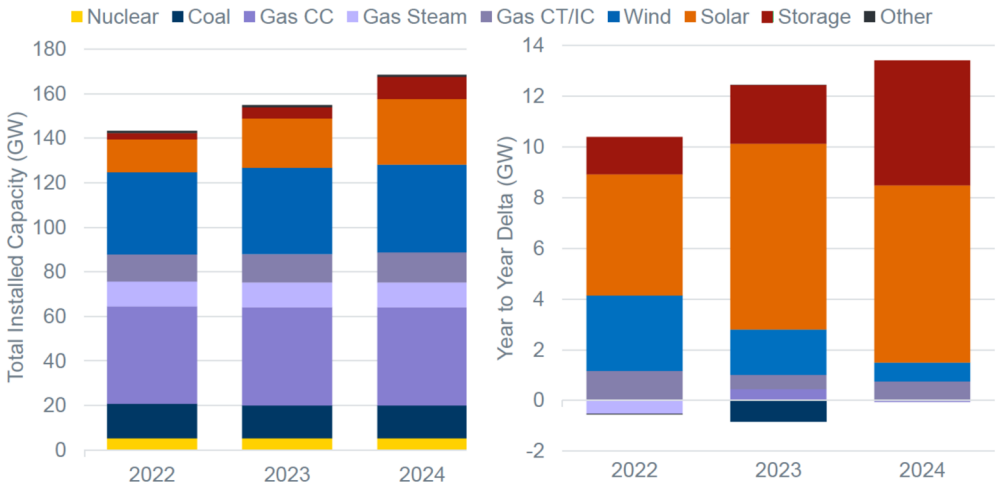
61,027 MW of net new solar and wind added (2009-2024)

Total Thermal Fleet is 88,779 MW*

- 42% is older than 30 years (36,951 MW) (1995)
- 27% is older than 40 years (24,129 MW) (1985)
- 13% is older than 50 years (11,773 MW) (1975)
- 3% is older than 60 years (2,628 MW) (1965)

Key Takeaway: From January 2021 to March 2025, ERCOT synchronized approximately 45,000 MW of new generation.

Generation Capacity and Additions 2022 through 2024

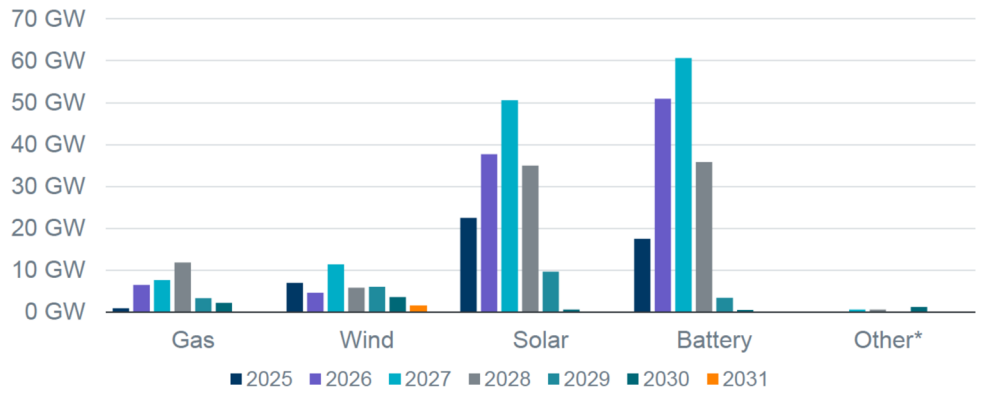


Key Takeaway: Most new generation over the past several years has been from solar, storage, and wind resources. Furthermore, most expected growth over the next few years continues to be from these resources.

Generation Interconnection

1,987 active generation interconnection requests totaling 400 GW as of February 28, 2025 (Solar 156 GW, Wind 40 GW, Gas 32 GW, Battery 169 GW, and Other 3 GW)

(excludes capacity associated with projects designated as Inactive per Planning Guide Section 5.2.5)

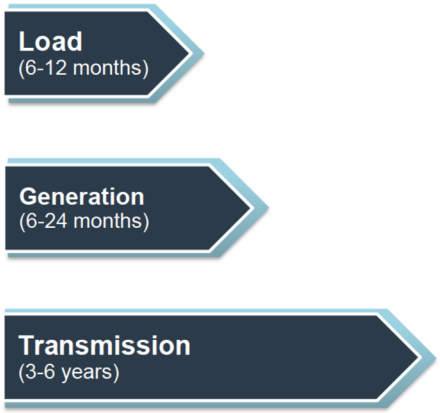


Key Takeaway: Solar and Battery Energy Storage account for more than 81% of the amount of generation seeking interconnection.

*includes petroleum coke, hydroelectric, fuel oil, geothermal energy, other miscellaneous fuels reported by developers, and fuel cells that use fuels other than natural gas

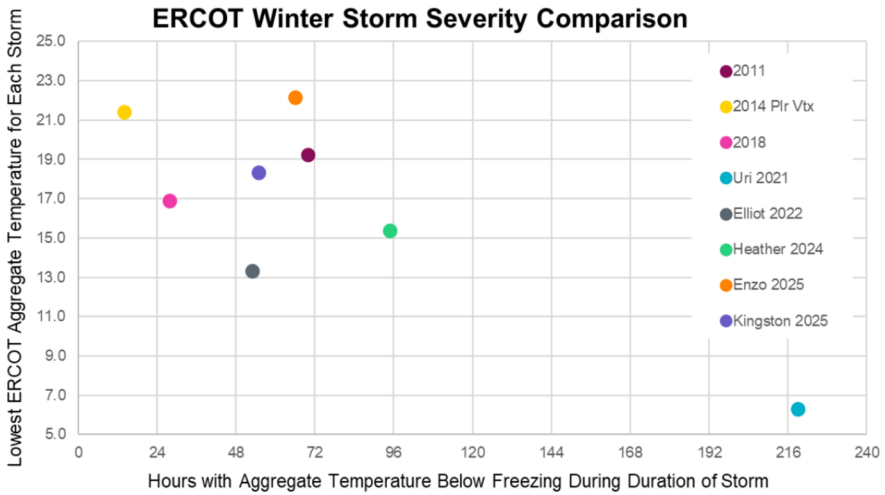
Transmission System Challenges & Complexities

- Demand is escalating as new large loads are added to the ERCOT system faster and in greater sizes than historical interconnections.
- The current generation mix is more diverse than previous portfolios, can be built faster, and is more geographically disbursed from load centers.
- While we're seeing changes in the speed of load growth and generation coming onto the Texas power grid, transmission still requires 3-6 years to be energized.



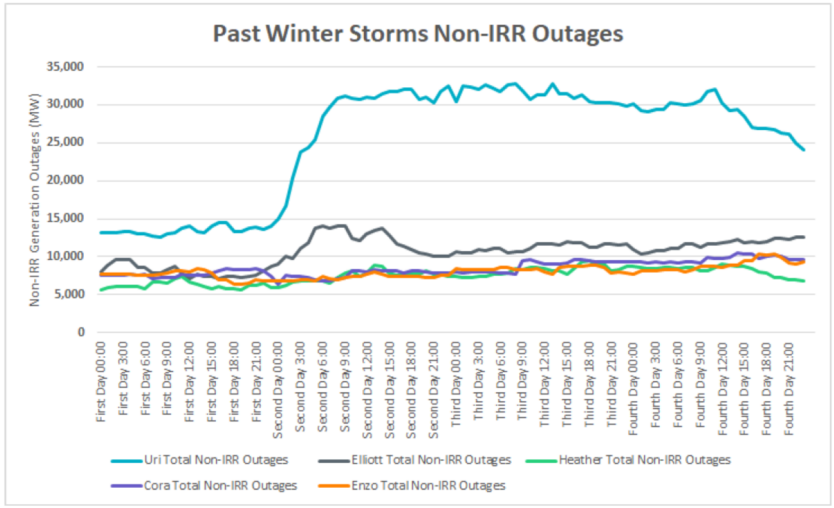
Key Takeaway: The forecasted pace of load growth could exceed the pace at which transmission capacity can be built to support it.

Comparison of Past Winter Storms



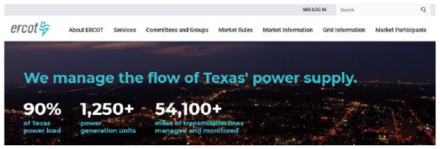
Key Takeaway: Winter Storm Kingston was less severe than several historical storms that have impacted the ERCOT region, however, it was the most severe storm this winter season.

Historical Non-Intermittent Renewable Resource (IRR) Outage Data from Previous Winter Storms



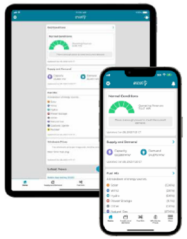
Key Takeaway: Non-IRR outages stayed at a consistent level across the past three winter storms.

ERCOT Communication Channels



ERCOT website – www.ercot.com

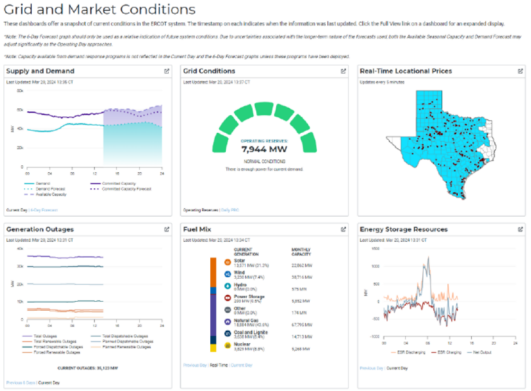
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- Daily and seasonal weather
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Mr. LATTA. Well, thank you very much for your statement.

And that concludes our opening statements from our witnesses. And at this time, we will start questions from our members. And I will start with myself for 5 minutes.

And I am going to ask the same question I have asked for the last 2 years, maybe just get an answer more or less from everyone: We have to have more or less power produced in this country?

Mr. ASTHANA. More.

Mr. VAN WELIE. More.

Ms. CURRAN. More.

Mr. DEWEY. More.

Mr. NICKELL. A lot more.

Mr. MAINZER. Significantly more.

Mr. VEGAS. Agreed. We need more.

Mr. LATTA. Thank you very much.

Mr. Asthana, if I can start my questions with you. There are reports of supply chain delays for dispatchable generation resources as well as ongoing delays for essential grid components such as distribution transformers. How important is it to address these delays quickly?

Mr. ASTHANA. Yes, I think it is both critical to address the delays quickly as well as try to be creative with the tools that we do have immediately. And we are trying to do both.

Mr. LATTA. Well, let me follow up. Your testimony also details a striking graph explaining the delta between grid additions and deactivations. How much value is there to bring back mothballed power plants back online immediately or short-term or long-term reliability challenges?

Mr. ASTHANA. I think it is an important part of the mix. And I think it is an important part of the mix because it requires less reliance on the supply chain. Because these plants exist, and so it is easier in some cases to actually restore them than to build a whole new one. But I think it is part of the solution. If we can get plants back from mothball, we would appreciate it.

Mr. LATTA. Let me just follow up real quick on that. In your testimony, you had mentioned—you said—how long does it take to build an AI plant?

Mr. DEWEY. Data center, maybe 18 months.

Mr. LATTA. OK. And then how long to build a power generation station?

Mr. ASTHANA. Five-plus years.

Mr. LATTA. Is that including the permitting?

Mr. ASTHANA. Including the permitting, yes.

Mr. LATTA. OK. Thank you.

Ms. Curran, your testimony similarly discusses the need to allow reliability to inform the pace of retiring generation resources. How can we ensure that the pace of retiring generation resources does not outpace the addition of new resources?

Ms. CURRAN. So first and foremost, it is considering reliability in those retirement decisions. Today, as those decisions are made, they are generally driven by policy, in some cases economics. But there is not a check, at least at the MISO, to determine what the impact would be on the ability to have sufficient energy to serve the system.

Mr. LATTA. OK. Thank you.

Mr. Asthana, if I could go back to you again. Your testimony went on to highlight some of the barriers of generation growth, including Federal and State energy policies, supply chain constraints, and systematic permitting challenges. As I stated in my opener, the markets that you administer do not operate in a vacuum.

How are the policies outside the purview of your electricity markets and grid operations causing premature retirements and inhibiting growth in generation development?

Mr. ASTHANA. Absolutely. So there is multiple, mostly decarbonation policies that are State and Federal that have either forced generators to choose between really expensive upgrades that they couldn't afford or to go offline and have pushed generation offline.

And, you know, I wrote down something you said, Chairman: "Markets cannot build what governments do not let them." I think we are seeing that. It is also true for power plants cannot operate if governments do not let them. And we have seen policies that do that.

An example of that is the EPA 111 decarbonization policy. I mean, again, I don't make a value judgment. Climate change, in my opinion, is real and needs to be addressed. But I think reliability needs to be addressed also and simultaneously.

Mr. LATTA. Let me follow up one last question to you. I have heard concerns from workers in an Ohio coal plant about what are the detrimental effects of the previous administration's policy and recent State=level initiatives that could threaten their jobs.

As you grapple with challenges resulting from rapid and widespread retirements of dispatchable generation without adequate replacement, is there merit in pausing the adoption of harmful policies at the Federal and State levels?

Mr. ASTHANA. For a reliability perspective, definitely there is merit in making sure that we don't retire generation that we will need to keep the lights on.

Mr. LATTA. Thank you.

In my last 38 seconds, Mr. Nickell—it will be real quick, if I may—while much of the focus of our electric grid is on increasing demands for electricity from data centers and domestic manufacturing, we also have to make sure the ratepayers are not unduly burdened. As you mentioned in your testimony, SPP enjoys some of the lowest wholesale electricity prices in the country because of your diverse generation mix in renewables and baseload.

Will new investments into energy-intensive industries raise costs on ratepayers, or how can these new investments lower price for households? I only have about 3 or 4 seconds.

Mr. NICKELL. Yes, it could. It depends on how you do it, and I think we have to be really smart about how we move forward with that. Today, transmission needed to serve new load is spread across the region. It is cost-shared. We may not be able to do that when large data centers are located in certain very specific locations. So we are evaluating that now.

Mr. LATTA. OK. Thank you very much. My time has expired.

I recognize the gentlelady from Florida, the ranking member of the subcommittee, for 5 minutes for her questions.

Ms. CASTOR. Well, thank you, Mr. Chairman.

Last week, the President fired—illegally fired the Commissioners from the Federal Trade Administration. Two of those members, Commissioners on the Federal Energy Regulatory Commission and the Nuclear Regulatory Commission, enjoy basically the identical statutory protections as the FTC Commissioners, meaning that the President likely thinks he can fire the FERC and NRC Commissioners too.

And I think the politicization of our energy regulators, allowing the President's whims to dictate which FERC and NRC Commissioners can serve, is an awful idea, and it follows the National Nuclear Security Administration firings by Elon Musk. All of this really socks it to consumers, whether we are talking affordability, reliability. It is just dangerous and costly.

Mr. Asthana, I heard you talk explicitly about a stable FERC and what that means to your operation. In fact, at one of our last hearings, a witness said they never want to see proceedings before FERC and State utility commissions to become politicized.

So I would like to ask each of you: Is more politicalization of FERC a good thing or a bad thing?

Mr. ASTHANA. Yes. I would say FERC is an incredibly professional body, and I think they make technical decisions, and we rely on that—on that technical expertise.

Ms. CASTOR. So just if you could answer maybe more or less, should FERC be more politicized or less politicized?

Mr. ASTHANA. I think less between those two choices, for sure.

Mr. VAN WELIE. So my observation over the years is FERC has tried to stay in the middle to the extent possible, and I think that less politicization is helpful.

Ms. CASTOR. Thank you.

Mr. VAN WELIE. The other point I would make is it needs to be alignment between Federal and State policies.

Ms. CASTOR. Thank you.

More or less politicized?

Ms. CURRAN. For the same reasons, I will also say less. The stability of FERC is very important to move all of these things forward.

Mr. DEWEY. A less politicized, balanced approached would make all this transition a whole lot easier.

Mr. NICKELL. Less politicized, independent absolutely is important for keeping the lights on.

Mr. MAINZER. A strong and independent FERC is essential to the success of our industry, so I would say less politicization.

Mr. VEGAS. Speaking on behalf of my peers since FERC really doesn't provide much oversight in Texas, I think a stable, independent FERC works best.

Ms. CASTOR. Thank you.

One of our greatest challenges today is getting new sources of electricity onto the grid as quickly as possible in this era of increased electricity demand. Interconnection processes, while critical to maintaining the reliability of the grid, can also take far too long under the current framework.

Last week, FERC Commissioner David Rosner wrote a letter to each of you detailing new opportunities to streamline the inter-

connection process. In a recent study by the Midcontinent Independent System Operator, MISO, an automated process was able to nearly replicate in 10 days the results of an interconnection study that took nearly 2 years to conduct.

So, Ms. Curran, can you briefly talk about what MISO found? What are the results? How can other grid operators start looking at automating and speeding up their interconnection studies?

Ms. CURRAN. Sure. Absolutely. One of the challenges, actually, in operating the grid is that there is not a lot of software development that happens in this space.

There is a vendor that has come to market that has put some automation around work that currently takes more of a guess-and-check approach by our engineers, and by automating some of that work with a codified rule set, we have been able to speed up on small samples the progress of the queue study by quite a bit. We are very optimistic about it. We are starting to apply it to larger samples. We do spend a lot of time with our peer RTOs sharing best practices, including information about what we are doing here.

Ms. CASTOR. Thank you.

And, Mr. Nickell, you have also had some success here. What else can FERC do to support this kind of innovation?

Mr. NICKELL. Encourage us, which clearly is happening with the letter from Commissioner Rosner. Very much appreciate what he has tried to do with that.

Ms. Curran spoke about the fact that we share best practices already, and we have got a lot that we are really focusing on. We call it transformative technology. We are going to have to rely on that, and we are going to have to depend on artificial intelligence to make the solutions not only quicker but much better.

So thank you for your support, and we will need that support from FERC and the encouragement that they have already begun to provide.

Ms. CASTOR. Thank you very much.

I will yield back.

Mr. LATTA. Thank you. The gentlelady yields back.

The Chair now recognizes the gentleman from Kentucky, the chairman of Energy and Commerce Committee, for 5 minutes for questions.

Mr. GUTHRIE. Thanks. Thanks, Mr. Chair. I appreciate the recognition.

Thank you all for being here.

You know, on the FERC and then the other agencies, we just can't assume that the members of those agencies don't have agendas as well. And so we want them to work—want them to work properly, but we also have oversight and checks and balances we need to have.

When I first came into the role that I have this Congress right before—actually, I have kind of been associated more with the healthcare side of this committee. Our committee has a broad—as I pointed to Mr. Dingell earlier, we have a lot of broad jurisdiction.

And I had an opportunity that—we are actually going to have a great opportunity in a couple of weeks to have a hearing with Eric Schmidt from—Google Eric Schmidt, not Senator Eric Schmitt—wrote a book with Henry Kissinger called "Genesis," presented it

at the Library of Congress, and I walked away with my mouth open, my heart beating, going, "Wow, this is the fight of our lives. Are we going to win the AI battle with China?" And it really is. It is the fight of this committee, I think, or at least the direction I want to take the committee.

And he didn't say this. These are my words, not his, but essentially he said it. He said that it is like being the dollar being the world currency. Somebody is going to have the world currency. Europe has chosen not to be that by their energy policies and their regulatory policies, which is right in the purview of this committee. China—we don't want to have the regulatory policies of China, but we—so if you talk to people in this area, they say we have the brain power. We have the capital. We have to have a stable regulatory environment, and we have to have the energy. We absolutely have to have the energy.

And so if you look at the demand and growth of energy, what the scary thing about it is, even if we said, "All right, let's go full bore," we are still probably a decade behind where we need to be.

And so when I talked in my opening statement—so this is for Mr. Asthana and Mr. Nickell. In my opening statement, I mentioned that we are going to take offload power, baseload power—we are going to take it offline as much as—almost as much as we are going to—demand is going to grow in the next few years.

And so what do we need to do, Mr. Asthana—is that how you say it correctly?

Mr. ASTHANA. Yes.

Mr. GUTHRIE. And Mr. Nickell. So what do we need to do to reverse just retirement of generation we know that produces energy that we need?

Mr. ASTHANA. I think there are a couple of things, Chairman. One is just sending the right price signals so that those generators can afford to stay. Those do lead to increases in prices for customers, but I think that is——

Mr. GUTHRIE. How do we send the right price signal?

Mr. ASTHANA. Our markets are doing that. Our markets are holding up a mirror and reflecting back the supply-and-demand situation, and this pricing is being——

Mr. GUTHRIE. So that happens without government doing anything? There is no initiative we need to do to——

Mr. ASTHANA. Not for Congress, I would say. I think FERC is critical in making sure that the markets are holding up a true mirror to the supply and demand situation but not for Congress. I think——

Mr. GUTHRIE. What would be a not-true mirror if they are holding up—what would FERC do to hold up not a true mirror?

Mr. ASTHANA. Well, I would say there is a lot of tweaking that can happen around the market rules, and we have been continuously improving them. But the fact is I think that all of our markets are in some shape or form signaling we need more supply, and that is—

Mr. GUTHRIE. But that is my question, I guess.

So if the market is signaling you need more supply, and you are saying—you are taking baseload power offline—not because of

what Congress or the government is doing, it is because the market signal is not there—I don't understand that then.

Mr. ASTHANA. Yes. So let me get to the second part of my answer, which is the markets cannot keep a power plant open if it is illegal to operate the power plant, no matter what price signal you sent.

Mr. GUTHRIE. OK.

Mr. ASTHANA. And I think—so there are laws, whether they are environmental laws passed by the States or the Federal Government——

Mr. GUTHRIE. I get your point. There is not a role in the market. There is a role in us to allow you to participate in the market.

Mr. ASTHANA. Yes.

Mr. GUTHRIE. OK. OK. That makes sense. All right.

Mr. Nickell?

Mr. NICKELL. You bet. And thank you for the question.

So I mentioned in my testimony earlier that RTOs have a role to play, and that role consists of leadership and vision and communication. We have to be more visible, and within SPP's footprint, we have done just that. We have been communicating the challenge that we are facing.

Mr. Asthana talked about market signals. For us, what that looks like is setting a requirement that all load serving entities have to meet for excess generation, and that requirement has been increased now three times over the last 2 years.

Mr. GUTHRIE. You need stability in the market.

Mr. NICKELL. So utilities know that in order to be able to meet that requirement, they can't retire generation until significant replacement generation is available.

Mr. GUTHRIE. All right. Thanks. And I only have 20 seconds.

So, I mean, if the world's existential threat is climate change, or if you believe it—I am simplifying this to two. It is a little more complicated—dominating AI over—being the world platform for AI.

If you go the European route and say it is all climate change and we are going to let AI not participate in that market, that world—if you go that route, you are going to cede the AI to China. And China is building a coal plant every 2 weeks to support the energy, first of all. So you are not going to win. You are going to lose both. And that is why we have to focus on making sure we win this battle in a responsible way.

So thank you, and I will yield back.

Mr. LATTA. Thank you. The gentleman yields back.

The Chair now recognizes the gentleman from New Jersey, the ranking member of the full committee, for 5 minutes for questions.

Mr. PALLONE. Thank you, Chairman Latta.

You know, I want to say with the full committee chairman, I want to win the AI battle with China too, but you have got a national security advisor who can't even send an email without jeopardizing national security. I mean, I don't know how the hell we are going to win an AI battle with China with these characters running the show, including the Vice President and the Secretary of Defense and the others. I mean, it is like a clown show. But, in any case, let me go back to the issue at hand.

Mr. Asthana, as I alluded in my opening statement, I am incredibly frustrated at the cost that PJM's failures are imposing on my constituents. The vast majority of the rate increase on New Jersey families is due to what happened with PJM's capacity market.

So do you think it is fair that families around the region are seeing their bills spike? Simple question.

Mr. ASTHANA. Let me correct the record. So New Jersey imported last year 43 percent of the energy that it consumed, OK? And that is New Jersey's right to have that plan. That is a benefit of being a PJM.

New Jersey's plan to make up that gap was to build offshore wind from 2018 onward. And New Jersey came to us and said, "Hey, can you help us with the offshore wind plant?" And we put in probably more effort than we have with any other State to help New Jersey with the offshore wind plant, and we were proud to do it. And, in fact, the New Jersey BPU gave us credit for saving New Jersey consumers $900 million through our work.

Now, the problem is there is not one turbine spinning——

Mr. PALLONE. I have to get to my other questions. But, yes, the Trump administration is doing whatever they can to stop any kind of offshore wind. They repealed all the permits and whatever. So to talk about offshore wind when you have an administration that is totally opposed to any kind of wind power, I don't even know what the point is.

But, look, you said in your testimony more supply, more demand. You said that you are trying to create more supply now. But I just think it is a shame that New Jersey families are paying for what I consider PJM's mistake. The changes that PJM is making that you talked about, whether it is the processes to get energy hooked up to the grid or for regional plant—transmission planning or capacity markets—all of these changes should have been made years ago, in my opinion.

So why didn't PJM make its reforms to its interconnection queue and grid-planning processes a decade ago? Why did it wait so long?

Mr. ASTHANA. Well, just to clarify my answer earlier since you asked, the reason we don't have turbines spinning offshore in New Jersey—it happened before the current administration.

Mr. PALLONE. No, I know. But, look, Trump has killed the whole thing. So, you know, he made that decision to pull it all. It is a political decision. It is a mistake.

Back to this. Why didn't PJM make its reforms to its interconnection queues and grid-planning process a decade ago? Why did it wait so long? I appreciate you testified about how you are trying to increase supply and address these things, but what was the reason for the delay?

Mr. ASTHANA. It wasn't a delay, Ranking Member. We have been making continuous reforms for the last decade, and the process for interconnection needs to match the type of generators that are interconnecting. And so when the generators shifted to more intermittent renewable generators, we shifted our process with the support of FERC.

And I would point to you, we have 50,000 megawatts of generation ready to go—ready to go—on a system that only consumes 150,000 at peak——

Mr. PALLONE. Well, I just think you should have made these changes sooner, and the pace of change just hasn't been acceptable.

But I want to shift to a national problem. The Inflation Reduction Act is, in large part, responsible for making nearly all the planned new electricity generation in this country feasible. Without it, the economics for many of these projects simply wouldn't work, driving rates up even higher for families.

So let me just ask—I know there is only a minute—Mr. van Welie. In your testimony, you mentioned the battery storage, wind resources, and grid-scale solar make up nearly the entire of ISO New England's interconnection queue. Would it be good or bad for your grid's reliability if the repeal of the Inflation Reduction Act meant that none of those projects were ever built, if you will?

Mr. VAN WELIE. I think it is going to make it harder for the supply resources to come forward.

Mr. PALLONE. All right. See, I mean, my point with the two—both gentlemen is I think that we need more supply. There is greater demand. We need to have all kinds of energy generation. I am an advocate for wind, for solar, for nuclear, and I understand that we also need more with fossil fuels. We need all of the above.

But what I see happening here is that, you know, right now, because of the efforts by the Republicans, you know, to repeal the Inflation Reduction Act, that is not going to happen. And there is going to be less supply and greater demand, and that is not a good thing.

So thank you. Thank you, Mr. Chairman.

Mr. LATTA. Thank you. The gentleman's time has expired and he yields back.

The Chair now recognizes the gentleman from Texas, the vice chair of the subcommittee, for 5 minutes for questions.

Mr. WEBER. I thank the chairman for the recognition.

I do want to make note that the Member from New Jersey calling the administration clowns was an editorial statement and not necessarily reflecting the view of the management. I want to get that in the record.

But I also want to ask some of you all—we will start over here with you on the left. Do you ever feel or hear—or you feel about hearing about you are somewhat unfairly criticized because sudden environmental changes happen which you had zero control over? Do you all ever feel like you are unfairly criticized in that regard?

Mr. ASTHANA. Thank you for the question. I think I would say yes, but I also think it is fair to hold us to a high standard. We want to be held to a high standard.

Mr. WEBER. OK.

You are next. You are feeling, yes or no, unfairly criticized?

Mr. VAN WELIE. Yes.

Mr. WEBER. OK.

Ma'am?

Ms. CURRAN. Sure.

Mr. WEBER.Sir?

Mr. DEWEY. Absolutely. We strive to be the authoritative source, the independent source of information. So as long as we can stick to the facts and its balanced assessment of what the impact to

some of these policies are, that is generally a safe place to be, and it is helpful—

Mr. WEBER. Kind of like Sergeant Friday. They just stick to the facts.

Sir?

Mr. NICKELL. You asked a difficult question. We deserve the criticism that we deserve. There are things that we can do better and we will do better, and we deserve criticism for those.

Mr. MAINZER. I think at the end of the day it all starts with accountability—with extreme accountability for reliability. If we get criticized, we will take it, but we are always going to stay focused on producing results.

Mr. WEBER. Mr. Vegas?

Mr. VEGAS. Vice Chairman, we are always working to get better. Continuous improvement is our motto.

Mr. WEBER. Absolutely. And I hope people watching this interview or seeing it later—this hearing—recognize that you all have a very critical place to play—a role to play.

So I am going to come back to you, Mr. Vegas. In Texas, as you discussed in your testimony, Texas is seeing significant investments into data centers and manufacturing facilities because of our business-friendly State posture and access to reliable and affordable power, quite frankly. Can you discuss how these particular opportunities are important to potential economic development projects?

Mr. VEGAS. It is critical. Economic growth is directly correlated with energy reliability and affordability, and we recognize that in Texas. The light regulatory environment that we have enables resources to be added to our grid more quickly than virtually anyplace else in the U.S. on both the supply and on the demand side. That is the engine for economic growth, and we continue to try to do everything to—

Mr. WEBER. And we recognize that. I am glad you all do.

And for our colleagues across the aisle who have filed a proposition to make ERCOT join the rest of the grid, you know, we have a bumper sticker that says, "Don't mess with Texas." So we want to adhere to that.

How do you conduct generation and resource planning to ensure all electricity consumers are paying the lowest possible rates and yet still have reliable power? You actually alluded to it in your testimony.

Mr. VEGAS. Yes. Affordability is something that is at the front of our strategic pillar and focus. So we think about reliability as well as affordability.

And the way we do allocations in Texas, you know, everything just flows down to load, to consumers, large and small alike. And so it is really important, especially as we go into a growth environment—which we are all going into—to look at how that cost allocation is done to make sure it is continued to be done fairly.

We have a method that we have been using for the last 20 years. It has been working, but we are going into a new phase. Looking forward, it is a good time to look at that again and make sure it remains fair.

Mr. WEBER. Well, thank you for that. And ERCOT leads the Nation in renewable energy. Of course, you weren't there when the CREZ project went into effect. You know, I spent 4 years in the Texas House before I got demoted to Congress. And so we passed that project. We made sure that energy was efficient.

So wind and solar are compromising 42 percent of ERCOT's installed generation capacity, and yet Texas remains well-balanced with dispatchable sources providing 65 percent of deliverable energy. Given that solar is one of the fastest energy generation sources and its role that it plays in ERCOT, how important is us in Texas that solar technology is manufactured right here in the U.S. of A.?

Mr. VEGAS. It is critical that we see the supply chain move here to the United States. The security and the reliability of that supply chain is fueling the growth and a lot of the energy supply in the country. So the ability to have that supply chain protected here in America is critical.

Mr. WEBER. So when you see restraints on supply chains—I know this is a question for each and every one of you, but I am down to 27 seconds—on those supply chains, and these things are getting built in China as well as other countries, you all have to cringe. You have to know in your heart of hearts that this stuff needs to be done in the United States of America.

Mr. Chairman, I am going to yield back you 10 seconds.

Mr. LATTA. The gentleman yields back.

And the Chair now recognizes the gentleman from New Jersey's Eighth District for 5 minutes of questions.

Mr. MENENDEZ. Thank you, Chairman.

This summer, my constituents in New Jersey are bracing for a 17 percent increase in their utility bills. This jump is completely unacceptable and unsustainable, especially considering it was avoidable. PJM blames these increases on increasing demand and decreasing supply. I would like to understand these claims a bit better, specifically the point on decreasing supply.

One of the biggest drivers in the last capacity auction was a significant change in how dependable PJM assumed natural gas plants were. According to its independent market monitor, fully half of the price increase we saw in this auction was due to the change in how reliability was calculated. To put it in plain English, it turns out that natural gas plants were less reliable than we thought, and now our constituents are paying the price.

Mr. Asthana, can you talk about why PJM only updated those accreditation values for natural gas plants last year and not earlier, especially after Winter Storm Uri in Texas, where we saw thermal plant outages drive a huge amount of the unexpected outages?

Mr. ASTHANA. Thank you for that. That is a great question.

The answer to that is because after Winter Storm Uri in Texas—we get our natural gas from the Marcellus and Utica shales from our region. And we went to the industry in that region and said, "Hey, are we protected? Are we winterized? Are we protected against this sort of winter outage risk in the fuel supply system?" And the answer was yes. And then we had Winter Storm Elliott,

and we learned that we weren't. We lost almost a quarter of our generation.

And so immediately after Winter Storm Elliott, we said we have to recognize this risk that we have now seen in how we accredit generation, and that is when we took action.

Mr. MENENDEZ. OK. But we have to acknowledge, right, there is increasingly changing weather patterns, right? And so we have to sort of be a little bit more on the forecast front than we can do in sort of historical trends, because these changes are happening so quickly that to prevent these types of outages and shortages, we need to be a little bit more forward-thinking and think about redundancy to ensure we are not just hoping for the best-case outcome but preparing for the worst-case outcome.

I know you have also referenced eight policies driving generator retirements. I just want to make the point that, even though policy may have influence on such retirements, PJM and its partners have reasonably known for years about a large number of these retirements. Surely the capacity market has known about these retirements for a long time as well and priced them in.

The discussion about transitioning to clean energy sources has been ongoing for decades. These retirements of decarbonization policies which PJM blames for decreasing supply should not have been a surprise.

As Ranking Member Pallone mentioned, PJM by far has the worst backlog and slowest interconnection process of any other grid operator in the country. Thousands of projects are waiting to get connected. As you talk to us about the importance of building more power, your organization has lagged in its ability to actually connect power to the grid. Now our constituents are paying for this mismanagement, and I am concerned that my constituents will continue to foot the bill with additional increases in 2026 and beyond.

So will PJM commit to taking every step possible to bring new generation online, including the clean energy sources already in the queue, and bring down costs for New Jerseyans?

Mr. ASTHANA. Yes. We are definitely committed to that.

I do have to correct you. We do not have the worst queue in the country, particularly when you adjust for the size of our system. We serve 21 percent of U.S. GDP. We believe we have less than 20 percent—much less than 20 percent of the national queue. So the work that we have done on our queue is showing dividends.

But to your question, absolutely. New Jersey is critical to us. We want to do everything we can to support you, and we are committed to accelerating our queue continuously as much as we can.

Mr. MENENDEZ. I appreciate it. What immediate steps is PJM taking to address their interconnection backlog?

Mr. ASTHANA. Well, the steps we have taken already that I pointed out have got us from almost 200,000 megawatts in the queue down to 67,000 left to go, with 50,000 more through the queue signed, ready to build, some of which we are building.

So for that 67,000, we have a FERC-approved process. We are executing it now. We will get 17,000 of that by the end of this year, the other 50,000 by the end of next year. Then we will be on a reg-

ular 1-to-2-year queue cycle, which is a huge advancement from where we have come, and we are not stopping there.

On top of that, we have just opened two additional windows for generators to come into the queue to add to what we already have. So we are growing the queue by opening the door, and we have a lot of people that want to come through that door, and we are committed to processing them as well.

Mr. MENENDEZ. And just real quickly, with respect to the energy capacity that is cleared but is yet to be connected to the grid, what challenges are those developers facing in getting their projects online?

Mr. ASTHANA. A lot of supply chain issues, financing issues, and a lot of what we call NIMBY issues—not in my back yard. People don't want the infrastructure where they live.

Mr. MENENDEZ. And with respect to supply chain and financing, does the disruptive nature of this administration help with supply chain issues and with financing issues? Yes or no.

Mr. ASTHANA. I am not sure.

Mr. MENENDEZ. I think the answer is no.

Thank you so much. I yield back.

Mr. WEBER [presiding]. The gentleman yields back.

The Chair now recognizes the gentleman from Alabama, Mr. Palmer.

Mr. PALMER. Thank you, Mr. Chairman.

Ms. Curran, MISO issued warnings about brownouts and blackouts. What was the basis for those warnings?

Ms. CURRAN. If you are speaking to the NERC assessment that recently came out, we do a forward projection of the expected supply-and-demand balance.

Mr. PALMER. That was the basis? The NERC assessments?

Ms. CURRAN. The NERC assessment, I think, was where that forecast was made, via NERC.

Mr. PALMER. Wasn't the NERC assessment that the biggest challenge for meeting power demand and avoiding the blackouts and brownouts the change to the resource mix?

Ms. CURRAN. No. The NERC assessment laid the information that we showed, which says that our forecast of the amount of supply that is available to meet the demand that we expect faces shortfalls in the coming years.

Mr. PALMER. But I think the MISO report also indicated that it was the shutting down of hydrocarbon-produced power and trying to replace it with renewables had created basically, in my terminology, a deficit in power output that has not yet been met.

The NERC report, particularly in 2023, in assessing the challenges facing our power grid, said that the single biggest challenge or threat for power output was the change in resource mix. In other words, to put it in lay terms, we have shuttered too many hydrocarbon plants without bringing online enough renewables to meet the demand.

When you take that in context to the fact that we are in an arms race with China for development of artificial intelligence and quantum computing, I think it really becomes problematic. And we keep talking about—we get into my colleagues on the other side of the aisle and their concerns about the climate. We all are concerned

about climate issues, but we are losing sight of what I think is a major national security issue.

If China—whoever takes the lead in artificial intelligence and quantum computing, they are going to be the superpower. And we don't have the power generation capacity right now that we are going to need. We have got to build these data centers. They are going to require massive amounts of power.

So I am glad to hear—and I am not sure I have heard this before from some of my colleagues, that they support all of the above, including nuclear, which is where I think we need to go.

I am going to ask Mr. Vegas, Mr. Asthana, Ms. Curran, Mr. Nickell. In your opinion, did the EPA take—each of you coauthored comments—I will set this up—to the EPA during the previous administration which expressed strong concerns about the Clean Power Plant 2.0 because of the impact it would have on reliability within each of your footprints. And then those in charge of ensuring grid reliability in your respected areas—it should have been imperative that the EPA, who does not have the necessary expertise to analyze reliability, listen to those concerns.

And what I would ask each of you, in your opinion, did the EPA take your concerns into consideration when they were finalizing the Clean Power Plant 2.0?

Mr. Vegas?

Mr. VEGAS. No, I don't think EPA adequately considered reliability in making their final determinations——

Mr. PALMER. Mr. Asthana?

Mr. ASTHANA. Yes. I would say the same thing as Mr. Vegas said.

Mr. PALMER. Ms. Curran?

Ms. CURRAN. So a little more nuance from me. I think that they did make some changes in response to our feedback, but as my colleagues noted, not nearly sufficient to address the issue at hand.

Mr. PALMER. Mr. Nickell?

Mr. NICKELL. Congressman Palmer, I would agree with Ms. Curran. I think they did listen. I don't think they went far enough.

Mr. PALMER. But would you all agree that the Clean Power Plant 2.0 impacts reliability in your area and ultimately will impact the ratepayer?

Mr. Vegas?

Mr. VEGAS. Yes. It has the potential to shut down nearly 14,000 megawatts of coal plants in our region, which would affect reliability and cost.

Mr. PALMER. Which goes back to the point I am making earlier that we have shut down too much hydrocarbon-generated power without bringing renewable power online or some other form of power generation to meet the demand.

Same question to you, Mr. Asthana.

Mr. ASTHANA. Yeah. It definitely raises reliability concerns for us.

Mr. PALMER. Ms. Curran?

Ms. CURRAN. Yes. Reliability concerns.

Mr. PALMER. Thank you.

Mr. Nickell?

Mr. NICKELL. Yes. Absolutely increases our reliability concerns and increases our concerns about the affordability of electricity as long as those units are needed to be maintained online.

Mr. PALMER. Real quickly, in my last second here, would it have been more workable if FERC or some other agency had done the actual reliability assessment? Quickly, yes or no.

Mr. Vegas?

Mr. VEGAS. I am sorry. I didn't understand the question.

Mr. PALMER. Would the EPA rule have been more workable if the Agency or FERC had conducted an actual reliability assessment of the rule's impacts and adjusted the rule to prevent these impacts?

Mr. WEBER. Very quickly, please.

Mr. VEGAS. It would have been more—yes, it would have been more effective.

Mr. PALMER. Mr. Asthana?

Mr. ASTHANA. That is a tough hypothetical for me to answer.

Mr. PALMER. Ms. Curran?

Ms. CURRAN. Somebody needs to be doing reliability analysis on retirement.

Mr. PALMER. That is a good answer. Thank you.

Mr. Nickell?

Mr. NICKELL. I agree with Ms. Curran.

Mr. PALMER. Mr. Chairman, I yield back.

Mr. WEBER. The gentleman yields back.

The gentleman recognizes the lady from Virginia, Ms. McClellan, for at least 5 minutes.

Ms. MCCLELLAN. Thank you, Mr. Chairman and Ranking Member Castor, for having this hearing.

Mr. Asthana, I am glad that you mentioned the lessons learned from Winter Storm Elliott. As you know, Virginians will never forget Winter Storm Elliott in 2022 when more than 100,000 people in the Commonwealth and 1.5 million others in nearby States lost power. And while we expected some outages, 40 gigawatts of coal and natural gas plants failed, shutting down, as you said, a quarter of PJM's generation capacity. Gas plants alone, whether due to the issues at the power plant or issues with gas availability, were responsible for 70 percent of the outages.

Now, that didn't need to happen. And with more clean energy generation and smarter long-term transition planning, we could have kept the lights on and saved families money.

Renewables actually performed well during the storm, and wind power exceeded expectations thanks to the strong winds of the hurricane.

As you mentioned, we can't afford to ignore these lessons, particularly as climate change continues to make winter storms and other extreme weather events more frequent and severe. And so, while we want to ensure that we have enough generation to meet demand, we want to also make sure it is reliable and can meet peak demand.

And so when clean energy combines with energy storage, these generation sources can play a key role in stabilizing the grid during peak demand, and clean and renewable energy are also becoming

cheaper to operate than fossil-fuel-based generation and help protect consumers from fuel cost spikes.

So the Coastal Virginia Offshore Wind Project is one that we care very much about in Virginia, Democrats and Republicans. And if it had been up and running during Winter Storm Elliott, it is estimated it could have saved ratepayers an estimated $10 million in a single day.

So, Mr. Asthana, would you agree that adding renewable energy paired with storage to the grid can benefit grid reliability?

Mr. ASTHANA. Yes, it definitely can, and we would love more of that, and we support Coastal Virginia Offshore Wind significantly.

If I may, I just wanted to add one clarification. The outages that consumers saw during Winter Storm Elliott in Virginia were not because we didn't have generation. It was because of icing and storm damage for more local power lines.

Ms. MCCLELLAN. OK. But it was the gas power plants, right?

Mr. ASTHANA. It wasn't really because of the gas power plants. It was because of storm damage to the local—even though we had a lot of gas power plants fail, in part thanks to exports from Rich in New York, we had enough power to serve all our customers.

Ms. MCCLELLAN. But the point is you had gas power plants fail, and if the wind project had been up, the wind generation could have helped to keep people online during that.

Mr. ASTHANA. It would have helped us import less from New York.

Ms. MCCLELLAN. I am going to take that as a yes.

So you can understand why I am perplexed that the Trump administration has this all-out war on wind and wants to prohibit any new wind projects, when we keep hearing from our friends on this committee on the other side of the aisle that we need more generation. That includes more renewables in the mix. And so I am glad we agree that that would help.

And I hope PJM keeps this in mind as it makes selections for its projects that it is expediting under the new Reliability Resource Initiative framework, because I am concerned that if frameworks like that are used for more than a one-time fix, it could permanently imperil the benefits that consumers see from regional grids and competition.

So can you confirm that PJM views RRI as a one-time intervention into its interconnection queue?

Mr. ASTHANA. Yes.

Ms. MCCLELLAN. Thank you.

Now, I was very glad to hear all of the witnesses talk about how important an independent FERC is, and I agree. But FERC is not the only Federal agency that is important to whether new generation projects come online. Is that right?

Mr. Asthana, I will start with you.

Mr. ASTHANA. Yes. There are various agencies that have a role.

Ms. MCCLELLAN. And two of those are the Department of Energy and EPA, right?

Mr. ASTHANA. [Nonverbal response.]

Ms. MCCLELLAN. And you cannot have new generation come online without mandated-by-law reviews by EPA, right?

Mr. ASTHANA. I think it depends on the State. So I don't know the answer to that question specifically.

Ms. MCCLELLAN. OK. Well, subject to check, it is yes.

But you would agree that the Department of Energy and EPA play an important role in new power generation coming online?

Mr. ASTHANA. Yes, I agree.

Ms. MCCLELLAN. OK. And yet, President Trump and DOGE have led to the firing of over a thousand employees from the Department of Energy——

Mr. WEBER. The gentlelady's time has expired.

Ms. MCCLELLAN [continuing]. And the EPA, and that is going to take us in the wrong direction.

And I yield.

Mr. WEBER. The gentlelady's time has expired.

The Chair now recognizes the gentleman from Georgia, Mr. Allen, for 5 minutes.

Mr. ALLEN. Thank you, Chair Weber and Chair Latta, for convening this hearing to hear our Nation's regional grid operators. I would also like to thank all of you for your testimony today.

Obviously, we pointed out the importance of grid reliability as paramount. We have rising electricity demand, and we must ensure that our grid's capacity meets that demand.

Georgia benefits from a vertically integrated energy system ,which I believe delivers reliable and affordable power tailored to our State's unique needs. Nuclear energy plays a vital role in this equation. My district is the location of Plant Vogtle. We are very proud of this achievement. It is the Nation's largest clean nuclear energy facility, the first two new reactors built in over 30 years, and it exemplifies our commitment to sustainable, dependable power.

Mr. Asthana and Mr. Dewey, while State and Federal efforts have aimed to prevent the premature closure of nuclear power plants, some facilities have nonetheless shut down earlier than anticipated. Had those plants not been allowed to close, what effect would they have had on wholesale energy and capacity prices, and how would open plants have impacted consumers in your region?

Mr. Asthana?

Mr. ASTHANA. Yes. We need more nuclear, and if we had it, it would—other things being equal, result in lower prices.

Mr. ALLEN. Okay. Mr. Dewey?

Mr. DEWEY. Same situation in New York. The closure of the Indian Point plant was deemed to be a safety issue by New York State as a policy matter. That eliminated 2,000 megawatts of carbon-free supply close to New York City that would have certainly—certainly did impact capacity prices.

Mr. ALLEN. OK. Ms. Curran and Mr. Vegas, Congress has been working to speed the licensing and deployment of nuclear reactor technologies. Are either of you working to develop incentives in how prices are formed to encourage investment in the very long-term assets nuclear power provides to the systems?

Mr. VEGAS. Yes. Congressman Allen, we are looking at opportunities inside of the Texas Legislature to incentivize the development of nuclear power in the State of Texas.

Mr. ALLEN. OK. Mr. Curran?

Oh, Ms. Curran. I am sorry.

Ms. CURRAN. That is OK. Just making sure it was me.

So our States are largely vertically integrated, and so it is the State utility regulatory commissions that are making those resource decisions. So while our market signal does provide information about the overall supply/demand balance, ultimately, those choices are made in the States.

Mr. ALLEN. A question for all of our witnesses. Nearly 20 percent of our Nation's electricity is generated by 94 nuclear reactors constructed 40 to 50 years ago. These reactors represent enduring assets, continue to deliver significant value long after the visionary decisions to build them were made. Today's market conditions, however, would likely discourage companies from pursuing such generational investments. As States grapple with rising power demands, they are seeking innovative tools to drive the deployment of next-generation nuclear facilities.

So I offer this question to all of our witnesses: How can these potential State actions fit within your markets?

Starting with you, Mr. Asthana.

Mr. ASTHANA. Yes. I would like to clarify. About half of our States are actually vertically integrated, where the States can make that decision on what they want to build, and then the other half, it is based on the market.

But I do think it is difficult for private capital to build nuclear power plants today. It is just really difficult. It is very risky and very expensive. And so I think if we as a Nation want more nuclear power, we should think about ways to support it federally.

Mr. ALLEN. Uh-huh. Mr. van Welie?

Mr. VAN WELIE. Good question. So it really comes down to the States. I mentioned in my testimony that the States have the ability to select resources and make longer-term commitments to certainly resource classes. There is renewed entry in small modular reactors in New England. So there are conversations happening in State legislatures and with governors.

And so, you know, ultimately, I would make the same point Ms. Curran made, which is the ISO does not select these resources. It is really up to State policymakers to decide how they want to go about incentivizing or contracting for certain resource types.

Mr. ALLEN. Yes. Ms. Curran?

Ms. CURRAN. Yes. I have nothing to add to that.

Mr. ALLEN. OK. Mr. Dewey?

Mr. DEWEY. New York State has initiated a blueprint process for exploring the development of new nuclear, specifically small modular reactors. We would welcome that from a grid operation standpoint, and with our all-in approach towards generation, we think it would be a good mix for our fleet.

Mr. ALLEN. OK. I am out of time. So if you would submit for the record the answer to that question, I would appreciate it. And I have an additional question that I will submit to you, and if you would answer that for the record.

With that, I yield back, Mr. Chairman.

Mr. WEBER. The gentleman yields back.

The Chair recognizes the gentlelady from Colorado for at least 5 minutes.

Ms. DEGETTE. Thank you so much, Mr. Chairman.

Mr. Allen, I have such good news for you because in the last Congress when we had Chair Duncan of this subcommittee and I was the ranking Democrat on this subcommittee, we passed the ADVANCE Act, which we actually all voted for on both sides of the aisle in this committee. It went to the floor. We passed it, and President Biden signed it.

And what this bill was designed to do is exactly what you are concerned about, which is to streamline and modernize the regulations around nuclear power.

And as Mr. Pallone said, my colleagues on the other side of the aisle really every time seem stunned that Democrats support an all-of-the-above approach. But as we are seeing large loads like data centers and increasing demand for electricity all across America, we recognize that we are going to have to have an all-of-the-above approach, including renewables and everything else.

So, you know, let's stop acting like we haven't done anything, because the last Congress we did some very important things. One of the important things we did was the Inflation Reduction Act. I want to talk to some of you about that.

Now, all of the panelists early in this hearing, all of you said that demand for electricity is going to increase in this country. Is there anybody who disagrees with that?

No. They are all shaking their heads no.

And so the second question is, regardless of the source of the power to accommodate the increase, we are just going to need to have a variety of sources for electricity transmission, and we are going to have to increase reliability. Does anybody disagree with that statement?

No. They are all shaking their heads no.

Well, so one other question is, all of your grids that you are talking about here today, they don't just rely on fossil fuels. They also rely increasingly on renewable energy. Does anybody disagree with that statement?

No. They are all shaking their heads no.

Here is why I ask that. Because my colleagues on the other side of the aisle are implying that the way we are going to solve the issue of increased demand and increased reliability is by just simply jettisoning renewable energy and going, I guess, to nuclear and fossil fuels.

Is there anybody who thinks that your agencies and the people who you—are running the grids could jettison all renewable energy?

No. They are all shaking their heads no.

There was a recent study that was published by a think tank called RMI, and what it said is that the Inflation Reduction Act made clean energy cheaper than more than 90 percent of proposed gas plants.

And, Mr. Chairman, I would ask unanimous consent to put that article into the record.

Mr. WEBER. So ordered.

[The information appears at the conclusion of the hearing.]

Ms. DEGETTE. Thank you.

Now, collectively, the IIJA and the IRA allocated almost $17 billion in loans and grants for grid development, but despite that, the Republicans voted 54 times to repeal the clean energy plan since the Democrats passed the IRA.

So I don't have time to ask all of these wonderful witnesses today. So the one closest to me is Mr. Asthana. I am sorry for you. But what I want to ask you is, if we repealed all of that money going for grid development from the IRA, would that help or hurt our ability to stabilize the grid and to increase production?

Mr. ASTHANA. I think in the near term, the interconnection queue is full of a lot of renewable projects, many of whom are, I am sure, counting on the IRA. And so I am sure it would make those less likely to come, and we do need them to come.

Ms. DEGETTE. OK. Does anybody disagree with that on this panel?

No. They are all shaking their heads no.

Now, I just want to ask one more thing to follow up on what Ms. McClellan was asking.

Mr. van Welie, in your written testimony you talked about offshore wind as a potential vital resource for grid reliability in New England. Is that right?

Mr. VAN WELIE. Correct.

Ms. DEGETTE. Now, were you aware that, as part of the very early Executive orders, President Trump signed an Executive order putting a halt to wind production offshore nationwide?

Mr. VAN WELIE. Yes.

Ms. DEGETTE. What would that do to the ability to have reliable grid production in New England?

Mr. VAN WELIE. It has an impact, as I said in my testimony, towards the end of the decade because we were counting on these resources coming into the system by the end of the decade.

Ms. DEGETTE. Thank you.

And, Mr. Chairman, I would ask unanimous consent to put a copy of that Executive order into the record.

Mr. WEBER. Without objection, so ordered.

[The information appears at the conclusion of the hearing.]

Mr. WEBER. The gentlelady's—

Ms. DEGETTE. Thank you so much. I yield back.

Mr. WEBER [continuing]. Time has expired. She yields back.

The gentleman now recognizes the gentleman from Texas, Mr. Pfluger, for 5 minutes.

Mr. PFLUGER. Thank you, Mr. Chairman.

I want to state that I believe in the best of the above, not all of the above, and I think that differs from State to State. In west Texas, we have no access to hydropower, unfortunately, like they do in the Pacific Northwest. But if you have access to affordable, reliable sources, then we should use those.

Mr. Vegas, I think we need to do a math problem here. So sorry for math in public, but let's talk about what the current demand is in Texas for what ERCOT is serving. What are we seeing annually?

Mr. VEGAS. Current demand peak in the summer is around 80 to 85 thousand, and in the winter about 80,000.

Mr. PFLUGER. OK. And in the next 3 or 4 years with added industrialization, added population, data centers, what do we think that is going to grow to in Texas?

Mr. VEGAS. We are now forecasting that, by 2030, we expect around 150,000 megawatts. So that is an additional 65,000 megawatts over where we are today.

Mr. PFLUGER. Almost double?

Mr. VEGAS. Almost double.

Mr. PFLUGER. In 3 to 4 years. This is incredible.

So what I want to get to is, when you look at the balance, you are balancing price. You are balancing reliability. You are balancing all these different things.You know, what are the best sources that you are looking for today at 85 and, in 3 years, at 150-plus?

Mr. VEGAS. So we are getting to a point on the Texas grid where you can start to see that the peak demand is exceeding the dispatchable generation that we have available on the grid. So it is important, as we look forward, to meet the demands of this growth to grow the supply in a balanced way.

The balanced resource mix brings, I think, the best portfolio for consumers. It brings cost combinations that vary and give the optimal price, and it also brings characteristics around reliability and resilience that are important.

So as we look forward, we need to make sure we keep up with firm dispatchable generation in addition to the strong growth that we continue to see on renewables.

Mr. PFLUGER. Firm dispatchable generation.

So I just looked it up on your website, ERCOT.com. And right now in my hometown, it is 78 degrees. And we have got a little bit of wind, which is serving 18 percent of the grid, 45 percent solar.

But talk to us about when it is hot or when it is cold and how reliable on those days where you have 100-degree-plus—which we have about 90-plus days in the summer in Texas of 100 degrees or more—or when it is cold. How reliable are those sources?

Mr. VEGAS. Yes. As I said earlier, over the course of a year, the actual delivered energy on the Texas grid, 65 percent of it comes from our thermal fleet, which is our coal, our natural gas, and our nuclear. They are the backbone of reliability. They complement what we are getting from the renewable mix as well. And right now we need all of the supply that is there. It is clear that we need it all. We are seeing 63 percent right now coming from renewables.

But when the wind isn't blowing and when it is nighttime and in the summer when it is hot, you still need a lot of energy to support that air-conditioning load, and that requires long-duration, dispatchable resources to do that.

Mr. PFLUGER. I have only taken a few weather classes in my life, but I would invite my colleagues on the other side of the aisle to come out to west Texas in the summer. It is miserable. When the wind blows in the springtime, it at least cools you off, but not in the heat of the summer.

NERC said that we are in a reliability crisis. That is their 2024 overview, their analysis. Do you agree with that going forward?

Mr. VEGAS. I think the concern with the pace of load growth and the pace of retirements, coupled with the lack of dispatchable, long-

duration resources coming online, leads to that being a logical conclusion.

Mr. PFLUGER. Mr. Asthana, I feel like there were responses that you had in a previous line of questioning, and I would like to give you a minute or so if you want to clear up anything or talk about the role of natural gas, which, obviously, I think as you look at ERCOT is very important, and it seems like it is to you as well.

Mr. ASTHANA. Thank you for that. The only clarification I would make is about half of our system, our capacity is natural gas. And the rate of investment in natural gas infrastructure has significantly lagged the rate of growth of natural gas utilization. And so natural gas is becoming less flexible for us, and that is why one of the things I mentioned in my top six hit list is making sure that we invest in natural gas infrastructure, because we need it to be flexible.

Mr. PFLUGER. Mr. Vegas, I will end with you in the last few seconds. When government dictates policy that doesn't allow you to have the right capacity or the right mixture, what does that do to affordability, reliability, and, at the end, what does it do to our national security?

Mr. VEGAS. It is absolutely detrimental to affordability and to reliability, and it risks our energy security.

Mr. PFLUGER. Thank you. Mr. Chairman, I yield back.

Mr. WEBER. The gentleman yields back.

The Chair now recognizes the gentlelady from California, Ms. Matsui, for at least 5 minutes.

Ms. MATSUI. Thank you, Mr. Chairman. I want to thank the chairman and the Ranking Member Castor for calling this hearing today.

And I want to have a special welcome to the California ISO president, Elliot Mainzer. You haven't been asked many questions, so I will ask you a lot of them today.

At any rate, grid operators face many challenges today: rising electricity demand, aging infrastructure, rising energy costs, and the need to reduce greenhouse gas pollution. My Republican colleagues often say we need more energy, not less. Well, I agree. We need more energy, but it must be cleaner, cheaper, and built faster than we have in decades.

Yet President Trump is deliberately obstructing energy projects, freezing funding, halting critical projects, and firing Federal employees responsible for maintaining and permitting our energy infrastructure. Reuters reported last week that President Trump and Elon Musk's mass layoff have predictably slowed Federal energy permitting.

Mr. Mainzer, hypothetically, if many energy projects in California were delayed because there is no Federal employees to review permits, how would that impact grid reliability?

Mr. MAINZER. Given the increasing demand for electricity, anything that crimps the supply will have detrimental impacts on reliability.

Ms. MATSUI. OK. It has also been reported that President Trump and Elon Musk have fired Bureau of Reclamation employees that operate and maintain critical hydropower infrastructure.

Mr. Mainzer, hypothetically, if we see a significant reduction in hydropower output because these systems are not adequately maintained, how would that impact grid reliability?

Mr. MAINZER. Well, hydropower plays a critical role not only within California but in the broader West, also in the Pacific Northwest. So maintaining and maintaining the health of those assets is critically important.

Ms. MATSUI. OK. The Federal Government is not Twitter. We cannot let Elon Musk play around and gamble with our critical infrastructure. If a dam fails or the electric grid goes down, the consequences could be catastrophic.

Meanwhile, congressional Republicans are planning to repeal Federal energy tax credits that are currently financing hundreds of energy projects across the country. Independent analyses from Aurora Energy Research and Energy Innovation show that repealing the IRA tax credits would cost American families billions in higher energy costs and reduce new energy deployment by hundreds of gigawatts.

Mr. Mainzer, hypothetically, if there is a significant drop in the number of financially viable energy projects over the next 10 years, how would that affect reliability?

Mr. MAINZER. Again, I think as I and my other colleagues have mentioned here today, anything that is going to impact the supply of commercially viable projects to meet the rapidly growing demand in our grids is going to be problematic and could potentially compromise reliability and affordability.

Ms. MATSUI. OK. So that would impact our ability to meet new energy demand and slow down the time to power up our new data centers?

Mr. MAINZER. Yes.

Ms. MATSUI. OK. I know a lot of my Republican colleagues think clean energy is unreliable, and many of my colleagues like to point to California as proof that clean energy is unreliable, but that view is really badly outdated.

Mr. Mainzer, very briefly, can you talk about how grid reliability has improved in California over the last few years?

Mr. MAINZER. A reliable grid relies on a portfolio of resources of different attributes and complementary characteristics. What we have found in California, as we have seen the State choose to elect a much larger proportion of solar energy in particular, is that by pairing those resources with dispatchable batteries, that that has helped to increase reliability in recent years.

So it is a portfolio effect. We need to plan carefully, but by carefully considering all the different resource attributes and making sure that they are all available to the system, we have been able to significantly improve reliability in recent years.

Ms. MATSUI. OK. Thank you.

CAISO has also worked to improve reliability in meeting rising demands by supporting the build-out of long-distance transmission infrastructure and by participating in larger energy markets spanning 10 Western States.

Mr. Mainzer, can you briefly explain how improving interregional energy transfer across the Western U.S. helps to improve reliability and meet rising demand?

Mr. MAINZER. Yes, thank you. We have been very fortunate over the last decade to be able to take advantage of the significant transmission connectivity that exists between California and the Northwest and the desert Southwest. And by leveraging that transmission connectivity and resource diversity, we have been able to operate a Western Energy Imbalance Market that has significantly improved reliability and affordability. We are also engaged in working with other States and other utilities to further enhance the Western grid, which will make a big difference in reliability going forward.

Ms. MATSUI. OK. Thank you very much. My time is up. I yield back.

Mr. WEBER [presiding]. The gentlelady yields back. The Chair now recognizes the gentlelady from Tennessee for 5—at least 5 minutes.

Mrs. HARSHBARGER. At least 5 minutes. Thank you, Mr. Chairman. Thank you to the witnesses for being here today.

Mr. Nickell, I am going to start with you, so listen closely. I am going to come up with a scenario for you. And in this scenario, let's assume that Southwest Power Pool increases its wind capacity by 30-fold over two decades. And let's say that on a very windy day, as much as 90 percent of your regent's demands met by wind power. The date is February 27. And let's just say that changing wind speed caused generation to plummet by 12,000 megawatts in just 2 hours. So what are you going to do when the wind dies down in this scenario?

Mr. NICKELL. That is an interesting scenario. I don't know where you picked up on that.

Mrs. HARSHBARGER. Right out of my head.

Mr. NICKELL. It is a real scenario. It is something we have experienced. And what we were forced to do is to rely on the backup generation that we had available, and that primarily consists of gas generation because it can be started quickly, it can be ramped up quickly, and it could meet the need very reliably. So that is what we did.

Mrs. HARSHBARGER. OK. Thank you for that answer.

Ms. Curran, it is your turn. In this scenario, let's say that you experience a wind drought that lasts 40 consecutive hours. How do you make up for that?

Ms. CURRAN. Thank you, another familiar scenario that did happen to us. The way you make up for it is with resources that do have fuels that are available on demand. So in MISO that would be coal and gas generation that is able to run for that duration.

Mrs. HARSHBARGER. Yes. Thank you, ma'am.

Now, Mr. Asthana, it is your turn. The date is December 24, 2022, during one of the coldest days that the Tennessee Valley Region's ever experienced in decades. And TVA calls and says it doesn't have enough power to meet this demand. So what do you do, sir?

Mr. ASTHANA. That is a great question. Thank you. They did call. They called me directly.

Mrs. HARSHBARGER. Yes, they did.

Mr. ASTHANA. And we did our best to support them with a significant amount of exports.

Mrs. HARSHBARGER. So what kind of exports?

Mr. ASTHANA. They were on the margin, natural gas and oil.

Mrs. HARSHBARGER. And why did you still have enough power on your wires to help TVA while still meeting your own needs?

Mr. ASTHANA. Well, we had healthy reserves then, and so we were able to support our neighbors. And it wasn't just TVA. We were exporting power to multiple neighbors at the same time.

Mrs. HARSHBARGER. Yes. I remember that, and I had a lot of companies that had to shut down from some brownouts and blackouts.

You know, I have looked at all your testimony, and the key challenges every one of have you talked about was the rising demand in energy due to electrification, manufacturing growth, data centers, you know, producing AI. And then you talk about generation transition, accelerated retirements of transitional power plants who are outpacing new renewable generation capacity. You talked about extreme weather impacts and then transmission limitations. And current infrastructure is inadequate to meet growing needs. And new projects face regulatory and logistic hurdles.

And, you know, the testimony paints a really clear story, and for one, wind energy may have value to power companies, but it cannot be depended upon when people need it most. And this wind energy has been widely deployed around the country because of generous government subsidies which increase reliability problems, as it crowded out more reliable sources.

So I personally think that it is astonishing that wind continues to receive government subsidies, and especially while the utility companies still have to keep their other power plants online even when they aren't making any money, just to make up for the overbuilt wind. As long as the policies that we make here continue to emphasize unreliable weather-dependent energy rather than supporting the no-fail grid, blackouts are going to keep happening, aren't they?

And so I think it is time we have to revisit our priorities and focus our efforts toward keeping the lights on, ladies and gentlemen. So with that, Mr. Chairman, I yield back. Thank you all.

Mr. WEBER. The gentlelady yields back.

The Chair now recognizes the gentlelady from Washington for at least 5 minutes.

Ms. SCHRIER. Thank you, Mr. Chairman. Thank you to our witnesses as well. As all of you know, the Pacific Northwest does not have an RTO or ISO represented here. Our energy markets and balancing authorities are very different. RTOs are not, though. Most of us are seeing exploding load growth in the Northwest because of affordable energy. In the Pacific Northwest, it is chip fabrication and data center expansion that are the demand drivers.

Now, depending on who you ask, we are likely facing a nearly 16 percent increase in load growth by the end of the decade, fivefold increase in what was previously forecasted, and we have heard today about how long it takes to interconnect and to build new energy.

Now, I say "likely" because we don't have great quality of data inputs for these models, and accurately forecasting load growth from data centers is difficult because they are notoriously secretive.

We also know these companies shop around to multiple utilities, potentially duplicating the same load in several service territories.

For the existing data centers, operators often don't want to share data about their energy uses for proprietary or national security concerns.

Mr. Asthana, you have been on a lot today. I have got another one for you. Given the surge of demand that you are seeing at PJM, I am more concerned about making sure we are building strategically than about overbuilding. But considering all of these challenges, how do we ensure that power planters have the right tools to accurately predict load growth?

Mr. ASTHANA. A wonderful question. Thank you for that. We are at a time where growth demand is growing rapidly and the rate of the growth is incredibly uncertain. I mean, it is really hard, all the issues you talked about, whether you are double-counting something or not, and so we significantly discount down from the gross numbers that are being submitted to our utilities. In fact, they will discount their numbers based on their own criteria, some of which are—have people put up money behind this project, or is this just a conversation or a signed contract? But I do think this is an opportunity for continued refinement.

Ms. SCHRIER. Does discounting numbers mean lowballing the estimate?

Mr. ASTHANA. No, not lowballing but applying criteria. So if you start with a gross pool that is huge and it is not just plausible, how do you cut down to what you think is reasonable? Their filters apply. Have these people, you know, put up money? Do they have a signed contract? Have they acquired the land?

Ms. SCHRIER. Got it. OK, thank you.

We all agree we are going to need a lot of energy and really fast, and we want more domestic manufacturing. We talk about that all the time. We are going to win, that we need to win the AI race with China, and that is going to require a ton of energy. And no power planter is saying natural gas won't be part of that puzzle. Absolutely will. But really, we should all have the goal of deploying more non-GHD-emitting energy. So let's do these things, like nuclear and geothermal and the like.

My next question is for Mr. Mainzer and Mr. Nickell. At the last hearing with your organizations, I asked both CAISO and SPP about the governing structures of day-ahead markets developing in the West. And there have been significant developments since then with Bonneville's draft decision to join SPP markets plus. But I would love to hear from each of you how utility membership in your market would uniquely benefit the Pacific Northwest in the face of surging growth from data centers and manufacturing. And I am going to start with Mr. Nickell.

Mr. NICKELL. So thank you for that question, Congresswoman. SPP's current 14-State footprint is flush with a lot of wind generation. In fact, you heard it earlier today that we have seen as much as 90 percent of our demand served by wind generation. We know it is not always available. It is plenty available when the wind is blowing. And the same thing can be said of the solar generation that is in the desert Southwest part of the United States. When the

Sun is shining, it is a tremendous resource, and we love having it available to us.

The same thing is true of the hydro generation of the Pacific Northwest. We find that for those participants that want to participate in our market, a tremendous opportunity to leverage a diverse portfolio of renewable generation that is very important to you and to your constituents in the Northwest.

Ms. SCHRIER. Thank you. Mr. Mainzer.

Mr. MAINZER. Which I would just add that from a physics and economics perspective, we have that connectivity today to the Bonneville system. We have been leveraging it for years and providing billions of dollars of economic and reliability benefits, and I give Bonneville a lot of credit for pushing the envelope on governance. And we're also reforming our governance structure to address their concerns. Thank you.

Ms. SCHRIER. And thank you for heading up on development for so many years. Thank you. I yield back.

Mr. LATTA [presiding]. The gentlelady's time has expired, and yields back.

The Chair now recognizes the gentlelady from Iowa's First District for 5 minutes for questions.

Mrs. MILLER-MEEKS. Thank you, Chairman Latta and Ranking Member Castor, for holding this important hearing on grid reliability. Iowa's First District has emerged as a national leader in renewable energy, including wind energy, with 59 percent of our electricity now generated from this renewable resource. It has the power to be transformative to our region, driving down energy costs for families and businesses while also creating jobs in manufacturing.

Our success with wind demonstrates how quickly clean energy can be deployed at scale. In just 5 years, we have reduced coal dependence from 45 percent to 23 percent while maintaining some of the lowest electricity rates in the country.

However, as I have already heard, we have to recognize that a balanced, diversified approach is critical for grid reliability. Our natural gas facilities in Coralville and Burlington provide flexible generation needed. Our historic Keokuk Hydroelectric Plant contributes baseload renewable power that has been operating reliably since 1913. And we have an additional hydroelectric plant at Lake Red Rock.

The closure of Iowa's only nuclear plant, Duane Arnold, represented a loss of 601 megawatts of carbon-free baseload power. And I am encouraged by next year's discussion about potentially restarting operations at this facility.

And as we listen to testimony from the regional grid operators today, I am particularly interested in MISO. I have been there. I had a wonderful tour, and I encourage all Members to visit their grids and how they are integrating increasing amounts of renewable energy while ensuring we maintain sufficient dispatchable resources to address the reliability challenges highlighted in your memorandum.

The recent loss of load expectation, a 2025, 2026 study found that wind's effective load-carrying capability in winter dropped drastically from 53 percent to 29 percent year over year. And we,

of course, saw that in the polar vortex in Texas. As a State that is invested heavily in wind, this is concerning. What is driving this change, and what are the implications for future wind development?

And, Ms. Curran, what is your approach to maintaining reliability?

Ms. CURRAN. Thank you. One of the implications of this portfolio shift that is underway is that we have increasing dependencies and correlations between our type of generation, and we are increasingly looking at what is available when it is most challenging from an operational perspective, including the time when you most need resources maybe changing. And that certainly affects that accreditation.

We are very focused on making sure that we are coming up with the right values so that those that are making the decisions to invest in resources can understand what value they provide, both from that capacity perspective as well as energy.

The other piece of the equation that we have not talked a lot about today is transmission. So transmission is necessary to get the resources from where they are generating to where they are needed. At MISO, we benefit from a large geographic diversity, and that means we have the opportunity to transport power across multiple States that may have different weather patterns at different times to help meet that reliability need.

Mrs. MILLER-MEEKS. Thank you.

Mr. Asthana, President Trump has made it clear that he sees colocation as a key arrangement to power data centers. However, colocation arrangements and PJM have become a major policy topic at FERC and in States that inhibited timely access to energy for data centers. When structured correctly, colocation can provide timely access to energy while ensuring other ratepayers are held harmless. How can PJM ensure that colocation arrangements are allowed to move forward in a timely manner?

Mr. ASTHANA. We actually made a filing with FERC yesterday highlighting three different ways in our current rules that you can actually accomplish colocation, and then we suggested five other mechanisms to do that. And now we are awaiting feedback from FERC on how best to proceed.

Mrs. MILLER-MEEKS. Thank you. In the 2024 Long-Term Reliability Assessment, NERC recommends that to maintain demand and supply balance, dispatchable generators, including carbon-based fuel generators, must be available and capable of following changing electricity demand.

And for the past 2 years when I was on this committee, we have hammered on this. To ensure reliability, what measures are you taking to discourage premature retirement of carbon-based fuel generators, such as the Power Plant 2.0 rule? How are we able to maintain dispatchable—our energy when we are retiring carbon-based fuel generators prematurely?

Mr. ASTHANA. Yes, I mean, for me, I think I partially answered this earlier, but part of it is through sending the right market price signal to induce in the State. Part of it is through working with our States and, you know, Federal regulators to try to ensure that we don't have rules that force these generators offline prematurely.

Ms. CURRAN. And I would say the same market rules that ensure that these resources get appropriate compensation, and then in our ability as having a regional view providing information about what the supply/demand balance really is. And we have seen States taking action based on that information that we have provided.

Mrs. MILLER-MEEKS. Thank you so much. Mr. Chair, I have a question to submit for the record, and I yield back.

Mr. LATTA. Thank you. The gentlelady's time has expired, and yields back. The Chair now recognizes the gentlelady from Texas' Seventh District for 5 minutes for questions.

Mrs. FLETCHER. Well, thank you so much, Chairman Latta. And thank you to our witnesses for your time and your testimony today. I am glad to have Mr. Vegas here from ERCOT as a fellow Texan for this important hearing. And no surprise, I will have a few questions for you.

But I think there has been a really important theme that has come out of today's hearing. And as we have discussed, the United States is on the brink of a new boom in energy demand. And demand arises from things we have touched on, from data centers and AI development, from widespread electrification, to, as you noted, Ms. Curran, efforts to reshore American manufacturing that we have undertaken over the last 4 years, including through some very important legislation passed by Congress.

And I think you all have made clear that this is an area where smart policy is needed and that this committee and this Congress have an important role to play in setting that policy.

It is kind of contrary to the efforts underway to take a chain saw to the Federal Government. This is precisely where we need smart policy and nationwide coordination and sharing of knowledge.

This is really core to what government is about, right, pooling our resources and our expertise to keep us safe, right. To make sure that the lights come on 24 hours a day, 365 days a year, to make sure that we have power when we need it. It is important to our safety. It is important to our national security. It is important to our ability to grow our economy. It is important to life, liberty, and the pursuit of happiness.

And so, before we look forward to some of the issues that have been raised, I want to look back on one thing, Chairman Latta, just to touch on this. I understood you to say something in your opening statement about wind and solar not being as reliable during weather events. And I just want to point out that, during Winter Storm Uri, we actually found that solar generation was the only one of the resources to outperform, or cuts worst-case scenario expected output. So I do think that there are lessons to be learned from our experience in Texas, and I would be glad to share them when we have more time on this committee.

But I do want to talk about this energy demand and growth. I know it varies by region. And in Texas, we are already home to 330 data centers, approximately 60,000 Texans employed there. More on the way. And I understood that ERCOT is forecasting nearly 76 percent load growth by 2030. And while we have seen commitments to build a variety of generation, we know that demand is going to exceed current generation capacity without continued investment.

So Mr. Vegas, I want to ask you: Last month, ERCOT released its capacity to demand and reserves report for 2025 through 2029, and it indicates that, absent major changes, ERCOT's reserve margins will drop to negative values within 2 years.

Can you just explain what that means for consumers? In real terms, does that mean rolling blackouts, higher energy bills? How are you protecting ERCOT customers from the market shock that the large data centers might bring in this increased demand?

Mr. VEGAS. So I think it is helpful to set a little context on that report. That report is a very rigidly structured report that requires us to report effectively the amount of generation that is in our queue that we expect to come online, the amount of load that is expected to be built based on the rules in how we count load.

And so, what it does not reflect is as important as what it does. What it does not reflect is the response of the market to the conditions as they evolve over time. So what we would expect to see as we get to a condition where demand is growing, supply needs to keep up, we would expect to see prices start to be more elevated on a consistent level in the wholesale market that would send signals to developed resources. It would also send signals to slow down load growth. Load is very responsive to prices. And so it doesn't reflect those dynamics of the market working.

And so I don't want consumers to think it is forecasting blackouts or brownouts in the future. What it is forecasting is that there needs to be a concerted effort to match the demand growth with supply. The market economics should deliver that. But without that market dynamic, we are looking at shortfalls in the future.

Mrs. FLETCHER. OK. Well, I think that that is helpful so that folks aren't too worried. But I do know that there are proposals in the legislature, for example, that would sort of hamstring ERCOT's ability, I think, to quickly add some renewable assets to the grid and that, you know, you are forced to pair them with natural gas and/or coal plants.

So I think, you know, from your perspective as a grid operator, do those kinds of policies that limit the development of certain energy resources help or hurt your ability to meet demand?

Mr. VEGAS. Right now, we need policies that support the growth of all the resources that can come onto the grid. And I emphasize, again, the balance of those resources is so critical to meet the future demand that is coming, because it is such a large growth. We need to have a balanced portfolio going forward.

Mrs. FLETCHER. Thank you so much. I have gone over my time. But, again, thank you all, and thank you, Mr. Chairman, and I yield back.

Mr. LATTA. Thank you very much. The gentlelady's time has expired, and yields back. The Chair now recognizes the gentleman from South Carolina's Seventh District for 5 minutes of questions.

Mr. FRY. Thank you, Mr. Chairman. I really appreciate that. This issue is especially critical for South Carolina in the Seventh District, where economic growth and energy security really go hand in hand. As we continue to witness rising energy demands with manufacturing, with data centers, and electrification efforts, we have to be prepared to ensure our grid remains reliable and resilient. Your testimony has talked about that a lot.

South Carolina has faced fewer reliability risks thanks to our strategic decisions. But they still do exist.

Ms. Curran, as we have discussed today, it is unclear whether the generation expected to come online will be enough to meet future demand and replace retiring resources. Developers seeking to enter the market are hampered by permitting delays, supply chain issues, and overly burdensome environmental regulations.

Are there changes to market rules or new technologies that can help us maximize the capacity and efficiency of our current grid to improve reliability over the next few years?

Ms. CURRAN. Sure. So having some of those new technologies or other changes are one of the pieces of the portfolio we will have to do maximizing our existing system is important. One of the most important tools from the MISO perspective is actually the operations of the MISO market. One of the things we do is seek to actually get the most out of the existing assets we have within the constraints of reliability, which means we are not leaving excess capacity on the system, be that generation or transmission capacity. And I think that is a model for all electricity operation.

Mr. FRY. Do you find that model duplicated across other sectors? I mean, like with your neighbors here, do they do the same thing roughly?

Ms. CURRAN. So we have and do that maximization, for example, with our neighbors, PJM and SPP. It is not necessarily, though, the same across the country, including in those areas that don't have a regional transmission organization.

Mr. FRY. Thank you for that. Is MISO currently utilizing AI models to improve operational efficiencies and system management? And if so, can you expand on how these tools are enhancing your ability to forecast demand, manage resources, and mitigate reliability risks?

Ms. CURRAN. Absolutely. As we have talked about a lot today, there are a lot of new variables in the system. You have this intermittent generation, you have changing load patterns, be it from data centers or just consumer changes, weather impacts, and the like. There is a lot more uncertainty in the system.

We use in our operation something we call an uncertainty management model, where we leverage artificial intelligence to better forecast what the next day might look like with all of that variability, though taking in all of those very hard-to-forecast variables, and trying to come up with an impact.

We have seen tremendous results both in reliability, but probably more importantly getting that reliability more affordably. So we have been able to plan better, and that results in lower cost for customers from using that technology.

Mr. FRY. Thank you for that.

Mr. Asthana, your testimony highlights the importance of reliability must-run, RMR, agreements as a critical tool for ensuring short-term reliability as plants retire and new resources come online. Can you describe how PJM utilizes these agreements to maintain grid reliability during those transitions?

Mr. ASTHANA. Yes, we like to use reliability must-run contracts as little as possible. They are really only used for local transmission constraints. So when a generator wants to retire and sub-

mits that request to us, and we feel like we need that generator to keep the grid reliable for local transmission constraints until we can build the transmission system, then we enter or seek to enter into a reliability must-run agreement with that generator. But we want to use it as little as possible and let the markets work as much as possible.

Mr. FRY. You want to build new plants, or a new generation, right?

Mr. ASTHANA. We definitely want new generation, yes.

Mr. FRY. Are there ways in which these agreements can be improved to offer additional flexibility, particularly in light of the supply chain challenges and infrastructure delays that we have?

Mr. ASTHANA. Are you asking about reliability must-run contracts, or just in general?

Mr. FRY. Right. Yes, sir.

Mr. ASTHANA. Yeah, we are working with our members right now on ways that we might improve our reliability must-run process.

Mr. FRY. And how would that look? Just curious.

Mr. ASTHANA. We haven't decided. But some of the things that we are thinking about are whether we have a standard contract with every generator that wants to—or that ends up needing to sign up, or with the spoke contract. So that is an example. But there's a host of issues that are on the table and being considered.

Mr. FRY. OK. Thank you for that. Mr. Chairman, I yield back.

Mr. LATTA. Thank you. The gentleman yields back. And the Chair now recognizes the gentleman from New York's 20th District for 5 minutes for questions.

Mr. TONKO. Thank you, Mr. Chair. I associate myself with the consensus that we have heard from our witnesses—and thank you all for being here—on the importance of building new transmission for improving reliability and bringing new resources online. But I would also like to hear more about how New York is pursuing other strategies for addressing reliability challenges.

So, Mr. Dewey, first let me thank you for your leadership at my home ISO. I appreciate the work you and the team at the ISO do each and every day and respond to New York's needs.

We know New York is dealing with increasing electric demand, especially chip manufacturing upstate, and an aging generation fleet. For the past several hearings, I have been trying to highlight the role that demand management, including energy efficiency and demand response can play in reducing peak demand, improving system reliability.

So can you discuss what New York is doing to simultaneously support grid reliability and energy-intensive economic development? And do you see a role for demand-side policies to contribute to New York ISO's efforts?

Mr. DEWEY. Thank you, Congressman. I would say that the ability for demand to be flexible and to recognize the opportunities for flexibility in demand—whether it be demand response, whether it be load shifting to different hours of the day—is going to be absolutely crucial to maintain reliability in this modern grid, where the intermittency of variable resources like wind and solar can vary a lot over time. We are going to need to have that flexibility in the

load profile. We are going to need to be able to recognize which loads can be flexible.

Some of the data center loads, and some of the chip manufacturing, which is so crucial to both jobs and national security issues to onshore more of that processing, they have a very constant fixed demand, and they can't be as flexible. So we have got to look for opportunities that other loads that can participate in that way can do so and coming up with the appropriate market mechanisms in place to provide the right kind of incentives and provide the right kind of revenues to recognize the willingness to do that.

Mr. TONKO. Thank you. And part of the challenge of meeting this new demand is certainly interconnecting new resources. So what changes have you made to your interconnection process, and have they been working?

Mr. DEWEY. So we have reformed our interconnection process really three times over the last 6 years. Most recently, the reform process culminated in our filing. We mentioned—I think the gentleman from New Jersey mentioned for a quarter 2023, we have issued and filed our compliance filing to be completely compliant with that new rulemaking from FERC. And we have initiated our transition cluster that does the combined study of all the resources in that mix.

We have the largest interconnection queue that we have ever seen at the New York ISO. And we are proceeding along a timeline that will allow us to finish it quicker than we ever have.

Mr. TONKO. Thank you. And if the overwhelming majority of projects in the queue today are battery and solar and wind projects, is it fair to say these technologies are important to future reliability in New York?

Mr. DEWEY. I would clarify that the entirety of the New York ISO queue is wind, solar, and storage. So it is crucial that we bring these resources online, that we locate them and site them at the right location so they maximize the benefit and reliability of the system, and we come up with the necessary upgrades, including transmission expansion, that would enable that reliable operation, yes.

Mr. TONKO. There has been much talk in Congress about repealing Federal tax energy incentives like the ITC and PTC through the reconciliation process. If those credits were to disappear, I think it is pretty safe to assume it will be, you know, a huge implication for the wholesale market. Project developers may need to bid into the energy market at higher prices to make their projects economically viable. Capacity payments may need to be higher to introduce, or to induce a stronger investment signal that fewer projects are going to be developed.

So, Mr. Dewey, I realize you may not have done independent analyses on this issue yet. Maybe you could just talk in hypotheticals. Does what I am suggesting check out? What could be the impact on energy prices and investments in the ISO market if these tax incentives go away?

Mr. DEWEY. In a hypothetical sense, I would expect that some of the viability of these projects, generally, would come into question based on the financing arrangements that they have to develop and construct them. At a minimum, I would anticipate higher costs

when they come, interconnect into the system, which would ultimately result in higher costs passed down to consumers.

Mr. TONKO. And we know that there have been considerable—much considerable confusion about how tariffs on Canadian energy might affect New York's electricity. Our systems are interconnected, and New York has long benefited from that importation of clean, reliable Canadian hydropower. We also know that Ontario has considered imposing a surcharge on its electricity exports.

How is the ISO prepared for the possible imposition of tariffs and export charges on Canadian power?

Mr. DEWEY. I would say that the interconnection between New York ISO, and really, the whole northeastern United States and Canada is mutually beneficial from both the reliability and an economic standpoint. And I say mutually beneficial because it works both ways across the border with tremendous benefits throughout the region.

We have put in mechanisms to collect and remit those tariffs if we need to. And we are working closely from a reliability standpoint to make sure that at least on an energy basis, but hopefully on an economic, day-to-day basis that power will continue to flow. Thank you.

Mr. TONKO. Thank you so much. And with that, Mr. Chair, I yield back.

Mr. LATTA. Thank you. The gentleman's time has expired, and yields back.

The Chair now recognizes the gentlelady from Florida's 15th District for 5 minutes of questions.

Ms. LEE. Thank you, Mr. Chairman, for convening this important hearing. And thank you to all of our witnesses for being here today to testify.

As our energy demand continues to rise due to growth in manufacturing, advances in technology, like artificial intelligence, and increasing electrification, it is critical that our electricity production and transmission are prepared to meet these needs.

Alarmingly, in their 2024 Long-Term Reliability Assessment, the North American Electric Reliability Corporation found that most of the continent is at risk of experiencing electricity shortfalls within the next 5 years. Considering these developments, I look forward to speaking with our witnesses who represent regional grid operators from across the country on how we can best strengthen our electric grid, prevent shortfalls, and meet this growing demand for power.

Mr. van Welie, in your testimony you mentioned that independent system operators in States play a joint and complementary role in resource adequacy. I am interested in discussing further the role that state policies can have on reliability and affordability of the electric grid. The Trump administration recently discussed moving forward with building national gas pipelines across New York and into New England to help supply energy to that region.

What would additional natural gas capacity mean for reliability in the New England area? And what impact do you see winter weather conditions having on consumer demand for natural gas?

Mr. VAN WELIE. So I will start at the end of your question, which is New Englanders have lived with a natural gas pipeline con-

straint for 20 years. So we know what happens. When it gets cold, it will switch to burning other stored fuels, typically oil and imported LNG. So the question, you know, with regard to the benefits of relieving that pipeline constraint, clearly the region recognizes, and I think the States understand that additional pipeline capacity would be beneficial. But they have made very distinct policy choices over the last several decades to work around that issue. So there are workarounds. But, ultimately, this decision about fuel infrastructure is really in the States' hands.

Ms. LEE. And if you would tell me about some of those workarounds. And as lawmakers seek to address the growing electric demand, what factors are the most important for them to be considering?

Mr. VAN WELIE. Well, I think in New England what policymakers are generally doing is trying to weigh affordability versus decarbonization objectives. And so, as they think about the relative weight of those two objectives, they tend to steer the policies one direction or the other,

Ms. LEE. In my home State of Florida, a recent report from Tampa Electric found that 70,000 Florida businesses are directly fueled by natural gas. Would more natural gas capacity drive investments into economic development projects, like manufacturing facilities, that require significant amounts of affordable energy?

Mr. VAN WELIE. I think it is—there is a complex answer to a simple question in the sense that ultimately to build new gas infrastructure into New England, you need to have a custom for that. So the pipelines will not build on speculative need. They need customers to do this. And, ultimately, the customer decision rests with the States ultimately. And we had this conversation about a decade ago. So I think the prevailing policy wisdom has been to rely on stored fuels and imported LNG. I think the conversation is starting to turn to whether or not it makes sense to relieve those constraint directly.

Ms. LEE. Thank you. And Mr. Asthana, you mentioned in your testimony that PJM facilitates the transfer of power to and from interconnected neighboring systems, including the Midcontinent Independent System Operator and the Southwest Power Pool to help meet electricity demands. Can you elaborate on how PJM works with neighboring jurisdictions to coordinate operations?

Mr. ASTHANA. Yes, thank you. We have joint operating agreements with our neighbors. So when we export to the Southwest Power Pool, they are not an immediate neighbor, w go through the Midwest ISO. But, particularly, with the Midwest ISO and with New York, we are continuously coordinating power flows back and forth. And then with Duke in the Carolinas and with TVA also, all of their operators are talking between our systems. Because our systems impact each other. It is actually one big electrical system. And so you do have to coordinate at the seams.

Ms. LEE. Thank you, Mr. Chairman. I yield back.

Mr. LATTA. Thank you very much. The gentlelady yields back.

And the Chair now recognizes the gentleman from Texas' 33rd District for 5 minutes for questions.

Mr. VEASEY. Thank you, Mr. Chairman. I think everybody knows, and it has been briefly talked about—Mr. Vegas knows this

very well—that Texas is growing very, very rapidly. We are having record-setting growth. We are also having record-setting heat. And every now and again we will have some record-setting cold. And demand is likely to continue growing. And as I stated in our last hearing in the subcommittee, ERCOT does a great job in enabling new generation in its interconnection process. And to its credit, ERCOT vastly outpaces other regions in bringing new generation online, but that is only part of the question.

You know, we are constrained by our grid infrastructure. And our failure to invest in grid infrastructure is a threat to our economic and national security. And unfortunately, I don't think that we are doing enough.

There has been a lot of talk today about generation and load growth, and rightly so. But today, I would like to hear from Mr. Vegas about a couple of other things focusing on Texas and our grid, and that is ERCOT's transmission planning and its demand response initiatives.

And, Mr. Vegas, how is ERCOT considering transmission planning, given ongoing congestion issues around the State?

Mr. VEGAS. Thank you for the question, Congressman. Transmission planning is absolutely one of the critical legs of the stool to ensuring the reliability, resiliency, and to enable the growth that we have been talking about.

We have recently actually published a new regional transmission plan which lays out what the grid in ERCOT needs over the next 10 years, and it has new elements in it.

Today, the ERCOT transmission system operates at a peak of 345,000 volts. We have laid out a plan that continues that strategy, but also one that adds a new extra high -oltage network at 765,000 volts. That is helping to address the large power flows that are going to have to move around the State. It helps with congestion management, could eliminate a lot of the congestion constraints that we have, and will support the kind of growth that we are talking about.

Mr. VEASEY. Yes, I also wanted to ask, too, when we had the Winter Storm Uri that, you know, we were, what, 1 minute and 30 seconds away from the entire grid crashing down, you know, one of the things that hasn't been talked enough about that I think we should talk more about is the winterization of Texas' infrastructure. You know, we saw failures in both renewable and, you know, natural gas components during that storm.

And I want to ask you, in a State like Texas it would be fairly inexpensive to do things like winterize, you know, wind turbine blades, but you wouldn't want to spend a lot of money enclosing, for instance, outdoor, you know, gas facilities and things like that. That could end up being very, very costly.

And in a State like Texas, what can they do to protect those larger, older platforms that are going to be much, much tougher to winterize?

Mr. VEGAS. Yes, the kind of tactics that they are using are putting in wind breaks, putting in thermal heaters near where there's critical components and valves, compressors, elements that when they are exposed to the wind typically are the ones that are at highest risk.

Historically, Texas has always been—weatherized their system for the heat of the hot summers so that they could run. So enclosing, it was never really a strategy. So that now we are seeing more significant cold winter weather, what we need to do is deal with the changes that that brings in, and that is what they are doing to those gas plants as well as to the natural gas facilities, is managing the wind chills, the weather breaks, and things like that.

Mr. VEASEY. If we have another storm like Uri next winter, has enough already been done to prevent those older, larger platforms from crashing again?

Mr. VEGAS. I think the weatherization measures we have in place today are very good. During any extreme weather event, there is always a risk of impact. Remember, these are 40-, 50-, 60-year-old machines that we are talking about. They do fail under duress and extreme conditions. But we are much better prepared today than we were during Winter Storm Uri.

Mr. VEASEY. And also, too, I wanted to just ask very briefly in the last remaining seconds here. Everybody is always concerned about reliability and affordability, and not just the large industrial loads that we talk a lot about here. What strategies are being implemented to increase demand response participation among our residential and small-business customers?

Mr. VEGAS. Thank you for that question. We actually have initiated a strategic program this year to initiate a new Consumer Residential Demand Response Program that is going to be financially supported by ERCOT. That work is going to be done in conjunction with the Public Utility Commission. And our goal is to have that meaningfully advanced throughout this year and available for residential consumers soon.

Mr. VEASEY. Thank you.

Mr. VEGAS. I would like to also add, we do have good residential programs in place today, but we want to grow them even further.

Mr. VEASEY. Right.

Mr. VEGAS. I think it is a great opportunity.

Mr. VEASEY. Thank you very much. Thank you, Mr. Chairman, I yield back.

Mr. LATTA. The gentleman yields back the balance of his time.

The Chair now recognizes the gentleman from Texas'—oh, I am heading that way. OK. Let's see, we have the gentleman from Texas for the next 5 minutes for his questions.

Mr. GOLDMAN. Thank you, Mr. Chairman. Thank you all very much for being here and for your time.

Mr. Vegas, just for the record, so everyone knows, you were not there during Winter Storm Uri?

Mr. VEGAS. That is correct.

Mr. GOLDMAN. And have done a remarkable job since then. ERCOT has, the entire team has, the entire new team that has been put there.

It was a perfect storm. It was extremely unique, as people said, 100-year storm. And just for the record as well, have y'all had to shed load at all or request a shedding of load in the State of Texas since you have been in power?

Mr. VEGAS. No, we have not.

Mr. GOLDMAN. Thank you very much. I kind of rest my case with that. It is my opinion that there certainly was human error involved during the record storm. And I just want to thank you for your leadership and all of ERCOT for what you have been able to accomplish and do in the last several years. So thank you very much.

Mr. VEGAS. Thank you.

Mr. GOLDMAN. With that, I will turn to a little bit of the panel.

Mr. Asthana, you talked about permitting reform. What reform needs to happen in permitting? I am sorry if these questions have been asked and we are here at the end, get the very last questions. And so I am sorry if that was asked earlier.

But if you don't mind, what kind of reforms need to be put in for permitting?

Mr. ASTHANA. Yes, I mean, there was bipartisan permitting reform that was being advanced in Congress before, and we were supportive of that. But I think the broader point is, it is taking too long to build new generation and very difficult to build new transmission, and there are good reasons for that. People don't want large infrastructure on their property and near them, and we need to respect that.

But I think we are going to have to solve this issue. And I think giving authority to—and there are various bodies you could give authority to—but giving centralized authority to approve permitting, I think, is one idea.

Mr. GOLDMAN. Something like the nuclear modular reactor, does that excite you or concern you?

Mr. ASTHANA. I think it is exciting. Definitely exciting.

Mr. GOLDMAN. Good. OK.

Mr. van Welie, you said there was new supply coming online. What type of new supply is coming online in your area?

Mr. VAN WELIE. Well, sir, so the proposed new supply was offshore wind. So as I mentioned in my testimony, given——

Mr. GOLDMAN. Sorry to interrupt. You said the new supply is wind coming offline?

Mr. VAN WELIE. Offshore wind.

Mr. GOLDMAN. Offshore wind.

Mr. VAN WELIE. Yes.

Mr. GOLDMAN. What happens if the wind doesn't blow?

Mr. VAN WELIE. I think the region is going to have to—well, your question is whether the wind doesn't blow or whether the offshore wind comes online.

Mr. GOLDMAN. So you said the new generation is offshore wind coming online.

Mr. VAN WELIE. Right.

Mr. GOLDMAN. What happens if the offshore wind doesn't blow?

Mr. VAN WELIE. I think you have to have enough resource on the system to back that up.

Mr. GOLDMAN. So will you have enough? If that is the new coming online, what is the backup to that if the wind doesn't blow?

Mr. VAN WELIE. Well, sir, the good thing about offshore wind in the wintertime, it actually helps with the gas constraint that we have on the system because the wind profiles in the winter are actually quite favorable. So it helps displace the use of stored fuels.

Of course, there will be times when an offshore wind does not blow, and at those times, you have to depend on other resources like natural gas or oil resources.

Mr. GOLDMAN. Do you have enough natural gas?

Mr. VAN WELIE. Now modeling, we have enough in combination with the offshore wind to make it work.

Mr. GOLDMAN. Right now?

Mr. VAN WELIE. Right now.

Mr. GOLDMAN. So what is the solution moving forward?

Mr. VAN WELIE. The solution moving forward is that the region is going to have to deal with the energy constraint. It really comes down to storage of energy in some form. The question is, what does that look like? Or you could solve this problem through moving to other technologies like small modular reactors. So there's a variety of options, and the States are going to have to think about where they want to see a policy to address this over time.

Mr. GOLDMAN. And what is your personal position on the modular reactors?

Mr. VAN WELIE. I am in favor of them.

Mr. GOLDMAN. OK. Thank you very much.

Mr. Chairman, I will yield the rest of my time. Thank you, panel, very much for your time.

Mr. LATTA. Well, thank you very much.

The gentleman yields back the balance of his time.

The Chair recognizes the gentleman from California's 50th District for 5 minutes of questions.

Mr. PETERS. Thank you, Mr. Chairman. I had to step out a little bit. I didn't hear and I don't think there has been any discussion whatsoever of conservation as part of this conversation. The idea that you don't even think about not burning energy as part of this approach to supply, I think we are letting it get away from us.

And, in fact, this week what we are voting on, the business of the House of Representatives is to overturn efficiency standards for refrigeration that would help us save energy and make us have to produce that much less energy. And I just think it is crazy.

The other thing I still recommend and I am still interested in is the Energy Innovation and Carbon Dividend Act, which is a way to price carbon and then return the dividends to people so that their overall tax burden doesn't go higher but they have an incentive to conserve energy. We should provide that incentive from every economic decision maker in the economy, from a household to the biggest corporation. It just makes sense to me.

As we face a challenge which is really unprecedented, I certainly think we ought to build everything we can. We ought to build as much generation and transmission as we can. And for years, I have said I have sounded the alarm that our energy grid is too small, it is too old, and it is done. And we have to do better.

But the construction of new high-voltage transmission in the U.S. which allow us to send energy from where it is abundant to where it is needed is slowed to a trickle. In 2023, we built just 55 miles of new high-voltage transmission.

At our current pace, we will build in this decade a fifth of the transmission we did a decade ago. The truth is that building big projects in America has become extraordinarily difficult. Our agen-

cies don't have enough people who are funding to permit these projects in a timely manner. Large-scale projects also face litigation, complex environmental review, bureaucratic delays. And we all ought to be about fixing that. And certainly, this committee knows that I have been working on permitting reform to the displeasure of some of the incumbents on the environmental side, because we have to get this done. But I think conservation ought to be something that we think about as well.

Let me just ask—you know, Mr. Asthana, you were asked for some specifics on permitting reform. I am going to just say, what I would ask for all of you, and maybe you can provide this in writing, is if your companies have experiences that they have—you can go to your lawyers about this, if you need to—but if you have got experiences that this committee should understand that you think don't make any sense, that could be improved, just specific recommendations on laws that could be changed, I would love to hear them. I think we are ready for that here. And I think all of the above means all of the above.

You know, credit to Texas, by the way, which has the closest thing to a free market in energy that we have. They are building more wind than anybody, because that is what the market demands. And good for them. You know, they deserve our congratulations. And I think in some ways we could learn some lessons from them.

Mr. Mainzer, I know in California we have been working hard on interconnection as a priority for years. California has added 20 gigawatts of new resources, 11 gigawatts of storage while investing in transmission. Can you talk about how grid capacity is a barrier to getting new resources on the grid and how CAISO is trying to interconnect in smarter ways that we might learn from here?

Mr. MAINZER. Absolutely. Thank you, Congressman. So we have also been, just actually just last year submitted very significant package of reforms to our interconnection community process to FERC that were fully approved. We have already put them into place. Last fall, we have seen a 67 percent reduction in requests in queue in our current cluster.

So we are absolutely taking friction out of the system there. We need to keep moving. We need to keep going. And that process is grounded in the coordination that we have with the State agencies to on-board up to 85 gigawatts in new resources over the next decade.

Mr. PETERS. I put forward a number of bills to help efficiently plan and permit transmission projects. And one of them is my bipartisan Speed and Reliability Act, which streamlines permitting for lines that significantly relieve grid congestion and improve reliability.

Ms. Curran, you say in your testimony that approving and building new high-voltage transmission lines is a complex and lengthy process. Congratulations on that. That is well stated. But maybe you could give me a little bit of color on that.

What do you find is a challenge for you? And what is the complexity you think doesn't need to be so complex?

Ms. CURRAN. Sure. So really, I think about the length of time and the complexity in three phrases: first planning, then permit-

ting, then actually building it. And the role of the ISO is really on the side of the planning. We have been successful in taking an approach where we look at multiple values for transmission—not just economic but also reliability, also enabling whatever the State or member needs are and have gotten a fair amount of transmissions built. Our States have really leaned in on the permitting questions. But we have also made decisions like trying to utilize existing transmission.

The key in our world is, who pays for it? And so having a business case that shows benefits well in excess of cost has been, I think, the secret to getting that transmission approved.

Mr. PETERS. OK. I am out of time, Mr. Chairman. But I would ask that I be permitted to ask that those questions be submitted in the record, answers on specific ideas from the operators on permit reform, and I yield back.

Mr. LATTA. Thank you very much. The gentleman yields back.

And the Chair now recognizes the gentlelady from North Dakota for 5 minutes for questions.

Mrs. FEDORCHAK. Excellent. Thank you. Thank you all for being here. I have said to a few of you that this panel is the most powerful panel of people in our whole country. And I mean that sincerely. Because at this table—and I hope my colleagues appreciate just how much, experience and technical expertise exists at this table—you have the power to pretty much bring us all to our knees and shut our whole country down. So thank you for everything that you do every day to keep our economy going and our communities safe.

So a couple of questions I would like to dig into here. First of all, are government incentives affecting what types of resources are coming into the market and getting into the queue? And if you could each just kind of say, like, either in your view, in your market, the impact that the government incentives are having on what resources come would be either significant, modest, minimal, or any qualification you want to say. Starting with you, Mr. Asthana.

Mr. ASTHANA. Yes, I would say they are significant and the incentives from the Federal Government are significant, and then our different States have different incentives that make a difference as well.

Mrs. FEDORCHAK. OK.

Mr. VAN WELIE. I would agree with that point.

Mrs. FEDORCHAK. Significant?

Mr. VAN WELIE. Significant, yes. State and Federal.

Mrs. FEDORCHAK. Excellent.

Ms. CURRAN. Yes, also significant. We have seen over a number of years that, depending on what the incentive is, the makeup of our queue and the volume of generation in it does change fairly dramatically.

Mrs. FEDORCHAK. OK.

Mr. DEWEY. It is a very significant driver in New York, yes.

Mrs. FEDORCHAK. OK.

Mr. NICKELL. I agree with everything that has been said so far. Significant.

Mr. MAINZER. I would probably characterize it as modest to significant only because the major driver of our queue is really State policy at this particular juncture, so—but it is certainly an impact.

Mr. VEGAS. And in Texas it is significant impact as well.

Mrs. FEDORCHAK. OK. And so across the board significant, and State policy also being significant. What I didn't hear, or what I think is missing in there, is that it is market forces that's driving what comes into the queue or even like the demand—what you need, what the markets need doesn't seem to be factoring in there. That to me is a pretty significant problem that we all ought to be thinking about moving forward.

There is a lot of talk about costs. And, you know, what is low cost? You know, everyone wants low costs. Everyone wants to keep the cost down for consumers.

Mr. Nickell, in SPP—and I am going to ask Ms. Curran, too, in MISO—what costs are often not included in this calculation of different comparisons between fuel, you know, in terms of their total cost to the grid? What costs are not included in that often, in your opinion?

Mr. NICKELL. I think, you know, the cost of reliability risks are often not included. We know from Winter Storm Uri—at least, reports have indicated—$200 billion-plus of cost just as a result of that one event. And I think we oftentimes too quickly forget about the cost of not being able to provide reliable electric service. We think all too often about the cost of investment.

Mrs. FEDORCHAK. Yes.

Mr. NICKELL. The cost to invest new transmission, the cost to invest new generation. We forget about the benefits of resilience, and we forget about the cost of not having reliable service.

Mrs. FEDORCHAK. OK. Very good. And, Ms. Curran, I am going to skip you for now and ask everybody one quick question.

If you could tell us—if you could pick one thing—I know there's many things you have highlighted today that you want us to take away—but what is the one thing—if you could pick one thing that we need to correct to meet and maintain reliability, meet the demand, what is the sort of one thing you would say we need to do quickly or first?

Mr. ASTHANA. I think hang onto the generation that we have already to start with.

Mrs. FEDORCHAK. OK.

Mr. VAN WELIE. I will add the paying attention to the gas/electric interdependency because we need to view this as one system, not separate systems.

Mrs. FEDORCHAK. Excellent.

Ms. CURRAN. I will also say hold onto the generation we have, slow down those retirements of existing units.

Mr. DEWEY. I would say hold onto the generation, but also make sure that the market signals and the development of the markets align with the type of reliability attributes that you need so we attract the right kind of investment.

Mrs. FEDORCHAK. Excellent.

Mr. NICKELL. Only because I want to be a little different.

Mrs. FEDORCHAK. It is OK to be the same.

Mr. NICKELL. I think we need to more effectively use the grid we already have.

Mrs. FEDORCHAK. OK.

Mr. MAINZER. I would say we want to ensure we have strong accountability mechanisms to resource adequacy.

Mr. VEGAS. I agree with all of my peers. And I will just add, incentivizing reliability discretely and explicitly will be very helpful.

Mrs. FEDORCHAK. Excellent. Thank you all. I yield back.

Mr. LATTA. The gentlelady's time has expired, and yields back.

The Chair now recognizes the gentleman from Massachusetts' Fourth District for 5 minutes for questions.

Mr. AUCHINCLOSS. Thank you, Chairman. Before I begin the questions, I do want to dig into the concept of the market for energy production, because Democrats actually really agree. We want competition in the market for energy generation, because as the gentleman from Texas, Mr. Pfluger, said earlier, different types of generation portfolios make sense in different States. And we want low cost and reliability to be rewarded, which is why we passed the Inflation Reduction Act, which said (1) there is an overall negative externality associated with fossil-fuel-emitting types of generation, and so we are going to issue a tech-neutral tax credit to all clean sources of generation that don't have greenhouse gas emissions, which have a negative externality. But we are not going to pick winners or losers in that form of clean energy generation.

The IRA was an energy pro-market piece of legislation. And it is, in fact, the Trump administration who is picking winners and losers and distorting energy markets. They are doing so with tariffs on electricity from Canada. They are doing so by canceling offshore wind contracts, despite the fact that in some States offshore wind is an important part of that generation portfolio. They are doing so by trying to get fossil fuels to jump the queue.

So when we talk about energy markets, it is Democrats who are supporting well-functioning energy markets, and it is the Trump administration that is impairing them.

Let's talk now about how this is affecting Massachusetts, Mr. van Welie. First of all, tariffs. New England is a net importer of electricity, correct?

Mr. VAN WELIE. Correct.

Mr. AUCHINCLOSS. And we get that from Canada?

Mr. VAN WELIE. And from New York.

Mr. AUCHINCLOSS. But New York gets some from Canada too?

Mr. VAN WELIE. Correct.

Mr. AUCHINCLOSS. Now, under chapter 27 of the Harmonized Tariff Schedule of the United States, electrical energy is identified as a good but has a, quote, "free tariff designation that is not subject to the border entry procedures through which custom duties are imposed."

Public statements have suggested that it would not be tariffed, but do you know?

Mr. VAN WELIE. We do not know. We have asserted what you have just said, but we have also put in a backstop, which is to ask the FERC to give us the permission to allocate the cost if we need to collect those monies.

Mr. AUCHINCLOSS. And what is the cost of that uncertainty to New England ratepayers?

Mr. VAN WELIE. It depends on the level of the tariffs. At the level of 25 percent, there is probably of the order of about $160 million a year.

Mr. AUCHINCLOSS. And even the uncertainty is impairing your ability to run the grid?

Mr. VAN WELIE. Not at this point. So tariffs, you know, will affect price in some way, but they shouldn't—it shouldn't affect reliability.

Mr. AUCHINCLOSS. But are you having to spend resources and time on figuring out how you would levy that tariff?

Mr. VAN WELIE. Yes, of course.

Mr. AUCHINCLOSS. Yes. And that has an indirect cost.

Let's talk about our reliance on liquefied natural gas. That is our sort of swing winter source of energy, yes?

Mr. VAN WELIE. Correct.

Mr. AUCHINCLOSS. And it comes mostly from Trinidad and Tobago?

Mr. VAN WELIE. Correct.

Mr. AUCHINCLOSS. And the Everett port terminal?

Mr. VAN WELIE. Correct.

Mr. AUCHINCLOSS. And it is subject to global spot prices?

Mr. VAN WELIE. Well, I would say it is another major import point for New England, which is the same joint terminal in New Brunswick. Between that terminal——

Mr. AUCHINCLOSS. Between those two.

Mr. VAN WELIE [continuing]. And Everett is where the gas comes.

Mr. AUCHINCLOSS. But it is subject to the spot price globally, right, that LNG?

Mr. VAN WELIE. Correct.

Mr. AUCHINCLOSS. So Massachusetts is at the whim of global movements in LNG prices, right? So when something exogenous happens like, I don't know, Russia invades Ukraine, we bear the brunt of higher LNG prices?

Mr. VAN WELIE. That is correct.

Mr. AUCHINCLOSS. So Massachusetts is not in control of its own energy destiny right now?

Mr. VAN WELIE. Correct. I think Massachusetts can do some things to reduce those effects.

Mr. AUCHINCLOSS. Yes. And those things could include offshore wind?

Mr. VAN WELIE. And—yes—or dual fueling, or relieving the gas pipeline constraints.

Mr. AUCHINCLOSS. Let's talk about some of those in the next minute.

Mr. VAN WELIE. Uh-huh.

Mr. AUCHINCLOSS. Offshore wind, as you said—actually, the wind does blow in the wintertime pretty consistently, which is exactly when we have that peak LNG demand. So offshore wind would be very helpful in offsetting our vulnerability to global LNG spot prices.

Nuclear. Would it help us if we built a nuclear power plant in Massachusetts?

Mr. VAN WELIE. It would, but I think that will be some time before that would be practically realized.

Mr. AUCHINCLOSS. Well, the best time to plant a tree is 20 years ago, but the second best time is now, right?

Mr. VAN WELIE. I agree.

Mr. AUCHINCLOSS. And then tell me about dual use in our last 30 seconds.

Mr. VAN WELIE. Say again?

Mr. AUCHINCLOSS. Dual use. The dual fueling.

Mr. VAN WELIE. Dual fuel. So that is really to allow—we have some 7,000 megawatts of gas on these resources that cannot access gas from the pipelines when it gets cold. So one way of working around the gas constraint is for the New England States to allow for permitting of dual fueling——

Mr. AUCHINCLOSS. Dual fueling.

Mr. VAN WELIE [continuing]. Which would allow them to switch to fuel oil and utilize that fuel instead of gas.

Mr. AUCHINCLOSS. Thanks for your time and your expert testimony, Mr. van Welie.

I yield back.

Mr. LATTA. Thank you. The gentleman yields back.

The Chair now recognizes the gentleman from New York's 23rd District for 5 minutes for questions.

Mr. LANGWORTHY. Thank you very much, Mr. Chairman.

Mr. Dewey, the New York ISO has repeatedly raised strong concerns over our State's aggressive transition away from sources of energy like natural gas and towards, quote, "renewables" like wind and solar. In a 2023 report, the ISO stated, "It is important to note that commercially available technologies to provide dispatchable, nonemitting supply do not exist at scale at this time."

Does the ISO's definition of "dispatchable" encompass the ramp-up time for this nonemitting supply mentioned in this and other reports?

Mr. DEWEY.Yes, it does. When we talk about dispatchable, emission-free resources, we are projecting the need and the necessity to have a resource that can both meet the State's climate legislation, which mandates a carbon-free electric system by 2040, as well as continuing to meet the dispatchability requirements of managing the grid. That gap, that resource, does not exist today. The technology does not exist today.

Mr. LANGWORTHY. What impact does a longer ramp-up time for these sources of generation like wind and solar have on grid reliability in a State, particularly when we experience weather events like Winter Storm Elliott that hit my district in the winter of 2022?

Mr. DEWEY. It requires extensive planning. It requires a lot of focused attention on the planning models so that we are not caught surprised by those swings in weather. It requires us to have additional and subsequent resources on standby in case we get those forecasts wrong so that we can quickly shift to fill in the gap that can sometimes surprise us if it happens too quickly.

Mr. LANGWORTHY. Thank you. As you point out in your testimony today, the 2024 to 2034 RNA directly implicates our State's own public policies in the concerns over declining reliability margins. Specifically, since the enactment of New York's Climate Leadership and Community Protection Act, more than twice the capacity of generation has been deactivated than has been added to the

system. You go on here in your testimony to mention how this transition is raising new challenges for grid reliability in the event of significant weather events.

Mr. Dewey, has any oversight been conducted by the Federal Energy Regulatory Commission into these reliability concerns voiced by New York ISO, and has FERC given any warning signals to the State of New York based on what seem to be very consistent concerns with reliability resulting from public policy choices?

Mr. DEWEY. We had a lot of engagement and a lot of oversight with the North American Electric Reliability Corporation, or NERC, which is the reliability arm of the FERC. They are predominantly the enforcement arm to make sure reliability criteria is met. We work very closely with them to make sure that the market rules that we develop that we administer under the FERC tariffs contemplate some of the changes that we are going to see on the electric power grid.

So, primarily, that engagement is with NERC on reliability and with FERC on the implementation of the market rules necessary to be able to meet those reliability criteria.

Mr. LANGWORTHY. OK.

And on this subject of State-level policy choices impacting reliability and affordability, Mr. van Welie, in 2013, you testified before this committee that there were concerns in ISO New England that insufficient natural gas infrastructure would result in increased costs, increased emissions, and reduced reliability. You reiterated your testimony in 2017, and in today's testimony you stated that ISO New England gets more than 50 percent of its electricity from natural gas, yet it doesn't have enough natural gas pipeline capacity in the winter.

With this history, Monday's Washington Post reports that electricity costs in New England are 40 percent more than in the rest of the country. Do you continue to have fuel security concerns, and would additional pipeline capacity sourcing domestic supplies to source efficient natural gas lower costs for consumers and address fuel security concerns?

Mr. VAN WELIE. So the actions that States have taken in the last decade have mitigated some of the price effects of the gas constraint by essentially taking demand off the system, and they have done that through investment in generation and demand response and energy efficiency, but the long-run concern still is there.

And to your point, I think the gas constraints have resulted in big costs every winter when it gets cold and we have had to rely on LNG or oil. So I think the policy question for the States is how best to mitigate those effects.

Their actions have also focused on trying to add offshore wind into the mix because that would be beneficial. To the extent offshore wind is delayed, I think the conversation will turn to what are the other possibilities. And so the options on the table would be additional pipeline infrastructure, the dual fueling that I mentioned, and I would say one thing Congress could help us with here is the Jones Act.

So I saw an article just earlier this week that Puerto Rico is now finally getting domestic LNG shipped to it, and it would be helpful if New England could access domestic LNG. We export it at $6 for

million Btu, but we are having to import it at $35 to $40 per million Btu. So I think Congress—that is something that could help.

Mr. LATTA. I am sorry. The gentleman's time has expired.

Mr. LANGWORTHY. My time has expired. Thank you, and I yield back.

Mr. LATTA. Thank you very much.

The Chair now recognizes the gentleman from Ohio's 12th District for 5 minutes for questions.

Mr. BALDERSON. Your colleague from Ohio. Thank you, Mr. Chairman.

Thank you all for being here today. I do have to—just in case, Mr. Vegas, I don't get to you, I have a question for you. But we miss you in Ohio. Good seeing you.

My first question is for Mr. Asthana. I would like to start with you and follow up on a conversation I had with your colleague, Asim Haque, during a hearing this subcommittee held earlier this month.

PJM's existing install capacity mix is overwhelmingly made up of dispatchable power generation such as natural gas, nuclear, and coal. However, as of a few days ago, only 5 percent of the active projects in the PJM queue are thermal generation. Additionally, between 2022 and 2023, PJM saw over 11,000 megawatts of generation deactivated, and only 4,000 megawatts of new generation added to the grid.

Do you have any concerns with the lack of dispatchable power generation entering PJM's interconnection queue, and are there enough of these projects to offset premature retirements and meet the rising growth demand?

Mr. ASTHANA. Yes. We do have concerns with the lack of dispatchable generation in the queue, and we have taken significant action to deal with that, including our Reliability Resource Initiative. And I am happy to talk about that if you would like.

Mr. BALDERSON. Thank you. FERC recently approved PJM's Reliability Resource Initiative, or RRI, to allow shovel-ready projects that enhance grid reliability to get built and connected to the grid as quickly as possible. So I do want you to expand on it a little bit. PJM recently announced that the RRI received 94 applications, totaling over 26 gigawatts of nameplate capacity.

Mr. Asthana, I understand PJM is actively reviewing these applications. Can you discuss how you will score or weigh these projects to ensure they will get built and online as quickly as possible?

Mr. ASTHANA. Yes. Thank you for the question, Representative.

So our goal with this initiative was to get shovel-ready projects that had certain attributes, and those attributes were really reliability-supporting attributes. We are really excited that we have gotten almost 2x subscription of this opportunity—27 gigawatts, almost—and now we are scoring them. We are scoring them based on 100-point scale based on criteria like ELCC and UCAP, which are technical terms for just firmness and reliability support, also on viability and project support and things like location. So if they are located—projects are located in a more constrained area, they will get extra points.

So there is a set of criteria. It adds up to 100 points. And, really, we are looking for viability, constructability, how quickly they can

come online, and how much they can support the reliability of the grid.

Mr. BALDERSON. OK. A followup to that is how can grid operators, FERC, and Congress, build off this initiative to get more generation built and connected?

Mr. ASTHANA. Yes. I am happy to ask my colleagues here.

I know we have all talked about this, and some other systems are considering similar initiatives, but I think it is really important when we are facing a problem without a clear solution—which is generators are retiring—we need to serve more load and that we be creative and come up with ways to fill the pipeline with the type of generators that will serve that load, and that is what we are trying to do with this initiative. And we are happy to share our experience with others.

Mr. BALDERSON. Thank you very much.

Mr. Vegas, I did have time for you, but it is also for Asthana. I would like Mr. Vegas to go first.

Last year, PJM, ERCOT, SPP, and MISO jointly filed an amicus brief with the DC Circuit Court against the Biden EPA's Clean Power Plant 2.0. I am extremely grateful that, just a few weeks ago, Administrator Zeldin announced that EPA will be reconsidering the Clean Power Plant 2.0 along with dozens of other Biden-era rules and regulations.

Since I am limited on time, Mr. Asthana and Mr. Vegas—and, Mr. Vegas, you go first—if the Clean Power Plant 2.0 were to remain in effect, would your service territory see an increased risk of rolling brownouts and blackouts?

Mr. VEGAS. Yes. That plan had risked more than 14,000 megawatts of existing coal plants that are serving the grid today. They would be at risk, and that would be a significant reliability concern.

Mr. BALDERSON. Thank you very much.

Mr. Asthana?

Mr. ASTHANA. Yes. That plan would have increased the reliability risk and will in our region if it goes forward.

Mr. BALDERSON. Thank you both.

Thank you, everybody.

Mr. Chairman, I yield back.

Mr. LATTA. Thank you very much.

I will just let everyone know they did just call votes. It is the only way we will get through, we still have about six members that are still on the list.

And so, at this time, we are going to go to the gentleman from Colorado for 5 minutes for questions.

Mr. EVANS. Thank you, Mr. Chairman and Ranking Member.

Thank you, of course, to the witnesses for coming today.

Mr. Nickell, my first question will be to you. We have heard a lot of conversation today about how we need more power, and I don't know that I have fully wrapped my mind around some of the nuances that I am sure you are much more familiar with, particularly when it comes to power versus dispatchable power and things like cost efficiency versus reliability in terms of actually obtaining that power.

And so what I mean by that is I have been on the floor for some of my largest electric utility providers in Colorado where they are talking about not just what is currently powering the grid but looking forward into the future in terms of weather reporting to figure out what is the weather going to be. Is the wind going to be blowing? Is the Sun going to be shining? Where is not only the affordable power going to come from or forecasted to come from in the next couple of hours to days, but is it the most cost efficient? Is it the most reliable?

So can you just speak a little bit to the complexities of managing a grid, understanding that not all power is created equal and drawing some of the distinctions between the dispatchable power and the variable power and also the most affordable power versus the most reliable power?

Mr. NICKELL. Sure. And thank you for the question. It is a difficult question to answer, but I will do my best.

So, when I think of dispatchable power, that is generation that has fuel that can be stored. It is not weather dependent. And so, gas, for example, is a primary source of dispatchable generation today in SPP's footprint, as is coal generation. Nuclear as well is a dispatchable, although not as quickly dispatchable as gas and coal.

So, when we have weather-dependent situations on the grid, we have to depend on dispatchable generation to show up in order to deal with that intermittent nature of renewable generation.

I will give you an example. On June 6 of 2024, last year, out of 32,000 megawatts of nameplate wind capacity, only 100 megawatts were produced. One hundred divided by 32,000 megawatts is a really small number. It is practically zero. And that is across 14 States in the middle part of America, where wind is supposed to be at its strongest potential.

So we have to have dispatchable generation that has fuel available to be able to offset the fact that that wind generation didn't show up.

Mr. EVANS. So, in that space, we talked about the dispatchability and the reliability. Can you also speak to the affordability? I am from a State that does wholesale power, and so I have had conversations with the folks that are looking to the next 24 hours and the next 72 hours for those bulk power purchases.

Can you speak to the end impact for the consumer in terms of not only the reliability but the affordability in looking at the power mix that is going to supply the grid?

Mr. NICKELL. So affordability comes into play (1) at the State level. For SPP, we still have vertically integrated utilities, and the State regulators have jurisdiction over the affordability equation.

I will say that if, for example, a power plant that is a wind generator only gets a certain amount of capacity credit and, for example, it only, let's say, on average is about 20 percent—a gas generator gets about 90 percent capacity credit—it would take 5 times as much nearly of wind generation to offset the cost of a single gas plant.

So that is the equation. That is the cost equation that each of our utilities and their States have to manage in order to figure out what is the most affordable plan going forward to serve demand.

Mr. EVANS. So, to your previous example, you were talking about 32,000 megawatts of wind generation, and you have seen that dip down to 100 megawatts of wind generation. You have still got to be able to fuel the grid.

Mr. NICKELL. That is right.

Mr. EVANS. Is it more or less expensive in those situations to have to go get power from a dispatchable source versus from a 32,000 megawatt facility that, at that particular moment, is only producing 100?

Mr. NICKELL. Well, it is not a matter of affordability at that point, it is a matter of keeping the lights on. So you have no other choice but to use what is available and what has actually already been paid for by the ratepayers in the footprint. So at that point, it is not a matter of affordability, it is a matter of reliability.

Mr. EVANS. Thank you.

I yield back, Mr. Chairman.

Mr. LATTA. The gentleman yields back.

The Chair now recognizes the gentleman from Georgia for 5 minutes for questions.

And, again, we are about 5 minutes into votes right now.

Mr. CARTER OF GEORGIA. Mr. Chair?

Mr. LATTA. I am sorry. I guess they had the order wrong on my sheet.

The gentleman from Pennsylvania.

Mr. JOYCE. First, I want to thank Chairman Latta for allowing me to waive on to this important hearing.

When it comes to energy production, all energy is not created equal. The capacity factors of wind and solar are simply too small to provide the reliable energy that our grid requires today. What we need in plain terms is more baseload generation. We need more coal, more gas, and more nuclear.

It does not matter how many gigawatts of wind and solar capacity are built if they are not generating them when you need them. Unfortunately, we are doing worse than not building dispatchable generation. We are actually retiring it. We are shutting it down.

PJM—and I thank you for testifying here today—is the Nation's largest RTO, and includes my district in Pennsylvania. PJM released a report in 2023 projecting 40 gigawatts of reliable dispatchable generation will retire by 2030, roughly 25 percent of the system's installed capacity at that time. PJM labels the majority of these retirements as policy-driven decisions.

This is a time when demand is actually growing. Pennsylvania is in a great position to benefit from the investment in jobs of the AI revolution, but we need to have the energy available to build it. With Microsoft and Amazon poised to build colocated data centers in Pennsylvania, we need to steady the ship. We need to encourage investment to unleash the energy that is underneath the feet of my constituents.

Mr. Asthana, do you agree with me that we need more dispatchable generation built within PJM?

Mr. ASTHANA. Yes, very much so.

Mr. JOYCE. Mr. Asthana, PJM has a variety of tools to incentivize building new generation, and I am encouraged by the success of the Reliability Resource Initiative, but it is a one-time

fix, and the potential 26.6 gigawatts of additional power is simply not enough. Holding consistent capacity auctions are critical to providing long-term solutions for the PJM market.

Do you believe that the capacity auctions are working to incentivize building and retaining that generation, and if not, how can it be changed to attract new investment?

Mr. ASTHANA. Yes. We are seeing the capacity auctions work. So we have seen multiple generators withdraw their retirement notices, for example. We have seen a nuclear power plant, the Crane Clean Energy Center—835 megawatts—announce that it is coming back. Homer City in Pennsylvania, the plant was demolished, but they are looking at repowering—using that site to build a very large gas generator. And, while the capacity market isn't the only reason, it is definitely setting the stage for these decisions.

Now, I think the challenge that we are facing looking forward is that there is a big backlog for turbines. And so there is a big price premium for turbines. And so the price of the capacity market will have to ascend to incent new generation that is not already—beyond what is in the queue already is going to be really high, and I think it is going to create affordability issues that we are going to have to deal with.

Mr. JOYCE. Mr. Asthana, I am concerned that PJM gave into political pressure of some of the Governors of its member States, and this is a very distressing precedent. What are the dangers of Governors in the future influencing PJM's market to score short-term political points?

Mr. ASTHANA. Yes. Thank you for that question. We did have fairly bipartisan support for instituting, I think, a short-term price gap, if that is what you are referring to. We had 11 of our 13 States write to us and support that, and five Governors.

But I do think it is important to let our markets work, and we are going to have to make sure that we really allow that in the future.

Mr. JOYCE. I think that the path that PJM currently is on is unsustainable. When some member States shut down baseload power plants and others harm investment in new generation, this is creating a situation that will make the grid unstable. If this continues, it will be blackouts during extreme weather events, and my concern is that this will ultimately cost human lives.

I thank you, Chairman Latta, for holding this important hearing and allowing me to waive on. I yield the balance of my time.

Mr. LATTA. Thank you. The gentleman yields back the balance of time.

The Chair now recognizes the gentleman from Georgia for questions.

Mr. CARTER OF GEORGIA. Thank you, Mr. Chairman. Thank you for allowing me to waive on. I will be very brief.

I thank all of you for being here. This is extremely important, particularly in the State of Georgia, eleven years in a row the number-one State in which to do business. We have over 50 major data centers. So as you can see, we have a great need for electricity.

We are very blessed to have providers in our State who have—Georgia Power and Oglethorpe Power have invested in a nuclear

reactor. So that is very important, but delivery of that is extremely important, too.

So, in the brief time that I want to ask you just a couple of questions. And I will go to you, Mr. Nickell. I will ask you.

Tell me about the permitting process, because that is one thing that we really want to concentrate on in this administration and in this session and in this Congress, is the permitting. I don't care what sector of our economy you are talking about. Whether you are talking about energy, whether you are talking about healthcare, technology, I have people in my office all the time. Permitting. Regulations. "It is crushing us. It is crushing us." All the same. So tell me about that.

Mr. NICKELL. So I think a bipartisan permitting process is absolutely fundamental and critical to support a quicker build-up of the resources and the transmission infrastructure that we need.

We hear all the time about how projects have been slowed down because they can't get built for a various number of reasons, and I think that is the number-one problem that we have—that we have to deal with in order to speed up the construction of the actual infrastructure that we need.

Mr. CARTER OF GEORGIA. Mr. Curran, would you have an opinion on that as well?

Ms. Curran. I am sorry.

Ms. CURRAN. That is fine.

I think it is the same kind of answer. We have seen good work in our States to accelerate permitting, particularly of transmission lines, but there are still a number of roadblocks that we run into. We recently had a transmission line go into service after—I think it was about 13 years after approval due to permitting issues.

Mr. CARTER OF GEORGIA. Great. Again, I thank all of you for being here. This is extremely important, and we appreciate your attention to it.

I yield back, Mr. Chairman.

Mr. LATTA. I thank the gentleman for yielding back.

Seeing no other Members wishing to ask questions, I want to thank our witnesses for appearing today. Members have 10 additional questions—or may have additional questions for you.

I remind Members they have 10 business days to submit additional questions for the record, and I ask the witnesses to submit their responses within 10 business days upon receipt of the questions.

I also ask unanimous consent to insert in the record the documents included on the staff hearing documents list. Without objection, so ordered.

[The information appears at the conclusion of the hearing.]

And, without objection, the subcommittee is adjourned. I want to, again, thank our witnesses for their excellent testimony today.

[Whereupon, at 1:41 p.m., the subcommittee was adjourned.]

[Material submitted for inclusion in the record follows:]

U.S. Committee on Energy and Commerce
Subcommittee on Energy
"Keeping the Lights On: Examining the State of Regional Grid Reliability"
March 25, 2025
Documents for the Record

1. Letter from the American Gas Associations (AGA), addressed to Chairman Latta and Ranking Member Pallone, submitted by the Majority.
2. Letter from the SAFE Center for Grid Security, addressed to Chairman Latta, submitted by the Majority.
3. Report from the North American Reliability Cooperation (NERC) entitled "2024 Long-Term Reliability Assessment," submitted by the Majority.
4. Report from the North American Reliability Cooperation (NERC) entitled "Reliability Insights The Interconnected Gas and Electric Systems," submitted by the Majority.
5. Infographic from the North American Reliability Cooperation, submitted by the Majority.
6. Letter from the American Public Power Association (APPA), addressed to Chairman Guthrie, Chairman Latta, Ranking Member Pallone, and Ranking Member Castor, submitted by the Majority.
7. Article from Energy Wire entitled "Trump Says Coal Should Make a Comeback. At what price?," submitted by the Minority.
8. An RMI report entitled "The Business Case for New Gas is Shrinking," submitted by the Rep. DeGette.
9. An Executive Order entitled "Temporary Withdrawal of All Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects," submitted by Rep. DeGette.



The Honorable Brett Guthrie
Chairman
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

The Honorable Frank Pallone
Ranking Member
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

Re: House Committee on Energy and Commerce Subcommittee on Energy Hearing titled "Regional Grid Reliability"

Dear Chairman Guthrie and Ranking Member Pallone:

The American Gas Association ("AGA") respectfully submits this letter to the Energy and Commerce Subcommittee on Energy ("Committee") to highlight the importance of the natural gas system to the reliability and resiliency of the electric system, as well as to residential, commercial, and industrial customers that directly use natural gas. This letter also provides an overview of one of AGA's reliability and resiliency efforts to meet the growing national demand for energy while maintaining affordability for consumers. More than 189 million Americans and 5.8 million businesses use natural gas because it is affordable, reliable, and safe. Importantly, on the coldest day of the year, the natural gas system delivers 3 times more energy than the electric system delivers on the hottest day of the year. The overall goal should be to preserve and enhance reliability and affordability for all customers, both gas and electric.

AGA, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 79 million residential, commercial, and industrial natural gas customers in the U.S., of which 94 percent — more than 74 million customers — receive their gas from AGA members. AGA is an advocate for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industry associates. Today, natural gas meets one-third of the United States' energy needs.[1]

A resilient energy system is essential to the operation of nearly every critical function and sector of the U.S. economy as well as the communities that depend upon its services. Disruptions to the U.S. energy system have the potential to create widespread economic and social impacts, including losses in productivity, health, and safety issues, and — in the most extreme cases — loss of life. The highest priority for a natural gas local distribution company ("LDC") is the delivery of natural gas to its customers safely, reliably, responsibly, and at just and reasonable rates.[2] LDCs across the country are obligated, in accordance with applicable state law and regulatory requirements, to distribute natural gas to retail, residential, commercial, governmental, and industrial customers — including electric generators.[3] These

[1] For more information, please visit www.aga.org.
[2] Elements of an LDC's retail services are regulated at the state level and not by the federal government. *See, e.g.,* 15 U.S.C. § 717(b) ("The provisions of this chapter . . . shall not apply . . . to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.").
[3] Most laws or regulations that govern utility service include the concept of the "obligation to serve." In short, this duty stems from the reality that when a franchise service territory is granted by a state or regulatory entity, a public interest is established in maintaining reliable service.

requirements underscore the fact that residential and business customers require uninterrupted service for human need purposes, such as home heating, and business purposes.

The natural gas and electric sectors are mutually dependent on each other and over the last several years, AGA and its members have actively engaged in a variety of forums to discuss issues related to the reliability and resilience of the energy system, as well as gas-electric coordination matters. Enhancing gas-electric coordination, particularly for winter weather preparedness remains a critical priority for AGA and its members. As electricity demand is expected to increase, the electric sector will become even more dependent on natural gas and other commodities to generate electricity. In light of this, investing in appropriate energy infrastructure will be pivotal to reliably meet demand growth.

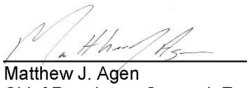
As the power system becomes more reliant on natural gas fueled generation for reliability, pipelines and storage facilities are essential to provide that service. A robust natural gas system is critical in providing gas and electric system reliability during extreme weather events. Currently, approximately 25 percent of the natural gas used for power generation is delivered by natural gas utilities; utilities use on- and off-system storage, as well as pipeline transportation, to ensure natural gas service to customers behind the city gate. As the energy system evolves, new and updated infrastructure may be required to ensure service and meet the additional demands on the system, from residential, business, industrial, and electric generation customers.

The Committee should be aware that the National Association of Regulatory Utility Commissioners ("NARUC") Gas-Electric Alignment for Reliability ("GEAR") task force was established to address the gas-electric challenges facing the energy industry today. Late last year, the GEAR task force unanimously recommended the creation of the Natural Gas Readiness Forum — an industry-led voluntary effort aimed at improving the communication, preparation, and readiness of the energy sector, via a multi-state forum of stakeholders from the various elements of the natural gas and electric value chains, as well as federal and state regulators. The GEAR working group recommended that the Natural Gas Readiness Forum be administered by AGA.

AGA convened the first Natural Gas Readiness Forum meeting on December 16 and 17, 2024 in Atlanta, Georgia. The two-day event included representatives from across the natural gas value chain including representatives from the Federal Energy Regulatory Commission, Department of Energy, North American Electric Reliability Corporation, regional transmission operators, electric generators, energy trade associations, state regulatory utility commissions and state energy offices. AGA will continue to convene such meetings to ensure preparedness of the natural gas value chain.

The American Gas Association thanks the Energy and Commerce Subcommittee on Energy for continuing discussions on reliability and its efforts to identify solutions to the challenges facing the energy industry today. AGA offers its assistance as a resource to the Committee to achieve those solutions. If you have any questions regarding this submission, please do not hesitate to contact the undersigned.

Respectfully,



Matthew J. Agen
Chief Regulatory Counsel, Energy
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The Honorable Bob Latta
House Committee on Energy & Commerce
Subcommittee on Energy
2123 Rayburn House Office Building
45 Independence Avenue SW
Washington, D.C. 20515

Dear Chairman Latta,

As Executive Director of the SAFE Center for Grid Security, I am writing in support of policy initiatives that consider national defense priorities and the importance of a reliable U.S. electric grid. SAFE was founded in 2004 to develop and advocate for policies to improve America's energy, economic, and national security. The men and women who comprise the Armed Forces and the installations on which they serve rely on power delivered by the grid every day. Domestic electricity that is reliable, abundant, and stable in price is not just integral to American economic competitiveness, but it is also foundational to our national security.

Ensuring National Security through Grid Reliability

The reliability of the U.S. electric grid is inextricably linked to national security. Our military installations, critical defense operations, and defense industry hubs depend on a stable and reliable power supply to maintain readiness, deterrence, and response capabilities. Yet, our aging and overstressed grid infrastructure is increasingly vulnerable to extreme weather, cyberattacks, and physical threats. In fiscal year 2021 alone, Department of Defense (DoD) installations across the United States experienced over 6,000 energy outages, leading to more than 3,000 days of lost power—an unacceptable level of risk for our national defense.[i]

Energy permitting reform is a crucial step in strengthening grid reliability and ensuring that our armed forces remain mission-ready. By streamlining the permitting process for critical energy extraction, generation, and transmission projects, permitting reform will facilitate the expansion of a reliable and modern grid capable of supporting military installations and their surrounding communities.

Grid Reliability as a National Defense Imperative

Almost all DoD installations rely on civilian power grids, which are increasingly vulnerable to disruptions.[ii] Recent hurricanes, such as Helene and Milton, have demonstrated how power outages can severely impact military readiness, with some bases left unable to operate effectively for days. Additionally, targeted attacks—such as the 2022 assault on Duke Energy substations in North Carolina, which left tens of thousands in the defense community without power—underscore the growing threat to critical defense infrastructure.

Without robust transmission expansion and permitting reform, these vulnerabilities will persist, leaving installations at risk of prolonged outages that jeopardize operations, communications, and force mobilization. Just 24 hours without power can result in mission-critical failures, loss of situational awareness, and compromised national defense capabilities.

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Grid Disruptions to National Security by the Numbers

- **5** – The number of military bases that experienced power losses that left servicemembers largely unavailable to respond to other potential threats during Hurricane Helene.[iii] Moody Air Force Base specifically suffered severe damage, including widespread outages and losses of communication capabilities.
- **700** – The number of airmen who worked to restore the installation's essential services during Hurricane Helene, with power gradually coming back online after several days.[iv]
- **36,000** – The number of individuals in the defense community surrounding Fort Liberty, North Carolina, who were affected by a significant power outage in 2022. This disruption, which lasted several days, was caused by deliberate attacks on two Duke Energy substations in Moore County.[v] Fort Liberty, home to the 82nd Airborne Division, is crucial for rapid global deployment capabilities, with the ability to mobilize within 18 hours of notification.[vi]
- **70** – The number of tenant commands, including two Nimitz-class aircraft carriers and Joint Base Lewis-McChord (JBLM), that were impacted during an attack on substations operated by Tacoma Power and Puget Sound Energy in Washington state.[vii] JBLM is home to the 62nd Airlift Wing, which operates C-17s for worldwide combat and humanitarian missions.[viii] These events highlight the vulnerability of grid infrastructure supporting key military installations and their surrounding communities.
- **More than 12** – The number of utility companies across the country that were targeted by cyber-attacks in 2019 alone.[ix]

Permitting Reform Strengthens Grid Reliability to Protect National Security

Permitting reform will enable faster development of new transmission lines that connect different grid regions, ensuring military bases have access to diverse and abundant power sources. When one region is compromised due to extreme weather or attack, a more interconnected grid allows installations to draw power from unaffected areas, mitigating risk. By streamlining the permitting process for new energy infrastructure, permitting reform ensures that critical transmission projects are built faster, reducing the likelihood of prolonged blackouts that could disrupt defense readiness. Each additional gigawatt of interregional transmission capacity can significantly reduce outages and save millions in avoided costs from power failures.[x] Permitting reform will facilitate the integration of a broader range of domestic energy resources, ensuring that military installations have access to stable and diverse energy supplies. For military installations, such improvements in reliability can mean the difference between sustained operations and catastrophic failures. More specifically, permitting reform aimed at improving grid reliability for national defense includes:

- **An "all the above" approach to expediting the development of domestic energy resources:** Reforms to simplify permitting by reducing delays and eliminating duplicative paperwork for oil, natural gas, coal, nuclear, renewable energy, energy storage, hydropower, geothermal, and liquified natural gas export projects is the most essential first step in improving grid reliability. Utilizing of all the energy resources our country has to offer would allow us to take full advantage of our domestic supply, reducing risk and securing the grid.

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- **Establishing adaptive frameworks for transmission expansion:** As our electricity consumption continues to rise, so does the necessity of expanded transmission to adequately move power where we need it around the country. Permitting delays are a significant impediment to completing essential energy projects. Today, it takes up to 15 years to develop a new transmission line in the United States.[xi] Permitting reform designed to facilitate the construction and financing of new transmission projects while optimizing the use of current ones through line upgrades and use of grid-enhancing technologies is essential to power grid expansion that balances the need for growth with fair cost distribution and efficient resource utilization.
- **Mandating collaborative interregional planning:** The current lack of interregional transmission planning is a significant barrier to building a more resilient and efficient grid. Neighboring transmission planning regions would be required to draft joint interregional transmission plans to optimize grid reliability and affordability. By mandating collaborative planning across regions and streamlining the approval process, we facilitate the development of high-voltage, interregional transmission projects that are crucial for enhancing grid reliability and dominance.
- **Reducing the burden of unproductive lawsuits:** Delays in the courts cause costs to build up for developers and threaten the economic viability of projects, and that is on top of the inherent risk of deferring infrastructure deployments while the grid is woefully unprepared to meet future demand and respond to security challenges. While permitting reform wouldn't eliminate frivolous lawsuits, it would help reduce the risk of excessive project delays while still giving impacted communities time to address legitimate concerns.

Congressional Permitting Action Can Protect National Security

Grid security is national security. Without the ability to quickly build and deploy critical energy infrastructure, military bases and defense operations remain vulnerable to catastrophic disruptions. Permitting reform represents a necessary change that will expedite the modernization of America's energy grid, ensuring our armed forces have the reliable power they need to maintain operational dominance.

I urge you to support permitting reform to safeguard our national defense from grid failures, fortify our military installations, and uphold America's strategic readiness. I welcome the opportunity to further discuss the implications of grid reliability on national security and look forward to working together to enhance our nation's dominance.

Sincerely,

Danielle Russo
Executive Director, Center for Grid Security
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[iii] National Defense University Press. "Realizing Energy Independence on U.S. Military Bases." *National Defense University Press*, https://ndupress.ndu.edu/Media/News/News-Article-View/Article/2808076/realizing-energy-independence-on-us-military-bases/.
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[vii] About (navy.mil)
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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2024 Long-Term Reliability Assessment

December 2024



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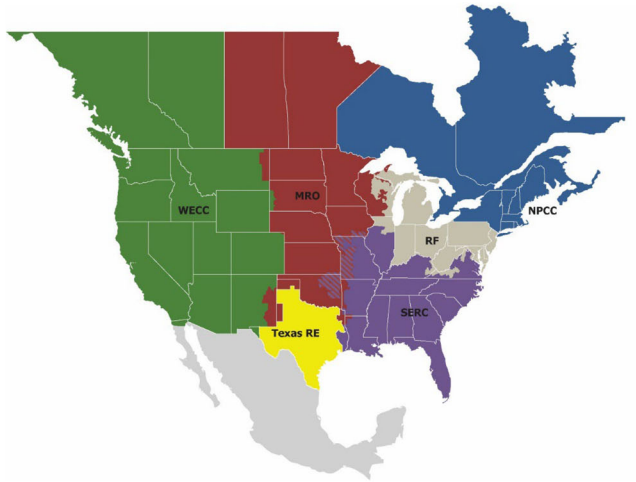
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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area basis (see **Regional Assessments Dashboards**) to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer-review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer-review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees subsequently accepted this assessment and endorsed the key findings.

NERC develops the *Long-Term Reliability Assessment* (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations;[3] this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2024 about known system changes with updates incorporated prior to publication. This *2024 LTRA* assessment period includes projections for 2025–2034; however, some figures and tables examine data and information for the 2024 year. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the **Demand Assumptions and Resource Categories** section of this report. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment; it is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through NERC's Electricity Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policymakers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

[1] NERC Rules of Procedure - Section 803
[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."
[3] Title 18, § 39.11 of the Code of Federal Regulations
[4] BPS reliability, as defined in the How NERC Defines BPS Reliability section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.
[5] ERO Reliability Assessment Process Document

Assumptions

In this *2024 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2024. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

1. **A reliability assessment of the North American BPS with the following goals:**
   a. Evaluate industry preparations that are in place to meet projections and maintain reliability
   b. Identify trends in demand, supply, reserve margins, and probabilistic resource adequacy metrics
   c. Identify emerging reliability issues
   d. Focus the industry, policymakers, and the general public's attention on BPS reliability issues
   e. Make recommendations based on an independent NERC reliability assessment process
2. **A regional reliability assessment that contains the following:**
   a. A 10-year data dashboard
   b. Summary assessments for each assessment area
   c. A focus on specific issues identified through industry data and emerging issues
   d. A description of regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

In the *2024 LTRA*, NERC finds that most of the North American BPS faces mounting resource adequacy challenges over the next 10 years as surging demand growth continues and thermal generators announce plans for retirement. New solar PV, battery, and hybrid resources continue to flood interconnection queues, but completion rates are lagging behind the need for new generation. Furthermore, the performance of these replacement resources is more variable and weather-dependent than the generators they are replacing. As a result, less overall capacity (dispatchable capacity in particular) is being added to the system than what was projected and needed to meet future demand. **The trends point to critical reliability challenges facing the industry: satisfying escalating energy growth, managing generator retirements, and accelerating resource and transmission development.**

This *2024 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next 10 years; it also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS. The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors. Summaries of the report sections are provided below.

Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal and extreme weather conditions. NERC's evaluation of resource adequacy in the LTRA considers both the capacity of the resources and the capability of resources to convert inputs (e.g., fuel, wind, and solar irradiance) into electrical energy. NERC used both a probabilistic assessment and a reserve margin analysis to assess the risk of future electricity supply shortfalls. Both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development.

Areas categorized as **High Risk** fall below established resource adequacy criteria in the next five years. High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Extreme weather, producing wide-area heat waves or deep-freeze events, poses an even greater threat to reliability. **Elevated-Risk** areas meet resource adequacy criteria, but analysis indicates that extreme weather conditions are likely to cause a shortfall in area reserves. **Normal-Risk** areas are expected to have sufficient resources under a broad range of assessed conditions. The results of the risk assessment are depicted in **Figure 1**.

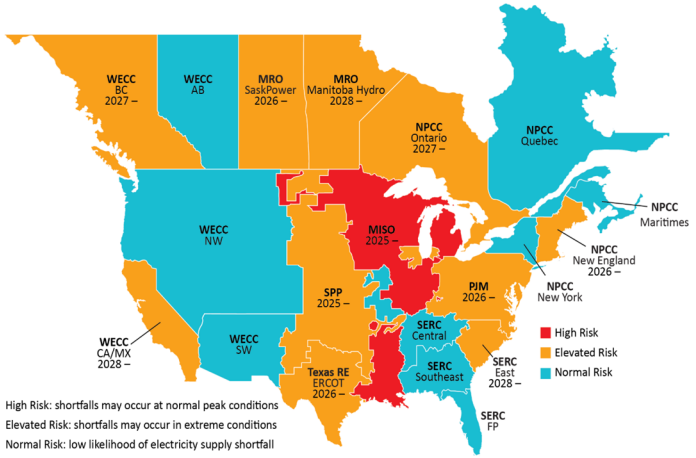


Figure 1: Risk Area Summary 2025–2029

Regional Assessments Dashboards

The **Regional Assessments Dashboards** section contains dashboards and summaries for each of the 20 assessment areas, developed from data and narrative information collected by NERC from the six Regional Entities. Probabilistic Assessments (ProbA) are presented that identify energy risk periods and describe the contributing demand and resource factors.

Table 1: Capacity and Energy Risk Assessment Area Summary			
Area	**Risk Level**	**Years**	**Risk Summary**
MISO	High	2025 -	Resource additions are not keeping up with generator retirements and demand growth. Reserve margins fall below Reference Margin Levels (RML) in winter and summer.
Manitoba	Elevated	2028 -	Potential resource shortfalls in low-hydro conditions, driven by rising demand.
SaskPower	Elevated	2026 -	Risk of insufficient generation during fall and spring when more generators are off-line for maintenance.
Southwest Power Pool (SPP)	Elevated	2025 -	Potential energy shortfalls during peak summer and winter conditions arise from low wind conditions and natural gas fuel risk.
New England	Elevated	2026 -	Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of supply shortfalls in extreme winter conditions.
Ontario	Elevated	2027 -	Reserve margins fall below RMLs as nuclear units undergo refurbishment and some current resource contracts expire. Demand growth is also adding to resource procurement needs.
PJM	Elevated	2026 -	Resource additions are not keeping up with generator retirements and demand growth. Winter seasons replace summer as the higher-risk periods due to generator performance and fuel supply issues.
SERC-East	Elevated	2028 -	Demand growth and planned generator retirements contribute to growing energy risks. Load is at risk in extreme winter conditions that cause demand to soar while supplies are threatened by generator performance, fuel issues, and inability to obtain emergency transfers.
ERCOT	Elevated	2026 -	Surging load growth is driving resource adequacy concerns as the share of dispatchable resources in the mix struggles to keep pace. Extreme winter weather has the potential to cause the most severe load-loss events.
California-Mexico	Elevated	2028 -	Demand growth and planned generator retirements can result in supply shortfalls during wide-area heat events that limit the supply of energy available for import.
British Columbia	Elevated	2027 -	Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Risk from Additional Generator Retirements

Plans for generator retirements continue at similar pace and scale to levels reported in the *2023 LTRA*. Confirmed generator retirements (52 GW by 2029 and 78 GW over the 10-year period) are accounted for in the Capacity and Energy Risk Assessment above. Economic, policy, and regulatory factors spur further fossil-fired generators to retire in the 10-year horizon. Announced retirements, which include many generators that have not begun formal deactivation processes with planning entities, total 115 GW over the 10-year period. The effect of all retirements on the assessment area Planning Reserve Margins (PRM) can be seen in **Figure 2**. On-peak reserve margins fall below RMLs; the levels required by jurisdictional resource adequacy requirements) in the next 10 years in almost every assessment area, signaling an accelerating need for more resources.

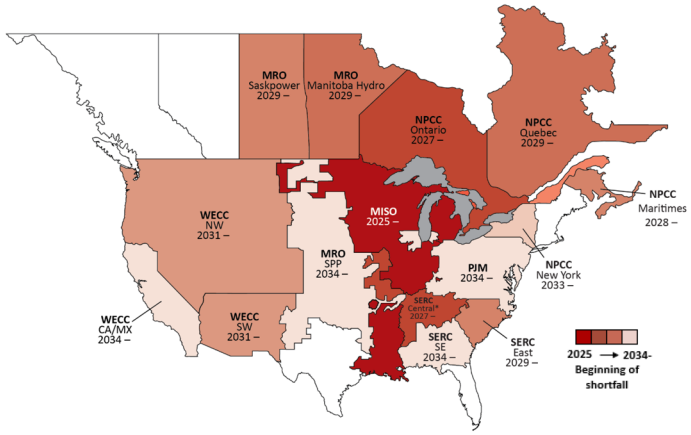


Figure 2: Projected Reserve Margin Shortfall Areas

Changing Resource Mix and Reliability Implications

New resource additions continue at a rapid pace. Solar PV remains the overwhelmingly predominant generation type being added to the BPS followed by battery and hybrid resources, natural-gas-fired generators, and wind turbines. New resource additions fell short of industry's projections from the *2023 LTRA* with the notable exception of batteries, which added more nameplate capacity than was reported in development last year.

As older fossil-fired generators retire and are replaced by more solar PV and wind resources, the resource mix is becoming increasingly variable and weather-dependent. Solar PV, wind, and other variable energy resources (VER) contribute some fraction of their nameplate capacity output to serving demand based on the energy-producing inputs (e.g., solar irradiance, wind speed). The new resources also have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. As generators are deactivated and replaced by new types of resources, ERS must still be maintained for the grid to operate reliably.

Natural-gas-fired generators are a vital BPS resource. They provide ERSs by ramping up and down to balance a more variable resource mix and are a dispatchable electricity supply for winter and times when wind and solar resources are less capable of serving demand. Natural gas pipeline capacity additions over the past seven years are trending downward, and some areas could experience insufficient pipeline capacity for electric generation during peak periods.

Trends and Reliability Implications

Demand and transmission trends affect long-term reliability and the sufficiency of electricity supplies. A summary for each is provided below and further discussed within the **Demand Trends and Implications** and **Transmission Development and Interregional Transfer Capability** sections.

Demand Trends

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb; demand growth is now higher than at any point in the past two decades. Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. The size and speed with which data centers (including crypto and AI) can be constructed and connect to the grid presents unique challenges for demand forecasting and planning for system behavior. Additionally, the continued adoption of electric vehicles and heat pumps is a substantial driver for demand around North America. The aggregated BPS-wide projections for both winter and summer have increased massively over the 10-year period:

- The aggregated assessment area summer peak demand forecast is expected to rise by 15% for the 10-year period: 132 GW this LTRA up from over 80 GW in the *2023 LTRA*.
- The aggregated assessment area winter peak demand forecast is expected to rise over almost 18% for the 10-year period: 149 GW this LTRA up from almost 92 GW in the *2023 LTRA*.

Transmission Trends

For the first time in recent years, transmission projections reported for the LTRA reflect a significant increase in transmission development. This year's cumulative level of 28,275 miles of transmission (>100 kV) in various stages of development for the next 10 years is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning stages of development.

New transmission projects are being driven to support new generation and enhance reliability. Transmission development continues to be affected by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, 68 projects totaling 1,230 miles of new transmission are delayed by siting and permitting issues, according to data collected for the LTRA. Questions of cost allocation and recovery can also challenge transmission development when the benefits apply to more than one area, as often occurs with projects that enhance interregional transfer capability.

In NERC's separate Interregional Transfer Capability Study (ITCS), which was performed to meet requirements contained in the Fiscal Responsibility Act of 2023, NERC found that an additional 35 GW of transfer capability across the United States would strengthen energy adequacy under extreme conditions. Increasing transfer capability between neighboring transmission systems has the potential to alleviate energy shortfalls in some areas identified in this LTRA's **Capacity and Energy Risk Assessment**. Conversely, when resource plans are developed that address these same energy shortfalls, such as through resource additions, demand-side management initiatives, or changes to generator retirement plans, the need for increased transfer capability will also change. Planners have options for reducing energy adequacy risks from extreme weather. Selecting the best course of action will depend on weighing these options against various engineering, economic, policy, reliability, and resilience objectives.

The ITCS provides foundational insights that facilitate stakeholder analysis and actions; it is not a transmission plan. In the future, NERC will extend the study beyond the congressional mandate to include transfer capabilities from the United States to Canada and among Canadian provinces.

Emerging Issues

The **Emerging Issues** section discusses developments and trends that have the potential to substantially change future long-term demand and resource projections, resource availability, and reliable operations of the BPS. Topics include data centers and large industrial loads, battery energy storage systems, electric vehicles and load, and energy drought. NERC's RSTC has formed new task forces where needed to address emerging issues.

Recommendations

To address the energy and capacity risks identified in this LTRA, NERC recommends the following priority actions:

1. **Integrated Resource Planners, market operators, and regulators: Carefully manage generator deactivations.** Independent System Operator/Regional Transmission Organizations (ISO/RTOs) should evaluate mechanisms and process enhancements for obtaining information on expected generator retirements that would support early identification of reliability risks. State and provincial regulators and ISO/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulatory and policy-setting organizations must use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be developed and placed in service.

2. **NERC and Regional Entities: Improve the LTRA by incorporating new analysis and criteria to inform stakeholders of future reliability risks.** NERC increased the frequency of the ProbA from biennial to annual and included unserved energy and load-loss metrics as the basis for risk analysis in this year's LTRA. To be more effective in using energy criteria and outputs of probabilistic analysis, NERC must specify consistent methods and assumptions for assessment areas to follow in preparing the annual ProbA. NERC and the Regional Entities, in consultation with the RSTC, should also continue to enhance NERC's LTRA to assess ERSs in the future system and the potential impact of new and evolving electricity market practices, regulations, or legislation on resource adequacy. Finally, NERC should work with the Regional Entities to perform wide-area energy analysis with modeled interregional transfer capability. Wide-area energy analysis will support the evaluation of extreme weather and regional fuel supply issues on an interconnection level.

3. **Regulators and Policymakers: Streamline siting and permitting processes to remove barriers to resource and transmission development.** As ISO/RTOs continue looking for opportunities to speed transmission planning processes, delays from siting and permitting activities will need to be reduced. These are the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.

4. **Regulators, electric industry, and gas industry member organizations: Implement a framework for addressing the operating and planning needs of the interconnected natural gas-electric energy system.** Various initiatives were launched in the past year to address the reliability needs that arise from the complexity of interconnecting natural gas and electric infrastructure. Voluntary actions taken by the natural gas industry in response to the North American Energy Standards Board (NAESB) Forum report are a positive step toward improving winter readiness. The National Association of Regulatory Utility Commissioners (NARUC) launched its Gas-Electric Alignment for Reliability (GEAR) task force this year and recently created the Natural Gas Readiness Forum. For its part, NERC continues to collaborate extensively with industry and policymakers. NERC has enhanced its Reliability Standards requiring generators to prepare for winter extremes, implement training, and establish communication protocols between generators and grid operators. Current standards projects encompass extreme weather planning and energy assurance requirements. NERC will continue to provide full support to initiatives aimed at achieving a reliable interconnected energy system and urges regulators and policymakers to support needed avenues of coordination between the two sectors.

5. **Regional transmission organizations, independent system operators, and FERC: Continue to ensure essential reliability services are maintained.** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs.[7] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to ERSs. As replacement resources are interconnected, these new resources should be capable of supporting voltage, frequency, ramping, and dispatchability. Many technologies can contribute to ERSs, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.

In addition to these priorities, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. All recommendations are listed in the **Recommendations and ERO Actions Summary** section.

[7] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

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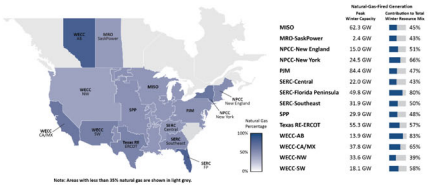
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NPCC, Inc.
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WECC

Reliability Insights

The Interconnected Gas and Electric Systems

March 2025

North America's electric generating resources are significantly shifting due to retirements of conventional generation coupled with the growth in solar, battery, natural gas, and wind resources. Regulatory rulings and state policies are driving the development of more renewable energy resources. Meanwhile, due to the rapidly retiring coal fleet, natural-gas-fired generation has increased its share of the thermal resource mix and represents more than 80 percent of peak winter capacity in some areas of North America.



This growing dependence on natural gas infrastructure has created new operational and planning challenges, such as those experienced during Winter Storm Elliott in December 2022 (when extreme temperatures in the Eastern Interconnection precipitated a sharp spike in peak electricity demand, driving many grid operators to declare energy emergencies). At the same time, natural gas production in Appalachia fell by more than 6 billion cubic feet (Bcf) per day due to freeze-offs at the wellhead, other mechanical freezes, and icy roadways that delayed repairs. This loss in supply for major gas pipeline operators in the region threatened fuel delivery to power sector customers. At one point, unplanned generation outages caused by freezing generators and fuel supply issues totaled 90,500 MW, equivalent to 13 percent of the resources in the U.S. Eastern Interconnection. In the Southeast, Transmission Operators ordered more than 5,400 MW of firm load shed, the largest recorded manual load shed in the Eastern Interconnection's history. Natural gas production was also extremely impacted, leaving the Marcellus and Utica Shale formations with a production drop of 23% and 54%, respectively, at its peak. This event, and others, spotlights the wide-area challenges that winter weather can bring and energy constraints that may not be resolved by relying on assistance from neighboring areas.

The critical role of dispatchable power generation, such as coal, natural gas, and nuclear, in maintaining grid reliability (particularly during periods when weather-dependent variable resources like wind and solar are unavailable) became evident in 2016. A well leak at the Aliso Canyon natural gas storage facility in Southern California disrupted essential natural gas infrastructure, directly impacting bulk power system (BPS) reliability. This incident highlights the increasing vulnerability of the electric system as reliance on natural gas grows—any outage at a key facility can have significant consequences. Ensuring the resilience of natural gas storage, pipelines, compressor stations, and liquefied natural gas facilities is essential for the electric industry to meet its reliability obligations.

Interconnected Systems Need Coordinated Planning and Operations

The natural gas and electric systems are constituent parts of an interconnected energy delivery system. High-profile disruptions to natural gas availability in recent years have raised awareness of the interdependence between the natural gas system and the BPS infrastructure, resulting in calls for closer coordination in planning and operating these two systems to identify and mitigate risk.

Key Reliability Risks

Natural Gas Supply and Transportation Risks

- **Production Well Freeze-Offs and Winterization:** During extreme cold, natural gas wells can freeze, leading to significant reductions in supply.
- **Dependence on Electricity:** Upstream and midstream gas facilities (compressors, processing plants, and wellheads) rely on electricity from the grid to operate.
- **Pipeline Constraints:** Constrained pipeline capacity, particularly in the U.S. Mid-Atlantic and Northeast, poses challenges in delivering natural gas during peak demand, leaving little operational flexibility should any natural gas facilities be out of service.

Electric and Gas Market Harmonization

- **Scheduling:** Discrepancies between gas and electric market schedules can lead to delays in natural gas availability for power generation during peak demand.
- **Operational Coordination:** Inadequate communication between market operators and pipeline operators prevents alignment of resource availability and electricity demand.
- **Planning Coordination:** Gas and electric system planning is not integrated, and assessments of infrastructure are needed to assure the reliability and adequacy of both systems.

Resource Adequacy and Capacity to Support Large Ramps

- **Winter Peak Demand:** Extreme cold can cause sharp increases in electricity demand during the morning and evening hours, requiring generation resources to ramp up quickly.
- **Generation Preparedness and Fuel Assurance:** Natural gas power plants that are ill-prepared for rapid ramping may fail to secure fuel in real-time conditions.

Vulnerabilities in Generator Winterization

- **Implementation Challenges:** Despite recent progress, some generators still face challenges implementing comprehensive winterization measures.

Opportunities for Mitigation

- **Enhanced Winterization Requirements:** Continue monitoring of compliance with mandatory generator winterization requirements as well as voluntary pipeline and production well winterization standards.
- **Operational Preparedness:** Identification of critical gas facility loads by local grid operators and inclusion in restoration plans will speed recovery during interruptions and limit cascading effects on gas production.
- **Improved Communication Protocols:** Information-sharing practices between market operators and fuel providers should be strengthened to align generation capacity with fuel delivery timelines.
- **Market Reforms:** Market structures to better assure operational performance and fuel certainty by incentivizing and rewarding actions that promote reliability (e.g., firming fuel supply and transportation, as well as winterization investments) should be developed.
- **Cross-Market Coordination:** Policy initiatives that promote closer alignment of gas and electric market schedules during critical weather periods are necessary.
- **Capacity and Energy Planning for Ramps:** Investments in flexible generation and storage solutions are needed to support larger, more frequent ramping events.
- **Regulatory Reform:** Formalized coordination and collaboration, including the development of Standards that encompass both systems, will help assure the reliable operation of both systems.

Conclusion

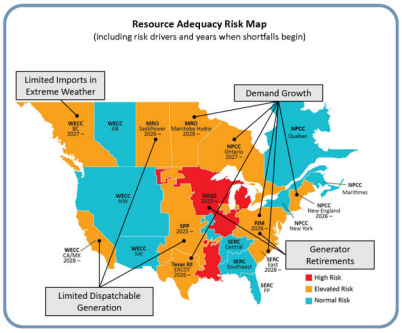
Reliable natural gas supply and electric system performance are essential to meet energy demands. The reliable delivery of energy to end users during extreme weather will be better assured by addressing risks to reliability across both systems. Immediate action is needed across the policy, market, and infrastructure domains to bolster grid resilience during winter's toughest moments.

2024 Long Term Reliablity Assessment

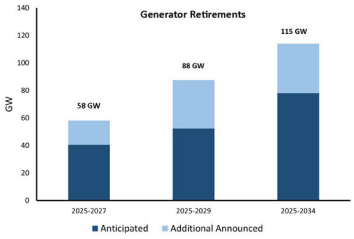
LTRA Report | LTRA Video

NERC's *2024 Long Term Reliability Assessment* (LTRA) identifies reliability trends, emerging issues and potential risks to the bulk power system over a 10-year horizon. This year's report points to the mounting reliability challenges that industry is facing — satisfying escalating energy growth, managing generator retirements and removing barriers to resource and transmission development. Recommendations to address reliability concerns include managing generator deactivations, enhancing future LTRAs with more expansive energy risks analysis, streamlining siting and permitting, promoting natural gas-electric system coordination and ensuring essential reliability services are maintained.

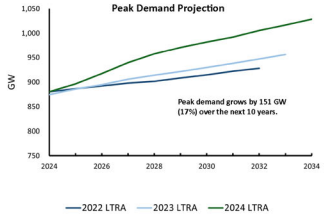
Resource Adequacy Risk Map
(including risk drivers and years when shortfalls begin)



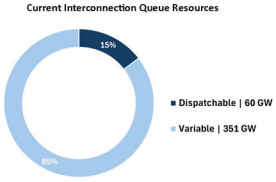
Accelerating Retirements: Resource needs to meet escalating demand growth are threatened by the current pace of generator retirements.



Escalating Demand Growth: Peak demand and energy forecasts have jumped and are at their highest levels in decades.



Declining Dispatchable Resources: Replacement resources projected over the next decade are more weather dependent and lack key reliability attributes.



NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
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RELIABILITY | RESILIENCE | SECURITY

March 25, 2025

The Honorable Brett Guthrie
Chairman
Energy and Commerce Committee
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, D.C. 20515

The Honorable Frank Pallone
Ranking Member
Energy and Commerce Committee
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, D.C. 20515

The Honorable Bob Latta
Chairman
Energy and Commerce Committee
Subcommittee on Energy
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, D.C. 20515

The Honorable Kathy Castor
Ranking Member
Energy and Commerce Committee
Subcommittee on Energy
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, D.C. 20515

Dear Chair Guthrie, Ranking Member Pallone, Chair Latta, and Ranking Member Castor:

The American Public Power Association (APPA) appreciates the opportunity to submit a statement for the record for the House Energy & Commerce Committee's Subcommittee on Energy hearing on, "Keeping the Lights On: Examining the State of Regional Grid Reliability."

APPA is the national trade organization representing the interests of the nation's 2,000 not-for-profit, community-owned electric utilities. Public power utilities are in every state except Hawaii. They collectively serve over 54 million people in 49 states and five U.S. territories, and account for 15 percent of all sales of electric energy (kilowatt-hours) to end-use consumers. Public power utilities are load-serving entities, with the primary goal of providing the communities they serve with safe, reliable electric service at the lowest reasonable cost, consistent with good environmental stewardship. This orientation aligns the interests of the utilities with the long-term interests of the residents and businesses in their communities. While public power utilities serve some of the nation's largest cities, nearly 1,600 of the 2,000 in operation serve rural communities. Utilities are facing unprecedented demand growth from traditional loads, data centers, and electrification at a time when traditional generation is retiring prematurely, and new, reliable generation cannot be built quickly enough. Most public power utilities are load-serving entities (LSEs) responsible for keeping the lights on. The grid operators have a critical role to play in assisting LSEs in addressing demand growth and resource adequacy issues.

Looking at the challenges of grid reliability more broadly, APPA supports efforts in Congress to enact policies that support public power utilities in providing reliable and affordable electricity to their constituents. APPA appreciates the House Energy & Commerce's work on these critical issues.

Interconnection Queues

Meeting the unprecedented load growth requires continued improvements to the process for interconnecting new, reliable generation to the grid. The Federal Energy Regulatory Commission (FERC) has approved several changes designed to speed up the interconnection process, including a recent change to PJM's interconnection queue that provides a one-time opportunity for shovel-ready, reliable resources to address near-term resource adequacy concerns. Nevertheless, in 2024 only 50 gigawatts of new capacity was added to the grid. Congress should continue to monitor the pace of resource additions in 2025 and provide oversight of FERC's continued efforts to speed up interconnection queues. Resources needed by LSEs for reliability must be considered in any efforts to streamline or prioritize interconnection queues.

Enhanced Coordination of Gas and Electric Sectors

In 2023, natural gas accounted for over 40 percent[1] of utility-scale electricity generation in the United States, with millions of Americans also relying on natural gas directly for cooking and heating their homes. To maintain current reliability and to manage the increased load from economic growth, data centers, and electrification, natural gas must continue to play an instrumental role in the electric system. While the electric and natural gas industries have long been intertwined, the relationship has become more critical in recent decades as a larger share of electricity is generated using natural gas.

For these reasons, APPA supports a readily available and affordable supply of natural gas, as well as the pipeline infrastructure necessary to ensure reliable and timely delivery where it is needed. APPA supports higher standards for delivery, notification, and transparency from the natural gas industry, whether the industry adopts and implements those standards voluntarily or through increased government oversight, including but not limited to, the establishment of a natural gas reliability organization, that carries out similar functions in the natural gas business as the North American Electric Reliability Corporation (NERC) does for electric reliability, as proposed by the 2023 North American Energy Standards Board Gas Electric Harmonization Forum Report.

Permitting Reform

APPA supports efforts in Congress to streamline the federal permitting process, eliminate excessive regulatory barriers, and ensure more predictable and timely decisions from relevant

[1] U.S. Energy Information Administration; What is U.S. electricity generation by energy source? (Feb. 2024) https://www.eia.gov/tools/faqs/faq.php?id=427&t=3

federal agencies. Despite abundant resources and potential projects to meet the rapidly growing demand for electricity, permitting red tape, needlessly burdensome regulations, and conflicts between state and federal priorities have slowed energy infrastructure development to a crawl. Utility customers ultimately pay the high cost of slow, cumbersome permitting rules.

APPA encourages Congress to prioritize infrastructure-neutral permitting reform to ensure public power utilities have the clarity and certainty to invest in required generation, distribution, and transmission infrastructure to meet rising demand and ensure grid reliability.

Supply Chain

Finally, public power utilities continue to contend with supply chain constraints for various critical grid and electric generation components. Supply chain constraints and shortages threaten the reliability of the electric grid and the nation's economy.

APPA was pleased to see the Department of Energy (DOE) take positive steps last April in its final transformer efficiency standards rule. APPA also greatly appreciates the work done by House Energy & Commerce Committee members to advocate for a balanced approach to transformer efficiency. However, despite these achievements, public power utilities still face supply chain issues, from transformers to gas turbines, making it difficult to meet rising demand and ensure grid reliability.

Congress should encourage DOE and other federal agencies to collaborate and work with public power and the broader electric sector to ensure a robust supply chain of critical components is available and accessible for electric utilities.

Conclusion

APPA commends the committee for holding today's hearing and for the ongoing focus of the House Energy & Commerce Committee and the Subcommittee on Energy to the issues impacting public power utilities, in particular, rising demand and resource adequacy, as they work to provide reliable, affordable, and sustainable power to millions of American homes and businesses.

ENERGYWIRE

Trump says coal should make a comeback. At what price?

A deal to keep two Baltimore power plants open into 2029 is the tale of repeated failures by the largest U.S. power market to plan for a future without coal.



BY: **PETER BEHR** | 03/25/2025 06:38 AM EDT



Brandon Shores power plant in Baltimore.| abriggs21/iStock

ENERGYWIRE | *First in an occasional series on PJM, the Eastern power market.*

In the tiny community of Orchard Beach on the western entrance to Baltimore Harbor, the dominant feature isn't the modern townhouses and modest bungalows or the cattails and bulrushes lining the creeks.

Looming over everything is a cluster of exhaust stacks at two large coal-fired electric power stations just to the north. "They're just ugly," said Zachary Guy, a resident of the neighborhood who took a break from working on his mother's vehicle to comment on the power units, the oldest of which has been operating for 40 years.

If federal regulators approve, utility customers in the greater Baltimore area will have to pay a $754 million surcharge to keep the plants owned by Houston-based Talen Energy cranking out more than a combined 1,500 megawatts for another four years. Brandon Shores and the smaller H.A. Wagner stations were scheduled to retire this year, adding more closures to the 15-year-long exodus from coal by U.S. power producers opting for cleaner and cheaper alternatives.

Without the plants, however, the region's shrinking power reserves would enter a dangerous place. The risk would be cascading multistate power outages, according to officials of the PJM Interconnection, which operates the grid serving Maryland and a dozen other states and the District of Columbia.

"You don't want to get anywhere near there," said Joseph Bowring, president of Monitoring Analytics, PJM's independent market monitor.

The surcharge payments will continue until 2028 or 2029 at least, when PJM hopes to complete installation of new and upgraded high-voltage transmission lines to deliver enough imported power to replace the plants. The transmission cost: an estimated $1.5 billion, more than two-thirds of it also landing on Maryland utility customers, according to state officials.

Without approval of the payments plan, now pending at the Federal Energy Regulatory Commission, Talen Energy had said it would close the plants, clean up the sites and build a waterfront development. Under its almost inscrutable operating rules, PJM is powerless to keep the plants in business.

Maryland's Office of People's Counsel, in a filing at FERC, put it more simply: Talen Energy was able to "extract a high level of compensation under threat of

shutting down the power plants."

If the PJM settlement with Talen goes through, Maryland's consumer advocate initially estimated residential electricity bills would go up by $247 a year for three or four years, with an average annual hike of $2,685 for commercial customers. While those figures will be cut down by other parts of the proposed settlement, the cost of the transmission projects will be part of customer bills for many years, said Deputy People's Counsel William Fields.

Those are all economic decisions made by powerful organizations and companies. An expanded version of that confronts President Donald Trump and his administration as they promise to bring back coal and expedite natural gas generation to power a build-out of data centers and win the race against China for artificial intelligence supremacy.

Doug Burgum, speaking as the Interior secretary and chair of Trump's new White House energy council, told Bloomberg Television that U.S. demand for more electricity through 2030 requires keeping coal plants running for longer — and could mean resurrecting coal generation that has already shut down. Most of those coal units closed because they were decades old, polluting, and less profitable than natural gas generation or bringing more wind and solar power onto the electric grids.

"Under the national energy emergency, which President Trump has declared, we've got to keep every coal plant open," Burgum said.

U.S. power producers haven't opened a large coal-fired power plant since 2013, and there have been no major plans to add more coal capacity in the future. Burgum has downplayed even the idea that companies and U.S. policies are invested in a transition to energy technology that pollutes less and emits fewer greenhouse gas emissions.

"That is one of the big lies of the climate extremists," Burgum said during the interview earlier this month at an oil and gas conference in Houston. "We're in a period of energy addition."

Trump, in announcing a national energy emergency in January, could invoke wartime authority to order any U.S. power plant to keep operating, possibly for

indefinite periods, legal scholars point out. Trump has also asserted all major actions by independent agencies that regulate the economy, including FERC, to be under the president's control. That could pull consequential decisions over wholesale power prices into the Trump White House — and potentially lead to a pricing scheme that pays premiums to the energy companies and private investors that own America's remaining coal plants.

The pending decision on a big payment to Talen Energy to keep the Baltimore plants running signals a costly return to coal, whether to ensure the lights stay on or to satisfy political promises. If Trump directs energy markets to pay for coal generation — at whatever the price — it would weigh heavily against Trump's pledge to drive down energy costs for voters.

'A very dangerous place'

Today, old fossil fuel plants are retiring faster than their power can be replaced with new generation of any kind, with the problem most severe in PJM and the Midcontinent Independent System Operator (MISO) in the central U.S., according to the 2024 Long Term Reliability Assessment by the grid's monitor, the North American Electric Reliability Corp. (NERC). And this is happening amid an unexpected surge in power demand to run new data centers with enormous energy appetites.

"We are heading toward a very dangerous place in terms of our reliability," FERC Chair Mark Christie said in an earlier interview.

"Our infrastructure is not being built fast enough to keep up with the rising demand," John Moura, NERC director of reliability assessments and performance analysis, said in releasing the long-term assessment. Within 10 years, the amounts of surplus power available to meet peak electricity needs will fall below safety levels in nearly every part of the United States, NERC concluded.

"You have a significant number of states…where it's harder and harder, or nearly impossible, to build the infrastructure necessary to produce electricity," said Kent Chandler, former chair of the Kentucky Public Service Commission and former president of the Organization of PJM States.

Grid operators weren't expecting the sudden power growth projections from data centers and new power plants that emerged in the past two years, says Scott Niemann, managing director of ESAI Energy, Massachusetts-based grid analysts. "So the need really shifted from building renewables to meet [state] mandates to getting electricity from any source you can get it from, whether it's renewable or gas fired, to meet the demand growth."

PJM could see a capacity shortage as soon as the mid-2026 delivery year, said Mark Takahashi, chair of PJM's Board of Managers.

Born nearly a century ago by utilities in Pennsylvania, New Jersey and Maryland who wanted to pool power supplies, PJM today is the largest of the seven U.S. regional power organizations. Its control room operators must maintain a moment-to-moment matching of power supply with demand in its 13-state region of 65 million people from the mid-Atlantic beaches to Chicago.

The two Baltimore plants, Brandon Shores and H.A. Wagner, are the most important power source in central Maryland. They can serve more than 1 million households. For most of their lives, the plants have also been the state's largest source of global-warming CO_2 emissions, and in Brandon Shores' case, a persistent source of health-threatening sulfur dioxide exhaust from its two coal-fired steam plants.

The owner of the plants, Talon Energy, which went through a bankruptcy reorganization in 2022, has no "duty to serve" Maryland customers. The Maryland plants are part of its asset portfolio affected by profit-seeking options that include pursuing data center contracts and repurchasing its stock shares to boost their value.

Facing a lawsuit by the Sierra Club over the two plants' emissions, and emissions regulations, Talon announced in 2023 it would close the plants this year. Given a glacial decision-making process at PJM, with its more than 1,000 members, that much power was not replaced, forcing PJM to pay Talen to keep running until new power could be substituted.

"Brandon Shore's pending retirement was foreshadowed long before" the 2023 announcement, Maryland People's Counsel argued. Yet until the

announcement, “PJM does not appear to have done any pro-active review” of options for replacing the lost power, the office added.

Today, PJM has a comfortable security margin of spare capacity across its system. Its 1,408 generators of all kinds can produce a peak of 183,000 MW of power, well above the top demand forecast for this summer of 154,000 MW, PJM says. (For comparison, the 94 U.S. commercial reactors produce 97,000 MW of peak power.)

By 2030, however, PJM predicts maximum demand could rocket up to more than 180,000 MW if a predicted surge in data center demand occurs. Today’s generation capacity of 183,000 MW will drop by 40,000 MW if all the plants that say they plan to retire actually do so by 2030, PJM says. New power plants to replace the retired ones have not materialized.

Clean energy and lost opportunity

A flood of proposed power plant projects has stacked up at PJM, the vast majority of which are small solar plants. That gives PJM an opportunity to create a balance of carbon-free renewable energy, storage, nuclear power and gas-fired generation.

PJM failed to seize that opportunity, critics say.

Corporate power buyers with clean energy goals sought out solar power deals in PJM, but developers faced a costly, drawn-out process for approval to connect to the transmission grid. They waited four years or more for a go-ahead, analysts have documented.

By then, financing commitments had aged out, momentum had faded and stalled, according to analysis by the Lawrence Berkeley National Laboratory and other reviews.

PJM denied a request to interview its top executive. The regional grid, which dispatches generation and manages electric reliability, reports it had approved 37,000 MW of new projects, mostly solar, as of the end of 2023. As of last September, none had been built.

PJM has tried to catch up with the problem of the long queue of proposed generation projects. “Frankly, one of the top jobs that PJM had was running the queue," Chandler said. "That's certainly been a failure on their part.”

Natural gas projects now must deal with backlogged order books at gas turbine manufacturers and threats of shortages of imported grid components targeted by Trump’s tariffs. New gas generating plants are key to Trump’s plans, but they require building more gas pipelines, typically against local opposition.

On top of that is the damage to investor confidence stemming from the head-spinning vertigo between 2021 and now. Former President Joe Biden made a major policy drive at moving away from coal for good and making big investments in advancing this century’s energy technology. Trump has spent almost every day of his new term cutting funding for clean energy and talking up oil, gas and coal.

“It is absolutely true that uncertainty is keeping new generation from being built,” Chandler said.

PJM’s annual “capacity auction” — the strategy it uses to line up commitments for future supplies from power plant owners — has not enticed much new generation.

PJM solicits bids from generators to supply power at the generators’ chosen price, and PJM chooses the least expensive ones, with the payments ultimately passed on to power customers. Plant owners selected in the auction commit to provide power in an upcoming “delivery” year, along with the payments they receive, also face a heavy fine if they don’t deliver power when called on by PJM.

The average incentive price for the 2024-2025 year was $29 per megawatt per day in most of PJM, for a total cost to customers of $2.2 billion, a price too low to prompt owners to build new plants or maintain old ones, analysts said.

Then came the data center demand eruption. With a power shortage looming, the price in last year's auction, for the 2026-2027 delivery year shot up 900 percent to nearly $270 per MW per day in most of PJM, bringing the charge to customers to $14.7 billion. Maryland customers, cornered in the easternmost

part of PJM with the fewest power supply options, were stuck with an even higher price, $466 per MW per day.

The next auction, scheduled this June, would be under a new set of rules continuing the churn of policy changes PJM has rolled out in recent years to get the results it wants and needs, Chandler said. These changes, like the payments to Talen Energy for the Baltimore plants, require FERC approval.

For the upcoming auction Pennsylvania Gov. Josh Shapiro demanded and got PJM to agree to lower the maximum permitted bid from $500 per MW per day to about $325 per MW per day. “We believe that not moving forward with this settlement would have left us in an untenable situation,” said Stu Bresler, PJM executive vice president for market services and strategy.

“Supply and demand are not only getting tighter, but the situation is almost accelerating in that direction,” Besler said.

The dilemma is unfolding. “Everybody wants capacity, but nobody's happy to bear the costs of funding those investments, and so nothing has happened, which leaves us kind of where we are today,” Niemann said.

UP NEXT IN **THIS EDITION OF ENERGYWIRE**

DOE axes 4 major efficiency rules

BY CHRISTA MARSHALL



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Solid-state cooling: How cutting-edge technologies can help solve the cooling challenge. >>

The Business Case for New Gas Is Shrinking

The Inflation Reduction Act makes clean energy cheaper than more than 90 percent of proposed gas plants.

December 8, 2022

By Lauren Shwisberg

As the dust settles following the passage of the Inflation Reduction Act (IRA), the electricity industry is only beginning to understand its true impacts. One of

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those impacts is the continued erosion of the business case for new fossil gas power plants.

Over the past decade, fossil gas power plants became the default resource option for utility investment, making up a majority of capacity additions. While over the past few years the total capacity of plants built has **declined** and high **profile** **cancellations** have increased, the IRA's tax incentive provisions will accelerate deployment of cleaner, cheaper electricity — making gas an even less competitive choice.

New RMI analysis shows just how much the IRA changes the game.

The Analysis

We used our Clean Energy Portfolios Model — updated to include resource cost projections that reflect post-IRA levels of tax credits — to identify the lowest cost portfolio of wind, solar, battery energy storage, energy efficiency, and demand flexibility that can provide the same estimated services as a proposed fossil gas plant.

When we ran 76 GW of fossil gas plants proposed before 2035 through our Clean Energy Portfolios Model, we found that the vast majority of plants were more expensive than their respective clean energy portfolios (CEPs), shown in Exhibit 1. In a scenario where clean

Clean Fuel Standards: The Market-Based Policy for States Looking to Clean Up Transportation

Clean Energy 101: Solid-State Cooling

CATEGORIES

Africa

Amory Lovins

Building Electrification

Buildings

Carbon Markets

China

Cities

Climate Data

Commercial Buildings

e-Lab: Electricity Innovation Lab

Electricity

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energy resources use the 30 percent Investment Tax Credit or the Production Tax Credit at $26/MWh, clean energy outcompetes 93 percent of proposed fossil gas plants – more than 20 percent more than pre-IRA.

With additional bonuses for investment in energy communities, use of domestically sourced resources, or siting in low-income communities, in nearly every instance, clean energy beats gas on cost alone. That means that when taking full advantage of the tax credits in the IRA, clean, renewable sources will be cheaper than 99 percent of proposed gas plants – plants that are contributing to price volatility in American household energy bills.

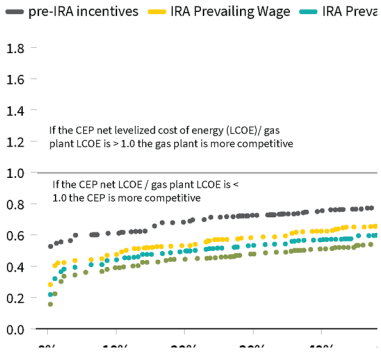
When taking full advantage of the tax credits in the Inflation Reduction Act, clean, renewable sources will be cheaper than 99 percent of proposed gas plants.

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Impacts of IRA incentives on the percent cumulative capacity of competitive CEPs



IRA credit scenario assumptions and results

Credit scenario (2022$)	CEP results
Pre-IRA Incentives	72% of plants outcompeted
Prevailing wages - ITC at 30%, PTC at $26/MWh	93% of plants outcompeted
Prevailing wages +	

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The Power of Financial Incentives

One of the main reasons for this is that post-IRA solar and wind costs are expected to plummet. Analysts are projecting that renewables costs will continue to fall – with jaw-droppingly low prices for wind and solar by the end of the decade.

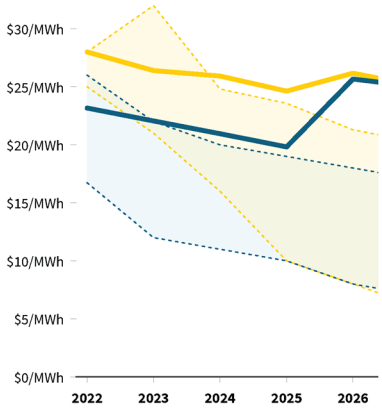
Credit Suisse, for example, **made headlines** when it projected $5/MWh wind and solar by 2029. S&P Global and IHS Markit **projected** numbers nearly as low – with about $10/MWh solar in 2030 falling to $5/MWh by 2035. Consulting firm ICF's **projections**, though slightly less bullish, still predict that a levelized cost of energy for solar and wind in 2030 will be 20–35 percent and 38–49 percent lower, respectively, than pre-IRA.

In most of these forecasts, renewable costs fall below the go-forward cost of a combined cycle gas plant – generally expected to be at least $30–$40/MWh. This means it will be cheaper on a per megawatt hour basis to build new wind and solar than to continue to operate existing gas.

Exhibit 3 aggregates these projections (Credit Suisse, S&P Global and IHS Markit, and ICF's low projections for 2030) into charts that show an indicative range of levelized cost of energy for wind and solar post-IRA, compared with NREL's 2022 Annual Technology Baseline pre-IRA.

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Analyst projections of solar and wind LCOE pre-IRA and post-IRA ($2021)



Source: RMI analysis of NREL 2022 Annual Technology Baseline data (Wind Class 4, Utility

While our analysis in the Clean Energy Portfolios Model only looked at battery energy storage and demand flexibility to provide firm, dispatchable energy, a host of new resource options may also be **cost-competitive** with fossil gas by the end of the decade. A range of "clean firm" technologies will increasingly compete directly with fossil gas, such as alternative energy storage technologies, geothermal, advanced nuclear, hydrogen-fired turbines, and carbon capture and storage.

Updated Resource Plans and Procurement Processes Can Unlock $5 Billion per Year in Savings

RMI's analysis and other independent analysts are showing that the IRA can fundamentally change the math on the next right utility investment — and deliver substantial savings to customers. These aren't far-off future projections either. Cheaper, cleaner energy is the result of strong policy we passed this year.

There are actions **regulators** and utilities can take today to realize the IRA's projected **$5 billion** per year in savings for their ratepayers. New resource plans can include updated resource costs that accurately represent the new tax credits, seek to represent the full range of resources that may be commercially available within the planning horizon, and demonstrate how they will use additional IRA funding sources such as **the Energy Infrastructure Reinvestment program**. While costs remain uncertain, regulators and utilities can use **all-source procurement** — a competitive process that solicits bids from all types of resources — for near-term needs to discover the market prices and relative competitiveness across resources.

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As these changes begin to make their way into utility planning and procurement, we're starting to see results:

- DTE Energy in Michigan filed its Integrated Resource Plan in early November, with a scenario that factored in IRA tax incentives. Utility executives **reported** that they expected the IRA to lower the price tag of their 20-year plan for customers about $500 million.
- The Minnesota Public Utilities Commission approved Xcel's request this week to build 460 MW of solar at a retiring coal plant site — part of a CEP that will avoid a new gas plant. Xcel **reported** that the IRA was anticipated to save ratepayers 30 percent over its initial estimate of project costs.
- **Duke Energy** in Florida is providing customers with a $56 million refund as a result of solar tax credits.
- **Ameren** is proposing to lower customer rates by 4.5 percent.

To fully realize the benefits of the IRA, now is the time for utilities and regulators to reevaluate plans for investing in new fossil gas power plants and take advantage of the opportunity to deliver ratepayer savings with cleaner options.

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The WHITE HOUSE

PRESIDENTIAL ACTIONS

Temporary Withdrawal of All Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects

The White House

January 20, 2025

January 20, 2025

MEMORANDUM FOR THE SECRETARY OF THE TREASURY
THE ATTORNEY GENERAL
THE SECRETARY OF THE INTERIOR
THE SECRETARY OF AGRICULTURE
THE SECRETARY OF ENERGY
THE ADMINISTRATOR OF THE ENVIRONMENTAL PROTECTION AGENCY

SUBJECT: Temporary Withdrawal of All Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects

Section 1. Temporary Withdrawal of Areas. Consistent with the principles of responsible public stewardship that are entrusted to this office, with due consideration for a variety of relevant factors, including the need to foster an energy economy capable of meeting the country's growing demand for reliable energy, the importance of marine life, impacts on ocean currents and wind patterns, effects on energy costs for Americans –– especially those who can least afford it –– and to ensure that the United States is able to

maintain a robust fishing industry for future generations and provide low cost energy to its citizens, I hereby direct as follows:

Under the authority granted to me in section 12(a) of the Outer Continental Shelf Lands Act, 43 U.S.C. 1341(a), I hereby withdraw from disposition for wind energy leasing all areas within the Offshore Continental Shelf (OCS) as defined in section 2 of the Outer Continental Shelf Lands Act, 43 U.S.C. 1331. This withdrawal shall go into effect beginning on January 21, 2025, and shall remain in effect until this Presidential Memorandum is revoked.

To the extent that an area is already withdrawn from disposition for wind energy leasing, the area's withdrawal is extended for a time period beginning on January 21, 2025, until this Presidential Memorandum is revoked.

This withdrawal temporarily prevents consideration of any area in the OCS for any new or renewed wind energy leasing for the purposes of generation of electricity or any other such use derived from the use of wind. This withdrawal does not apply to leasing related to any other purposes such as, but not limited to, oil, gas, minerals, and environmental conservation.

Nothing in this withdrawal affects rights under existing leases in the withdrawn areas. With respect to such existing leases, the Secretary of the Interior, in consultation with the Attorney General as needed, shall conduct a comprehensive review of the ecological, economic, and environmental necessity of terminating or amending any existing wind energy leases, identifying any legal bases for such removal, and submit a report with recommendations to the President, through the Assistant to the President for Economic Policy.

Sec. 2. Temporary Cessation and Immediate Review of Federal Wind Leasing and Permitting Practices**.** (a) In light of various alleged legal deficiencies underlying the Federal Government's leasing and permitting of onshore and offshore wind projects, the consequences of which may lead to grave harm — including negative impacts on navigational safety interests, transportation interests, national security interests, commercial interests, and marine mammals — and in light of potential inadequacies in various environmental reviews required by the National Environmental Policy Act to lease or permit wind projects, the Secretary of the Interior, the Secretary of Agriculture, the Secretary of Energy, the Administrator of the Environmental Protection Agency, and the heads of all other relevant agencies, shall not issue new or renewed approvals, rights of way, permits, leases, or loans for onshore or offshore wind projects pending the

completion of a comprehensive assessment and review of Federal wind leasing and permitting practices. The Secretary of the Interior shall lead that assessment and review in consultation with the Secretary of the Treasury, the Secretary of Agriculture, the Secretary of Commerce, through the National Oceanic and Atmospheric Administration, the Secretary of Energy, and the Administrator of the Environmental Protection Agency. The assessment shall consider the environmental impact of onshore and offshore wind projects upon wildlife, including, but not limited to, birds and marine mammals. The assessment shall also consider the economic costs associated with the intermittent generation of electricity and the effect of subsidies on the viability of the wind industry.

(b) In light of criticism that the Record of Decision (ROD) issued by the Bureau of Land Management on December 5, 2024, with respect to the Lava Ridge Wind Project Final Environmental Impact Statement (EIS), as approved by the Department of the Interior, is allegedly contrary to the public interest and suffers from legal deficiencies, the Secretary of the Interior shall, as appropriate, place a temporary moratorium on all activities and rights of Magic Valley Energy, LLC, or any other party under the ROD, including, but not limited to, any rights-of-way or rights of development or operation of any projects contemplated in the ROD. The Secretary of the Interior shall review the ROD and, as appropriate, conduct a new, comprehensive analysis of the various interests implicated by the Lava Ridge Wind Project and the potential environmental impacts.

(c) The Secretary of the Interior, the Secretary of Energy, and the Administrator of the Environmental Protection Agency shall assess the environmental impact and cost to surrounding communities of defunct and idle windmills and deliver a report to the President, through the Assistant to the President for Economic Policy, with their findings and recommended authorities to require the removal of such windmills.

(d) The Attorney General may, as appropriate and consistent with applicable law, provide notice of this order to any court with jurisdiction over pending litigation related to any aspect of the Federal leasing or permitting of onshore or offshore wind projects or the Lava Ridge Wind Project, and may, in the Attorney General's discretion, request that the court stay the litigation or otherwise delay further litigation, or seek other appropriate relief consistent with this order, pending the completion of the actions described in subsection (a) or subsection (b) of this section, as applicable.

This memorandum shall be implemented consistent with applicable law and subject to the availability of appropriations.

This memorandum is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person. You are authorized and directed to publish this memorandum in the *Federal Register.*



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Responses to Questions for the Record of
Manu Asthana, President and CEO
PJM Interconnection, LLC

Energy and Commerce Committee
Subcommittee on Energy's Hearing on March 25, 2025
"Keeping the Lights On: Examining the State of Regional Grid Reliability"

The Honorable Robert E. Latta

1. As stated in President Trump's Executive Order "Removing Barriers to American Leadership in Artificial Intelligence" (AI EO) on January 23, 2025 "It is the policy of the United States to sustain and enhance America's global AI dominance in order to promote human flourishing, economic competitiveness, and national security." President Trump has made it clear that he wants the US to be the global leader in AI and unleash American energy. How does PJM plan to ensure sufficient supply of energy to meet the needs of data centers in a timely manner?

Response: *For several years, PJM has expressed growing resource adequacy concerns based on the following trends we are seeing play out across many parts of our country; (1) premature, primarily policy-driven retirements of resources continue to outpace the development of new generation; (2) aggressive load growth driven primarily by the advent of AI technology and data centers in our footprint, but also by increasing electrification and industrial development; and (3) rising costs and supply chain challenges associated with construction of new generation. PJM's capacity market serves to send a price signal to attract new supply resources to connect to the grid to ensure that we meet the growing demand we expect to come online over the next few years. Along with the capacity market price signal designed to attract new supply resources, PJM has taken several steps to expedite the interconnection of new resources to meet these growing needs. For example, the Reliability Resource Initiative (RRI) has resulted in the addition of 51 projects totaling over 9,300 MW (UCAP) of generation with commercial in-service dates as early as 2027 to supplement projects already in the interconnection queue.*

2. As you mentioned in your testimony, the PJM region is seeing tremendous growth in demand for energy from data centers and use of artificial intelligence that are of critical importance to our national security. What is PJM doing to ensure that existing customers are not shouldering the costs of data centers and that new customers pay for their fair share of using the transmission system?

Response: *The allocation of costs relating to new transmission facilities necessary to serve data centers and other large customers is determined by the Federal Energy Regulatory Commission (FERC). FERC's policies relating to the cost allocation for high-voltage transmission facilities includes a "beneficiary pays" principle.*

3. PJM recently announced a partnership with Google to utilize artificial intelligence models to optimize interconnection applications. This new innovative approach could greatly streamline the interconnection process to expand access to reliable and affordable electricity.

a. Can you discuss how PJM intends to utilize Google's AI models?

Response: *PJM continually looks for improvements to automate and expedite its interconnection processes. This includes the recently announced partnership with Google and Tapestry to utilize AI to implement further improvements and automation to our tools and processes. The intent of this effort is to bring multiple grid models together into a unified model so operators and developers can access everything they need to make critical decisions in one place.*

b. How will this cut down on extensive delays in interconnecting new resources to the grid?

Response: *PJM's stakeholder-driven reforms to expedite the review of interconnection applications were approved by FERC in November 2022 and fully implemented in 2023. More recently, these queue reforms have been supplemented by additional efforts to connect resources to the grid more quickly and PJM now expects to eliminate the remaining backlog in the queue by the end of next year. While our collaboration with Google and Tapestry has only recently begun, we expect that automation enhancements that result from this effort will substantially reduce the length of time it takes to conduct some time-consuming interconnection tasks.*

4. Accurate and transparent electricity load forecasting is a linchpin of modern economic development. States rely on these forecasts to plan new industrial parks, data centers, and manufacturing hubs, while utilities use them to schedule grid expansions and major infrastructure investments. Despite the vital role of load forecasts in spurring economic growth, practices vary widely among states, utilities and RTO/ISOs, often leading to inconsistent data, misaligned investment signals, and unnecessary risk for both utilities, and both large and residential customers. Recent inconsistencies underscore how a patchwork of forecasting methodologies can exacerbate speculation in large load interconnection requests, inflate demand projections, and drive-up costs. These issues cross both state and federal jurisdictions and regional differences.

a. What steps is PJM taking to ensure its load forecasting is transparent, predictable and correctly anticipating future capacity and infrastructure needs to power AI infrastructure?

Response: *PJM continually refines its load forecasting processes to ensure that we are most accurately predicting future system needs. We work closely with our electric utilities across our region to gather information regarding where on the grid we expect the AI infrastructure to be developed. Of course, the growth in load to meet the increasing demands of data centers were not anticipated until recently and more developments affecting the growth rate of AI can occur. Notably, PJM's Long Term Load Forecast Report is released every January and captures any changes that we may expect to alter the forecast.*

b. What, if any, barriers exist to increased transparency on potential load growth from AI?

Response: *The AI industry's substantial growth was not evident until recently and the proprietary nature of many aspects of this industry makes it difficult to predict its trajectory. Advancements in chip technology, cooling mechanisms and other efforts to increase efficiencies and reduce the energy-intensive nature of this industry contribute to the difficulty in predicting exactly how much load growth will be attributed to AI.*

5. How can RTOs accelerate transmission expansion to support load growth without creating excessive costs for ratepayers?

Response: *As you are aware, FERC issued Order No. 1920 last year – a landmark rule that reformed nearly every aspect of regional transmission planning, from the time horizon (i.e., 20 years) to a requirement that transmission planners consider a broad set of benefits when planning new facilities. PJM is currently working towards compliance with this rule. However, while we can plan for the immediate and long-term needs of the system, if developers are unable to construct the necessary transmission infrastructure, having the best planning practices are of no effect. Notably, FERC's rule did not address the impediments relating to speeding up the permitting processes. While Congress has attempted to address the challenges associated with permitting and siting delays, these legislative attempts have been unsuccessful. As for cost, again, the various formulae for cost allocation are determined by the Federal Energy Regulatory Commission.*

6. From a siting and permitting perspective, what do you see as the challenges and barriers to constructing sufficient transmission infrastructure needed for reliable, safe, affordable, and timely delivery of power?

Response: *Building energy infrastructure is extremely challenging, particularly in urban and dense areas including the 13 state territory serviced by PJM. Specifically, transmission developers regularly encounter delays associated with obtaining the necessary permits to construct a transmission line. These delays, at all levels of government (i.e., local, state, federal), often takes years to navigate. PJM has supported efforts to advance permitting reform at the federal level and continually works with its states to advance projects through the state-level siting approval processes. Additionally, grassroots community opposition to transmission infrastructure can add years to the development of a project, or terminate a project entirely. While early input from the community is essential, there should also be a recognition of the immense public benefit that this infrastructure will provide to all utility customers.*

a. What role, if any, should Congress and FERC play in siting and permitting for regional or interregional transmission?

Response: *It is widely known that our Nation has not kept pace with the development of new high-voltage transmission lines necessary to support the growth in electricity usage, connect new generation and maintain grid reliability. Time and again, the inability to obtain the necessary permits in a timely manner is cited as a top factor by developers as to why needed transmission infrastructure projects are not getting built. If left to persist in its current state, this lengthy and cumbersome patchwork of permitting processes will threaten the ability of grid operators like PJM to reliably deliver power to customers. Congress and FERC should consider passing legislation or promulgating rules that ensure that project reviews (e.g., environmental studies) are performed quickly and permitting determinations are made within a specified period.*

7. With current policies, do you think we can build all the generation and transmission needed in time for this AI race?

Response: *It is hard to predict the pace of the AI race, but as noted above, the Nation has not kept pace with the development of energy infrastructure (both generation and transmission). Comparably few miles of transmission lines have been developed in recent years and reserve margins across a large part of our country are declining. This challenge is illustrated in the 2024 NERC Long-Term Reliability Assessment which explains that much of the Eastern Interconnection is at an elevated or high risk of supply shortfalls in the near future.*

8. What would be your top priority or need from states, FERC or Congress to assist you in meeting new demand —especially if we need even more power than projected? Are you equipped today to meet increased future demand at the pace needed and to maintain affordability and competitive rates?

Response: *My immediate priority (to meet demand) is to ensure that we retain the generation that is currently on the system. With demand increasing substantially, we cannot afford additional retirements. Additionally, to the extent we can bring retired generating units back online quickly, we should consider that possibility.*

9. When describing the coordination needed to export power to neighboring ISO's, you mentioned that your systems all impact each other. With that in mind, can premature retirement of baseload generation in one ISO also impact the reliability of the power system in neighboring ISOs?

Response: *Yes. The RTOs and ISOs are connected to each other. Degraded reliability in a neighboring RTO/ISO has the potential to impact PJM's reliability.*

10. The balance of your resource mix is an important component of reliably operating the grid. No matter how much wind and solar you build, you need baseload, dispatchable energy to support the system when the sun doesn't shine and the wind doesn't blow. In your testimony, you highlighted that only 5% of queued generation capacity is natural gas; meanwhile, over 95% of the queue is made up of wind, solar, and storage. Can you describe the impact that losing the balance of resource mix would have on the system? Should the federal government create incentives for the development of reliable, dispatchable power?

Response: *PJM is fuel and technology neutral. We currently have a diverse fuel mix which allows the grid to benefit from the characteristics of many different types of generating resources. As you note, the composition of the interconnection queue is very different than our current portfolio of resources and there will inevitably be increased challenges associated with operating the grid based predominately on intermittent resources. In the absence of the substantial deployment of battery energy storage systems, there will be a continued need to have dispatchable, baseload units on the system.*

11. The rate of investment in natural gas infrastructure is lagging behind the rate of investment in natural gas. In order to unleash the potential of our abundance of natural gas, we need to invest in infrastructure like natural gas pipelines to get the gas where it needs to go. What are the roadblocks we currently face in developing natural gas pipelines and how may they be addressed.

Response: *Similar to the difficulties faced in developing power generation and electric transmission infrastructure, it is exceedingly difficult to construct new natural gas pipeline infrastructure in the United States, particularly in the Northeast. Many existing interstate pipelines are fully subscribed with limited or no available capacity during peak periods. Expediting the permitting processes at the federal and state level will address one of several factors that contribute to the lack of natural gas infrastructure development.*

The Honorable Kathy Castor

1. One of our greatest challenges today is getting new sources of electricity on the grid as quickly as possible in this new era of increasing electricity demand. Interconnection processes – while critical to maintaining the reliability of the grid – can also take far too long under the current framework.

On March 17, FERC Commissioner David Rosner wrote a letter to each of you detailing new opportunities to streamline the interconnection process. In a recent study by the Midcontinent Independent System Operator (MISO), an automated process was able to nearly replicate in ten days the results of an interconnection study that took nearly two years to conduct.

a. Please describe your experience with interconnection automation technologies to date and the prospects for further deploying them going forward.

Response: *PJM continually looks for improvements to automate and expedite its interconnection processes. This includes the recently announced partnership with Google and Tapestry to utilize AI to implement further improvements and automation to our tools and processes. The intent is to bring multiple grid models together into a unified model so operators and developers can access everything they need to make critical decisions in one place. While our collaboration with Google and Tapestry has only recently begun, we expect that automation enhancements that result from this effort will substantially reduce the length of time it takes to conduct some time-consuming interconnection tasks.*

b. Please describe how FERC and Congress can each support such innovation.

Response: *FERC and Congress can support innovation by ensuring that grid operators have the flexibility to experiment with new methods and processes without adhering to uniform, one-size-fits-all rules (e.g., allow regional variation to suit the needs of a particular grid operator).*

The Honorable Scott Peters

1. Have you experienced permitting delays that this committee should better understand? What are some key/important examples?

Response: *Permitting delays are common in our industry and regularly occur throughout the country. Time and again, the inability to obtain the necessary permits in a timely manner is cited as a top factor by developers as to why needed transmission infrastructure projects are not getting built. If left to persist in its current state, this lengthy and cumbersome patchwork of permitting processes will threaten the ability of grid operators like PJM to reliably deliver power to customers. Congress and FERC should consider passing legislation or promulgating rules that ensure that project reviews (e.g., environmental studies) are performed quickly and permitting determinations are made within a specified period.*

2. What laws (on permitting specifically, but also planning, siting, interconnection, cost allocation, etc.) should be changed/amended/improved with regard to permitting?

Response: *Building energy infrastructure is extremely challenging, particularly in urban and dense areas including the 13 state territory serviced by PJM. Specifically, transmission developers regularly encounter delays associated with obtaining the necessary permits to construct a transmission line. These delays, at all levels of government (i.e., local, state, federal), often takes years to navigate. PJM has supported efforts to advance permitting reform at the federal level and continually works with its states to advance projects through the state-level siting approval processes. At the federal level, all laws relating to the permitting and siting of energy infrastructure should be reviewed and modernized. Additionally, grassroots community opposition to transmission infrastructure can add years to the development of a project, or terminate a project entirely. While early input from the community is essential, there should also be a recognition of the immense public benefit that this infrastructure will provide to all utility customers.*

3. What are your specific challenges when it comes to planning and cost allocating high voltage transmission lines?

Response: *Transmission planning is a complex and challenging assignment and considers many variables. PJM continually plans for transmission both within our footprint and with our neighboring grid operators using a process known as the Regional Transmission Expansion Plan (RTEP). Through the RTEP, PJM identifies emerging needs of the grid, potential reliability violations, areas for market efficiency improvement, and public policy requirements. This process occurs through an open and transparent stakeholder process subject to the oversight and approvals of FERC. Of course, the price tag of transmission solutions are not cheap and the cost of transmission packages could run into the billions of dollars. As for cost, the various formulae for cost allocation are determined by the Federal Energy Regulatory Commission. Allocating the costs of these projects is exceedingly difficult when particular customers (or states) that are expected to pay for a particular project argue that they will not receive benefit from that project. While FERC's Order 1920 reforms are intended to address the complicated issues associated with transmission planning and cost allocation, it is too early to tell whether these new policies will be effective.*

Gordon van Welie
President and Chief Executive Officer

June 11, 2025

The Honorable Robert E. Latta
Chairman
Subcommittee on Energy
2125 Rayburn House Office Bldg.
Washington, D.C. 20515-6115

Dear Chairman Latta:

Thank you again for the opportunity to appear before the House Subcommittee on Energy on March 25, 2025, and I appreciate the opportunity to respond to the questions below.

Please be in touch with any further questions or if I can provide additional information.

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Sincerely,

Gordon van Welie
President and CEO
ISO New England

cc: The Honorable Kathy Castor, Ranking Member, Subcommittee on Energy

The Honorable Scott Peters

The Honorable Robert E. Latta (OH-05)

1. *As stated in President Trump's Executive Order "Removing Barriers to American Leadership in Artificial Intelligence" (AI EO) on January 23, 2025 "It is the policy of the United States to sustain and enhance America's global AI dominance in order to promote human flourishing, economic competitiveness, and national security." President Trump has made it clear that he wants the US to be the global leader in AI and unleash American energy. How does ISO New England plan to ensure sufficient supply of energy to meet the needs of data centers in a timely manner?*

Response:
The New England region is not currently seeing the same growth in data centers or other large loads as other regions across the country. This is due to a variety of factors, including the generally high cost of electricity in the region. However, ISO New England does have several planning tools available that could be deployed to prepare for the potential growth of data centers in our region. ISO New England annually releases a long-term load forecast that sets out the 10-year projections of electric energy usage and seasonal peak demand in New England. This forecast allows the ISO to determine the region's future resource adequacy requirements; evaluate the reliability and economic performance of the electric power system; plan needed transmission improvements; and coordinate maintenance and outages of generation and transmission infrastructure assets. As part of this study work, the ISO's load forecasting team also tracks relevant trends in energy usage, such as changes in transportation and heating electrification, to study their potential impacts on state and regional electric energy and demand. While the New England region is not currently seeing the same growth in these large loads, these analytical tools could be used by the ISO, regional regulators, transmission owners, and market participants to plan and respond to potential data center development in New England. Transmission planning is only one component of the regional response. Market participants must develop new supply to support the increased demand, Transmission Owners must be able to support the interconnection of additional loads, and state and federal regulators have jurisdiction over both the interconnections of large loads and the cost impacts on regional consumers. The issue of how best to accomplish the latter point is currently before the FERC.

2. *Accurate and transparent electricity load forecasting is a linchpin of modern economic development. States rely on these forecasts to plan new industrial parks, data centers, and manufacturing hubs, while utilities use them to schedule grid expansions and major infrastructure investments. Despite the vital role of load forecasts in spurring economic growth, practices vary widely among states, utilities and RTO/ISOs, often leading to inconsistent data, misaligned investment signals, and unnecessary risk for both utilities, and both large and residential customers. Recent inconsistencies underscore how a patchwork of forecasting methodologies can exacerbate speculation in large load interconnection requests, inflate demand projections, and drive-up costs. These issues cross both state and federal jurisdictions and regional differences.*
    a. *What steps is ISO New England taking to ensure its load forecasting is transparent, predictable and correctly anticipating future capacity and infrastructure needs to power AI infrastructure?*
    b. *What, if any, barriers exist to increased transparency on potential load growth from AI?*

Response:
The ISO regularly consults with state policymakers, utilities, and other stakeholders to ensure our load forecasting is anticipating future demands on the bulk electric power system. For example, the NEPOOL Load Forecast Committee provides input on the development of the long-term load forecast. The long-term load forecast process is also discussed at multiple working groups, including the Distributed Generation Forecast Working Group and Energy Efficiency Forecast Working Group, as well as the Planning Advisory Committee meetings throughout the year. These discussions serve as a forum to ensure that our load forecasts are capturing emerging load trends in our region. The ISO regularly engages with state policymakers to understand the potential impact of their policies on electric demand, including electrification initiatives and other drivers of the need for additional resources and infrastructure. One challenge to identifying potential load growth from AI is that the predictability of related loads does not follow traditional economic trends.

3. *How can RTOs accelerate transmission expansion to support load growth without creating excessive costs for ratepayers?*

Response:
ISO New England, working with the states and regional stakeholders, has facilitated the development of $13 billion in new transmission infrastructure since 2002. The open and transparent planning process identifies cost-effective transmission projects to meet reliability standards. In addition, the ISO is currently working with the states to facilitate new transmission development through a first-of-its-kind regional solicitation. In May 2024, the ISO filed Phase 2 of the Longer Term Transmission Planning (LTTP) tariff changes with the Federal Energy Regulatory Commission (FERC), which would create a new process to give the New England states greater control in achieving their energy policies and goals. On July 9, 2024, the FERC accepted that filing. The changes create a new process that will operate in addition to current transmission planning protocols. ISO New England issued a request for proposals (RFP) on March 31, 2025, in accordance with Phase 2.

Phase 2's cost allocation guidelines include additional metrics for evaluating a potential transmission project. Since they help power flow from locations that are more suited to larger renewable resources (e.g., offshore wind, rural solar farms) to more densely populated areas, large transmission projects may offset the need to build new generating resources or operate existing generating resources in those densely populated areas. The new filing allows the ISO to include these regional benefits in its evaluation process.

4. *From a siting and permitting perspective, what do you see as the challenges and barriers to constructing sufficient transmission infrastructure needed for reliable, safe, affordable, and timely delivery of power?*
    a. *What role, if any, should Congress and FERC play in siting and permitting for regional or interregional transmission?*

Response:
As the regional grid operator, ISO New England has no authority over siting processes or permits. However, we have observed regional challenges similar to other parts of the country, such as local opposition to specific projects and supply-chain-related challenges. These issues can complicate the speed and ability to develop transmission infrastructure in New England. Congress and FERC play important roles in setting the

framework for regional and interregional transmission planning, such as through the reforms embodied in FERC Order 1920. Siting and permitting of transmission are under the jurisdiction of the states, and this has proven to work well in New England. As is evidenced by the recent agreement on a Long Term Transmission Planning protocol, and the request to issue an RFP to strengthen the transmission corridor from New Hampshire to Maine, the states are working collaboratively in the best interests of the region.

5. *Regarding planning for transmission, what specific impediments have you identified to current state, regional, and interregional planning for transmission projects?*
    a. *What are examples of impediments you have identified and what is necessary for system planners to overcome these impediments?*
    b. *What reforms do you recommend to improve state, regional, and interregional planning to overcome these impediments?*

Response:
As mentioned above, ISO New England has implemented Phase 2 of its Longer Term Transmission Planning (LTTP) process. In any discussion of transmission development, it is important to have an established cost allocation mechanism. Through LTTP Phase 2, the ISO has implemented a consensus-based cost allocation mechanism that has the support of the New England states. We believe this new process represents a significant and innovative enhancement, which will help overcome certain impediments to transmission planning and development in our region.

6. *In the last Congress and the previous administration, there was a lot of talk about transmission policy reform.*
    a. *How does your organization plan transmission in your region and with other regions? What should Members understand about the nature of transmission planning as it exists today?*
    b. *Does a top-down approach, through FERC, serve the interests of utilities and grid operators that are already expending tremendous time and engineering resources on design new transmission?*

Response:
ISO New England has a robust process for planning transmission to address reliability needs. We are implementing a new process to plan transmission to address state policy objectives. We are also actively engaged with the New England states on potential interregional transmission expansion. We conduct transmission planning in New England in an open process through the Planning Advisory Committee (PAC). While the ISO plays an important role in identifying needs and performing technical analyses, the states have jurisdiction over transmission siting, and early participation of the states in the regional planning process is common and essential. Given the unique policy objectives of the different states and the different topologies of the transmission system, it is important to allow for regional differences in transmission planning.

7. *What would be your top priority or need from states, FERC or Congress to assist you in meeting new demand —especially if we need even more power than projected? Are you equipped today to meet increased future demand at the pace needed and to maintain affordability and competitive rates?*

Response:
As I stated in my testimony, the ISO and the states have a joint and complementary role to play in achieving resource adequacy. The ISO needs to design and implement effective market designs to produce efficient pricing/incentives to retain and develop resources and ensure that the transmission system is robust (including implementing interconnection queue reforms). In particular, the ISO is proposing reforming the capacity market to implement a prompt, seasonal capacity auction with marginal capacity accreditation. It is essential that the region complete the design and regulatory process in time to implement the new market in 2028, and we need the support of the states, the market participants, and the FERC to achieve this goal. The New England states can expand various financial hedging arrangements that they have directed retail utilities to employ in the past to protect consumers against undue price volatility in both the energy and capacity markets. The combination of the competitively determined reference price for capacity in the ISO's prompt capacity auction and financial hedging arrangements between wholesale buyers and sellers help incent the development of new supply to meet the resource adequacy standard. Moreover, the states can address barriers to entry for resources participating in wholesale electricity markets. In addition, the states could do more to encourage demand response by increasing the deployment of advanced metering and variable retail rate designs. I believe our region will be equipped to meet future demands on the bulk electric power system if the states, the ISO, and the FERC can work together to ensure regional resource adequacy through a stable wholesale market supported by adequate retail consumer rate protections (using familiar financial hedging arrangements) overseen by state-level regulatory agencies. The pace of electricity demand growth and resource retirements will be key factors in determining the need for new energy resources and infrastructure.

The Honorable Kathy Castor (FL-14)

1. *One of our greatest challenges today is getting new sources of electricity on the grid as quickly as possible in this new era of increasing electricity demand. Interconnection processes – while critical to maintaining the reliability of the grid – can also take far too long under the current framework.*

   On March 17, FERC Commissioner David Rosner wrote a letter to each of you detailing new opportunities to streamline the interconnection process. In a recent study by the Midcontinent Independent System Operator (MISO), an automated process was able to nearly replicate in ten days the results of an interconnection study that took nearly two years to conduct.
   a. *Please describe your experience with interconnection automation technologies to date and the prospects for further deploying them going forward.*
   b. *Please describe how FERC and Congress can each support such innovation.*

Response:
ISO New England is in the process of implementing important new interconnection reforms as directed by FERC. These changes build on the ISO's recent enhancements to the study process and are intended to expedite the interconnection process. The ISO continually evaluates the potential opportunity for further improvements to the interconnection process that are suitable for this region. The ISO is in favor of automating processes where it is practicable and is currently evaluating a number of different software tools. The "develop or buy" decision will be based on our assessment of our needs, the cost of the third-party tools, and our ability to develop in-house tools and capabilities.

The Honorable Scott Peters (CA-52)

1. *Have you experienced permitting delays that this committee should better understand? What are some key/important examples?*
2. *What laws (on permitting specifically, but also planning, siting, interconnection, cost allocation, etc.) should be changed/amended/improved with regard to permitting?*

Response:
As the regional grid operator, ISO New England has no authority over siting or permitting of energy infrastructure.

3. *What are your specific challenges when it comes to planning and cost allocating high voltage transmission lines?*

Response:
There is agreement on cost allocation for new transmission to address state policy objectives, and there is a longstanding cost allocation mechanism to develop transmission for regional reliability. There are provisions within the ISO planning process for elective transmission projects whereby the project developer secures funding for the project outside of regional cost allocation mechanisms. There are also provisions within the ISO planning process for the states to identify alternative cost allocation mechanisms.

Responses to Questions for the Record from the hearing entitled
"Keeping the Lights On: Examining the State of
Regional Grid Reliability."

Jennifer Curran, Senior Vice President, Planning and Operations
Midcontinent Independent System Operator, Inc. (MISO)

House Committee on Energy and Commerce,
Subcommittee on Energy

June 11, 2025

The Honorable Robert E. Latta (R-OH)

1. As stated in President Trump's Executive Order "Removing Barriers to American Leadership in Artificial Intelligence" (AI EO) on January 23, 2025 "It is the policy of the United States to sustain and enhance America's global AI dominance in order to promote human flourishing, economic competitiveness, and national security." President Trump has made it clear that he wants the US to be the global leader in AI and unleash American energy.

How does MISO plan to ensure sufficient supply of energy to meet the needs of data centers in a timely manner?

As a general matter, the jurisdictional authority to assure resource adequacy belongs to the states and other Relevant Electric Retail Regulatory Authorities (RERRAs) in the MISO region, but MISO actively collaborates with them to achieve the shared mission of ensuring reliability. MISO also collaborates with neighboring regions to facilitate interregional transfers of electricity. Key mechanisms include:

- Providing RERRAs with region-wide information on where resource adequacy conditions are moving. Examples include MISO's annual Regional Resource Assessment, the annual Organization of MISO States – MISO Survey, and ongoing work on load forecasting.

- An annual Planning Resource Auction to provide a tool allowing market participants with excess capacity to sell to other market participants who may expect a shortfall in meeting their resource adequacy requirements.

- Long-Range Transmission Planning within the MISO region and the Joint Targeted Interconnection Queue study with neighboring regions to facilitate the construction of the new transmission lines necessary to deliver energy from where it is produced to where it is needed.

- Ongoing work to improve the timeliness of MISO's Generator Interconnection Queue by leveraging a combination of process and technology improvements. MISO is also seeking FERC approval for a temporary Expedited Resource Additions (ERAS) study process to expedite the approval and construction of generation projects needed to address near-term reliability issues.

2. Accurate and transparent electricity load forecasting is a linchpin of modern economic development. States rely on these forecasts to plan new industrial parks, data centers, and manufacturing hubs, while utilities use them to schedule grid expansions and major infrastructure investments. Despite the vital role of load forecasts in spurring economic growth, practices vary widely among states, utilities and RTO/ISOs, often leading to inconsistent data, misaligned investment signals, and unnecessary risk for both utilities, and both large and residential customers. Recent inconsistencies underscore how a patchwork of forecasting methodologies can exacerbate speculation in large load interconnection requests, inflate demand

projections, and drive-up costs. These issues cross both state and federal jurisdictions and regional differences.

a. What steps is MISO taking to ensure its load forecasting is transparent, predictable and correctly anticipating future capacity and infrastructure needs to power AI infrastructure?

MISO is refining its load forecasting to better capture the evolving demands of AI and large-scale computing. This includes moving beyond traditional econometric models toward more detailed, end-use and market-based approaches that can better represent fast-growing segments like data centers. A key focus is on hourly-based modeling to track how load shapes are changing over time with shifts in technology and operations.

To support a well-rounded view of future demand, MISO draws on a range of inputs—member data, public announcements, third-party sources, and industry studies. These inform development of a range of forecasts that reflect assumptions for key variables such as adoption rates and facility efficiency. This helps facilitate planning without relying on any single data source.

MISO maintains transparency through regular stakeholder engagement—sharing forecasts, methodologies, and assumptions via workshops, whitepapers, and public data releases. Forecasts are being developed on a regular cadence, enabling MISO to incorporate new information more systematically and keep pace with rapidly evolving load drivers.

b. What, if any, barriers exist to increased transparency on potential load growth from AI?

Several factors create challenges in obtaining the information needed to accurately project load growth from AI. AI developers typically scout for multiple locations across various MISO members with masked company names for a single intended project. Until a location is secure, developers are sensitive about publicly disclosing the cost of competitive bids. Therefore, public land transactions are often the only observable signal of future data center development, but they provide little insight into load requirements, timelines, or viability.

Additionally, estimating energy use from land commitments is unreliable. Power Usage Effectiveness – a metric used to measure the energy efficiency of a data center – varies significantly across facilities due to design, operations, and climate. Retrofits and technology changes further affect load, making early-stage projections highly uncertain.

Also, Regional Transmission Organizations (RTOs) often do not have access to metered/end-use data, which limits the ability to validate or refine forecasts. Load data available to RTOs is often aggregated or otherwise adjusted before it reaches

us. Additionally, data sharing requirements may limit the willingness of entities to share commercially sensitive data with RTOs.

3. How can RTOs accelerate transmission expansion to support load growth without creating excessive costs for ratepayers?

MISO's processes have been successful in balancing the need for transmission expansion through pairing near-term transmission evaluation with a range of long-term scenarios to ensure that any recommended transmission is a least-regret solution to the near and long-term needs of the transmission system. As an example of this long-term planning, MISO analyzed and approved three regional portfolios (MVP 2011[1], Long Range Transmission Planning Tranche 1[2], and Long-Range Transmission Planning Tranche 2.1[3]) resulting in more than $37B of transmission investment and 345 and 765 kV regional solutions with benefits ranging in different portfolios from 1.6 to 3.8 benefit-to-cost ratios. These portfolios proactively identified solutions with benefits commensurate with costs, and they will result in a cost-effective transmission expansion for customers that support both resource change and load growth. These transmission recommendations are paired with a cost allocation design that aligns the benefits and assigned costs, lessening localized costs for transmission that will result in broader benefits.

4. From a siting and permitting perspective, what do you see as the challenges and barriers to constructing sufficient transmission infrastructure needed for reliable, safe, affordable, and timely delivery of power?

MISO's planning process attempts to identify and approve transmission in a 'just-in-time' manner – that is, we approve projects with consideration of how long these siting and permitting processes take, matching the timing of our approval to ensure they can be constructed by the time they are needed. We also partner with our members in our planning process to reduce siting and permitting risk and timelines through leveraging existing transmission corridors to minimize the need to attain new rights-of-way for transmission infrastructure. Finally, we support our members as the projects go through the appropriate state processes.

These processes can take time, and if that timeline is extended, it can delay the value to customers and more importantly put at risk the ability to maintain reliable delivery of power. However, in MISO, and with the steps outlined above, we work in concert with

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our members and our state regulatory agencies to minimize these timelines, with credit to states in our footprint for well-defined and efficient regulatory processes.

a. What role, if any, should Congress and FERC play in siting and permitting for regional or interregional transmission?

The state regulatory agencies in MISO have well-defined processes which reduce the timelines regarding regulatory approval for the transmission infrastructure to attain the necessary permits as much as possible. However, MISO has experience with transmission projects incurring significant delays (i.e., 10+ years) attaining the necessary permits from multiple federal entities and subsequent court challenges, especially when the siting involves crossing major rivers. These federal processes could be improved with Congressional or FERC input.

5. Regarding planning for transmission, what specific impediments have you identified to current state, regional, and interregional planning for transmission projects?

MISO has experienced limited impediments in transmission planning processes.

Specifically, MISO has been successful in creating three regional portfolios (MVP 2011[4], Long Range Transmission Planning Tranche 1[5], and Long-Range Transmission Planning Tranche 2.1[6]) resulting in more than $37B of transmission investment and 345 and 765 kV regional solutions with benefits ranging in different portfolios from 1.6 to 3.8 benefit-to-cost ratios. In addition to adding four new 765 kV tie-lines with interregional neighbors with Tranche 2.1, MISO's three Interregional Targeted Market Efficiency Project (TMEP) studies have resulted in ~$22M of investment and an estimated ~ $140M in benefits.

These processes can always be improved. MISO continues to work with our members and neighbors to align the definition of benefits for a given transmission study and to ensure appropriate cost allocation mechanisms are in place. For example, transmission driven by needs beyond NERC defined criteria, including economics or resilience, requires careful alignment from the start of analysis through the recommendation of solutions from identified needs. This can be further complicated by the uncertainty inherent in long-term timeframes. Without careful coordination and alignment on the

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assumptions and what to do with the results of studies, needed solutions can be delayed, impacting the efficiency of the transmission system.

a. What are examples of impediments you have identified and what is necessary for system planners to overcome these impediments?

Careful coordination is required at the start of any analysis to ensure that there is alignment on the potential benefits of transmission and how the costs could be allocated. This also includes alignment on what the future transmission system may look like, knowing that there are a range of possibilities. Recent federal actions, including FERC Order 1920, helps through providing a framework to use when considering the range of possibilities for the future transmission system, assisting with these impediments.

Ultimately, without support on cost allocation from member utilities and regulators, the projects and benefits identified in the planning process will not move forward. While the MISO region has been able to bring our members and states together to support cost allocation in the past, we continue to face the risk this may change in future planning studies. As noted, regional cost allocation in a multi-state region is a lengthy, complicated negotiation that only magnifies when trying to put in place interregional cost allocation methods for transmission lines that are benefiting neighboring multi-state entities, such as PJM, SPP, and TVA.

b. What reforms do you recommend to improve state, regional, and interregional planning to overcome these impediments?

FERC Order 1920 creates a common framework which can assist with transmission planning. It is also important, in the implementation of FERC Order 1920 or other reforms, that they provide sufficient flexibility for regional variation, rather than a prescriptive approach. This regional variation enables system planners to recognize the benefits that their customers value, ultimately providing more avenues for useful transmission construction than a one-size-fits-all approach.

6. In the last Congress and the previous administration, there was a lot of talk about transmission policy reform.

a. How does your organization plan transmission in your region and with other regions? What should Members understand about the nature of transmission planning as it exists today?

MISO's transmission planning approach identifies and supports the development of cost-effective transmission infrastructure that is sufficiently robust to meet reliability needs, enable a competitive energy market, support state and member policy goals, and allow for competition among transmission developers. Additionally, these processes must be inclusive, independent, and transparent, with opportunities for stakeholders to participate and provide input throughout.

These processes include studies which focus on new generation resource integration, long-term transmission needs, near-term reliability requirements (including load integration), economic analysis, and interregional planning. Through them, MISO shares information with stakeholders and partners with other regions to identify transmission opportunities and takes action to find solutions. For example, MISO has ongoing studies with PJM and SPP at this time to understand and consider potential solutions that cross regional boundaries based on future system needs.

b. Does a top-down approach, through FERC, serve the interests of utilities and grid operators that are already expending tremendous time and engineering resources on design new transmission?

The most efficient transmission planning approach must combine a top-down, long-term approach, such as those conducted by regional transmission organizations with consideration of more local and near-term needs best known by the utilities which directly serve end use customers. These processes are best defined with regional flexibility and in coordination with state entities and local stakeholders. The introduction of additional prescriptive requirements by FERC or any other entity creates a risk of hindering flexibility and removes opportunities to meet our members' unique needs and may result in inefficient transmission recommendations.

7. With current policies, do you think we can build all the generation and transmission needed in time for this AI race?

MISO's goal is to ensure that our processes appropriately support the generation and transmission required to support new large loads. This includes an expedited review of transmission needs for new loads, and it also includes a generation interconnection process which enables generation necessary for large load interconnections to be reviewed in a timely manner.

MISO's Expedited Project Review for transmission solutions provides an expedited review of transmission needs allowing Transmission Owners the ability to move forward with approved MTEP projects to meet load growth in as soon as 30 days, with additional time required for certain complex load integrations. These studies include the full suite of studies that are considered for our normal project review as well as coordination with our neighbors, in a more rapid timeline.

MISO has proposed an expedited study process to bring new generation resources online within a single calendar quarter, aiming to address the urgent resource adequacy and reliability concerns driven by rapid load growth. Traditional interconnection queue timelines are too lengthy to keep pace with this unprecedented need. While MISO is actively implementing long-term reforms—including automation and a queue cap—to shorten these timelines, this temporary fast-track solution offers a critical bridge. By accelerating projects meeting stringent eligibility requirements that are backed by their

state or other relevant authority, MISO ensures resources can receive a Generator Interconnection Agreement in a significantly shorter timeframe.

8. What would be your top priority or need from states, FERC or Congress to assist you in meeting new demand —especially if we need even more power than projected? Are you equipped today to meet increased future demand at the pace needed and to maintain affordability and competitive rates?

MISO has identified several challenges and opportunities to address growing demand. To address near-term needs, MISO is working with our stakeholders and the FERC to improve its existing processes and mechanisms. This includes the proposed expedited study process, designed to temporarily speed up the approval of key generation projects until longer-term enhancements to the generator interconnection queue process are effective.

It is also important to let reliability needs drive the pace of retirement of existing electric generating resources and to shape the mix of new resources being built. Today, no single resource type or technology can meet all our nation's electricity needs. For the foreseeable future, resource planners need to carefully assess the reliability impact before retiring existing electric generating resources and consider the operating characteristics and accredited generating capacity of new resources to ensure we can meet our nation's electricity needs every hour of every day.

Finally, it is important to consider barriers to the timely construction of new generation and transmission. Currently, the MISO region has over 56 GW of projects that have been approved but are not yet operational, and project developers have indicated that more than half of those are delayed, often due to regulatory hurdles, supply chain challenges, and labor shortages.

9. MISO and most other ISOs agreed, the Environmental Protection Agency's Clean Power Plan 2.0 negatively impacted the reliability of the bulk power system. If FERC was able to step in and make recommendations based on reliability during rule making processes, could that have a positive impact on the reliability of the bulk power system?

MISO respects the jurisdictional authority of both FERC and EPA and remains committed to sharing information and insights based on our experience as an RTO to support effective rulemaking. To that end, MISO has expressed its view that rulemaking should include provisions addressing reliability concerns. For example, in December 2023, MISO submitted joint comments – along with the Electric Reliability Council of Texas (ERCOT), PJM, and Southwest Power Pool (SPP) – to the EPA recommending that the agency craft a "Reliability Safety Valve" that would provide a reliability assurance mechanism to address potential resource adequacy issues.

The Honorable Mariannette Miller-Meeks (R-IA)

1. Ms. Curran, since 2022 MISO has developed and approved two tranches of significant transmission development under its Long-Range Transmission Planning (LRTP) Process. Please provide a detailed description of the generation resource mix for the MISO footprint that MISO transmission planners and stakeholders used to develop the tranches of the LRTP.

MISO can't predict the future, but it can make educated projections about what the electric system will look like in the coming years. To do that, MISO works with stakeholders to create forecasted scenarios which we call "Futures."

MISO's Futures study captures a range of potential system conditions over a 20-year planning horizon. The scenarios establish a bookended range of economic, policy, and possibilities such as load growth, carbon policy, and generation retirements. These forecasts hedge uncertainty by utilizing stakeholder information, policy direction, industry trends, and capacity expansion modeling.

Futures provide the foundation for MISO's transmission planning – both local and regional. By representing multiple possibilities for future system growth, fuel availability, market conditions, and regulatory environments, the scenarios also inform State and member resource planning. MISO is currently in the process of updating and expanding its Futures Planning Scenarios to reflect evolving conditions. These updated Futures will be utilized for future LRTP processes.

For the most recent LRTP Tranche 2.1, MISO utilized Futures Planning Scenarios published in November 2023. It was determined that Future 2A, which falls roughly in the middle of the range of possibilities, was most aligned with an optimized, least-cost expansion that meets member goals. This projected that by 2042:

- Electricity Production will be comprised of 51% wind, 22% solar, 1% natural gas, 1% coal, 7% nuclear, 2% hybrid resources, 8% storage discharge, 0.3% flexible resources (future resources with flexible attributes), and 8% other (e.g., hydroelectric, geothermal, biomass, fuel oil, etc.).

- Generating Accredited Capacity will be comprised of 34% wind, 24% solar, 14% natural gas, 1% coal, 3% nuclear, 2% hybrid resources, 7% battery, 6% flex resources, and 9% other resources.

The Honorable John James (R-MI)

1. I've heard repeatedly that strengthening the grid is a vital step necessary for meeting growing energy demands. Democratic governors in Lansing, Springfield, and St. Paul, however, are pushing "net zero". The Clean Power Plan 2.0, which is the catalyst for "net zero" mandated renewables and carbon capture for resources such as natural gas. While bipartisan, carbon capture is still a relatively new technology that is in development and needs time before it can be mandated.

Given MISO's purview of the Midwest, specifically Michigan, I wanted to quote one of your colleagues who testified in 2023 on behalf of MISO before this committee, where he mentioned the following:

"Controllable, dispatchable resources are being retired and replaced primarily with weather dependent, non-dispatchable, and variable generation types to achieve carbon reduction goals."

He went on to list the risks of weather dependent sources, which according to him were declining accredited capacity, diminishing resource attributes, and operational challenges. In your written opening statement, you mention that weather dependent energy sources do not provide "24/7 availability, flexibility, and duration attributes compared to the retiring power plants they are replacing."

a. I'd like to know from you what role natural gas will have in a state like Michigan in the foreseeable future. To the extent that you collaborate with stakeholders, I would also appreciate your thoughts on how the federal government can free up the regulatory environment for natural gas to best serve the "generation mix," given its reliability.

Today, no single electric generating resource type or technology can meet all our nation's electricity needs. While wind and solar, which comprise the bulk of new electric generation being built, bring many benefits such as being carbon free and having low electricity production costs, they don't have the same 24/7 flexibility and availability of the natural gas and coal burning power plants they are replacing. Promising future technologies – such as longer-duration battery, small modular nuclear reactors, and green hydrogen – are likely several years away from grid-scale viability. Thus, for the foreseeable future, natural gas will continue to play an important role by providing dispatchability and flexibility attributes, effectively serving as a 'reliability insurance policy' during challenging operating conditions.

b. I wanted to ask you about nuclear energy. I am excited that Palisades is coming back online, but arguably we cannot stop there. What is MISO's assessment of nuclear energy in Michigan and throughout the Midwest vis-à-vis the grid?

Resource planning decisions are the purview of the Relevant Electric Retail Regulatory Authorities (RERRAs) in the MISO region. MISO respects their jurisdiction and is committed to supporting their efforts to ensure the reliability of the bulk electric system.

In general, however, achieving regional reliability requires both adequate accredited generating capacity and adequate amounts of various operational attributes. The operational characteristics of nuclear energy have historically made it useful as a source of baseload electric generation, complementing the flexible characteristics of natural gas and the low-cost and emissions-free

characteristics of wind and solar. These are some of the many factors that RERRA's consider when making their resource planning decisions.

The Honorable Kathy Castor (D-FL)

1. One of our greatest challenges today is getting new sources of electricity on the grid as quickly as possible in this new era of increasing electricity demand. Interconnection processes – while critical to maintaining the reliability of the grid – can also take far too long under the current framework.

On March 17, FERC Commissioner David Rosner wrote a letter to each of you detailing new opportunities to streamline the interconnection process. In a recent study by the Midcontinent Independent System Operator (MISO), an automated process was able to nearly replicate in ten days the results of an interconnection study that took nearly two years to conduct.

a. Please describe your experience with interconnection automation technologies to date and the prospects for further deploying them going forward.

MISO's implementation of Suite of Unified Grid Analyses with Renewables ("SUGAR") software utilizes advanced data and analytics using machine learning and artificial intelligence to create reliable and informed planning and operations, as well as significantly lower study and modeling times. Full implementation of SUGAR will take study times from more than three years to under one year. But it will likely take about three years for the full implementation of SUGAR. Allowing for an accelerated study process for certain projects will address queue backlog until the entire queue process is improved to a near one-year timeframe.

b. Please describe how FERC and Congress can each support such innovation.

MISO has a culture of continuous improvement and actively seeks to examine, test, and, where appropriate, incorporate new processes and technologies that will continue to support reliability while improving efficiency and effectiveness. This can most readily be achieved through a statutory and regulatory environment that prioritizes reliability and encourages innovation.

Public discourse by policymakers and lawmakers, such as this Subcommittee's recent hearing and FERC technical conferences – including FERC's July 2025 Technical Conference on "Increasing Efficiency through Improved Software – also stimulate broader conversations and information sharing around the shared challenges facing the electric industry and potential innovations to help address those challenges.

The Honorable Scott Peters (D-CA)

1. Have you experienced permitting delays that this committee should better understand? What are some key/important examples?

MISO is facing a growing resource adequacy and reliability challenge across its region. As of June 11, 2025, more than 56 gigawatts of generation within the MISO footprint had executed Generator Interconnection Agreements but had not yet come online. In late 2024, MISO surveyed interconnected customers to better understand this disconnect and identify the causes of these delays. While responses varied—from economic conditions to supply chain constraints—a common theme emerged: regulatory challenges were reported across nearly all states and fuel types, highlighting a widespread barrier to timely project completion and grid readiness.

MISO has experience with transmission projects incurring significant delays (i.e., 10+ years) attaining the necessary permits from multiple federal entities and subsequent court challenges, especially when the siting involves crossing major rivers. These federal processes could be improved with Congressional or FERC input.

2. What laws (on permitting specifically, but also planning, siting, interconnection, cost allocation, etc.) should be changed/amended/improved with regard to permitting?

MISO does not advocate for a specific statute, but as a general principal we urge the prioritization of reliability needs, mitigation of hurdles to developing new generation and transmission, and streamlining of statutes and regulations that can hinder progress toward achieving reliability goals.

3. What are your specific challenges when it comes to planning and cost allocating high voltage transmission lines?

MISO has experienced limited impediments in transmission planning processes.

Specifically, MISO has been successful in creating three regional portfolios (MVP 2011[7], Long Range Transmission Planning Tranche 1[8], and Long-Range Transmission Planning Tranche 2.1[9]) resulting in more than $37B of transmission investment and 345 and 765 kV regional solutions with benefits ranging in different portfolios from 1.6 to 3.8 benefit-

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These processes can always be improved. MISO continues to work with our members and neighbors to align the definition of benefits for a given transmission study and to ensure appropriate cost allocation mechanisms are in place. For example, transmission driven by needs beyond NERC defined criteria, including economics or resilience, requires careful alignment from the start of analysis through the recommendation of solutions from identified needs. This can be further complicated by the uncertainty inherent in long-term timeframes. Without careful coordination and alignment on the assumptions and what to do with the results of studies, needed solutions can be delayed, impacting the efficiency of the transmission system.

Ultimately, without support on cost allocation from member utilities and regulators, the projects and benefits identified in the planning process will not move forward. While the MISO region has been able to bring our members and states together to support cost allocation in the past, we continue to face the risk this may change in future planning studies. As noted, regional cost allocation in a multi-state region is a lengthy, complicated negotiation that only magnifies when trying to put in place interregional cost allocation methods for transmission lines that are benefiting neighboring multi-state entities, such as PJM, SPP, and TVA.

New York ISO
Independent System Operator

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June 11, 2025

Calvin Huggins
Legislative Clerk
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, DC 20515
Calvin.Huggins1@mail.house.gov.

Re: Additional Questions for the Record: "Keeping the Lights on: Examining the State of Regional Grid Reliability"

Dear Mr. Huggins:

On behalf of Richard Dewey, President and CEO, New York Independent System Operator, please find enclosed responses to questions received by your office to be entered into the final record for the above-named hearing, held on March 25, 2025.

If you desire additional information on this or any other matter, please do not hesitate to reach out to me directly.

Sincerely,

Kevin Lanahan
Vice President
External Affairs and Corporate Communications

Enc.

Additional Questions for the Record

The Honorable Robert E. Latta (R-OH)

1. **As stated in President Trump's Executive Order "Removing Barriers to American Leadership in Artificial Intelligence" (AI EO) on January 23, 2025 "It is the policy of the United States to sustain and enhance America's global AI dominance in order to promote human flourishing, economic competitiveness, and national security." President Trump has made it clear that he wants the US to be the global leader in AI and unleash American energy. How does NYISO plan to ensure sufficient supply of energy to meet the needs of data centers in a timely manner?**

The swift development of energy-intensive projects like semi-conductors, data centers and hyper scale computing promises to change not just the electric system but society as a whole. It is imperative during this period of transition that we maintain an adequate supply of resources with the right performance characteristics to meet growing consumer demand for electricity.

The number of new interconnection requests from large loads has grown dramatically in just a few years. In 2022, six large load projects in the interconnection queue accounted for 1,045 megawatts (MW). As of April 2025, there were 20 large load projects in the queue, which would collectively add nearly 4,400 MW of load to the grid. Load forecasters anticipate that as much as roughly 2,500 MW of that new demand will be on the system by 2035. The increase in forecasted demand poses a major challenge to grid reliability in New York.

As initially highlighted in our *2024 Reliability Needs Assessment* (RNA), some large load projects are expected to have flexibility in the amount of power they need from the grid. More specifically, the 2024 RNA assumed that approximately 1,200 MW of demand from large loads can be reduced during peak periods, which can provide an important reliability benefit.

The ability to shift load from times of greater system demand to times with lower demand or higher renewable energy production could significantly reduce the amount of generation capacity buildout required to serve demand.

Additionally, early in 2025, the NYISO launched a complete review of the capacity market structure to determine if alternatives or enhancements to the existing structure might better facilitate growing demand for electricity while also meeting the NYISO's regulatory mandate for maintaining reliability.

For over 20 years, the current capacity market design has served system reliability well, driving cost efficiencies, achieving emissions reductions, while retaining existing resources and supporting additional supply. A review of the capacity market framework will help determine what, if any, changes might be necessary moving forward. This review is timely in consideration of forecasted increases in load, projected shifts in hourly peak demand, and new, large-scale, energy-intensive microchip fabrication and data centers seeking to locate in New York.

2. **Accurate and transparent electricity load forecasting is a linchpin of modern economic development. States rely on these forecasts to plan new industrial parks, data centers, and manufacturing hubs, while utilities use them to schedule grid expansions and major infrastructure investments. Despite the vital role of load forecasts in spurring economic growth, practices vary widely among states, utilities and RTO/ISOs, often leading to inconsistent data, misaligned investment signals, and unnecessary risk for both utilities, and both large and residential customers. Recent inconsistencies underscore how a patchwork of forecasting methodologies can exacerbate speculation in large load**

interconnection requests, inflate demand projections, and drive-up costs. These issues cross both state and federal jurisdictions and regional differences.

- **a. What steps is NYISO taking to ensure its load forecasting is transparent, predictable and correctly anticipating future capacity and infrastructure needs to power AI infrastructure?**
- **b. What, if any, barriers exist to increased transparency on potential load growth from AI?**

There is inherent uncertainty in forecasting the adoption of emerging technologies and predicting the pace of development with regard to energy-intensive data centers and manufacturing facilities seeking to connect to the grid. To keep the system reliable during this period of uncertainty means our Planning engineers are running multiple models, with scenarios that provide outlooks for a range of possible outcomes. Subsequently our planning and forecasting work at the NYISO has become more complex, but we embrace this challenge to serve our mission and support consumers, investors and policymakers.

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The NYISO is expected to release the 2025-2034 Comprehensive Reliability Plan (CRP) in November 2025. The CRP, issued biennially, sets forth a plan to maintain a reliable bulk electric grid based on expected changes and forecasted conditions over a ten-year planning period.

The CRP will review the reliability margins forecasted from previous CRPs to identify the historical trends and further investigate a variety of risk factors and plausible ways the system could change over the next ten years. In consideration of increasing uncertainty about key system trends over the next ten years, the CRP will also consider and analyze uncertainty factors, including large loads. There is significant uncertainty about the recent trend of large loads seeking to connect to the NYISO. This is a trend that system operators around the country are grappling with, and the NYISO is actively coordinating with its peers to best capture the reliability impacts of different types of large loads. For example, data centers potentially have very different operating characteristics depending on whether they are used for cloud computing, AI, or crypto mining.

3. **How can RTOs accelerate transmission expansion to support load growth without creating excessive costs for ratepayers?**

4. **From a siting and permitting perspective, what do you see as the challenges and barriers to constructing sufficient transmission infrastructure needed for reliable, safe, affordable, and timely delivery of power?**
   - **a. What role, if any, should Congress and FERC play in siting and permitting for regional or interregional transmission?**

5. **Regarding planning for transmission, what specific impediments have you identified to current state, regional, and interregional planning for transmission projects?**
   - **a. What are examples of impediments you have identified and what is necessary for system planners to overcome these impediments?**
   - **b. What reforms do you recommend to improve state, regional, and interregional planning to overcome these impediments?**

6. **In the last Congress and the previous administration, there was a lot of talk about transmission policy reform.**
    a. **How does your organization plan transmission in your region and with other regions? What should Members understand about the nature of transmission planning as it exists today?**

    b. **Does a top-down approach, through FERC, serve the interests of utilities and grid operators that are already expending tremendous time and engineering resources on design new transmission?**

Answer for Questions 3-6:

Under the Comprehensive System Planning Process (CSPP), the NYISO is responsible for planning for the bulk transmission system through its Short-Term Reliability Process, Reliability Planning Process, Economic Planning Process, Public Policy Transmission Planning Process, and Interregional Planning Protocol. These processes identify needs that must be addressed and/or opportunities for transmission development. The Transmission Owners (TOs) in New York State are responsible under the Local Transmission Planning Process to plan for their respective Transmission Districts or facilities. In doing so, the TOs are responsible for identifying and addressing local needs through the development of a Local Transmission Owner Plan (LTP). The LTPs serve as inputs into the NYISO's planning studies.

The Public Policy Transmission Planning Process serves as the mechanism by which the NYISO considers transmission needs driven by public policy requirements. At its core, this process provides for the NYISO's evaluation and selection of transmission solutions to satisfy a Public Policy Transmission Need. The Public Policy Transmission Planning Process has seen success through the NYISO Board of Directors having selected four transmission projects to address the following Public Policy Transmission Needs: Western New York (Empire State Line), AC Transmission Segment A (Central East Energy Connect), AC Transmission Segment B (Segment B Knickerbocker-PV), and Long Island Offshore Wind Export (Propel Alternate Solution 5). The major components of the transmission projects selected to address the Western New York, AC Transmission Segment A and AC Transmission Segment B needs are currently in service, while the Propel Alternate Solution 5 project is in the early stage of development with an identified in-service date of May 2030 to the meet the need.

New York has strong interregional transmission connections to ISO-NE, PJM, IESO, and HQ that are leveraged to support the economic and reliable exchange of electric energy. New York is a historic importer of electric energy from PJM, IESO, and HQ, while it has typically exported to ISO-NE on a net annual basis.

The NYISO collaborates with its regional neighbors, PJM, ISO-NE, and Canada through its Northeastern ISO/RTO Planning Coordination Protocol ("Northeast Protocol"). The Northeast Protocol includes the following requirements:

- Exchanging data and information,
- Coordinating interconnection requests and transmission requests with cross-border impacts
- Developing a Northeastern Coordinated System Plan
- Performing planning studies through an open stakeholder process, and
- Allocating the costs associated with interregional projects having a cross-border impact consistent with each party's tariff and applicable federal regulatory policy.

Under the Northeast Protocol, the Joint ISO/RTO Planning Committee ("JIPC") was formed to address interregional transmission planning issues, including system needs and proposed system improvements that reflect, among other things, resource diversity, environmental compliance obligations, and resource retirements. This allows consideration of the impact of interconnections with neighboring systems, such as opportunities for the exchange of capacity and energy, and tie lines facilitate access to a diversity of resources and potential economic opportunities for energy exchange.

7. **What would be your top priority or need from states, FERC or Congress to assist you in meeting new demand —especially if we need even more power than projected? Are you equipped today to meet increased future demand at the pace needed and to maintain affordability and competitive rates?**

The NYISO released the 2024-2034 RNA in November 2024. The report, issued biennially, highlights growing risks to electric system reliability, including projected increases in peak demand due to electrification of the transportation and building sectors; additional generator deactivations; delayed implementation of planned infrastructure projects; and extreme weather.

The 2024-2034 RNA found that if demand on the grid grows at a rate greater than the buildout of new generation and transmission, reliability deficiencies could arise within the RNA's ten-year planning period. It also detailed how the advance of new technology and economic development is compounding the complexity of maintaining reliability. The combination of near-term growth in demand from data centers, semiconductor fabrication, and new manufacturing facilities present significant challenges for grid planning over the next several years.

The 2024 RNA initially identified a reliability need in New York City beginning in summer 2033. The need was driven by a combination of the legislatively mandated deactivation of generating units owned by the New York Power Authority (NYPA) by the end of 2030, forecasted increases in peak demand, and limited new supply. To underscore how narrow reliability margins create uncertainty, the NYISO's most recent annual forecast update projects roughly 200 MW less demand in New York City by 2035. The reduction reflects slower adoption rates for electrification technologies and is enough to eliminate the reliability need identified in the 2024 RNA. While the reliability need identified by the 2024 RNA no longer exists, significant uncertainties associated with future demand growth from large loads and the changing supply mix could result in the identification of reliability needs in the future.

The RNA also shows that the early stages of the transition of the supply mix, driven by public policies, are resulting in the retirement of fossil fuel generation faster than renewable resources are entering service. This trend has led to concerns over declining reliability margins across the state — an important element for grid reliability. Since the enactment of the state's Climate Leadership and Community Protection Act, more than twice the capacity of generation has deactivated than has been added to the system. Should this trend continue, the RNA warns that additional reliability needs may be identified, both statewide and for localities. The RNA also evaluates the potential for additional retirements of gas-fueled resources in New York City, driven by state policies, that could also result in additional reliability needs without additional resources to replace them.

The potential risks and resource needs identified in the RNA may be resolved by new capacity resources coming into service, construction of additional transmission facilities, increased energy efficiency, integration of distributed energy resources (DERs) and/or growth in demand response participation.

The RNA also emphasizes the need for additional transmission infrastructure to move renewable electricity from where we expect it will be sited to where it will be needed to serve demand. Building more generation to meet growing demand alone will be inadequate to meet the needs of a modern grid — we also need to move that electricity readily around the state as consumer demand dictates.

The Honorable Kathy Castor (D-FL)

1. **One of our greatest challenges today is getting new sources of electricity on the grid as quickly as possible in this new era of increasing electricity demand. Interconnection processes – while critical to maintaining the reliability of the grid – can also take far too long under the current framework.**

   On March 17, FERC Commissioner David Rosner wrote a letter to each of you detailing new opportunities to streamline the interconnection process. In a recent study by the Midcontinent Independent System Operator (MISO), an automated process was able to nearly replicate in ten days the results of an interconnection study that took nearly two years to conduct.

   a. **Please describe your experience with interconnection automation technologies to date and the prospects for further deploying them going forward.**
   b. **Please describe how FERC and Congress can each support such innovation.**

In May 2024, the NYISO implemented new procedures to improve the efficiency and transparency of its interconnection process. The inaugural cluster study commenced in August 2024 and more than 240 generation projects are currently advancing through the first phase of the cluster study — a crucial step and significant milestone toward integrating new generation facilities onto the grid.

The new process, which expedites the interconnection study process for developers, was developed in response to the regulatory reforms required by FERC Order No. 2023.

The interconnection process requires significant coordination between utilities, developers, and state and local governments. NYISO leads this process, ensuring that projects can connect to the grid without harming the system or imposing undue costs on consumers to upgrade the electric system.

Overall, key improvements include a feasibility screen and a two-phase cluster study approach. The cluster study approach limits the number of "mid-stream" project modifications during the interconnection process to help speed timelines and avoid the possibility of one project creating delays for other projects looking to move forward within the cluster.

- The two-phase study includes several decision periods with commercial readiness deposits and withdrawal penalties, to incentivize uncertain projects to exit the queue early.
- The study process includes firm tariff-mandated study deadlines for work performed by the NYISO and utilities and tariff consequences for missed deadlines.
- The two-phase study aligns the treatment of generating facilities 20 MW or smaller with the overall process, incorporating all generation facilities into a single, standardized process.
- The new rules provide for additional pro forma documents and agreements to expedite the interconnection process, the negotiation of required agreements, and the construction of required upgrades.

A new interconnection portal was also developed. The interconnection portal is a digital platform where developers and utilities submit and gain information on pending interconnection proposals and applications. The NYISO has made several improvements to the interconnection portal to enhance the user experience and streamline the process.

These improvements include:

- **Streamlined Inquiry Submissions:** The portal now offers a more streamlined process for submitting inquiries, making it easier for users to request information and assistance.
- **Enhanced Transparency:** The portal provides improved transparency of project progress and status, which helps parties stay informed about developments during the study process.

- **On-Demand Access:** Users have on-demand access to common interconnection questions, which provide immediate answers to frequently asked questions.
- **Ongoing Technology Improvements:** NYISO has held numerous focus groups with developers since 2023 to identify areas for improvement with the portal. NYISO continues to engage with customer focus groups and other stakeholders to discuss and develop additional portal functionality.

These steps demonstrate NYISO's deep commitment to improving the efficient integration of new generation projects onto the grid.

The Honorable Scott Peters (D-CA)

1. **Have you experienced permitting delays that this committee should better understand? What are some key/important examples?**

2. **What laws (on permitting specifically, but also planning, siting, interconnection, cost allocation, etc.) should be changed/amended/improved with regard to permitting?**

Answer for Questions 1 and 2:

Through the NYISO's interconnection process, major generation, transmission, and load projects are studied to assess the reliability impact they may have on the electric system. The interconnection process is coordinated by the NYISO but requires significant involvement by both the electric utilities and developers. Each party has an important role to play, and success of the process depends on coordination and timely delivery of information by all participants. Through the interconnection process, as required by FERC, the NYISO seeks to balance the demands of open access to the electric system with grid reliability while protecting customers from undue costs.

In May 2024, the NYISO implemented new procedures to improve the efficiency and transparency of its interconnection process. The new process, which expedites the interconnection study process for developers, was developed in response to the regulatory reforms required by FERC Order No. 2023.

It is important to note that, for various reasons, not all proposals in the interconnection queue are destined to enter commercial operations. Multiple factors outside the scope of the NYISO's control can impact whether a project elects to move forward with the interconnection process, including the status of siting and permitting, investment risks, and supply-chain concerns. These factors can result in developers electing to defer or drop out of the process, even after the final interconnection studies have been completed and interconnection costs have been allocated and accepted.

3. **What are your specific challenges when it comes to planning and cost allocating high voltage transmission lines?**

FERC Order No. 1000 directed regional transmission planners – including the NYISO – to, among other things, consider transmission investment needs driven by federal, state, and local public policies in their planning processes. In New York, transmission needs driven by public policy requirements are identified by the state Public Service Commission and the NYISO evaluates and selects the more efficient or cost-effective solutions to address those needs through a competitive, multi-step process, called the "Public Policy Transmission Planning Process."

Step 1: The NYISO solicits proposals for transmission needs driven by public policy requirements from interested parties. These proposals, as well as any suggestions from the NYISO, are collected and provided to the New York Public Service Commission (PSC) for consideration.

Step 2: The PSC considers and identifies proposed transmission needs, following public comment. During this period, the PSC examines the public policy requirements and considers whether there are requirements driving the need for additional transmission investment. Consistent with state law, the PSC seeks public comment, and many parties, including the NYISO, actively participate in this part of the process.

Step 3: Once the PSC identifies a specific need for the power system, the NYISO requests and evaluates proposals from qualified developers. Following receipt of proposed solutions to a public policy transmission need identified by the PSC, the NYISO conducts a comparative evaluation of the solutions based on their ability to satisfy the needs identified by the PSC and other criteria aimed at identifying the more efficient or cost-effective solution. The NYISO's evaluation is performed transparently with continuous input from stakeholders and developers through its governance process.

Step 4: Based upon results of the NYISO's evaluation and input from stakeholders, the NYISO Board of Directors may select the more efficient or cost-effective solution. Following selection, the designated developers will proceed with the development and construction of the project.

In recent years, four major transmission projects have been approved through the NYISO's Public Policy Transmission Planning Process. The Empire State Line, which was completed June 1, 2022, will improve access to renewable hydroelectric energy from the Niagara Power Plant. The AC Transmission Projects – comprised of Segment A and Segment B – which increase delivery of clean power generated in northern and western New York to downstate customers.

The Propel Alternate Solution 5 project was approved to meet the Long Island Offshore Wind Export Public Policy Transmission Need ("Long Island PPTN"), which was declared by the PSC on March 19, 2021. The PSC's order declared that the Climate Leadership and Community Protection Act (CLCPA) constitutes a Public Policy Requirement driving the need for transmission to increase the export capability from Long Island to the rest of New York State to facilitate transfer of the full output of offshore wind projects. The Propel Alternate Solution 5 project is in the early stage of development with an identified in-service date of May 2030 to the meet the need.

Through our Public Policy Transmission Planning Process, a historic level of investment in the New York State transmission system is underway, with projects that will deliver more clean energy to New Yorkers and enhance the resiliency and reliability of the grid.

SPP Southwest Power Pool

Working together to responsibly and economically keep the lights on today and in the future.

June 11, 2025

Via U.S. and electronic mail

The Honorable Robert E. Latta, Chairman
Subcommittee on Energy
U.S. House of Representatives Committee on Energy and Commerce
c/o Calvin Huggins, Legislative Clerk
2125 Rayburn House Office Building
Washington, DC 20515
Email: Calvin.Huggins1@mail.house.gov

Dear Chairman Latta:

Thank you for the opportunity to appear before the Subcommittee on Energy on Tuesday, March 25, 2025, to testify at the hearing entitled "Keeping the Lights on: Examining the State of Regional Grid Reliability."

Pursuant to the Rules of the Committee on Energy and Commerce, please find the attached responses to the questions submitted by Members.

Thank you again for your time and for allowing me the opportunity to deliver my testimony before the Subcommittee.

Sincerely,



Lanny Nickell
President and Chief Executive Officer
Southwest Power Pool
201 Worthen Drive
Little Rock, AR 72223

The Honorable Robert E. Latta (R-OH)

1. **As stated in President Trump's Executive Order "Removing Barriers to American Leadership in Artificial Intelligence" (AI EO) on January 23, 2025, "It is the policy of the United States to sustain and enhance America's global AI dominance in order to promote human flourishing, economic competitiveness, and national security." President Trump has made it clear that he wants the U.S. to be the global leader in AI and unleash American energy. How does SPP plan to ensure sufficient supply of energy to meet the needs of data centers in a timely manner?**

SPP is actively preparing to meet the rapid load growth driven by AI and large data centers. SPP's strategy to power the AI revolution combines aggressive generation procurement, innovative process reforms, demand-side management, and proactive grid expansion – all to ensure that data centers can access reliable power when they need it without delay. These collective actions will unleash American energy in our region to support AI growth, consistent with the national policy goal.

Our planners forecast that peak demand in our region could grow up to 75% over the next decade, largely due to an emerging wave of energy-intensive data centers. To ensure sufficient supply for this growth, SPP is working to bring new generation online more quickly and to fully utilize existing resources. We have developed an Expedited Resource Adequacy Study (ERAS) – a fast-track generation interconnection process – specifically to accelerate the addition of new generating capacity needed for these large loads. Pending FERC approval, ERAS will run in parallel to our standard queue and allow load-serving entities to nominate critical projects that can be built and deliver power within about five years, significantly cutting the normal interconnection timeline. In addition, SPP is streamlining its overall interconnection study process with a goal of offering generation interconnection agreements within one year of application by the end of 2025 (down from the multi-year timeline of the past).

SPP's all-of-the-above approach also leverages demand-side solutions to maintain near-term reliability. We recognize that building new power plants can take several years, while data center demand is materializing on a shorter timeframe. As a result, SPP is expanding demand response programs to help bridge the supply-demand gap until new generation is in place. By encouraging large consumers to curtail usage during peak periods and by enhancing energy efficiency, we can mitigate strain on the system in the interim.

At the same time, SPP continues to facilitate a robust pipeline of new resources: more than 160 GW of generation projects – nearly three times our existing peak load – are currently seeking interconnection to our grid including a substantial mix of battery storage and quick-start gas generation that will help meet data centers' 24/7 power needs. Even if only a fraction of these proposed projects is built (as we anticipate under our expedited processes), they will provide a sufficing supply cushion for new high-tech loads.

Finally, SPP is reinforcing its transmission infrastructure to deliver this energy reliably and on time. Serving large data centers often requires targeted transmission upgrades, and SPP's regional planning process identifies and accelerates those investments needed to serve new industrial load. In fact, our latest transmission expansion plan called for more than five times the investment of any prior plan, underscoring the scale of build-out required for rising demand. We are working closely with state authorities and stakeholders to site and construct new lines as efficiently as possible.

2. **Accurate and transparent electricity load forecasting is a linchpin of modern economic development. States rely on these forecasts to plan new industrial parks, data centers, and manufacturing hubs, while utilities use them to schedule grid expansions and major infrastructure investments. Despite the vital role of load forecasts in spurring economic growth, practices vary widely among states, utilities, and RTO/ISOs, often leading to inconsistent data, misaligned investment signals, and unnecessary risk for both utilities and both large and residential customers. Recent inconsistencies underscore how a patchwork of forecasting methodologies can exacerbate speculation in large load interconnection requests, inflate demand projections, and drive up costs. These issues cross both state and federal jurisdictions and regional differences.**

    a. **What steps is SPP taking to ensure its load forecasting is transparent, predictable and correctly anticipating future capacity and infrastructure needs to power AI infrastructure?**

SPP is enhancing its load forecasting processes to ensure they are as transparent and forward-looking as possible, especially given the influx of AI-driven demand. First, we have bolstered the data inputs and collaboration behind our forecasts. SPP now works in close coordination with our member utilities, state regulators, and large customers to gather timely information on emerging loads (like planned data centers) so that our regional forecasts reflect these projects as soon as they are on the horizon. For example, we engage with economic development agencies and companies to understand potential new load well before it materializes, rather than waiting for it to appear in historical data. This collaboration helps make our forecasting more predictable and proactive. We have also increased transparency by sharing our forecasting assumptions and results openly through stakeholder forums. SPP's load forecast methodology and key drivers – such as expected growth from electrification and AI – are discussed with stakeholders in our planning working groups, ensuring that utilities and states can provide input and see how the numbers are derived. By harmonizing assumptions across our footprint, we avoid the patchwork of differing methodologies that you noted. In short, SPP is moving toward a more unified, scenario-based forecasting approach that is communicated clearly to all stakeholders, so that everyone from state officials to generators has a consistent expectation of future demand.

In addition, SPP has begun incorporating advanced analytics and higher-frequency updates into our forecasting process. We recognize that traditional methods must be supplemented given

the unprecedented growth in data center load. SPP is exploring the use of machine learning tools to analyze trends in large customer usage and to improve load predictions under various conditions. We have also shortened our forecast update cycle. Instead of waiting for an annual process, we can adjust our long-term load outlook more frequently if we learn of major new industrial projects or if trends (like AI adoption rates) accelerate unexpectedly. This agility improves accuracy and ensures we signal the need for new capacity or infrastructure with as much lead time as possible. Finally, to directly support planning for AI-related loads, SPP's upcoming Integrated Transmission Planning (ITP) assessments will include high-demand growth scenarios (for example, a scenario with a significant number of new data centers) to test that our future grid can meet those needs. By stress-testing our system against these potential futures, we can identify needed upgrades or resources early. All of these steps – better data sharing, stakeholder transparency, analytical innovation, and scenario planning – help SPP produce load forecasts that are credible, consistent, and aligned with the actual growth we expect from AI and other drivers. Our goal is that no one is caught off guard by large load additions: we want our forecasts to accurately anticipate capacity and infrastructure requirements so that we build out the grid in tandem with rising demand, not after the fact.

b. What, if any, barriers exist to increased transparency on potential load growth from AI?

One significant barrier to full transparency in load growth is the uncertainty and confidentiality surrounding large new projects like AI data centers. Often, tech companies and developers closely guard their expansion plans for business reasons, and local utilities might be bound by non-disclosure agreements. This can delay when and how such information reaches SPP's planners. In some cases, a data center project might not become public until the company announces it, which compresses the time we have to incorporate it into forecasts. Another barrier is the lack of standardized reporting requirements for anticipated large loads. Today, approaches vary: one state or utility might immediately report a prospective large load to the RTO, while another might wait until a project is certain or until the customer signs a contract. These inconsistent practices, as the question noted, can lead to patchy data. This patchwork crosses state and federal lines. For instance, some – but not all - states require utilities to submit integrated resource plans that include future large loads. RTOs currently lack a uniform mechanism to collect large-load information across all members.

Additionally, forecasting AI-related demand is inherently challenging, which can hinder transparency simply because of the wide range of possible outcomes. The pace of AI adoption and the energy efficiency improvements in data center technology are moving targets. This means any single forecast has a larger margin of error that must be understood. We address this by publishing not just a single number but ranges or scenario outcomes, which is a more transparent way to communicate uncertainty. However, not all jurisdictions are accustomed to scenario-based planning, which could be seen as a barrier because it requires stakeholders to digest a more complex picture rather than one definitive load growth figure.

Finally, on the technical side, sharing granular data about potential industrial loads can run into privacy and security concerns. For example, disclosing the exact locations or sizes of future AI facilities might raise competitive or even national security issues, if tied to sensitive computing tasks. SPP must balance transparency with these concerns by aggregating or anonymizing data center load information in our public forecasts. The key barriers are information delays and confidentiality, inconsistent reporting practices, forecasting uncertainty, and data sensitivity. SPP is actively working with utilities, states, and FERC to mitigate these barriers by developing protocols for earlier notice of large load interconnection requests and by encouraging a more standardized approach to load forecasting across our region. We believe that continued collaboration among states, utilities, RTOs, and customers (possibly supported by guidance from FERC or DOE) will gradually improve transparency around AI-driven load growth.

3. How can RTOs accelerate transmission expansion to support load growth without creating excessive costs for ratepayers?

RTOs such as SPP can accelerate necessary transmission build-out in a cost-effective manner by planning proactively and leveraging cost-sharing strategies that ensure projects deliver high value for their cost. One important approach is comprehensive, forward-looking planning: by anticipating where load growth will occur (for instance, identifying corridors likely to see new data centers or electrification loads), we can design transmission upgrades that meet those needs before they become urgent, thereby avoiding expensive last-minute solutions. Proactive planning also enables us to right-size projects by building a single larger regional line that addresses multiple future needs. This approach is often more economical than many piecemeal upgrades. SPP's experience has shown that well-planned transmission investments yield significant net benefits. In fact, studies of our total transmission portfolio have found roughly $5 in benefits for every $1 of transmission cost – achieved through reduced energy prices, improved reliability, and reduced generator expenses. SPP's 2024 transmission portfolio, our latest and largest, projects $8 in benefits for every $1 of cost. By focusing on projects with such strong benefit-to-cost ratios (SPP requires robust economic justification for major upgrades), we ensure that accelerating expansion actually lowers total system costs for consumers.

In parallel, cost-sharing mechanisms are key to protecting ratepayers. SPP's Highway/Byway cost allocation method internally socializes most of the cost of 300+ kV "highway" lines across the whole region (on the theory that such lines provide regional benefits). When a specific new customer or generator drives the need for a transmission upgrade, that entity is often assigned a portion of the cost through established interconnection procedures. In SPP, if a particular large customer addition necessitates a line, that customer can be allocated costs in a way that prevents existing ratepayers from footing the entire bill. RTOs can also work with state regulators to augment these mechanisms. For example, states can allow utilities to negotiate transmission contribution agreements with large new industries, ensuring those new loads help offset the expense.

From a project execution standpoint, accelerating build-out can reduce costs by avoiding inflation and congestion costs that accrue with delay. RTOs therefore coordinate closely with

permitting agencies to prevent unnecessary holdups (we address permitting improvements further below). We also utilize competitive bidding processes for transmission projects where applicable (as mandated by FERC's Order 1000) to drive down construction costs through competition. Moreover, SPP and other RTOs continually look for innovative solutions to maximize existing infrastructure. For example, advanced line monitoring and dynamic line ratings can increase throughput on current lines, and targeted upgrades (such as tower or conductor replacements) can boost capacity at lower cost than building entirely new corridors. These measures can buy time or even substitute for major new builds, supporting load growth at minimal expense.

The keys are strategic planning and prudent cost allocation. By planning expansions that clearly benefit consumers and by sharing costs among all who benefit (including the new loads themselves), RTOs ensure that an accelerated transmission build yields net savings. SPP's record of low wholesale prices – the lowest of any RTO in the nation – attests that we have expanded our grid in a way that ultimately drives costs down for ratepayers through improved efficiency and access to low-cost generation. We intend to continue that approach even as we speed up projects to meet rising demand.

4. **From a siting and permitting perspective, what do you see as the challenges and barriers to constructing sufficient transmission infrastructure needed for reliable, safe, affordable, and timely delivery of power?**

Constructing major transmission infrastructure faces several well-known challenges on the siting and permitting front. A primary barrier is the multi-jurisdictional nature of major power lines. SPP's footprint covers parts of 14 states, and a new regional line may need approval from each state it crosses, each with its own processes and criteria. Coordinating and securing permits from multiple state commissions and local authorities can be time-consuming and often unpredictable. In some cases, one state's denial or lengthy approval process can stall a line that is regionally beneficial. This patchwork of state siting authority, without an effective overarching approval mechanism, is a significant hurdle to timely transmission development.

Another challenge is landowner and public opposition that can arise over new lines. New transmission corridors can impact private lands, and even when they confer broad public benefits, affected communities may raise concerns about environmental, visual, or property value impacts. Addressing these concerns – through routing adjustments, fair compensation, or lengthy hearings – often extends project timelines. We've seen instances in which urgently needed lines encounter delays due to organized local opposition or difficulties in acquiring rights-of-way. Additionally, the required environmental reviews (for example, federal NEPA reviews) for large projects can be lengthy, and waiting for specialized equipment or construction resources (supply chain constraints) can further push out construction schedules.

   a. **What role, if any, should Congress and FERC play in siting and permitting for regional or interregional transmission?**

Congress and FERC can serve as supportive partners to state authorities in transmission siting and permitting. It is important that states maintain primary responsibility for routing and local approval, but federal entities can help in several ways. For instance, where a regionally or nationally significant transmission line is being held up, a federal siting authority could provide a path forward if state permitting is unreasonably withheld or delayed. By offering limited authority for FERC to issue construction permits for projects deemed to be in the national interest (in cases where state processes have reached an impasse), the federal government would ensure that critical lines do not fall through the cracks. Any such authority would need to be used judiciously and in consultation with the affected states, acting only as a last resort to prevent stalemates while respecting state and local input.

Also, Congress and FERC can foster collaboration across jurisdictions. They could facilitate or encourage joint state-federal task forces or commissions that work on multi-state transmission projects, helping states coordinate timelines and share best practices in permitting. Moreover, Congress might consider providing incentives or funding mechanisms (grants, financing assistance, etc.) that encourage states to participate in regional transmission solutions. Overall, Congress and FERC's role should be one of coordination and enablement – providing tools, guidance, and support to streamline multi-state projects – rather than direct override of state authority. By acting as partners to the states, the federal government can help ensure that important regional or interregional lines are evaluated from a broader perspective and are not unduly hindered by misaligned processes, all while honoring the states' primary jurisdiction in siting decisions.

5. Regarding planning for transmission, what specific impediments have you identified to current state, regional, and interregional planning for transmission projects?

Several impediments hinder effective transmission planning at the state, regional, and interregional levels. At the state level, one impediment is that state resource planning and transmission planning are sometimes misaligned. Individual states often conduct integrated resource plans (IRPs) for generation or have specific policy goals (e.g., renewable portfolio standards or other preferences) that do not always feed directly into the regional transmission planning process. If a state's plan isn't fully synchronized with the RTO's assumptions, needed transmission projects might not be identified in time. Additionally, states may be reluctant to commit to certain transmission projects if they fear their ratepayers will primarily be paying for benefits that accrue elsewhere. Such indecision can impede support for otherwise beneficial regional lines. At the regional (RTO) level, a key impediment is the sheer complexity and duration of the planning process. Traditional regional planning can be slow, with multiple study cycles, stakeholder iterations, and reevaluations. This means that by the time a plan is approved, the underlying assumptions (like load growth or generation locations) may have changed. SPP has recognized this and is moving toward a Consolidated Planning Process (CPP). CPP optimizes public policy, reliability, economic, persistent operations, and GI needs into a single transmission portfolio. CPP establishes an upfront cost for GI customers to connect while simultaneously building out the transmission system, fixing needs that had previously been disparately

identified in GI and transmission planning business functions on different timelines and assumptions. CPP and innovative automation will lead to accelerated generation. Historically, generation interconnection studies, transmission expansion studies, and reliability studies were conducted separately, potentially missing holistic solutions. Another impediment is the difficulty in planning "ahead of need." RTOs are obliged to demonstrate clear needs and benefits for new lines, but some potential needs (for example, a large future load or generation project that is still speculative) are hard to quantify with certainty, so those projects don't get approved in advance. This means planning can become reactive rather than proactive, complicating efforts to meet fast-moving changes in demand or generation trends. Moreover, stakeholder consensus can be hard to reach for regional plans. Utilities, independent transmission developers, and other stakeholders often have differing priorities, which can water down or delay decisive action in an RTO planning cycle.

For interregional planning, one of the biggest impediments is that each region uses different criteria and models, making joint identification of projects very challenging. Even when two RTOs see potential benefit in a cross-border line, differences in planning methodologies (for example, how future generation is forecasted or how reliability criteria are applied) can result in disagreements on the project's value or necessity. The current FERC rules (Order 1000) require interregional coordination. In practice, though, only projects that independently appear in the plans of each region move forward, creating a high bar that has resulted in virtually no major interregional lines being built. Another impediment is cost allocation across regions. If SPP and a neighboring RTO plan a joint project, there may be no agreed mechanism on how to split costs in proportion to benefits, which discourages proposing such projects in the first place. Finally, uncertainty around future generation locations (for instance, where new wind or solar will be built in two different regions) makes it hard to plan a tie-line to exchange power. Without clear policy signals or commitments, planners tend to hold off on large interregional ideas.

a. What are examples of impediments you have identified and what is necessary for system planners to overcome these impediments?

One example is the impediment of cost allocation disagreements, which we encountered in trying to plan transmission upgrades along the seam between SPP and MISO. In one case, our joint studies identified a set of potential interregional projects that could enable more than two dozen GW of new generation across both regions. However, moving these projects forward was impeded by debates over how the costs should be split, since each region's stakeholders felt they might be subsidizing the other. Overcoming this impediment would likely require a pre-agreed-upon cost allocation formula or policy at the interregional level, perhaps guided by FERC, so that when a beneficial project is identified we aren't starting from scratch on cost-sharing negotiations. For instance, if there were a rule in place that divides costs based on each region's projected usage or benefit (using metrics like production cost savings or reliability improvements), planners could proceed knowing any qualifying project will have a defined cost split. Establishing such cost-sharing principles in advance would remove a major barrier to approving interregional lines.

Another concrete example is timing misalignment between regional planning cycles. A few years ago, SPP developed a long-range transmission plan that identified a high-voltage line in our northwest area. Meanwhile, a neighboring region saw a similar need on their side of the border slightly later. Because the projects didn't line up in the same planning cycle, neither region approved it as a joint project. The impediment here was the lack of a flexible planning window because each RTO was on a rigid schedule for approving projects. To overcome this, planners might need the ability to perform special joint studies on demand, outside the regular planning cycle, when an opportunity for a mutually beneficial project is evident. Some progress is being made. SPP and MISO, for example, have conducted joint targeted studies to address specific issues. The key will be institutionalizing that agility so that planning processes can respond to emerging needs in near-real time.

We also identified the impediment of inconsistent data or assumptions between planning entities. For example, if SPP assumes a certain level of energy export capability from its grid, but a neighboring system does not mirror that assumption (perhaps they assume far less import capacity on their side), a beneficial tie-line project might not show up as needed in both models. We saw this in a renewable-rich scenario in which SPP identified potential to export wind energy, but the neighboring region's model capped imports due to its own internal limitations – thus an interregional upgrade didn't register as high-value for them. Overcoming this requires system planners to improve data sharing and scenario alignment. One necessary step is developing common planning scenarios or base models that both regions analyze together, so we're working off the same expectations. Planners are now discussing joint planning models, and additional support from FERC in standardizing assumptions across regions could significantly help. If both sides evaluate projects using a unified set of assumptions about things such as electric vehicle growth or data center additions, we can reach agreement more easily on the need for a given line.

Overcoming these impediments will require a combination of policy and process improvements. System planners need clear, consistent policies for cost allocation (so everyone pays their fair share), more flexible and frequent coordination between regions (so timing mismatches don't hold projects back), and standardized planning assumptions (so all parties are modeling the same future). It will also take a willingness among all parties – states, RTOs, and federal regulators – to embrace new planning paradigms, such as scenario-based planning for uncertain futures, instead of relying solely on deterministic forecasts. With these changes, planners would be better equipped to identify and advance the transmission projects needed for our rapidly evolving grid.

6. What should Members of this Committee understand about the nature of transmission planning as it exists today?

SPP's transmission planning in our region is a collaborative, iterative process that involves our member utilities, regulators, and other stakeholders at every step. We follow a continuous ITP process: we regularly conduct 20-year, 10-year, and near-term studies to identify upgrades needed for reliability, economic efficiency, or public policy reasons. These studies use detailed

power flow models and scenarios that incorporate expected generation developments and demand growth. The planning process is governed by FERC-approved criteria and requirements, which means RTO planners can't simply build whatever lines they want – we must demonstrate concrete needs and benefits for any new project. For example, in SPP any economically driven project must meet a benefit-to-cost ratio threshold (currently 1.25:1 for most projects) to ensure it will provide net value to ratepayers. As a result, many potential projects are studied but rejected if they don't meet that threshold. In essence, our planning approach is somewhat conservative by design to protect consumers from over-building. The downside is that this caution can lead to under-building if emerging issues (such as sudden large industrial load growth) weren't fully anticipated in the models.

When it comes to planning with other regions, SPP does coordinate, but the structure is more limited than intra-SPP planning. We have joint planning agreements with neighboring grid operators (for example, with MISO to our east and ERCOT to our southwest) in which we exchange models and identify any issues that could be solved by interregional projects. In practice, however, interregional planning tends to be handled case-by-case rather than through a fully integrated joint plan. Each RTO still primarily plans for its own region's needs first. Members of this Committee should understand that today's transmission planning is highly thorough but also methodical – sometimes to a fault. It involves extensive engineering studies and stakeholder vetting, which means it can take years from identifying a need to getting a project approved. The process is consensus-based. Committees of stakeholders must agree on the plans. This inclusive approach ensures no one's concerns are ignored, but it can also result in compromises or slower progress on contentious projects.

Another key aspect of transmission planning today is that it must balance multiple objectives: reliability (keeping the lights on if something goes wrong), economic efficiency (reducing overall electricity cost by alleviating congestion), and public policy support (integrating renewables or meeting state clean energy goals). In SPP's planning, we incorporate all three objectives, but we do so within the framework of FERC-approved rules and metrics. This means RTO planners rigorously analyze needs and benefits, often eliminating projects that don't clearly satisfy the criteria for at least one of those objectives. Thus, while our planning process has successfully produced a robust regional grid with low wholesale costs, it can be slow to adapt to very rapid changes.

SPP plans transmission through a stakeholder-inclusive, rigorous analytical process within our region, and we coordinate at the seams with our neighbors through formal but limited interregional protocols. Transmission planning is complex, data-driven, and consensus-oriented. It has served to keep our system reliable and costs low for consumers. But without changes, the process may struggle to keep up with the unprecedented pace of change, such as the rapid demand increases from AI and electrification. We are working within our stakeholder process to make planning more agile, but any significant shift will require broad agreement to ensure we maintain the careful balance between being proactive and protecting ratepayers.

7. While much of the focus on our electric grid is on increasing demand for electricity from data centers and domestic manufacturing, we must also ensure that ratepayers are not unduly burdened by new infrastructure development. As you mention in your testimony, SPP enjoys some of the lowest wholesale electricity prices in the country, served by a diverse generation mix of renewables. What steps are you taking to keep electricity affordable for consumers even as significant new investments in the grid are made?

Preserving affordability while expanding the grid is a top priority for SPP. We have several strategies in place to make sure that adding infrastructure for new demand does not unduly burden our consumers. First, SPP's planning process itself is geared toward cost-effective projects. We require a demonstration of strong economic value for major expansions (via benefit-to-cost tests), which means we only pursue projects that are expected to reduce overall costs or are necessary for reliability. This ensures that any new transmission investment pays off in the long run through lower congestion costs, improved access to cheap power, or enhanced reliability (avoiding expensive outages).

Second, we utilize cost allocation methods that spread the costs of big projects broadly and fairly. High voltage transmission lines that benefit the entire region have their costs shared region-wide under our Highway/Byway approach, so no single area is unfairly saddled with the expense if the benefits are widespread. Conversely, if a new industrial customer (such as a large manufacturing plant or data center) triggers the need for an upgrade, that customer is required to bear an appropriate portion of the cost through our interconnection and service agreements. By having new entrants "pay in" for the infrastructure they necessitate, we protect our existing ratepayers from absorbing all the costs of growth. In many cases, large companies are willing to invest in the necessary upgrades because they also benefit from the resulting reliability and capacity.

Third, SPP's diverse resource mix – including a very large portfolio of low-cost wind energy – has been instrumental in keeping wholesale electricity prices low, and it will continue to be our advantage. During high-demand periods, having plentiful wind (and increasing solar) generation means we can supply a lot of energy at near-zero fuel cost. That inherently suppresses market prices compared to regions that rely on more expensive fuel. We are integrating new renewable projects alongside load growth, which helps ensure that even as consumption rises, the marginal cost of energy remains low. It's worth noting that adding large new loads can actually improve overall system economics if managed well: they create additional demand that our existing generation fleet (especially low-cost resources) can serve, which can spread fixed costs over more kilowatt-hours. In other words, growth can be a "win-win" if planned properly – the new industries get the reliable power they need, and existing consumers benefit from economies of scale and a broader revenue base supporting the grid.

We also coordinate closely with state regulators on rate impacts. As projects move through approval, we analyze their effect on rates and look for ways to mitigate any sudden increases. This might involve phasing project construction over time or sequencing investments so that

we avoid "rate shock." SPP's oversight, together with state public utility commissions' review of utility investments, provides a check that infrastructure spending remains prudent and in the public interest.

Our approach to maintaining affordability is to build only what is needed and build wisely, allocate costs fairly (especially to those driving the need), and take full advantage of our low-cost generation to serve new demand. Thanks to these measures, SPP has kept wholesale rates among the lowest in the nation even as we expand the grid, and we plan to continue that record by ensuring new investments are efficient and beneficial to all consumers.

8. **What would be your top priority or need from states, FERC, or Congress to assist you in meeting new demand—especially if we need even more power than projected? Are you equipped today to handle even higher demand growth?**

Our top priority request from states, FERC, and Congress is help in speeding up the entire development process for new resources and infrastructure. In practical terms, this means faster permitting and siting approvals, timely regulatory approvals for projects, support for attracting investment into generation and transmission, and an overall climate that encourages innovation in grid management. If those pieces fall into place, we believe we can meet even more demand than currently projected. Internally, SPP has the technical expertise, detailed planning frameworks, and operational experience to manage very high load growth – we have robust reliability protocols and a proven track record of keeping the lights on under stress. The primary constraints we face are external: the time it takes to get new power plants and transmission lines sited, approved, financed, and built. So, we ask our state and federal partners to help accelerate those timelines wherever possible.

Specifically, states and FERC can continue to streamline permitting and reduce unnecessary delays for projects that our studies show are needed. Congress can assist by ensuring federal agencies coordinate their reviews and by providing any needed authority or funding to break bottlenecks in project development. Additionally, support for research and deployment of advanced grid technologies (such as energy storage, smart grid controls, and automation) would help us innovate in serving load more efficiently.

Are we equipped today for even greater demand? Yes, given the proper enabling conditions. SPP's operations team and infrastructure have proven adept at handling record peaks and integrating new resources quickly when required. We maintain a healthy planning reserve margin and are continually adapting our market and operational rules to ensure reliability with growth. If demand exceeds our current forecasts, we will respond by invoking our expedited interconnection processes, further ramping up demand response, and accelerating project planning cycles to keep ahead.

FERC could also help SPP and other regions meet vastly increasing demand by continuing to support the refinement of the interconnection processes, including needed short-term changes. The generator interconnection process in SPP, like those in other regions, was not initially

designed to handle the growth of new resources and their differing characteristics, which led to the large interconnection queue backlogs and uncertainty regarding the cost and timing of interconnecting to the transmission system. To address these significant interconnection challenges, SPP filed with FERC a proposed one-time expedited study process to address near-term resource adequacy needs. Specifically, SPP identified a subset of critical generation projects that could realistically be built and placed online within a short horizon and also proposed to fast-track the interconnection studies for these projects outside of the normal queue sequence. If FERC approves this proposal, SPP will be able to quickly interconnect capacity that is urgently needed for reliability by prioritizing certain projects and bypassing some of the current queue backlog. In short, with faster approvals, sufficient investment, and supportive policies, SPP is confident that it can reliably power even more aggressive economic growth. Our regional grid has the foundation and resilience to accommodate surging demand. Policymakers, we need assistance in removing the barriers that slow down adding capacity. With that support, we would stand ready and fully equipped to keep the electricity supply adequate and reliable, no matter the intensity of the AI boom.

The Honorable Rick Allen (R-GA)

1. **Nearly twenty percent of our nation's electricity is generated by 94 nuclear reactors. Constructed forty to fifty years ago, these reactors represent enduring assets that continue to deliver significant value long after the visionary decisions to build them were made. Today's market conditions, however, would likely discourage companies from pursuing such generational investments. As states grapple with rising power demands, they are seeking innovative tools to drive the deployment of next-generation nuclear facilities. a. How can these potential state actions fit within your markets?**

Because nuclear units have very low fuel costs and high reliability, we expect they would run at high capacity and help displace more expensive generation, which would be a win for consumers. The presence of a state-supported nuclear facility would not disrupt market operations; rather, it would be another source of stable, around-the-clock power contributing to grid reliability.

One thing to note is that SPP's resource adequacy requirements (i.e., our planning reserve margin) already give credit for the capacity value of all resources. A new nuclear plant would provide firm capacity that helps the region meet peak demand, and it would be counted toward the utility's capacity obligation just as a natural gas or coal plant is. In SPP, most utilities remain vertically integrated and use the market for economic dispatch. So, if a state commissions a nuclear unit for a utility, that utility can invest in it and recover costs through state-regulated rates, while the plant's output is optimized by the SPP market. This hybrid approach has worked for other resources. For example, many of our utilities have added wind farms due to state policy or economics, and those resources integrate smoothly into our market. The same would be true for nuclear. In essence, state actions to promote nuclear development can fit hand-in-glove with

SPP's market because the market will simply accept the new plant as a supply resource and ensure it's used efficiently across the region.

From a market rule standpoint, there may be some considerations to ensure fair play. For instance, if a nuclear plant has state-guaranteed cost recovery, it might bid into the market at very low prices (since it's not solely dependent on market revenue). SPP's market monitoring would ensure that the plant's offers reflect its true operating costs and follow our conduct rules. Additionally, if multiple states in our region pursue small modular reactors or other advanced nuclear projects, SPP could see periods of excess baseload generation. Our market's LMP (Locational Marginal Pricing) mechanism would handle this by lowering prices and even allowing negatively priced offers if necessary, signaling those units to curtail if cheaper resources (such as wind at night) oversupply the grid. However, nuclear plants are very flexible in terms of fuel availability (they run regardless of weather), so they complement intermittent renewables by providing a steady backbone of generation. In summary, we see state-driven nuclear initiatives as compatible and even beneficial in SPP. The market provides an efficient dispatch and regional distribution for the power, and the states provide the impetus and financial framework to get these long-lived assets built. We are prepared to integrate next-gen nuclear plants and ensure they operate in concert with our other resources.

2. **In its 2024 Long Term Reliability Assessment Report, the North American Electric Reliability Corporation (NERC) recommends that to maintain demand and supply balance, dispatchable generators, including fossil fuel generators, must be available and capable of following changing electricity demand. a. To ensure reliability, what measures are you taking to discourage the premature retirement of fossil fuel generators?**

SPP recognizes the crucial role that dispatchable generators – notably our coal and natural gas fleet – play in maintaining reliability, especially during periods when renewable output is low or demand is unexpectedly high. While the decision to retire generation is made by asset owners (often guided by economics or policy), SPP has taken several measures within our authority to encourage the retention of needed resources and to manage retirements in a reliability-conscious way. First, SPP has a Generator Retirement Process that requires advance notification of any planned generator retirement or suspension. When a member utility notifies us of a potential retirement, our engineering staff conducts a thorough reliability impact assessment. If that analysis finds that the generator is needed to maintain system reliability (voltage support, etc.) under certain conditions, SPP can designate it as a "must-run" unit or require transmission upgrades before it can retire. This ensures that units providing critical reliability services are not turned off before replacements or mitigations are in place.

Additionally, SPP has been publicly voicing the need for careful pacing of retirements. Our leadership, including Lanny Nickell, has stressed in multiple forums that we should hold on to the generation we already have until new resources are ready. By communicating this urgency to our stakeholders and regulators, we aim to build consensus that premature retirements pose a risk. Many of our member utilities have responded by revisiting their resource plans to either

defer retirements or invest in life-extension projects for key plants. On the market side, SPP's energy and ancillary services markets provide revenues to generators that help keep them economic. We are examining whether market mechanisms can be adjusted to better value the flexibility and capacity that fossil units provide. For example, our Operating Reserve Demand Curve (ORDC) during scarcity will raise prices when capacity is tight, incentivizing utilities to keep their generators online or to build new ones. Ensuring those price signals are robust is one way to discourage shutting down a plant that might later be needed. We have also added an additional winter seasonal capacity requirement, which could emphasize the importance of maintaining units, especially through the winter when their capacity value is highest.

The Honorable Kathy Castor (D-FL)

1. **One of our greatest challenges today is getting new sources of electricity on the grid as quickly as possible in this new era of increasing electricity demand. Interconnection processes – while critical to maintaining the reliability of the grid – can also take far too long under the current framework. On March 17, FERC Commissioner Mark C. Christie wrote a letter to each of you detailing new opportunities to streamline the interconnection process. In a recent study by the Midcontinent Independent System Operator (MISO), an automated process was able to nearly replicate in ten days the results of an interconnection study that took nearly two years to conduct.**

    a. **Please describe your experience with interconnection automation technologies to date and the prospects for further deploying them going forward.**

SPP has deployed multiple automation tools to speed up our generation interconnection studies. Starting in 2022, these tools have been key to unlocking our Generation Interconnection backlog. To date, much of SPP's interconnection study process has involved detailed power flow simulations and engineering judgment by our planning staff, which, as noted, can be time- and labor-intensive. We recognize the promise shown by new automation technologies – including advanced software and even AI/machine-learning tools – to drastically reduce study times. In fact, we have begun internal evaluations of similar automated screening tools. For example, SPP has tested software that can automatically model the impact of a new generator on nearby transmission elements and produce a first-pass list of required upgrades. Our initial experience with these tools is encouraging: they can handle repetitive calculations much faster than a human, and they allow engineers to focus on analyzing results rather than setting up runs. In some of our cluster studies, we've used improved algorithms to autogenerate network models and contingencies, which shaved some weeks off preparation time.

We have not yet fully implemented an AI-driven study that compresses two years into 10 days, as MISO's report suggests, but we are laying the groundwork for greater automation. SPP recently invested in modernizing our IT and modeling infrastructure – essentially upgrading the computer platforms that host our power flow cases – to ensure we can run complex simulations in parallel and handle large data outputs. As part of our ERAS (Expedited Resource Adequacy Study) initiative, we are considering automated workflows that would allow us to conduct many

study scenarios in a short period and cross-verify the results. The prospects for further deployment of automation are very promising: we foresee using automation to perform standard calculations (including short-circuit duty checks, voltage drop assessments, and thermal overload screening) near instantaneously for each interconnection request.

One insight from our experience is that automation works best for the routine, rule-based parts of the study, whereas human engineers are still needed for complex planning judgments (such as deciding among alternative network upgrade solutions or negotiating how to allocate costs in a cluster). So, we anticipate a hybrid approach: automation will dramatically compress the technical analysis phase, and our planners will then validate and refine the results. This should yield the best of both worlds – speed and thoroughness. We are optimistic that with continued development, interconnection automation can greatly accelerate our processes, and SPP is committed to adopting these technologies as they prove reliable. We expect to incrementally roll out more automated tools in the next few years, which should help us keep pace with the surge in interconnection requests while maintaining reliability standards.

2. **This past winter, when much of the East Coast experienced record demand and wholesale electric prices soared to approximately $700 in certain areas, SPP faced similar cold conditions. How did the availability and amounts of wind, solar, and storage resources in SPP help to limit wholesale prices and maintain reliability in your region?**

During severe cold snaps, SPP's substantial wind generation and growing solar resources provided a crucial cushion that kept power prices manageable and the lights on. In the winter event referenced, our region was fortunate to have significant wind generation available, which continued to produce power even in frigid conditions. The Great Plains often experience strong winds during winter weather events, and that renewable output meant we did not need to rely solely on very expensive fuel-burning generators. Thousands of megawatts of wind (which has near-zero fuel cost) were on the margin or were displacing costlier gas-fired units, keeping our prices moderate compared to other regions. However, it's important to note that wind is an inherently variable resource. In fact, SPP has faced severe operational challenges in past events when wind generation output dropped off steeply. This experience reminds us that while wind's contributions can be significant, maintaining reliability also depends on having sufficient dispatchable and backup resources ready when wind availability changes rapidly.

In concrete terms, SPP's wind output can supply 30% or more of our electricity even on very cold winter days, which during this event helped offset high fuel costs. Solar resources, while a smaller portion of our mix, also contributed—especially on clear winter afternoons—by shaving the peak slightly and providing energy during daylight hours when natural gas supply was tight. Most importantly, SPP's balanced resource mix (not only wind and solar, but also gas, coal, and a bit of nuclear) meant that when natural gas spot prices spiked in the East, SPP could lean more on coal and wind and was not as exposed to extreme fuel costs. In terms of reliability, having ample wind and other available generation allowed SPP to meet the demand without resorting to emergency measures. We did not have to import vast amounts of power at exorbitant prices;

in fact, at times our wind farms were producing abundantly while some of our neighboring regions were struggling with supply. SPP was even able to export some power to assist others. This capability to draw on our renewable fleet and diversified supply demonstrated how those resources bolster reliability – we kept the lights on at home and helped limit price spikes regionally.

That said, our operators were careful to manage the grid knowing that wind can drop off if weather conditions change. We always ensure we have fast-start gas units and other reserves ready in case the wind output suddenly falls. The steep wind reductions we've seen on other occasions have reinforced the need for this preparedness. Overall, though, in this particular winter event the synergy of our wind, solar, and traditional resources was a clear success: it protected consumers from the worst of the price shocks seen elsewhere and kept our region reliable under very challenging conditions.

The Honorable Scott Peters (D-CA)

1. **Have you experienced permitting delays that this Committee should better understand? What are some key/important examples?**

Yes, SPP and its member utilities have encountered delays permitting various transmission projects, and these experiences highlight some common obstacles. One example involves a high-voltage 345 kV line from western Oklahoma to load centers in Arkansas that was identified in our most recent regional transmission expansion plan. This line required approvals from multiple state authorities and extensive environmental review. During the process, one state's siting proceeding took considerably longer than anticipated – nearly two years of adjudicatory hearings and route adjustments – due to local opposition and debates over the necessity of the line. Meanwhile, in the neighboring state, regulators were ready to approve it. The misalignment effectively stalled the project until the slower process concluded. This delay not only deferred the reliability and economic benefits the line would have provided but also led to cost escalations (as labor and material costs rose during the waiting period). It exemplifies how even a single state's protracted timeline can hold up a multi-state project.

Another key example is the challenge faced in attempting to build interregional transmission. A notable case was a proposed project to connect SPP's grid with the Southeast – the Plains & Eastern Clean Line high-voltage direct current (HVDC) project – to enhance transfer capability between our region and the Tennessee Valley area. Even though technical studies showed strong benefits from this project, it ran into a permitting roadblock: no single state wanted to take the lead on a line that mostly traversed another state en route to a different region, and there was no federal permit or authority to bridge that gap at the time. The project languished because acquiring dozens of county and local permits across multiple states without a clear state-level champion proved unworkable. This kind of delay was effectively an indefinite stall – it underscores that for interregional lines, the permitting framework itself can be a barrier, as much as any one jurisdiction's delay. When every state can veto or slow the portion of the line

in its borders and there's no overarching process to adjudicate the broader need, projects that would benefit an entire region can fail to move forward.

2. What laws (on permitting specifically, but also planning, siting, interconnection, cost allocation, etc.) should be changed, amended, or improved with regard to permitting?

Several areas of law and regulation could be revisited to improve the permitting landscape for transmission. One major issue is the current limitation of federal backstop siting authority for interstate transmission lines. Under Section 216 of the Federal Power Act, FERC was given some authority to step in if states failed to act on certain "national interest" transmission projects. Congress may want to examine how "national interest" transmission corridors or projects are defined. Currently, the designation process (through the Department of Energy) is narrow and infrequent, focusing on specific corridors. Many worthwhile projects – for example, lines that enable largescale renewable integration or improve interregional transfer capacity for reliability – might not fall under the existing corridor designations. Expanding the criteria or definitions in law to explicitly include these types of projects as being in the national interest could help prioritize them for action and support.

Another area for potential improvement is the creation of mechanisms to facilitate interregional projects. Today, there is no entity with the mandate to plan and execute interregional transmission on a truly national scale. One idea that has been discussed is establishing a federal "Transmission Infrastructure Bank" or fund that could provide financing and, critically, provide streamlined federal permitting for the projects it supports. In other words, if a project is recognized and backed by such a federal program, it might automatically receive coordinated federal review (perhaps consolidating what would otherwise be separate approvals from agencies like DOE, the Corps of Engineers, Fish & Wildlife Service, etc.). Tying federal financial incentives to expedited permitting could encourage developers to pursue ambitious lines that cross multiple jurisdictions. Even without a new institution, providing funding for interregional projects (through grants or loan guarantees) combined with a one-stop federal permitting process would address both the economic and procedural challenges these lines face.

Regarding planning, one improvement could be to better integrate transmission planning with generation resource planning and policy incentives. Federal law could encourage or require that when there are major federal incentives for new generation (such as tax credits for renewables, storage, or emerging technologies), there is parallel consideration of the transmission needed to accommodate that generation. This might be achieved by expanding FERC's mandate to consider generator interconnection upgrades as part of regional transmission plans rather than as separate, ad-hoc processes. Essentially, aligning the timing and scope of generation and transmission planning through policy would help ensure the grid is ready to deliver the energy from new resources to consumers.

Another key impediment is the lack of accountability in interregional transmission planning. As mentioned earlier, FERC's Order 1000 requires coordination, but if two regions can't agree on a project, there's no mechanism to compel action. Congress could consider empowering a

federal-state collaborative body or task FERC with more authority to press for interregional solutions. For instance, a reform could stipulate that if identified interregional needs persist unmet, a joint federal-state commission could step in to craft a solution, or FERC could be given authority to allocate costs for an interregional line that studies show to be highly beneficial (even if the regions individually did not include it in their plans). Adding a measure of accountability or consequence when interregional planning yields no results would incentivize regions to find common ground.

On interconnection, FERC is already moving forward with rule changes to address queue backlogs, and SPP is implementing new processes to expedite priority projects. Also, Congress could examine possible legal barriers to region-wide funding of network upgrades for high-priority interconnection projects (for example, whether to socialize the cost of network reinforcements needed for a large cluster of new generators that provide public benefits). Ensuring that cost allocation principles can be applied flexibly for interconnection-related upgrades might help certain critical generation projects move ahead faster when they support reliability or policy goals.

Cost allocation in general is often "the elephant in the room." Currently, each RTO and interregional pairing develops its own cost allocation rules, which can lead to disputes and delays, especially for projects spanning multiple jurisdictions. While FERC does have significant authority in this area now, a consistent framework across the country for cost-sharing would reduce one major source of friction in getting projects approved.

We also see opportunities in leveraging existing infrastructure corridors to streamline permitting. Laws or policies that promote the use of existing federal land rights-of-way (for instance, along highways, railroads, or pipelines) for new transmission could simplify the process. Steps like this one would make it faster to build along established pathways where impacts are known and manageable.

3. What are your specific challenges when it comes to planning and cost allocating high-voltage transmission lines?

When planning high-voltage transmission lines, one major challenge we face is forecasting the future accurately enough to justify such large projects. Extra-high-voltage lines (300 kV and above) are significant investments meant to last for decades, so planning them requires assumptions about long-term generation development, load growth, and policy changes. If those assumptions are contentious among stakeholders, it's challenging to get agreement on the plan. For instance, if we predict a large amount of solar will be built in a certain area and propose a large 500 kV line out of that area, some stakeholders might question that prediction and oppose the line as premature. We try to mitigate such concerns with robust scenario analysis and by presenting multiple what-if cases, but uncertainty remains a hurdle.

Another specific challenge is that the benefits of a high-voltage line are widespread, which makes determining beneficiaries – and thus assigning costs – difficult. SPP has an internal

Highway/Byway cost allocation method, which, as mentioned, socializes most of the cost of 300+ kV lines across the whole region on the principle that such lines provide regional benefits. While this approach has generally worked within SPP, we still encounter debates at the margins. One challenge is coordinating cost allocation at seams with other regions. If SPP and a neighboring region both stand to gain from a new interregional line but we cannot agree on how to share the costs, one region could end up bearing the full cost (which its stakeholders may resist). Or, the project is downsized or shelved to avoid cross-border cost issues, which could lead to potentially missing out on economies of scale and broader benefits.

Even within SPP, despite our cost allocation framework, there can be tension between those who build transmission and those who primarily pay for it. Some of our member companies are primarily transmission owners/builders, while others are mainly transmission customers. The ones who build get to recover their costs from everyone, but sometimes entities that aren't building feel they have less control over the planning yet still must pay – this dynamic can cause friction. We manage it through our stakeholder governance process (which gives all members a vote in planning decisions), but differences in perspective can arise over what projects are truly needed and who should bear the costs.

There is also the interplay with local transmission planning to consider. A high-voltage "highway" line might eliminate the need for some lower-voltage upgrades in a local area, which is beneficial overall, but local utilities want assurance that the major line will indeed address their reliability issues. We must carefully coordinate the timing of the big regional line with local needs. If the larger project will take many years to build, we might have to implement interim solutions such as smaller upgrades or operational fixes) to maintain reliability in the short term. Deciding who pays for those interim measures when a bigger fix is on the horizon can complicate cost allocation further. .

Finally, a very practical challenge is that high-voltage lines are extremely expensive and can bump up against rate impact concerns. Even if the benefit/cost analysis is very favorable region-wide, a single $500 million line will increase transmission rates for everyone. We plan carefully to phase in costs or group projects to optimize construction schedules. If multiple large lines are identified at once, we often need to sequence them over time to avoid an unacceptable one-time rate spike. This sequencing can, however, prompt debate – some would prefer their area's needed project be built last, so others' projects go first and use up the initial rate capacity. This tendency can add another layer of discussion as we prioritize projects, because stakeholders naturally want to minimize their short-term rate impact.

California ISO

California Independent System Operator Corporation

Responses to Questions for the Record of Elliot Mainzer,

President and Chief Executive Officer,

the California Independent System Operator (CAISO)

The House Committee on Energy and Commerce

Subcommittee on Energy, Hearing on March 25, 2025

"Keeping the Lights On: Examining the State of Regional Grid Reliability"

The Honorable Robert E. Latta

1. As stated in President Trump's Executive Order "Removing Barriers to American Leadership in Artificial Intelligence" (AI EO) on January 23, 2025 "It is the policy of the United States to sustain and enhance America's global AI dominance in order to promote human flourishing, economic competitiveness, and national security." President Trump has made it clear that he wants the US to be the global leader in AI and unleash American energy. How does CAISO plan to ensure sufficient supply of energy to meet the needs of data centers in a timely manner?

Response: *As the home of Silicon Valley, the CAISO is working diligently to serve emerging large electric loads within our footprint, including major enhancements to the transmission system in Silicon Valley. The CAISO implements its coordinated forward planning process with state energy agencies. In 2022, the CAISO, the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) entered into a memorandum of understanding (MOU) to improve coordination and to enhance resource and transmission planning to achieve state reliability and policy needs. The CAISO manages the transmission planning and generator interconnection processes, which carefully account for the inputs provided by the CEC's demand forecast, the CPUC's integrated resource planning, and additional inputs from non-CPUC jurisdictional local regulatory authorities. All of these processes have a minimum 10 to 15-year horizon, with the CAISO also providing transmission assessments 20 years into the future.*

Based on this coordination and the work of utilities and developers, new supply resources are coming online at a rapid pace. Since 2020 about 25 GW of new generation capacity has been added to the CAISO grid, including approximately 7 GW last year. This new capacity includes over 12 GW of battery storage. To help maintain a robust pace of new resource development, the CAISO recently implemented major reforms to its interconnection process to support resource development consistent with state and local resource planning and CAISO transmission planning. The CAISO's implementation of its new interconnection reforms has shown a material reduction in projects clogging the CAISO interconnection study process.

The CAISO recognizes that our work continues in order to maintain the pace of new resource development to meet growing electric demands, including growing data center demands. We continue to work with the CPUC CEC, and all stakeholders, to enhance planning processes further, including coordinating with the CEC year-round as it updates demand forecasts to incorporate new information on data center and other large load growth, and with the CPUC as it enhances its resource procurement framework.

2. Accurate and transparent electricity load forecasting is a linchpin of modern economic development. States rely on these forecasts to plan new industrial parks, data centers, and manufacturing hubs, while utilities use them to schedule grid expansions and major infrastructure investments. Despite the vital role of load forecasts in spurring economic growth, practices vary widely among states, utilities and RTO/ISOs, often leading to inconsistent data, misaligned investment signals, and unnecessary risk for both utilities, and both large and residential customers. Recent inconsistencies underscore how a patchwork of forecasting methodologies can exacerbate speculation in large load interconnection requests, inflate demand projections, and drive-up costs. These issues cross both state and federal jurisdictions and regional differences.

a. What steps is CAISO taking to ensure its load forecasting is transparent, predictable and correctly anticipating future capacity and infrastructure needs to power AI infrastructure?

Response: *The CAISO relies on the CEC's long-term demand forecast as an input into its transmission planning process. The CAISO works closely with the CEC as it develops updates to its demand forecast each year. The CEC develops its annual forecast through a public process with opportunities for stakeholder engagement and comment. The CEC also works directly with load-serving entities, industry experts, and utilities who manage load interconnection requests to share information and understand the magnitude and nature of large load growth, including increasing requests to connect data centers.*

b. What, if any, barriers exist to increased transparency on potential load growth from AI?

Response: *The CEC continues to work with utilities, industry, and experts in the field to gain additional insights into load growth from AI, data center load profiles, and utility load applications to continue to enhance the CEC's data center forecasts. This process will help identify barriers to understand potential load growth from AI and how to gain greater certainty about where and when that load growth will occur.*

3. How can RTOs accelerate transmission expansion to support load growth without creating excessive costs for ratepayers?

Response: *The CAISO is doing all we can to help bend the cost curve for consumers in the right direction. Over the past several years, the pace for bringing new resources online to meet growing demand has accelerated and the CAISO has been working to reduce "friction" on the grid and advance transmission expansion in a number of different ways:*

o Reforming our interconnection process so that it is nimbler, allowing new generating capacity to be onboarded more quickly and efficiently;

o Exploring a wide variety of possible solutions in the CAISO's annual transmission plans before recommending the most cost-effective options possible, including grid-enhancing technologies that can – where applicable – increase capacity for a fraction of the cost of new lines;

o Coordinating closely with our partners in state government, most notably the CPUC and CEC so our distinct roles in planning, building and operating the transmission grid complement one another and do not work at cross purposes, which would cause delays that increase costs.

4. From a siting and permitting perspective, what do you see as the challenges and barriers to constructing sufficient transmission infrastructure needed for reliable, safe, affordable, and timely delivery of power?

a. What role, if any, should Congress and FERC play in siting and permitting for regional or interregional transmission?

Response: *The CAISO is not a siting or permitting entity and is also not a developer. The CAISO defers to these entities with respect to the challenges and barriers to constructing transmission as well as the role that Congress or FERC should lay in siting and permitting regional or interregional transmission.*

As a regional transmission planner, the CAISO does proactively and regularly plans to meet the challenges of tomorrow and welcomes the opportunity to discuss how to build the grid of the future. As an example, the CAISO's most recent annual transmission plan approved transmission to account for resource needs of more than 76,000 MW by 2039. The CAISO's July 2024 20-Year Transmission Outlook provides a macro analysis of California's future transmission network to meet the state's energy goals and highlights the challenges associated with building major pieces of infrastructure. This work also supports our coordination with other planning regions in the West.

5. Regarding planning for transmission, what specific impediments have you identified to current state, regional, and interregional planning for transmission projects?

a. What are examples of impediments you have identified and what is necessary for system planners to overcome these impediments?

Response: *The impediments for transmission planning likely differ between regions. The CAISO encourages a planning framework that accounts for differences among regions, and that emphasizes outcomes over process. At this point, we do not see the need for increased process reforms. Instead, federal authorities should encourage partnership among neighboring balancing authorities and planning regions to maximize benefits to electricity customers. Fostering existing partnerships to deploy infrastructure solutions and balance supply and demand across the western United States is essential to ensure electric reliability and affordability.*

b. What reforms do you recommend to improve state, regional, and interregional planning to overcome these impediments?

Response: *The impediments for transmission planning likely differ between regions. The CAISO encourages a planning framework that accounts for differences among regions, and that emphasizes outcomes over process. At this point, we do not see the need for increased process reforms. Instead, federal authorities should encourage partnership among neighboring balancing authorities and planning regions to maximize benefits to electricity customers. Fostering existing partnerships to deploy infrastructure solutions and balance supply and demand across the western United States is essential to ensure electric reliability and affordability.*

6. In the last Congress and the previous administration, there was a lot of talk about transmission policy reform.

a. How does your organization plan transmission in your region and with other regions? What should Members understand about the nature of transmission planning as it exists today?

Response: *The CAISO has leveraged our engagement with state and local regulatory authorities to ensure proactive, coordinated transmission planning. Our transmission planning process is open to the public and transparent. To develop the plan, we build on prior planning work, identify scenarios to study, rely on state-identified resource portfolios, and examine proposed transmission additions. The 2024-2025 Transmission Plan, which was recently approved by the CAISO's Board of Governors, approved 31 regional (within the ISO footprint) transmission projects, for a total infrastructure investment of an estimated $4.8 billion. Of the 31 projects, 28 were reliability-driven, meaning that they primarily support load growth and evolving grid conditions, ensuring a reliable system.*

The CAISO also regularly engages with neighboring planning regions on interregional projects (projects across multiple planning region footprints), as required under FERC Order No. 1000. However, the interregional planning process required by FERC Order No. 1000 has not yielded any interregional transmission projects in the West. Given this reality, the CAISO has relied on the ability to engage in voluntary agreements and bilateral agreements with other neighboring balancing areas to enable development and develop a cost-allocation framework for new multi-state transmission lines. Further, the CAISO developed a new approach to planning and financing independent transmission development through creation of the subscriber participating transmission owner model, which FERC approved in 2024 and enables new transmission projects to be connected to the CAISO balancing authority area and be placed under the CAISO's operational control. Rather than allocating costs through the transmission access charge, the model allows transmission project developers to receive transmission project funding through the cost of the associated generation.

The CAISO's proactive approach to infrastructure development has enabled the CAISO to onboard and connect 25 GW of generation in the past five years, which has sustained the grid and economic growth during several extended extreme heat and weather events over the past few years.

b. Does a top-down approach, through FERC, serve the interests of utilities and grid operators that are already expending tremendous time and engineering resources on design new transmission?

Response: *Each transmission provider is unique in its approach to transmission planning. The FERC established framework for transmission planning has helped advance the CAISO's efforts. In addition, FERC has recognized the need for regions to deviate from a one-size fits all approach, which has been particularly helpful in certain cases. Congress and FERC should avoid adoption of overly prescriptive requirements that may not advance the objective of deploying new transmission.*

7. What would be your top priority or need from states, FERC or Congress to assist you in meeting new demand —especially if we need even more power than projected? Are you equipped today to meet increased future demand at the pace needed and to maintain affordability and competitive rates?

Response: *The CAISO works hard to prepare to meet increased future demand at the pace necessary to maintain reliability and affordability by approving the necessary infrastructure projects to meet the CAISO's projected demand. The coordination and synchronization of our planning process with state processes to forecast demand and direct resource procurement provides a powerful tool to meet increased future demand while considering affordability. Support for these processes should address current barriers to energy infrastructure development, such as supply chain disruptions, workforce shortages, price uncertainty, access to capital, and permitting process.*

The Honorable Rick Allen

1. Nearly twenty percent of our nation's electricity is generated by 94 nuclear reactors. Constructed forty to fifty years ago, these reactors represent enduring assets that continue to deliver significant value long after the visionary decisions to build them were made. Today's market conditions, however, would likely discourage companies from pursuing such generational investments. As states grapple with rising power demands, they are seeking innovative tools to drive the deployment of next-generation nuclear facilities.

a. How can these potential state actions fit within your markets?

Response: *The CAISO is currently operating Diablo Canyon Power Plant, located in San Luis Obispo County, California, through 2030. Based on current state resource planning, the state has not identified additional nuclear projects in the state. The CAISO's infrastructure planning processes and generator interconnection process are designed to help advance and connect generation consistent with state resource plans. Our energy and ancillary markets provide the ability of all interconnected resources to offer their supply to serve demand and provide mechanisms to operationalize the attributes those resources provide, including the provision of energy, ancillary services, and flexibility. The development of a day-ahead market construct throughout the western United States will help ensure resources located in participating balancing authority areas support efficient and reliable operation of the grid.*

The Honorable Kathy Castor

1. One of our greatest challenges today is getting new sources of electricity on the grid as quickly as possible in this new era of increasing electricity demand. Interconnection processes – while critical to maintaining the reliability of the grid – can also take far too long under the current framework. On March 17, FERC Commissioner David Rosner wrote a letter to each of you detailing new opportunities to streamline the interconnection process. In a recent study by the Midcontinent Independent System Operator (MISO), an automated process was able to nearly replicate in ten days the results of an interconnection study that took nearly two years to conduct.

a. Please describe your experience with interconnection automation technologies to date and the prospects for further deploying them going forward.

Response: *Given the evolution of the CAISO's interconnection processes and the challenges we face in maintaining the pace of new resource interconnections to meet new load requirements, we agree exploring this topic is timely and necessary. We are open to any solutions that can help us achieve and sustain the pace of resource interconnection necessary to meet near-term reliability needs and longer-term policy requirements.*

The tools we have reviewed to date address two discrete components of the interconnection process: (1) managing intake of new interconnection requests to collect and validate necessary data and models, and (2) conducting the necessary power system studies to determine network upgrade requirements. The CAISO's recent interconnection challenges have resulted from unprecedented amounts of capacity submitted to the interconnection queue, which rendered study results meaningless. Therefore, we have focused our deployment of tools on the interconnection request intake process.

The CAISO transitioned to a cluster study process roughly a decade ago, essentially "batch processing" applications with rigid timelines established in tariffs. An unprecedented number of applications eventually required a delay in processing results in our interconnection queue cluster 14 in 2021 and major interconnection reform in 2023 and 2024. During this timeframe, the CAISO has generally sustained study timelines. However, after the cluster 15 interconnection request window in 2023, the number and capacity of interconnection requests in our queue far exceeded the capacity we expect to need over the next 20 years. This surplus has led the CAISO to prioritize management of the number of requests to yield more viable projects at the beginning of the process.

Given our previous experiences, the CAISO is focusing its investment and new applications on the issue of interconnection request intake and management. We are in the process of transitioning from our legacy Resource Interconnection Management System (RIMS) tool to a third-party application to manage the interconnection application and study process as well as the contracting and queue management processes. This new, customized platform, known as the Grid Resource Interconnection Portal (GRIP) allows increased levels of automation between the CAISO, transmission owners, and interconnection customers, and enhanced opportunities for data validation and management. The portal provides a

single application for all interconnection customers and CAISO staff to access and update data on individual projects, significantly reducing email traffic and automating processes. For example, this application can reduce the time required to develop a single Generator Interconnection Agreement from several weeks to a few minutes. Additional enhancements to GRIP will provide increased transparency on project permitting, procurement, and construction information provided by the interconnection customers and participating transmission owners. We understand that the software provider expects to develop artificial intelligence capabilities in the future to streamline data validation and model building capabilities.

Regarding tools to automate and streamline the interconnection study process, the CAISO currently relies on the PowerGEM TARA power flow software tool. We have explored opportunities to more efficiently build models and complete studies; however, our review suggests only modest benefit from the use of new tools for the CAISO at this time. We will continue to explore the potential benefits of advanced software solutions in the interconnection study process, seeking solutions tailored to our greatest challenges.

b. Please describe how FERC and Congress can each support such innovation.

Response: *FERC has demonstrated considerable interest in this topic, with a technical workshop on interconnection and follow-up discussions on the use of advanced software and artificial intelligence with transmission planners. FERC continues to support information sharing related to best practices and opportunities for efficiency. Congress can support funding for projects that seek to adopt these new technologies.*

The Honorable Scott Peters

1. Have you experienced permitting delays that this committee should better understand? What are some key/important examples?

Response: *Infrastructure permitting delays have occurred within the CAISO region as they have in other regions of the country. In recent years, the CPUC and state legislature recognized a need to reform state electric infrastructure permitting processes to support the rapid development of new grid infrastructure and connection of new supply resources to support growing electric demands. As a result, the state of California has advanced legislation in recent years to reform state electric infrastructure permitting processes. These directives, along with several other transmission infrastructure permitting and siting reforms were adopted and implemented by the CPUC earlier this year. The intent of these reforms is to modernize and accelerate how transmission infrastructure is planned, permitted, and built.*

2. What laws (on permitting specifically, but also planning, siting, interconnection, cost allocation, etc.) should be changed/amended/improved with regard to permitting?

Response: *The CAISO is not a siting or permitting entity and is also not a developer. The CAISO defers to these entities with respect to the challenges and barriers to constructing transmission as well as the role that Congress or FERC should lay in siting and permitting regional or interregional transmission.*

3. What are your specific challenges when it comes to planning and cost allocating high voltage transmission lines?

Response: *The CAISO prepares its annual Transmission Plan as part of its core responsibility to identify and plan the development of solutions to meet the future needs of the CAISO-controlled transmission grid. The Plan is prepared through the annual transmission planning process that culminates in a CAISO Board of Governors approval of the Transmission Plan.*

The need for additional generation of electricity over the next 10 years has escalated rapidly in California to meet forecasted demand and implement the state's energy policies. This increased need for resources corresponds to an accelerated pace for new transmission development. To help ensure we have the transmission in place to support new resources and loads reliably and cost-effectively, the ISO's 2024-2025 Transmission Plan builds on the much more strategic and proactive approach initially adopted in the 2022-2023 Transmission Plan and carried forward since to better synchronize power and transmission planning, interconnection queuing and resource procurement. The CAISO's cost allocation rules for transmission have provided a durable approach to allocate the cost of high-voltage lines either to customers in a participating transmission owner or across the CAISO system. In addition, FERC recently approved an alternate model in which subscribers to a new high-voltage transmission line pay for the cost of that line. Two projects, TransWest Express and Sunzia, are seeking to participate under this alternative model to connect out of state resources to the CAISO. Our coordination with adjacent states, utilities, and developers provides a new path to support development across the region. The CAISO strives to find cost allocation solutions that meet the needs of the grid, and the customers served in the region.

Figure 1 reflects recent transmission developments in the Western United States. These transmission projects will support resources identified in the CPUC's resource planning efforts and increase reliability and foster economic development in the West.

Policy attention should address the current barriers to energy infrastructure development, such as supply chain disruptions, workforce shortages, price uncertainty, access to capital, and permitting delays.

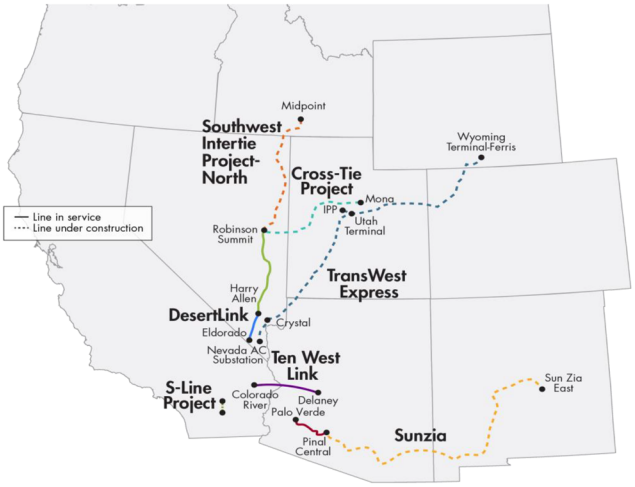


Figure 1. Multi-state transmission projects that deliver west-wide benefits and enhance resilience.

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June 11, 2025

Via FedEx Overnight and Electronic Delivery: Calvin.Huggins1@mail.house.gov

Congress of the United States
House of Representatives
Calvin Huggins
Legislative Clerk
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, DC 20515-6115

RE: May 28, 2025 Request for Responses to Additional Questions for the Record

Dear Mr. Huggins:

Attached below please find my responses to the questions included in Chairman Latta's letter of May 28, 2025. If Members have any additional questions, please do not hesitate to contact me.

Sincerely,

/s/ Pablo Vegas
Pablo Vegas
President and Chief Executive Officer
Electric Reliability Council of Texas, Inc.
(512) 248-6597
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Attachment

Attachment—Responses to Additional Questions for the Record

The Honorable Robert E. Latta (R-OH)

1. **As stated in President Trump's Executive Order "Removing Barriers to American Leadership in Artificial Intelligence" (AI EO) on January 23, 2025 "It is the policy of the United States to sustain and enhance America's global AI dominance in order to promote human flourishing, economic competitiveness, and national security." President Trump has made it clear that he wants the US to be the global leader in AI and unleash American energy. How does ERCOT plan to ensure sufficient supply of energy to meet the needs of data centers in a timely manner?**

   Many data centers have chosen to locate within the Electric Reliability Council of Texas (ERCOT) Region due to Texas's favorable business environment and the beneficial dynamics of relatively short interconnection time and reliable service available in the ERCOT Region. Approximately 6.5 gigawatts (GW) of data center load is currently located in the ERCOT Region and 44.1 GW of data center load is projected to be developed in the ERCOT Region by 2031:

ERCOT Data Center Load (in GW)*			
	Crypto	Non-Crypto	Total
As of January 2025	3.7	2.8	6.5
Projected 2026	6.6	5.2	11.8
Projected 2027	8.9	9.4	18.3
Projected 2028	11.4	16.8	28.2
Projected 2029	12.5	20.8	33.3
Projected 2030	15.1	25	40.1
Projected 2031	17.1	27	44.1
*Projections Based on ERCOT Adjusted Load Forecast			

   Meeting this demand will require significant investment in new generation, a challenge the Texas Legislature has sought to address through the creation of the Texas Energy Fund, which incentivizes the development of dispatchable generation in Texas. Under the longstanding market design in the ERCOT Region of Texas, ERCOT's role in ensuring sufficiency of the generation supply is to provide private generation developers the information they need about current and future generation adequacy to make investment decisions. ERCOT provides semi-annual projections of resource adequacy in its Capacity, Demand, and Reserves (CDR) reports, the latest of which showed significant demands on ERCOT resources beginning in summer 2028.[1] ERCOT believes this information is useful to generation investors in planning new generation for the ERCOT Region. As further described below in response to Rep. Latta's second question, ERCOT has also announced

[1] The most recent CDR Report, revised in May 2025, is available on the Resource Adequacy page of the ERCOT website at: https://www.ercot.com/gridinfo/resource.

additional changes to its forecasting methodologies that will help ensure accurate projections for investors.

ERCOT has several initiatives in place and under development to ensure data centers can be reliably interconnected in a timely manner. In March 2022, ERCOT implemented an interim interconnection process for large loads.[2] ERCOT also established the Large Flexible Load Task Force (now known as the Large Load Working Group[3]) to provide a forum for stakeholder engagement on the development of large load interconnection processes, among other issues. On May 15, 2025, the Public Utility Commission of Texas (PUCT) approved Nodal Protocol Revision Request (NPRR) 1234 and Planning Guide Revision Request (PGRR) 115 to establish a permanent process for the interconnection of large loads in the ERCOT Region.[4] These formalized the definition of "Large Load," established a Large Load Interconnection Study process akin to the interconnection study process used for generation, and adopted modeling and telemetry requirements to better support load forecasting and operational transparency.

Beyond improving the interconnection process for artificial intelligence (AI) data centers and other large loads, there is a greater need to move power from generation to load throughout the ERCOT Region. In April 2025, the PUCT approved a step change from the historical use of 345-kilovolt (kV) transmission voltage in the ERCOT Region by authorizing three transmission import/export paths between West and Central Texas using 765-kV transmission lines for the Permian Basin Reliability Plan.[5] With many data centers choosing to site in West Texas, these larger, more efficient transmission lines will help to ensure that more power is available in that fast-growing area of the ERCOT Region. As part of the annual Regional Transmission Plan (RTP) process in 2024, ERCOT also identified the need for a set of 765-kV transmission lines in East Texas as part of the 765-kV Strategic Transmission Expansion Plan (STEP).[6]

On June 1, 2025, the Texas Legislature passed Senate Bill (SB) 6, which establishes several requirements related to large loads, including AI data centers. Section 2 of SB 6 requires the PUCT to adopt a rule establishing standards for interconnection of large load customers in the ERCOT Region, including mandating disclosure by large load customers of on-site backup generating facilities. ERCOT is required to establish a threshold for certain energy emergency conditions in which it may direct large load customers with backup generating

[2] *See* Market Notice W-A032522-01: https://www.ercot.com/services/comm/mkt_notices/W-A032522-01.

[3] https://www.ercot.com/committees/tac/llwg.

[4] *See* NPRR1234, available on ERCOT's website at: https://www.ercot.com/mktrules/issues/NPRR1234#summary; *see also* PGRR115, available on ERCOT's website at https://www.ercot.com/mktrules/issues/PGRR115.

[5] *Reliability Plan for the Permian Basin Region under PURA § 39.167*, PUCT Project No. 55718, Second Order Approving the Reliability Plan for the Permian Basin Region (Apr. 24, 2025); *see also*, ERCOT Permian Basin Reliability Plan Study and Addendum (Sept. 11, 2024), available on the ERCOT website at: https://www.ercot.com/files/docs/2024/07/25/2024-ERCOT-Permian-Basin-Reliability-Plan-Study-Report-and-Addendum.zip.

[6] More information on the 765-kV STEP is available in ERCOT's January 2025 report available on ERCOT's website at: 2024-regional-transmission-plan-rtp-345-kv-plan-and-texas-765-kv-strategic-transmission-expans.pdf.

facilities to deploy those facilities or curtail their load. SB 6 also specifies that several aspects of the large load interconnection process must be standardized, including establishing a flat fee for transmission screening studies, a method for large load customers to demonstrate site control, and uniform financial commitment requirements for the development of transmission needed to serve large load customers. Finally, SB 6 requires the PUCT to adopt criteria that will govern how ERCOT includes forecasted large loads in its transmission planning and resource adequacy models and reports. Together, these new measures will help to make the large load interconnection process more efficient and will also improve the accuracy and consistency of forecasting for large loads, which will better support investment decisions in transmission and generation development to serve those large loads.

2. **Accurate and transparent electricity load forecasting is a linchpin of modern economic development. States rely on these forecasts to plan new industrial parks, data centers, and manufacturing hubs, while utilities use them to schedule grid expansions and major infrastructure investments. Despite the vital role of load forecasts in spurring economic growth, practices vary widely among states, utilities and RTO/ISOs, often leading to inconsistent data, misaligned investment signals, and unnecessary risk for both utilities, and both large and residential customers. Recent inconsistencies underscore how a patchwork of forecasting methodologies can exacerbate speculation in large load interconnection requests, inflate demand projections, and drive-up costs. These issues cross both state and federal jurisdictions and regional differences.**

    a. **What steps is ERCOT taking to ensure its load forecasting is transparent, predictable and correctly anticipating future capacity and infrastructure needs to power AI infrastructure?**

As noted in response to the prior question, the Texas Legislature recently passed SB 6, which requires the PUCT to adopt a rule establishing criteria governing ERCOT's inclusion of forecasted large loads in transmission planning and resource adequacy models and reports. Upon the PUCT's adoption of that rule, ERCOT anticipates that these criteria will help to ensure standardization of forecast methodologies and thereby further support the transparency, predictability, and accuracy of ERCOT's load forecasts.

In the interim, ERCOT has worked to improve the transparency and accuracy of its load forecasts, including analyzing historical data related to large loads that actually materialized. Specifically, ERCOT evaluated megawatt levels and interconnection timelines at which those loads were ultimately energized and applied the rates of actualization to the utilities' most recent forecasted load data. On April 8, 2025, ERCOT presented this "ERCOT Adjusted Load Forecast" (EALF) to its Board of Directors.[7]

[7] ERCOT's presentation of the ERCOT Adjusted Load Forecast to the ERCOT Board of Directors is available on ERCOT's website at: https://www.ercot.com/files/docs/2025/04/07/8.1-Long-Term-Load-Forecast-Update-2025-2031-and-Methodology-Changes.pdf.

ERCOT primarily uses load forecasts for two purposes: resource adequacy evaluations and transmission planning. Resource adequacy assesses the level of generation available to serve load, while transmission planning assesses the ability to move energy from generation to where it is needed on the grid to serve load. As described in ERCOT's filing to the PUCT on May 1, 2025, ERCOT is applying the EALF for resource adequacy evaluations.[8] However, because developing transmission takes longer than developing generation, ERCOT utilized a different variation of the load forecast adjustment to develop the 2025 RTP: the ERCOT Transmission Planning Adjusted Load Forecast (ETPALF). Unlike the EALF, the ETPALF maintains the projected in-service dates provided by the entity responsible for providing retail delivery service to the load. ERCOT sought and received a good cause exception from the PUCT to deviate from the requirements of the ERCOT Planning Guide in order to apply this accuracy adjustment in the transmission planning context to the 2025 RTP.[9] ERCOT is confident that use of the EALF for resource adequacy and the ETPALF for transmission planning will provide a more accurate forecast for developers and investors in the ERCOT Region to utilize for their development and investment decisions. ERCOT only anticipates these to be necessary as an interim measure until the PUCT adopts criteria to further guide the forecast development process.

b. What, if any, barriers exist to increased transparency on potential load growth from AI?

The first barrier ERCOT often encounters is that large load customers may be unwilling to share competitive or potentially sensitive information, including the type of load planned for a particular interconnection location. Without this information, it is difficult to determine whether a large load is an AI-related data center or another type of large load.

The second is that large load developers will often submit a planned load at multiple locations on the grid—sometimes in different power regions—to maintain optionality if one location is more advantageous or expeditious than another. There is no formal information sharing process among power regions to identify whether a large load submitted the same project in multiple regions. This significantly complicates load forecasting and planning efforts.

3. How can RTOs accelerate transmission expansion to support load growth without creating excessive costs for ratepayers?

Three areas of improvement would help ERCOT support acceleration of transmission development in the ERCOT Region. First, the ability to identify and remove speculative or duplicative loads would be instrumental in improving the accuracy of load forecasts. Public Utility Regulatory Act (PURA) § 37.0561(d), as adopted in Texas's SB 6, will

[8] *Reports of the Electric Reliability Council of Texas,* PUCT Project No. 55999, Update on ERCOT's Adjusted Load Forecast and Request for Good Cause Exception for 2025 Regional Transmission Plan at 5 (May 1, 2025); *see also, Reports of the Electric Reliability Council of Texas,* PUCT Project No. 55999, ERCOT's Revisions to Adjusted Load Forecasts and Amended Draft Proposed Order at 5–6 (June 4, 2025).

[9] *Reports of the Electric Reliability Council of Texas,* PUCT Project No. 55999, Order Granting Good Cause Exception (June 5, 2025).

require large loads to disclose substantially similar requests made within Texas. The development of processes to facilitate information sharing among power regions would help Independent System Operators[10] (ISOs) and Regional Transmission Organizations (RTOs) identify duplicative loads outside their regions and account for them in their regional planning processes.

Second, requiring large loads to demonstrate robust financial commitments to support transmission construction—through the posting of security deposits or otherwise—will support accelerated transmission development and help reduce speculative loads. PURA § 37.0561(h), also adopted in SB 6, will establish uniform financial commitment requirements for the development of transmission infrastructure needed to serve a large load customer.

Third, the standardization of information included in ISO load forecasts will also make transmission development planning more efficient. As previously noted, PURA § 37.0561(m) requires the PUCT to establish criteria for ERCOT's inclusion of forecasted large loads in its transmission planning and resource adequacy models and reports.

4. **From a siting and permitting perspective, what do you see as the challenges and barriers to constructing sufficient transmission infrastructure needed for reliable, safe, affordable, and timely delivery of power?**

As the ISO, ERCOT does not engage in siting and permitting of transmission infrastructure and is not well placed to comment on challenges experienced in regard to these issues. From an ISO planning perspective, the need for transmission buildout would be minimized if large loads self-provide sufficient generation to serve their load, relying on the electric grid only for backup power. ERCOT understands that some large loads in the ERCOT Region currently self-provide generation or are planning to do so.

   a. **What role, if any, should Congress and FERC play in siting and permitting for regional or interregional transmission?**

ERCOT does not see any benefit in Congress or the Federal Energy Regulatory Commission (FERC) playing a role in siting or permitting transmission facilities. In Texas, this is regulated by the PUCT, consistent with the historical practice of transmission siting being a matter of state, rather than federal, jurisdiction.[11] This has allowed Texas to prioritize rapid siting and permitting for transmission projects by establishing a statutory requirement that the PUCT approve or deny an application for a certificate of convenience

[10] While ERCOT is not an RTO or an ISO as those terms are defined in Section 3 of the Federal Power Act (16 U.S.C. § 796), ERCOT performs many of the same functions in its role as the PUCT-certified independent organization for the ERCOT Region under Public Utility Regulatory Act § 39.151. Consequently, references to ERCOT as an ISO in these responses should be understood to be based on ERCOT's role under Texas state law rather than the Federal Power Act definition of an ISO.

[11] Subject to certain exceptions in which both federal and state approvals are required, such as where transmission facilities would cross federally owned land or property under the jurisdiction of the U.S. Army Corps of Engineers.

and necessity (CCN) 180 days after the application is filed.[12] This arrangement also allows flexibility in transmission planning to address current and future needs of the ERCOT System, such as the PUCT's recent approval of the first 765-kV transmission infrastructure in the ERCOT Region.[13]

5. Regarding planning for transmission, what specific impediments have you identified to current state, regional, and interregional planning for transmission projects?

In addition to some of the challenges noted in prior responses, ERCOT has experienced issues obtaining adequate modeling information for large loads, particularly dynamic modeling information for processor-based loads. ERCOT has robust requirements for generators to provide dynamic modeling information, but similar requirements do not currently exist for large loads. ERCOT has observed that large loads often do not ride through when a fault occurs on the system, which introduces a potentially significant reliability risk. Requiring these loads to provide dynamic models—not just steady-state models—would help ERCOT assess the impact of transmission faults on these loads and the areas where they interconnect. A workshop is scheduled for June 13, 2025, to discuss potential solutions to these and other issues with stakeholders.[14] Better modeling information will ultimately assist ERCOT in identifying the necessary transmission improvements to accommodate the integration of large loads.

a. What are examples of impediments you have identified and what is necessary for system planners to overcome these impediments?

As noted in ERCOT's response to Question 2.b. from Rep. Latta, the difficulty in identifying speculative or duplicative loads complicates ERCOT's transmission planning efforts, and steps are being taken to address this issue. Additional measures that could help address these impediments are discussed in ERCOT's response to Question 5.b. from Rep. Latta.

b. What reforms do you recommend to improve state, regional, and interregional planning to overcome these impediments?

Establishing a national or international large load site development list and improving large load development forecasts would give transmission planners better insight into the overall development patterns of large loads, including instances in which a customer is considering multiple sites for a single project. Transmission planners do not currently have insight into how and whether projects will materialize, impacting their ability to plan for those that do ultimately seek to interconnect and energize.

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[12] Public Utility Regulatory Act, Tex. Util. Code § 37.057.

[13] *See Reliability Plan for the Permian Basin Region under PURA § 39.167*, PUCT Project No. 55718, Second Order Approving the Reliability Plan for the Permian Basin Region (Apr. 24, 2025).

[14] More information on the workshop will be posted to ERCOT's website at: https://www.ercot.com/calendar/06132025-Large-Load-Workshop.

Given the size of many of these projects, the difference between having each interconnection request materialize versus just one materialize has a significant impact on the transmission planning necessary to reliably serve anticipated future load. Because of this, reforms that improve the accuracy of forecasting the development of large loads will help overcome impediments to planning reliable transmission. Such reforms could include a site development list or some other mechanism for developers to share additional details with transmission planners about their intentions, such as which interconnection requests are associated with which projects and realistic development timelines for multi-stage projects.

Establishing standards governing how large loads ride through grid disturbances will create consistent behaviors that will also help remove impediments to reliable transmission planning. The North American Electric Reliability Corporation (NERC) recently analyzed a significant loss of data center load in the Eastern Interconnection caused by the response of a data center's equipment to a transmission fault that would not typically have resulted in significant loss of load.[15] This incident illustrates the significant impact on system stability of the failure of large loads to ride through system disturbances. Ensuring predictable behavior from large loads in response to system disturbances will greatly assist in reliable transmission planning by reducing the number of potential scenarios planners need to consider over the course of the planning process.

6. In the last Congress and the previous administration, there was a lot of talk about transmission policy reform.

a. How does your organization plan transmission in your region and with other regions? What should Members understand about the nature of transmission planning as it exists today?

ERCOT plans transmission through the annual development of the RTP and the biennial development of the Long-Term System Assessment (LTSA), each of which is governed by the ERCOT Planning Guide.[16] The RTP was adopted to satisfy NERC Reliability Standards and uses a six-year planning horizon to identify regional and ERCOT-wide reliability and economic transmission needs in the medium term. The RTP identifies specific transmission projects that address identified reliability and economic needs. Transmission Service Providers subsequently submit individual transmission projects to the ERCOT stakeholder-composed Regional Planning Group (RPG) for evaluation and recommendation before bringing certain types of transmission projects to the PUCT for review and approval in the CCN process. The LTSA is a longer-term evaluation that forecasts the needs of the ERCOT System through the next 20 years. As described in ERCOT Planning Guide § 3.1.1.1(1), due to the significant uncertainty of a 20-year planning horizon, the LTSA is not intended to recommend specific system upgrades; rather, it evaluates a wide range of scenarios to identify robust upgrades across a range of

[15] NERC's analysis of this incident is available at https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf.

[16] *See* ERCOT Planning Guide § 3, available at: https://www.ercot.com/mktrules/guides/planning/current.

scenarios or those that might be more economical than upgrades that only consider the six-year horizon evaluated in the RTP process. Because the ERCOT Region is not part of the Eastern or Western Interconnections but is instead an independent interconnection, ERCOT has not historically engaged in formalized transmission planning with other power regions. Transmission planning in the ERCOT Region is solely regulated by the PUCT, which has generally allowed transmission development to occur more quickly than other power regions in the United States.

b. Does a top-down approach, through FERC, serve the interests of utilities and grid operators that are already expending tremendous time and engineering resources on design new transmission?

For the ERCOT Region of Texas, a top-down approach through FERC would not serve the interests of utilities and grid operators in developing new transmission. As noted in ERCOT's response to question 4.a. from Rep. Latta, regulating transmission policy, planning, and development at the state level has served Texas and the ERCOT System well by allowing fast, flexible transmission siting and permitting. Requiring FERC regulation of transmission planning in Texas would likely slow the transmission development process, which would inhibit ERCOT utilities' ability to meet anticipated future system needs.

7. What would be your top priority or need from states, FERC or Congress to assist you in meeting new demand —especially if we need even more power than projected? Are you equipped today to meet increased future demand at the pace needed and to maintain affordability and competitive rates?

As new demand grows, a lack of generation resources will quickly limit the ability to serve it. The best way for states and Congress to assist in meeting new demand while maintaining affordability and competitive rates is to preserve ERCOT's independence from plenary FERC jurisdiction, revise relevant regulations to allow for more rapid development and deployment of new generating resources—including nuclear—and to allow aging thermal generation resources to extend their operational lifespans to the greatest extent possible. While existing thermal generation resources will ultimately need to be retired, keeping them operational for as long as is feasible allows them to serve as a bridge solution to ensure demand can be served reliably while new generation resources are developed.

8. The balance of your resource mix is an important component of reliably operating the grid. No matter how much wind and solar you build, you need baseload, dispatchable energy to support the system when the sun doesn't shine and the wind doesn't blow. In your testimony, you highlighted that less than 5% of queued generation capacity is natural gas; meanwhile, over 94% of the queue is made up of wind, solar, and storage. Can you describe the impact that losing this balance of resource mix would have on the system? Should the federal government create incentives for the development of reliable, dispatchable power?

Losing sufficient dispatchable thermal generation in the balance of the resource mix will result in controlled customer outages during extended periods in which low output from

weather-dependent renewable resources is coupled with high demand, especially during situations involving extreme weather, such as winter storms and certain summer weather patterns. While batteries can help cover short gaps in output from weather-dependent renewable resources, existing batteries fully discharge in a matter of hours at their maximum output, making them a poor substitute for dispatchable thermal generation in serving load during the longer gaps in output from weather-dependent renewable resources, which are likely to occur on a more frequent basis. For context, the development of grid-scale batteries in the ERCOT Region in the past five years—totaling almost 15,000 megawatt hours of energy storage capability—has only resulted in the equivalent energy delivered of a single large gas-fired combined cycle plant running for approximately 12 hours. Consequently, dispatchable thermal resources will remain a vital part of the resource mix for the foreseeable future, and it therefore would be beneficial for the federal government to reconsider regulations that disincentivize or otherwise hinder the operation and upkeep of existing dispatchable thermal generation and the development of new dispatchable thermal generation. The Texas Legislature has introduced a state-level incentive to put dispatchable megawatts on the grid quickly through the Texas Energy Fund, which is administered by the PUCT.

The Honorable Rick Allen (R-GA)

1. **Nearly twenty percent of our nation's electricity is generated by 94 nuclear reactors. Constructed forty to fifty years ago, these reactors represent enduring assets that continue to deliver significant value long after the visionary decisions to build them were made. Today's market conditions, however, would likely discourage companies from pursuing such generational investments. As states grapple with rising power demands, they are seeking innovative tools to drive the deployment of next-generation nuclear facilities.**

    a. **How can these potential state actions fit within your markets?**

Four nuclear units at two generation plants operate in the ERCOT Region today—namely, Comanche Peak in Glen Rose, Texas, and the South Texas Project in Bay City, Texas. ERCOT supports the addition of more nuclear facilities in the ERCOT Region. In August 2023, Texas Governor Greg Abbott directed the PUCT to establish a working group to identify means of eliminating impediments to the development of advanced nuclear reactors in Texas.[17] Led by then-PUCT Commissioner Jimmy Glotfelty, the PUCT established the Texas Advanced Nuclear Reactor Working Group to perform this evaluation. Comprising over 100 stakeholders and nuclear experts, the working group collectively spent over 50,000 hours performing this evaluation and presented its conclusions in the report *Deploying a World-Renowned Advanced Nuclear Industry in Texas: Considerations and Recommendations for Action.*[18] The report identified the

[17] Available on the Governor's website at: https://gov.texas.gov/uploads/files/press/Jackson,_Kathleen_08.16.23.pdf.

[18] *Texas Advanced Nuclear Reactor Working Group,* PUCT Project No. 55421, Deploying a World-Renowned Advanced Nuclear Industry in Texas: Considerations and Recommendations for Action (Nov. 18, 2024), available at: https://gov.texas.gov/uploads/files/press/TANRWG_Advanced_Nuclear_Report_v11.17.24c_.pdf.

benefits of supporting advanced nuclear power in Texas and proposed seven recommendations for legislative action. The 89th Texas Legislature passed House Bill 14 to establish the Texas Advanced Nuclear Energy Office and invest $350 million in grants to eligible nuclear construction projects to jumpstart next-generation nuclear development in Texas. By streamlining the nuclear development process so that development time and costs can be more competitive, these state actions move Texas to the forefront of advanced nuclear development and are anticipated to position the ERCOT Region for growth in this crucial baseload generation technology.

The Honorable Kathy Castor (D-FL)

1. **This past winter, when much of the East Coast experienced record demand, wholesale electric prices soared to approximately $700 in certain areas. In contrast, when ERCOT faced similar cold weather challenges, wholesale prices were dramatically lower than in other regions. Can you explain how the availability and amounts of wind, solar and storage resources in ERCOT helped to limit wholesale prices and helped maintain reliability in your respective regions?**

   Weatherization of all generation resources under standards promulgated by the PUCT[19] helped ensure that all types of resources remained operational and available to serve demand during the cold weather event, which—in addition to effective demand response provided by industrial loads—helped maintain system reliability. The strong wind that accompanied ERCOT's recent periods of cold weather also helped limit wholesale prices, but there is no guarantee that future cold weather events will include strong wind, particularly during cloudy or nighttime conditions when solar production is reduced or nonexistent.

The Honorable Scott Peters (D-CA)

1. **Have you experienced permitting delays that this committee should better understand? What are some key/important examples?**

   While ERCOT does not own generation or transmission facilities and therefore is not generally involved in permitting processes, ERCOT is impacted by the outcomes of these processes. The transmission permitting process in Texas is highly efficient, with a 180-day statutory deadline for the PUCT to grant or deny CCNs for transmission facilities. Consequently, ERCOT has not generally been impacted by permitting delays with respect to transmission facilities. In regard to permitting delays for generation facilities, any streamlining or expediting of permits provided by the Nuclear Regulatory Commission for development of nuclear generation facilities would be beneficial in supporting the development of this key generation type.

[19] *See* 16 Tex. Admin. Code § 25.55.

2. **What laws (on permitting specifically, but also planning, siting, interconnection, cost allocation, etc.) should be changed/amended/improved with regard to permitting?**

   Based on ERCOT's experience with the transmission siting and permitting process overseen by the PUCT, state-level permitting has proven to be a highly effective way to develop and construct transmission facilities. Consequently, any permitting-related changes at the federal level should focus on maintaining and enhancing state autonomy in the permitting arena. However, ERCOT has occasionally encountered scenarios in which relief in the form of an order issued under section 202(c) of the Federal Power Act[20] was necessary to ensure limitations contained in emissions permits did not jeopardize reliability during periods of anticipated high demand or severe weather.[21] Consequently, the permitting process and regime for generation resources should be reformed to maximize the operational flexibility of dispatchable thermal resources, which are (and will remain) crucial to ensuring system reliability.

3. **What are your specific challenges when it comes to planning and cost allocating high voltage transmission lines?**

   High voltage transmission lines, such as the 765-kV voltage level approved in May 2025 by the PUCT for use as export/import paths between West and Central Texas in the Permian Basin Reliability Plan[22] and anticipated to be used in Central and East Texas under the 765-kV STEP plan,[23] are expected to complement the existing 345-kV transmission network to act as backbone grid lines that more efficiently transfer higher amounts of power between areas of the ERCOT Region with less right of way required and lower amounts of line losses. Higher-voltage transmission lines should be evaluated in planning processes based on their ability to move power regionally and on the increased resilience they offer.

   Cost allocation of transmission investments in the ERCOT Region is established by statute in PURA § 35.004(d)–(d-3) and is regulated by the PUCT. Cost allocation of transmission in the ERCOT Region does not vary based on voltage level, with the exception of allowances for transmission-level generation interconnection costs.

[20] 16 U.S.C. § 824a(c).

[21] *See, e.g.*, https://www.ercot.com/services/comm/mkt_notices/M-C090723-01.

[22] *See Reliability Plan for the Permian Basin Region under PURA § 39.167*, PUCT Project No. 55718, Second Order Approving the Reliability Plan for the Permian Basin Region (Apr. 24, 2025).

[23] More information on the 765-kV STEP is available in ERCOT's January 2025 report available on ERCOT's website at: 2024-regional-transmission-plan-rtp-345-kv-plan-and-texas-765-kv-strategic-transmission-expans.pdf.