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Grid Deployment Office
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Re: Comments of the R Street Institute in Response to Request for Information (RFI) - Accelerating Speed to Power

The R Street Institute (RSI) appreciates the Department of Energy's (DOE) RFI regarding stakeholder input on how to best utilize DOE funding programs and authorities to rapidly expand energy generation and transmission grid capacity to meet electric demand growth.[1] RSI particularly supports DOE's emphasis on reliability and affordability.

The power industry is not designed for rapid infrastructure change. Delays are, to some extent, unavoidable, as generation, transmission, and distribution infrastructure take years to develop. This has created an imbalance in response to the unexpected load growth seen in recent years.

Pairing competitive markets for power generation and retail services with sound cost-of-service oversight for transmission and distribution would provide a cost-effective path to correct this imbalance, but current regulatory and market structures cannot support the conditions this approach requires. As a recent RSI briefing for DOE highlighted, the main issues threatening least-cost, reliable service are rooted in government failures: anti-competitive generation and retail laws alongside deeply flawed permitting, siting, interconnection, transmission, and distribution policy.[2] Because transmission policy falls largely under federal jurisdiction, another RSI briefing for DOE outlined federal reforms that lower electricity cost trajectories while expanding capacity.[3]

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[1] "Accelerating Speed to Power/Winning the Artificial Intelligence Race: Federal Action to Rapidly Expand Grid Capacity and Enable Electricity Demand Growth," Request for Information, Department of Energy, Sept. 18, 2025. https://www.energy.gov/sites/default/files/2025-09/55587_Speed_to_Power_FINAL.pdf.
[2] Devin Hartman et al., "Achieving Affordable, Reliable, and Secure Power," Department of Energy briefing by the R Street Institute, Oct. 16, 2025. https://www.rstreet.org/outreach/achieving-affordable-reliable-secure-power-briefing-for-the-doe-nedc.
[3] Devin Hartman et al., "Transmission Cost Drivers and Policy Remedies," Department of Energy briefing by the R Street Institute, Nov. 3, 2025. https://www.rstreet.org/outreach/transmission-cost-drivers-and-policy-remedies.

Although DOE does not have the authority to reform most policy flaws, it does have significant influence as a convener, information provider, funder, and innovation hub. Our comments herein suggest the ways in which DOE influence could be most impactful in this regard. They draw from:

- Past RSI research, including a 12-part bulk reliability reform paper;[4]
- A paper RSI co-authored with the Conservative Coalition for Climate Solutions on energy innovation policy;[5] and
- Extensive stakeholder outreach, such as multiple convenings of national electric consumer groups on transmission reform.

The DOE RFI poses questions within five categories; we have organized our suggestions in the same categories for ease of review.

1. **Large-Scale Generation and Transmission Projects to Enable Load Growth**

Section one of the RFI inquires specifically about proposed projects with respect to DOE funding, technical assistance, and siting and permitting support. As a public policy think tank, RSI refrains from identifying specific projects worthy of DOE support. Instead, we suggest key project selection criteria DOE should strongly consider:

- *Peg DOE spending to prudent investments in early-stage technologies or those with especially long lead times.* Mature technologies face few, if any, constraints to capital access. Public funding of these projects, therefore, tends to constitute an inefficient transfer from taxpayers to developers. Early-stage technologies, however, often struggle to attract capital because of higher natural or regulatory risk factors. Advanced transmission technologies (ATTs), such as grid-enhancing technologies (GETs) or high-performance conductors (HPCs), are particularly important to prioritize, given their early commercial stage and high- and rapid-impact potential. Leveraging cost-containment mechanisms, like reverse auctions, helps minimize the risk of crowding out private-sector funding. Cost-conscious solicitation processes can also help identify projects that ensure taxpayers get the most return per dollar spent. Importantly, projects with especially long lead times may struggle to attract capital at optimal levels (i.e., difference between private capital and social discount rates). Advanced nuclear is one such technology set, and an emphasis on early-stage nuclear would help comply with Executive Order 14302.
- *Prioritize siting and permitting support for projects based on their commercial readiness status, delivery timeline, and market impact*. Permitting and siting obstacles vary greatly between project types, geography, and other parameters. It can therefore be helpful to select projects based on a market test of their siting and permitting sensitivity. This information is provided in investor documents, and DOE can provide a standardized template for applicants to report

[4] Devin Hartman et al., "Twelve Policy Priorities to Secure Bulk Electric Reliability," *R Street Policy Study* No. 322, May 2025. https://www.rstreet.org/wp-content/uploads/2025/05/FINAL-r-street-policy-study-no-322.pdf.
[5] Nick Loris and Philip Rossetti, "Conservative Energy and Environment Priorities for 2025," Conservative Coalition for Climate Solutions and the R Street Institute, February 2025. https://www.c3solutions.org/wp-content/uploads/2025/02/White-Paper-Conservative-Environmental-Priorities-2025.pdf.

permitting and siting burdens in a way that makes comparisons clear. Transmission congestion patterns provide a proxy for the market impact of a project based on its location.

- *Provide technical assistance with the goal of optimizing public procurement, and emphasize more innovative, early-stage technologies that face undue regulatory barriers to entry*. The informational barriers to entry are highest for novel technologies. These include challenges to understanding if and how they integrate into nuanced electricity market design rules (e.g., energy storage), align with frequent regional transmission operation (RTO) rule changes, or qualify as solution sets in interconnection and transmission planning processes (e.g., ATTs). The value of DOE technical assistance may be limited on a project basis and better directed toward project classes or specific regulatory or business processes. DOE technical assistance could lower taxpayer burdens and advance innovation by improving government energy procurement, such as that coordinated through the General Services Administration (GSA). For example, DOE could help inform GSA on innovative, long-term power agreements like becoming an anchor tenant for merchant high voltage direct current transmission projects.

2. High-Priority Geographic Areas for Targeted DOE Investment

The most significant infrastructure needs that follow geographic patterns tend to be areas with the least transmission headroom. Low-cost, rapid-deployment applications include:

- GETs in load pockets or export-constrained areas;
- HPCs along chronically congested paths (e.g., narrowly constrained corridors) with old infrastructure. This would get ahead of suboptimal "wreck and rebuild" projects; and
- ATTs and better seams management solutions, such as intertie optimization, at the highest value interregional interfaces. Leveraging the North American Electric Reliability Corporation's (NERC) Interregional Transfer Capability Study would serve as a good proxy for reliability needs, but it does not capture economic benefits (i.e., congestion or capital-avoidance savings).

Federal investments should anticipate future congestion patterns, which are driven by changes in the generation fleet and load patterns. Given large geographic variances in load-growth readiness, the location of load growth is arguably as or more important than the level of load growth. For example, whether data-center expansion occurs more within existing clusters (i.e., exacerbates load pockets) or in areas with transmission headroom has enormous bearing on grid-infrastructure requirements.

Past may not be prologue. Only in recent years have grid constraints become a central factor in siting criteria, while artificial intelligence workloads—particularly model training that has different latency and compute timing needs—have led data center developers to favor locations with higher and more reliable power capacity than earlier applications required. Energy constraints now appear to be the foremost consideration in many regional site-selection processes, though this trend could be offset by other factors, such as an increase in county-level moratoria on data-center construction.[6] Given these

[6] See, e.g., Mike Carter and Robert Hines, "Choosing an Optimal Site Location," 7x24 Exchange International, 2025. https://www.7x24exchange.org/7x24-news/data-centerschoosing-an-optimal-site-location.

dynamics, RSI stresses the need for DOE to have independent information sources that reflect emerging commercial conditions affecting where data-center and manufacturing load growth will likely occur.

3. Use of DOE Funding, Financing, and Technical Assistance

Generally, DOE technical assistance is most effective when it remedies information deficiencies. DOE funding and financing should deploy taxpayer dollars prudently to address legitimate market failures, such as knowledge spillovers and learning-by-doing. RSI recommends aligning DOE spending with research and development (R&D) spillover benefits and pursuing better program implementation practices. These include outcomes-based improvements to "program performance metrics, constant program reevaluation to determine when to phase-out government investment, stronger linkages to private sector needs and interests, and scrutinizing expenditures in the context of a constrained fiscal environment."[7] R&D programs must also be durable across administrations to strengthen their performance.

DOE Programs

DOE would benefit from strengthening its innovation agenda, investing less in low-risk, mature technology, which typically crowds out private capital, and investing more in riskier, early-stage concepts and technologies, even if failure rates are higher. The Advanced Research Projects Agency-Energy (ARPA-E) is one such model.

To start on this path, DOE should reform the Loan Programs Office (LPO) and return to its roots as an innovation program. This would require building a performance-based risk tolerance. Past RSI work has suggested that LPO reform should:[8]

- Restore conditionality requirements that focus on deploying early-stage, nascent technologies rather than mature ones. The previous administration's use of LPO to subsidize mature technologies traded innovation priorities for political ones.
- Define energy market innovation needs that LPO loan-guarantee recipients should address, similar to how ARPA-E defines objectives for grant recipients.
- Adopt competitive mechanisms for LPO loan guarantees to reduce their politicization. This would lower the risk of new loan guarantees being rescinded by the next administration. DOE should explore the use of reverse auctions for loan determinations.
- Adjust eligibility or selection criteria based on the risk management incentives of loan recipients. Cost-of-service utilities already socialize risk among captive customers, subject to regulatory

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[7] Devin Hartman, "Beyond Preferences: Embracing a Competitive Energy Vision," testimony to the Subcommittee on Energy, U.S. House Committee on Energy and Commerce, March 29, 2017, p. 15. https://docs.house.gov/meetings/IF/IF03/20170329/105798/HHRG-115-IF03-Wstate-HartmanD-20170329.pdf.

[8] Philip Rossetti, "Low-Energy Fridays: Loan guarantees for energy innovation is an interesting idea ruined by politicians," Dec. 6, 2024. https://www.rstreet.org/commentary/low-energy-fridays-loan-guarantees-for-energy-innovation-is-an-interesting-idea-ruined-by-politicians/.

oversight; thus, loans have limited potential to de-risk their projects. Competitive enterprises and their investors internalize risk and are better suited to efficiently use loans.

Recent DOE decisions underscore the need for these reforms. DOE recently withdrew a loan for the Grain Belt Express project—one of the few competitive transmission projects using novel technology and voluntary cost allocation (i.e., market revenues, rather than captive customers)—but approved a loan for a routine and largely risk-free American Electric Power transmission system rebuild. This substitution of liquid private capital formation with public loans is an inefficient use of taxpayer spending that risks crowding out investment in innovative, competitive projects.

With regard to other programs:

- **The Transmission Facilitation Program (TFP)** has proven useful in financing anchor tenant projects and launching public-private partnership opportunities. This may hold additional promise with power marketing authorities in the future. It is worth considering whether to migrate TFP to a risk-based model; if doing so would require statutory change, DOE could highlight this in its next Congressional budget request.
- The prioritization of improving the **Grid Resilience and Innovation Partnerships (GRIP)** depends on whether the program's budget will be significant. It could be merged with another program, but its community-engagement element is a thread to explore deeper, within GRIP or elsewhere. RSI has identified that the foremost barrier to new generation and transmission in many areas is state and local policies, particularly alongside community opposition.[9]
- The **Interconnection Innovation e-Xchange (i2x)** program has a commendable objective: convening stakeholders to identify interconnection barriers, share best practices and lessons learned, and test innovative interconnection solutions. This remains a valuable mission because incremental regional practices have become the de facto laboratories of interconnection reform (e.g., cluster processes). However, i2x has been too fixated on wind and solar. It should be retained, enhanced, and expanded to facilitate technology-neutral generation.

Gaps in Capital Availability

Although capital availability does not appear to be a major barrier to generation or transmission investment in most regions, many utilities lack sufficient balance-sheet capacity to finance all the generation expansion to meet rising load growth.[10] This problem should not be placed on federal taxpayers but rather addressed by states, recognizing that generation is not a natural monopoly and by opening access to competitive generators and allowing consumers to contract freely. The

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[9] Devin Hartman et al., "State Energy Infrastructure Permitting and Siting Series: Introduction and Methodology," July 10, 2024.
https://www.rstreet.org/commentary/state-energy-infrastructure-permitting-and-siting-series-introduction-and-methodology.

[10] Thomas L. Keefe et al., "2026 Power and Utilities Industry Outlook," Deloitte, Oct. 29, 2025.
https://www.deloitte.com/us/en/insights/industry/power-and-utilities/power-and-utilities-industry-outlook.html.

"speed-to-market" responsiveness between competitive generators in restructured states and cost-of-service generators is evident.

Transmission capital is already robust, with monopoly utilities typically recovering costs automatically in a nearly risk-free environment. Such cost-of-service regulation often carries perverse incentives for project selection based on cost and speed-to-market.[11] The capital-access limitations instead accrue to third-party developers or transmission customers who bear costs and risk themselves but are often shut out of the marketplace by incumbent transmission owners. For example, third-party suppliers and customers are often willing to finance grid enhancements like network upgrades to expedite low-cost interconnection, yet utilities seek to block this form of market access. If a lack of utility capital were the norm, utilities in RTOs would likely welcome prospective generators and customers paying for network upgrades upfront.

For transmission and generation, DOE could incentivize more efficient business models and productive state and federal policy reforms by making funding conditional on competitive ownership status (i.e., competitive suppliers and voluntary consumer offtakers). This would naturally direct capital toward geographic areas where markets identify the greatest need. For example, competitive-project eligibility would reward merchant models that do not result in captive customer bases or the purchase of anchor capacity through a network open season in transmission-constrained areas (e.g., northern Virginia, Columbus, etc.) that are not fully subscribed.

Technical Assistance and Interagency Coordination

RSI's reliability paper flagged the lack of coordination between policymaking authorities as a core impediment to generation and transmission development.[12] DOE technical assistance would be highly valuable in improving interagency coordination with the Federal Energy Regulatory Commission (FERC) on speed-to-power initiatives. Memoranda of Understanding are useful tools to routinize interfaces that match interagency competencies and resources. A specific suggestion is for FERC and DOE to co-host a technical conference or workshop on speed to power.[13] Considerations for this action include:

- Integrating DOE technical assistance and lab support into FERC's policymaking processes on key issues like ATT commercial readiness and demonstration experience, best practices in interconnection and load forecasting, opportunities to use HPC in transmission planning processes, and potential for seams management improvements;
- Creating a forum for learning opportunities, which would help motivate bottom-up regional stakeholder process improvements; and

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[11] Hartman et al., "Transmission Cost Drivers and Policy Remedies." https://www.rstreet.org/outreach/transmission-cost-drivers-and-policy-remedies.
[12] Hartman et al., "Twelve Policy Priorities to Secure Bulk Electric Reliability." https://www.rstreet.org/wp-content/uploads/2025/05/FINAL-r-street-policy-study-no-322.pdf.
[13] Hartman et al., "Transmission Cost Drivers and Policy Remedies." https://www.rstreet.org/outreach/transmission-cost-drivers-and-policy-remedies.

- Building a record on which FERC or other parties could act (e.g., data and reporting requests, rulemakings, investigations, complaints).

There is a clear precedent and need for this action. Conferences and workshops are among FERC's most powerful tools to address pressing or novel issues. The ability of the Commission to engage interested parties directly and for those parties to provide relevant and responsive information into a record that can be used to effectuate outcomes is powerful. FERC has routinely used technical conferences and workshops to better understand interested parties' resources, retail ratemaking perspectives, RTO market issues, and bulk reliability concerns. FERC also has experience jointly hosting these fact-finding opportunities, including coordination with both state regulators and NERC.

DOE staff expertise and resources can identify high-impact projects and inform permitting and siting decisions at the state and federal levels. For example, joint efforts by DOE and the Department of the Interior under the previous administration identified categorical exemptions under the National Environmental Policy Act (NEPA).[14] In light of the Supreme Court's *Seven Counties* decision, DOE may wish to assist broader efforts within the administration to determine the new regulatory baseline for NEPA permitting.[15] The Coordinated Interstate Transmission Applications and Permits instrument can streamline federal transmission permits and serve as a conduit for state participation, creating a single process while respecting jurisdictional boundaries.

Although the RFI only prompted federal interagency coordination, RSI asserts that most of the variables in load growth readiness reside under state authority.[16] Identifying and implementing effective state reforms requires specialized expertise in electricity as well as permitting and siting—skills that exceed the capacity of many state agencies. Therefore, DOE should aim to maximize state interfaces, either through its own initiatives or by augmenting those of other agencies, such as the collaboration between FERC and the National Association of Regulatory Utility Commissioners (NARUC).[17]

State public service commissions (PSCs) face a severe capacity deficit that limits their ability to enact and implement the reforms needed for load-growth readiness. DOE could reinvigorate state-assistance programs to enhance technical knowledge on issues including large-load tariffs, load forecasting, interconnection and transmission practices, and the merits of joining or reforming organized wholesale electricity markets. DOE previously had a cooperative agreement with NARUC, which may be an avenue

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[14] "Biden Administration Adopts Comprehensive NEPA Regulations: Key Points to Know," Baker Botts, May 9, 2024. https://www.bakerbotts.com/thought-leadership/publications/2024/may/biden-administration-adopts-comprehensive-nepa-regulations---key-points-to-know.

[15] See, e.g., Tommy P. Beaudreau et al., "Supreme Court Decision in *Seven County* Advances Permitting Reform," WilmerHale, June 9, 2025. https://www.wilmerhale.com/en/insights/client-alerts/20250609-supreme-court-decision-in-seven-county-advances-permitting-reform.

[16] Hartman et al., "Achieving Affordable, Reliable, and Secure Power." https://www.rstreet.org/outreach/achieving-affordable-reliable-secure-power-briefing-for-the-doe-nedc.

[17] "Federal-State Current Issues Collaborative," Federal Energy Regulatory Commission, Nov. 5, 2025. https://www.ferc.gov/federal-state-current-issues-collaborative.

for future program administration. Should DOE pursue this again, it is important to view states as innovative laboratories rather than subordinates, meeting each according to its individual PSC needs.

Data Access and Sharing

Customers, suppliers, and other collaborating groups need access to grid and energy usage data to evaluate bill impacts, identify optimal locations to site new resources and large loads, generate bills, and participate in RTO markets. DOE has supported work to develop model data-access and privacy practices for customer energy-usage data (DataGuard) as well as a standard to support access to such data (Green Button). Nevertheless, data access continues to be a barrier to customer choice and the development of new resources and services that support infrastructure deployment. For projects receiving DOE grant funding that include a data-access component, DOE should require adherence to data-access practices and requirements, including reliance on available standards to support sharing data (e.g., Green Button).

Transmission congestion remains difficult to assess outside of RTOs. This lack of visibility has prompted a coalition of consumer groups, led by the Electricity Consumers Resource Council, to advocate for an Independent Transmission Monitor.[18] FERC has made no progress on advancing such an effort. DOE could assist by collecting and publishing proxies for transmission congestion outside of organized wholesale electricity markets or by financing third parties to do so. Evaluating the economic merits of ATTs in these regions is highly valuable, and the inability to measure avoided congestion outside organized markets has hindered further FERC policy on ATT use beyond Order 881. Without better congestion data, it will be difficult to implement the transmission reforms sought by the Trump Administration's AI Action Plan.

Transmission project transparency is also very poor, and DOE could help address this issue. Within RTOs, data is non-standardized and often unreliable. Outside RTOs, the data is even worse, if it is available at all. Specifically, there is very limited publicly available information on cost drivers, project scope, and project timelines, nor is there any systematic or uniform recordkeeping. The Energy Information Administration (EIA) publishes some aggregated transmission-expenditure data but does not provide detailed build costs or full breakdowns by project or region.[19] Overall, the modeling and forecasting of transmission in EIA's *Annual Energy Outlook* remains limited.

4. Load Growth Trends

[18] Karen Onaran et al., "Post-technical Conference Comments of the ITM Coalition," Federal Energy Regulatory Commission, March 23, 2023. https://elcon.org/wp-content/uploads/3.23.23-AD22-8-ITM-Coalition-Post-Tech-Conf-Comments.pdf.

[19] See, e.g., "Electricity Market Module of the National Energy Modeling System: Model Documentation 2025," U.S. Energy Information Administration, July 2025. https://www.eia.gov/outlooks/aeo/nems/documentation/electricity/pdf/EMM_AEO2025.pdf.

Load growth rates, location, and shape all have major implications for infrastructure use, needs, total costs, rate impacts, and system reliability. One of RSI's DOE briefings highlighted the following high-level observations on load growth trends:[20]

- Retail utility forecasts are typically the basis for NERC assessments, RTO market design, and often transmission planning. This means errors in retail forecasts under state jurisdiction snowball into inaccuracies at the wholesale level under federal jurisdiction.
- Load forecasting accuracy has been a major concern, as evidenced by a September letter that then-FERC Chairman David Rosner sent to RTOs on improving large-load forecasting.[21] Traditional forecasting methods like econometric approaches are no longer as reflective of load growth as they previously were. Furthermore, utilities chronically over-count each large load inquiry as firm load, which inflates forecasts. Power consumers like data centers and manufacturers often issue multiple inquiries to inform site selection for a single facility.
- Historically, utilities have overforecasted demand. Although recent load growth was initially under-forecast early this decade, the forward price curves now imply less load growth than utility forecasts suggest.

RSI assessed load growth trends in three footprints at the center of the load-growth discussion for this set of comments. Specifically, we used monthly data from three RTOs: the Midcontinent Independent System Operator (MISO), the PJM Interconnection (PJM), and the Electric Reliability Council of Texas (ERCOT). We also pulled forward market data from the Intercontinental Exchange. We observed the following load patterns:

- The historical monthly load forecasts for ERCOT between 2021 and 2024 indicate a recurring pattern of forecast overestimation, with many months where actual peak demand fell short of projections. This tendency is most evident in 2021 and 2024, suggesting that forecast models may have over-anticipated load recovery or weather-driven peaks during those periods. During several months in 2022 and 2023, actual loads exceeded forecasts, likely reflecting stronger-than-expected demand growth tied to economic expansion, higher summer temperatures, and rising electrification loads, particularly from industrial and data-center activity. The alternating sign and growing spread of deviations over time show increasing uncertainty in load shape in ERCOT. For future/forward markets between 2021 and 2025, 2022 marked the peak in forward pricing (18-month forward averages have been captured for each given year, e.g., year 2022 reflects July 2022 to December 2023) due to fuel and weather shocks. Forward prices corrected in 2023, followed by a 2024 uptick tied to demand growth and other challenges. The 2025 outlook has shown moderation.
- MISO's load forecasts from 2021 to 2024 were relatively accurate, with deviations generally confined within a narrow +/- 2 percent range. This pattern suggests that MISO's forecasting models have effectively captured broad demand trends but may still slightly overstate load

[20] Hartman et al., "Achieving Affordable, Reliable, and Secure Power." https://www.rstreet.org/outreach/achieving-affordable-reliable-secure-power-briefing-for-the-doe-nedc.

[21] David Rosner, "Chairman Rosner's Letter to the RTOs/ISOs on Large Load Forecasting," Federal Energy Regulatory Commission, Sept. 18, 2025. https://www.ferc.gov/news-events/news/chairman-rosners-letter-rtosisos-large-load-forecasting.

growth, likely due to assumptions around industrial recovery, weather-normalized demand, or economic expansion after 2020. In MISO, 2022 also marked the high point of forward pricing. The market corrected in 2023, rebounded in 2024 as grid and capacity risks resurfaced, then declined to 2023 levels in 2025.

- In PJM, there were large forecast deviations between 2021 and 2024, particularly in 2023. PJM's actual loads were significantly lower than forecasted, pointing to persistent overestimation of demand growth. This likely reflects structural shifts in PJM's load composition, such as energy-efficiency gains and slower industrial recovery, combined with weather variability. Compared to ERCOT and MISO, PJM's deviations are much wider and less symmetric, showing higher uncertainty in load dynamics across its large, diverse footprint. For forward prices, the highest volatility was between 2021 and 2023. After a decline in 2023, there has been a slight upward trend.

DOE can improve load forecasting accuracy in various ways. These include:

- Leveraging DOE convening power to bring together regulators, utilities, advocates, developers, experts, and large-load representatives to understand modeling, inputs, and project development. PSCs and FERC need to understand utility forecasting modeling, including accessibility of software. They also need to understand the accuracy of inputs and need experience with innovative methods to improve them, such as load collateral requirements;
- Preparing reports detailing best practices in load forecasting;
- Funding, providing technical assistance, or conducting independent load forecasting for RTOs and FERC or at the utility-level for PSCs; and
- Funding and otherwise fostering the development of tools to help inform load forecasting inputs. For example, the National Renewable Energy Laboratory developed a spatial tool to help identify significant data-center development.[22]

DOE action to promote voluntary information sharing between load forecasting experts and regulators would be beneficial. However, DOE should refrain from the pursuit of forecasting standards. Centralized standards for load forecasting may constrain innovation and limit discovery.

5. Grid Infrastructure Constraints

In this section, RSI provides an overview of load growth readiness factors, as well as specific insight into two prompted areas of the RFI inquiry: interconnection and policy and regulatory uncertainty. To underscore the importance of reforms to unleash all resource types, we conducted a novel scenario analysis of resource additions by 2030. We also provide insights into the importance of demand-side management, which the RFI did not specifically seek but is critical to the objective of speed to power.

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[22] National Renewable Energy Laboratory, "Accelerating Speed to Power," U.S. Department of Energy, last accessed Nov. 19, 2025.
https://maps.nrel.gov/speed-to-power/data-viewer?vL=6834e82591241decedd4ef8c%2C682746c9d58843cf7876093e%2C6838ae2891241decedd4ef8f%2C685c736d77a7c73f0a473a5d&b=%5B%5B-77.346977%2C42.231886%5D%2C%5B-68.611395%2C44.215849%5D%5D.

As we outlined in an October 2025 DOE briefing, six items factor into load-growth readiness:[23]

1. Accurate load forecasting;
2. Effective wholesale competition;
3. Effective retail competition;
4. Efficient permitting and siting, especially at the state level;
5. Efficient interconnection; and
6. Economical transmission expansion.

Based on these parameters, the area that is the most load-growth ready is ERCOT. ERCOT has the most efficient interconnection process and the most robust wholesale and retail competition in the country. It also has a relatively economical transmission-expansion process. In addition, Texas has relatively efficient permitting and siting laws, and the state is projected to have the highest load growth in the country. Texas distribution utilities and ERCOT have had load-forecasting challenges such as those noted above, but these are somewhat tempered because Texas relies on forward market expectations—not capacity planning like other states—to drive generation decisions.

Every other footprint has major limitations in multiple categories. For example, the Northeast and Mid-Atlantic have mostly effective retail and wholesale competition but face challenging state permitting and siting regimes that inhibit infrastructure development.[24] In the Southeast and much of the West, the opposite is true: Most states have ineffective retail and wholesale competition but more favorable infrastructure permitting and siting laws.[25] Interconnection has lower barriers to entry in RTO footprints, but FERC-jurisdictional RTOs remain well behind ERCOT in efficiency.

Similarly, economical regional transmission practices are far superior in RTO footprints, which make greater use of ATTs, rely on independent planning and cost-benefit tests, and put many transmission needs out for competitive bid. However, more than 90 percent of transmission investments are made outside of these processes; they are initiated by incumbent transmission monopoly utilities as local projects or initiated by RTOs as reliability-need projects, which are exempt from economic criteria.[26] Such projects are developed by monopoly utilities with no cost-benefit testing, with ineffective cost-of-service prudence reviews, and are exempt from competitive forces. A FERC complaint brought by leading electric consumer groups, on which RSI provided expert testimony, sought to close the regulatory gap over local

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[23] Hartman et al., "Achieving Affordable, Reliable, and Secure Power." https://www.rstreet.org/outreach/achieving-affordable-reliable-secure-power-briefing-for-the-doe-nedc.

[24] Michael Giberson and Devin Hartman, "Electric Paradigms: Competitive Structures Benefit Consumers," *R Street Policy Study* No. 293, September 2023. https://www.rstreet.org/wp-content/uploads/2023/09/FINAL_r-street-policy-study-no-293.pdf.

[25] Ibid.

[26] Johannes Pfeifenberger, "Transmission landscape and Outlook," Brattle Group, Oct. 9, 2025. https://www.brattle.com/wp-content/uploads/2025/10/Transmission-Landscape-and-Outlook-Proactive-Planning-for-a-More-Cost-effective-and-Affordable-Energy-Transition.pdf.

and reliability-need projects and redirect capital toward economical processes conducted by independent entities.[27]

While transmission warrants the most federal attention given jurisdictional considerations, DOE technical assistance, reporting efforts, and other functions should increasingly emphasize market advantages in the load-growth era. In previous eras of anticipated load growth, cost-of-service utilities made inefficient capital decisions that forced captive customers to pay stranded costs for decades.[28] In contrast, competitive generators shouldered the risk of load-growth rates and location, resulting in more efficient capital decisions and better risk management.[29] The current load-growth era is in its early stages, but competitive generators and retailers are showing signs of outperformance.[30] This is buttressed by the fact that competitive markets are far more equipped to economically and reliably integrate unconventional resources, namely those that are variable (e.g., wind and solar), use-limited (e.g., energy storage), and flexible demand. Cost-of-service utility planning in fragmented territories is increasingly economically inefficient and poses a reliability liability for regional resource and energy adequacy. For example, more than 90 percent of MISO needs are met by state integrated resource planning, which has created inefficiencies and has already led to capacity shortfalls.[31]

Interconnection

A recent RSI policy study on electric reliability identified generator interconnection (GI) as the main resource-adequacy concern within the industry's control.[32] Current GI practices unnecessarily increase network upgrade costs that, even though predominantly incurred by generators, are entirely passed on to customers under cost-of-service generation or partially passed on to customers (e.g., higher power purchase agreement prices). FERC issued Order 2023 to improve GI processes, but the order did not fix the primary problems.[33] RSI subsequently organized a coalition of consumer groups calling for deeper FERC reform, which sparked Senate legislation.[34] FERC did not, however, take policy action and instead

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[27] Michael Giberson, "Testimony in support of complaint at FERC in Industrial Consumers of America et al v. Avista Corporation; Idaho Power Company et al," R Street Institute, Dec. 19, 2024. https://www.rstreet.org/outreach/michael-giberson-testimony-in-support-of-complaint-at-ferc-in-industrial-consumers-of-america-et-al-v-avista-corporation-idaho-power-company-et-al.

[28] Devin Hartman, "The Grid of the Future," *American Interest*, June 18, 2018. https://www.the-american-interest.com/2018/06/18/the-grid-of-the-future.

[29] Ibid.

[30] Devin Hartman, "How to Liberate Electric Power," *National Affairs*, Spring 2025. https://www.nationalaffairs.com/publications/detail/how-to-liberate-electric-power.

[31] Devin Hartman, "Strengthening Electric Reliability Through Markets in the Midwest," June 23, 2022. https://www.rstreet.org/commentary/strengthening-electric-reliability-through-markets-in-the-midwest.

[32] Hartman et al., "Twelve Policy Priorities to Secure Bulk Electric Reliability." https://www.rstreet.org/wp-content/uploads/2025/05/FINAL-r-street-policy-study-no-322.pdf.

[33] Hartman, "Statement for the Record, Hearing on 'The Power Struggle: Examining the Reliability and Security of America's Electric Grid.'" https://www.rstreet.org/outreach/letter-to-the-house-committee-on-oversight-accountability-about-grid-reliability.

[34] Ethan Howland, "Consumer groups, R Street urge FERC to expand interconnection reform proposal to increase savings," *UtilityDive*, June 9, 2023. https://www.utilitydive.com/news/ferc-interconnection-reformproposal-r-street-elcon-nasuca/652570.

held a workshop.[35] In the absence of regulatory action, RTOs have brought customized reforms to FERC for approval by individual RTOs. As a result, ad-hoc, piecemeal, regional approaches to incremental GI reform have become the new status quo.

The overall impact of these incremental reforms is mixed. Some reduce financial, informational, or procedural barriers to entry, which expedite speed to power. For example, considerable optimism surrounds the Southwest Power Pool's "consolidated planning process."[36] Other proposals, however, entrench incumbent transmission utilities further and undermine bedrock open-access transmission policy rather than hold transmission providers accountable for producing expeditious and accurate GI study assessments.[37] The merits of some recent reforms remain unclear, such as the fate of cluster-study processes.

Together, this suggests significant value in continuing to research comparative GI practices and creating a community to determine best practices. Research at the Lawrence Berkeley National Laboratory has provided tremendous value and played a central role in FERC's 2024 GI workshop.[38] RSI highly recommends that the DOE continue to support this effort. RSI also reiterates the value of DOE support for i2x, which is an excellent community for identifying best GI practices. Such efforts are critical for identifying improvements to business processes and tools that provide information for generators in a manner that does not further burden GI queues in search of price discovery.

The related issue of large-load interconnection is in a more nascent stage. Last month, DOE asked FERC to consider an advanced notice of proposed rulemaking (ANOPR) for interconnection of retail loads over 20 megawatts with final FERC action by April 30, 2026. This is warp speed by FERC standards. Stakeholders are scrambling to develop high-quality comments to DOE's 14-page ANOPR, and the record at FERC will be lackluster, given the accelerated comments window for such a novel issue. This could be disastrous for FERC's final rule. If FERC fails to support a final rule with sufficient evidence, it will not withstand judicial scrutiny.

To be clear, DOE's ANOPR proposes that FERC extend its reach into planning processes far beyond what the agency oversees today. This is a highly sensitive federalist matter; FERC has never before exercised this type of authority over retail loads. This month, the National Association of Regulatory Utility

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[35] "Innovations and Efficiencies in Generator Interconnection Workshop (Day 1 of 2)," Federal Energy Regulatory Commission, Sept. 10, 2024. https://www.ferc.gov/news-events/events/innovations-and-efficiencies-generator-interconnection-workshop-day-1-2-09102024.

[36] Ethan Howland, "SPP proposes landmark merger of transmission planning, interconnection processes," *UtilityDive*, Nov. 4, 2025. https://www.utilitydive.com/news/spp-consolidated-transmission-planning-interconnection-ferc/804590.

[37] Amanda Durish Cook, "MISO Tells Board RA Fast Lane in Interconnection Queue is a Must," RTOInsider, Dec. 12, 2024. https://www.rtoinsider.com/93864-misoboard-ra-fast-lane-interconnection-queue-must.

[38] See, e.g., https://emp.lbl.gov/queues.

Commissioners passed a resolution urging FERC to resist the ANOPR push to give the regulator jurisdiction over large interconnecting loads.[39]

For an issue this important and complicated, particularly given the major federalist questions, it is highly advisable that DOE give FERC more time, narrow the ask of FERC, or have FERC delay final action on aspects of the ANOPR by choosing not to implement it as proposed. A rushed rulemaking will be technically suboptimal, less durable, and more vulnerable to excessive litigation. Changes need to come immediately, as a final rule cannot deviate substantially from a notice of proposed rulemaking, which FERC will have to issue expeditiously to meet DOE's timeline.

Policy and Regulatory Uncertainty

Research, such as a recent Energy Uncertainty Index, shows that energy-sector policy uncertainty is associated with slower economic growth.[40] Debt markets remain resilient, but risks are mounting.[41] In particular, the "main risk for debt issuance and spreads going into 2026 is continued uncertainty around US tariffs compressing margins for more levered borrowers."[42]

The U.S. electric policy and regulatory landscape, both federally and in many states, has become less stable and predictable, creating substantial artificial risk. This is driving up risk premiums for all types of generation and transmission, as noted by former FERC chairs, industry analysts, and financial market behavior.[43] In fact, leading developers recently remarked that risk premiums are "offsetting any benefits you're getting from reduced interest rates. It's counterproductive."[44]

While the uncertainty of obtaining approvals for permits and interconnection receives much warranted attention, less attention has been paid to permitting permanence. Government approvals are rules-based constructs. Adherence to the rule of law is central to drive investor confidence, and thus paramount to drive speed to power for generation and transmission.

Generation and transmission infrastructure-investment horizons span five to eight presidential cycles. This makes investors less sensitive to the preferences of any given administration and more inclined to base decisions on the long-term policy climate. Actions like the Obama administration's Keystone XL

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[39] Robert Mullin, "Regulators Urge FERC to Honor State Authority over Large Load Interconnections," RTOInsider, Nov. 11, 2025. https://www.rtoinsider.com/119453-regulators-urge-ferc-honor-state-authority-large-load-interconnections.

[40] Tam Hoang-Nhat Dang, et al., "Measuring the energy-related uncertainty index," *Energy Economics*, August 2023. https://www.sciencedirect.com/science/article/abs/pii/S0140988323003158.

[41] S&P Global Market Intelligence, "Big Picture 2026 Debt Markets Outlook: Resiliency persists as risks mount," Nov. 2, 2025. https://www.capitaliq.spglobal.com/apisv3/spg-webplatform-core/news/article?id=94471079&KeyProductLinkType=11.

[42] Ibid.

[43] Rich Heidorn Jr., "FERC Veterans Share Worries over Agency's Independence," RTOInsider, Oct. 27, 2025. https://www.rtoinsider.com/118169-ferc-veterans-share-worries-agencys-independence.

[44] Ibid.

rejection, the Biden administration's "LNG pause," or the Trump administration's pause on a nearly complete offshore wind project create long-term uncertainty and chill capital markets. Crucially, punitive actions on one resource class set a precedent for executive overreach, which drives long-term risk premiums for other forms of infrastructure. Relatedly, the domestic oil and gas industry has recently grown more uncertain about the future, given recent policy developments.[45]

Sage advice came from Senator Lisa Murkowski in September: "We should not retreat from an all-of-the-above policy. It cannot just be empty rhetoric."[46] Indeed, the Trump administration and DOE must stay true to the spirit of unleashing *all* American energy, as envisioned in Executive Order 14154.[47]

DOE has undertaken recent actions that exacerbate uncertainty, such as the overuse of emergency actions under Section 202(c) of the Federal Power Act to subsidize existing power plants. The law limits orders to just 90 days to let a unit waive environmental compliance. This is sufficient to address emergencies like hurricanes, fuel freezes, and wildfires that last days or weeks. However, DOE used the law in May to block two plants—Campbell and Eddystone—from retiring despite an absence of emergency conditions. Then DOE used it again in August when those orders expired. It is expected that DOE will do so again this month. This is problematic for a number of reasons, including:

- *Negligible direct reliability benefit and possible net-negative reliability effect*. Per RSI's recent DOE briefing, markets have exhibited patterns of cancelling planned deactivations and returning mothballed plants voluntarily in response to rising load growth amid constrained new entry.[48] Some power plants, depending on locational factors, can retire without the region compromising the achievement of reliability objectives. 202(c) actions and similar interventions mute price signals for new entry, which creates reliability risk. Emergency mechanisms do not cover operating upgrade costs for aging power plants, which are already known for high forced-outage rates given the low quality of their maintenance. For example, Eddystone was not dispatched by PJM in most of July despite four Maximum Generation Emergency alerts.[49] System reliability also depends on credible schedules, and unpredictable emergency actions jeopardize long-run reliability plans.

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[45] Shelby Webb, "Oil execs worried about Trump's energy policies, Dallas Fed says," EnergyWire, Sept. 25, 2025. https://subscriber.politicopro.com/article/eenews/2025/09/25/oil-execs-worried-about-trumps-energy-policies-dallas-fed-says-00578223.

[46] Kelsey Tamborrino, "Murkowski knocks Trump administration's clean energy clampdown," PoliticoPro, Sept. 17, 2025. https://subscriber.politicopro.com/article/2025/09/murkowski-doubles-down-on-all-of-the-above-amid-federal-actions-on-wind-solar-00568293.

[47] "Unleashing American Energy," The White House, Jan. 20, 2025. https://www.whitehouse.gov/presidential-actions/2025/01/unleashing-american-energy.

[48] Hartman et al., "Achieving Affordable, Reliable, and Secure Power." https://www.rstreet.org/outreach/achieving-affordable-reliable-secure-power-briefing-for-the-doe-nedc.

[49] Karin Rives, "Aging coal, gas plants see limited use despite US DOE emergency orders," S&P Capital IQ, Oct. 27, 2025. https://www.capitaliq.spglobal.com/apisv3/spg-webplatform-core/news/article?id=94192784&KeyProductLinkType=58&utm_source=MIAlerts&utm_medium=realtime-minewsresearch-newsfeature-energy%20and%20utilities-regulatory%20roundup&utm_campaign=Alert_Email.

- *Excessive cost*. Market constructs already exist to ensure compensation for resource and energy adequacy. They procure such reliability services at least cost. When older, inefficient plants have going-forward costs that exceed the market price, it is a signal that the resource is being displaced by lower-cost new entry. Consumers benefit from competition, which grinds down long-run costs. Serial emergency orders break this economic feedback loop. They subsidize existing plants at a higher cost to customers—who are forced to pay the subsidy—while crowding out lower-cost new entry. Campbell and Eddystone subsidies alone are expected to impose tens of millions of dollars in additional costs on PJM and MISO ratepayers in 2025.[50]
- *Heightened uncertainty and litigation risk*. The reliability rationale for the two 202(c) actions discussed is flimsy, making it ripe for judicial challenge. States and stakeholders are already litigating. DOE has not articulated a coherent policy position on how it will use this authority in the future, which chills investment. The plant owners, competing developers, potential investors, and other market participants cannot anticipate what DOE will do.

RSI's recent reliability paper has a section on appropriate policy responses to concerns over premature retirements.[51] The main concern is states forcing premature retirements of economical power plants, which is not what DOE actions have addressed to date. The paper examines use parameters for reliability must-run (RMR) agreements, but similar guidelines may apply to the use of 202(c):

- Use clear, transparent reliability criteria for invoking 202(c), including a defined reliability service need for a specific emergency, a demonstration of uneconomic status, and the passage of a benefit-cost test;
- Consider cost-effective market alternatives to 202(c) actions, such as alternative new generation;
- Prevent plant owners from seeking cost-of-service subsidies and retirement threats to exercise market power, which raises market prices without risking losses; and
- Provide a clear action plan to alleviate the need to retain the subsidized power plant that provides other market participants with a clear set of forward expectations, which reduces uncertainty and investment distortions.

Accredited Capacity Additions by 2030

RSI conducted an analysis to demonstrate the effects of public policy on near-term capacity additions for reliability purposes. Given the long lead times to develop generation, we examined projects with mature development status (announced, permitted, or under construction) expected to be operational by 2030 ("Tier 1" resources). We accounted for uprates to nuclear and natural gas plants and one nuclear restart. Unannounced greenfield projects are outside this delivery timeframe. Although some boilerplate industry reports (e.g., EIA) suggest that projects like new natural gas-fired plants and solar-plus-storage may have lead times of 2 or 3 years, this is not consistent with current commercial climates (e.g., supply chain backlogs, high artificial barriers to entry). Therefore, we excluded unannounced greenfield projects from consideration for projects with 2030 in-service dates.

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[50] Ibid.

[51] Hartman et al., "Twelve Policy Priorities to Secure Bulk Electric Reliability." https://www.rstreet.org/wp-content/uploads/2025/05/FINAL-r-street-policy-study-no-322.pdf.

We used DOE's 2025 Resource Adequacy Report for nameplate capacity additions and reliability accreditation calculations.[52] Capacity accreditation, or the portion of nameplate capacity that is considered reliable for meeting system peak demand, was based on Effective Load Carrying Capability (ELCC) or performance-based metrics. We used the ELCC factors based on averages of MISO, PJM, and SPP's 2024 ELCC reports. These averaged: solar (35 percent), wind (12 percent), 4-hour battery (90 percent), natural gas (95 percent), and nuclear (95 percent). Although accreditation varies by footprint, this roughly represents national averages. Batteries are secondary power sources that contribute disproportionately to accredited capacity because of their high ELCC rating (90 percent), so we ran the analysis with and without storage across all scenarios.

Table 1. Capacity Additions by 2030, Four Scenarios

Resource	Nameplate Additions (GW)	Unrestricted Accredited Additions (GW)	60% Restricted (wind, solar, gas only)	60% Restricted (wind, solar only)	60% Restricted (gas only)
Solar	72.5	25.4	10.16	10.16	25.4
Wind	52.8	6.3	2.52	2.52	6.3
Battery (4-hr)	50.6	45.6	45.6	45.6	45.6
Gas	20	19	7.6	19	7.6
Nuclear	1.2	1.10	1.10	1.10	1.10
Total	197.1	97.4	66.98	78.38	86
Total (no storage)	146.5	51.8	21.38	32.78	40.4

We applied four scenarios to determine 2030 accredited capacity, as shown in Table 1. The first is an unrestricted scenario, used for illustrative purposes. New generation development is facing high artificial barriers to entry, particularly for wind, solar, and natural gas plants. Historical data (2000 to 2018) indicate that only about 19 percent of projects (and 14 percent of capacity) have reached operation.[53] Therefore, we used three combinations of 60 percent restrictions (40 percent of projects online) on wind, solar, and gas to show three forward-looking, infrastructure-aware scenarios. This may be consistent with a realistic outlook of state and federal speed-to-power efforts to accelerate project completion by addressing bottlenecks.

Key findings include:

[52] Department of Energy, "Evaluating the Reliability and Security of the United States Electric Grid," July 2025. https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[53] Joseph Rand et al., "Queued Up: 2024 Edition," Lawrence Berkeley National Laboratory, April 2024. https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_1.pdf.

- In an unrestricted scenario (100 percent of projects online), projects with mature development status expected to be operational by 2030 would increase accredited capacity by 97.4 GW with storage and 51.8 GW without storage. Batteries account for 47 percent of accredited additions, wind and solar account for 33 percent of accredited additions, gas for 20 percent, and nuclear for 1 percent;
- Under the most restricted scenario, which is 60 percent project restriction for wind, solar, and gas, accredited capacity gains drop to 67 GW and 21.4 GW without batteries;
- Under 60 percent project restriction for wind and solar, accredited capacity gains stand at 78.4 GW and 32.8 GW without batteries;
- Under 60 percent project restriction for natural gas, accredited capacity gains stand at 86 GW and 40.4 GW without batteries; and
- The core policy takeaway is to unleash the deployment of *all* energy sources. Alleviating constraints on renewables, followed by gas, is most important to achieve speed to power by 2030.

We believe this analysis undersells nuclear restarts because of data limitations in the DOE report. The report included only the restart of the Salem Generating Station in 2029, which is a 1,170 MW facility. This overlooks recent announcements to restart the Three Mile Island and Duane Arnold nuclear plants.[54] Although incorporating these facilities should more than double accredited nuclear capacity additions, it would still be the smallest resource addition class by 2030 (i.e., less than 6.3 GW of accredited wind capacity additions). Nuclear restart potential is limited, and aspirations for new greenfield nuclear might factor into a 2040 analysis. Notably, it took 15 years to complete the Vogtle nuclear plant after the utility received approval to expand an existing facility.

RSI appreciates the opportunity to provide these comments to DOE.

Respectfully submitted,

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[54] Laila Kearney and Vallari Srivastava, "NextEra Energy partners with Google to restart Iowa nuclear plant," *Reuters*, Oct. 28, 2025.
https://www.reuters.com/business/energy/nextera-energy-partners-with-google-restart-iowa-nuclear-plant-2025-10-27.

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