Spring 2026

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ENERGY INDUSTRY UPDATE

POWER BRIEF

Executive Summary

As we settle into 2026, policy uncertainty, growing energy demand, and continuing focus on affordability are influencing U.S. energy infrastructure needs and its pace of development. In this Power Brief, we discuss several topics that illustrate challenges and opportunities for the energy industry:

- **Gas pipeline development:** As gas demand increases to satisfy growing gas-fired power production and LNG exports, the midstream sector has been adding pipeline capacity to move gas to key users and exporters. Growing demand by large loads for dispatchable, gas-fired capacity is set to continue or perhaps accelerate this trend.
- **ISO New England capacity market changes:** Several regional markets are assessing their capacity market constructs as reserve adequacy and affordability considerations meet a changing resource mix. New England is moving from a three-year forward capacity auction to seasonal and month-ahead solicitations to ensure "real" capacity is procured.
- **Offshore wind:** In recent years, offshore wind development had been active in the U.S. Eastern Seaboard, aided by state policies and the Biden administration's target of 30 GW by 2030. The Trump administration has different priorities, pausing all offshore wind energy leases pending review. It is unclear whether the industry can sustain these projects through current headwinds.
- **Transmission and distribution development:** Transmission development has been stymied by issues of cost allocation, siting, and permitting. The addition of high-voltage lines and interregional transmission has been especially rare. Many industry participants are hoping that federal permitting reform can get across the finish line to enable system expansion as energy demand grows. Affordability remains a strong focus as capital spending on distribution increases at a growing pace.
- **PJM developments:** The PJM Interconnection, the United States' first fully functioning regional transmission organization, has long been at the forefront of contending with complex issues. It now deals with several that may be coming to other grid operators. We look at a few current issues: tightening reserve margins, data center growth and its implications, long interconnection queues, and rising capacity prices.
- **Large load tariffs:** There has been much popular and political discussion of the possible effects of large loads on energy affordability for other customers. Regulators, utilities, and large customers continue to use tailored tariff terms, as well as unique structures, to ensure proper ratepayer protections.

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TABLE OF CONTENTS

Topic #1

Gas Pipeline Development

Gas Demand Ramping Up

Continued Growth in Gas Demand

- Natural gas demand in the United States continues to grow. EIA estimated that gas demand across all end uses grew by 1.5% in 2025, with gas for power generation comprising 39% of gas demand.
- Behind increasing gas demand are two principal drivers:
  - LNG exports: The development of LNG export facilities added nearly 10 Bcf/day to gas demand since 2019. With expected liquefaction terminal completions, up to an additional 15 Bcf/day in incremental demand is expected, for a total of 30 Bcf/day.
  - Power generation: Growth in large loads (data centers and industrial facilities) and, to a lesser extent, electrification of buildings and transportation has led to an increase in projected gas-fired power generation. As of late 2025, companies had planned investment in more than 200 gas-fired plants with a total capacity of 133 GW.
- While solar and solar/battery hybrid projects remain the predominant anticipated resources in interconnection queues, gas units remain important firming for resource adequacy.

Demand in Context

- One recent analysis found that U.S. gas demand, including both domestic consumption and net exports, could reach 125 Bcf/day by 2030 compared with 109 Bcf/day in 2024, a 14% increase.

Figure 1.1: Comments on Gas Demand Growth by Selected Industry Players (and Date of Comment)

Citi Group (May 2024)	The call on U.S. gas could grow by ~20 Bcf/day or more by 2030
East Daley (Feb. 2025)	4.2 to 6.1 Bcf/day of new gas demand for data center power demand of up to 81 GW
Bloomberg New Energy Finance (Sept. 2025)	Estimated ~7 Bcf/day of gas demand from data centers and a doubling of LNG exports from ~16 Bcf/day (Sept. 2025) to ~30 Bcf/day by 2030
Expand Energy (Oct. 2025)	We see demand growing about 20 Bcf/day between now and the end of the decade
TC Energy (Nov. 2025)	[We expect] 45 Bcf/day by 2035 driven by electrification, LNG exports, and the rapid expansion of data centers (in reference to North American natural gas demand)
Enterprise Products Partners (Nov. 2025)	8 to 22 Bcf/day by 2030, with 3 to 5 Bcf/day specifically from AI and data centers and 5 to 12 Bcf/day from waterborne LNG exports
Enbridge (Nov. 2025)	17 Bcf/day of additional LNG-related natural gas demand expected to enter service by 2030
Kinder Morgan (Dec. 2025)	Natural gas demand that we expect between the end of 2024 and 2030…it's going to be between 22 and 28 Bcf/day
EIA (Jan. 2026)	Total demand, including exports, to reach 119 Bcf/day in 2027

Sources: S&P Global Market Intelligence; EIA; McKinsey & Co.; National Center for Energy Analytics/ Hamm Institute for American Energy; North American Electric Reliability Corp; Oilprice.com; company investor presentations and earnings calls; ScottMadden analysis

Speed to Power = Speed to Gas?

Figure 1.2: Illustrative Gas Burn per GW for Selected Gas-Fired Power Technologies

Technology	Assumed Heat Rate (MMBTU/MWh)	Gas Usage/Year per GW (MMBTU)	Gas Usage/Day (Bcf) per GW	Incremental Gas Burn (Bcf/Day) at 55 GW
Aeroderivative GT – Simple Cycle	8.33	72,953,280	0.19	10.60
CT – Simple Cycle	9.14	80,083,920	0.21	11.64
CC 1x1x1	6.23	54,539,760	0.14	7.93

Note: The figure above is a simple, high-level calculation to illustrate the potential magnitude of incremental gas consumption, assuming only gas-fired units powering facilities 24/7/365. It does not account for other possible resources (e.g., renewables, storage) or environmental or other constraints on power production.

Speed to Power to Meet Data Center Growth

- The utility industry has been engaged in almost constant discussion of artificial intelligence and the data centers that facilitate it (as well as other online commerce).
- Capital spending on data centers is being met with planned power generation and electrical infrastructure by utilities, merchant generators, and behind-the-meter solutions developers.
- While many of the largest tech companies and hyperscalers have interest in non-emitting resources (renewables, nuclear), near-term power needs (next five years) are focused on natural gas-fired units to satisfy build schedules, data center uptime requirements, and to balance renewable resources.

Converting Power Demand to Gas Demand

- Projections of gas-fired power generation for data center applications vary. Estimates depend upon several factors (see Figure 1.2), including:
  - Percentage of data center demand met by gas-fired units
  - Technology type (e.g., combined cycle, simple cycle or aeroderivative gas turbines, gas-fired reciprocating engines) and heat rates
- Factors that could moderate these forecasts include supply chain constraints, local and regulatory opposition, and “phantom” data centers as hyperscalers shop the same project in various jurisdictions.

Sources: Industry news; EIA (referencing Sargent & Lundy); GE Vernova; ScottMadden analysis

Prospects for Increasing Gas Deliverability

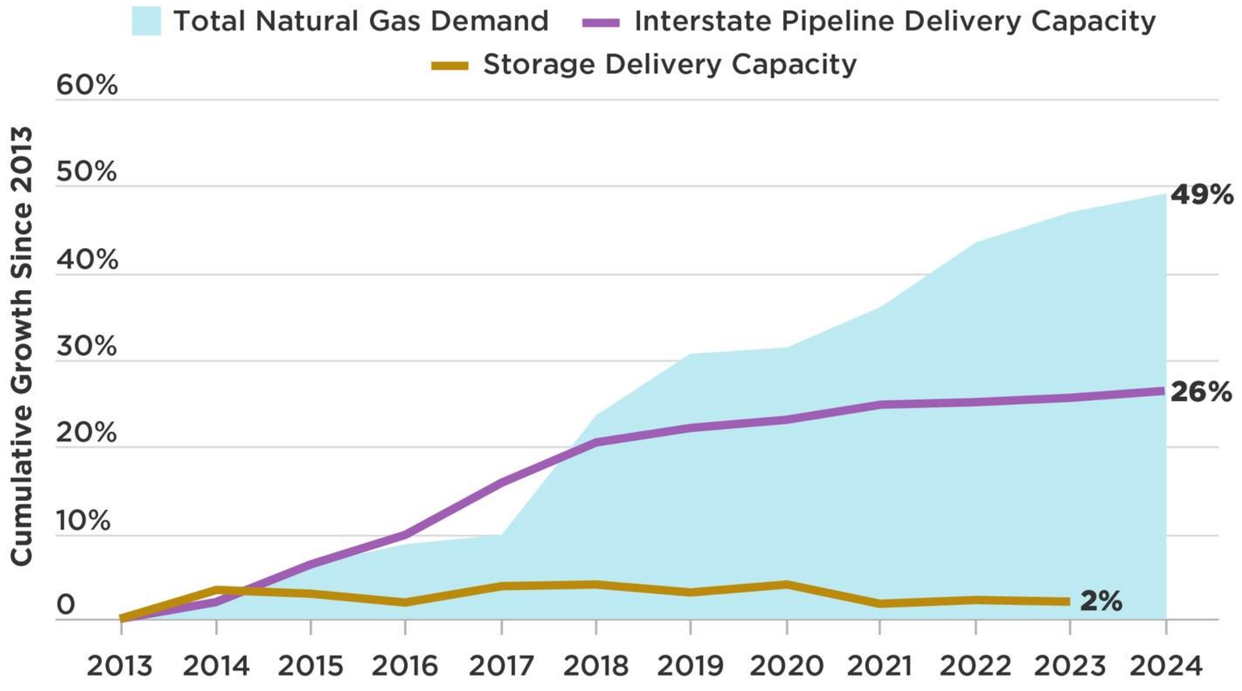
Pipeline Additions Meeting Demand?

- As shown on Figure 1.3, midstream additions and expansions have not grown at the same rate as gas demand.
- However, after hitting a recent low in 2022, gas pipeline additions (both intra- and interstate) totaled 17.8 Bcf/day in 2024. Over the past five years, pipeline additions totaled about 50 Bcf/day (see Figure 1.4).
- While not matching demand growth rates, natural gas pipeline projects are being completed. In 2024, projects totaling 6.5 Bcf/day were completed, increasing takeaway capacity from Appalachian, Permian, Haynesville, and Eagle Ford production regions.
- Increased capacity is debottlenecking with location-specific benefits: in the Northeast, improving reliability and affordability; in the South, benefiting LNG export corridors.

Storage Needed for Flexibility

- Some argue that a commensurate increase in pipeline capacity with gas demand may also require additional storage, given needed flexibility for gas demand variability from power demand, including onsite, behind-the-meter generation.
- According to S&P Global, as of late 2025, nearly 400 Bcf of new gas storage capacity is in various stages of development; 300 Bcf of that is along the U.S. Gulf Coast.

Figure 1.3: Storage Delivery and Interstate Pipeline Capacity Growth vs. U.S. Gas Demand Growth (2013–2024)

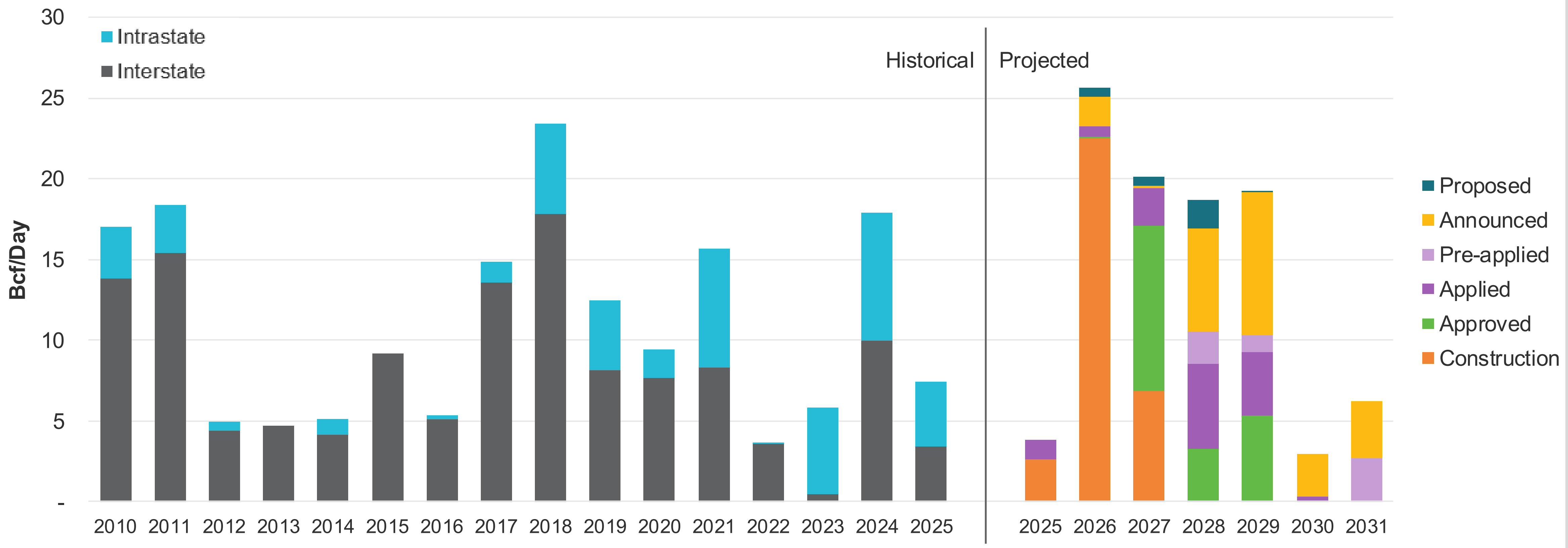


Note: 2023 is the most current data for storage delivery capacity.
Source: Data from EIA. 2025.

Sources: S&P Global Market Intelligence; EIA; McKinsey & Co.; National Petroleum Council; ScottMadden analysis

Prospects for Increasing Gas Deliverability (Cont.)

Figure 1.4: Historical and Projected Gas Pipeline Capacity Additions by Type, Project Status, and Actual/Expected Year in Service (in Bcf/Day) (2010–2031P)

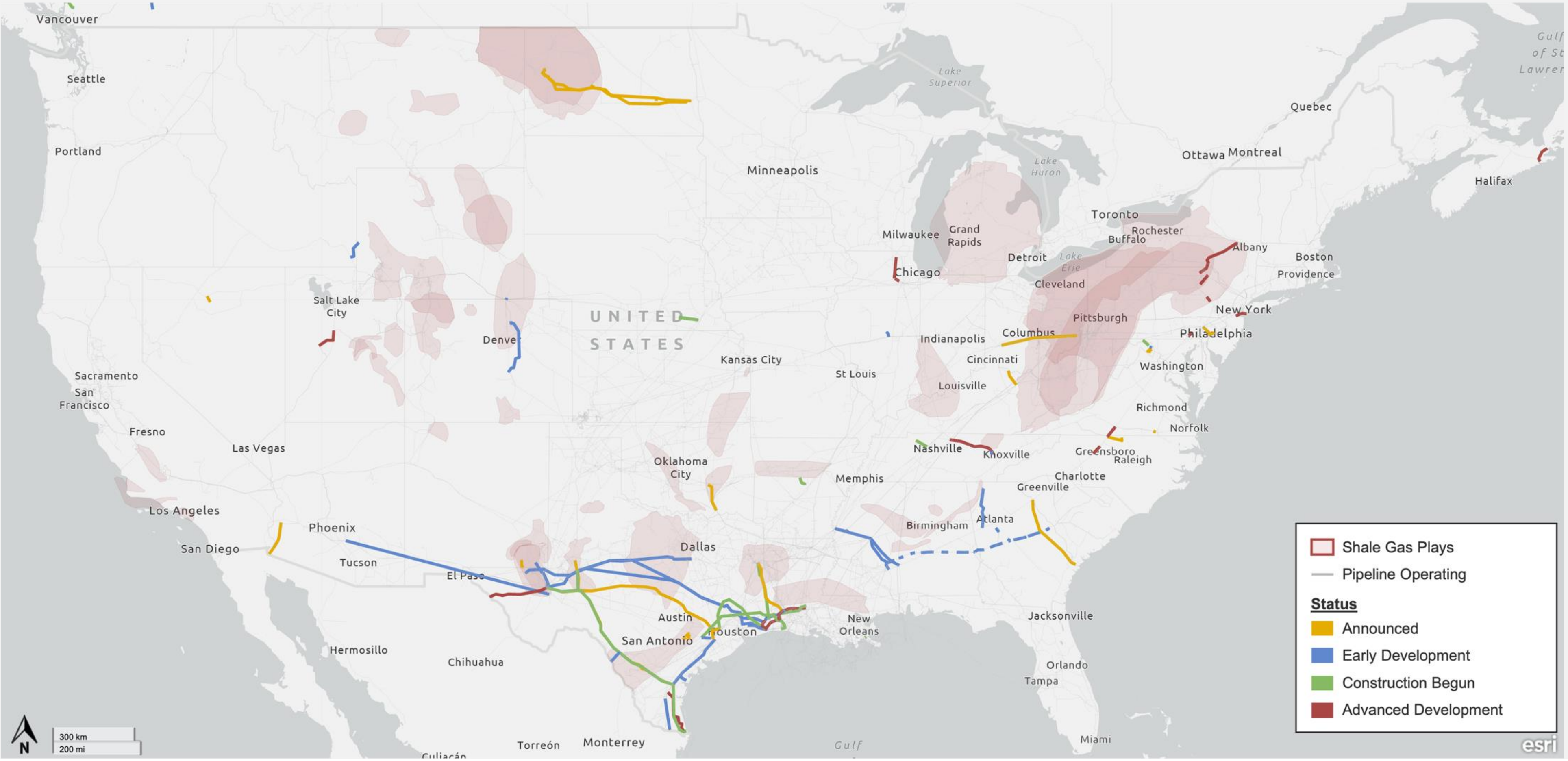


Note: 2025 "projected" projects are those which expected in-service date was 2025 but had not been completed as of Jan. 2026. P means projected.

Sources: EIA (data as of Jan. 2026); ScottMadden analysis

Prospects for Increasing Gas Deliverability (Cont.)

Figure 1.5: Significant U.S. Lower 48 Proposed Pipeline Projects by Status and Shale Gas Play Locations



Note: Includes pipeline projects >10 miles and >0.1 Bcf/day capacity

Source: S&P Capital IQ

Overcoming Potential Barriers to Pipeline Expansion

Permitting and Local Opposition Slows Build

- A significant number of pipeline projects—about half—from 2010 to 2024 were flow reversals (backhaul), with few greenfield pipe additions.
- With more greenfield projects being proposed, those projects are subject to significant local and organized environmental opposition. For example, Transcontinental Gas Pipe Line Company's Northeast Supply Enhancement project as been caught in litigation challenging the project's water quality permit, which has been a key focus of pipeline project challenges.
- FERC Chair Swett, in testimony before Congress, noted that Clean Water Act provisions can effectively veto federal projects, since federalism provides states with significant leverage in CWA §401 certification.

"Energy Dominance" Posture May Drive Development

- Since assuming office in January 2025, the Trump administration has used executive orders and federal administrative policy (such as NEPA interpretations) to reduce barriers to certificating energy infrastructure.
- With a shuffling of members, FERC, too, is focusing on what is required by law for their review versus policy preferences.
- Finally, bipartisan legislative action is in motion (see Figure 1.6), seeking to streamline permitting for energy infrastructure projects of all kinds. While the SPEED Act has passed the House in December 2025, Senate approval is proving slower to achieve in a contentious partisan environment.

Figure 1.6: Key Provisions of the Standardizing Permitting and Expediting Economic Development (SPEED) Act

Reforms to the National Environmental Policy Act (NEPA) Federal Permitting Procedures under the SPEED Act

- Codifies NEPA to be a procedural, not substantive, statute
- Broadens the range of agency exemptions for NEPA documents
- Limits on new research and "late-breaking" studies after permit applications submitted, preventing delays from continuously updating analyses
- Confines reviews to environmental impacts that "share a reasonably close causal relationship" to the project, not those that are speculative or separate in time or place from the project (e.g., upstream or downstream)
- Shortens NEPA judicial review deadlines to 150 days (from current two- to six-year statute of limitations for energy infrastructure and transport projects, respectively)
- Affords "substantial judicial deference" to agency NEPA decisions
- Restricts litigation standing to commenters directly/negatively impacted
- Limits cooperating agency review only to matters within their jurisdiction
- Requires multi-agency environmental reviews concurrently with NEPA
- Permits prior environmental analyses for substantially similar actions
- Narrows the definition of several terms triggering NEPA review

Sources: National Petroleum Council; S&P Global; Bipartisan Policy Center; National Association of Manufacturers; ScottMadden analysis

Topic #2

ISO New England Capacity Reforms

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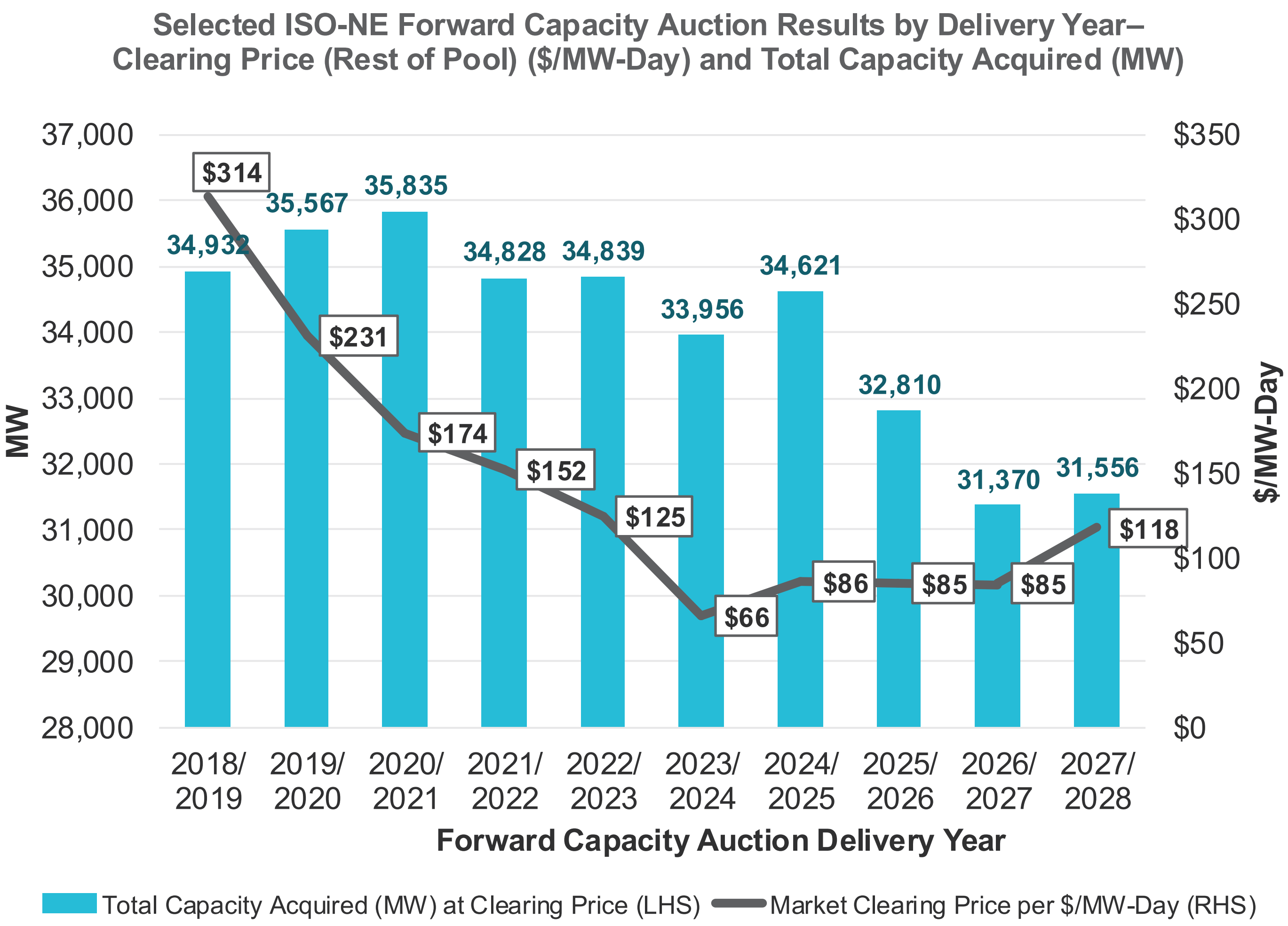
ISO New England Works on Changing Its Capacity Market

Another ISO Looks at Its Capacity Market

- Capacity market constructs are being reevaluated in several markets, considering state policy interests in the resource mix (i.e., emissions), prices and affordability, and speed to resource development.
- Since 2008, ISO-NE has had a three-year procurement forward capacity auction (FCA). The objective was to provide known pricing in exchange for a commitment of supply resources and to afford sufficient time for development and financing of new resources before delivery.
- ISO-NE began stakeholder discussions of potential capacity market redesign in summer 2023. An ISO-NE-commissioned white paper issued in 2024 observed that since the FCA was established, some trends warranted reexamination of the capacity market:
  - State policies and technology development had shifted regional resources toward solar and wind resources and energy storage and reductions in dispatchable fossil-fueled resources (different operating characteristics).
  - The process and time for resource development was longer, more complicated, and uncertain.
  - Focus on summer peaks has shifted to winter months given increasing winter peaks and longer-duration energy constraints during winter.

Figure 2.1: Selected Historical Forward Capacity Auction Results



Note: LHS means left-hand side. RHS means right-hand side.
Sources: ISO New England; Analysis Group; ScottMadden analysis

Market Changes and Issues the Reforms Are Intended to Solve

Figure 2.2: Key Features of Planned ISO-NE Capacity Auction Changes

Capacity Auction Reform – PD		Capacity Auction Reform – SA	
Prompt Period Auctions	**Deactivation Process**	**Seasonal Auctions**	**Accreditation**
■ Auctions 1 to 2 months before capacity delivery month ■ Resources must have achieved in-service operation ■ Sealed bid auction with “final and best” offers vs. current “descending clock auctions” with multiple rounds ■ Similar price formation as today: supply matched with demand curves will continue to be derived based on capacity’s MRI* value, with a calculated net CONE** to translate MRI values to capacity prices	■ Deactivation determinations much closer to the intended deactivation date ■ Deactivation notification required one year ahead of the intended commitment period, with reliability review after notification ■ Delayed deactivation is possible if needed for local transmission security ■ Deactivations cannot be revoked, but process will exist for reentry ■ Market power tests for effects of deactivation	■ Seasonal auctions—separate summer (May–October) and winter (November–April) capacity commitments—with prices and obligations reflecting seasonal reliability needs rather than a single annual peak ■ Resource deliverability will be considered in auctions linked to accreditation ■ Auctions designed for 1 day in 10 years loss of load expectation but splits 1-in-10 into ½ day per season	■ Maximum capacity value would be set to the product of (i) the resource’s maximum capability and (ii) the resource’s MRI ■ Considers suitability—i.e., that each resource is unique, with different performance characteristics under various system conditions ■ Fuel assurance will be a consideration: gas-fired resources with firm contracts or alternative fuel choices provide greater reliability value than those without

Two Phases, Four Key Features

- Capacity auction reform (CAR) is proceeding in two work streams: CAR-PD (Prompt/Deactivation) and CAR-SA (Seasonal/Accreditation). The key features of each are illustrated in Figure 2.2.
- CAR-PD has been submitted to FERC for approval, and the ISO is working to submit its CAR-SA proposal to FERC by the end of 2026.

Potential Issues Resolved

- Stakeholders, including power generators, are largely supportive of the proposed reforms.
- Moving to seasonal and prompt month (rather than forward) auctions are expected to solve the following issues:
  - Phantom entry – the resource not being ready or built before its performance period: capacity must be operational to bid
  - Auction input accuracy: prompt month auctions reduce uncertainty in supply/demand conditions, and the ISO hopes it will reduce administrative burden
  - Reflection of seasonal resource performance versus years ahead, full-year approach

Notes: *MRI means marginal reliability impact, which accredits summer and winter resources based upon modeled or estimated expected performance during simulated hours where resource adequacy is at risk. **Cost of new entry, or the annual revenue a new generation resource of a reference technology (often assumed to be a gas-fired combustion turbine) needs from the capacity market to be financially viable, after accounting for expected revenues from energy and ancillary services markets.

Sources: ISO New England; Day Pitney; ScottMadden analysis

Potential Risks of Reform and Next Steps

Figure 2.3: High-Level Schedule of Activities for ISO New England Capacity Auction Reform

Areas of Potential Risk with Auction Reforms

- Elimination of forward auctions may affect financing risk and cost of new resources, as potential capacity revenues will not be determined until the resource is ready for delivery.
- A shorter procurement horizon may afford less ability to respond to emerging reliability issues and supply-demand imbalances, with potential shortfalls. This may also affect pricing, potentially increasing volatility and market power issues.
- The ISO has effectively gone “all in” with no transition period or hybrid forward/prompt approach to introduction of its new auction processes. With FERC’s approval, it postponed its Forward Capacity Auction 19 (for the 2028/29 delivery period), originally scheduled for 2025, targeting February 2028 for the first implementation of the new construct for the delivery period of June 2028 through May 2029.

What’s Next

- ISO-NE made an initial filing on Dec. 31, 2025, asking FERC to issue an order on the CAR-PD capacity market reforms by March 31.
- Work will continue through 2026 in refining the seasonal auction and accreditation reforms, with a FERC filing for approval expected sometime in Q4 2026 (see Figure 2.3).
- The ISO anticipates “future refinements and conforming changes will be needed to reach a steady state design” and will spend 2026 preparing for the first prompt/seasonal auctions in early 2028, including design details, modeling and market design, and tariff review and amendments.
- ISO-NE anticipates working on its next stage of longer-term Capacity Auction Reform road map in 2027.

Sources: ISO New England; ISO Newswire; FERC; Perplexity AI; S&P Capital IQ; ScottMadden analysis

Topic #3

Offshore Wind

Market Pressures and Policy Changes Dampen Offshore Wind

Market Conditions Remain Challenging

- Persistent macroeconomic hurdles—specifically inflation, high interest rates, and supply chain bottlenecks—continue to strain the U.S. offshore wind sector.
- These pressures have forced developers to abandon several projects or incur penalties to exit economically unviable power purchase agreements signed years ago.
- Compounding these issues, recent tariffs on aluminum and steel have driven up the costs of critical components like cables and wind towers, placing even greater financial pressure on the sector.

Trump Administration Stymies Development

- Federal agencies have suspended new offshore leasing, withdrawn billions in federal funding and loan guarantees, requested voluntary remands of approved permits, and issued stop work orders for projects under construction.
- The approach reflects President Trump's focus on "energy dominance" by prioritizing fossil resources and dispatchable generation resources, such as nuclear and geothermal.
- This represents a dramatic reversal for an industry previously buoyed by President Biden's goal to deploy 30 GW of offshore wind by 2030.

Figure 3.1: Status of Select U.S. Offshore Wind Projects (as of Feb. 4, 2026)

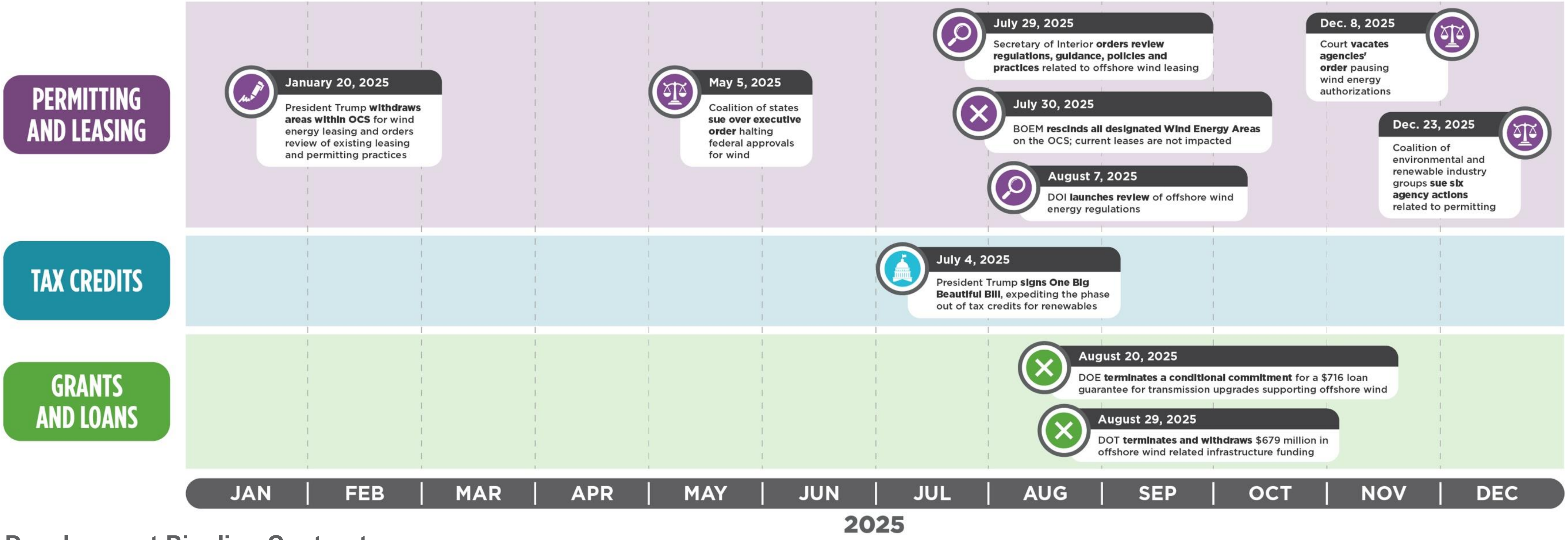
Project Name	Current Status	Capacity (MW)	Location	Developer	BOEM COP Approval	Online Date
Block Island Wind Farm	Operating	30	RI	Ørsted	NA	Dec. 2016
Coastal Virginia Offshore Wind Pilot	Operating	12	VA	Dominion Energy	NA	Oct. 2020
South Fork Offshore Wind	Operating	132	NY	Ørsted/ GIP	Jan. 2022	Mar. 2024
Empire Wind 1	Under Construction	810	NY	Equinor	Feb. 2024	Apr. 2027
Revolution Wind	Under Construction	704	RI	Ørsted/ GIP	Nov. 2023	Nov. 2026
Coastal Virginia Offshore Wind Commercial Project	Under Construction	2,857	VA	Dominion Energy	Jan. 2024	Early 2027
Sunrise Wind	Under Construction	924	NY	Ørsted	Jun. 2024	Jul. 2027
Vineyard Wind 1	Under Construction	812	MA	Vineyard Offshore	Jul. 2021	Feb. 2026
Atlantic Shores	Approved	1,290	NJ	EDF	Oct. 2024	2028
Maryland Offshore Wind	Approved	1,709	MD	US Wind	Dec. 2024	2029+
SouthCoast Wind	Approved	2,400	MA	Engie/ EDP	Jan. 2025	2030
New England Wind 1 & 2	Approved	1,871	MA	Avangrid	Jul. 2024	2028+

Notes: BOEM is U.S. Bureau of Ocean Energy Management. COP means construction and operating plan.

Sources: DOE; U.S. Dept. of the Interior; U.S. Dept. of Transportation; Harvard Law School; EPA; selected legal dockets; S&P Capital IQ; industry news; ScottMadden analysis

Federal Actions Are Impacting Development Pipeline

Figure 3.2: Timeline of Key Legislative, Regulatory, and Executive Actions (as of Feb. 4, 2026)



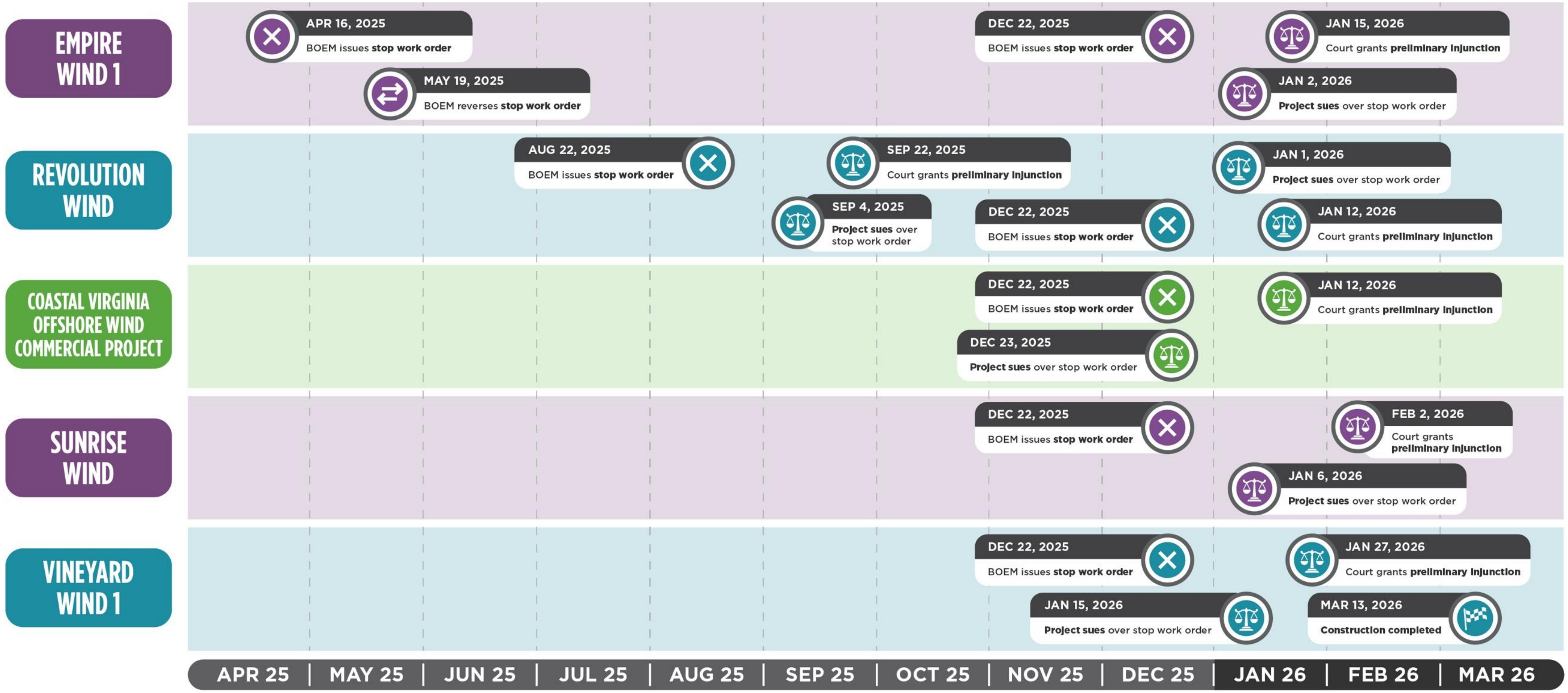
Development Pipeline Contracts

- The industry is being forced to reevaluate active projects and long-term strategies. Completing projects already under construction has emerged as the top priority, while projects in advanced development face an uncertain path forward. It remains unclear whether any projects will break ground during the current administration.
- Recent forecasts illustrate the "strategic pause" in U.S. offshore wind development. The Energy Industries Council found that planned offshore wind capacity dropped by more than half, sinking from 45 projects totaling 55.9 GW in Q3 2024 to 23 projects totaling 25.4 GW in Q3 2025.

Sources: U.S. Bureau of Ocean Energy Management (BOEM); DOE; U.S. Dept. of the Interior (DOI); U.S. Dept. of Transportation (DOT); Harvard Law School; EPA; selected legal dockets; S&P Capital IQ; FirstEnergy; ScottMadden analysis

Federal Actions Are Impacting Development Pipeline (Cont.)

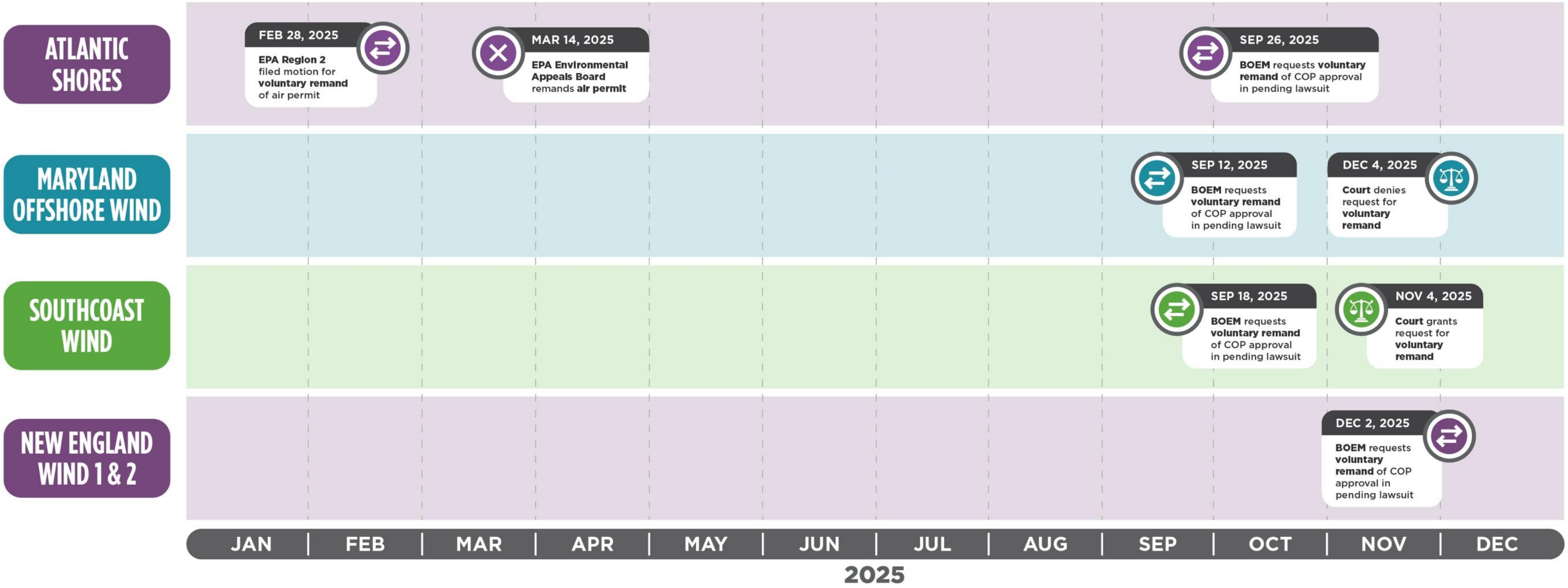
Figure 3.3: Timeline of Key Actions for “Under Construction” Offshore Wind Projects (as of Mar. 13, 2026)



Sources: U.S. Bureau of Ocean Energy Management (BOEM); DOE; U.S. Dept. of the Interior (DOI); U.S. Dept. of Transportation (DOT); Harvard Law School; EPA; selected legal dockets; S&P Capital IQ; FirstEnergy; ScottMadden analysis

Federal Actions Are Impacting Development Pipeline (Cont.)

Figure 3.4: Timeline of Key Actions for Selected "Approved" Offshore Wind Projects (as of Feb. 4, 2026)



Note: COP means construction and operating plan.

Sources: U.S. Bureau of Ocean Energy Management (BOEM); DOE; U.S. Dept. of the Interior (DOI); U.S. Dept. of Transportation (DOT); Harvard Law School; EPA; selected legal dockets; S&P Capital IQ; FirstEnergy; ScottMadden analysis

Mounting Headwinds Will Have Lasting Impacts

Long-Term Implications

- Recent federal actions are driving higher costs and construction delays. As a result of the stop work order, Dominion Energy increased the projected cost of Coastal Virginia Offshore Wind Project (CVOW) to $11.5 billion and pushed full completion to early 2027. As of October 2025, the project was expected to cost $11.2 billion and be operational by the end of 2026.
- Stop work orders are also disrupting access to specialized offshore wind vessels. Revolution Wind sought an injunction in part because its contract for a dedicated installation vessel was scheduled to expire February 22, 2026.
- Credit ratings agencies have responded with a more negative view of offshore wind developers. In August 2025, S&P Global Ratings lowered Ørsted's issuer credit rating to BBB- from BBB.
- Federal uncertainty is impacting state-level procurement timelines. In January 2026, the Massachusetts Department of Public Utilities delayed execution of offshore wind supply contracts for a fifth time, citing "ongoing uncertainty caused by federal level activities."

> *The **prime duty** of the United States government is to **protect the American people**. Today's action addresses emerging **national security risks**, including the rapid evolution of the relevant adversary technologies, and the vulnerabilities created by large-scale offshore wind projects with proximity near our East Coast population centers. The Trump administration will always **prioritize the security of the American people**.*
>
> —Secretary of Interior Doug Burgum in press release announcing stop work orders issued for Empire Wind 1, Revolution Wind, CVOW, Sunrise Wind, and Vineyard Wind 1 (December 22, 2025)

> *The **sudden emergence** of a new **'national security threat'** appears to be less a **legitimate, rational finding of fact** and more a **pretextual excuse** to justify a **predetermined outcome** consistent with the President's frequently stated personal opposition to offshore wind.*
>
> —Joint Letter to Secretary Doug Burgum from Kathy Hochul, Governor of New York; Maura Healey, Governor of Massachusetts; Ned Lamont, Governor of Connecticut; and Dan McKee, Governor of Rhode Island (December 24, 2025)

Sources: Dominion Energy; selected legal dockets; S&P Global Ratings; Massachusetts Dept. of Public Utilities; Dept. of the Interior; industry news

Topic #4

Transmission & Distribution Developments

Transmission Expansion to Meet Load Growth and Reliability

Aligning Transmission with Growing Needs

- Across the United States, electric load has been growing, and this trend is expected to continue for the next decade and beyond.
- Much industry discussion has focused on generation resources to serve this growing demand, but transmission development will support deliverability and growing power demand in addition to addressing reliability needs as reserve margins tighten.
- More generally, both peak load and energy usage have been growing. Peak demand is projected to grow at approximately 3.7% and energy use at 5.7%, each annually, through 2030. This compares with a flat transmission line-miles net growth rate from 2019 to 2024 per EEI.
- As shown in Figure 4.2, there remain ambitious plans to develop more than 24,000 line-miles in the United States through 2036. Much remains in the planning stage. Nearly 70% have cited reliability as the primary driver.
- However, while interregional transmission projects can allow system operators to take advantage of geographic diversity during extreme weather events, NERC has observed that intraregional transmission projects continue to greatly outnumber interregional transmission expansion.
- More generally, very little high-voltage transmission (345 kV+) has been added in the past several years (see Figure 4.1).

Figure 4.1: Historical Transmission Line-Miles Additions by Voltage Band and Year in Service (2017–2025)

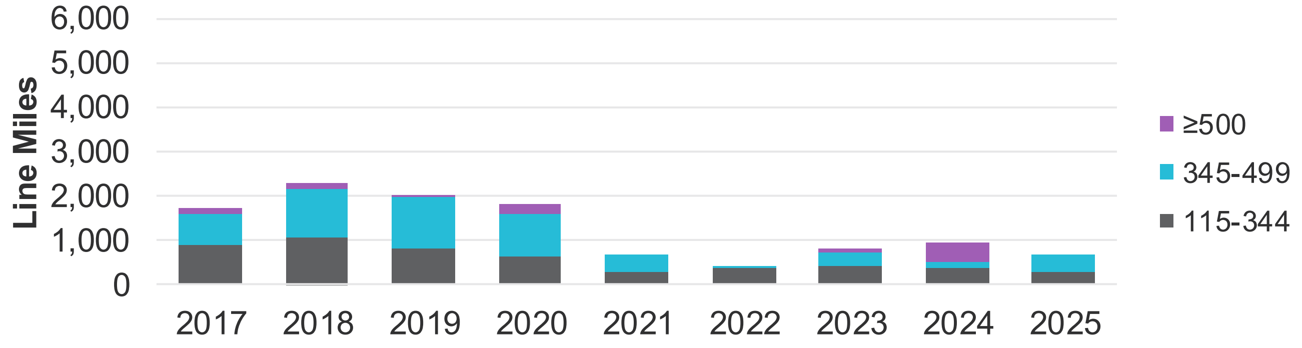
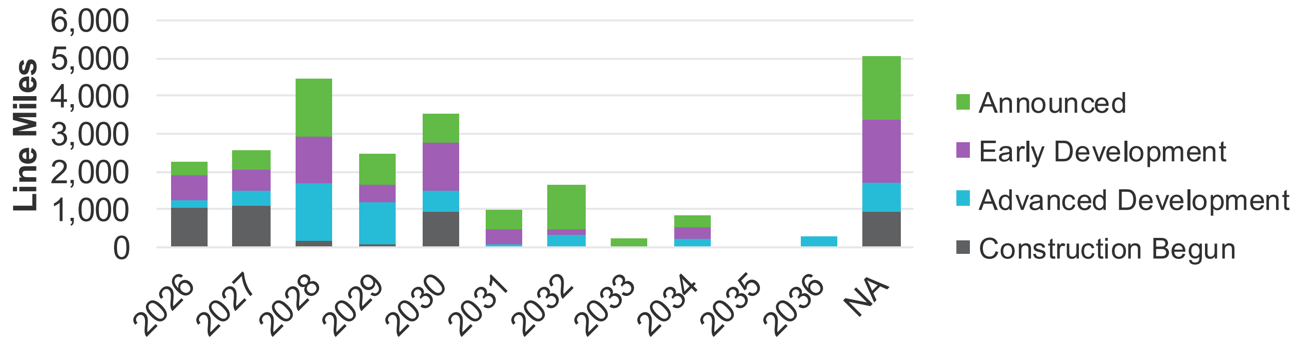


Figure 4.2: Projected Transmission Line-Miles Additions by Project Status and Expected Year in Service (2026–2036P)



*Notes: S&P data as of March 1, 2026. NA means projects for which expected year in service was not indicated. Excludes cross-border and non-contiguous U.S. lines as well as lines <115 kV. Excludes projects for which actual or projected completion dates were unavailable. Line-miles rounded to nearest mile. P means projected.

Sources: NERC; Grid Strategies; EEI; industry news; S&P Capital IQ (transmission data); ScottMadden analysis

Transmission Expansion (Cont.)

Figure 4.3: Selected Major Transmission Plans

Region	Portfolio (Estimated Cost)	Facilities	Notes
Midcontinent ISO	Tranche 2.1 ($22B)	Includes 1,800 miles of 765-kV backbone transmission and another 1,800 miles of 345-kV lines	■ Approved Dec. 2024 ■ Benefit-cost ratio: $1.80 to $3.50 for every $1 invested (note: five MISO states have challenged the benefit-cost analysis)
PJM Interconnection	2025 Regional Transmission Expansion Plan Window 1 ($11.8B)	Includes new 500 kV and 765 kV lines, grid enhancing technologies, and PJM's first underground HVDC line and backbone projects in VA, central OH, and WV/PA	■ Approved Feb. 2026 ■ PA's Office of Consumer Advocate opposes the plan as proposed
Electric Reliability Council of Texas	Strategic Transmission Expansion Plan Eastern Backbone ($9.4B)	Includes 1,109 miles of new 765-kV single-circuit transmission lines	■ Approved Dec. 2025 ■ Expected online in 2030-31
Southwest Power Pool	2025 Integrated Transmission Plan ($8.6B)	Includes four 765-kV facilities approved for construction	■ Approved Nov. 2025 ■ Benefit-cost ratio: $12.10 to $17.60 for every $1 invested

Major "Backbone" Projects Proposed but Some Impediments

- FERC Order 1920, issued in May 2024, encouraged long-term regional transmission planning by requiring transmission providers to conduct comprehensive, long-term planning for regional facilities over a 20-year horizon, to be updated at least every five years. A few transmission organizations had considered long-term needs, even before promulgation of Order 1920. Compliance filing status is shown at Figure 4.4 (next page).
- Several regional transmission organizations have proposed large, 765-kV backbone projects as part of their regional transmission expansion plans (or RTEP), a significant increase in such projects. Some examples are shown at Figure 4.3. Drivers cited include reliability, congestion relief, and accommodation of system expansion and growing load.
- Barriers to expansion remain. Some stakeholders have pushed back on MISO's proposed $22.1 billion Tranche 2.1 transmission portfolio and PJM's proposed 2025 RTEP, citing cost concerns. Permitting, siting, and high materials costs continue to pose impediments to expeditious development of higher-voltage transmission. It is unclear whether permitting reform will emerge from Congress given other partisan issues (see Gas Pipeline Developments section). The recent Supreme Court decision invalidating the Trump administration's emergency tariffs will not at present affect the Section 232 tariff regime on raw materials essential for transmission such as copper, steel, and aluminum but could reduce certain electrical equipment.

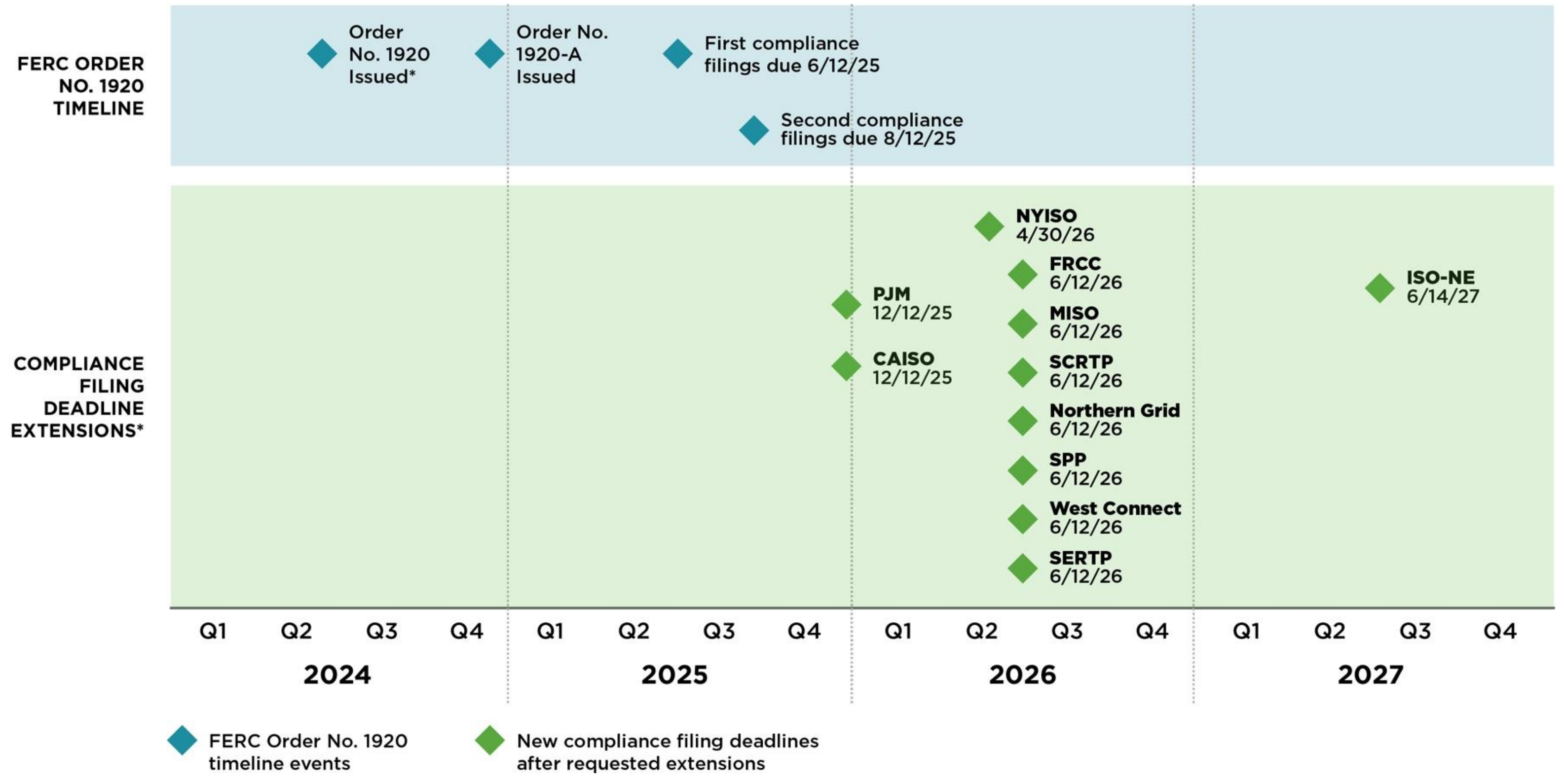
Sources: Association of General Contractors of America; Utility Dive; S&P Global Market Intelligence; PJM; Grid Strategies; ScottMadden research

Order 1920 Compliance

Compliance Deadlines Approaching

- In May 2024, FERC promulgated Order 1920. The central requirement of Order 1920 was to mandate regional planning, using best available data, that looks ahead at least 20 years to develop projections derived from at least three "plausible and diverse long-term scenarios" of long-term transmission needs.
- In cost-benefit analyses, benefits to be evaluated go beyond reliability alone to include:
  - Avoided or deferred reliability transmission facilities and aging infrastructure replacements
  - Resource adequacy benefits
  - Lower energy costs
  - Reduced losses
  - Reduced congestion
  - Capacity cost benefits from reduced peak energy losses
  - Mitigation of extreme weather events and unexpected system conditions
- Filings were originally due in mid-2025, but many extensions have been granted. The current filing deadlines are shown at Figure 4.4.

Figure 4.4: FERC Order No. 1920 Regional Compliance Filing Schedule (as of Mar. 5, 2026)*

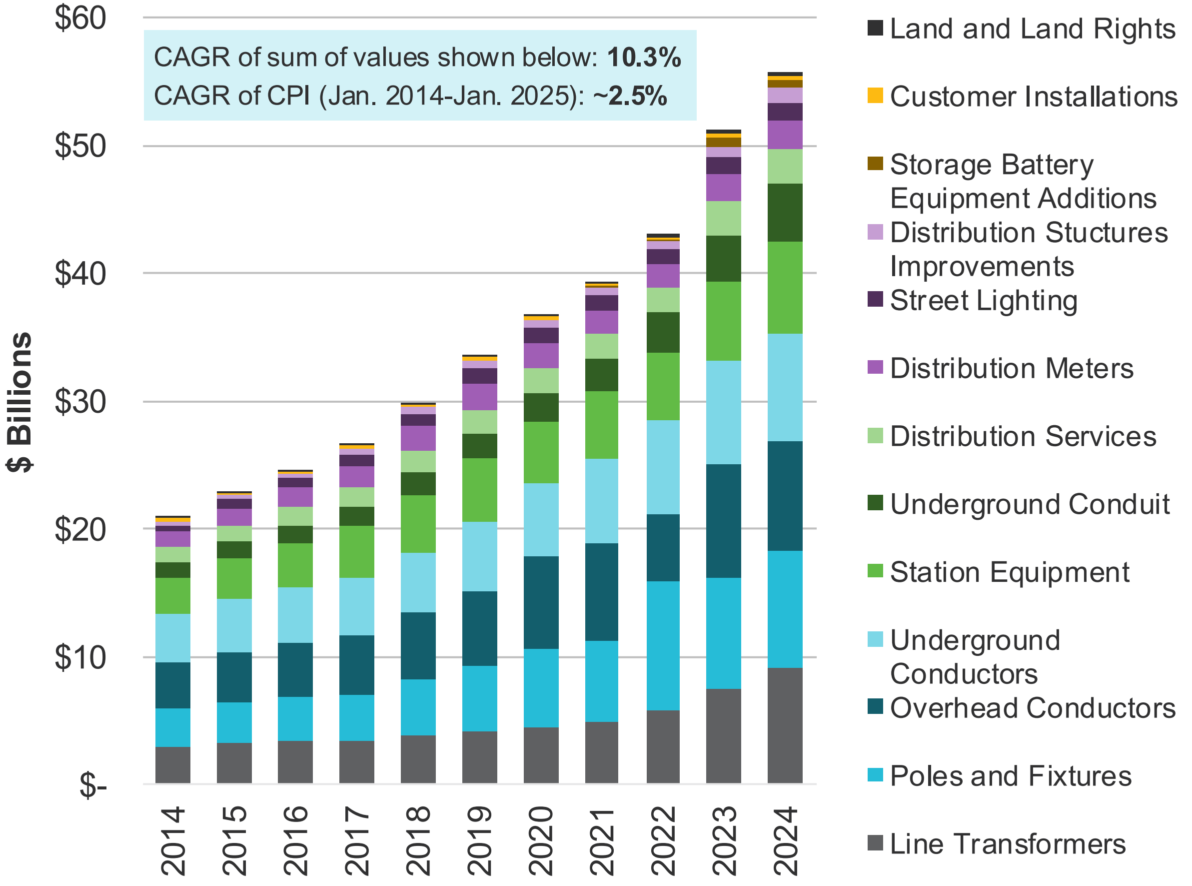


Note: *Order 1920 requires transmission providers to submit two compliance filings. This timeline shows deadline extensions for the first compliance filing, which encompasses all requirements except for those related to interregional coordination.

Sources: Grid Strategies; FERC; ScottMadden analysis

Distribution Investment Grows Amid Affordability Discussion

Figure 4.5: Electric and Combination Operating Companies Electric Distribution Additions by Year and Type (2014–2024) ($ Billions)



Note: Excludes asset retirement costs and leased property additions.
Source: S&P Capital IQ (FERC Form 1 data); ScottMadden analysis

Focusing on Affordability

- The utilities sector has been focused on maintaining affordability for customers.
  - A recent study by DOE's Lawrence Berkeley National Laboratory noted that nominal retail electricity prices vary by region but nationally have largely tracked inflation.
  - It also noted that residential price increases have been in line with many other household expenditures.
- The study acknowledged, looking at 2019-24 trends, that inflation-adjusted transmission and distribution expenditures have increased, with increases in distribution spending widespread across regions.

Drivers of Distribution Capital Spending

- Factors driving distribution capex include:
  - Aging infrastructure: Replacement of 50+-year-old facilities
  - Equipment hardening: Increased spending on adaptation and resilience and system hardening, including both proactive (wildfire mitigation, storm preparation and undergrounding, renewable intermittency) and reactive (storm recovery) measures
  - Supply-chain constraints: T&D equipment costs rising far above inflation
- Interestingly, while energy storage investment has increased significantly (nearly $550 million in 2024), the greatest increases in distribution spending remain poles, wires, and transformers (see Figure 4.5), with many utilities upgrading facilities (e.g., steel for wood poles).

Note: CPI (all urban customers) calculated on YOY basis, from chained and not seasonally adjusted data.

Sources: Lawrence Berkeley National Laboratory; EIA; S&P Capital IQ (FERC data); ScottMadden analysis

Topic #5

PJM Developments

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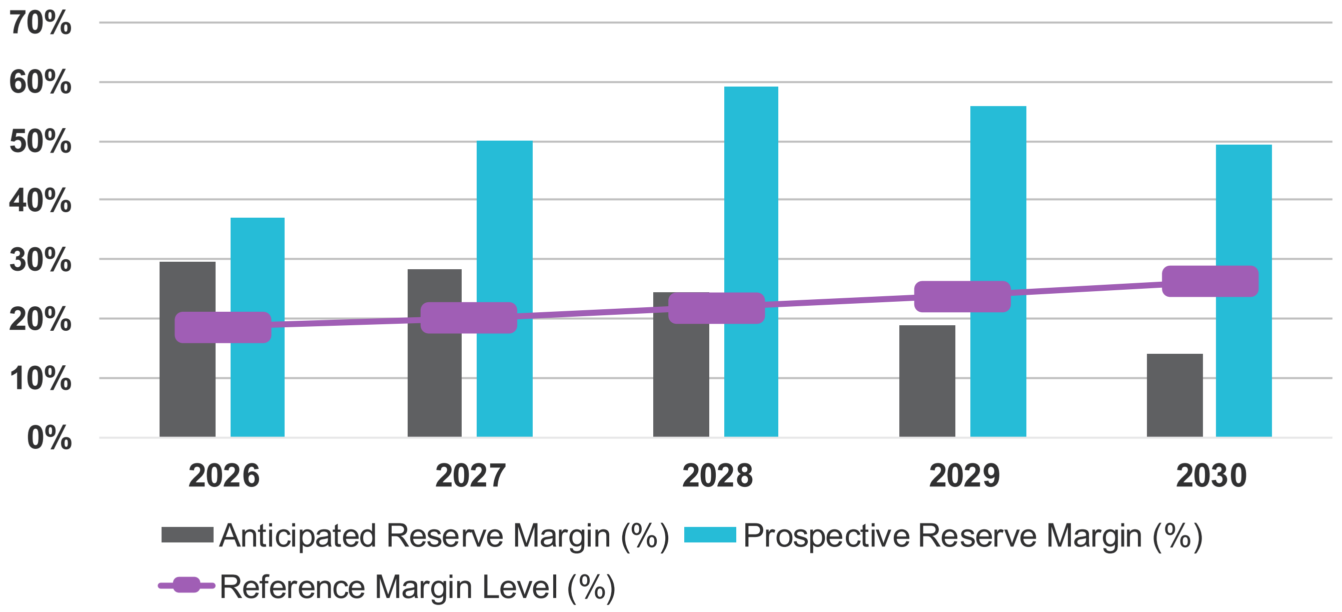
NERC Notes Extreme and Rapid Tightening of Supply and Demand

PJM Reserve Margin Shortages Ahead?

- NERC released its latest Long-Term Reliability Assessment in January 2026. PJM is among the assessment areas designated as “high risk,” meaning its anticipated resources fall short of operational resource adequacy targets.
- PJM’s load forecast has increased year over year due to the growth of data centers, economic growth, and increased electrification. PJM net energy load growth is projected to average 4.8% per year over the next 10 years, up from 2.3% in previous forecasts.
- At the same time, available generation capacity has decreased due to retirements and delays in new additions. Dispatchable resources are retiring faster than they can be replaced. Roughly 40% of new interconnection requests are solar resources.
- As a result, the anticipated reserve margin drops below reference reserve margin beginning in 2029. In addition, a key concern is shortages during extreme winter conditions when generator performance and fuel supply constraints are most critical.
- PJM has launched several interconnection queue reforms and “fast-track” initiatives to add additional generating capacity to resolve this looming shortfall.

Figure 5.1: PJM Summer Planning Reserve Margin (2026–2030)



Anticipated Reserve Margin: Percent of anticipated resources remaining after meeting demand. Includes existing resources, Tier 1 capacity additions, firm capacity transfers, less confirmed retirements.

Prospective Reserve Margin: Percent of prospective resources remaining after meeting demand. Includes anticipated resources, existing “other” capacity, Tier 2 capacity additions, expected (non-firm) capacity transfers, less unconfirmed retirements.

Reference Margin Level: Target amount of reserve capacity kept above forecasted peak demand to ensure a sufficient power supply.

Sources: PJM, NERC

Data Center Expansion Drives Unprecedented Surges in Electricity Demand

Figure 5.2: PJM Historical and Forecast Summer Peaks (2000–2045)

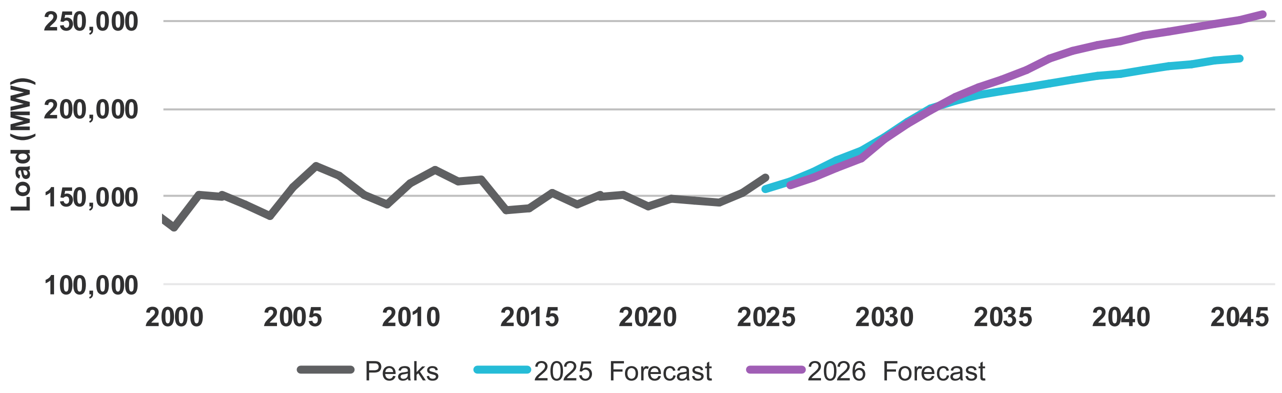
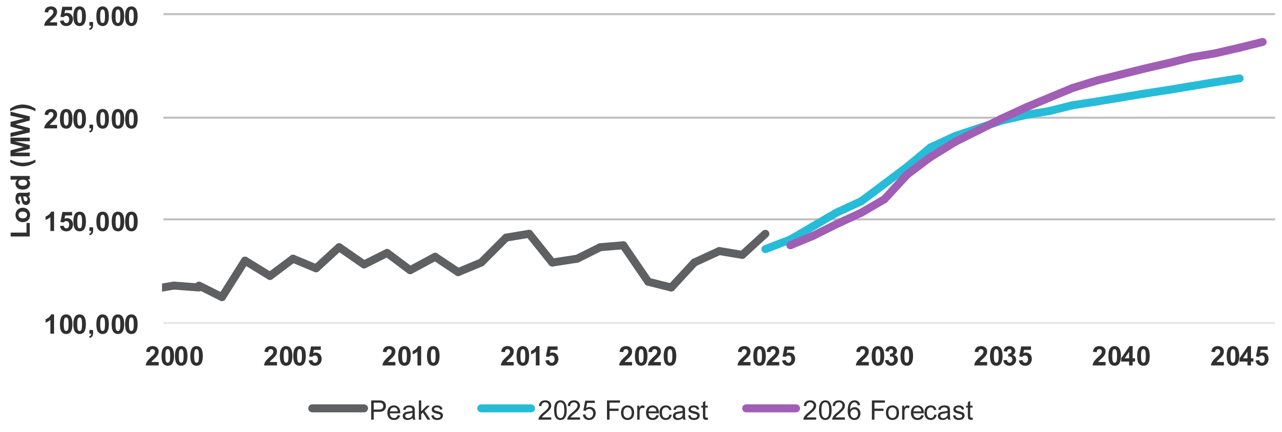


Figure 5.3: PJM Historical and Forecast Winter Peaks (2000–2045)



2026 Load Forecast: Refining Growth Trajectory

- PJM anticipates lower peak demand in the near term through 2032 due to updates to the electric vehicle and economic forecasts as well as improved vetting of requested adjustments for data centers and large loads. PJM currently forecasts:
  - Summer peak load increasing from ~161,000 MW in 2025 (historical data) to ~217,000 MW in 2035 (3.0% CAGR)
  - Winter peak load increasing from ~143,000 MW in 2025 (historical data) to ~200,000 MW in 2035 (3.4% CAGR)
- To help address this substantial growth, the PJM Board of Managers initiated the Critical Issue Fast Path in August 2025, a decision-making method to quickly advance matters through the PJM stakeholder process. In January 2026, the board directed PJM to begin implementing:
  - Significant load forecasting improvements and increased roles for states
  - Avenues for new large loads to bring their own new generation or enter into a connect and manage framework subject to earlier curtailment
  - Creation of an accelerated interconnection track for state-sponsored generation projects
  - Immediate initiation of a backstop generation procurement process to address short-term reliability needs
  - A review of PJM markets to assess how they can best work in combination to support investment

Source: PJM

PJM Overhauls Interconnection Queue to Accelerate New Generation

First-ready, First-served Process Moving Toward Steady State

- In June 2022, PJM filed proposed reforms with FERC to transition to a "first-ready, first-served" clustered cycle approach, prioritizing projects demonstrating readiness to reduce withdrawals and restudies. FERC approved PJM's filing in November 2022, and in July 2023, issued Order 2023 requiring similar reforms for all transmission providers.
- To manage an initial backlog of ~230 GW in interconnection projects, PJM established two transition cycles (TC1 and TC2). This transition period incorporated a "fast track"—an expedited process prioritizing projects requiring grid upgrade costs of less than $5 million, allowing them to advance more quickly outside the standard queue.
- PJM launched several additional fast-track initiatives to address near-term supply shortages and accelerate resource additions:
  - **Reliability Resource Initiative:** PJM attracted more than 11 GW of applications for "shovel-ready" resources capable of beginning operations primarily by 2030 and fully by 2031.
  - **Surplus Interconnection Service:** This is an expedited process that allows facilities that do not run continuously (e.g., renewables) to allocate unused interconnection capacity to additional resources, such as co-located batteries.
  - **CIR Transfer Efficiency Enhancements:** This initiative expedites the transfer of Capacity Interconnection Rights (CIRs) from a closing power plant to a new replacement resource.
- Moving forward, PJM aims for a one- to two-year processing timeline for issuing new generation interconnection agreements under the reformed cluster study process. Cycle 1 applications are due by April 27, 2026.

Figure 5.4: PJM's Interconnection Process Evolution

Sources: PJM, FERC

FERC Orders Reforms for Co-Locating Generation and Large Loads

Co-Location Comes Under Scrutiny

- Large loads, especially data centers, are seeking "speed to power" to serve new data centers and other facilities. Co-locating these facilities with large generation plants is increasingly of interest. These co-location arrangements challenge legacy interconnection assumptions, as those generators' net injections to the grid may be much less than host facility consumption.
- In March 2024, for example, Talen Energy sold a data center campus with up to 960 MW of capacity to Amazon Web Services (AWS). The campus is located adjacent to Talen's Susquehanna 2.5 GW nuclear plant. The companies planned to power the data center using a "behind-the-meter" or "co-located" setup. The setup required amending the PJM FERC-approved Interconnection Service Agreement (ISA) to increase co-located load from 300 MW to 480 MW.

Free Rider or Fair Deal?

- In June 2024, Exelon and American Electric Power (AEP) filed a protest with FERC, challenging the amended ISA. The companies argued that the data center campus should not be allowed to operate as a "free rider" on the transmission system. In November 2024, FERC rejected the amended ISA, noting it failed to meet the "high burden" required to justify the non-conforming provisions that deviated from the standard PJM ISA.
- In February 2025, FERC issued a show cause order, citing concerns that PJM's Open Access Transmission Tariff lacked clarity on rates, terms, and conditions for co-location arrangements. In the proceeding, FERC defined co-located load as a "configuration [that] refers to end-use customer load that is physically connected to the facilities of an existing or planned customer facility on the interconnection customer's side of the point of interconnection to the PJM Transmission System."
- Talen Energy and AWS transitioned to a front-of-the-meter arrangement in June 2025.

> "*Should **large quantities of load** rush to **co-locate with generation** on terms that bear even a resemblance to the ISA at issue here, **PJM capacity markets** will have steadily decreasing volume as the **capacity resources flee** to serve load that uses and benefits from—but does not pay for—the **transmission system** and the **ancillary services** that keep the system running. This will **harm existing customers**.*
>
> —Excerpt from protest filed with FERC by Exelon and AEP

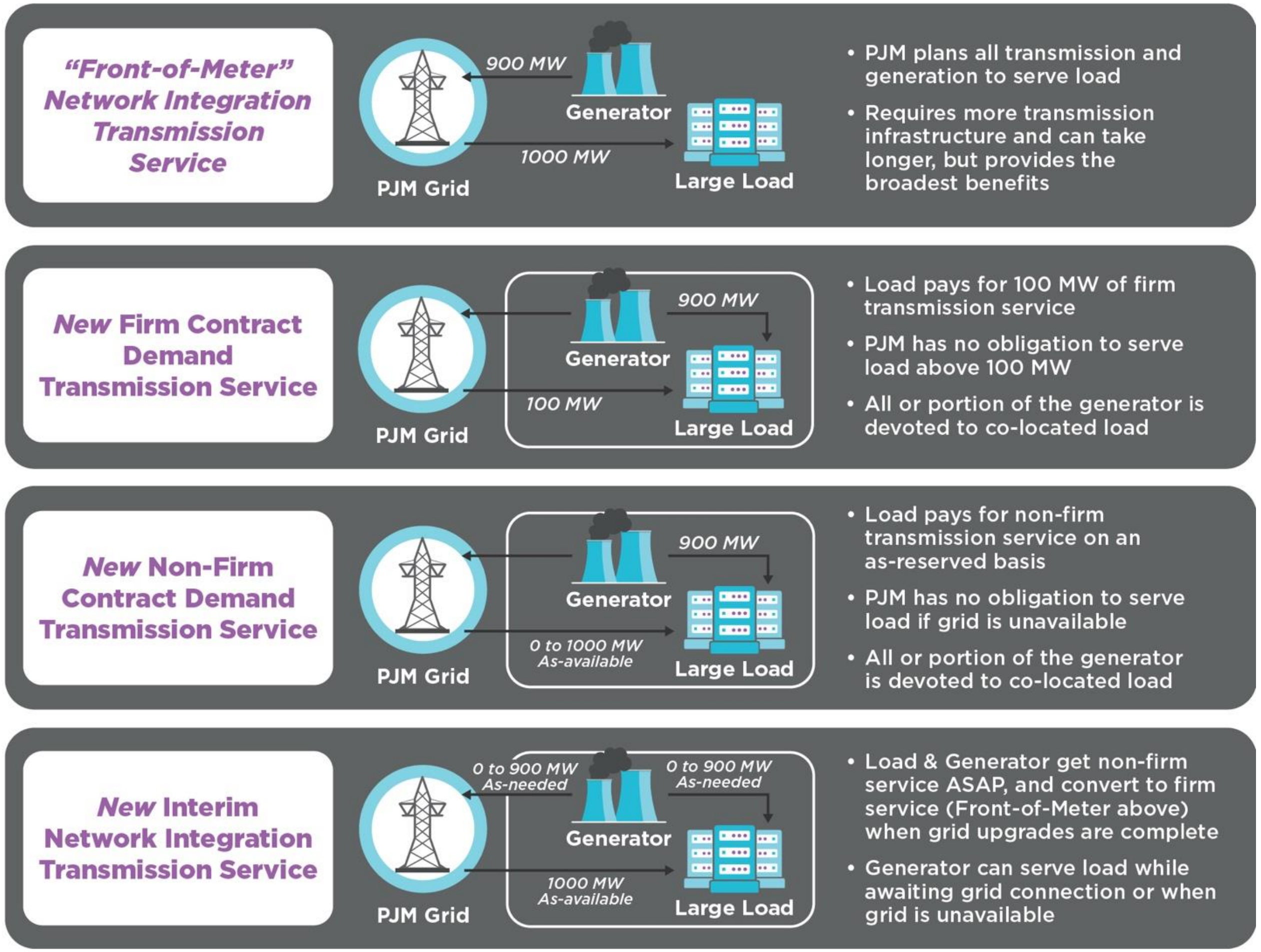
Sources: FERC; Utility Dive; Akin; Steptoe & Johnson

Co-Locating Generation and Large Loads (Cont.)

FERC Orders New Transmission Services

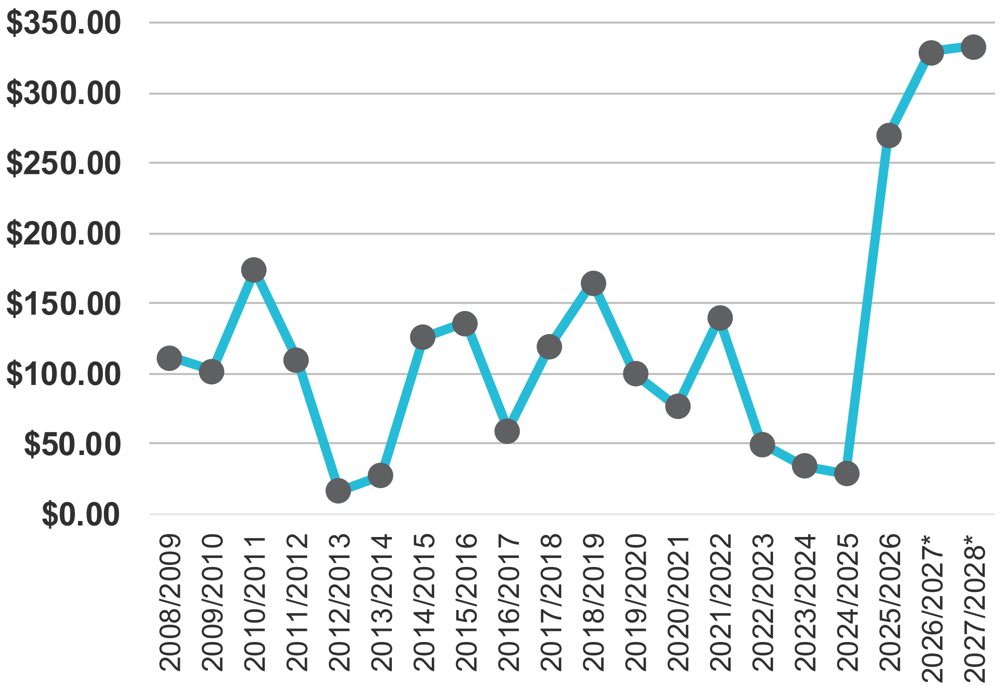
- In December 2025, FERC found PJM's Open Access Transmission Tariff unjust and unreasonable, notably rejecting the "all-or-nothing" approach that forced co-located loads to either disconnect entirely or pay for full network integration transmission service.
- FERC directed PJM to establish new transmission services to ensure co-located data centers pay an equitable share for ancillary services while creating a clearer path for their interconnection. The new transmission services will allow eligible customers to select from the following new services (also see Figure 5.5):
  - **Firm Contract Demand Transmission Service:** A permanent option for loads using special protection schemes to cap their grid withdrawals at a specific level, paying only for the capacity they contract to use
  - **Non-Firm Contract Demand Transmission Service:** An "as-available" service with no capacity backing, requiring the load to curtail during grid stress
  - **Interim Network Integration Transmission Service:** A bridge option allowing load to energize sooner while waiting for upgrades required for full firm service
- FERC also required eligible co-located customers to pay regulation and black start charges on a gross-demand basis.

Figure 5.5: New PJM Transmission Services



Surging Capacity Market Prices Trigger Policy Responses

Figure 5.6: PJM-RTO Capacity Market Clearing Prices ($/MW-day)



Note: *The 2026/2027 and 2027/2028 prices were subject to FERC-approved price collars negotiated between Gov. Josh Shapiro and PJM.

Capacity Market

- Capacity prices have spiked across PJM from $28.92/MW-day in the 2024/2025 auction to $333.44/MW-day in the 2027/2028 auction (see Figure 5.6). Rising prices have prompted interventions to protect consumers:
  - Pennsylvania Gov. Josh Shapiro and PJM reached a settlement agreement in January 2025, to establish a price collar for the 2026/2027 and 2027/2028 auctions.
  - In February 2026, PJM announced it would seek FERC approval to extend the current price collar to the 2028/2029 and 2029/2030 auctions while a review of market rules is conducted in 2026.
- In addition, the 2027/2028 auction was the first time in PJM history that a capacity auction failed to procure sufficient capacity to meet the overall RTO-wide reliability requirement.

Backstop Auction

- In January 2026, the Trump administration and governors of 13 states urged PJM to undertake an emergency backstop procurement no later than September 2026 to address prices and shortfalls.
- In February 2026, PJM presented to stakeholders a working paper proposing:
  - **Term:** Up to 15-year contracts for capacity from new generation and uprates
  - **Stages:** Two-staged process to recognize different time frames needed for early stage and later stage developments
  - **Procurement Structure:** Bilateral contracts between supply and demand and/or PJM as the administrator and counterparty
- PJM expects to file a formal plan with FERC by this summer and hold the auction later in 2026.

Sources: PJM: FERC: S&P Capital IQ

Topic #6

Large Load Tariff Developments

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Large Load Tariff Development and Adoption Spreads

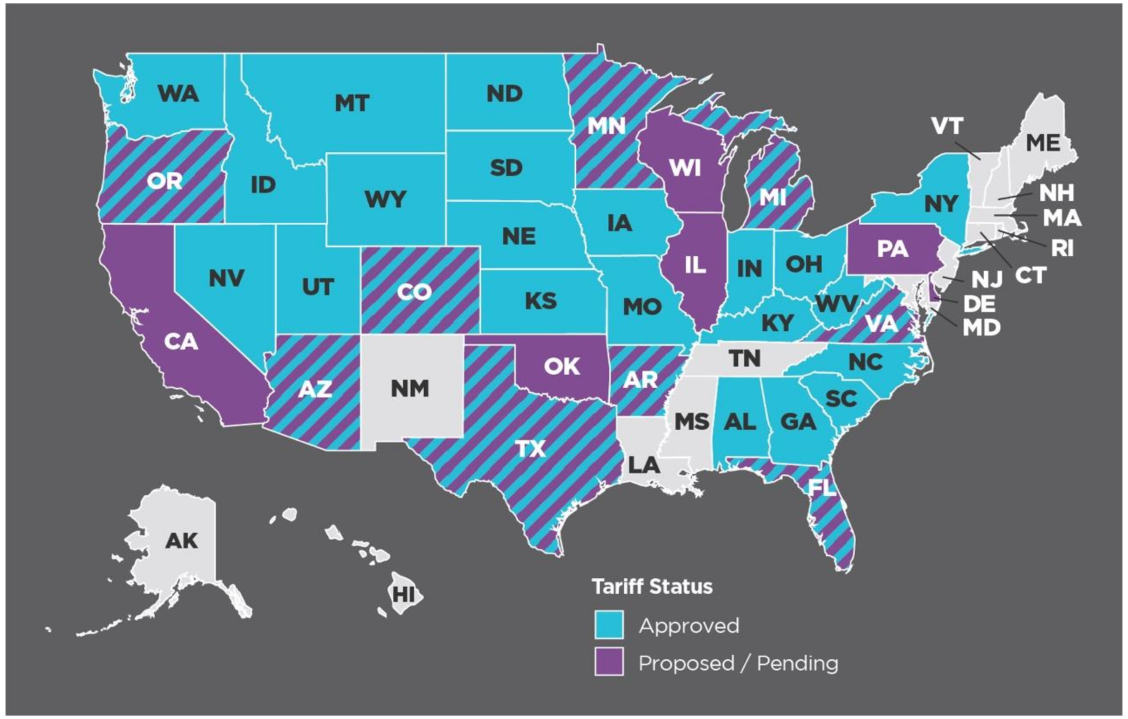
Data Center Impact on Retail Electricity Prices

- Amidst increasing energy prices, affordability remains a core focus of utilities, regulators, and elected officials. A persistent question in these debates is, What impact are data centers having on electricity prices? A February 2026 study prepared for the Edison Electric Institute found:
  - Data centers have generally not caused retail rate increases, with one exception in parts of the PJM region where capacity price increases were driven partly by data center demand.
  - Protective large load tariffs and agreements are being implemented to prevent cost shifts to existing customers.

Large Load Tariffs Used to Address Multiple Issues

- Beyond basic cost allocation concerns, Lawrence Berkeley National Laboratory (LBNL) notes that large load tariffs can also be used to address:
  - Appropriate mitigation of financial risks associated with stranded assets from underutilized utility system investments
  - Mitigation of operation and resource adequacy risks (e.g., demand exceeds supply or voltage fluctuations)
  - Appropriate risk-sharing in commercializing newer electricity technologies (e.g., advanced geothermal)
  - Accommodating the diverse needs of large-load customers (e.g., carbon-free generation or onsite generation)
- The value of large load tariffs is evidenced by their growing adoption across the country. According to data tracked by Smart Electric Power Alliance and NC Clean Energy Technology Center, more than 75 large load tariffs have been approved or proposed in 36 states (see Figure 6.1).

Figure 6.1: Approved and Proposed Large Load Tariffs



As of March 31, 2026

Sources: Charles River Associates; Lawrence Berkeley National Laboratory; Smart Electric Power Alliance; NC Clean Energy Technology Center

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Numerous Design Elements Enable Tailoring of Large Load Tariffs

Robust Menu of Design Options

Common objectives addressed in large load tariffs include eligibility and applicability, contract size, contract duration and exit fee, and energy source. Within each objective, multiple design elements can be used to tailor large load tariffs to meet the specific needs of an individual utility or jurisdiction. Figure 6.2 below details select design elements identified by LBNL.

Figure 6.2: Selected Design Elements of Large Load Tariffs

Objective	Design Element	Description
Eligibility and Applicability	Minimum load requirement	Lower-bound load threshold for customers to be eligible for tariff
	Applicability to specific customer types	Tariff may be unique to the specific large-load customer taking service under the tariff (e.g., data centers)
	Monthly demand charge	Minimum specified percentage of forecasted maximum demand that must be purchased
	Recovery for study costs	Customer pays for studies assessing whether the load can safely and reliably be added to the grid
	Customer credit ration and/or collateral requirements	Minimum credit ratings and/or collateral requirements to mitigate the financial risks to utilities and ratepayers
Contract Size	Contracted capacity and energy	Total amount of capacity (MW) and/or energy (MWh) to which a customer is obligated
	Resizing or reassignment of contracted capacity/energy	Terms allowing resizing of contracted obligations or reassign/sell contracted obligations to another utility customer
	BTM resources as backup and supplemental power	Resources may be used to improve site reliability, reduce contracted obligations, and/or manage financial charges
	Load factor	Define the ratio of average load (MW) and peak load (MW) in a specific time period that large load customer must maintain
Contract Duration and Exit Fee	Contract duration	Specifies contract time period to mitigate speculative and underutilized utility infrastructure investments
	Ramp times	Extended time period to reach contract size requirements and navigate transmission or interconnection processes
	Exit fee	Charges incurred if large load customer chooses to exit or terminate service before the end of contract term
Energy Source	Clean energy requirements	Identifies mechanisms to support regional, state, and corporate clean energy or sustainability goals
	Ability to leverage specific generation technologies	Identifies specific generation technologies that will be procured by the utility on behalf of the large load customer

Source: LBNL

NiSource Develops Alternative with GenCo to Serve Data Centers

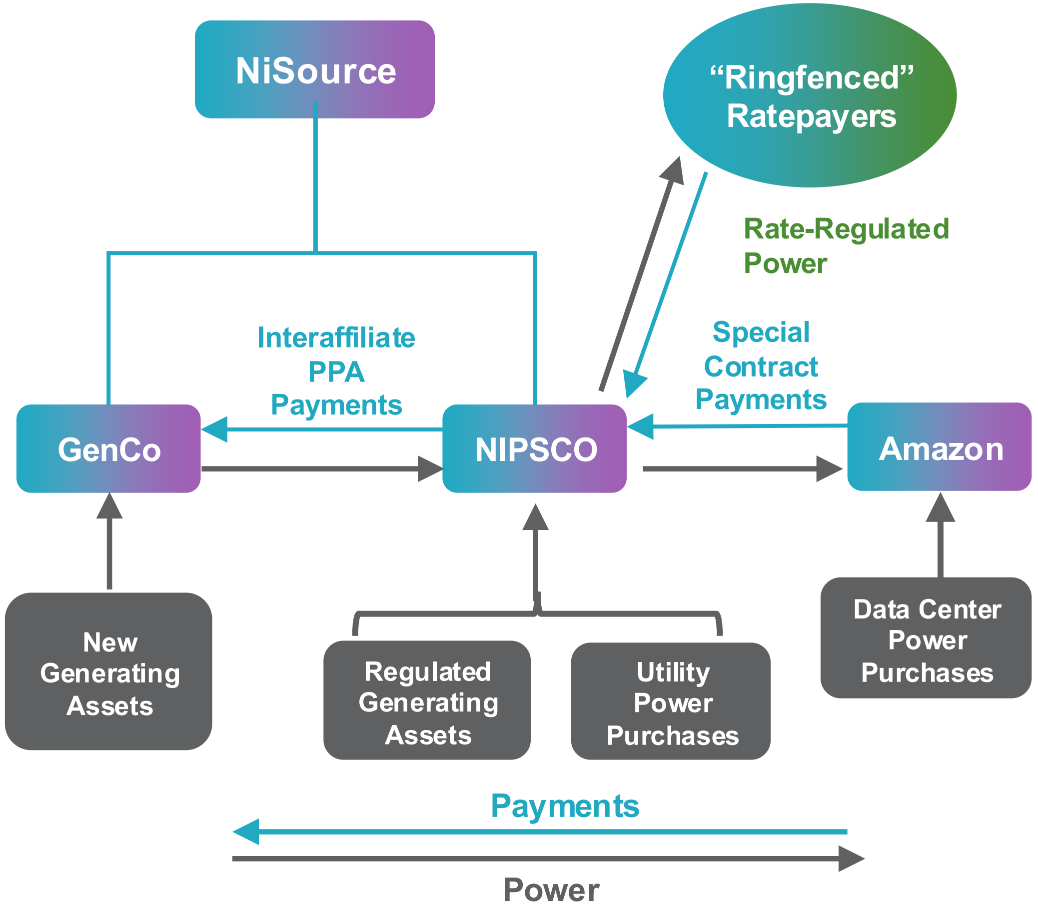
NiSource Creates Affiliate to Address Large Loads

- In September 2025, NiSource received state regulatory approval to establish NIPSCO Generation LLC (GenCo), a special operating subsidiary that will build and own generation resources dedicated to serving large data centers in NIPSCO's service territory (see Figure 6.3).
- GenCo will have no service territory or retail customers but rather will sell power to NIPSCO under an inter-affiliate power purchase agreement (PPA), which must be approved by the Indiana Utility Regulatory Commission and FERC.
- In addition, NIPSCO has filed to establish a "special contract" with Amazon to power data centers. Amazon will purchase up to 2,400 MW of firm load capacity from NIPSCO by year-end 2032. NIPSCO will procure the energy and capacity needed for the Amazon data centers from GenCo.
- NIPSCO and NiSource argue using an affiliate to build generation assets to serve data centers creates a ringfence around traditional ratepayers, thereby providing enhanced financial protections amidst data center growth.

Concerns Include "Black Box" Risk and Erosion of Competition

- Consumer advocates argue the confidential contracts between NIPSCO and third parties, such as Amazon, create a confidential "black box" because the pricing and terms are redacted as trade secrets. For advocates, this raises concerns about cost allocation and safeguards to prevent costs shifting to traditional ratepayers.
- Independent power producers contend the GenCo model sidelines competitive procurement and could position utility-owned affiliates as the default supplier for data center growth.
- NiSource contends that "black box" risk is mitigated given commission oversight and that it had no pre-existing obligation to competitively procure resources, and it expects to benchmark or use competitive procurement for its needs.

Figure 6.3: Overview of NiSource GenCo and Related Special Contract Arrangement



Sources: Utility Dive; Indiana Utility Regulatory Commission; Amazon; NIPSCO: NiSource

Glossary

Bcf – billion cubic feet

Bcf/d – billion cubic feet per day

BTM – behind-the-meter

CAISO – California Independent System Operator

CC – combined cycle

CT – combustion turbine

CVOW – Coastal Virginia Offshore Wind project

CWA – Clean Water Act

DOE – U.S. Department of Energy

EEI – Edison Electric Institute

EIA – U.S. Energy Information Agency

EPA – U.S. Environmental Protection Agency

FERC – Federal Energy Regulatory Commission

FRCC – Florida Reliability Coordinating Council

GT – gas turbine

GW – gigawatt

ISA – interconnection service agreement

ISO – independent system operator

ISO-NE – ISO New England

kV – kilovolt

LNG – liquified natural gas

MISO – Midcontinent Independent System Operator

MMBTU – million Btu

MW – megawatt

MWh – megawatt-hour

NEPA – National Environmental Policy Act

NERC – North American Electric Reliability Corporation

NYISO – New York Independent System Operator

PJM – PJM Interconnection LLC

RTO – regional transmission organization

SCRTP – South Carolina Regional Transmission Planning

SERTP – Southeastern Regional Transmission Planning

SPP – Southwest Power Pool

T&D – transmission and distribution

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PJM Developments	▪ Why Power Utilities Must Recalibrate Strategy Now ▪ EV Interconnection Process Transformation
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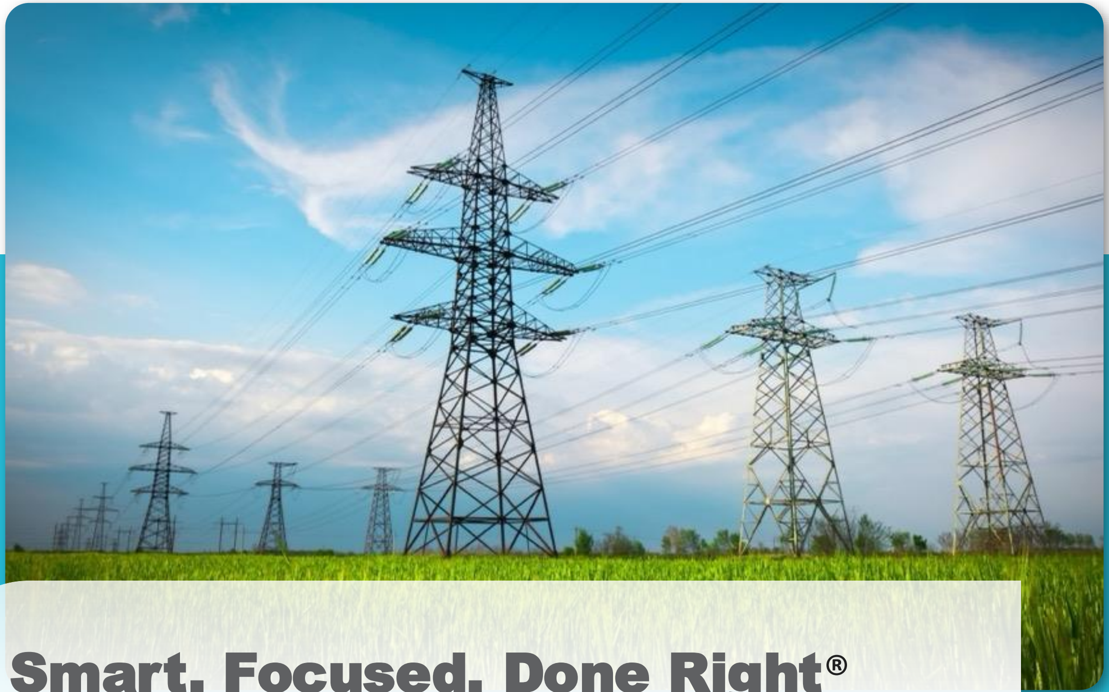

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