Testimony of Tom Falcone
President, Large Public Power Council
Before the Subcommittee on Energy

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

Hearing: *AI and the Grid: Meeting Growing Power Demand While Protecting Ratepayers*

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Executive Summary

The Large Public Power Council represents 29 of the nation's largest state- and locally-owned, not-for-profit public power systems. LPPC members provide reliable and affordable electricity at cost to more than 30 million Americans across 23 states and territories, including districts represented by Members of this Committee, with direct accountability to the people we serve.

The issues before the Subcommittee are not theoretical for public power. LPPC members currently power more than 18 percent of the nation's AI and data center load and account for approximately 36 percent of expected new data center interconnections over the next five years. Over the next decade, LPPC members expect to invest roughly $166 billion in electric infrastructure and build approximately 59 gigawatts of new generation to meet rising demand.

LPPC's central message is straightforward: the United States should build the infrastructure needed to support AI leadership and economic growth, while ensuring that existing customers do not subsidize large or speculative load requests.

Federal policy should promote credible load forecasts, cost-causation-based rates, and practical customer commitments. Large-load customers should pay the costs of the infrastructure and services needed to serve them. Congress should support best practices and information sharing while preserving state and local discretion over resource adequacy and retail ratemaking. Treasury and the IRS should clarify private business use regulations so public power utilities can secure prudent long-term large-load customer commitments without jeopardizing tax-exempt financing. Transmission policy should require tangible net customer benefits, cost allocation based on benefits and cost causation, meaningful input from affected communities, preservation of public power's Section 201(f) Federal Power Act protections, region-level consent for interregional cost allocation, and project-specific review before mandating advanced technologies.

Opening Statement

Chairman Latta, Ranking Member Castor, Chairman Guthrie, Ranking Member Pallone, and Members of the Subcommittee, thank you for inviting me to testify.

My name is Tom Falcone, and I am President of the Large Public Power Council. I previously spent a decade at the Long Island Power Authority, a public power utility serving 1.2 million customers, including as Chief Executive Officer and Chief Financial Officer, and earlier worked as an investment banker advising utilities.

LPPC represents 29 of the nation's largest state- and locally-owned, not-for-profit public power systems. Our members provide reliable, affordable electricity at cost to more than 30 million Americans across 23 states and territories, including districts represented by Members of this Committee. LPPC members own approximately 80 gigawatts of generation, and operate more than 50,000 circuit-miles of high-voltage transmission. We are directly accountable to the people we serve.

The issues before the Subcommittee are not theoretical for public power. LPPC members currently power more than 18 percent of the nation's AI and data center load and account for approximately 36 percent of expected new data center interconnections over the next five years. Over the next decade, LPPC members expect to invest roughly $166 billion in electric infrastructure and build approximately 59 gigawatts of new generation to meet rising demand.

The policy challenge is straightforward: the United States should build the infrastructure needed to support AI leadership and economic growth, while ensuring that existing customers do not subsidize large or speculative load requests.

That requires three practical considerations.

First, load forecasts must be credible. Load forecasting is the beginning of the planning process. It affects generation planning, transmission planning, resource adequacy, market signals, customer rates, and reliability. But forecasts are inherently uncertain when a few very large customers drive the projected growth. Utilities and regulators need to distinguish committed load from probable or speculative load, and customer financial commitments are the best evidence that a request is real.

Second, rates and contracts must follow cost causation. Existing customers should not provide a free option to large customers that request service, cause utilities to build infrastructure, and then fail to use the capacity they requested. No developer would build a large skyscraper without an anchor tenant financially committed to use the space. The same principle should apply when a customer request triggers major electric grid investments, especially when those grid investments may last 60 to 100 years, while the customer's own business and technology cycle is closer to 10 years. Large-load tariffs and contracts can protect existing customers through minimum demand obligations, deposits, collateral, exit fees, take-or-pay commitments, customer contributions, and other tools. Those tools are not barriers to growth. They are safeguards that allow growth to proceed without shifting costs to families, small businesses, and other existing customers.

Third, federal policy should support best practices while preserving state and local discretion. PURPA has historically been used to require state commissions and utilities to consider federal standards without requiring adoption. If Congress uses that framework here, it should maintain the ability of state commissions and public power governing boards to apply appropriate forecasting and ratepayer-protection practices through existing public processes, without creating duplicative proceedings or conflicting standards.

There is also a related public power-specific federal regulatory issue that deserves attention: Treasury's private business use rules for tax-exempt bonds. Public power utilities need long-term commitments from large retail customers to protect existing customers and finance infrastructure. But current tax rules can make those prudent commitments difficult when tax-exempt bond-financed facilities are involved. LPPC is working with Treasury on a narrow regulatory solution, and we would welcome support for that effort.

Finally, transmission policy should be disciplined. Planning should begin with an accurate load forecast, evaluate available resources, and then compare the best ways to meet any deficiency, whether through generation, transmission, storage, demand response, reconductoring, grid-enhancing technologies, or other tools. Transmission projects should deliver tangible net benefits to the customers who fund them, costs should follow benefits and cost causation, affected states and communities should have meaningful input, and public power's Federal Power Act protections should be preserved. For interregional projects, each affected region should consent before its customers are assigned costs. Advanced technologies should be encouraged where useful, but not mandated without project-specific review.

LPPC's message is practical. We should serve new large loads and build the infrastructure the country needs. But we should do it in a way that protects existing customers, respects state and local authority over retail rates, and gives utilities the tools to distinguish real demand from speculative requests.

Thank you. I look forward to your questions.

Written Testimony

I. Introduction

Chairman Latta, Ranking Member Castor, Chairman Guthrie, Ranking Member Pallone, and Members of the Subcommittee, thank you for the opportunity to testify on behalf of the **Large Public Power Council**.

My name is **Tom Falcone**, and I serve as President of LPPC. I previously spent a decade at the Long Island Power Authority, a public power utility serving 1.2 million customers, including as Chief Executive Officer and Chief Financial Officer, and earlier worked as an investment banker advising utilities. LPPC represents 29 large public power utilities across 23 states and territories, including districts represented by Members of this Committee. LPPC members are state- and locally-owned, not-for-profit utilities that provide reliable, affordable electricity to the communities we serve. We operate for customers, not shareholders, through local governing boards accountable to the public.

LPPC members own and operate significant generation, transmission, and distribution infrastructure. We serve more than 30 million Americans, own approximately 80 gigawatts of generation, and operate more than 50,000 circuit-miles of high-voltage transmission. We also deliver strong customer outcomes: LPPC members operate some of the most reliable systems in the country, with one-third fewer service interruptions than the national average, and offer residential rates approximately 19 percent below the national average. LPPC members also score on average within the top 25 percent for customer satisfaction in J.D. Power's Electric Utility Customer Satisfaction Study.[1] We are central to meeting the nation's emerging demand from AI, data centers, advanced manufacturing, and other large-load growth.

[1] Large Public Power Council, *About LPPC* one-page fact sheet, available at link.

The issues before the Subcommittee are not theoretical for public power. LPPC members already power 3.8 gigawatts, or approximately 18 percent, of the nation's AI and data center load. Over the next five years, LPPC members are expected to account for 14.2 gigawatts, or approximately 36 percent, of incremental AI and data center load additions. Our members also serve approximately 1.8 gigawatts of advanced manufacturing and industrial large-load customers, projected to grow to approximately 3.4 gigawatts over the next five years.[2]

The Subcommittee's hearing asks the right question: how can the country meet growing power demand while protecting electric customers?

LPPC's answer is direct: the United States should build the generation, transmission, and grid infrastructure needed to support economic growth and AI leadership, but the customers driving new costs and risks should pay the costs of the infrastructure and services needed to serve them. Existing families, small businesses, and local employers should not subsidize large or speculative load requests.

The seven bills and discussion drafts before the Subcommittee today address important, related parts of that challenge: load forecasting, ratepayer protection, AI and high-performance computing, advanced transmission technology, and transmission cost allocation.

II. Public Power's Role in Serving Large Load Growth

Public power utilities have always been builders. They finance, own, and operate long-lived infrastructure on behalf of their communities. That includes power plants, transmission lines, distribution systems, and customer-service platforms.

[2] Large Public Power Council, *Private Use Fact Sheet*, available at link.

Over the next decade, LPPC members expect to invest roughly $166 billion in electric infrastructure and build approximately 59 gigawatts of new generation to meet rising demand from data centers, advanced manufacturing, and electrification. That projected investment represents approximately a 71 percent increase in capital expenditures compared with the prior decade and approximately a 74 percent increase in generation capacity.[3] The planned buildout spans natural gas, nuclear, pumped hydro, storage, wind, and solar.

The scale and concentration of today's load growth creates new planning challenges. Historically, if a utility needed more capacity, it could plan for broad community growth over many years, build at a scale that lowered costs for all customers, and reasonably expect the system to grow into that investment over time. That model becomes harder when growth is concentrated in a small number of very large customers whose future demand is uncertain, each with a load measured in hundreds of megawatts or more. In some cases, a single new customer request can equal a significant share of a utility's existing system peak.

A utility often needs to make major investments years before serving a new large customer, and many of those assets have useful lives measured in decades. If the customer does not materialize, ramps more slowly than projected, reduces its requested demand, or leaves the system, the cost falls on existing customers. This mismatch in investment horizons is central to the risk: electric grid investments are often planned, financed, and operated over 60 to 100 years, while the large customers' own business and technology cycle is closer to 10 years. That difference does not mean utilities should not serve large-load customers. It means customer commitments must be durable enough to match the infrastructure risk their requests create.

For public power, that risk is especially consequential. Public power utilities are not-for-profit and serve customers at cost. If a large new customer causes a utility to invest in infrastructure

[3] Large Public Power Council, *About LPPC* one-page fact sheet, available at link.

and then does not use the capacity it requested, the stranded cost risk ultimately belongs to the community unless appropriate customer commitments are in place.

That is the practical context for the Subcommittee's work on load forecasting and ratepayer protection: utilities need credible forecasts before they build, and existing customers need protections if projected large loads do not materialize.

III. Load Forecasting and Ratepayer Protection Are Interrelated

Three bills before the Subcommittee address closely related ratepayer-protection issues. The **Load Forecasting Enhancement Act** focuses on improving the quality, transparency, and usefulness of electric load forecasts, including whether large-load customers have made financial commitments. The **Ratepayer Protection Act** focuses on ensuring that large-load customers pay the costs of the generation, transmission, and distribution infrastructure needed to serve them. **H.R. 6529, the Protecting Families from AI Data Center Energy Costs Act**, would direct the Federal Energy Regulatory Commission (FERC) to convene stakeholders and identify strategies and rate structures to protect residential and small commercial customers from costs associated with large loads.

These bills address the same core challenge from different directions. Utilities need credible forecasts before they build, and existing customers need protections if projected load does not materialize. Financial commitments connect the two issues: they make load forecasts more reliable and help ensure that the customers driving new costs bear the costs and risks they impose.

Every major planning decision begins with a forecast. Load forecasts affect resource adequacy, generation investment, transmission planning, interconnection studies, organized market

signals, capital budgeting, and retail rates. When a small number of very large customers drive projected growth, forecast error can lead to overbuilding, underbuilding, distorted market signals, and unnecessary cost shifts. The challenge is determining which new service requests are real enough to plan and invest around.

Data center and AI customers often face real uncertainty about their own long-term electricity needs. Their demand depends on the growth of their business, the location of their customers, AI workloads, chip efficiency, cooling systems, and the pace of technological change. Recent rapid efficiency improvements in AI inference are welcome, but they also reinforce the central point: long-term AI-related demand is difficult to forecast.[4]

For that reason, utilities and regulators need to distinguish between three categories of load:

1. **Committed load** backed by executed contracts, deposits, collateral, take-or-pay obligations, or other binding financial commitments by the requesting large-load customer;
2. **Probable load** supported by concrete development evidence, such as site control, permitting milestones, construction timelines, or customer-specific development milestones, but not yet backed by binding commitments to fund utility infrastructure; and
3. **Speculative load** reflected in early-stage inquiries, placeholder requests, nonbinding expressions of interest, or multiple competing large-load customer requests across jurisdictions.

[4] Amin Vahdat and Jeff Dean, "How much energy does Google's AI use? We did the math," *Google Cloud Blog*, Aug. 21, 2025. Google reported that, over a recent 12-month period, the energy footprint of the median Gemini Apps text prompt dropped 33-fold while response quality improved. Google compared May 2025 results to a May 2024 baseline and noted that the data and claims had not been verified by an independent third party.

A load forecast that treats all three categories the same can overstate demand, distort market signals, and cause overbuilding. A forecast that ignores large-load requests can understate demand and threaten reliability.

That is why financial commitments matter. A customer's willingness to make a binding commitment is often the best indicator that the request reflects real demand. It also aligns the customer's incentives with the utility's investment decisions. If a customer wants the utility to reserve capacity, build infrastructure, or procure supply, the customer should bear the cost and risk of that reservation. That is especially important when the grid investment may last far longer than the customer's own planning horizon.

The same principle applies to ratepayer protection. Existing customers should not provide a free option to large new customers that request service, cause utilities to build infrastructure, and then fail to use the capacity they requested. No developer would build a skyscraper without an anchor tenant that is financially committed to use the space. The same principle should apply when a customer request triggers major electric grid investments. The customer that causes the cost should pay the cost.

In the large-load context, cost causation principles should apply to the cost of generation, transmission, distribution, interconnection facilities, network upgrades, planning reserves, ancillary services, and other system impacts.

Large-load tariffs and contracts can implement that principle through a range of tools, including:

- Minimum contract terms;
- Separate rate classes where appropriate;
- Minimum billing demand or take-or-pay obligations;
- Exit fees and termination charges;

- Deposits, collateral, or parent guarantees;
- Customer contributions for dedicated facilities;
- Cost responsibility for upstream transmission or distribution upgrades;
- Milestone requirements before load is counted in planning studies;
- Load ramp schedules;
- Capacity release or reassignment provisions; and
- Interruptible or flexible-service provisions where feasible.

These tools are not punitive. They allow utilities to serve large new customers while protecting existing customers from cost shifts and aligning customer commitments with the infrastructure built to serve them.

LPPC supports the development of best practices for both load forecasting and large-load ratepayer protection. Better forecasting can help utilities, regulators, and markets plan more accurately. Cost-causation-based rate structures, financial assurances, and customer contributions can make those forecasts more credible and protect customers if forecasts prove wrong.

At the same time, Congress should be careful not to change federal-state roles in resource adequacy and retail ratemaking unnecessarily. States, public power governing boards, and utilities that face significant large-load growth are already acting through large-load tariffs, special contracts, minimum billing obligations, deposits, exit fees, customer contributions, and other tools.[5] Load growth is not evenly distributed across the country, and one national rate design or load-forecasting methodology will not fit every system.

[5] Smart Electric Power Alliance and NC Clean Energy Technology Center, *Database of Emerging Large-Load Tariffs (DELTa)*; Rusty Haynes and Justin Lindemann, "U.S. Data Center Gold Rush Drives Surge in New Utility Tariffs," Smart Electric Power Alliance, Apr. 20, 2026. SEPA reported that, as of March 31,

Local facts matter. A 100 MW load served from a constrained part of the grid is different from a 500 MW load at a transmission node with available capacity. A flexible load is different from a load that must operate continuously. A public power utility outside an organized market faces different planning and procurement questions than a utility inside one.

The PURPA treatment in the two bills differs. The **Load Forecasting Enhancement Act** exempts public power utilities from the new PURPA "consideration-and-determination" requirement as "nonregulated electric utilities," while the **Ratepayer Protection Act** applies to nonregulated electric utilities. Where PURPA applies, it should preserve the traditional "consider-and-determine" framework, recognize actions already underway, and avoid duplicative proceedings, conflicting standards, or uncertainty about resource adequacy and retail ratemaking authority.

For public power, local authority is central. Public power utilities should be able to consider and apply appropriate forecasting and ratepayer-protection practices through their governing boards and existing public processes. Where action is needed in organized markets, FERC already has authority through its oversight of organized markets to promote appropriate load-forecasting standards and related best practices.

LPPC also supports best-practices and information-sharing approaches. **H.R. 6529** is a useful model: it would convene the right stakeholders and produce recommendations and best practices while preserving state and local authority over retail rates. Public power's practical experience with large-load growth can also help inform FERC, state commissions, and other stakeholders as they develop load-forecasting and ratepayer-protection best practices.

2026, DELTa included 77 approved and proposed tariffs and service rules targeting large-load customers across 60 utilities and 36 states, including 51 approved tariffs or service rules and 26 pending proposals.

IV. Treasury Private Business Use Rules Are a Public Power-Specific Barrier to Ratepayer Protection

A related federal regulatory issue affects public power's ability to implement the ratepayer-protection goals discussed at this hearing: Treasury's private business use rules for tax-exempt bonds.

Like roads, bridges, schools, and water systems, public power infrastructure is long-lived public infrastructure. Public power utilities rely on tax-exempt financing to build that infrastructure at the lowest reasonable cost for their communities. That benefit flows directly to customers and is one of the core tools public power uses to keep rates affordable.

As discussed above, serving very large new loads can require long-term customer commitments. If a public power utility must build generation, transmission, substations, or other infrastructure to serve a large retail customer, the utility may need contract terms, minimum payment obligations, termination charges, collateral, or other commitments that match the cost-recovery risk of the investment. Existing customers should not be left with stranded costs if a large load does not materialize, ramps more slowly than projected, or terminates service early.

Current private business use rules complicate that goal. Long-term retail service arrangements with a large new customer create tax risk if tax-exempt bond-financed facilities are involved, even where the utility is providing customary retail electric service through an integrated public power system and the customer is paying its cost of service. The current three-year safe harbor for such customer contracts is too short for infrastructure that may take six or more years to plan and build, with costs recovered over decades.

Nor can public power avoid the issue simply by limiting financing of new projects to taxable debt. The private business use tests apply system-wide. A single large contract can create risk

for outstanding tax-exempt bonds tied to existing system assets, not just a new facility built after the customer requests service. That can force public power utilities to choose between accepting substantial system-wide financial risk for existing customers or being constrained in serving new customers that request power in the communities we serve.

This is not a request for Congress to address private business use regulations as part of the legislation before the Subcommittee. LPPC raises the issue because it is directly relevant to the ratepayer-protection principles at the center of this hearing, including the customer commitments, financial assurances, and cost-causation tools contemplated by the bills under consideration. It is also one of the most significant federal regulatory impediments public power utilities face in obtaining the long-term customer commitments needed to protect existing customers.

LPPC is seeking a narrow regulatory clarification from Treasury and the Internal Revenue Service. The objective is not to allow tax-exempt bonds to finance private projects. The objective is to clarify that public power utilities can enter into prudent long-term retail contracts with qualified large retail customers, provided the contracts are based on generally applicable or cost-based rates, the customer pays the costs of the service and infrastructure needed to serve it, and bond-financed facilities remain part of the integrated public power system rather than dedicated to the customer's exclusive private use.

We would welcome the Subcommittee's support in encouraging Treasury and the IRS to address this issue through targeted regulatory guidance.

V. AI and High-Performance Computing for Bulk-Power System Operations

The **Affordable Innovation for the Grid Act** raises a focused question: how AI and high-performance computing technologies can enhance the capacity, reliable operation, and operational efficiency of the bulk-power system.

LPPC supports that inquiry. The bill appropriately directs the Department of Energy (DOE), in consultation with FERC and the Electric Reliability Organization, to assess current applications, adoption levels, and technical, regulatory, cybersecurity, and operational limitations.

AI and high-performance computing may help utilities and grid operators improve system visibility, analyze constraints, manage congestion, support probabilistic operations, and evaluate system conditions more efficiently. But the bulk-power system is critical infrastructure. Any expanded use of these tools should be evaluated for reliability, cybersecurity, operational transparency, cost-effectiveness, and practical implementation limits.

Federal policy should encourage innovation, but it should not assume that every technology is ready for every system or every operating function. AI and high-performance computing should be deployed where they are proven, secure, cost-effective, and consistent with reliable system operations.

VI. Transmission Planning, Cost Allocation, and Advanced Grid Technologies

Three bills before the Subcommittee address transmission-related issues. The **Advanced Transmission Technology to Reduce Rates Act** would direct DOE to establish a clearinghouse for advanced transmission technologies and provide request-based technical assistance to utilities, transmission organizations, and state commissions, including assistance with cost-benefit frameworks. **H.R. 6633, the High-Capacity Grid Act**, would establish a best-available transmission conductor standard and create presumptions for and against prudence

and cost recovery. **H.R. 6336, the Fair Allocation of Interstate Rates Act**, addresses cost allocation for interstate transmission projects, particularly where a project is driven by one state's policy choices.

These bills address specific issues, but they sit within a broader transmission-policy question: how to build needed infrastructure while protecting customers from unnecessary costs. LPPC evaluates these proposals against a consistent set of principles. Transmission projects should solve identified needs, provide tangible net customer benefits, assign costs based on net benefits and cost causation, preserve public power's Section 201(f) Federal Power Act protections, and allow project-specific engineering and cost-benefit review.

The starting point should be disciplined planning. Planners should begin with an accurate and credible load forecast. They should then evaluate the resources available to meet that forecast. If there is a deficiency, they should compare the available ways to solve it, including generation, transmission, storage, demand-side resources, reconductoring, grid-enhancing technologies, non-wires alternatives, or some combination of those tools, based on cost, reliability, timing, feasibility, and customer benefits.

Transmission is an important tool, but it should not be assumed to be the answer before the need and alternatives are evaluated. The country has not built large amounts of net generation capacity or transmission over the last 20 years, but that period also had relatively little load growth. With load growth returning, utilities will need more resources. In some cases, the best answer will be new transmission, particularly where it provides access to surplus energy or capacity, diversity benefits, or lower-cost resources. In other cases, transmission may be less useful, particularly where many regions are short of resources at the same time and the real need is additional supply, not simply more transfer capability. In those cases, the better answer

may be new generation located closer to load, storage, demand-side resources, or other local solutions.

LPPC supported **FERC Order No. 1920** because we support disciplined, long-term regional transmission planning when it strengthens planning, protects customers, and preserves public power's statutory protections. Those same guardrails should apply if Congress considers broader transmission legislation, including potential FERC siting authority for appropriate projects.

Project certification should be tied to a long-term regional planning process approved by FERC, not a new overlapping process. Any certified project should be anchored to an appropriate framework for cost allocation and cost recovery, with meaningful consultation for affected states, landowners, and the public. Interregional projects should be selected only with the approval of each participating region. Certification should also be revisited before construction begins if material facts change, including if project costs materially rise, projected customer benefits materially decline, load forecasts materially change, or other key assumptions shift.

LPPC is sympathetic to the concern underlying **H.R. 6336, the Fair Allocation of Interstate Rates Act**. Electric utility customers should not be assigned costs for transmission projects that do not provide them meaningful benefits. LPPC has objected to non-consensual **interregional** cost allocation, and the bill is sensible to the extent it prevents one region or state from being assigned costs for another state's policy-driven project without consent.

The distinction between regional and interregional cost allocation matters. Within an organized market or FERC-approved planning region, cost allocation occurs under established tariffs, planning processes, stakeholder procedures, benefit metrics, and dispute-resolution mechanisms. States, utilities, and customers are accustomed to working within those regional frameworks, and FERC has long permitted regional cost allocation where costs are tied to

benefits and cost causation. Interregional allocation is different. It can require one region's customers to pay for projects shaped by another region's assumptions, policy choices, planning criteria, or resource needs, often without the same shared governance framework.

H.R. 6336 appears to change the default rule for policy-driven projects, including within regional transmission planning processes. The bill would presume that benefits accrue only to consumers in the policy-driving state and would require express consent before costs could be allocated to consumers in another state.

A consent requirement is appropriate for interregional cost allocation, where each affected region should agree before its customers are assigned costs. But Congress should be careful about applying the same approach to regional projects where customers in another state may receive measurable benefits, such as reliability, congestion relief, resource adequacy, resilience, reduced losses, optionality, or access to lower-cost generation. LPPC's preferred approach is to preserve evidence-based regional benefit analysis while ensuring that customers are not involuntarily assigned costs for policy-driven projects that do not provide them net benefits.

LPPC supports the approach in the **Advanced Transmission Technology to Reduce Rates Act**. A DOE clearinghouse, request-based technical assistance, state commission support, cost-benefit analysis, and voluntary wildfire-mitigation best practices can help utilities and regulators evaluate advanced technologies more effectively. Importantly, the bill does not impose a deployment mandate. That is the right approach.

LPPC also supports considering advanced conductors where they solve an identified need and provide net customer benefits. But the **High-Capacity Grid Act** is more challenging because a best-available conductor standard is not universal. The right technology depends on the application and use case, including system need, voltage level, terrain, structure condition,

outage constraints, wildfire risk, constructability, cost, supply chain, warranty terms, long-term maintenance obligations, vendor support, and customer benefits. A conductor with the highest theoretical capacity may not be the best choice for customers if it carries higher supply-chain risk, shorter warranty coverage, limited vendor support, higher lifecycle cost, or operational characteristics that do not fit the project.

The bill's presumptions may distort planning. Presuming that a designated best-available conductor is prudent and just and reasonable could encourage deployment even where the technology is not necessary or cost-effective. Presuming that failure to use that conductor is imprudent could discourage project-specific engineering judgment and legitimate alternatives. LPPC has not seen studies showing that project-level conductor decisions are systematically wrong where an established technology, with adequate supply, is the best fit for the use case. Nor is lack of cost-recovery justification the principal barrier we see where advanced conductors are the best solution for the project.

A better approach would encourage consideration of advanced conductors and allow project sponsors to justify technology choices based on load growth, system need, cost, reliability, constructability, supply chain, and customer benefits, without automatic presumptions for or against cost recovery.

In short, federal policy can help accelerate needed transmission and encourage advanced technologies. But it should do so through disciplined planning, evidence-based cost allocation, project-specific technology review, meaningful consultation with affected states and communities, and preservation of public power's Federal Power Act protections.

VII. Recommendations

LPPC respectfully offers the following recommendations:

1. **Improve load forecasting through best practices.** Load forecasts should distinguish committed, probable, and speculative load, and should treat financial commitments as a central indicator of whether a large-load request is sufficiently certain to plan and invest around.
2. **Protect existing customers through cost causation.** Large-load customers should pay the costs of the infrastructure and services needed to serve them, including the risk that requested capacity is not ultimately used.
3. **Use federal convening and reports to spread best practices.** FERC, DOE, state regulators, public power utilities, ratepayer advocates, and large-load customers can help identify practical approaches to forecasting, rate design, financial commitments, early termination, reduced usage, and flexible-load structures.
4. **Preserve state and public power discretion.** Federal policy should support best practices and information sharing without overriding state commissions or public power governing boards on resource adequacy and retail ratemaking. Where PURPA applies, Congress should preserve the traditional “consider-and-determine” framework, recognize actions already underway, and avoid duplicative proceedings or conflicting standards.
5. **Address the public power tax issue through Treasury regulations.** Treasury and the IRS should clarify private business use rules so public power utilities can enter into prudent long-term retail contracts with large-load customers that protect existing residential and commercial customers without jeopardizing tax-exempt financing.
6. **Evaluate AI and high-performance computing carefully.** Advanced computing tools may improve bulk-power-system operations, but they should be evaluated for reliability, cybersecurity, transparency, cost-effectiveness, and operational feasibility before deployment.

7. **Support non-mandatory advanced transmission technology tools.** DOE clearinghouses, request-based technical assistance, cost-benefit frameworks, funding support, and voluntary wildfire-mitigation best practices can help utilities and regulators evaluate advanced transmission technologies without imposing one-size-fits-all mandates.
8. **Avoid rigid best-available-technology presumptions.** Advanced conductors should be considered where they solve an identified need and provide net customer benefits, but technology choices should be justified project by project rather than governed by automatic presumptions for or against cost recovery.
9. **Apply disciplined transmission planning and cost-allocation principles.** Transmission projects should be tied to long-term regional planning, solve identified needs, provide tangible net customer benefits, preserve public power's Federal Power Act protections, include meaningful consultation with affected states, landowners, and the public, and allow reconsideration before construction if material facts change. Costs should follow evidence-based benefits and cost causation. Regional cost allocation should preserve evidence-based benefit analysis. For interregional projects, each affected region should consent before its customers are assigned costs.

VIII. Conclusion

The United States can meet the energy needs of AI, data centers, advanced manufacturing, and economic growth. Public power is ready to help build that future.

But speed must be matched with discipline. Load forecasts must be credible. Customer commitments must be real. Rates must reflect cost causation. Large-load customers should pay the costs of the infrastructure and services needed to serve them. Federal policy should support

state, local, and public power efforts to protect existing customers from cost shifts, while preserving the discretion needed to adapt those protections to local facts.

The same discipline should apply to transmission and grid technology. Transmission projects should be planned around demonstrated needs, evaluated against reasonable alternatives, and approved only where they provide tangible net benefits to the customers who will fund them. Costs should follow net benefits and cost causation. For interregional projects, each affected region should consent before its customers are assigned costs. Advanced technologies should be encouraged where they are proven, cost-effective, and consistent with reliable system operations, but they should not be mandated without project-specific review.

Finally, federal tax regulations should support, not impede, prudent customer commitments. Treasury can help public power utilities protect existing customers by clarifying private business use rules so utilities can enter into long-term large-load retail contracts.

LPPC appreciates the Subcommittee's focus on strengthening the grid while protecting ratepayers. We look forward to working with Congress, FERC, DOE, Treasury, state regulators, public power boards, regional grid operators, and large-load customers to ensure that new demand supports the communities we serve.

Thank you for the opportunity to testify.

Biographical Statement of Tom Falcone

Tom Falcone is President of the Large Public Power Council, which represents 29 of the nation's largest not-for-profit public power systems. Together, LPPC members provide electricity to more than 30 million customers across 23 states and territories.

Prior to joining LPPC in 2024, Mr. Falcone spent a decade at the Long Island Power Authority serving as Chief Executive Officer and Chief Financial Officer. LIPA is the nation's third-largest public power utility. During his tenure, LIPA increased grid investment by more than 300 percent, reduced outages by 40 percent, achieved top-tier reliability, obtained four credit-rating upgrades, and reduced leverage by 25 percent. LIPA also secured approval for $3.3 billion in transmission investments to integrate 3,000 megawatts of clean energy and launched the nation's first utility-scale offshore wind farm.

Before joining LIPA, Mr. Falcone worked as an investment banker and advisor to public power utilities, investor-owned utilities, and governments, helping raise more than $25 billion for infrastructure investments across the country. He received a Bachelor of Science in Economics from the Wharton School of the University of Pennsylvania.