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Regional Transmission Organizations: Problem or Solution?

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The Issue

The bulk power system—an interconnected network of generating plants and high-voltage transmission lines—is an often-overlooked part of the electric industry. Over two-thirds of the country's electric demand and supply is coordinated by regional transmission organizations (RTOs).[1]

Competition among generators has improved efficiency and reduced consumer costs, but the wholesale power markets have been beset by structural, regulatory, and market failures. RTOs have repeatedly redesigned markets and changed rules; the result has been greater market uncertainty, higher wholesale prices, inadequate transmission capacity, and reduced reliability.

RTOs primarily respond to rising demand and transmission constraints by coordinating new transmission projects, with costs often socialized across ratepayers. Doing so indirectly subsidizes poorly sited intermittent generation yet fails to prioritize reliable generation near new demand.

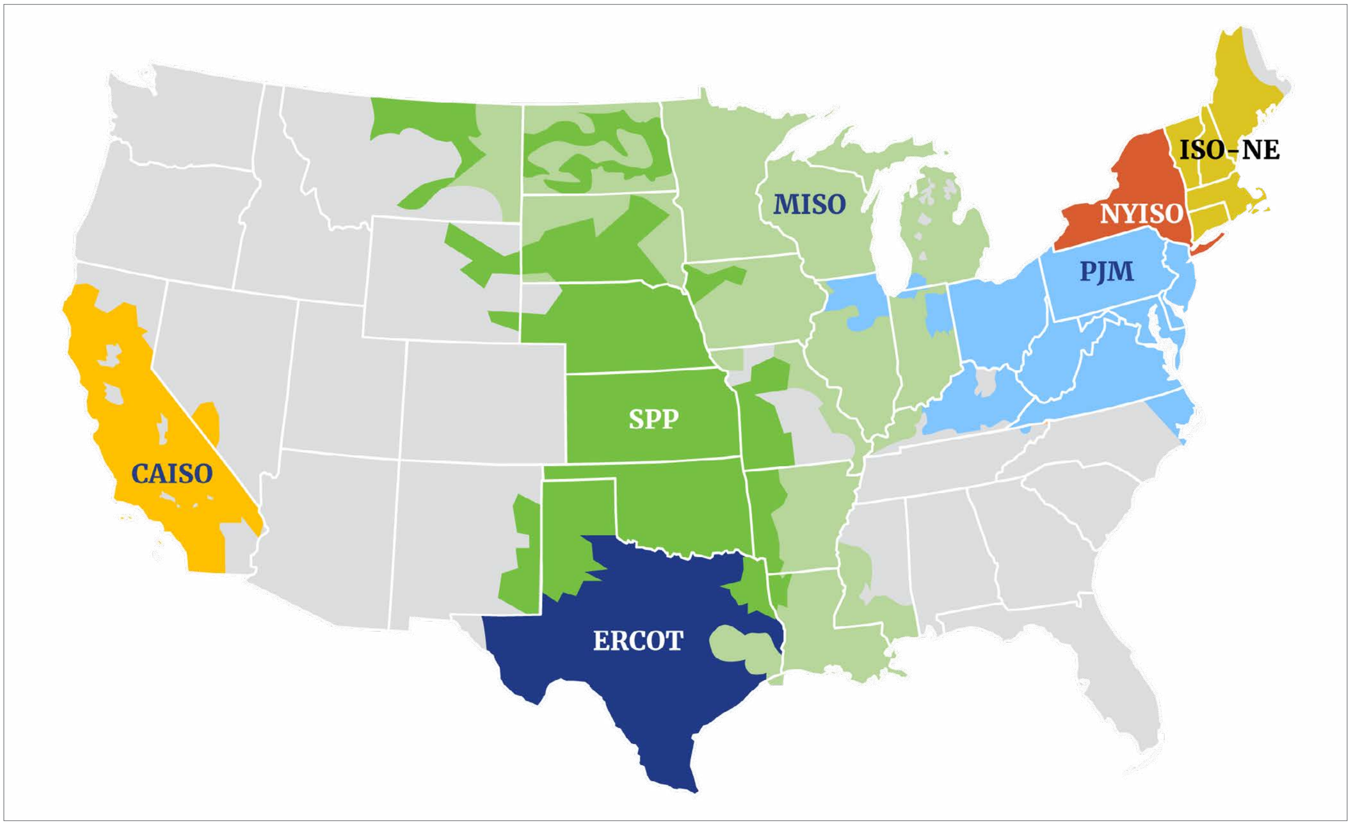
Today's RTO models are not working as they were designed. Regulatory complexity, market-distorting subsidies, and rapid growth in electricity demand require a reassessment of whether RTOs should be reformed or replaced to keep electricity affordable and reliable.

The Reality

Many RTOs are an evolution of traditional power pools, which were first formed almost a century ago and involve multiple utilities coordinating the operation of their generating plants to reduce the risk of outages. Pennsylvania-New Jersey-Maryland (PJM) Interconnection began in 1927 as a power pool, and others followed.[2] The operators that resulted, shown in **figure 1**, include both RTOs and independent system operators (ISOs).

Figure 1.

U.S. RTOs and ISOs



Note: Seven regional transmission organizations (RTOs) and independent system operators (ISOs) manage the grid and wholesale markets across much of the United States. Four are RTOs: Southwest Power Pool (SPP), Midcontinent ISO (MISO), PJM Interconnection (PJM), and ISO New England (ISO-NE). Three are ISOs: California ISO (CAISO), Electric Reliability Council of Texas (ERCOT), and New York ISO (NYISO).

Source: Adapted from "RTO Backgrounders," Sustainable FERC Project, accessed August 20, 2026, https://sustainableferc.org/rto-backgrounders-2.

To expand the benefits of power pools beyond generator coordination, the Federal Energy Regulatory Commission (FERC) sought to develop competitive wholesale power markets that would encourage greater efficiency and lower costs. RTOs—FERC's preferred instrument—were tasked with overseeing these markets, planning for new high-voltage transmission lines, and ensuring that new generators could connect to growing power grids. The first such RTO was the Electric Reliability Council of Texas (ERCOT), which was originally formed in 1970 as a power pool and became an RTO in 1996.[3] PJM, the nation's largest RTO, covers all or part of 13 mid-Atlantic states and the District of Columbia.[4]

Most RTOs attracted little attention due to their limited policymaking role, but that has changed recently for three reasons. First, electricity demand has newly accelerated with the growth of power-hungry artificial intelligence applications and data centers.[5] Second, state and federal environmental policies have effectively forced the closure of many fossil-fuel power plants,[6] while subsidies and mandates have incentivized new renewable generation, primarily through wind and solar photovoltaic plants. However, wind and solar are less reliable because they supply electricity only intermittently—when the wind blows or the sun shines—which dramatically increases the complexity of grid operations. Third, as conventional generation has declined, electricity prices have risen. The increase in price has been especially notable in PJM's forward capacity market, which is designed to secure capacity several years into the future (see **box 1**).

Box 1: Energy Versus Capacity

The capacity of a generating plant measures the instantaneous power that it can supply. Power is a function of voltage and current and represents the rate at which electrical energy is transferred through a circuit. For example, a generating plant with a nameplate capacity of 1,000 megawatts (MW) can produce 1,000 MW of power under standard conditions.

Energy equals power delivered over a given period. For example, 1 megawatt-hour (MWh) of energy is equivalent to 1 MW of power for an hour. It could also represent 2 MW for half an hour, and so forth. Energy markets pay only for energy that is dispatched and price it in terms of dollars per MWh.

Capacity markets, on the other hand, pay power plants based on the MW capacity they are expected to provide. RTOs with capacity markets start with a required reserve margin, which represents the percentage of total generating capacity that must be available above forecast peak demand. This ensures that sufficient generating capacity is in place to meet peak demand while also accounting for unexpected events, such as generator outages. They then accredit different resources and allow those resources to bid out their accredited capacity until the reserve margin is reached.

Market failures, whether perceived or actual, have been widely studied.[7] In effect, market failures prevent competitive markets from functioning as intended. In the case of RTOs and wholesale electric markets, the proximate causes are the subsidization of renewable energy,[8] the exercise of market power,[9] and the failure of RTO pricing constructs to accurately value reliability.[10] RTOs have a limited tool kit with which to address these issues.

Renewable Energy Subsidies and Mandates

Federal and state renewable energy subsidies, including tax credits, and state mandates for wind and solar generation, such as renewable portfolio standards, have distorted wholesale electricity markets. First, these policies have increased the number of hours during which market prices are artificially low or negative, creating financial hardships for unsubsidized coal and nuclear generators that cannot be quickly ramped up or down in response to changing market prices.[11] Second, because wind and solar generation are intermittent and variable, they have also led to more frequent scarcity conditions even in normally well-supplied markets, thereby contributing to the severity and unpredictability of price spikes.[12] Third, they have encouraged development of otherwise uneconomic generating supplies, further distorting wholesale markets.[13]

Market Power

In competitive markets, individual participants cannot affect the overall market price. Organized wholesale electric markets, however, have proven vulnerable to market-power manipulation by certain generation owners, especially in the capacity markets created by some RTOs.[14] In the early 2000s, for example, Enron Corporation and its affiliates exploited loopholes in the California wholesale market that drove up wholesale prices and contributed to the state's electricity crisis, which cost consumers billions of dollars.[15] Market manipulation can also involve withholding generation supplies to raise prices. Some states have even attempted to require local utilities to build ratepayer-subsidized generation in an effort to lower market prices by artificially increasing supply.[16]

Enron's conduct and the California electricity crisis were major drivers that led RTOs to establish myriad rules governing the prices that suppliers can offer, including the minimum and maximum prices and the methods used to set those bounds. Other provisions specify how generators offer capacity to the market. In some ways, there has been an arms race between wholesale generators and RTOs, with the former seeking to maximize profits and the latter aiming to ensure competitive prices that send appropriate price signals for new supply within the narrow confines of their limited tools.[17] But the frequently changing market rules imposed by RTOs to produce more competitive outcomes have a problem: increased uncertainty, which can reduce new investment by making future rules difficult to predict.

Valuing Reliability with RTO Market Prices

To remain economically viable, generating plants must recover their operating costs and provide their owners with an adequate return on investment; this can be especially problematic for peaking generators, which are designed to operate only a few times per year when demand is greatest.[18] These power plants are needed to provide the level of reliability that electricity consumers expect, but how often they run and how much revenue they receive is highly uncertain.

RTOs regularly cap wholesale electricity prices, in part because severe price spikes are politically untenable.[19] While price caps reduce the incentive to manipulate prices, they create another problem, termed *missing money*.[20] When prices are capped, some generators may not earn enough revenue during periods of scarcity to remain economically viable. When older generators are forced to exit the market or demand grows beyond existing supplies, prices should increase and create an incentive to develop new generating resources. However, price caps limit this incentive. Consequently, the market can be chronically undersupplied, which leads to higher market prices unless other mechanisms are created to address the missing-money issue.

Capacity markets—a potential remedy for the missing-money problem associated with price caps in wholesale energy markets—have been adopted by several RTOs, including PJM. In effect, capacity markets establish a fixed amount of supply for a future period (usually three years ahead, in the case of PJM) and allow generators to bid on supplying that capacity.[21] The goal is to get iron in the ground that can provide electricity whenever called upon and meet the RTO's reliability standard, regardless of how often that capacity is needed.

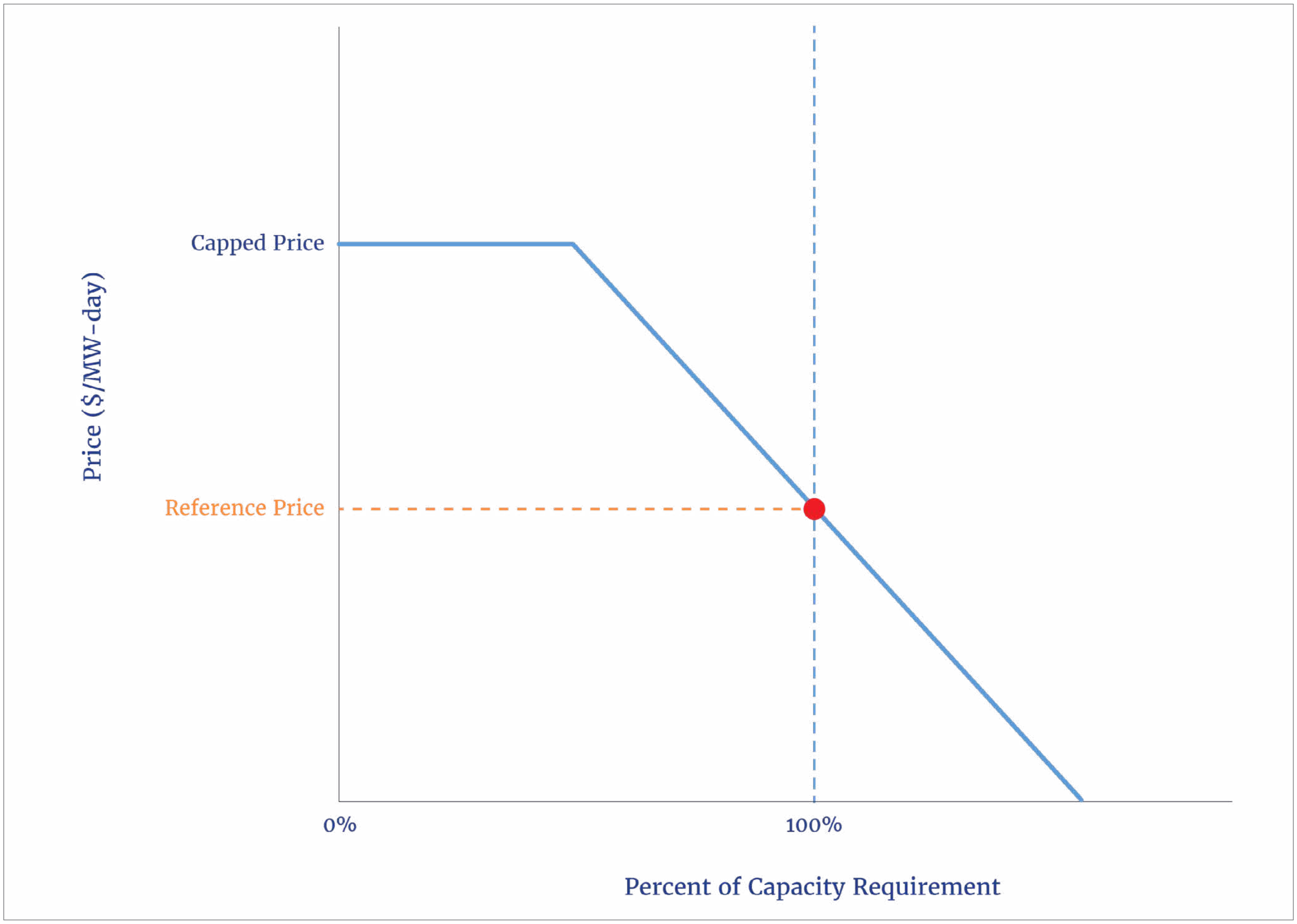
A key problem with capacity markets is that they are artificial. Unlike the energy market, in which supply and demand interact based on an actual commodity[22]—that is, MWh—RTOs administratively establish the capacity demand curve and then create rules requiring generation owners to supply the capacity specified by the curve (see **figure 2**).[23]

As shown in **figure 2**, the reference price is based on the revenue that a new peaking generator would need to recover the missing money after accounting for expected revenues from selling peak MWh and ancillary services.[24] The reference price is thus determined administratively. Capacity beyond that point still has value, but the price declines as additional capacity enters the market and eventually falls to zero.

The market-clearing price is determined in part by generation owners' offers for their available capacity. Those offers are subject to regulation, including the quantity of capacity (MW) that each generator provides and the prices at which it can be offered. There can also be an administratively set price cap, which varies but is typically 150% of the reference price. Regulators set the cap based on their determination of the appropriate trade-off between providing sufficient incentives for new entrants and preventing excessive charges to consumers. But there is no empirically optimal trade-off; it is effectively a regulatory judgment. Moreover, despite the close regulation of capacity-market prices, these markets are highly susceptible to market power and price manipulation.[25]

Figure 2.

RTO Capacity Demand Curve



Source: Adapted from Mathangi Srinivasan Kumar, "ICAP Demand Curve," presentation at New York Independent System Operator (NYISO) Intermediate ICAP Course, Rensselaer, NY, May 20–21, 2026, slide 17.

The amount of capacity an RTO credits to a generator is sometimes called *unforced capacity* (UCAP). In effect, it is the installed or nameplate capacity less the expected reduction from planned outages (e.g., scheduled maintenance) and forced outages (e.g., equipment breakdowns).[26] Typically, UCAP for fossil-fuel and nuclear generators is based on experience. For existing generators, that means their own past performance; for new generators, it means experience with the same class of generator.

Determining UCAP for wind and solar generation is more difficult because of those resources' inherent intermittency. RTOs account for this problem by estimating how much wind and solar generation can contribute to peak demand—a calculation based on the expected availability of those resources when electricity demand is forecast to be greatest.[27] If demand were to peak at an unexpected time, wind and solar generation might still be unavailable.

In PJM, capacity lost through retirements of conventional generating plants has thus far exceeded the added capacity from wind and solar. As peak demand has increased, the loss of conventional capacity caused the overall price to increase to about $325/MW-day for the 2026–27 delivery year (June 1–May 31) and to just over $333/MW-day for the 2027–28 delivery year—increases of almost 1,000% over the 2024–25 auction clearing price of about $29/MW-day.[28] The estimated ultimate dollar impact to retail ratepayers is about $16 billion per year.[29]

Market power has been especially problematic in capacity markets, in part because the demand curves created by RTOs such as PJM are inelastic.[30] In other words, the capacity demand curve, such as the one illustrated in **figure 2**, is relatively insensitive to price. Moreover, utilities and other energy suppliers must purchase a fixed amount of capacity based on their expected peak demand—regardless of price.[31] This gives suppliers of capacity significant leverage to affect market-clearing prices. Although RTOs have numerous rules to mitigate market power, overly onerous rules can discourage entry by new suppliers and cause prices to increase further as demand grows.

Limited RTO Tool Kit

The final problem faced by RTOs is their limited tool kit. An RTO that forecasts insufficient generating capacity to meet the reserve margin required for future peak demand cannot—short of rationing electricity through much higher prices or rolling blackouts—force market participants to add capacity, especially reliable and dispatchable generating capacity.[32] If specific regions have limited inbound transmission capacity, most RTOs cannot force new transmission lines to be built without approval from FERC and the affected states.[33]

Additionally, RTOs' market design modifications can be challenged by market participants and regulators. Such challenges can take years to resolve, which creates uncertainty for potential suppliers.

Due to the complexities of the power system—electrons obey the laws of physics, not economics—adding new generation and transmission capacity to the existing grid cannot be done arbitrarily; it requires detailed and often time-consuming studies to ensure that the rest of the grid is not adversely affected. The time required for such studies has become controversial as generator queues grow, especially for wind and solar generators seeking to connect to the grid.

Perspective

Perhaps the most radical solution would be to abandon the RTO framework and return to the previous system of power pools, which primarily combined generating resources to improve reliability. Although this alternative would eliminate formal markets overseen by RTOs, wholesale power markets would still exist. Under this approach, RTOs would function solely as grid operators, while market participants would be able to trade electricity according to their own rules.

RTOs identify the need for new generating and transmission capacity to meet reliability requirements. They could also solicit bids for new generating capacity in specific locations, much as they now do for new transmission. However, doing so may raise concerns about competition, particularly if RTOs succumb to political pressure and build new generating capacity. Another option would be to regulate new generating capacity on a cost-of-service basis, as FERC now provides for reliability-must-run generators, or to allow such capacity to participate as a competitive wholesale generator.[34]

A less radical solution would be to eliminate the price caps in wholesale energy markets and, consequently, the need to address the missing-money problem. Doing so would also require severe penalties to be imposed on generators that were found to be engaging in anticompetitive behavior to manipulate prices. Generators participating in an RTO-administered wholesale market would still be required to agree to specific participation rules.

A recent report by PJM addresses the limitations of its wholesale capacity-market design and offers three alternatives.[35] These include stabilizing existing markets through long-term forward commitments by load-serving entities; differentiating reliability standards, rather than applying a single standard for all areas and customers; and transitioning away from a capacity market, maintaining it as a backstop while focusing on energy and ancillary services markets. These alternatives, however, are relatively narrow and do not encompass the full range of possible solutions.

Federal and state subsidies for wind and solar generators, along with state renewable-supply mandates, could be addressed by changing how these resources are compensated in RTO energy markets or by requiring them to meet specified reliability criteria.[36] Subsidized generators could instead engage in bilateral transactions with utilities or competitive retail electric sellers. Alternatively, generators receiving the production tax credit could be required to forgo the credit as a condition of participating in an RTO market. Because wind and solar generation are variable, another option might be to mandate that such generators pay a reliability-compensation fee or incorporate sufficient storage to mitigate the effects of intermittency.[37]

Another issue is how to allocate the costs of new transmission capacity. Currently, generation owners pay the direct costs of interconnection to the bulk power system, while the costs of adding transmission capacity are socialized across all transmission users and, ultimately, retail consumers. Alberta, Canada, for example, has developed an alternative based on cost-causation principles.[38] Under its system, new generators must make up-front, nonrefundable transmission-reinforcement payments tied to a generator's location and the attributes of the electricity it provides. Far-flung generators pay more than those near load centers, while intermittent providers such as wind and solar pay more than generators whose output can be scheduled.

Finally, RTOs could encourage development of private grids for large loads that might later be integrated into the overall bulk power system. Doing so would address the current issue of RTOs being unable to keep up with growing demand.

None of the necessary reforms will be easy to make. However, the existing system is failing to ensure reliable and affordable electricity. As electricity continues to grow in importance to the U.S. economy, policymakers will need to look toward the future and be willing to confront entrenched interests to implement reforms.

Notes

1 RTOs developed from independent system operators (ISOs); both operate wholesale markets, but RTOs meet additional Federal Energy Regulatory Commission (FERC) criteria and some operators remain ISOs. Although FERC distinguishes the two, RTOs and ISOs perform essentially the same functions.

2 "Benefits of PJM Membership," PJM Learning Center, PJM, accessed August 6, 2026, https://learn.pjm.com/electricity-basics/benefits-of-pjm-membership; and "Electric Power Markets," FERC, last updated March 27, 2025, https://www.ferc.gov/electric-power-markets.

3 "ERCOT Organization Backgrounder," Electric Reliability Council of Texas (ERCOT), accessed August 20, 2026, https://www.ercot.com/news/mediakit/backgrounder.

4 PJM, *PJM—At a Glance* (PJM, 2025).

5 Jonathan Lesser and Patrick J. McCormick III, *America's Electricity Grids: At a Crossroads* (National Center for Energy Analytics, 2026).

6 Elias Johnson, "Planned Coal-Fired Power Plant Retirements Continue to Increase," *Today in Energy*, March 20, 2014.

7 The literature on market failures was first developed almost 70 years ago with the publication of Francis Bator, "The Anatomy of Market Failure," *Quarterly Journal of Economics* 72 (August 1958): 351–79. See also Ronald H. Coase, "The Problem of Social Cost," *Journal of Law and Economics* 3 (October 1960): 1–44, which argued that the cost of addressing market failures in the form of externalities (e.g., pollution) can be greater than the losses they cause to society.

8 Paul L. Joskow, "Challenges for Wholesale Electricity Markets with Intermittent Renewable Generation at Scale: The U.S. Experience," *Oxford Review of Economic Policy* 35, no. 2 (2019): 291–331; and Sylwia Bialek and Burçin Ünel, "Efficiency in Wholesale Electricity Markets: On the Role of Externalities and Subsidies," *Energy Economics* 109 (2022): 105923.

9 "Market Power Analysis," FERC, last updated December 4, 2023, https://www.ferc.gov/power-sales-and-markets/electric-market-based-rates/market-power-analysis.

10 Bialek and Ünel, "Efficiency in Wholesale Electricity Markets"; and Erik Ela et al., *Evolution of Wholesale Electricity Market Design with Increasing Levels of Renewable Generation*, NREL/TP-5D00-61765 (National Renewable Energy Laboratory, 2014).

11 U.S. Department of Energy (DOE), *2013 Economic Dispatch and Technological Change: Report to Congress* (DOE, 2014), 3–6, 7–8.

12 For an estimate of the costs imposed by variable wind and solar output on a competitive generation market, see Michael Reed and Brent Bennett, *The Cost of Wind and Solar Variability to Texas Ratepayers* (Texas Public Policy Foundation [TPPF], 2025).

13 Jonathan A. Lesser, "Gresham's Law of Green Energy," *Regulation* 33, no. 4 (Winter 2010–11): 12–18.

14 FERC, *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861 (FERC, 2019).

15 FERC, *Price Manipulation in Western Markets: Findings at a Glance*, Staff Report, Docket No. PA02-2-000 (FERC, 2003); and FERC, *The Commission's Response to the California Electricity Crisis and Timeline for Distribution of Refunds* (FERC, 2005).

16 Jonathan Lesser, "Do Green Subsidies Work?" *RealClearEnergy*, September 3, 2024.

17 Lesser and McCormick, *America's Electricity Grids*.

18 For plants owned by regulated utilities, these costs are generally recovered through the retail rates those utilities charge.

19 Selahattin Murat Sirin and Ibrahim Erten, "Price Spikes, Temporary Price Caps, and Welfare Effects of Regulatory Interventions on Wholesale Electricity Markets," *Energy Policy* 163 (April 2022): 112816.

20 Paul L. Joskow, "Capacity Payments in Imperfect Electricity Markets: Need and Design," *Utilities Policy* 16, no. 3 (2008): 159–70.

21 PJM, "RPM Auctions," in *Manual 18: PJM Capacity Market*, rev. 62 (PJM, 2025), 117–18.

22 Capacity is a commodity, but electrical energy is ultimately consumed.

23 See, for example, Mathangi Srinivasan Kumar, "ICAP Demand Curve," presentation at New York Independent System Operator (NYISO) Intermediate ICAP Course, Rensselaer, NY, May 20–21, 2026. This presentation explains the various steps in creating the installed capacity curves used by NYISO. RTOs hold auctions for capacity to be delivered in the future, which reflects the time necessary to build new generating facilities.

24 Ancillary services are those needed to maintain certain system conditions, such as frequency and voltage, within close tolerances to ensure that the power system is reliable. See "Ancillary Services," FERC, last updated August 4, 2026, https://www.ferc.gov/ancillary-services.

25 Monitoring Analytics, "Capacity Market," in *2025 State of the Market Report for PJM*, vol. 2 (Monitoring Analytics, 2026), 305–70. The report identifies the 2025–26, 2026–27, and 2027–28 capacity-market results as not competitive and discusses PJM's market-power mitigation rules.

26 NYISO, *Installed Capacity Manual*, ver. 18.0 (NYISO, 2026), 64–70.

27 The technical term for this calculation is *effective load-carrying capacity*.

28 PJM, *2024/2025 RPM Base Residual Auction Results* (PJM, 2023); PJM, *2026/2027 Base Residual Auction Report* (PJM, 2025); and PJM, *2027/2028 Base Residual Auction Report* (PJM, 2025).

29 Monitoring Analytics, *2026 Quarterly State of the Market Report for PJM: January Through June* (Monitoring Analytics, 2026), 392.

30 See, for example, Monitoring Analytics, "Capacity Market," which concluded that "structural market power is endemic to the capacity market" (306).

31 PJM, *Manual 18: PJM Capacity Market*, rev. 62 (PJM, 2025), 166–71.

32 Lesser and McCormick, *America's Electricity Grids*.

33 The exception is ERCOT, which is entirely contained within the state of Texas and is therefore generally not subject to FERC regulations when planning its transmission system. ERCOT's transmission-planning processes are still subject to oversight by the Public Utility Commission of Texas and the Texas Legislature.

34 This would also require mitigating, as FERC currently does, the market power of any generator.

35 PJM, *Powering Reliability Through Market Design* (PJM, 2026).

36 Michael Reed and Brent Bennett, *Reliability Standards to Reduce the Cost of Wind and Solar Volatility in Texas* (TPPF, 2025).

37 See, for example, Public Utility Commission of Texas, *Project No. 58198: Rulemaking to Implement Firming Reliability Requirements for Electric Generating Facilities in the ERCOT Region Under PURA § 39.1592: Order Adopting New 16 TAC § 25.65* (Public Utility Commission of Texas, 2025).

38 Jason Doering, "TRP: 'The Right Path' for Transmission in Alberta," *oHmLand* (blog), December 16, 2024.

About the Authors

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Jonathan A. Lesser is the president of Continental Economics, with years of experience working and consulting for regulated utilities and government. He has addressed numerous economic and regulatory issues affecting the energy industry in the United States, Canada, and Latin America—including gas and electric utility structure and operations, cost-benefit analysis, mergers and acquisitions, cost allocation and rate design, asset-management strategies, cost of capital, depreciation, risk management, incentive regulation, economic-impact studies, and general regulatory policy. Lesser has prepared expert testimony and reports for numerous utility commissions and international regulatory bodies and has testified before Congress and numerous state legislative committees. He is the coauthor of three textbooks: *Environmental Economics and Policy* (Addison Wesley Longman, 1997); *Principles of Utility Corporate Finance* (Regulatory Economics Publishing, 2011); and the widely used *Fundamentals of Energy Regulation*, 3rd ed. (Regulatory Economics Publishing, 2020), as well as numerous academic and trade press articles. Lesser was previously an adjunct fellow with the Manhattan Institute for Policy Research. He holds a BS in mathematics and economics from the University of New Mexico as well as an MA and a PhD in economics from the University of Washington.

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