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
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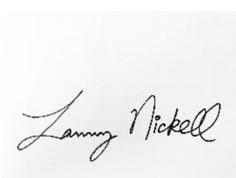
Dear Chairman Latta:

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,



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<u>The Honorable Robert E. Latta (R-OH)</u>

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.

<u>The Honorable Kathy Castor (D-FL)</u>

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.