Optimizing Grid Infrastructure and Proactive Planning to Support Load Growth and Public Policy Goals

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Executive Summary

The power sector is facing the highest level of growing demand in decades, driven by the rapid expansion of new data centers, reshoring of manufacturing, and the electrification of end uses. To meet projected demand, the US electricity supply will have to expand more than five times faster than in the prior two decades. This acceleration will intensify pressure on grid planning, strain supply chains, and complicate environmental policy while increasing capital investment needs and cost burdens for customers.

Accommodating this load growth in a manner that is timely, cost-effective, and consistent with public policy goals is both challenging *and* possible. It is possible by: (a) deploying commercially available new technologies and processes to increase the utilization of the existing grid; and (b) more proactive planning of the necessary new infrastructure. By mobilizing demand-side flexibility, increasing the utilization of the existing grid, and recognizing uncertain future needs through proactive planning, utilities and other grid operators can serve new loads while mitigating cost increases, thereby avoiding large bill increases for existing retail customers and protecting them from future risks. Combining more efficient capital utilization with more proactive planning thus offers a win-win proposition that protects customers, serves new loads more quickly, benefits utilities and grid operators, and supports a wide range of public policy goals for clean energy and economic development.

In this whitepaper, we highlight effective solutions to address these challenges and how they have been implemented across the industry. We offer actionable recommendations for regulators, system planners, utilities, and other key stakeholders to navigate obstacles related to supply, interconnection, cost, and environmental policy in the evolving power sector.

We do not attempt to cover the full scope of potential reforms to the power system that may be necessary under this new paradigm, such as changes to wholesale power markets or technological innovations that may become commercially available. Instead, we focus on practical and demonstrably implementable near- and medium-term actions that enhance the value of the existing grid and help improve planning for future investments.

Specifically, we document through case studies available solutions to address the many challenges faced by the industry today and recommend that grid planners, utilities, industry stakeholders, and regulators focus on the following four areas:

- **Maximize the value of the existing power system** by: (i) maximizing participation of distributed and demand-side resources and participation in enhanced rate options (e.g., managed EV charging and other load flexibility); (ii) broadening the deployment of grid-enhancing and advanced transmission technologies, including remedial action schemes; (iii) taking advantage of grid "upsizing" opportunities during refurbishment of aging existing transmission infrastructure; and (iv) facilitating and recognizing the value of increased and more efficient interregional trade.
- **Cost-effectively accelerate the grid connection of new loads and resources** by: (i) facilitating customer-sponsored generation investments and procurements to maintain resource adequacy to supplement conventional generation investments; (ii) minimizing the need for transmission upgrades and generation investments by facilitating co-location of generation and load in "energy parks"; and (iii) streamlining generator interconnection processes.
- **Implement proactive planning and procurement processes** to identify flexible, least-regrets solutions and, where necessary, attract new investments in a timely manner. Specifically, we recommend: (i) improving generation and transmission planning processes to mitigate risks of increasingly uncertain load forecasts; (ii) creating clean energy and economic development zones for which infrastructure can be planned proactively; (iii) reforming the generation procurement process to more flexibly and quickly address energy and capacity needs; (iv) proactively planning distribution system investments to more cost-effectively manage load growth (and capitalize on the flexibility of distribution-level resources); (v) improving load interconnection processes in line with policy objectives; and (vi) promoting the grid connection reforms necessary to speed up the integration of new loads and resources.
- **Introduce targeted affordability measures** by: (i) establishing and expanding energy efficiency and bill assistance programs for low-income and vulnerable customers; (ii) expanding incentives for demand-side management programs for low-income and vulnerable customers; and (iii) adopting best-practice rate designs for large customers to mitigate stranded-cost risks and minimize risks to existing customers.

Implementing these recommendations will increase the cost-effectiveness and timeliness of adding new loads and necessary resources to the power system, mitigating affordability concerns and boosting the efficiency of capital deployment. Implementing these recommendations will require action from a broad set of stakeholders.

On the policy and regulatory level, for example, the close collaboration between governors, legislators, state energy offices, and regulators will be important for state and regional initiatives. For example, governors can leverage their convening powers to facilitate multi-state efforts, championing public policy goals and innovative solutions, and work with utilities and the private sector. Legislators, on the other hand, will be crucial to authorize or direct many of the actions that regulators can implement and look to the legislature for direction, including on efforts to create renewable energy and economic development zone, streamline project siting and permitting, and establishing and expanding demand-side programs that benefit the power system and lower customer energy bills.

The stakeholder action matrix in Table ES-1 below summarizes the main recommendations that regulators, utilities, grid operators/planners, governors/legislators/policymakers, and other actors should prioritize. These stakeholder actions will require considerable effort, coordination, and collaboration.

TABLE ES-1: STAKEHOLDER ACTION MATRIX

	Solutions	Regulators	Utilities	Grid planners / operators	Governors and Legislators	Others
Maximize the Value of the Existing Power System *(Section III)*	*A. Enable distributed and demand-side resources*	✓	✓	✓		Third-party DER aggregators
	B. Enhance rate options	✓	✓		✓	
	C. Utilize GETs, ATTs, and RASs	✓	✓	✓	✓	
	D. Capitalize on transmission upsizing opportunities	✓	✓	✓		
	E. Facilitate interregional trade			✓	✓	
Cost-Effectively Accelerate the Grid Connection of New Loads *(Section IV)*	*A. Enable customer-sponsored generation*	✓	✓	✓	✓	
	B. Co-locate new generation and load	✓	✓	✓	✓	Energy park developers
	C. Streamline generator interconnection processes	✓	✓	✓		Transmission owners
Implement Proactive Planning and Procurement Processes to Accelerate the Necessary Investments *(Section V)*	*A. Proactively plan generation and transmission*	✓	✓	✓	✓	Power procurement authorities; State energy offices
	B. Reform generator procurement processes	✓	✓	✓	✓	Power procurement authorities; State energy offices
	C. Proactive plan distribution systems	✓	✓			
	D. Improve load interconnection processes	✓	✓		✓	State energy offices
Introduce Targeted Affordability Measures *(Section VI)*	*A. Offer energy efficiency and bill assistance*	✓	✓		✓	State energy offices
	B. Implement specialized rates for new large loads	✓	✓		✓	
	C. Explore alternative financing	✓	✓		✓	Private developers

I. Introduction

The US electric power system is entering a period of rapid and transformational load growth, driven by a convergence of factors, including the accelerating electrification of buildings and transportation, the re-shoring of industrial activity, and an unprecedented surge in demand from data centers. The scale of this challenge is placing pressure on utilities, system planners, policymakers, and regulators to serve the new loads quickly and cost-effectively, while still meeting state and corporate clean energy goals.

This pressure is particularly acute in the case of large loads, such as hyperscale data centers and advanced manufacturing facilities. These customers often require access to vast amounts of reliable power—hundreds of megawatts in some cases—and can begin operation in a few years. In contrast, expanding key components of the power systems can take up to a decade, if not longer. Concerns are mounting over the implications of this load growth on system affordability. Meeting this demand will require significant investments in generation, transmission, and distribution infrastructure, which are costly and can cause significant delays to customers' interconnection timelines. While many new large customers are prepared to pay a premium or invest in this infrastructure themselves to avoid interconnection delays, existing customers may ultimately bear the costs of upgrades if reforms are not implemented to reflect this price insensitivity and allocate costs fairly. These critical issues are currently under active consideration in various influential policy discussions and research, including at the Federal Energy Regulatory Commission (FERC),[1] reliability councils,[2] the US national labs,[3] and before state regulators and policy makers.[4]

At the same time, some jurisdictions with clean-energy goals face tensions between capturing the economic and societal value provided by these large load customers and limiting the greenhouse gas emissions associated with serving their demand for electricity. This challenge is

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1 Federal Energy Regulatory Commission (2025), "FERC Orders Action on Co-Location Issues Related to Data Centers Running AI," FERC News Releases.

2 See, for example, NERC (2025), *Characteristics and Risks of Emerging Large Loads*; and Elevate Consulting (2025), *An Assessment of Large Load Interconnection Risks in the Western Interconnection*, prepared for WECC.

3 See, for example, Frick, N.M. (2025), *Large Loads: Evolving Practices and Opportunities*, Berkeley Lab presentation to NASUCA.

4 See, for example, Silverman, A. et al. (2025), *A State Playbook for Managing Data Center-Driven Load Growth*, Johns Hopkins University; and Clean Energy States Alliance (2025), *Load Growth: What States Are Doing to Accommodate Increasing Electric Demand*.

further compounded as more large customers rely on on-site natural gas (and diesel backup) generation to meet their firm power requirements.

Addressing these challenges requires a range of short- and long-term reform efforts, from changes to electricity market design, improvements to transmission planning, and the generator interconnection and procurement processes across the country. We do not address the full scope of necessary reforms in this whitepaper. Rather, we identify near- and medium-term options that can (1) maximize the value of the existing power system, (2) cost-effectively accelerate the grid connection of new loads, (3) improve planning and procurement processes to enable proactive and cost-effective infrastructure development, and (4) offer targeted affordability measures to protect vulnerable customers and mitigate long-term cost risks.

While some of the solutions outlined here are already in use across the industry, others require at least some regulatory, institutional, or process changes to be fully realized. Across all recommendations, we emphasize practical steps that system operators, utilities, regulators, and customers can take today to meet tomorrow's needs—without losing sight of affordability, economic development, and environmental policy goals.

II. Current Challenges

The combination of data center developments, onshoring of manufacturing facilities, and electrification of transportation, home heating, and other energy end uses has added enormous pressure on the electricity system.[5] Projected rapid load growth associated with these developments, as shown in Figure 1 below, means that the country's electricity grid will have to expand at more than five times the pace of the past two decades.[6] Meeting this demand requires addressing a broad range of challenges in the next decade, including the efficient use and deployment of capital.[7]

Rapid load growth means that the electric power system will need substantial amounts of new investment in both generating resources and grid expansion. Yet, the industry's slow-moving planning processes and supply chain challenges often cause delays and sharply higher costs.

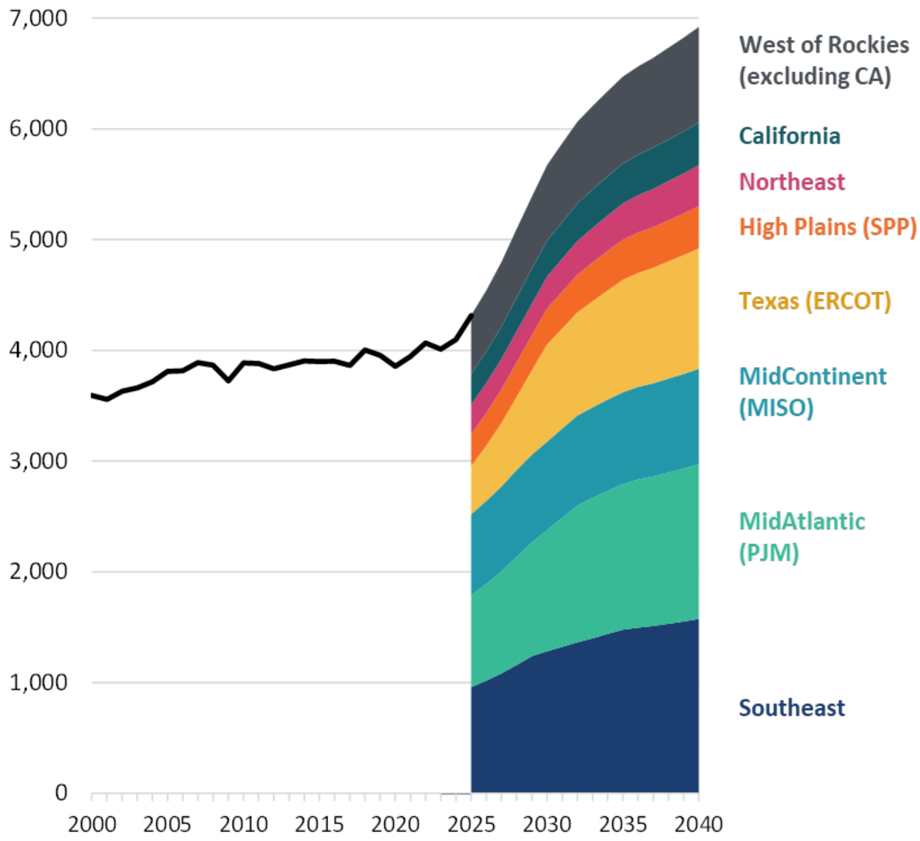
5 Tsuchida, T. B., et al. (May 2024), *Electricity Demand Growth and Forecasting in a Time of Change*, prepared for Clean Grid Initiative, The Brattle Group.

6 Newell, S., R. Hledik, and J. Pfeifenberger (April 2025), *Meeting Unprecedented Load Growth: Challenges & Opportunities*, The Brattle Group.

7 Fox-Penner, P. et al. (May 2025), *Affordability, Rates, and Clean Capital Efficiency: A Path for the Power Industry's Turbulent Next Decade*, The Brattle Group.

The lagging infrastructure development, in turn, delays how quickly data centers and manufacturing facilities can be brought online. In short, these challenges make it seemingly impossible to serve the loads reliably in a sufficiently timely, cost-effective, and environmentally acceptable fashion.

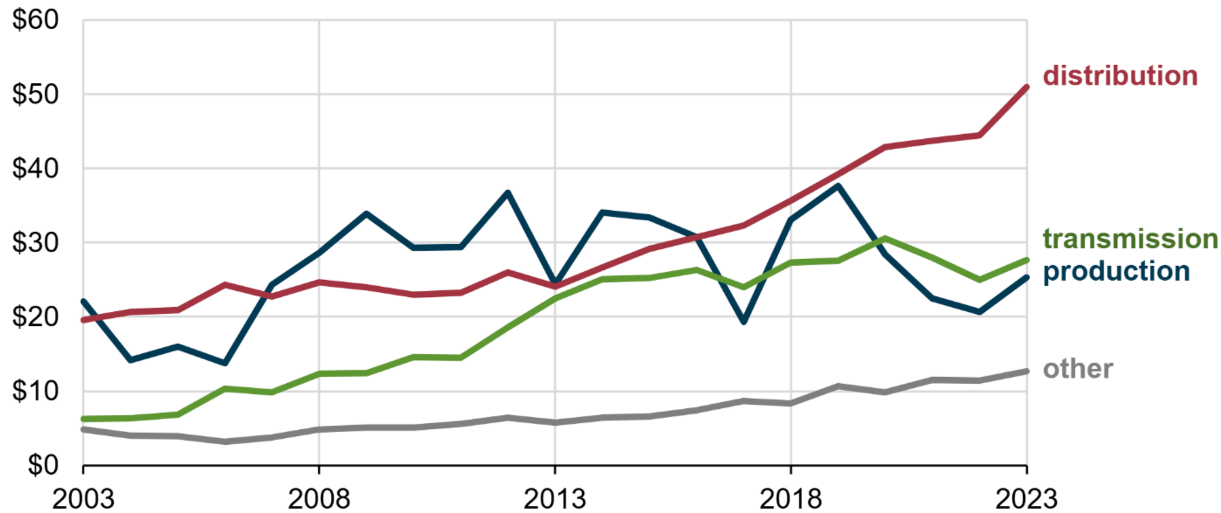
FIGURE 1: FORECASTED GROWTH OF US ELECTRIC ENERGY DEMAND (TWH/YR)



Source: The Brattle Group, based on an aggregation of individual regional transmission organizations (RTOs) and independent system operators (ISOs) and utilities' most recent forecasts.

At the same time, system costs have been increasing even prior to the current surge in electricity demand. Figure 2 below shows that annual capital expenditures on generation, distribution, and transmission more than doubled in real terms between 2003 and 2023. Notably, distribution spending increased by 160% and transmission spending nearly tripled. The surge in electricity demand takes place in an environment of already-increasing costs, with the potential to intensify capital investment needs and exacerbate affordability challenges.

FIGURE 2: ANNUAL US CAPITAL ADDITIONS BY SECTOR (2003–2023)
(2023 $billions)



Source: US Energy Information Administration (EIA) (2024), *Grid infrastructure investments drive increase in utility spending over last two decades*. Data sourced from US EIA and FERC financial reports as accessed by Ventyx Velocity Suite.

Beyond increasing system costs, additional challenges include:

- **Load growth uncertainty.** In the context of RTOs' forecasts of the projected rapid growth (shown for the US in Figure 1), questions remain about the firmness of hyperscalers' plans for new data centers and how future expansion will unfold as artificial intelligence (AI) training, usage, and computational efficiencies continue to evolve rapidly. There is also uncertainty about whether planned manufacturing plants will proceed. Perhaps realized growth in electricity demand is more likely to fall short of forecasts than to exceed them, particularly if some service requests are tentative or duplicative of requests in other candidate locations, or if a recession ensues. Yet even if only half of the anticipated demand growth materializes, the resulting demand growth rate would still far exceed the rate that the industry has experienced (and had to "deal with") in recent memory.
- **Resource adequacy concerns**. Many new generating resources will be needed to meet increased load and to replace retiring old plants. For example, about 68 GW of coal capacity has been announced for retirement by the end of this decade.[8] Hitachi Energy's Velocity Suite reports 65 GW of announced coal plant retirements by 2030 and another 15 GW by 2035, although some of these plants may opt to extend their lives if they can, and some may convert to natural gas. Some gas-fired power plants will similarly be retired during this period, adding to resource adequacy concerns.

[8] Celebi, M. et al. (2024), *A Review of Coal-Fired Electricity Generation in the U.S.*, The Brattle Group.

- **Delays and rising costs caused by supply chain constraints**. Multi-year backlogs for electrical equipment, such as gas turbines, power transformers, and high-voltage direct current (HVDC) equipment, make it exceptionally challenging to serve growing loads in a timely fashion.[9] The supply-chain bottlenecks (along with tariffs on imports affecting key inputs, such as steel) have also led to sharply higher equipment prices, including a reported tripling of the price of new natural gas turbines.[10]
- **Backlogged generator interconnection processes**. Even when resources could be added to the grid quickly—including solar and battery facilities that could be deployed in less than two years—the industry's grid-connection study process imposes multi-year delays. In many North American power markets, the generator interconnection studies alone last three to four years.[11]
- **Unrealized end-use efficiencies.** There is still untapped energy efficiency potential[12] and nearly 200 GW of cost-effective load flexibility potential in the US.[13] Load flexibility is particularly helpful as it can be used to quickly accommodate large new customers from a grid capacity and a resource adequacy perspective.[14] However, even though research has shown that virtual power plants (VPPs) have the potential to provide the same resource adequacy benefits as conventional resources, at a fraction of the cost, VPP deployment is still limited in many jurisdictions.[15]
- **Environmental challenges.** The rapid load growth and higher costs make the pursuit of clean energy goals significantly more challenging, both at the state and private/corporate levels. For many corporations, including those with clean energy objectives, getting their new data center and manufacturing facilities developed and supplied with electricity in a timely, reliable, and cost-effective fashion currently takes priority over environmental goals

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9 International Energy Agency (2025), Rising Component Prices and Supply Chain Pressures are Hindering the Development of Transmission Grid Infrastructure.

10 See comments from NextEra CEO: "We built our last gas-fired facility in 2022, at $785/kW. If we wanted to build that same gas-fired combined cycle unit today…$2,400/kW. The cost of gas-fired generation has gone up three-fold." Gas Outlook (2025), "Costs to Build Gas Plants Triple, Says CEO of NextEra Energy."

11 LBNL (2024), *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection*.

12 For example, in 2018, the Electric Power Research Institute (EPRI) estimated utility efficiency programs can realistically reduce electricity use by over 365 million MWh (365 TWh) by 2040 (link). For a 2023 update, see EPRI, *U.S. Energy Efficiency Potential Through 2045: Update on Potential for Energy Savings Through Utility Programs Across the Nation*, December 18, 2023.

13 US Department of Energy (2021), *A National Roadmap for Grid-Interactive Efficient Buildings*.

14 Norris, T. H. et al. (2025) *Rethinking Load Growth—Assessing the Potential for Integration of Large Flexible Loads in US Power Systems*.

15 The Brattle Group and LBNL (2024), *Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment*.

associated with of these investments. The high regional load growth and higher costs similarly challenge the clean-energy policy targets of individual states.

We discuss viable solutions that can at least partially address these challenges in the following four sections of this report:

- **Maximize the value of the existing power system** to get more out of the existing grid (Section III);
- **Cost-effectively accelerate the grid connection of new resources and loads** by addressing resource adequacy and grid investment needs (Section IV);
- **Implement proactive planning and procurement processes** to develop the necessary new investments in a more timely manner (Section V); and
- **Introduce targeted affordability measures** to protect low-income customers, mitigate stranded-cost risks, and hold existing customers harmless (Section VI).

III. Maximize the Value of the Existing Power System

A. Maximize participation of distributed and demand-side resources

SUMMARY: Distributed and demand-side resources can provide both energy and capacity as low-cost options to maintain resource adequacy and other grid services. States and utilities should consider scaling up promising demand-side programs, consider partnering with third-party vendors and aggregators, and provide targeted incentives for demand-side resource programs, particularly to low-income and vulnerable customers.

RELEVANT STAKEHOLDERS: Utilities, state regulators, third-party DER aggregators, grid operators, and planners.

IMPLEMENTATION NOTES: States would likely need to approve new utility programs and may set requirements for new DER compensation mechanisms or procurement targets. Grid operators and planners would need to enable the participation of DER aggregations, integrate them into market operations, and incorporate their impacts in planning assumptions.

Demand-side resources can be some of the most cost-effective and quickly deployed resources to serve load growth. Traditional demand response (DR) for peak shaving, emerging VPP applications to offer market dispatch and provide a range of grid services, energy efficiency (EE), time-varying rates (TVR), and distributed energy resources (DERs) can all help create more headroom in the electricity system to accommodate more load growth. This has been demonstrated in several recent studies, including the US Department of Energy's VPP Liftoff report, which estimates that 30–60 GW of VPP capacity operated on the grid in 2023.[16] Similarly, according to a recent Brattle report, the cost-effective load flexibility potential in New York is estimated to reach 3 GW by 2030, or 11% of the New York power system's summer peak

[16] US Department of Energy (2023), *Pathways to Commercial Liftoff: Virtual Power Plants*.

demand forecast.[17] Although states have been ramping up their EE programs by using public funds to incentivize commercial and industrial efficiency measures and providing support for low-income customers,[18] significant untapped EE potential remains.[19] Nationally, we have estimated that demand flexibility could scale to 200 GW if key barriers are addressed.[20]

To better leverage demand-side resources and provide much-needed capacity at low incremental cost to the system, utilities can immediately begin to more broadly deploy demand-side programs (instead of pilots), particularly where sufficient commercial experience already exists. For example, TVRs are popular among customers and have been demonstrably effective in reducing peak load across many jurisdictions.[21] In addition, jurisdictions that expect or are experiencing rapid and large-scale adoption of EVs should consider introducing full-scale EV managed charging programs, which have been demonstrated to be effective at alleviating distribution constraints.[22] Such programs could include passive management, where customers use a "set-it-and-forget-it" approach in response to price signals in their retail rate, and/or active management, where the utility or an aggregator could have direct control over the vehicle's charging schedule during a limited number of high-value hours.[23] For programs that are more innovative and/or untested, accelerated pilots may be prudent; however, utilities should ensure that behind such pilots are meaningful pathways to deployment at scale.

To take advantage of demand-side resources more quickly and on a larger scale, utilities could partner with third-party DR aggregators through competitive procurement of grid services. Third-party aggregators can complement utilities with implementation experience, administrative capacity, and technological capability that together allow the aggregators to scale DER programs quickly. Partnering with them would encourage innovation via competition and accelerate deployment while reducing the administrative burden on the utilities. See Figure 3 and FIGURE 4 below for examples of third parties providing aggregated DR services to

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17 Hledik, R. et al. (2025), *New York's Grid Flexibility Potential*, Vols I, II, III The Brattle Group.

18 American Council for an Energy-Efficient Economy, *2025 State Energy Efficiency Scorecard*.

19 The Electric Power Research Institute (EPRI) estimated in 2018 that utility efficiency programs can realistically reduce electricity use by over 365 million MWh (365 TWh) by 2040. EPRI, *U.S. Energy Efficiency Potential Through 2040: Summary Report* (2018).

20 Hledik, R. et al. (2019), *The National Potential for Load Flexibility*, The Brattle Group.

21 US Department of Energy (2021), *A National Roadmap for Grid-Interactive Efficient Buildings*.

22 Bailey, M. et al. (2024), *Electric Vehicles and the Energy Transition: Unintended Consequences of Time-of-Use Pricing*, NBER Working Paper 32886.

23 Under a set-it-and-forget-it approach, utilities should consider staggering the price signal over time to avoid a surge in charging load caused by simultaneous charging across customers. Indeed, a large body of research shows increased customer responsiveness and load reduction when DSM programs are deployed with enabling technologies that allow customers to participate passively through programming their preferences and usage patterns across different energy technologies. *See* Faruqui, A. and S. Sergici. *Household Response to Dynamic Pricing of Electricity—A Survey of the Empirical Evidence*. *J. Regul. Econ.* 38, 193–225 (2010).

incumbent utilities. To encourage effective and efficient participation of demand-side resources, utilities can also consider developing a comprehensive compensation mechanism reflective of the different value streams that demand-side resources contribute to the system.[24]

In general, it is beneficial for utilities to retain flexibility in the deployment of various demand-side program offerings. For example, if a program proves to be not cost-effective, utilities should not be obligated to proceed with its implementation. Conversely, if a program demonstrates effectiveness in reducing system costs ahead of the pilot's end date, utilities should be able to scale up the program without waiting for that end date.

Developing a dependable and mature market from which demand-side resources can be aggregated to contribute to system needs requires action from grid operators to better facilitate such aggregations into energy and ancillary service markets. Through and beyond their ongoing FERC Order No. 2222 filings, grid operators should continue to develop and accelerate the implementation of pathways for DER aggregations to participate in wholesale markets and remove barriers to entry.[25]

Large load customers can themselves be valuable sources of demand-side flexibility. A recent national study from Duke University found that operationalizing additional load flexibility from data centers (including net load flexibility created by dispatching on-site backup power) can help integrate as much as 76 GW of new load (about 10% of the country's aggregate peak demand),[26] and in its 2024 Reliability Needs Assessment NYISO anticipates flexible capacity from large load consumers to reach 1,200 MW over the next decade.[27] Given the often-high opportunity cost of load reductions for large consumers, these demand-side resources should be given strong market incentives to provide flexibility value to utilities and/or RTOs, linked to existing ancillary service products such as frequency regulation wherever possible.

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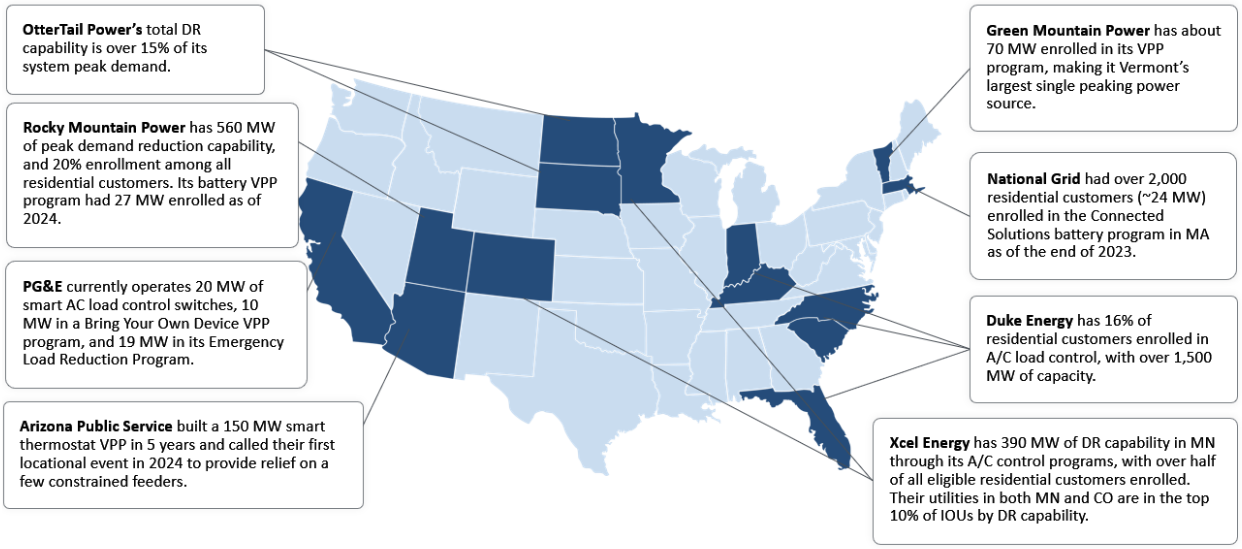
[24] For example, under New York's Value of Distributed Energy Resources (VDER) tariff, energy services created by DERs are compensated by incorporating the different value streams (e.g., energy, capacity, environmental value, among others) that the DERs provide. See NYSERDA (2024), The Value Stack.

[25] For specific opportunities that state regulators can take to accelerate DER aggregations, see Forrester, S. et al. (2025), *State Regulatory Opportunities to Advance Distributed Energy Resource Aggregations in Wholesale Markets*.

[26] Norris, T.H., et al. (2025), *Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems*. Some companies are currently exploring and experimenting with data center flexibility to be responsive to grid needs. *See* Tilton, J. (2025), Big Tech Tests Data Center Flexibility, IEEE Spectrum.

[27] NYISO (2024), *2024 Reliability Needs Assessment (RNA),* p. 13.

FIGURE 3: EXAMPLES OF DEMAND RESPONSE PROGRAMS



Sources: Figures from Hledik, R. et al. (2024), *Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment*. For detail about individual programs, please see Energy and Environmental Economics (2023), *Charging Forward: Energy Storage in a Net Zero Commonwealth*; *Power Magazine* (2024), "Peak Performance: APS's Virtual Power Plant Saves Big During Brutal Heatwave"; Rocky Mountain Power (2024), *Demand Side Management 2023 Annual Energy and Peak Load Reduction Report*; and RMI (2024), *Virtual Power Plant Flipbook*.

FIGURE 4: EXAMPLES OF DEMAND RESPONSE AGGREGATORS

Residential Focus

EnergyHub	*1.4 million devices; 2 GW of capacity*	Energy Hub helps utilities manage their smart thermostat, battery, and EV programs. In 2023 they enrolled 100,000 customers (90 MW) in Ontario's smart thermostat program in just 6 months.
RenewHome	*3 GW of capacity*	RenewHome helps customers manage their energy use. They work with 100+ utilities and are partnering with NRG to build a 1 GW virtual power plant in Texas.
Uplight	*7.8 GW of capacity*	Uplight provides utilities a platform to manage customer DERs. They worked with Consumers Energy's thermostat program to enroll 10,000 customers per week.

Commercial and Industrial Focus

CPower	*7 GW of capacity*	CPower helps customers manage and monetize their DERs. They have a portfolio of large customers, with 7 GW of capacity at more than 28,000 sites across the U.S.
Voltus	*7 GW of capacity*	Voltus helps customers manage and monetize their DERs. They have over 13,000 sites enrolled across over 60 programs to provide grid services.

Electric Vehicle Focus

ev.energy	*200,000 EVs under management*	ev.energy smart charging helps EV drivers optimize their charging schedules to reduce costs and carbon emissions and take advantage of off-peak rates. ev.energy has partnered with 55+ utilities across the globe and connected over 200,000 drivers, reducing peak charging load by over 90%.
WeaveGrid	*Supports over 30 utilities and OEM partners*	WeaveGrid leverages vehicle telematics, chargers, and utility data for managed charging and supports utilities serving more than 40% of EVs in the U.S. In 2022, it partnered with PG&E to launch the Resilient Charging Pilot, where about 5,000 EVs were provided passive and active managed charging options to enhance grid resilience.

Sources: Figures from Hledik, R. et al. (2024), *Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment*. For details about individual programs, please see WeaveGrid (2022), "WeaveGrid Launches evPulse for Northern and Central California-based EV drivers"; WeaveGrid, Enabling the EV Future; Ev.Energy, How MCE Achieved 90% Peak Load Reduction with a Managed EV Charging Program; Voltus, About Voltus; CPower, About CPower; Uplight (2021), Consumers Energy Provides 100,000 Pre-Enrolled Smart Thermostats to Save Money and Energy; Uplight, About Uplight; Renew Home (2024), "NRG, Renew Home and Google Cloud Announce Partnership; Renew Home, About Renew Home; EnergyHub, About EnergyHub; and *Utility Dive* (2024), "How an Ontario Virtual Power Plant Enrolled 100,000 Homes in Just Six Months."

B. Maximize participation in enhanced rate options

> **SUMMARY:** Utilities should consider (and regulators should consider requiring) expanded rate offerings that provide customers with price signals that reflect system conditions more accurately while accounting for customer preferences. Doing so would improve the efficacy of demand-side programs and incentivize customer behavior (e.g., load shifting)—particularly from commercial and industrial (C&I) customers—that helps alleviate stress on the grid, ultimately reducing system costs.
>
> **RELEVANT STAKEHOLDERS:** Utilities, state regulators
>
> **IMPLEMENTATION NOTES:** State regulators may consider mandating the development of certain rate options. Any proposed rate would require regulatory approval.

Demand-side management (DSM) programs are more successful when customers have meaningful financial incentives to participate and respond. Given the growing need for load flexibility in a system that is increasingly capacity-constrained, time-varying rates can be an effective mechanism to improve system reliability by encouraging customers to shift their usage to times of generation oversupply, and away from hours when renewable generation is unavailable or otherwise expensive to store. To that end, utilities should review and consider enhancing and expanding their rate offerings to provide customer choice while leveraging customer-side resources to meet evolving system needs.

The growth in residential advanced metering infrastructure (AMI) deployment across North America has enabled the deployment of TVRs to mass market customers. The time-of-use (TOU) rate offers time-varying price signals in an easy-to-understand manner while reducing adverse bill impacts for small customers, and some utilities have begun to deploy residential TOU rate offerings as the default (i.e., opt-out) option.

Studies have shown that the share of customers remaining on a TOU rate when deployed on a default basis can be multiples higher than the number of customers that sign up for a TOU rate when deployed on an opt-in basis.[28,29] In the US, default TOU rates have been deployed in

[28] Kahn-Lang, J. et al. (2025), *Different Prices for Different Slices: A Meta-Analysis of Time-Based Electricity Rates*, Resources for the Future, pp. 15–16.

[29] LBNL (2016), *Final Report on Customer Acceptance, Retention, and Response to Time-Based Rates from Consumer Behavior Studies*.

California, Colorado, Michigan, Missouri, and New York. Ontario also has a default TOU. While TOU rates do not dynamically reflect real-time market and grid conditions, they can be an effective tool to shift customer loads away from periods with high resource-adequacy risk and grid utilization.

Similarly, opt-in critical peak pricing rates would incentivize customers to dynamically reduce their electricity usage during a limited number of high-stress hours each year, with the benefit of lower rates during all other hours. For customers prioritizing convenience, opt-in subscription pricing rates could offer them a fixed monthly payment regardless of how much electricity they use, with the fixed amount being determined by the customer's historical usage.[30] When bundled with participation in energy efficiency and load flexibility programs, subscription rates can provide customers with cost savings and price stability while optimizing system usage.

We caveat that the design and deployment strategy of enhanced rates should account for objectives such as cost effectiveness and customer satisfaction.[31] For example, an opt-in peak-demand-based rate, potentially coupled with a time-varying rate, could help promote usage patterns that alleviate constraints on the distribution system and provide price signals for automated DSM programs to shift load. Such a rate would incentivize EV owners to charge their vehicles during periods of lower system demand.[32] The improved price signal would contribute to the success of the full-scale managed EV charging program discussed above. Furthermore, we note that simple TOU rates can have unintended consequences on distribution peaks (including the creation of new "shadow peaks"[33]) owing to differences in system constraints on the distribution versus the generation and transmission systems.[34]

C&I customers generally tend to be more responsive to price signals than residential customers, and opt-in critical peak pricing or "real-time" pricing programs would provide them with more options to adjust their usage, reduce their electricity bills, and contribute to the overall system

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[30] Subscription rate monthly payments are typically determined based on the customer's historical usage, plus a risk premium for the utility for hedging. See Fox-Penner, P. et al. (2020), *FixedBill Plus: Making Rate Design Innovation Work for Consumers, Electricity Providers, and the Environment*.

[31] For rate design considerations for large customers, please see LBNL and The Brattle Group (2025), *Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities*.

[32] The TOU rate must be designed carefully (e.g., with gradual, multi-step price changes) to avoid an outcome in which too many customers respond simultaneously to the start of a pricing block and consequently create new peaks on (and potential overloads of) the local distribution system.

[33] See Bailey, M. et al. (2024), *Electric Vehicles and the Energy Transition: Unintended Consequences of Time-of-Use Pricing*, NBER Working Paper 32886, which demonstrated that shadow peaks from EVs on TOU rates are avoided under managed EV charging programs.

[34] Turk, G. et al. (2024), *Designing Distribution Network Tariffs Under Increased Residential End-user Electrification*, MIT CEEPR Working Paper 2024-02.

efficiency. Interruptible tariffs, as well as pay-for-performance, can offer similar opportunities to manage peak loads. New large loads may be less responsive to price signals because of operational constraints or because of their high willingness to pay to avoid interruptions.

However, some technology companies have shown that it is possible to reduce electricity demand during peak hours by dispatching behind-the-meter generators (i.e., by building grid-responsive generators instead of simple backup generators) or by shifting non-urgent computing tasks to different times and locations without affecting the regular services used by customers.[35] Utilities can incentivize data center customers to leverage their load flexibility through meaningful financial incentives or even by offering more timely interconnection to customers with demand response capability (e.g., grid-dispatchable flexible loads or onsite generation).

C. Broaden deployment of grid-enhancing and advanced transmission technologies, remedial action schemes, and advanced conductors

> **SUMMARY:** Transmission planners should promote the use of grid-enhancing technologies (GETs), high-performance conductors (HPCs) and other advanced transmission technologies (ATTs), Remedial Action Schemes (RASs), and more quickly expand existing grid capacity (including interties with neighboring regions); address near- and medium-term reliability needs, mitigate grid congestion; and avoid uneconomic curtailment of renewable generation. Planners should consider implementing these solutions according to a "loading order" approach that prioritizes increasing existing grid capacity for near-term impact while the construction of new transmission lines can address longer-term needs.
>
> **RELEVANT STAKEHOLDERS:** Transmission planners (ISOs/RTOs, vertically integrated utilities), federal and state regulators, policymakers
>
> **IMPLEMENTATION NOTES:** Transmission planners can implement many of these technologies immediately. Meaningfully incorporating them into the

35 Mehra, V. and R. Hasegawa (2023), "Supporting Power Grids with Demand Response at Google Data Centers," Google Cloud. See also Giacobone, B. (2025), "Verrus Successfully Demos its Flexible Data Center Technology," Latitude Media.

> planning process would benefit from legislative mandates as well as broader planning reforms, as discussed in Recommendation V.A.

More interconnection capacity will be needed to serve the 175 GW of new load projected for 2030, as well as the corresponding generation resources. There are many ongoing efforts at different levels to streamline the process of planning, permitting, and constructing new transmission lines. However, it will still take many years to add new transmission lines, especially as the supply chain for certain types of transmission equipment is constrained. For these reasons, it is far more efficient and cost-effective to get more out of the existing systems.

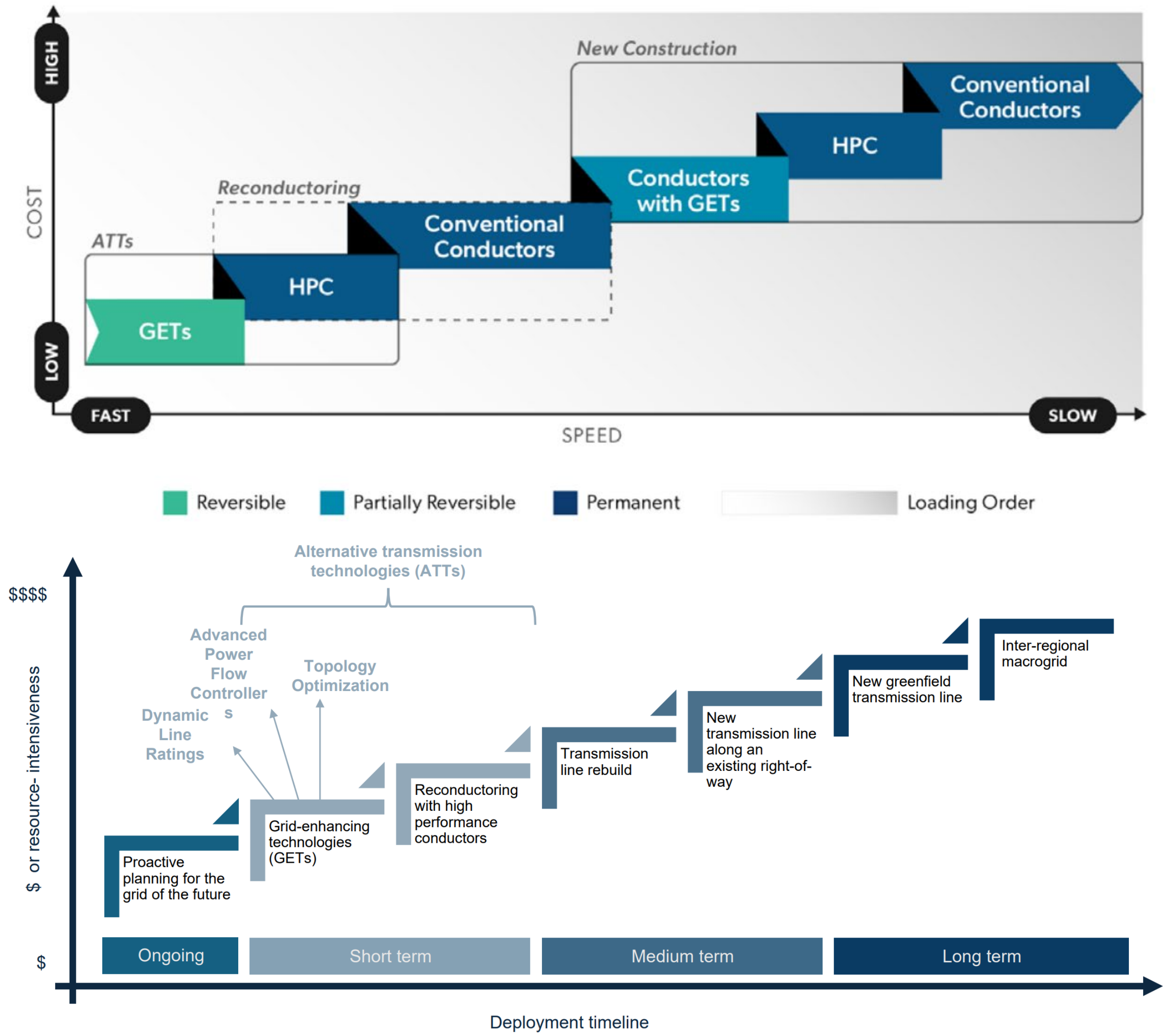
GETs, other ATTs, and RASs can quickly and cost-effectively create the additional grid capacity needed to serve new loads and interconnect the necessary resources at locations served by existing infrastructure.[36] While the benefits of GETs and other ATTs will be very location- and application-specific, commercial experience to date (discussed below) shows that these technologies often can be deployed in less than a year and reliably and cost-effectively enhance existing grid capacity by 20% to 30%.

Moreover, not only can these technologies enhance the existing transmission grid (including on a temporary basis until planned new transmission projects can be built and energized), but they also can amplify the capability of new transmission projects. In addition, the GET equipment can often be moved to different locations (e.g., after a line is rebuilt and upsized).

Figure 5 below illustrates the deployment timeline and cost of GETs, such as dynamic line rating (DLR), topology optimization, and advanced power-flow controls; ATTs such as high-performance conductors; and the upsizing of existing transmission lines in comparison to the construction of new greenfield transmission projects. Of course, new lines will be necessary to reach areas that are currently not served by the existing grid.

[36] For an overview of grid enhancing technologies (GETs) and advanced transmission technologies (ATTs), see: Massachusetts Clean Energy Transmission Working Group (2023), *Report to the Legislature*, Section 7; US Department of Energy (2022), *Grid-Enhancing Technologies: A Case Study on Ratepayer Impact*; US Department of Energy (2020), *Advanced Transmission Technologies*.

FIGURE 5: "LOADING ORDER" OF GETS, ATTS, AND NEW TRANSMISSION



Sources: Tsuchida, T.B. (2025), *Incorporating GETs and HPCs into Transmission Planning Under FERC Order 1920* and RMI (2024), *Alternative Transmission Technologies in Order 1920 and PJM.*

Grid operators who rely on static line ratings should consider transitioning to ambient adjusted rating (AAR) or directly to DLR. Studies show that AAR offers transmission capacity increases between 3% and 15% over SLR, and recent experience demonstrates that DLR can enhance SLR capacity by between 19% and 33%.[37] Although DLR requires sensors and telemetry, the costs of such equipment are a fraction of those involved in reconductoring or rebuilding transmission lines to expand their capacity. Box III-A describes the benefits experienced by PPL Electric Utilities as the first US transmission owner to implement DLR beyond the pilot stage.

[37] LineVision Inc. & National Grid USA (2021), *An Empirical Analysis of the Operational Efficiencies and Risks Associated with Static, Ambient Adjusted, and Dynamic Line Rating Methodologies*.

To address constraints in specific grid locations, grid operators should explore the use of topology optimization and advanced power-flow controls, which have been shown to efficiently alleviate constraints. Both these technologies optimize the existing grid by rerouting power around congested or overloaded transmission elements to under-utilized portions of the grid, thereby significantly expanding the grid's effective capability (see Box III-A below for examples of the benefits of topology optimization).[38]

Reconductoring existing lines with high-performance conductors can serve as a medium-term option to improve transfer capability, reliability, and resilience. HPCs, such as the Aluminum Conductor Composite Core (ACCC) technology, can harden the grid (by replacing old conductors with stronger, lighter, new conductors), reduce wildfire risks (by reducing line sag), and double the capacity of existing lines without requiring new towers.[39] HPCs can also be a cost-effective way to further increase transfer capability in a more timely fashion without the need for new transmission lines and, if necessary, without outages of the existing lines.[40]

Grid operators should consider structuring their use of these advanced transmission solutions based on a "loading order" that prioritizes increasing existing grid capacity ahead of the construction of new transmission lines, as shown in Figure 5 above.[41] This should also involve innovative dynamic contingency management options, including RASs, to create additional transmission capability necessary for interconnecting both new loads and resources.[42] Next, GETs and advanced conductors should be prioritized to increase the capacity of the existing grid (and rights-of-way) before transmission needs are addressed through new lines. These principles promote a more timely and cost-effective approach to grid expansion and have been used successfully. For example, in Germany, the legislatively mandated "NOVA principle" requires "grid optimization first, then grid strengthening, before any further grid expansion."[43]

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[38] For detailed case studies of topology optimization benefits, see Brattle (2024), *Topology Optimization Case Studies*.

[39] Clean Energy Transmission Working Group (2023), *Report to the Legislature*.

[40] For example, the Edison Electric Institute's (EEI's) prestigious 2016 Edison Award was received for and American Electric Power reconductoring project that was undertaken without an outage of the transmission line. AEP was able to "replace all 240 miles of line while they were in an energized state utilizing existing structures and right-of-ways [*sic*]." See "American Electric Power Awarded EEI's 2016 Edison Award."

[41] See Massachusetts Clean Energy Transmission Working Group (2023), *Report to the Legislature*, recommending the "loading order" approach and noting that Germany has legislatively required this grid planning approach (the NOVA principle) about a decade ago.

[42] For example, the CAISO has used RAS to create interconnection capacity for 21,000 MW of renewable generation resources, 16,000 MW of which are for "firm" delivery to support resource adequacy needs. See CAISO (2023), "Briefing on Resources Available for Near Term Interconnection." See also Norris, T.H. (2025), Testimony in front of the U.S. House Energy and Commerce Committee.

[43] TransnetBW, "NOVA Principle."

A recent Brattle review[44] of 25 case studies found that GETs and ATTs can provide each of the seven transmission benefits that FERC Order 1920 requires transmission providers to consider when planning transmission facilities.[45] GETs and ATTs can provide these benefits at lower cost, more quickly, and with greater complementarity, portability, and reversibility than traditional wires solutions. State policymakers and/or regulators can play an important role in facilitating the consideration and deployment of GETs and ATTs—indeed, several states have recently passed legislation requiring utilities and transmission planners to incorporate the consideration of GETs and ATTs into their planning processes.[46] Similarly, governors across the country have taken steps to accelerate the deployment of GETs and ATTs as part of their energy policy agenda.[47]

Finally, current transmission planning frameworks should be revised to incorporate more holistic processes in order to facilitate the use of GETs and ATTs to provide transmission benefits and associated cost savings (see Recommendation V.A). These processes should provide a consistent, multi-value framework to accurately capture additional benefits that a given transmission solution can provide beyond meeting minimum need requirements. Without a consistent framework that actively considers a broad range of benefits, high-value solutions with modest cost premiums are likely to be overlooked in favor of solutions that are slightly lower cost but provide little additional value beyond meeting the immediate need.

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44 Tsuchida, T. B., et al. (2025), *Incorporating GETs and HPCs into Transmission Planning Under FERC Order 1920*, The Brattle Group, prepared for the American Council on Renewable Energy.

45 The minimum set of transmission benefits that Order 1920 requires transmission providers to consider are: 1) Avoided or deferred reliability transmission facilities and aging infrastructure replacement; 2) reduced loss of load probability or reduced capital costs to meet planning reserve margin; 3) production cost savings; 4) reduced transmission energy losses; 5) reduced congestion due to transmission outages; 6) mitigation of extreme weather events and unexpected system conditions; and 7) capacity cost benefits from reduced peak energy losses. *See* Federal Energy Regulatory Commission, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 189 FERC ¶ 61,126 (Nov. 21, 2024), ¶¶ 369-433 (Order 1920-A) available at: https://www.ferc.gov/media/e-1-rm-21-17-001.

46 For more details, see: California Senate Bill 1006 (2024), Electricity: transmission capacity: reconductoring and grid-enhancing technologies; Maine Legislative Document LD 589 (2024), An Act to Ensure That the Maine Electric Grid Provides Additional Benefits to Maine Ratepayers; Massachusetts Senate Bill S.2531 (2024), An Act promoting a clean energy grid, advancing equity, and protecting ratepayers; Watt Coalition (2024), "Minnesota passes landmark legislation on Grid Enhancing Technologies"; Montana 68th Legislature House Bill 729 (2024), Providing for advanced conductor cost-effectiveness criteria; and Virginia HB 862 (2024), Electric utilities; integrated resource plans, grid-enhancing technologies and advanced conductors.

47 Forrester, F. and D. Lauf (2025), *Advanced Grid Technologies: Governor Leadership to Spur Innovation and Adoption*, National Governors Association.

BOX III-A: EXAMPLES OF GETS DEPLOYMENT IN OTHER JURISDICTIONS

PPL's and GRE's Dynamic Line Rating Implementation

Instead of rebuilding or reconductoring two congested 230-kV lines, a Pennsylvania utility, PPL, deployed dynamic line rating at a total cost of less than $300,000 over the course of a year.[48] By fully integrating DLR ratings into PJM's nodal day-ahead and real-time energy markets and operations, PPL avoided approximately $50 million in transmission expansion costs and immediately began generating congestion savings of approximately $20 million per year, with one line seeing winter congestion costs reduced from over $60 million to $1.6 million. DLR increased the transfer capability ratings of the lines by an average of 19% for the lines' "normal" ratings and by 9–17% for the lines' "emergency" ratings. Similarly, Great River Energy (GRE) had deployed DLR on nine lines and integrated with MISO regional market operations, when savings during a single hour with high wind generation were over $3 million, more than paying for the entire DLR investment.[49]

These types of DLR investments are significantly more widespread in Europe. For example, the Belgian grid operator, Elia, uses DLR on a system-wide basis involving 35 transmission lines. Elia's operational experience shows that DLR is more effective and more reliable than ambient-adjusted ratings (AAR), capable of increasing transmission ratings above static ratings on average by 27–30% over the course of a year.[50]

NewGrid Topology Optimization

A Brattle review of 22 case studies where the NewGrid Router topology optimization software was used found that the software expanded the grid's effective capability between 5% and 25% while meeting all reliability requirements by identifying grid reconfigurations that alleviated system constraints.[51] Case studies included Alliant Energy, whose use of NewGrid's software delivered US$24 million in net cost savings to customers in Iowa over a two-year period, and MISO, where a reconfiguration solution to facilitate the maintenance of a major 345 kV line generated congestion cost savings of US$3.5 million and production cost savings of US$1.1 million over a three-week period while also reducing wind curtailments by 86%.

SCE Deployment of High-Performance Conductors

Southern California Edison (SCE) chose an HPC solution to upgrade 137 miles of its Big Creek transmission corridor, increasing transmission capacity by 40%. Being able to reuse the existing towers saved SCE $50,000 per tower, streamlined the utility's permitting and environmental impact studies, and reduced construction time from 48 to 18 months.[52]

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[48] PPL Electric Utilities (2023), *PPL's Dynamic Line Ratings Implementation*.

[49] Great River Energy, "Dynamic Line Ratings" (October 2024), presented at the 15th Annual Colorado Rural Energy Association Energy Innovations Summit.

[50] *New York Power Grid Study - NYSERDA* (2021), Section III on Advanced Transmission Technologies, page 36.

[51] Ruiz, P. (2024), *Topology Optimization Case Studies*, The Brattle Group. See also EPRI (2025), *Transmission Topology Optimization, State-of-the-Art White Paper: A GET SET White Paper*.

[52] CTC Global (2018), *SCE Sag Mitigation Case Study*.

D. Take advantage of "upsizing" opportunities, particularly during refurbishment of aging transmission infrastructure

> **SUMMARY:** Much of the US transmission grid was constructed more than 50 years ago, and there will be a need for refurbishment in the future. When this need arises, utilities should proactively explore and identify opportunities to (a) upsize existing transmission lines where added transmission capability is needed now (and the upsizing avoids future refurbishment needs); and (b) where the refurbishment of aging lines becomes necessary now and adding transmission capability through upsizing of the lines is expected to be valuable in the future.
>
> **RELEVANT STAKEHOLDERS:** Transmission planners (ISOs/RTOs, vertically integrated utilities), regulators
>
> **IMPLEMENTATION NOTES:** Where expansion opportunities are created by an urgent need to refurbish aging infrastructure, this may require regulatory permissions in states that restrict building ahead of need.

Much of the US electric grid infrastructure was built in the 1960s and 1970s, approaching the end of its 50- to 80-year lifecycle, and much of it will need refurbishment in the coming years.[53] The refurbishment or reconditioning of an aging transmission asset presents an opportunity to evaluate whether upsizing opportunities exist, where capability can be added at low incremental costs. Utilities should improve their planning processes to increase the transparency, predictability, estimated cost, and likely timeframes of aging asset refurbishment needs, enabling the proactive identification of upsizing opportunities.

Even when there is no immediate need to refurbish an existing transmission facility, rebuilding the facility at a higher capacity may be a cost-effective way to address emerging constraints on the system. Being able to take full advantage of such upsizing opportunities thus requires that: (1) developing solutions to identified transmission needs implements a "loading order" in which grid-enhancing solutions are considered before upsizing solutions, and upsizing solutions are

[53] For example, as of 2023, 70% of lines and transformers deployed on the grid were over 25 years old and approaching the end of their typical 50–80-year lifecycle. See DOE Grid Deployment Office (2023), "What Does it Take to Modernize the U.S. Electric Grid?"

considered before new transmission solutions are contemplated;[54] and (2) aging asset refurbishment needs are identified well in advance so that upsizing opportunities can be contemplated (even in the absence of urgent additional transmission needs).

In making such assessments, multi-value assessment frameworks are needed to ensure that avoided future refurbishment costs are included in the benefit-cost analysis on a present value basis, as mentioned in Recommendation III.C and elaborated on in Recommendation V.A. For example, when New York needed to expand transmission capability to address public policy transmission needs, upgrading portions of aging existing transmission lines (and thereby avoiding future in-kind refurbishment costs) was identified as a cost-effective solution. Even though refurbishment needs were not urgent or upcoming in the near term, savings based on the present value of the avoided refurbishment costs accounted for up to 50% of the cost of the necessary transmission expansion.[55]

If the refurbishment of an existing transmission line is necessary now, but the need for additional transmission capability is uncertain but plausible, creating options for future expansion can be a prudent approach. For example, it may be prudent to rebuild an aging existing single-circuit transmission line with double-circuit towers and develop the capability to operate the line at a higher voltage in the future. Doing so creates the flexibility to quickly double or triple transmission capacity in the future at a modest cost by (a) converting the line to be operated at the higher design voltage; and (b) adding a second circuit to the transmission line. In addition, converting conventional transmission lines to HVDC technology can offer other attractive upsizing opportunities, providing high-capacity long-distance transmission at reduced right-of-way requirements.[56]

This recommendation is also consistent with FERC's recent Order No. 1920, which requires "[t]ransmission providers must evaluate right-sized replacements alongside other solutions and propose a point in time for submitting estimates of anticipated in-kind replacements of their existing transmission facilities early in each planning cycle. If identified, right-sized replacements are evaluated for efficiency and cost-effectiveness."[57]

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[54] As noted earlier, see Massachusetts Clean Energy Transmission Working Group (2023), *Report to the Legislature*, recommending the "loading order" approach and noting that Germany has legislatively required this grid planning approach (the NOVA principle) about a decade ago.

[55] See Pfeifenberger, J. P. et al. (2021), *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, The Brattle Group p 56.

[56] See Pfeifenberger, J. P. et al. (2023), *The Operational and Market Benefits of HVDC Transmission to System Operators*, The Brattle Group at pp. 80–82 and 129–131. See also, CAISO "HVDC-ready transmission" example discussed in Pfeifenberger, J. (2024)"Order 1920 Compliance: An Opportunity to Improve Transmission Planning beyond Mandates" The Brattle Group, slide 12.

[57] For a summary of the order, see Federal Energy Regulatory Commission (2025), "Explainer on the Transmission Planning and Cost Allocation Final Rule."

E. Facilitate (and recognize the value of) increased and more efficient interregional trade

SUMMARY: Existing interregional transmission can provide substantial cost savings by connecting low-cost interregional generation to load and providing resource adequacy during extreme conditions, but current operation of interties is largely inefficient. Intertie optimization should be pursued to take maximum advantage of available interregional transfer capability in real time and achieve substantial production cost savings. Additionally, regional grid operators should ensure that they appropriately recognize and model the resource adequacy provided by interties when conducting their internal resource adequacy assessments to avoid overbuilding capacity resources and thus raising costs.

RELEVANT STAKEHOLDERS: Regional grid operators

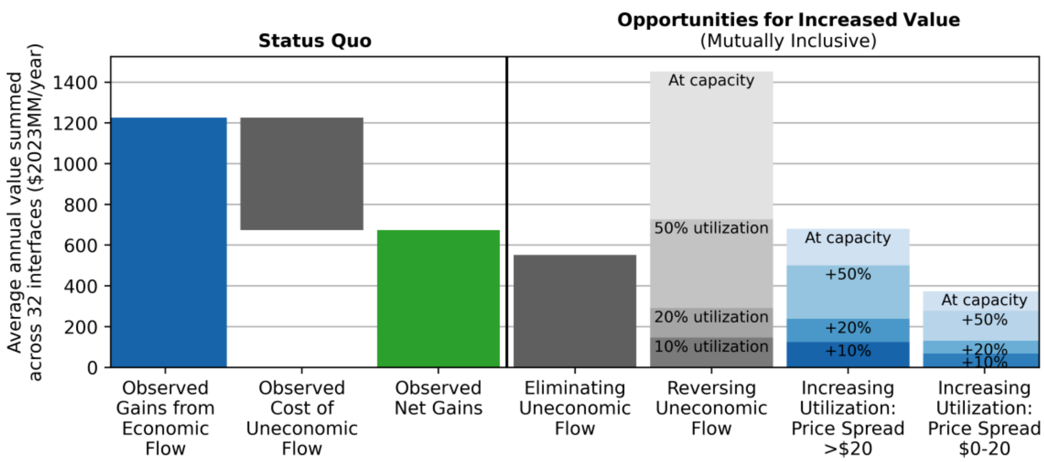
IMPLEMENTATION NOTES: Joint partnerships and working groups may help provide the collaboration between regional grid operators needed to advance intertie optimization. Existing regional interties would benefit from intertie optimization frameworks and resource adequacy frameworks that explicitly recognize the diversity of neighboring Balancing Authority Areas (BAAs).

Demand-side solutions alone are unlikely to suffice for meeting projected load growth. Large amounts of new supply will be needed. Since each type of supply resource has its own challenges, a diverse portfolio will be needed to provide enough supply quickly and cost-effectively. Trade between neighboring regions can provide significant value in this context by expanding the diversity of generation resources available. However, many individual regions in North America do not currently maximize the value of their existing interregional transmission connections. Facilitating efficient utilization of existing interties to connect lower-cost interregional generation with load and recognizing the capacity value of interties in resource adequacy planning would yield substantial cost savings without significant upgrades to transmission infrastructure.

Across North America, many interties are not optimized efficiently to maximize energy flow from lower-priced regions to higher-priced regions, thereby lowering power costs. In many cases, interties are either under-utilized (i.e., not maximizing the delivery of lower-cost power) or flowing power in the opposite direction to prices, from the higher-priced region to the lower-priced region.[58] This inefficient operation is caused by delays between intertie scheduling and actual power flow, a lack of economic coordination between RTOs/ISOs, and, in some cases, transaction costs levied by RTOs/ISOs on external transactions.[59]

Such inefficiencies result in substantial costs. A ten-year Lawrence Berkeley National Laboratory (LBNL) analysis across 32 North American interties found that uneconomic flows in the "wrong" direction cost $551 million per year on average (see dark gray bar in Figure 6 below).[60] Correcting existing trading inefficiencies by eliminating this uneconomic flow and maximizing utilization of lines flowing in the "right" direction could result in up to $3 billion per year of additional power system cost savings (represented by the sum of grey and blue bars on the right)—three times the value associated with existing trades over the interties (shown as the green bar).[61]

FIGURE 6: AVERAGE COST OF UNECONOMIC FLOWS AND VALUE OF INCREASING INTERTIE EFFICIENCY FOR NORTH AMERICAN POWER SYSTEM



Source: LBNL (2025) , *Interregional Electricity Transmission in the United States: Realized Savings and Opportunities for Increased Value, 2014–2023* (draft working paper).

To capture this value currently left on the table, regional grid operators should pursue efforts to implement intertie optimization frameworks that maximize the efficiency of existing interregional transmission capabilities. Such frameworks have been recommended by market monitors across the US for decades, but progress towards this goal has been limited largely to

58 See The Brattle Group and Willkie Farr & Gallagher (2023), *The Need for Intertie Optimization*.

59 *Ibid.*

60 LBNL (2025), *Interregional Electricity Transmission in the United States: Realized Savings and Opportunities for Increased Value, 2014–2023* (draft working paper).

61 As the authors point out, because the analysis does not consider convergence of price differences due to increased trades, these values will be upper bookend estimates. On the other hand, the values will be understated because the analysis is based on hourly (not 5-minute) real-time price differences.

the implementation of Coordinated Transaction Scheduling (CTS). CTS has been shown to be insufficient due to its reliance on forecasts of an increasingly volatile real-time market (amongst other things)[62]—LBNL found that 38–51% of flow volumes in markets with CTS *increased* system costs instead of reducing them. Box III-B highlights examples of intertie optimization in both the US and abroad.

Alongside energy value, interregional transmission can offer significant reliability and resource adequacy value by connecting balancing authorities with additional generating capacity outside of their BAA. Resource adequacy risks are heavily correlated with extreme weather events such as Winter Storm Uri in Texas in February 2021. Imports from neighboring regions not experiencing the same events (or less affected by them) are highly valuable, particularly as the share of intermittent resources in the generation fleet increases. In its Interregional Transfer Capability Study, the North American Electric Reliability Corporation (NERC) found that existing interties have substantial resilience value and that a further 35 GW of interregional transmission would be "prudent" to maintain resource adequacy under extreme conditions.[63] Despite this, many jurisdictions do not appropriately recognize the resource adequacy of existing (or proposed) interties when conducting resource adequacy assessments and determining capacity prices. In some cases, resource adequacy studies assume as little as 12% of the region's total summer import transfer capability is available for reliability.[64] This can result in over-procurement of additional generation capacity, ultimately increasing system costs.

To avoid these costs, regional grid operators should ensure that interregional transmission that allows flow to enter capacity-constrained regions is treated as a capacity resource that is able to meet resource adequacy requirements. To achieve this, resource adequacy analyses should include an assessment of the capabilities of neighboring systems to provide imports when they are needed. Box III-B discusses approaches that different jurisdictions have taken to recognize the resource adequacy value of interregional trade.

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[62] See Pfeifenberger, J. P. et al. (2023), *The Need for Intertie Optimization*, The Brattle Group.

[63] NERC (2024), *Interregional Transfer Capability Study (ITCS)—Parts 2* and 3.

[64] Based on research on ISO RA models and estimates of existing transfer capability from Part 1 of NERC's *Interregional Transfer Capability Study*.

BOX III-B: CASE STUDIES OF INTERTIE OPTIMIZATION AND INTERREGIONAL RESOURCE ADEQUACY FRAMEWORKS

Western US Energy Imbalance Markets (WEIM & WEIS)

In the Western US, two energy imbalance markets—the Western Energy Imbalance Market (WEIM) and the Western Energy Imbalance Service (WEIS)—have been created to optimize the real-time dispatch of resources across Western BAAs. Dispatch schedules of resources that are made available to the imbalance markets are adjusted to economically utilize the remaining available transmission between BAAs, optimizing the real-time interchange schedules of these interties. This optimization across BAAs has resulted in significant cost savings, with the WEIM (the older of the two markets) generating $6.6 billion of estimated benefits between its inception in 2014 and January 2025.[65]

European Flow-Based Market Coupling

Since 2006, power system operators in Central and Western Europe have engaged in an innovative effort to "couple" their power markets to optimize cross-border energy exchanges. Initial coupling efforts were limited to day-ahead markets and relied on system operators' estimates of the transfer capability across each border, but the framework evolved to rely on detailed power flow representations of the European grid (referred to as "flow-based market coupling" or FBMC) as well as include a cross-border intraday trading platform. FBMC is now used by system operators for both day-ahead and intraday trading, and studies have shown that this approach currently generates a welfare gain of around €116 million per year.[66]

NYISO Treatment of Interregional Transmission during Resource Adequacy Assessments

As part of its annual installed reserve margin (IRM) study, the New York ISO (NYISO) uses a resource adequacy model to quantify the incremental capacity needed to meet its loss of load expectation criterion. In the study, NYISO explicitly models its neighboring regions of PJM, ISO-NE, Hydro-Quebec, and IESO—including their load, capacity mixes, and interties (and corresponding firm capacity imports) to NYISO—to appropriately represent the incremental assistance that may be available from these neighboring regions during a resource adequacy event. The IRM study also models "emergency assistance" that NYISO may be able to receive from its neighbors. Thus, NYISO allows for capacity imports while also accounting for the resource adequacy value of any additional "uncommitted" capacity imports from its neighbors.[67]

European Resource Adequacy Assessment

Since 2021, the European Network of Transmission System Operators for Electricity (ENTSO-E), an association that represents European TSOs, has conducted an annual pan-European probabilistic resource adequacy assessment known as the European Resource Adequacy Assessment (ERAA). TSOs provide ENTSO-E with data on their forecasted load and resource mixes, and ENTSO-E conducts the 10-year analysis using a flow-based market representation of transfer capabilities between regions. This approach maximizes the efficiency of simultaneous interchanges between regions and provides a comprehensive understanding of resource adequacy concerns while recognizing the value of interregional trade (enabled by its aforementioned market coupling reforms).[68]

IV. Cost-Effectively Accelerate Grid Connection of New Loads

A. Facilitate customer-sponsored generation investments and procurements to maintain resource adequacy

SUMMARY: It is challenging to ensure there is sufficient generation capacity to service new large customers while also maintaining grid reliability. To accelerate the cost-effective integration of large industrial loads while maintaining resource adequacy, customers should be encouraged and allowed to self-supply their generation needs. Facilitating self-supplied generation can enhance system reliability, address transmission constraints, and promote the adoption of efficient on-site technologies. Utilities and regulators should encourage wheeling or sleeving arrangements, where customers procure their own power and rely on the utility's grid for delivery. Self-supply tariffs should be designed to avoid shifting costs of incremental grid investments to other customers without inadvertently creating barriers to customer self-supply.

RELEVANT STAKEHOLDERS: Utilities, regulators, RTOs/ISOs

IMPLEMENTATION NOTES: This would require utilities and regulators in jurisdictions without retail competition to allow for the direct procurement (or sleeving/wheeling) for large customers.

With strong business incentives to interconnect new loads to the grid quickly, some large customers will be willing to own, finance, or contract for their own generation needs as an

65 CAISO (2025), *Western Energy Markets Quarterly Benefits Reports*.

66 Ovaere, M. et al. (2022), *The Effect of Flow-based Market Coupling on Cross-border Exchange Volumes and Price Convergence in Central-Western European Electricity Markets*.

67 See New York State Reliability Council (2024), *New York Control Area Installed Capacity Requirement*, and NYISO (2024), *2024 Reliability Needs Assessment (RNA)*.

68 ENTSO-E (2023), *European Resource Adequacy Assessment—2023 Edition*.

alternative to often longer generation procurement and interconnection timelines. Customers procuring their own generation supply is already possible in jurisdictions with retail competition (see Figure 7).

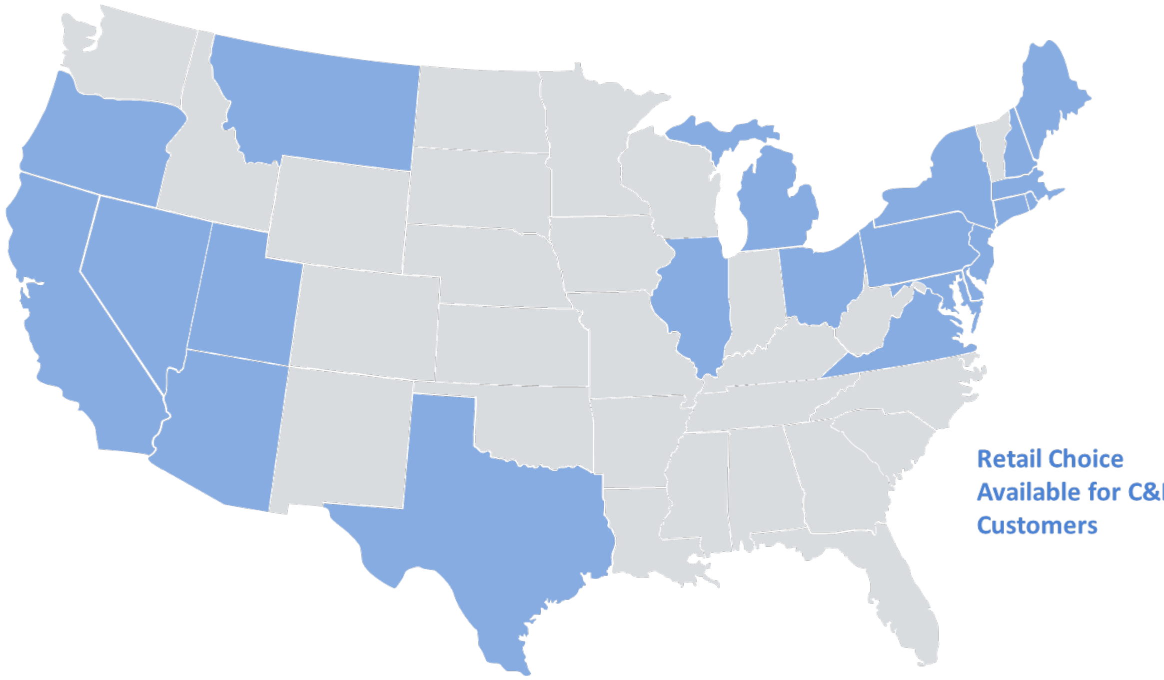
In jurisdictions without retail competition, utilities and regulators should encourage and allow these customers to self-supply through "wheeling" or "sleeving service" arrangements. Under a wheeling arrangement, customers would own or procure their generation resources themselves or through a third-party supplier, with the utility delivering the self-supplied power over its transmission and distribution grid. This approach is already implemented in many jurisdictions across North America (see Figure 7 below) and can be adapted to support clean-energy development goals (see NV Energy example in Box IV-A). To ensure system-wide resource adequacy and local reliability requirements, utilities and RTOs should further incorporate customers' self-supplied generation into their reliability operations and planning processes. Doing so would allow the accelerated deployment of generation through self-supply while also serving system-wide needs to maintain resource adequacy.

It should be noted that charging only for average transmission and distribution costs for self-supply options that are still grid-connected might not recover the full incremental resource adequacy and delivery costs associated with new loads, particularly if the interconnection results in additional backup generation, transmission, and/or distribution investments. In such cases, the burden of funding additional grid investments would be shared by other customers unless the self-supply tariffs are designed to also recover any incremental system costs. At the same time, rates used to recover the added costs (including for any backup generation service) should be designed carefully to avoid inadvertently creating barriers to customer self-supply.

Innovative rate design can help lower the costs for both the self-supply customer and the utility by leveraging the customer's behind-the-meter backup resources. For example, Black Hills Energy negotiated a contract that allows it to access Microsoft's onsite backup generation capacity for its Cheyenne, Wyoming data center during high-demand periods. The utility can call upon this backup generation to help meet peak load needs, effectively turning Microsoft's backup generators into a grid asset.[69]

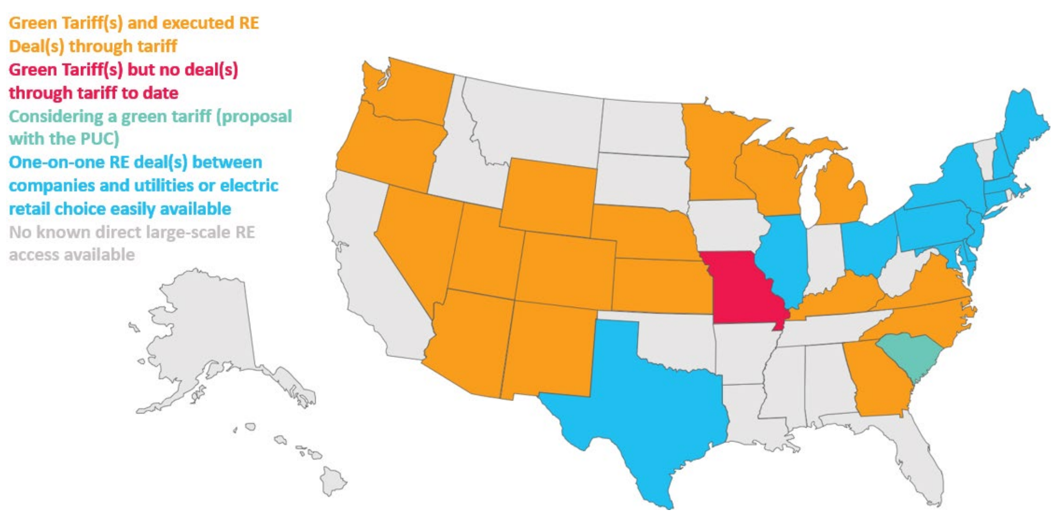
[69] Black Hills Energy (2020), *Energy Solutions for Data Centers*.

FIGURE 7: STATUS OF RETAIL CHOICE ACCESS FOR C&I CUSTOMERS IN THE US



Source: Adapted from Hibbard, P. (2023), *At the Crossroads: Improving Customer Choice for Products in the U.S. Electricity Sector, Analysis Group*, Figure 1, and Utah State Legislature (2025), S.B. 132 Electric Utility Amendment.

FIGURE 8: EXAMPLE GREEN TARIFFS AND RENEWABLE ENERGY DEALS IN THE US



Source: Clean Energy Buyers Association (CEBA), "Availability of Utility Green Tariff Programs," accessed Jan. 2023.

While self-supply options should be made available to new C&I customers to serve their needs for fast access to power while reflecting the incremental cost on the system, making these options available to existing C&I customers runs the risk of shifting fixed system costs onto other rate classes, such as the residential sector. Care should be taken to avoid retail access options that shift system costs onto other customers.

Alternatively, directly co-locating large loads with new generation in an “energy park” (discussed further in Recommendation IV.B) can avoid the need to plan for additional off-site capacity to the extent that on-site generation offsets on-site load. In addition to addressing system-wide resource adequacy needs, customer-owned or customer-contracted self-generation resources co-locating with load would address constraints on the transmission and distribution system if the dispatch of the customer-owned generation can be optimized (and automated) to reduce the net load at the customer location whenever necessary, thus avoiding costly and time-consuming transmission upgrades.

BOX IV-A: SLEEVING CONTRACTS, RETAIL ACCESS, AND ENERGY PARKS IN OTHER JURISDICTIONS

NV Energy Clean Transition Tariff: Google & Fervo Energy Geothermal

NV Energy—in partnership with Google—sought and recently received approval from regulators for a new "Clean Transition Tariff" that allows customers with average hourly load larger than 5 MW to pay a higher rate for clean, firm generation from emerging technologies.[70] Google supported the tariff as a means to finance a Fervo Energy geothermal project to supply its forthcoming data center load. NV Energy would buy electricity from the in-development 115-MW geothermal plant and sell it to Google at a set rate. In exchange, Google would have the plant's generation and capacity credited against the energy and demand charges, respectively, on the bill of its data centers.[71] This type of arrangement allows the customer to benefit from clean, firm supply while shouldering the incremental cost of the new generation instead of the utility.

Oregon Direct Access Program

Oregon allows retail access for large non-residential customers.[72] These customers may opt to purchase electricity from a public utilities commission (PUC)-certified electricity service supplier (ESS) other than their utility. The ESS is responsible for procuring generation and transmission service, while the local utility service provider is responsible for distribution. There are seven ESSs eligible to serve customers in Oregon.[73]

Intersect Power Energy Parks Projects

Energy parks are sites where large electricity consumers are co-located with generation assets that can be dispatched for grid-related needs, which can offer significantly faster grid access for new loads. Intersect Power has two energy parks in development. The $1 billion Meitner Project in Texas is developing 460 MW of wind and 340 MW of solar to power 400 MW of hydrogen electrolyzers.[74] Similarly, Google is investing a total of $20 billion in energy parks by the end of the decade to power data centers using solar and battery storage, with the first project expected to be operational in 2026 and complete in 2027.[75]

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70 Public Utilities Commission of Nevada (2024), Docket No. 24-05022—Clean Transition Tariff.

71 Penrod, E., "NV Energy seeks new tariff to supply Google with 24/7 power from Fervo geothermal plant." *Utility Dive* (June 21, 2024).

72 Oregon Public Utility Commission, "Direct Access."

73 Pacific Power, Oregon Direct Access and Portland General Electric, "Direct Access Operations."

74 Energy Innovation (2024), *Energy Parks: A New Strategy to Meet Rising Electricity Demand*.

75 Intersect Power (2024), "Intersect Power Forms Strategic Partnership with Google and TPG Rise Climate to Co-Locate Data Center Load and Clean Power Generation."

B. Minimize the need for transmission upgrades by facilitating co-location of new generation and load in "energy parks"

SUMMARY: Connecting large customers to the grid often triggers costly and time-consuming transmission upgrades that delay the customers' access to power and increase system costs. Co-locating new load with new on-site generation in precisely controllable "energy parks" (i.e., large microgrids) can minimize or avoid entirely the need for transmission upgrades, increasing speed to market while reducing system and customer costs and potentially providing emissions reduction benefits. To facilitate this co-location arrangement, transmission operators and owners should adopt interconnection processes that appropriately reflect the operation of co-located load and generation, and offer expedited screening processes given the controllable, non-firm nature of their grid injections.

RELEVANT STAKEHOLDERS: RTOs/ISOs, transmission owners, federal regulators, energy park developers

IMPLEMENTATION NOTES: States have different regulations on retail electricity sales to an end user that can affect the asset ownership and feasible contracting models of energy parks. Similarly, some RTOs/TOs may have restrictions on how they manage behind-the-meter resources or evaluate them to determine necessary grid upgrades.

In cases where large loads connecting to the grid would exceed existing transmission capacity, transmission upgrades are required.[76] Planning and constructing these upgrades often is costly and time consuming, resulting in long wait times for new customers as well as upward pressure on rates to recover the transmission investments. Large load customers therefore have a strong

[76] Beyond the need to increase grid and generation capacity to serve new loads, large electronic loads (such as data centers) increasingly contribute to grid reliability and stability challenges through rapid large demand fluctuations and inadequate low-voltage ride-through capabilities. If not addressed on the load side, these challenges may require additional grid-strengthening investments. See, for example, NERC (2025), *Characteristics and Risks of Emerging Large Loads*; Elevate Consulting (2025), *An Assessment of Large Load Interconnection Risks in the Western Interconnection*; Laube (2025), NERC Activities and Plans to Address Reliability Impacts from Large Load Integration, FERC Open Meeting April 17, 2025; and ERCOT Large Load Workshop (Event Details) June 13, 2025.

incentive to avoid triggering transmission upgrades that would increase the lead times—and potentially costs—of their projects.

The co-location of large new loads with dispatchable new generation has emerged as a potential solution to avoid time consuming and expensive transmission upgrades. Co-location of load with *existing* generation has been discussed in jurisdictions such as PJM,[77] but raises resource adequacy concerns by effectively reducing system-wide supply and can shift some of the existing costs from the co-located load to the remaining customers. In contrast, co-locating *new* load with *new* generation in an "energy park" (i.e., large micro grid that can precisely control its withdrawals and/or injections from the grid so it does not need to be studied as both as firm load and generation for the purpose of grid connections) can address both resource adequacy and transmission adequacy concerns by quickly connecting loads to power without requiring extensive transmission or generation investments and without raising concerns over unfair cost allocation. As demonstrated in a recent Brattle report, energy parks with new generation, co-located load, and mechanisms to reliable control net flows to and from the transmission grid can be connected with fewer transmission upgrades (and therefore more quickly) by locally supplying part or all of their load depending on grid capacity, conditions, and contingencies.[78]

Capturing the transmission benefits of energy parks requires interconnection study processes that are tailored to the co-location of new load and generation with controls that can precisely and reliably manage the energy park's net withdrawals (or injections) into the grid. Currently, many grid operators study co-located load and generation by separately considering the impacts of the new load and of the new generation without considering that the net grid impact can be greatly reduced through self-supply of the co-located loads. The existing study approaches often result in the identification of reliability risks and grid upgrades that do not reflect the controllable operating behavior of the co-located loads and resources.

For example, based on the interconnection approach used in ERCOT for Private Use Networks (discussed in Box IV-B), an "energy park integration approach" studies the composite behavior of co-located load and generation when operated with a control mechanism that limits grid withdrawals and injections (i.e., on-site load minus on-site generation) to the available grid capacity. Assessing the interconnection of an Energy Park from this integrated perspective can avoid triggering expensive transmission upgrades in both base-case reliability analyses and contingency analyses, as illustrated in Figure 9. Both PJM and MISO have expressed support for

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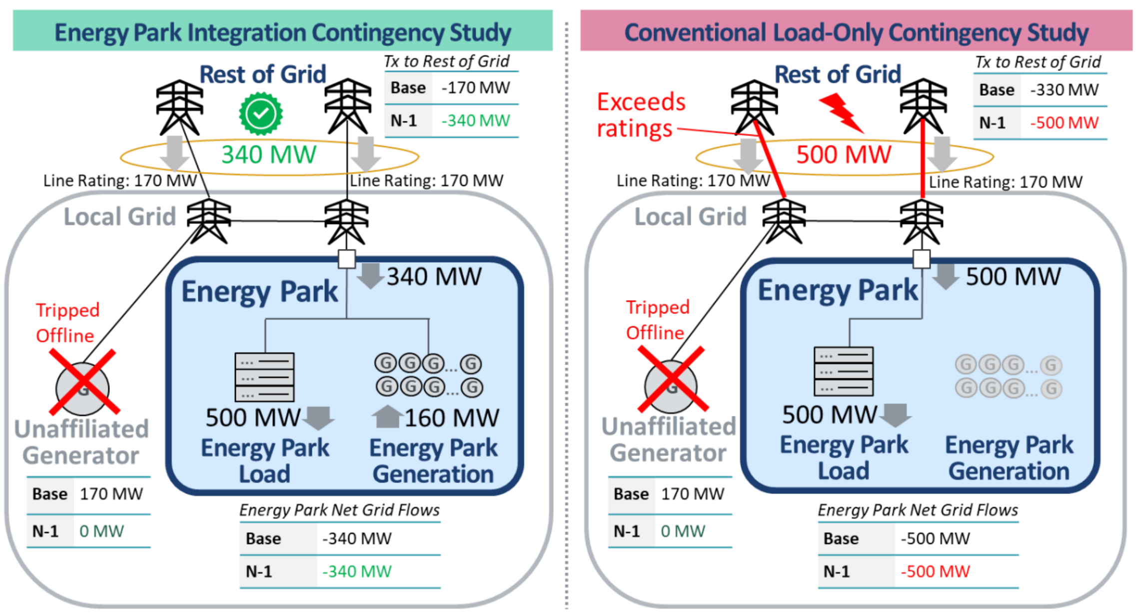
77 PJM, "Answer of PJM Interconnection L.L.C.," FERC Docket No. EL25-49-000, March 24, 2025, Exhibit B, and New Option 6, at page 16; PJM, Large Load Additions Workshop, May 9, 2025.

78 Levitt, A. et al. (2025), *Accelerating the Integration of New Co-located Generation and Loads*, The Brattle Group.

developing such integrated assessment processes for energy parks[79] and energy parks will be facilitated by new Texas legislation requiring that all large new loads over 75 MW are curtailable by the grid operators (e.g., through dispatching backup generation) for grid reliability needs.[80]

Furthermore, grid interconnection studies should specifically recognize that injections from an energy park to the grid are non-firm and controllable. In general, on-site generation at energy parks is designed primarily to self-supply the energy park's on-site load and only inject energy into the grid when grid capacity is available and when it is beneficial to do so. Energy park generation should therefore not be required to demonstrate "deliverability" in interconnection studies. The non-firm, controllable nature of their on-site generation means that energy parks should be expected not to cause any transmission impacts beyond designated levels. As a result, energy park interconnection could therefore be studied through an expedited screening process to allow the co-located load and generation to connect even more quickly.[81]

FIGURE 9: ILLUSTRATIVE CONTINGENCY ANALYSIS UNDER CONVENTIONAL INTERCONNECTION APPROACH (RIGHT) AND BRATTLE'S PROPOSED ENERGY PARK INTEGRATION APPROACH



Sources and notes: Levitt, A. et al. (2025), *Accelerating the Integration of New Co-located Generation and Loads*, The Brattle Group. This figure depicts an energy park with 500 MW of load and 550 MW of co-located generation, connected to the grid by a pair of transmission lines with a joint transfer capability of 340 MW. Under conventional

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[79] *Ibid.*

[80] Martucci, B., "Texas Law Gives Grid Operator Power to Disconnect Data Centers During Crisis," *Utility Dive* (June 25, 2025).

[81] Examples of expedited screening processes include PJM's Surplus Interconnection Service (SIS) process, which assesses the addition of new supply technologies to existing generators, and PJM's Capacity Interconnection Rights (RIC) replacement process, which assesses the replacement of a retiring generator with a different generation technology type.

load-only study criteria (shown on the right), significant transmission upgrades would be required to address the possible outage of an unaffiliated generator on the local grid. As shown on the left, these upgrades can be avoided when considering that the energy park's controls of load and generation will be able to limit grid imports to 340 MW (by dispatching at least 160 MW of self-generation within the energy park).

When powered by clean sources (with thermal backup generation for reliability), energy parks also offer emissions reduction benefits and can come in at lower cost than relying solely on on-site gas- or diesel-fired generation. These speed-to-market, emissions, and cost benefits have been illustrated for both completely islanded data center energy parks powered by solar and battery storage[82] and for energy parks connected to the grid.[83] These configurations can give rise to innovative business models that rely on on-site generation while awaiting interconnection and then sell this generation to the grid.

BOX IV-B: ENERGY PARK INTEGRATION PROCESSES IN OTHER JURISDICTIONS

ERCOT Interconnection Process for Private Use Networks

ERCOT has an integrated process for connecting load and generation that is co-located behind the same point of interconnection (referred to as Private Use Networks, or PUNs). The PUN interconnection process studies the PUN as independent load, independent generation, and a combination of load and generation in an integrated process.[84] Over 16 GW of PUN capacity is currently online in ERCOT, a quarter of which has been added in the last 10 years. While PUNs have historically been large industrial facilities, there is increased interest in PUNs as large loads such as data centers. ERCOT's Large Flexible Load Task Force has also recently proposed that large loads with co-located generation that are not registered as PUNs (and therefore cannot interconnect via the PUN process) also undertake a single interconnection study process, as opposed to separate load and generator interconnection processes.[85] Finally, Texas passed legislation requiring all large loads over 75 MW to be curtailable during emergency conditions,[86] which will provide strong incentives to enable on-site backup generation to support grid-related needs.

[82] Baranko, K. et al. (2024), *Fast, Scalable, Clean, and Cheap Enough—How Off-grid Solar Microgrids can Power the AI race*.

[83] Energy Innovation (2024), *Energy Parks: A New Strategy To Meet Rising Electricity Demand*.

[84] ERCOT (2025), *ERCOT Update to Texas House of Representatives Committee on State Affairs*, p6.

[85] ERCOT (2025), *Private Use Network (PUN) Capacity Report*.

[86] Martucci, B., "Texas Law Gives Grid Operator Power to Disconnect Data Centers During Crisis," *Utility Dive* (June 25, 2025).

C. Streamline generator interconnection processes

SUMMARY: Currently, generator interconnections are significantly delayed due to a large queue of interconnection requests that greatly exceed future resource needs. Improvements to generator interconnection processes are in progress, but more fundamental reforms will be necessary in many regions. In the meantime, the interconnection process can be accelerated significantly for a subset of interconnection requests, such as for shared interconnection points and shovel-ready projects at grid locations with existing or planned interconnection capacity.

RELEVANT STAKEHOLDERS: ISOs/RTOs, transmission owners, federal regulators

IMPLEMENTATION NOTES: This would require generation interconnection reforms beyond those of mandated in FERC Order 2023.

As researchers at LBNL have documented, over 1,500 GW of generation projects are currently in US grid operators' interconnection queues, with interconnection time requirements (from connection request to commercial operation) of over five years for recently built projects.[87] The interconnection study process now typically takes between 30 and 50 months in most US regions (other than Texas, which processes requests in approximately 20 months).[88] Reforms to the interconnection process will thus be necessary to efficiently utilize existing or proactively planned upgrades. While FERC Order No. 2023 required transmission providers to adopt some notable reforms, including cluster-based study processes and first-ready, first-served prioritization approaches, further work is needed to address issues that remain.

A recently released report includes four recommended reforms to continue to improve the interconnection study process through greater integration with transmission planning and other aspects of generator interconnection: [89]

- **Reform 1**: Adopt an interconnection entry fee for proactively planned interconnection capacity to provide generation developers with significant interconnection cost certainty

87 LBNL (2024), *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection*.

88 See *Ibid.*, at slide 35.

89 Hagerty, M. (2024), " Integrated Transmission Planning and Generator Interconnection at FERC Interconnection Workshop" and Grid Strategies and The Brattle Group (2024), *Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid*.

and address the cost allocation of the upgrades identified through proactive planning processes. This reform allows projects to move forward with upfront certainty by specifying in advance the cost information in exchange for taking on some of the cost of planned transmission buildout.

- **Reform 2**: Implement a fast-track process for resources that can utilize available existing and already-planned interconnection capacity, including the sharing and use of surplus interconnection service.[90] In combination with Reform 1, this reform creates a fast-track process that opens up available transmission headroom (for resources that do not require the planning of additional upgrades) and prioritizes its expedited use by the "most ready" generator projects.
- **Reform 3**: Optimize the interconnection study process to increase the amount of system headroom that is considered "available" for fast-track processes and increase the efficiency of the study processes themselves. In combination with Reforms 1 and 2, interconnection requests should proceed through the study process more quickly.
- **Reform 4**: Speed up the transmission construction backlog to address growing constraints to constructing network upgrades needed to bring new resources online.

While these four reform options are being pursued, several near-term actions are available to interconnect new resources more quickly and cost-effectively to the grid.[91] These include:

- **Implement a fast-track process for the sharing and transferring of existing points of interconnection (POIs)** to bypass long interconnection queues for (1) sharing of existing POIs (both surplus interconnection capacity and sharing of energy) and (2) transfers of existing POIs (e.g., POIs of retiring plants; POIs prebuilt through proactive planning). This would allow for the expedited utilization of POIs at retiring plants, most of which are in attractive locations for developing new storage, renewable generation, and other resources.[92] For example, this option would also allow for the expedited interconnection to POIs prebuilt by PJM for the states under the State Agreement Approach to the generators procured by states (e.g., New Jersey). Sharing POIs at an existing plant is similarly attractive since many aging resources are rarely dispatched when renewable generation output is high. For example, the Midcontinent ISO and Southwest Power Pool (SPP) processes for sharing of existing POIs through "energy displacement agreements" (between existing and

[90] See also GridLab (2025), *Surplus Interconnection Service: Unlocking Grid Reliability and Rapid Energy Deployment*.

[91] See Pfeifenberger, J. P.(2024), Ensuring Cost Effective Transmission to Support Affordable State Electricity Policies, The Brattle Group, at slides 27–33.

[92] See Spees, K. et al.(2022), *Illinois Renewable Energy Access Second Draft Plan*, The Brattle Group, p. 55.

new resources to ensure that the total amount of shared interconnection service at the POI remains the same) allow for interconnection timelines of less than a year.[93]

- **Identify existing "headroom" at possible POIs**. Experience shows that the clear and actionable identification of grid locations with existing headroom (e.g., in a "heat map") that allow "shovel-ready" resources to interconnect can dramatically accelerate generator interconnection timelines. For example, the California ISO (CAISO) has identified interconnection locations for 31 GW of solar resource (23 GW of which are firmly deliverable) with sufficient capacity to accommodate resource interconnection without the need for additional network upgrades.[94] Similarly, system operators in France and Denmark operate online portals that map available interconnection headroom and allow for rapid interconnection of generation resources that are "ready" (including permits) to connect.[95]
- **Fast-track "first-ready" projects**. Generation resources that can be developed quickly (e.g., shovel-ready projects) at existing or new POIs that require minimal grid upgrades should be fast-tracked through interconnection options that proceed separately from the generator interconnection queue of projects that require the planning and development of major new grid upgrades. An example of such a parallel process is PJM's "fast-lane" transition process for projects with minimal network upgrades.[96] Similarly, CAISO's 2023 Interconnection Process Enhancements allow for the acceleration of interconnection requests at POIs with sufficient headroom.[97]
- **Allow for grid-enhancing technologies (GETs) and Remedial Action Schemes (RASs) to address interconnection needs**. Some interconnection needs can be addressed by grid-enhancing technologies and/or "simple" (automated) remedial action schemes (RASs or system protection schemes, SPSs), which can avoid expensive and time-consuming grid upgrades. While GETs, such as dynamic line ratings and power flow control devices, only need to be "considered" per FERC Order 2023, they warrant more serious evaluation and application. Similarly, automated network protection schemes (such as using curtailments of resources during the outage of certain transmission lines to avoid overloads of the remaining grid) are widely embraced in the Western US, Europe, and Australia, but are not

93 American Electric Power (2023), "MISO/SPP Generator Replacement Process—PJM Interconnection Process Subcommittee;" MISO (2025), "Generator Interconnection Procedures (GIP);" GridLab (2025), Surplus Interconnection Service: Unlocking Grid Reliability and Rapid Energy Deployment.

94 CAISO (2023), Briefing on Resources Available for Near Term Interconnection.

95 Grid Strategies and The Brattle Group (2024), *Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid*.

96 PJM (2022), "Interconnection Process Reform Task Force (IPRTF) Transition Proposal Packages."

97 CAISO (2023), "2023 Interconnection Process Enhancements—Track 2 Straw Proposal."

considered by grid operators in the Eastern US. For example, the CAISO has identified 21 GW of interconnection headroom (16 GW of which are for firmly deliverable capacity resources) that can be created quickly and inexpensively with RAS.[98]

- **Simplify non-firm, energy-only (Energy Resource Interconnection Service or ERIS) interconnections with the option to upgrade to Network Resource Interconnection Service (NRIS, or capacity) later**. Many system operators have interconnection criteria for non-firm, energy-only resources that differ little from the interconnection criteria for firm capacity resources, which means even resources whose network interaction can be managed on a 5-minute basis through RTOs' market-based congestion management processes are required to wait (and pay for) expensive and time-consuming network upgrades, some of which may be quite distant from their POI. Simplifying energy-only interconnection criteria for new POIs to reflect the non-firm (i.e., dispatchable down or curtailable) nature of resources would avoid such time-consuming network upgrades and dramatically speed up interconnection timelines by relying on market-based congestion management to avoid network overloads, as illustrated in a recent Duke University study.[99] This is the practice in ERCOT (and to some extent SPP), which (as a result of its willingness to rely on market-based congestion management) is able to interconnect non-firm resources more quickly than any other of the US regional system operators.[100] SPP also provides resources with such non-firm interconnection agreements (ERIS) with the option to upgrade to firm capacity interconnection service (NRIS) at a later point.[101]

As discussed further in the next section, resource interconnection timelines and interconnection costs at new grid locations without existing headroom can be reduced significantly by considering projected future generator interconnection needs in proactive transmission planning processes.

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[98] CAISO (2023), "Briefing on Resources Available for Near Term Interconnection."

[99] Norris, T.H. and R. Watts (2024), *Modeling the Effects of Flexible Interconnection on Solar Integration: A Case Study*, Prepared for: FERC Innovations and Efficiencies in Generator Interconnection Staff-Led Workshop.

[100] Enel Green Power (2021), *Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning*.

[101] Grid Strategies & The Brattle Group (2024), *Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid*. While we recognize that different RTOs apply different levels of "firm" to ERIS interconnection standards, identified network upgrades should be consistent with the requested interconnection service level.

V. Implement Proactive Planning and Procurement Processes to Accelerate the Necessary Investments

A. Improve generation and transmission planning processes and create clean energy and economic development zones for which infrastructure can be planned proactively

SUMMARY: Generation and transmission planning processes can be enhanced by enacting **proactive, scenario-based planning practices** that allow for the identification of more flexible, cost-effective generation and transmission solutions. Enhanced proactive planning processes allow planners to plan a comprehensive range of possible futures and to anticipate and address a holistic set of system needs beyond solely reliability requirements. Such planning processes recognize the value of generation and grid solutions that are flexible and robust across all scenarios; they more explicitly recognize future uncertainties in planning in order to **develop "least-regrets" solutions** that maximize long-term cost savings while minimizing the risks of both over- and underinvesting in the grid. These planning processes should also leverage grid-enhancing and advanced transmission technologies and consider the economic benefits of expanding interties to neighboring regions.

Part of such proactive planning should involve the designation of **clean energy and economic development zones** to facilitate the pre-build of necessary transmission and generation infrastructure.

RELEVANT STAKEHOLDERS: Vertically integrated utilities, ISOs/RTOs, state governments and energy offices, and planning/procurement authorities

IMPLEMENTATION NOTES: Effective planning process would require coordination with state or federal energy policies and associated regulatory

> approval. Legislative action may be required to provide planning authority to participating entities and designate clean energy and economic development zones.

By integrating proactive, scenario-based planning into generation and transmission planning processes (as well as making distribution planning more proactive, as outlined in Recommendation V.C), grid planners can increase grid flexibility in both the near- and long-term, mitigate risks, and reduce system-wide costs. In many jurisdictions, the integrated resource planning (IRP) process is limited in scope and time horizon. IRPs often focus on the near-to-medium-term (e.g., the next 10 years) without considering long-term (10–30 years) system needs that may benefit from efficient near-term investment. Similarly, IRP objectives often focus mostly on "base case" reliability requirements, missing opportunities to increase grid flexibility, capture near-term economic and public policy benefits, and reduce system-wide costs, particularly in the longer term. To incorporate more proactive, holistic, and scenario-based approaches into generation and transmission planning processes, grid planners should adopt best practices for the following seven planning elements:

1. Use **scenario-based** planning that relies on a comprehensive set of scenarios that bracket the wide range of plausible futures, recognizing near-, medium-, and long-term uncertainties across a wide range of variables (such as fuel costs, technology costs, load growth, or environmental regulations).[102]
2. Rely on **holistic planning** to comprehensively address all projected generation and transmission needs, such as needs based on reliability and resource adequacy standards, state clean energy and economic development goals, consumer preferences, congestion

[102] As summarized in Slide 5 of Pfeifenberger, J.(2024), *Order 1920 Compliance: An Opportunity to Improve Transmission Planning beyond Mandates*, The Brattle Group, best-practice scenario-based planning processes have been developed by international oil companies in the 1940s and 1950s and successfully deployed for decades. This specific type of scenario-based planning ranks among the top ten management tools in the world today. See *Harvard Business Review* (2013), "Living in the Futures," and MIT (2001), *A Review of Scenario Planning Literature*.

This specific type of scenario-based long-term planning has been implemented, for example, by European and Australian grid operators. (See The Brattle Group (2024), slides 6 and 18). As summarized in Federal Energy Regulatory Commission (2024), "Explainer on the Transmission Planning and Cost Allocation Final Rule," scenario-based long-term planning has also been mandated by FERC in its recent Order 1920. This type of scenario-based approach has also been applied to utilities' integrated resource planning, such as by the Tennessee Valley Authority (TVA) (see TVA, "Integrated Resource Plan") or the Texas grid operator to develop long-term projections of generation and load additions used for grid planning (See Hagerty, M. et al. (2015) Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process, The Brattle Group.).

relief opportunities, generation interconnection needs, and current or future aging asset refurbishment needs.[103]

3. Make **near-term decisions considering long-term needs** to minimize expected long-term costs (e.g., to enhance the capacity of the existing grid, upsize existing facilities, or create low-cost expansion options, particularly during aging infrastructure refurbishments, based on long-term needs) as described in Recommendation III.D.
4. Develop portfolios of more **flexible, least-regrets solutions** that cost-effectively address a wide range of uncertain future generation and transmission needs (e.g., new single-circuit 500kV lines that are "HVDC-ready" or use double-circuit towers to create a low-cost opportunity for adding a second circuit in the future).[104,105]
5. Apply **"least-regrets" planning criteria** to reduce the risks of both over- and under-investment—including, for example, by explicitly considering the risk of high-cost future outcomes associated with not making certain investments that create low-cost expansion opportunities or increase flexibility.[106]
6. Use economic **benefit-cost analyses** to identify the grid solutions that, in addition to addressing reliability requirements, allow for the identification of transmission projects that can help reduce system-wide costs (e.g., by reducing congestion and making more lower-cost generation available to serve loads).[107]
7. Explicitly plan **interregional transmission** by considering the economic and public policy benefits of expanding interties with neighboring regions (see Recommendation III.E).

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[103] Pfeifenberger, J. (2024), *Order 1920 Compliance: An Opportunity to Improve Transmission Planning beyond Mandates*, The Brattle Group, Slides 4, 9, and 10.

[104] *Id.*, Slide 12.

[105] For example, Texas has constructed many of the transmission lines built to integrate low-cost onshore wind in the Competitive Renewable Energy Zones designated for western Texas as single-circuit 345kV lines with double-circuit cable towers. See *ERCOT's Competitive Renewable Energy Zones (CREZ) Transmission Optimization Study.*

[106] Pfeifenberger, J. (2024), *Order 1920 Compliance: An Opportunity to Improve Transmission Planning beyond Mandates*, The Brattle Group, Slide 11.

[107] *Id.*, Slides 7, 8, 18, and 41 (summarizing US and European experience with benefit-cost analyses for multi-value/multi-driver transmission planning).

For example, FERC's Order 1920 establishes a regulatory mandate under which US grid operators are required to employ benefit-cost analyses (quantifying at least 7 types of transmission-related benefits) to select the most beneficial transmission solutions in their long-term transmission planning processes. For a summary of Order 1920, see Federal Energy Regulatory Commission (2024), "Explainer on the Transmission Planning and Cost Allocation Final Rule."

These enhanced proactive and comprehensive practices increase the flexibility of generation and transmission plans to better manage uncertainty across possible futures while preserving optionality to avoid over-investment and more cost-effectively address future needs beyond reliability requirements. Previous studies and planning efforts have demonstrated that proactive planning can (1) reduce right-of-way needs by up to 50%; (2) reduce total customer costs by about 20%; and (3) reduce generator interconnection costs by over 50% compared to incremental solutions.[108]

Importantly, the scenarios considered during planning must include the full range of near-term outcomes as well as long-term ones. Doing so facilitates near-term decisions with long-term benefits, as discussed in point 3 above. For example, the costs and lead times for key grid components such as transformers have increased dramatically in recent years[109]—making the proactive decision to order key components now in anticipation of future needs would lower the long-term costs of supporting the system.

Planners should actively consider GETs and ATTs as possible solutions in their planning processes to address near-term needs and reduce long-term costs. As outlined in Recommendation III.C, these technologies can offer fast-track and low-cost grid solutions, including on a temporary basis ahead of upsizing existing transmission facilities or building new lines.

Planners should also consider enhancing their planning processes for interregional transmission to capture the economic benefits of restoring, expanding, and efficiently operating interregional transmission to neighboring jurisdictions. As described in Recommendation III.E, interregional electricity trade presents a significant strategic opportunity for regions to more flexibly address near-term system needs and lower long-term costs. Interregional transmission planning processes should fully reflect the economic and flexibility benefits that increased transfer capability to neighboring markets provides. If coordinated with neighboring grid operators, grid-enhancing technologies may be able to quickly expand existing transmission capacity on constrained interties, such as by implementing dynamic line ratings that can increase the capabilities of existing transmission lines by 20–30% during most of the year (as discussed in Recommendation III.C).

States may be well-placed to use these best practices to more quickly bring planning processes in line with their clean energy and economic development goals. In California, for example, the California Public Utilities Commission (CPUC) conducts generation planning in its IRP process

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108 Pfeifenberger, J.P. (2023), *The Benefit and Urgency of Planned Offshore Transmission*, Brattle Group.

109 Walton R., "US Should Create 'Virtual' Electric Transformer Reserve Amid Shortage Concerns: NIAC," *Utility Dive* (September 13, 2024).

and issues procurement orders to load-serving entities while closely coordinating with CAISO on grid planning.[110]

Similarly, in New York, the state's utilities conduct transmission planning for local needs under the supervision of the Department of Public Service via the Coordinated Grid Planning Process while NYISO plans the state's bulk transmission system;[111] the New York State Energy Research and Development Authority (NYSERDA) runs most major clean energy procurements (see Recommendation V.B for further discussion on NYSERDA's generation procurement process).[112]

Connecticut's Department of Energy and Environmental Protection and the Illinois Power Agency perform direct procurement planning (and, for Illinois, procurement functions) in their respective states, and others are increasingly considering similar direct state planning and procurement structures. For example, Maryland passed a bill in 2024 authorizing its Department of the Environment to design a centralized procurement framework,[113] and Massachusetts recently proposed a bill to centralize generation planning and procurement within the Department of Energy Resources (DOER).[114]

States can also play an important role in interregional transmission planning by coordinating to identify shared transmission priorities and propose steps to address planning challenges. For example, governors from Illinois, Michigan, Minnesota and Wisconsin, have actively encouraged improved long-term planning by the Midcontinent Independent System Operator (MISO) to support state policies.[115] Governors are also active in exploring state level permitting reforms[116] and the Northeast States Collaborative on Interregional Transmission brings together representatives from nine states' commissions, agencies, or governors' offices to coordinate interregional transmission expansion efforts.[117] In its recent Strategic Action Plan (developed by Brattle), the Collaborative identified near- and medium-term steps to enable identification, evaluation, selection, and cost-sharing between states of beneficial interregional

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[110] California Public Utilities Commission (2025), "Integrated Resource Plan and Long Term Procurement Plan (IRP-LTPP)."

[111] NY Department of Public Service (2025), "Coordinated Grid Planning Working Group."

[112] NYSERDA (2025), "Large-Scale Renewables."

[113] Maryland House Bill 1296 (2024), An Act Concerning Electricity—Offshore Wind Projects—Alterations.

[114] Commonwealth of Massachusetts (2025), "Governor Healey Unveils Energy Affordability, Independence & Innovation Act to Save Ratepayers $10 Billion," Press Release.

[115] Governors' MISO LRTP letter (June 2021).

[116] Governors Call for Energy Permitting Reform, National Governors Association (February 2025).

[117] The Collaborative comprises Connecticut, Delaware, Maine, Maryland, Massachusetts, New Jersey, New York, Rhode Island, and Vermont. Northeast States Collaborative on Interregional Transmission (2025), Ralph O'Connor Sustainable Energy Institute, Johns Hopkins University.

transmission projects.[118] This included developing and issuing a Request for Information on potential projects that could address low-regrets needs otherwise missed by existing interregional transmission planning processes, with a focus on "low-hanging fruit" with high near-term cost-effectiveness and implementation feasibility. Other near-term actions included process coordination and standardization across states (including transmission procurement and Order 1920 compliance filings) and joint efforts to address technical challenges (such as supporting HVDC design standards and reducing seams inefficiencies).

The benefits of proactive, scenario-based planning can be enhanced when combined with identifying and designating **clean energy and economic "development zones"** since such zones, which offer generation investment opportunities, will generally require new transmission infrastructure. Specifying a set of clean energy and economic development zones (with high resource potential and industrial load interconnection forecasts) allows planners to identify the grid infrastructure necessary to serve these zones under a range of plausible futures. This approach enables more efficient and cost-effective infrastructure planning by co-optimizing energy deployment with other resource needs, such as water and broadband access. See Box V-A below for an example of Australia's proactive planning process with renewable development zones and a grid solution developed by the CAISO that can flexibly address interconnecting between 1,600 MW and 8,500 MW of offshore wind generation. Examples of using proactive planning for developing renewable energy zones are also found in a number of US states. [119] Planning energy parks that collocate new loads and generation (see Box IV-A in Recommendation IV.A) would allow for maximization of the resource potential and forecast load in these zones with less overall grid infrastructure need.

State governments or RTOs/ISOs can designate these clean energy and economic development zones and, once designated and facilitated through the associated regulatory processes, planners can consider them in their planning process to pre-build the infrastructure necessary to serve the zones. States could also establish streamlined permitting processes for these zones

[118] DeLosa III et al. (2025), *Strategic Action Plan*, The Brattle Group, prepared for the Northeast States Collaborative on Interregional Transmission.

[119] For example, the $7 billion Texas Competitive Renewable Energy Zone project designed to interconnect around 11.5 GW of new wind generation capacity and led to a boom in renewable energy development in Texas. See, for example, Pfeifenberger et al., Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, The Brattle Group.

NREL researchers similarly examined proactive transmission planning to develop renewable energy zones in Colorado, Iowa, Kansas, Montana, Nebraska, New Mexico, Oklahoma, Wyoming and other US states. See Hurlbut et al. (2024), *Interregional Renewable Energy Zones*, National Renewable Energy Laboratory.

See also 10-YEAR Transmission Plan For the State of Colorado (2024), explicitly coordinating state-wide transmission planning for multiple needs, including larger transmission expansion projects to access specific resource-rich areas of the state (i.e. the Colorado Energy Resource Zones ("ERZs") as cost-effective means to meet the utilities' state-mandated clean energy plans ("CEPs").

to facilitate their development in a timely manner. For example, states can consider establishing standardized assessment and permitting processes for generating resources and transmission, including considerations of resource-specific needs, to accelerate approval timelines.

In addition, states can make the permitting process less onerous for high-priority resources and synchronize the environmental assessments and permitting needs to accelerate the approval process. Further, accelerated environmental assessment and permitting processes could be conducted for designated clean energy and economic development zones (see Recommendation V.A) to remove the need for individual project approvals within these zones. Box V-B provides examples of recent permitting reforms in the United States.

BOX V-A: EXAMPLES OF SCENARIO-BASED, LEAST-REGRETS PLANNING IN OTHER JURISDICTIONS

Australia's Integrated System Planning Process

The Australian Energy Market Operator (AEMO) employs best-in-class proactive, scenario-based long-term planning. Its Integrated System Plan[120] (ISP) is updated every two years and consists of a scenario-based analysis that considers long-term uncertainties and (least-regrets) risk mitigation over the next 30 years. The ISP identifies (1) actionable projects to address needs that are present across enough scenarios to have a high degree of certainty, and (2) future projects that are likely needed at some point in the future. The process values optionality (e.g., projects that can be built/expanded in stages; "early works" that make projects shovel-ready and enable them to be constructed quickly in the future) and builds in extensive stakeholder consultation.

The ISP is planning grid infrastructure for designated **Renewable Energy Zones** (REZs)—areas of high renewable resource potential within individual states that are targeted for large-scale renewable energy development.[121] First identified in 2018, these REZs are refined and updated by the AEMO through the ISP consultation process and by working with state and federal governments to account for changes in policy and infrastructure development.

CAISO's Flexible Offshore Wind Transmission Solution

In its most recent transmission plan, the CAISO designed an onshore grid solution that can flexibly address highly uncertain needs to connect offshore wind generation to its underdeveloped grid along the California North coast.[122] The now-approved transmission plan allows for connecting 1,600 MW of north-coast offshore wind generation by constructing two new 500 kV alternating current (AC) lines, one of which is designed to be converted to HVDC technology (with sufficient right of way to add a second line). This design allows offshore wind interconnection capability to first be expanded—if and when necessary—to 3,200 MW by converting the AC line to HVDC. By adding a second HVDC line (on the right-of-way of the first line) and other HVDC facilities, the transmission design ultimately could be expanded to connect up to 8,000 MW of offshore wind generation.

[120] AEMO (2024), *2024 Integrated System Plan (ISP)*.

[121] AEMO (2024), "*Appendix 3. Renewable Energy Zones.*" See also Renewable Energy Zones | Australian Energy Regulator (AER)

[122] California ISO (2024), "Board Approved 2023-2024 Transmission Plan." For a summary of this CAISO offshore wind transmission plan, see Slide 12 of Pfeifenberger, J. (2024), *Order 1920 Compliance: An Opportunity to Improve Transmission Planning beyond Mandates*, The Brattle Group.

BOX V-B: EXAMPLE PERMITTING REFORMS FROM OTHER JURISDICTIONS

State-level Permitting Reforms: New York, California, and Massachusetts

In recent years, several states have passed legislation to speed up the permitting process for clean energy projects. New York and California are notable examples, with New York passing the Accelerated Renewable Energy Growth and Community Benefit Act[123] in 2020 and California passing Assembly Bill 205[124] in 2022. These reforms ensure that siting and permitting decisions for renewable energy are confined to a single decision-making body and establish statutory time limits for issuing permits—one year from application completion in New York and seven months in California. They also mandate the provision of community and employment benefits to establish local buy-in early and mitigate local opposition. New York introduced further reforms in the 2024 "RAPID" Act, which brought permitting of transmission under the same entity as permitting of renewable energy generation, ordered the development of uniform standards for renewable and transmission facilities to avoid or minimize adverse environmental impacts, and required enhanced host community engagement and involvement.[125]

Similar permitting reforms were recently approved by the Massachusetts legislature.[126] Under the new laws, the state's Energy Facilities Siting Board is authorized to review the permitting process for clean energy projects with a capacity greater than 25 MW and set time frames for review "based on the complexity of the facility." It also requires the board to issue a final decision on the permit application within 15 months. Local governments will retain permitting control over smaller clean energy projects, but they are required to issue a permitting decision within 12 months.

[123] New York Power Authority (2021), "Governor Cuomo Announces New Regulations Adopted to Accelerate Renewable Energy Projects Across New York State."

[124] *Energy*, Assembly Bill No. 205.

[125] Cullen and Dykman LLP (2025), "New York's RAPID Act Intended to Accelerate the Environmental Review and Permitting Process for Siting Both Renewable Energy and Electric Transmission Line Projects," Legal Alerts.

[126] MA Senate Press Room, "Sweeping Climate Bill Passes the Massachusetts Legislature," November 14, 2024.

B. Reform generation procurement to more flexibly and quickly address energy and capacity needs

> **SUMMARY:** To bring low-cost generation online in a way that efficiently addresses various system needs, vertically integrated utilities and power procurement authorities should consider: procuring frequently and accelerate their competitive procurement processes, differentiating between procuring energy and capacity needs, and evaluating system impacts (such as transmission constraints and resource flexibility) in bid evaluations. Procurements should be structured to be technology-neutral and inclusive of all cost-effective options, including demand-side resources to maintain resource adequacy during periods of rapid load growth.
>
> **RELEVANT STAKEHOLDERS:** Vertically integrated utilities, power procurement authorities, state policymakers and energy offices, state regulators.
>
> **IMPLEMENTATION NOTES:** This would likely require state approvals.

Generation procurement processes should be frequent, specific, and efficient to bring the right generation quickly and at low cost. Best practices can be taken from utilities that rely heavily on accelerated, frequent procurements. For example, American Electric Power (AEP) frequently acquires resources through 5–7 month-long procurement processes, such as the one following this timeline:

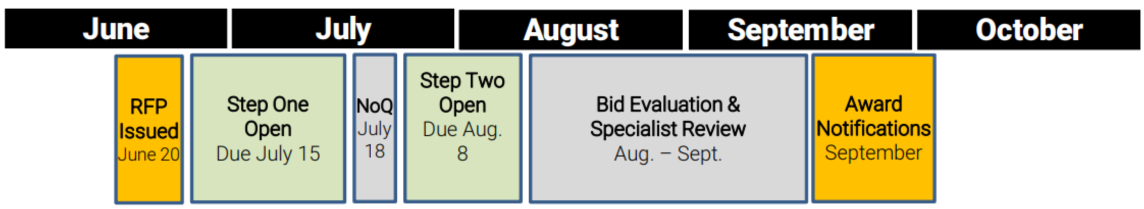
- In **October 2023**, AEP subsidiary Public Service of Oklahoma, publicly issued the draft of its "all-source" targeting 1,500 megawatts (MW) of SPP accredited capacity (wind, solar, batteries, natural gas plants, hydrogen plants, or other resources) through a combination of Purchase and Sale Agreements (PSAs, under which the utility will ultimately own the resource), Power Purchase Agreements (PPAs) and Capacity Purchase Agreements (CPAs);
- In **November 2023**, the final RFP was issued after stakeholder consultations;
- In **late January 2024**, bids were due; and
- In **June 2024**, the winning bid was selected.[127]

[127] AEP, "2023 ALL-SOURCE RFP." Generation resources bid in must have an expected Commercial Operation Date (COD) by 12/15/2027 or alternatively 12/15/2028.

Another AEP subsidiary, Indiana-Michigan Power, issued its final RFP in late September 2024. Bids are due in November 2024, and the winning bids are planned to be shortlisted in February 2025.

As Figure 10 below shows, NYSERDA uses an accelerated four-month procurement schedule for the annual acquisition of large-scale renewables on behalf of New York State.[128] The RFP was issued in June 2024, and NYSERDA received bid proposals from 38 projects, comprising 3.5 gigawatts (GW) of capacity and 6.5 terawatt hours (TWh) of generation. The evaluation of bid proposals concluded in October 2024, and contract executions were announced in May 2025.[129] The next procurement is planned for later in 2025, which will be the ninth annual such procurement by NYSERDA. The frequency and predictable nature of repeated procurements allow generation developers to meet these very accelerated procurement timelines.

FIGURE 10: NYSERDA 2024 LARGE-SCALE RENEWABLE SOLICITATION SCHEDULE



Source: New York Tier 1 RESRFP24-1 Proposers' Webinar (2024), New York Tier 1 RESRFP24-1 Proposers' Webinar.

Table 1 below summarizes the generation procurement recommendations presented in this section. First, issuing more frequent (e.g., annual or once every two years) procurements can reduce the procurement timelines and create the flexibility and speed needed to change loads, industry conditions, and resource needs.

[128] NYSERDA (2024), "Solicitations for Large-scale Renewables - NYSERDA."

[129] NYSERDA (2025), "Contracts Executed for 26 Large-Scale Land-Based Renewable Energy Projects," Press Release.

TABLE 1: SUMMARY OF RECOMMENDATIONS FOR GENERATION PROCUREMENT REFORM

Recommendation	Benefit
1. Increase procurement frequency and shorten procurement process	Accelerates load interconnection
2. Assess bids on their impact on capacity needs	Ensures that generation procurement is aligned with capacity needs
3. Include demand-side resources	Enables quick deployment of low-cost, utility-scale customer-side energy and capacity resources
4. Prioritize grid locations that have available or pre-planned capacity	Minimizes cost of infrastructure investments needed to service new generation
5. Prioritize resources that help alleviate transmission constraints	Ensures that procured generation lowers costs for ratepayers by avoiding congestion and reducing the need for and cost of congestion management
6. Consider intentionally supporting promising clean, dispatchable generation technologies (e.g., geothermal)	Invests in the development of industries that may offer significant value for the future electricity system
7. Allow utility self-build proposals to compete with third-party proposals	Allows the advantages of both public and private entities to compete to deliver the most cost-effective solution, and facilitates innovation in public-private partnerships

Utilities and power procurement authorities should also consider differentiating their procurement and bid selection processes to distinguish between energy and capacity needs and consider how these needs may vary in different parts of their systems. This would include further refinements on the valuation of bids that better reflect the seasonal and hourly shapes and flexibility of each asset. Further, demand-side resources should be explicitly included in generation procurements to enable third-party participation by more timely deployment of utility-scale customer-side energy and capacity resources[130] (see Recommendation IV.A).

Procurement should also strategically prioritize grid locations that have available or pre-planned capacity and prioritize resources that can help alleviate transmission constraints. To support resource adequacy needs, procurement should also take into consideration how the procuring entity can intentionally help develop promising clean energy technologies with significant capacity value (and dispatchable firm generation), such as geothermal resources.

While utilities may be able to build and own their own generation to meet energy and capacity needs, such self-build options should compete with third-party proposals in competitive solicitations. Additionally, innovative procurement models should be facilitated, such as build-

[130] Many utilities and power procurement authorities routinely issue RFPs for DSM resources. See Illinois Power Agency (2022), "Electricity Procurement Plan"; PacifiCorp (2022), "Exhibit A—Demand Response Request for Proposals"; American Electric Power (2023), "Request for Proposal—PJM Aggregated Demand Response Capacity."

transfer models, where private entities develop the resources and then transfer them to utility ownership, which is increasingly common in the US.[131] If the procuring entity is public, facilitating innovative public-private partnerships can allow for faster, cheaper generation procurement. Public entities have advantages such as access to lower-cost financing, whereas private entities often offer speed and innovation—these trade-offs should be considered as part of the competitive evaluation process during procurement.

C. Proactively plan distribution system investments to cost-effectively manage load growth (and capitalize on flexibility of distribution-level resources)

SUMMARY: Proactive distribution planning will become increasingly important as projected growth in building and transportation electrification places strain on the distribution system. Scenario-based planning that facilitates the prebuilding of projects in constrained parts of the grid can result in ratepayer savings while still serving growing electricity demand. To facilitate such planning, enhanced load forecasting capabilities with high locational and temporal granularity will be crucial.

RELEVANT STAKEHOLDERS: Utilities, state regulators

IMPLEMENTATION NOTES: This would require improvements to the spatial and temporal granularity of utility load forecasting and may benefit from regulatory mandates on distribution planning practices.

Many US jurisdictions have ambitious building and transportation electrification goals that will place strain on distribution systems. In the context of this distribution-level load growth, as with generation and transmission, distribution system planning can benefit from proactive, long-term, scenario-based system planning. Even though distribution projects have shorter lead times than transmission projects, relying on just-in-time, incremental upgrades alone will become increasingly costly and impractical—including when considering workforce

[131] For example, AEP offers an "Option To Build" (OTB) program where IPPs seeking interconnection design and construct necessary transmission facilities and transfer their ownership to AEP upon completion (AEP Transmission 2023, "Independent Power Producer (IPP) Option to Build Guidelines"). The OTB approach gives IPPs cost control over interconnection transmission upgrades and allows for expedited interconnection timelines.

development and management.[132] Preliminary results from Brattle's work on this topic (not yet public) indicate that proactive distribution system planning, aided with granular, bottom-up load forecasting and anticipatory distribution infrastructure upgrades, can lead to net savings to ratepayers and help meet increasing demand from the electrification of industrial and transportation industries. Utilities should explore (and regulators should facilitate) the prebuilding of projects in hot-spot areas before those areas reach the technical limits of the existing infrastructure.

Central to this enhanced planning function will be the development of accurate load forecasts as well as more proactive planning for and building of infrastructure upgrades. More locationally and temporally granular load forecasts will be critical, supported by advanced adoption models that incorporate both traditional variables—such as costs, policies, and customer preferences—and variables that are specific to different load types (e.g., vehicle type, charging technology characteristics, vehicle fleet electrification trends) across different scenarios. In addition, these forecasts must be aligned with the deployment and performance of demand-side programs (see Recommendation III.A) to ensure efficient usage of the power system and reduce total infrastructure needs at every level of the grid.

Other industry best practices in distribution system planning include the incorporation of non-wires alternatives—such as geographically-focused energy efficiency and demand response programs—into planning processes to defer substation capacity upgrades and optimize investments in high-growth areas. The use of utility-owned battery energy storage is also increasingly being used as a way to defer substation upgrades.

More broadly, we recommend that key stakeholders such as utilities and system operators identify and share best practices for conducting load forecasts. These practices should differentiate between shorter-term and long-term planning needs, reflect the degree to which new loads are co-located with new generation, and consider emerging practices. For instance, some entities rely on the standardization of the interconnection process and tariff terms and conditions to reduce uncertainty in load forecast (see Recommendation VI.B).[133] Load forecast

[132] External shocks and policy changes can quicken the pace of electrification and overwhelm grid planners. For example, in response to the 2022 energy crisis, the Dutch government moved to electrify critical parts of the country's economy at a rate that the distribution network could not keep up, As a result, thousands of businesses and households are waiting to connect to the power grid, hampering economic growth. See Hancock, A. and A. Bounds, "Netherlands Rations Electricity to Ease Power Grid Stresses", *Financial Times* (July 13, 2025). To address similar bottlenecks in the power grid, the Irish government is planning to allow private investors such as wind and solar project owners to develop, own, and operate their own distribution infrastructure. *See* Blackburne, A., "Ireland Overhauling Electricity Grid Rules, Opening Doors for Private Wires", S&P Global (July 16, 2025).

[133] Lam, L. (2025), *Electricity Demand Growth and Forecasting in a Time of Change*, New Mexico Public Regulation Commission Workshop on Large Load Growth.

accuracy can be enhanced by obtaining more detailed and granular information from large load customers, including expected hourly energy consumption profile, load ramp projections, as well as capability and willingness to operate flexibly (including through the dispatch of onsite generation).[134] In addition, greater coordination among load-serving entities and grid operators is essential for preventing double-counting, aligning load and generation interconnection processes, and enhancing the transparency and reliability of forecasts.

BOX V-C: NEW YORK'S PROACTIVE DISTRIBUTION PLANNING

The **New York State Public Service Commission** has launched a proceeding to develop a unified, proactive framework to anticipate and manage grid infrastructure needs driven by the rapid growth of EV adoption and building electrification.[135] As part of this initiative, utilities are required to submit a proposal outlining a long-term, coordinated planning process to evaluate and implement necessary grid upgrades. The proceeding also establishes a mechanism for utilities to propose urgent grid upgrades to be implemented within two years. Recognizing the importance of granular load forecasting, regulators direct utilities to conduct bottom-up modeling of EV charging load in a way that is consistent with top-down forecasting efforts. This proactive approach is designed to lower utility costs and accelerate electrification, supporting New York's climate objectives and economic development goals.

D. Improve existing load interconnection processes in line with policy objectives

SUMMARY: Key stakeholders should standardize interconnection processes to reduce load growth uncertainty and enhance planning efficiency. Interconnection processes and rate structures should be revised to reflect economic and energy policy objectives, and economic development rates should be reserved for strategically relevant, high-value, and price-sensitive loads. Utilities and regulators should consider exploring the extent to which a multi-criteria load auction may be a useful tool to allocate system headroom, which could also help reduce upward pressure on rates.

[134] Silverman, A. et al. (2025), *A State Playbook for Managing Data Center-Driven Load Growth*, Johns Hopkins University.

[135] NY Department of Public Service (2024), In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure.

RELEVANT STAKEHOLDERS: RTOs/ISOs, legislators/policymakers, state energy offices, regulators, utilities

IMPLEMENTATION NOTES: Revising and standardizing interconnection processes may require changes to existing regulations and statutes.

As electricity demand rapidly rises, standardizing load interconnection processes is essential to reducing uncertainty associated with load growth and enhancing planning efficiency. Many existing processes operate on a "first-come, first-served" basis, which enables speculative behavior and can inflate load forecasts with non-viable phantom projects. A consistent, transparent, and actively managed load interconnection process would help mitigate these risks and support more effective system planning.[136] Key elements should include clearly defined queue protocols, robust financial and commercial readiness criteria and requirements, a clear distinction between interconnecting firm and interruptible new loads (including those with co-located generation that is dispatchable for grid needs), and mechanisms to remove nonviable projects from the queue.

State policymakers should ensure that interconnection practices and cost recovery mechanisms for new customers are aligned with state energy and economic policy objectives. In areas with increasing resource constraints and high incremental system costs, both the interconnection process and applicable rate structure should reflect the contributions that large new loads make to state or regional policy objectives, including environmental, employment, economic development, and technical grid impacts. For example, some utilities are currently able to offer discounted economic development rates to attract large customers, but such incentives may be unnecessary in high-growth environments, where potential customers are willing to pay a premium to be connected to the grid in a timely manner. Thus, economic development rates could be strategically reserved for the most high-value, price-sensitive loads. For instance, in Québec, loads larger than 5 MW seeking to interconnect are evaluated by the province's Minister of Economy, Innovation and Energy based on the potential load's grid impacts as well as its economic, environmental, and social impacts, among other criteria.[137] Additional rate classes could also be created for qualified large loads, with incremental procurement costs

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[136] Freed, P. and A. Clements, "How to Reduce Large Load Speculation? Standardize the Interconnection Process," *Utility Dive* (February 19, 2025)

[137] Quebec Ministry of Economy, Innovation, and Energy, "Procedure for Obtaining Connection Authorization for Projects with Power Ratings of 5 MW or More" (June 7, 2024). In its proposal to change its general terms and conditions, Commonwealth Edison seeks to have the ability to prioritize the processing of service applications and the provision of service for loads with "economic development priority" as designated by the Illinois Department of Commerce and Economic Opportunity so long as the utility "does not prejudice other customers or applicants for service." *See* Commonwealth Edison (2025), Tariff Sheet Nos. 128, 149.1.

spread across all customers in that rate class (see Recommendation VI.B). This would make costs more predictable and less customer specific.

Policymakers could explore multicriteria load auctions as an alternative way to assign available "headroom" to loads willing to pay the incremental costs of serving them. Auction prices could start at the full incremental system cost of serving loads at specific locations. Customers could bid above that starting price to reflect their desire to connect quickly to use the available grid capacity. This process would better discover the true value customers place on connecting to the system quickly; the "surplus" received (i.e., the difference between the bid price and the incremental cost) could then be passed through to other ratepayers or used to pay for system upgrades that would benefit all customers. A load auction framework should still evaluate projects against criteria reflecting broader policy objectives but would introduce the opportunity to generate additional value that could lower system costs and reduce upward pressure on rates.

In many jurisdictions, revising existing load interconnection processes would require changes to current regulations and statutes. Such revisions should give special consideration to customers who apply for interconnection after having secured self-generation (either on-site or "virtually" through sleeving contracts) and who have already assumed the cost of the new energy and capacity resources needed to serve their load. Interconnection requests from these customers should be afforded the same treatment as those from customers directly served by utilities.

VI. Introduce Targeted Affordability Measures

A. Establish and expand energy efficiency and bill assistance programs for low-income customers

SUMMARY: Beyond the cost savings offered by the recommendations above, energy efficiency and conservation programs can provide targeted, meaningful support for low-income and vulnerable customers while reducing systemwide electricity consumption. Targeted bill assistance programs can provide further support to low-income customers and are a simple way to assist the most energy-burdened households. If administered by state governments, funding for programs can be designed in a more progressive manner through the tax base.

RELEVANT STAKEHOLDERS: Utilities, state governments

IMPLEMENTATION NOTES: This will require state legislatures to approve bill assistance if coming from the tax base, and regulatory approval if utility sponsored. It would also require targeted marketing of the programs to low-income customers who qualify but may not be aware of the programs.

Low-income households are most vulnerable to the economic impacts of rising energy costs. Targeted energy efficiency and bill assistance programs, as well as targeted efficiency and demand response programs, can provide relief to energy-burdened customers in an administratively efficient fashion. Such programs could be targeted specifically to customers below a certain income threshold.

Energy efficiency measures may be more valuable strategically than bill assistance because low-income energy efficiency measures reduce both household energy burdens and system energy consumption. Expanding funding for these programs also may be particularly necessary compared to other DSM programs (as described in Recommendation III.A) because the financial means and behavioral options of low-income customers tend to differ significantly from those of other customers.[138] Improving energy efficiency for low-income customers may also offer energy savings opportunities that are greater in magnitude than those of most other customers (e.g., due to poor home insulation or highly inefficient heating technologies).

A variety of bill assistance program designs exist, each with trade-offs between simplicity and the granularity with which they target the most vulnerable customers.[139] The simplest programs are bill discounts (either a flat discount or a percentage of a household's bill) administered as a credit on energy bills for households below a qualifying income threshold.[140] "Tiered" discount programs provide varying discounts based on income but are more administratively complex, while "percentage of income payment plans" are the most granular but administratively intensive program type, administering custom discounts that cap households' bills to a certain percentage of their household income. More granular targeting increases the efficiency of the program but may not be necessary or appropriate depending on the energy burden distribution of customers in the jurisdiction in question and the administrative capacity of the administering entity.

Eligibility for the programs should be assessed across all forms of household energy consumption, including electricity, gas, and transportation (i.e., a household's total "energy wallet"), and assistance should be provided accordingly. See Box VI-A for examples of bill assistance and energy efficiency programs in other jurisdictions.

Encouraging eligible customers to participate will be challenging. A recent report analyzing New Jersey's energy affordability programs found that only 20% of the eligible population participates in its comprehensive bill discount program.[141] To maximize participation, customers receiving other means-tested benefits should be enrolled automatically wherever possible. This may include state energy assistance programs as well as more general welfare programs at the state (e.g., income and disability assistance) and/or federal (e.g., Supplemental Nutrition Assistance Program, or SNAP) level. Administering programs through state governments could facilitate the data-sharing needed to automatically enroll customers.

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138 For example, while modest tax incentives (or financial rebates) may be sufficient to motivate most customers to implement energy efficiency measures that quickly pay for themselves, fully funded energy efficiency measures may be necessary for low-income customers who do not have the means to acquire the necessary energy-efficient equipment, even with available incentives through various programs.

139 Sergici, S. et al.(2024), *An Assessment of Energy Affordability in New Jersey and Alternative Policy and Rate Options*, The Brattle Group.

140 Note that *bill* discounts are distinct from *rate* discounts in that they are administered as a credit on a customer's bill rather than appearing as a lower electricity rate. We do not recommend rate discounts due to the possibility that they distort the price signals that customers receive, leading to inefficient energy consumption behavior (e.g., not reducing consumption when electricity is expensive).

141 Sergici, S. et al. (2024), *An Assessment of Energy Affordability in New Jersey and Alternative Policy and Rate Options*, The Brattle Group.

Additionally, financing programs through the tax base would avoid exacerbating existing rate pressures, recover costs in a more progressive manner, and potentially reduce administrative burden.[142]

In addition to low-income energy efficiency programs, targeted DSM programs for low-income households should form part of utilities' assessment of promising demand-side resource programs. Bundled programs that offer to install and then operate high-efficiency and/or smart devices in low-income households (potentially bundled with an advanced rate offering) could simultaneously reduce bills for vulnerable customers while providing system benefits from load shifting.

[142] Funding for these programs can also come from large load customers. For example, in Indiana, large data center customers agree to contribute to weatherization programs for income-qualified customers. *See* Silverman, A. et al. (2025), *A State Playbook for Managing Data Center-Driven Load Growth*, Johns Hopkins University.

BOX VI-A: BILL DISCOUNT AND ENERGY EFFICIENCY PROGRAMS IN OTHER JURISDICTIONS

National Grid (MA) Discount Program

National Grid currently offers a 32% discount on electricity bills and a 25% discount on gas bills for eligible customers. Customers with household incomes below 60% of the state median income (SMI, approx. US$87,000 for a family of four) are eligible to apply; they are also eligible if they receive benefits from another means-tested public benefit program or are eligible for LIHEAP (the US's federal bill assistance program). Roughly 160,000 customers received discounts on their monthly bills as of August 2024, of a total of 390,000 eligible.[143]

The MA DPU recently ordered National Grid to implement a tiered discount program for electricity by June 2025, starting at 71% for customers below the federal policy line and decreasing to the current 32% at 60% of SMI.[144]

PG&E California Alternate Rates for Energy (CARE)

PG&E offers 30–35% discounts on electricity bills and 20% discounts on gas bills for households earning less than 200% of the federal poverty level (i.e., US$62,400 for a four-person household).[145] Households are also eligible if they receive benefits from other public assistance programs, including Food Stamps, Supplemental Security Income (SSI), Medicaid, and others. In 2023, roughly 1.4 million customers were eligible, with PG&E administering US$988 million in discounts; administrative expenses were US$9.5 million.[146]

EmPOWER Maryland Limited Income Energy Efficiency Program

Maryland's EmPOWER program provides energy efficiency upgrades and equipment at no charge to households with a total household income below 80% SMI (US$97,800 for a family of four).[147] Eligible households receive an energy audit that identifies ways to reduce household energy costs (including behavioral changes), and recommended work is scheduled with a contractor. A follow-up audit evaluates energy efficiency improvements once the work is complete. Households are also automatically eligible if they receive assistance from any of a range of state and federal programs, including utility bill assistance, SNAP (food stamps) benefits, SSI, and Medicaid. In 2023, approximately 14,000 low-income homes and 2,500 multifamily properties were weatherized through the program at a total cost of US$24.2 million, with average energy savings per participant of 478 kWh.[148]

143 WBUR (2024), "Bigger Electric Bill Breaks are Coming for Some Low-Income Residents in Mass."

144 Massachusetts Department of Public Utilities (2023), D.P.U. 23-150, National Grid Electric Base Distribution Rate Case.

145 PG&E (2024), "California Alternate Rates for Energy (CARE) Program."

146 PG&E (2024), *PY2023 Low Income Annual Report*.

147 Maryland Department of Housing and Community Development (2024), "EmPOWER Maryland Limited Income Energy Efficiency Program."

148 Public Service Commission of Maryland (2024), *The EmPOWER Maryland Energy Efficiency Act Report of 2024*.

B. Develop rate design for large new loads to mitigate cost-shifts and stranded-cost risks

SUMMARY: Rate design can be an effective tool for sharing the burden of system costs and financial risks between large customers, other customers, and utilities while still meeting the needs of large consumers. Utilities should consider tariff structures designed for large customers and provisions to protect against stranded asset risks (e.g., by requiring long-term commitments to pay for contracted energy and/or capacity).

RELEVANT STAKEHOLDERS: Utilities, regulators

IMPLEMENTATION NOTES: This would require state regulatory approval of new retail rate offerings.

Numerous special rate structures are being explored by US utilities, regulators, and large-load customers to mitigate the impacts of projected load growth.[149] A recent study found that a wide range of tariff designs have recently been approved or proposed to balance large-load customers' power demands (and in some cases, the desire from jurisdictions to attract their investment) with resource adequacy, affordability, and emissions reductions.[150] These alternative rate structures attempt to straddle multiple issues, including fair allocation of incremental system costs to large-load customers, mitigation of financial risks from stranded assets, mitigation of operational/resource adequacy risks, risk-sharing in commercialization of newer electricity technologies, and accommodating the needs of large-load customers such as low-carbon supply and high reliability.

The increasing demand for electricity, largely from data center customers, presents an opportunity for utilities to attract new customers, benefit existing customers, and play a central role in enabling the US to become an AI leader. When pursuing this opportunity, utilities also need to weigh the potential risks of shifting costs from large customers to other customers and of stranded cost risks. Strategies to mitigate these risks through rate design have emerged across different jurisdictions in the US, and they vary based on regulatory model, system characteristics, and market characteristics. A review of recent rate offerings introduced by

[149] See Hledik, R. et al., *The Rate Exchange: May 2025*, The Brattle Group, for a summary of experience with retail rate designs for data centers and other large loads, including rate designs that mitigate cost-shifts to existing customers.

[150] Satchwell, A. et al. (2025), *Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities*.

utilities for large customers reveals that they have incorporated the following elements into their rate designs to mitigate risks:

- **Minimum charge:** Utilities are embracing minimum demand charges and minimum bills to ensure that large customers contribute to grid costs, even when their usage fluctuates. For example, AEP Indiana's recently approved tariff features a demand charge based on the higher of 80% of a customer's contracted capacity or 80% of their highest billing demand from the previous year. The minimum charge level is higher in AEP's proposed tariff in Kentucky (90%) and in AEP's proposed settlement in Ohio (85%; see Box VI-B).
- **Long-term contracts:** Many utilities are pairing minimum charges with extended contract terms to provide greater revenue certainty. Evergy's proposed LLPS tariff in Kansas and Missouri combines an 80% minimum demand charge with a 15-year contract term.
- **Collateral requirements**: To protect against financial risks if a large customer suddenly scales back operations or exits the market, utilities are requiring large customers to post large collateral. Customers with a good credit rating and sufficient liquidity may qualify for reduced collateral requirements.
- **Early termination fees**: Utilities may include stipulations that provide data center customers with the flexibility to terminate service early in exchange for a fee. NV Energy's recently approved Clean Transition Tariff includes an exit fee if a customer ends the contract before its full term.

Well-designed rate options for large customers also have the added benefit of improving forecasts of how much new load will materialize.[151] Having transparent and robust terms and conditions in place means that only potential customers who are serious about getting service will proceed, allowing utilities to have better visibility into the certainty of the different prospective loads.

[151] Lam, L. (2025), *Electricity Demand Growth and Forecasting in a Time of Change*, presentation in front of the New Mexico Public Regulation Commission.

BOX VI-B: EXAMPLE LARGE-LOAD TARIFFS FROM OTHER JURISDICTIONS

Indiana Michigan Power (I&M) Industrial Power Tariff

Proposed in November 2024, the tariff would require large loads with more than 70 MW of on-site capacity (or 150 MW aggregated across a company) to enter into long-term contracts with the utility for at least 12 years.[152] These contracts include a monthly demand charge equal to either 80% of the contract capacity or 80% of the customer's largest monthly demand (whichever is greater) to protect against generation and grid investments becoming stranded assets if the load does not fully materialize. Large loads can terminate their contracts or reduce them by more than 20% by paying an exit fee. The proposal is supported by data center stakeholders and consumer advocates and is subject to Indiana regulators' approval. The agreement also requires Amazon Web Services, Microsoft, and Google to each give US$500,000 per year for five years to the Indiana Community Action Association to support low-income Indiana residents.

AEP Ohio Proposed Data Center Tariffs

AEP Ohio proposed to require data centers larger than 25 MW to pay for 85% of the kW demand they expect to need each month for 12 years.[153] If the project is canceled or the data center cannot meet the obligations of its electric service agreement contracts, it must pay an exit fee equivalent to three years of minimum charges. The proposed tariff also includes minimum credit ratings on customers and provides the opportunity for customers to reassign up to 25% of their contracted capacity to another customer when exiting the system.

[152] Howland, E., "Indiana Michigan Power, Amazon, Google, others agree on large load interconnection rules," *Utility Dive* (November 25, 2024).

[153] Howland, E., "AEP Ohio reaches agreement with stakeholders on data center interconnection rules," *Utility Dive* (October 24, 2024). The proposal is recently approved by the Ohio Public Utilities Commission.

C. Explore alternative financing and regulatory mechanisms

SUMMARY: Alternative financing and regulatory mechanisms can help to mitigate the rate impacts of the investments needed across the power system in the face of unprecedented load growth. Regulators should explore levelized cost recovery frameworks and performance-based ratemaking and consider allowing utilities to pursue securitization for investment costs. Public-private partnership models can also assist with reducing financing costs and expedited construction of energy projects.

RELEVANT STAKEHOLDERS: Utilities, state policymakers, regulators, private developers

IMPLEMENTATION NOTES: Changes to ratemaking require regulatory approval. Legislative change may be required to authorize performance-based regulatory frameworks and securitization.

If implemented at scale, the solutions described throughout this report will help optimize how the existing power system is operated and maximize the value of energy resources, including customer-side assets. However, accommodating the unprecedented level of increase in electricity demand will necessitate substantial investments in new generation, transmission, and distribution infrastructure. To mitigate the rate impacts and financial strains associated with these investments, policymakers and regulators can encourage innovative regulatory models, fair cost allocation frameworks, and smart rate designs. Alternative ratemaking practices and public-private partnership (P3) models can play an important role in financing and accelerating the construction of new energy projects while supporting affordability objectives.

In the US, utility cost recovery typically follows the straight-line depreciation method, where depreciation is charged in equal installments over the life of an asset, and the rate base declines by a constant amount each year. Because of the "front-loaded" nature of this depreciation method, adding a new asset to a utility's rate case can lead to an initial rate shock.[154] As an alternative, "levelized" cost recovery can be used to create more even cost recovery, similar to a mortgage payment structure. Levelized ratemaking yields the same net present value of revenue as the straight-line depreciation method but offers the advantages of

[154] Graves, F. et al. (2007), *Rate Shock Mitigation*, report prepared by The Brattle Group for the Edison Electric Institute (2007).

improved rate stability and improved intergenerational equity, as customers today do not have to shoulder a disproportionate share of the capital cost recovery. Different versions of this ratemaking approach have been used across the power industry and in other regulated industries.[155]

For example, FERC approved levelized rates for Kern River Gas Transmission Systems in 2010, stating in its order: "Levelizing a pipeline's rates over its life provides lower rates at the initiation of service than a traditional rate making methodology but, over time as the traditional rate base declines, the levelized rate will become higher than traditionally designed rates. In essence, levelization is accomplished by the pipeline deferring to recovery of costs in later years that would otherwise be recoverable early in its life."[156] Similarly, in 2009, FERC approved Citizens Energy's request for a 30-year levelized rate approach for its share of a newly constructed electric transmission line in southern California.[157]

Securitization can provide another tool for promoting bill stability while reducing overall costs. This mechanism allows investment costs to be financed by dedicated bond issuances and repaid via non-by-passable charges on customer bills. Customers benefit from this mechanism through reduced overall financing costs (but at the expense of a non-by-passable charge). This mechanism has been applied to stranded cost recovery and to address large costs stemming from major events like wildfires and storm damage.[158]

Performance-based ratemaking (PBR) can serve as another regulatory tool to help lower customer costs while aligning utility performance with public policy goals. PBR frameworks incorporate tools such as performance incentive mechanisms (PIMs), revenue decoupling, and multi-year rate plans. [159] These mechanisms have been deployed in a number of jurisdictions to incentivize utilities to achieve outcomes related to cost control, improved reliability, energy efficiency, clean energy deployment, distributed energy resource (DER) integration, and rate

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155 Mudge, R. S.(2016), Prefiled Direct Testimony and Exhibits RSM-1 to RSM-2, filed in *In the Matter of the Revenue Requirement and Rate Design Study Filed by the Municipality of Anchorage d/b/a Municipal Light and Power*, Regulatory Commission of Alaska, Docket No. TA357-121 (Dec. 30).

156 Kern River Gas Transmission Co., Opinion No. 486-D, Order on Rehearing and Compliance, 133 FERC ¶ 61,162, November 18, 2010, p. 156.

157 Citizens Energy Corporation (2009),"Citizens Energy Provided Financing for 50% of the Sunrise Powerlink Project.", Order on Transmission Rate Incentives and Capital Cost Recovery Methodology, 129 FERC ¶ 61,242, Docket No. EL10-3-000, Issued December 17, 2009, p. 23.

158 Kevin, R. and G. Grossberg (n.d.), "The Rationale Behind U.S. Utility Securitization And Reasons For Recent Growth," S&P Global.

159 For a detailed description of these mechanisms and PBR, see Joskow P. (2024), *The Expansion of Incentive (Performance Based) Regulation of Electricity Distribution and Transmission in the United States*, MIT Center for Energy and Environmental Policy Research Working Paper Series.

design innovation, among many others.[160] (Box VI-C provides a case study for electric utilities in Hawaii and guidance to state legislators.) However, we note that a departure from the traditional cost-of-service regulation framework can invite lengthy and at times contentious back-and-forth among stakeholders, and the end results can sometimes fall short of the initial policy objectives.

In addition to alternative ratemaking practices, P3 models can also help lower the cost of developing new energy infrastructure.[161] These models have been deployed to develop large-scale electric transmission lines in the US, especially projects that cross multiple jurisdictions or enable remote renewable resources. The P3 structure can take advantage of the lower cost public debt, exemption from certain taxes, and private sector expertise in building, operating, and maintaining the energy project. These arrangements can also streamline the regulatory review and permitting process, build public support, and derisk large energy infrastructure projects. In certain cases, state eminent domain authority, though rarely used, may facilitate the resolution of right-of-way and land acquisition issues.

[160] These mechanisms typically apply to distribution utilities. Joskow argues that while "targeted incentives" available to transmission owners are designed to make it attractive for transmission owners to invest in transmission infrastructure and be part of an RTO, these incentives do not constitute to traditional PBR components/are not in the spirit of incentive regulation literature. While the FERC may have the authority to do more, practical, political, and administrative challenges may prevent it from doing so.

[161] Clean Air Task Force (2024), "Wired for Savings—Evaluating the Impacts of Alternative Transmission Financing and Development Models on California Ratepayers."

BOX VI-C: EXAMPLES OF PERFORMANCE-BASED RATEMAKING

Hawaii's Performance-Based Ratemaking Framework

The PBR framework for Hawaiian Electric Companies went into effect in 2021, consisting of a suite of mechanisms to promote policy goals such as renewable energy adoption, customer affordability, and customer service quality.[162] At the core of the framework is a five-year rate plan, with annual revenue targets (and consequently rates) adjusted annually using a formula that incorporates variables such as inflation, productivity, exogenous events, and customer dividend. The framework also includes performance incentive mechanisms ("PIMs") that provide additional revenue opportunities if the utility meets certain performance outcomes related to reduced interconnection times for DER systems, improved customer engagement, and effective utilization of advanced metering infrastructure, among others.[163] In addition, the framework introduces a process for expedited review for innovative pilot projects and programs.

Guidance on Performance-Based Ratemaking to State Legislatures

The National Conference of State Legislatures (NCSL) released in 2023 the report *Performance-Based Regulation: Harmonizing Electric Utility Priorities and State Policy*.[164] The report explores how state lawmakers can pursue PBR to utility regulation to reflect industry changes, meet consumer demands, and support state energy policy goals. It provides an overview of the most common performance-based approaches to utility regulation and an introduction to state legislatures' role in defining the goals and expected outcomes from transitioning from traditional cost-of-service regulation to a performance-based regulatory framework. As of 2023, at least 17 states and Washington, DC had enacted legislation that either allows for PBR or requires utilities to operate under PBR.

[162] Hawaii Public Utilities Commission (2024), Performance-Based Regulation (PBR) for the Hawaiian Electric Companies, Docket No. 2018-0088.

[163] Hawaii Public Utilities Commission (2024), Monitoring Hawaiian Electric's Progress, Docket No. 2018-0088.

[164] NCSL (2023), "NCSL Releases New Report on Performance-Based Regulation."

VII. Conclusion

This paper offers timely and cost-effective recommendations to address the significant challenges faced by the power industry today: unprecedented load growth demand from new data centers, re-shoring of manufacturing, the electrification of end uses, ambitious state energy policy goals, and the presence of supply chain challenges that exacerbate capital investment needs and the already-existing cost pressures on ratepayers.

We have shown how solutions to address these challenges have been implemented across the industry, and recommended steps that regulators, system planners, utilities, and other key stakeholders can take to address the supply, interconnection, cost, and environmental policy challenges that the power sector is facing. This includes measures to:

- Maximize the value of the existing power system;
- Cost-effectively accelerate the grid connection of new resources and loads;
- Implement proactive planning and procurement processes to identify flexible, least-regrets solutions; and
- Introduce targeted affordability measures for low-income and vulnerable customers while adopting best-practice rate designs for large customers to mitigate stranded-cost risks and minimize risks to existing customers.

Implementing these recommendations will increase the cost-effectiveness and speed at which new loads and resources can be integrated into the power system to achieve state policy goals, while mitigating affordability concerns and boosting the efficiency with which capital is deployed. Doing so will also require effort, coordination, and collaboration among a broad set of stakeholders.

List of Acronyms

AC	Alternating Current
AEMO	Australian Energy Market Operator
AEP	American Electric Power
AI	Artificial Intelligence
AMI	Advanced Metering Infrastructure
ATT	Advanced Transmission Technology
C&I	Commercial and Industrial
CA	California
CAISO	California Independent System Operator
CATF	Clean Air Task Force
CEEPR	Center for Energy and Environmental Policy Research
CEO	Chief Executive Officer
CEP	Clean Energy Plan
CO	Colorado
COD	Commercial Operation Date
CPA	Capacity Purchase Agreement
CPUC	California Public Utilities Commission
DC	District of Columbia
DER	Distributed Energy Resource
DOER	Department of Energy Resources (Massachusetts)
DPU	Department of Public Utilities (Massachusetts)
DR	Demand Response
DSM	Demand-Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERZ	Energy Resource Zone
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GET	Grid-Enhancing Technology
GW	Gigawatt
HPC	High-Performance Conductor
HVDC	High-Voltage Direct Current
IPP	Independent Power Producer
IRP	Integrated Resource Plan(ning)
ISO	Independent System Operator

ISP	Integrated System Plan (Australia)
kV	Kilovolt
kW	Kilowatt
LBNL	Lawrence Berkeley National Laboratory
LIHEAP	Low Income Home Energy Assistance Program
LLPS	Large Load Power Service
MW	Megawatt
MWh	Megawatt Hour
MISO	Midcontinent Independent System Operator
MIT	Massachusetts Institute of Technology
MN	Minnesota
NCSL	National Conference of State Legislatures
NRG	NRG Energy
NV	Nevada
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research and Development Authority
OEM	Original Equipment Manufacturer
OTB	Option to Build
PG&E	Pacific Gas and Electric Company
P3	Public-Private Partnership
PBR	Performance-Based Ratemaking
PIM	Performance Incentive Mechanism
PJM	PJM Interconnection, Inc.
PPA	Power Purchase Agreement
PSA	Purchase and Sale Agreement
RAPID	Renewable Action Through Project Interconnection and Deployment
RAS	Remedial Action Scheme
REZ	Renewable Energy Zone
RFP	Request for Proposal
RNA	Reliability Needs Assessment
RTO	Regional Transmission Organization
SMI	State Median Income
SNAP	Supplemental Nutrition Assistance Program
SPP	Southwest Power Pool
SSI	Supplemental Security Income
TOU	Time-of-Use
TVA	Tennessee Valley Authority
TVR	Time-Varying Rate
TWh	Terawatt Hour
VDER	Value of Distributed Energy Resources
VPP	Virtual Power Plant