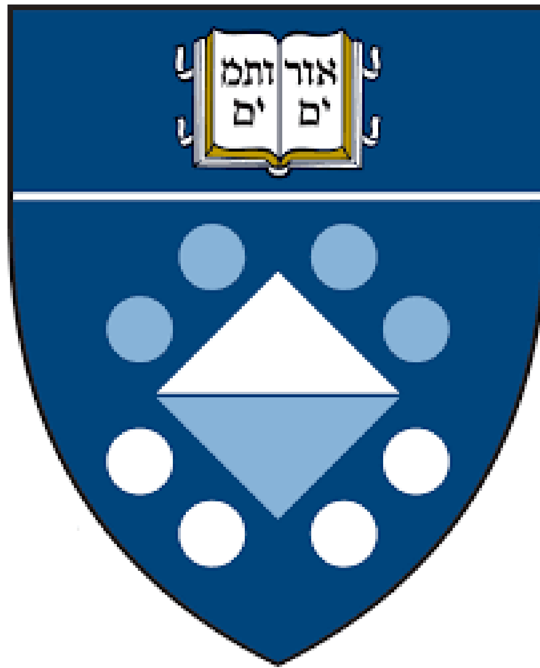

Yale University

Thurman Arnold Project

2026 Student Papers

Paper No. 02

Competition Concerns with Private Equity Ownership of Utilities

May 2026

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Competition Concerns with Private Equity Ownership of Utilities

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I. Introduction

On October 3, 2025, the Minnesota Public Utilities Commission (PUC) approved the sale of Minnesota Power, a previously publicly traded electric utility, to a consortium of investors led by the private equity investor Global Infrastructure Partners (GIP, owned by BlackRock).[1] Soon after, Blackstone's purchase of TXNM Energy—a utility stretching across Texas and New Mexico—was approved by both Texas regulators[2] and the Federal Energy Regulatory Commission (FERC).[3] And on March 2, 2026, in the biggest deal yet, a consortium including GIP and Sweden's EQT agreed to a $33.4-billion purchase (including debt) of AES, a holding company with utility subsidiaries in Ohio and Indiana.[4] These transactions loudly herald the arrival of private equity (PE) on the regulated utility scene, setting the stage for other private investors to acquire utilities across the country.

Many of these investors also own generation assets in competitive generation markets, raising the specter of anticompetitive and self-dealing behavior wherein the sell side (generators) receives advantages from the buy side (utilities) and vice versa.

In restructured (or "deregulated") electricity markets, wholesale generators bid in according to marginal cost, with the utility or other load-serving entity (LSE) buying power as needed. The day-ahead and real-time markets that connect these two parties are run by an independent system operator (ISO) or regional transmission organization (RTO). The costs of purchasing power incurred by the LSE are passed directly through to ratepayers, with no profit margin built in. However, utilities in deregulated markets are still able to earn a return on equity (ROE) on their investments in transmission and distribution (T&D). These utilities are thus still referred to as "regulated utilities."

PE acquisitions of electric utilities are occurring against the backdrop of rising electricity demand, driven by AI. Data centers for AI training and inference are extremely energy-intensive, and as they proliferate, the need for new electricity infrastructure grows. This is the opportunity

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[1] "Minnesota PUC Approves $6.2B Allete Sale to Private Equity | Utility Dive," https://www.utilitydive.com/news/minnesota-puc-allete-private-equity-blackrock-gip/802006/.

[2] TXNM Energy Inc, "Texas Commission Approves TXNM Energy Acquisition by Blackstone Infrastructure," https://www.prnewswire.com/news-releases/texas-commission-approves-txnm-energy-acquisition-by-blackstone-infrastructure-302681501.html.

[3] "TXNM Energy Gets FERC Approval for $11.5 Billion Blackstone Deal | Reuters," https://www.reuters.com/legal/transactional/txnm-energy-gets-ferc-approval-115-billion-blackstone-deal-2026-02-20/.

[4] Sumit Saha, "BlackRock, EQT-Led Group Seals $33.4 Billion AES Deal in Bet on AI Power Boom," Transactional, *Reuters*, March 2, 2026, https://www.reuters.com/legal/transactional/blackrocks-gip-eqt-buy-aes-corp-334-billion-deal-2026-03-02/.

on which PE firms seek to capitalize. However, infrastructure investment today is sized for AI capabilities tomorrow. If AI lags in deployment or becomes more efficient, infrastructure will have been overbuilt. And since utilities are guaranteed to fully make back their investments in infrastructure with a healthy return, they are incentivized to maximize such investments, while residential consumers remain on the hook for that infrastructure even if data center load projections do not fully materialize. Data centers are already contributing to electricity price increases for consumers; as the gap between infrastructure investment and fundamental AI market strength gets larger, electricity will only get more expensive.

At the same time, PUCs are struggling to adapt to the growing complexity of energy markets and systems. They are increasingly under-staffed and under-resourced in light of budgetary pressures and competing priorities, while utility proceedings become more intricate and regulatory mandates more diverse. Such a discrepancy between regulatory capacity and energy market complexity opens windows for anticompetitive and anti-consumer behavior, through foreclosure of rivals and rate increases unlinked to increases in base costs. Considering these growing capacity constraints, state attorneys general offices have an opportunity to complement PUCs in properly scrutinizing this emerging challenge of PE utility takeovers. In addition, there is a clear political upside to addressing this issue, because their constituents will care about the rising cost of electricity.

II. Market dynamics

In most markets, PE firms make profits in three main ways: operational improvements, financial engineering, and multiple arbitrage. Operational improvements include the standard ways of improving business fundamentals, such as growing revenue and cutting costs. Financial engineering often takes the form of leveraged buyouts, which involve borrowing other investors' money to purchase a company, increasing the company's value, selling, paying back the debt, and pocketing the valuation increase. (If valuation does not increase, PE firms protect themselves by putting the debt on the company's balance sheet, not their own.) Multiple arbitrage usually means acquiring and consolidating ("rolling up") smaller competing companies to exploit synergies and gain market power. Usually, PE firms sell portfolio companies five to seven years after purchase.

A. The private-equity business model and its manifestation in the utilities sector

In the regulated utility space, PE firms' investment incentives are almost the exact opposite of those in other markets in which they invest. For regulated utilities, revenue and profit increase when costs increase. Regulators limit utility revenues to two streams: operational expenditures (opex), which are day-to-day expenses like electricity purchases, salaries, and maintenance, and are directly passed through to ratepayers without any profit margin built in; and capital expenditures (capex), which are larger projects like T&D on which the utility is guaranteed to both make back its investment and receive a regulator-approved profit margin, or ROE. Therefore, since profit can only be made on capex, PE firms actually have every incentive to *maximize* costs of this kind.

From a consumer welfare perspective, understanding the distinction between PE investment in traditionally competitive sectors and regulated utilities is vital.

- The cost cuts traditionally sought by PE firms may actually be good for utility ratepayers, but utilities venerate capex and are indifferent to opex, or even hostile to it when it could displace capex projects. This opens the door to "gold plating" (inflated capital investments for the purpose of making profit), eliminates any inclination towards efficiency and low-capital solutions, and increases the risk of dangerous issues like deferred maintenance.
- Leveraged buyouts are a concern. Acquisition costs must be paid back, through some combination of returns on increased capex, reduced opex, and dividends. But if PE firms seek to finance future capital projects while maintaining their stakes, they will take out post-acquisition debt[5]; ratepayers pay the cost of capital in either case, meaning the interest on debt and/or the ROE.
- Since there is no horizontal competition between utilities—each one has a monopoly on T&D in its service territory—multiple arbitrage does not apply.
- In traditionally competitive sectors, PE firms' short five-to-seven year holding period is in part because most of the returns from such investments stem from the capital gains realized at sale. In private infrastructure deals—which include regulated utilities—most of the returns actually come from the annual yield generated by the company itself.[6] This means firms typically hold infrastructure assets for longer, as they are able to deliver profits to their investors without selling the company.

PE firms therefore do not face different financial incentives from any other type of controlling investor in the utilities sector. Capex bias is a function of the regulatory system under which utilities operate, not the source of their capital.

The anticompetitive incentives they face, though, *are* materially different. And given laxer reporting requirements for private investors, it is more difficult to police PE firms' practices, especially for under-resourced PUCs. These incentives, and the harms that flow from them, are explained in more detail in the next section.

B. The new, shaky load-growth environment

The reason for these recent PE takeover attempts is clear: for the first time in a generation, U.S. electricity demand is rising.[7] No longer are improvements in energy efficiency able to offset the new sources of load coming online.

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[5] Travis Kavulla, "High Power Bills Got You Down? Policy Strategies for Affordability," DLCC Winter Forum, December 12, 2025, https://www.nrg.com/assets/documents/energy-policy/dlcc-briefing-high-power-bills-got-you-down-121225.pdf.

[6] Katie O'Leary, "Infrastructure Private Equity: What You Need to Know," *Chronograph*, June 9, 2025, https://www.chronograph.pe/infrastructure-private-equity-what-you-need-to-know/.

[7] "After More than a Decade of Little Change, U.S. Electricity Consumption Is Rising Again - U.S. Energy Information Administration (EIA)," https://www.eia.gov/todayinenergy/detail.php?id=65264.

There are several components to this load growth—end-use electrification in transport and buildings, cryptocurrency mining, the reshoring of manufacturing operations—but the biggest contributor by far is the buildout of data centers. Large tech companies are scrambling to construct cutting-edge data centers to power their AI ambitions, a trend which is projected to place enormous strain on the power grid. Given the pace of buildout, the pressure to expand and modernize the grid, and to bring new generation online, is immediate. The potential financial reward of such pursuits has grown correspondingly.

Yet there are also reasons for skepticism. Much of the AI industry's market strength rests on future projections and circular investments—major chipmakers and "compute" providers are providing AI firms with generous cash infusions, who in turn contract with the chipmakers and compute providers for their services.[8] This creates an appearance of robust transaction volume, while usage and satisfaction metrics show questionable productivity increases when businesses integrate AI into their operations[9] along with plateauing numbers of paying personal users.[10] If investors begin to demand real returns based on fundamental growth and prudent capital expenditure, the data center pipeline may dry up.

Additionally, there is a growing body of evidence that data center loads are temporally and locationally flexible.[11] Specifically, training AI models is constant and compute-intensive, requiring more always-on power, but inference—answering people's AI queries and performing other day-to-day, consumer-facing operations—is much less so. (As users adopt AI "agents," which can work on tasks day and night without supervision, this may change.) Methods that allow AI companies to shift their computational loads to times of the day with lower system-wide electricity demand, or to other data centers facing less competition for power at a given moment, are quickly emerging.

Thirdly, AI training may become less compute-intensive overall. Large language models seem to be reaching a point of diminishing returns, with additional compute yielding fewer model improvements.[12] The success of China-based DeepSeek's AI model has also spurred interest in reasoning-based models that make more efficient use of fewer resources, both in terms of compute and electricity.[13]

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[8] "AI Circular Deals: How Microsoft, OpenAI and Nvidia Keep Paying Each Other," https://www.bloomberg.com/graphics/2026-ai-circular-deals/.

[9] Steve Lohr, "Companies Are Pouring Billions Into A.I. It Has Yet to Pay Off.," *The New York Times*, August 13, 2025, https://www.nytimes.com/2025/08/13/business/ai-business-payoff-lags.html.

[10] Menlo, "2025: The State of Consumer AI," *Menlo Ventures*, June 26, 2025, https://menlovc.com/perspective/2025-the-state-of-consumer-ai/.

[11] Tyler H. Norris, "Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems," Nicholas Institute for Energy, Environment & Sustainability, Duke University, February 5, 2025, http://nicholasinstitute.duke.edu/publications/rethinking-load-growth.

[12] Sara Hooker, "On the Slow Death of Scaling," SSRN Scholarly Paper no. 5877662 (Social Science Research Network, December 6, 2025), https://doi.org/10.2139/ssrn.5877662.

[13] "How DeepSeek Has Changed Artificial Intelligence and What It Means for Europe," Bruegel, December 8, 2025, https://www.bruegel.org/policy-brief/how-deepseek-has-changed-artificial-intelligence-and-what-it-means-europe.

LSE's yearly ROE and depreciation expenses for T&D expenses are commonly paid out by ratepayers over a twenty-year period. Generators signing power purchase agreements (PPAs) with LSEs to guarantee electricity delivery at a certain strike price often include protective provisions like (a) "take-or-pay" clauses—an obligation for the purchaser to pay a set amount of money each year regardless of whether they actually take the electricity[14]—and (b) "compensable curtailment" measures—triggered if the buyer refuses to take power because projected load failed to materialize during a certain market window[15]—in their contracts. Others participate in RTO-run capacity markets, whose payments to generators are entirely based on load forecasts. All of these generation expenses incurred by LSEs are passed through one-to-one to ratepayers.

Fundamentally, electricity prices are determined by a simple expression: total expenses and approved returns for electricity supply and delivery, divided by total electricity demand responsible for paying for them. If a customer class, say, data centers, is able to avoid paying its "fair share"—data centers and sympathetic politicians have been known to push to do so[16]—or if its demand is reduced, the denominator of that expression decreases. The value of the total expression thus increases. In short, data centers paying less or presenting less-than-projected demand increases electricity prices for everyone else.

The bottom line: if data center projects drop out of development after LSEs sign power agreements and expand T&D infrastructure, and if the data centers that do remain begin to operate more efficiently, consumers will be left holding the bag for unneeded, regulator-approved capital projects. The risks to consumers posed by the load-growth environment appear considerable. PE interest in regulated utilities must be weighed directly against these risks.

III. Potential competitive harms of private equity ownership of regulated utilities

The first potential competitive harm specific to PE ownership occurs in the interaction between generators and the LSE in the wholesale market. As things currently stand, a single major investor might own a maximum of 15-20% of a publicly traded utility's shares, with other major investors clustered around that same ownership percentage. This means enough investors—many of whom also have stakes in generation companies—have sway over utility behavior that one investor's generation portfolio is not given preference.[17] However, PE acquisitions consolidate control and

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[14] "Financing Renewable Energy Projects - Bankability of PPA | Article | Chambers and Partners," https://chambers.com/articles/financing-renewable-energy-projects-bankability-of-ppa.

[15] Barbara O'Neill and Ilya Chernyakhovskiy, *Designing Wind and Solar Power Purchase Agreements to Support Grid Integration*, NREL/TP--6A20-66543, 1262663 (2016), NREL/TP--6A20-66543, 1262663, https://doi.org/10.2172/1262663.

[16] Eliza Martin and Ari Peskoe, *Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power* (Environmental & Energy Law Program, Harvard Law School, 2025), https://eelp.law.harvard.edu/wp-content/uploads/2025/03/Harvard-ELI-Extracting-Profits-from-the-Public.pdf.

[17] This is distinct from the concept of "common ownership." In a common ownership setup, the same investor owns significant shares in competing firms. In the setup described here (which would be supplanted by consolidated PE control), a group of investors has shares in both the monopolistic buy-side utility and several competitive sell-side generation firms. The buy side would thus have little incentive to favor one sell-side firm over

eliminate these checks. In this case, leadership is free offer advantages to the assets on the wholesale side in subtle yet powerful ways. These methods may not rise to the level of overt bid rigging—forbidden in antitrust statute, guarded against by ringfencing measures, and highly scrutinized by regulators—but could involve advance notice before new requests for proposal (RFPs), overly burdensome technical requirements, and priority for T&D development that serves assets owned by the investors. Generators can facilitate these abuses by giving their build plans and cost structures to the LSE. This levying of informational and procedural advantages amounts to vertical foreclosure, favoring affiliated suppliers and raising rivals' costs.[18]

The second potential harm arises during PUC proceedings. The integrated resource planning (IRP) process is central to utility operations. IRPs, though overseen by regulators, are characterized by information asymmetry between the regulator and the utility. Utilities often forecast future load with proprietary data and modeling, using utility-specific assumptions and projections that favor capital-intensive assets. This often manifests as utilities presenting artificially high forecasted demand during proceedings, growing their potential rate base. These demand forecasts justify utilities signing more PPAs or generally create a strong market signal for generators. An investor could leverage that signal to finance generating assets for which it knows there would be a market: itself. This may also influence capacity market auctions, whose targets are based on LSEs' peak demand forecasts and whose winning bids become passthrough costs as well. That, along with the IRP, would enable the utility to request the approval of new T&D infrastructure, on which it is able to receive a return. Such a sequence of events, entirely plausible when the same investor owns assets on both sides of the wholesale-LSE divide, would greatly reduce competition in generation markets, insulate the investor from any market risk, and increase consumer bills by passing through higher wholesale costs and claiming ROE on inflated investments.

It is important to note here that this approximation of vertical integration would likely do nothing to reduce transaction costs in a way that could theoretically be passed on to consumers. Utilities would still be purchasing electricity on wholesale markets and passing those costs through one-to-one to ratepayers. They would still be forced to spend time and money on rate cases and IRP proceedings, another direct passthrough expense. And they would still have little to no incentive to reduce capital expenditures (capex), on which they receive a regulator-approved return. In fact, with fresh private equity cash to spend, the primary argument against exorbitant capex—namely, that it can sometimes be difficult to source that much upfront capital given debt-to-equity ratio requirements and regulatory scrutiny over ROE—evaporates.

Generators' costs could conceivably decrease as their market becomes more certain, which might lower the supply portion of consumer bills. But the distortions outlined above also work in

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another. Florian Ederer and Isabel Tecu, "Common Ownership: A Guide for Antitrust Practitioners," Antitrust Economics for Lawyers, September 8, 2025, https://florianederer.github.io/co_practitioners.p

[18] When assessing requests for blanket authorizations—which allow firms to undertake certain projects without case-by-case approval—for large asset managers like BlackRock looking to purchase utilities, former FERC Chairman Mark Christie consistently raised concerns over their ability to exert market power and reduce competition in the wholesale market.

the opposite direction, raising the costs of other dispatched suppliers. And crucially, despite decreases in affiliated generators' costs, the marginal producer and the market-clearing price would likely not decrease. This would allow affiliated generators to capture higher inframarginal rents, driving increased profits for unregulated entities without reducing consumers' supply bills.

To crystallize these concerns: GIP—whose newly purchased utilities sit in PJM and MISO, two large RTOs—could offer subtle advantages and market assurances to its ever-expanding generation portfolio and use oncoming demand to rationalize new return-generating infrastructure. This consolidation would give GIP tremendous ability to raise consumer prices while couching that ability in a tangle of holding structures and self-justifying arguments.

This challenge is not entirely new. In 2006, an electric utility called Duquesne Light Company, whose service territory includes Pittsburgh, PA, was sold (along with its sister companies in Duquesne Light Holdings) to a consortium of private investors including DUET, IFM, and Macquarie Infrastructure Partners.[19] When considering this transaction, FERC argued that the consortium did not hold enough assets in PJM—Duquesne's RTO—to allow the utility to "adversely affect prices or output in a downstream electricity market or discourage entry by new generators."[20] However, this decision was merely a snapshot in time; FERC noted that at the moment of the decision, "the [c]onsortium members' affiliated energy assets are limited to…a *de minimis* share of the generating capacity in PJM or any smaller relevant market within PJM."[21] The generation assets held by the PE firms buying electric utilities today look poised to surpass a *de minimis* share of the country's competitive generation in RTOs. State attorneys general must weigh the threat duly.

A. Existing holdings, planned projects, and the importance of proactiveness

In several states that participate in ISOs and RTOs, a single holding company is allowed to own both generation and T&D assets. Such states require the company to place a firewall between its competitive generation and regulated T&D businesses, to prevent profits from flowing from one subsidiary to the other. The potential for abuse of this setup is obvious, as indicated by the FirstEnergy case. However, PE ownership does not exacerbate these harms; any owner of such a holding company would be incentivized to use one subsidiary to support another. Scholarship on these abuses is plentiful and stretches back to the emergence of restructuring in the late 1990s and early 2000s, leading to high levels of regulatory awareness.

Therefore, this overview focuses specifically on generation holdings that are *not* under the same corporate structure as the regulated utility in question. Private investors own and operate generation companies in RTOs that compete in markets serving LSEs that they are buying up. But

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[19] *Docket No. EC06-160-000: Hearing before the United States of America Federal Energy Regulatory Commission* (2006), https://www.ferc.gov/sites/default/files/2020-05/E-2_21.pdf [hereinafter Duquesne].
[20] Duquesne 8.
[21] Duquesne 7.

since these two assets are not technically under the same corporate umbrella, the PE model of consolidated control and regulatory opacity makes it unique in terms of harms.

1. Minnesota Power sits in MISO, an RTO stretching from Manitoba in Canada south to Louisiana. Its new owner, GIP, holds a significant stake in Clearway Energy.[22] Clearway does not currently own and/or operate any generation in MISO but likely has projects in the queue. (A project developer's name remains confidential until the project signs an interconnection agreement, but Clearway submitted detailed feedback on MISO's planned interconnection queue reforms in 2023, indicating a stake in the outcome.[23])
2. Part of TXNM Energy sits in ERCOT, the ISO administering most of Texas' grid. Blackstone, its would-be buyer, has a significant stake in Invenergy.[24] Invenergy operates many utility-scale generation projects in ERCOT territory, including the Santa Rita East Wind Farm, the Samson Solar Energy Center, and the Goldthwaite Wind Farm.[25] Since the ERCOT grid is not connected to other grid regions across state borders, it is not subject to FERC jurisdiction.
3. AES is split between Indiana and Ohio, meaning it operates in both MISO and PJM. One of its prospective owners, GIP, has no current MISO utility-scale generation exposure, as detailed above. However, in PJM, GIP has stakes—through Clearway—in several large projects, including Mount Storm Wind Farm and Black Rock Wind Farm (not to be confused with BlackRock the firm), both in West Virginia.[26] AES' other prospective owner, EQT, fully owns Cypress Creek Renewables, which operates several projects in PJM and MISO as well.[27] The largest Cypress Creek project in PJM territory is Cobalt Solar in Pennsylvania, while the largest in MISO territory is McDonald Solar in Indiana.[28]

Current holdings are small and/or limited to developers whom PE firms do not fully control. As evidenced by the size of interconnection queues across all ISOs and RTOs in the U.S., though, there is enormous commercial interest in building generation. Developers like Clearway, Invenergy, and Cypress Creek are positioned to greatly expand their footprints, and investors may seek stakes in other developers as well. And private firms that *are* large players in generation, like Brookfield, may look to buy utilities themselves.

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[22] "NRG Completes Sale of Renewables Platform to GIP | Utility Dive," https://www.utilitydive.com/news/nrg-completes-sale-of-renewables-platform-to-gip/531429/.

[23] Clearway Energy Group, "Generator Interconnection Queue Improvements Proposal," Midcontinent Independent System Operator (MISO), August 9, 2023, https://cdn.misoenergy.org/Clearway%20Energy%20Group%20Feedback%20on%20PAC%20GI%20Queue%20Improvements%20Proposal%20(PAC-2023-1)%20(20230719)629932.pdf.

[24] "Blackstone Raises Investment in Invenergy Renewables to $4 Billion," https://www.reuters.com/sustainability/sustainable-finance-reporting/blackstone-raises-investment-invenergy-renewables-4-billion-2023-06-21/.

[25] "Invenergy Projects," https://wwww.invenergy.com/projects/our-projects.

[26] Clearway Energy, "Interactive Map," n.d., https://www.clearwayenergygroup.com/projects/.

[27] "Current Portfolio," https://eqtgroup.com/about/current-portfolio.

[28] "Cypress Creek Renewables — EIA Power Plants Database," https://www.interconnection.fyi/eia/projects/developer/Cypress%20Creek%20Renewables.

The status quo illustrates possible impacts, but real harms will intensify greatly in the near future. AGs' actions must therefore be proactive in nature. Within a single RTO, a generation-owning investor should not be permitted to purchase a utility, and a utility-owning investor should not be permitted to purchase a utility, without vigorous oversight, given the competitive concerns detailed above. Such guardrails are impossible without fact-finding, standard-setting, and relationship-building ahead of time. Waiting until after transactions are finalized and relying solely on bringing cases risks lengthy, difficult litigation against notoriously inscrutable parties.

IV. Tools and strategies for proactive intervention

In 2005, Congress repealed the Public Utility Holding Company Act (PUHCA) of 1935.[29] Under PUHCA, any firm that held meaningful operational control (above a 10-percent threshold) over a utility was deemed a holding company, and they were prevented from owning or operating interstate assets, borrowing or extracting dividends from their utility subsidiaries at unjustified rates, and overleveraging or otherwise pursuing a risky capital structure.[30] Its repeal opened the door for financial institutions and diversified companies to push investment into utilities, but it also allowed for interstate consolidation and financial gamesmanship. Private equity, with its opaque books and desire for control, is uniquely positioned to take advantage of the gap in oversight and enforcement.

The current federal antitrust regulators have taken some interest in the energy sector. On December 5, the Department of Justice filed the first settlement consent decree on an electricity merger in fourteen years, under which the energy producer Constellation Energy was forced to sell off assets within 240 days of acquiring its competitor Calpine.[31] In the same month, the Solicitor General testified against the integrated North Carolina utility Duke Energy to the Supreme Court, asserting Duke engaged in anti-competitive conduct against NTE, a rival producer;[32] Duke's petition for certiorari was denied and the two parties later settled. But smaller cases have evaded their attention.[33] States, therefore, must step in. Attorneys general have several options for rightsizing the involvement of the PE industry in the utilities sector and forestalling potential competitive abuses.

A. Engage more deeply with PUCs, both during proceedings and as a matter of course.

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[29] *Public Utility Holding Company Act of 1935: 1935-1992* (U.S. Energy Information Administration, 1993), https://www.eia.gov/electricity/archive/0563.pdf.
[30] *Id*.
[31] "Justice Department Requires Divestitures to Proceed with Constellation's Proposed $26.6 Billion Acquisition of Calpine," December 4, 2025, https://www.justice.gov/opa/pr/justice-department-requires-divestitures-proceed-constellations-proposed-266-billion.
[32] "US Solicitor General Tells Supreme Court to Reject Duke Energy Antitrust Appeal | Utility Dive," https://www.utilitydive.com/news/solicitor-general-supreme-court-to-reject-duke-antitrust-appeal/807025/.
[33] Katie Arcieri, "Duke Energy Settles Carolinas Power-Monopolization Lawsuit," March 6, 2026, https://news.bloomberglaw.com/antitrust/duke-energy-rival-power-firm-reach-deal-in-monopolization-suit.

Nineteen states within ISOs or RTOs already designate the ggeneral's office as the statewide consumer advocate,[34] allowing them to show up in front of PUCs and champion consumers. In those states, attorneys general can easily make their competitive concerns known as PUCs consider approving PE acquisitions. Doing so would elevate the matter politically but also add more depth to the conversation—most PUC deliberations to this point have not focused on competition.

In all states, though, attorneys general can work more closely with their PUC colleagues. This can be during rate cases and IRPs, as formal intervenors. But maybe more powerfully, attorneys general can be political and procedural allies. PUCs lack the resources to stand toe-to-toe with deep-pocketed PE firms. A partner in state government that is intimately versed in competition law and can contribute sheer man-hours to parse PE firms' claims could tip the scales.

B. Establish discovery roadmaps and preventive mechanisms.

For PE firms, motive and ability are clear; if they own generation within an RTO, buying a utility within the same RTO gives them opportunities to reduce competition and inflate profits. When a PE firm seeks to acquire a utility, attorneys general must both assess current potential for harm and put in place measures to limit harmful activities in the future.

The first task requires a discovery roadmap to guide front-end review. Attorneys general should look to compel private investors to disclose all generation holdings within the relevant RTO as part of this review. This disclosure should include ownership percentage and value, voting rights and board seats, and movement of key employees between affiliated organizations, among other relevant variables. It should also include research on PE ownership of other utilities, like water and natural gas, to see the impacts of the model on consumer welfare and competition in those sectors. PUCs and outside experts can collaborate on such a roadmap, to flag potential strategies PE firms might use to subtly advantage their generation assets and disadvantage rivals. If a threshold of wholesale generation market power is met, attorneys general can recommend or demand divestiture.

After acquisition approval, attorneys general must scrutinize future acquisitions in the generation market. Any generation purchased by the owner of the utility within the RTO raises competitive concerns. There are several ways to proceed— intervening during IRPs, mandating arm's-length transactions, bringing cases to FERC—but the first step is to consistently gather data on the owner's other business in the energy sector. Other data points to watch include credit facility drawdowns, debt guarantees, and T&D routes.

Blackstone's acquisition of TXNM Energy is the perfect test case. Part of TXNM is in ERCOT, as are several of Blackstone's generation holdings by way of its stake in Invenergy. The Texas Office of the Attorney General could assess Blackstone's level of influence on Invenergy's

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[34] These states are Alabama, Alaska, Arkansas, Illinois, Iowa, Kentucky, Massachusetts, Michigan, Minnesota, Mississippi, Nevada, New Mexico, North Carolina, Oklahoma, Rhode Island, South Dakota, Tennessee, Virginia, and Washington.

decision-making—subpoenaing documents as necessary—to see if Blackstone would be able to use TXNM to prop up Invenergy's ERCOT business and vice versa.

C. Suggest statutory language to legislatures.

Not all states provide the basis for robust merger review for utilities. Even some of the states that do, give this power to the PUC. Attorneys general can push state legislators to give them the specific authority to approve utility mergers alongside PUCs, instead of just receiving notice. PUCs do not have the same expertise in competition issues as attorneys general offices do, so the added layer of oversight would provide benefits.

Attorneys general can also push for interstate compacts that would help states within the same RTO coordinate policy on this issue. If states were able to work together to prevent generation in one state being used to advantage T&D in another, many of the most severe harms of PE utility ownership could be mitigated. (These compacts, however, require the approval of Congress.)

D. Press for a FERC consumer advocate and otherwise engage more robustly at FERC.

If an interstate compact is unworkable and interstate merger review is thus left to FERC, attorneys general can press FERC to create a consumer advocate. This entity would be able to convey competitive concerns during deliberations. Beyond that, though, attorneys general can provide joint written testimony before proceedings. Though FERC commissioners and staff are often lawyers, most are not trained in antitrust. A consumer advocate and/or a more involved group of attorneys general would amplify this perspective and give it credence.

E. Set up a NAAG working group with electricity law experts.

The National Association of Attorneys General (NAAG) could be an ideal forum to sketch out exact harms, roadmaps, and challenges to implementation. NAAG could set up a working group bringing attorneys general and their staff together with electricity law and competition experts. The working group could produce a white paper on best practices for authorities looking to solve the issues posed by PE investment in RTO-based utilities, with subgroups for each ISO and RTO. The current political moment creates an opportunity for attorneys general to take the reins on competition enforcement in the electricity sector.

Appendix

A. Electricity deregulation and innovation – a brief history

Over the last thirty years, the US electricity system has been buffeted by change from all directions. Originally, it was dominated by regulated utilities that enjoyed a government-sanctioned monopoly over all generation and T&D within their service territories. In 1996, the federal government began asserting its jurisdiction over the transmission network.[35] Three years later, the Federal Energy Regulatory Commission (FERC) formalized the structure for independent system operators (ISOs) and regional transmission organizations (RTOs), part of a broader campaign to make energy markets more competitive.[36] Under ISOs and RTOs, utilities were no longer able to make an ROE on generation—those assets had to be privately owned and subject to competitive auctions. This, along with retail competition, was the first fundamental rethink of the country's model of electric service. Though the grid still followed the logic that allowing competition in "poles and wires" made little economic sense—building two competing wires for one route served no purpose—generation and retail could be liberated from that logic, which did not necessarily hold true in their cases.

At around the same time, new innovations in generation were becoming increasingly viable in markets. Supply concerns with natural gas and oil, along with producer subsidies in China[37] and feed-in tariffs in Germany,[38] drove US deployment of solar power, creating scaled demand for suppliers that allowed them to lower their costs—which drove more deployment, and so on. Crucially, buildout accelerated in both the grid-scale and the distributed (rooftop) segments. Wind rode the same coattails, benefiting from tax credits in the '90s to slowly amass generation share.[39] The US energy mix started to incorporate sources of generation whose location mattered more than almost all legacy sources and whose output varied by the hour. This in turn has spurred greater interest in long-distance, high-voltage transmission lines, which cut across utility territories to efficiently bring large amounts of renewable electricity from isolated solar and wind hotspots to highly populated demand centers.

The years since have brought plenty more change. Solar and wind have been joined by batteries, a smoothing and stabilizing resource that functions, at once, as a source of supply *and*

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[35] "How Two FERC Orders Revolutionized the Power Utility Industry," December 20, 2024, https://www.bpa.gov/about/newsroom/news-articles/20241219-how-two-ferc-orders-revolutionized-the-power-utility-industry.

[36] Kenneth W. Costello and Robert E. Burns, *Regional Transmission Organizations and the Coordination of Regional Electricity Markets: A Review of FERC Order 2000* (The National Regulatory Research Institute, The Ohio State University, 2000), https://pubs.naruc.org/pub/FA860A98-9F87-51CE-66CB-99061504D141.

[37] Lei Bian et al., *China's Role in Accelerating the Global Energy Transition through Green Supply Chains and Trade* (Grantham Foundation, 2024), https://www.lse.ac.uk/granthaminstitute/wp-content/uploads/2024/02/Chinas-role-in-accelerating-the-global-energy-transition-through-green-supply-chains-and-trade.pdf.

[38] Christoph Böhringer et al., "The Impact of the German Feed-in Tariff Scheme on Innovation: Evidence Based on Patent Filings in Renewable Energy Technologies," *Energy Economics* 67 (September 2017): 545–53, https://doi.org/10.1016/j.eneco.2017.09.001.

[39] "Wind PTC Facts," *IER*, n.d., https://www.instituteforenergyresearch.org/wind-ptc-facts/.

demand. Grid-enhancing technologies (GETs) and advanced reconductoring offer solutions that maximize utilization of existing grid infrastructure and rights-of-way, potentially reducing the need for new lines. And distributed energy resources (DERs) and virtual power plants (VPPs)—which can reduce demand, provide consumers with their own power source, and send excess electricity back onto the grid—have broadened the definition of "supply" and made a previously one-way flow bidirectional.

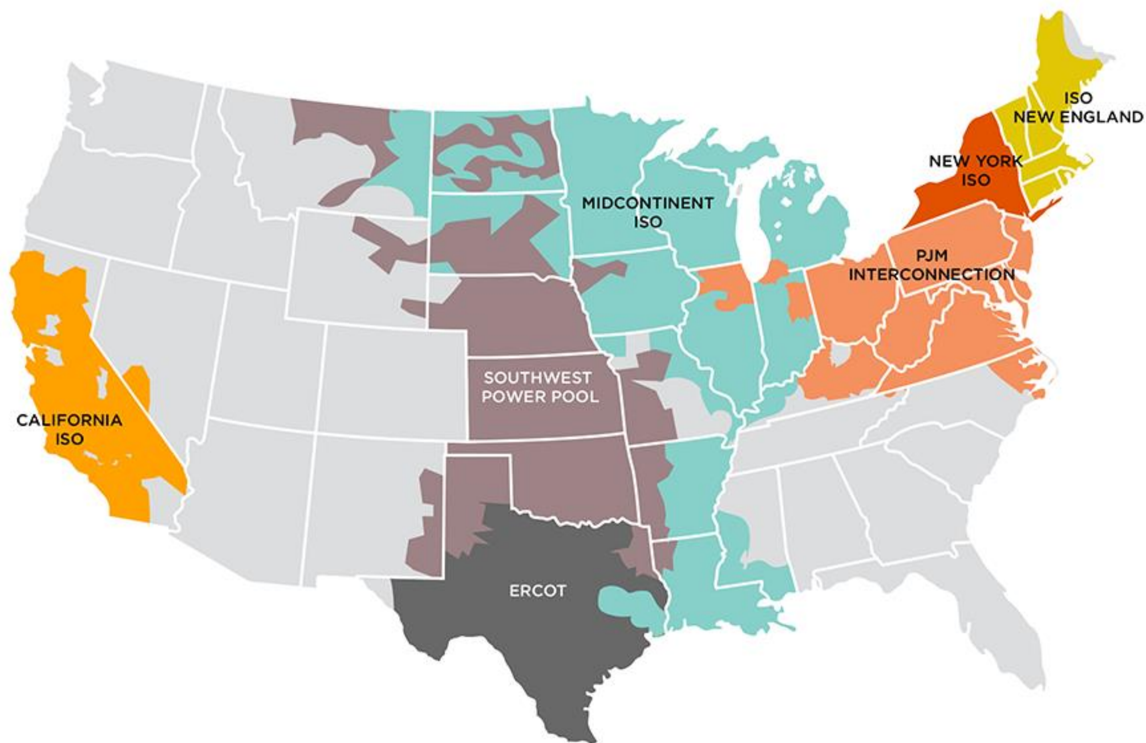
In short, utilities now are faced with a far more complex technological and regulatory landscape than utilities at the outset of the '90s. Of course, when deployed prudently, new technologies create possibilities for fewer emissions, lower cost, and greater reliability. An industry built on top of a regulatory compact to ensure a high level of customer service should evolve accordingly.

But the pace of change can, and has, created informational asymmetry. Utilities have highly granular (and sometimes proprietary) information on demand and supply, giving them windows to game markets and regulatory proceedings to their advantage. And since investor-owned utilities have monopolies over their territories and are only held in check by largely under-resourced PUCs, they can dominate regulators through sheer financial and organizational muscle. They can submit questionable demand forecasts, misrepresent the ROE needed to secure investment, flood proceedings with armies of lawyers, lobby state officials, and even influence the appointment of the commissioners themselves.

Utilities are dealing with a lot of change, but they have the wherewithal to weather it in ways that keep money coming in. PUCs are the ones that need help—and those in deregulated markets are contending with, in our view, especially underhanded tactics.

B. *Notable abuses in restructured markets*

The goal of deregulation and ISO/RTO formation was to break down generation monopolies and introduce competition. But one attendant development was the expansion, both geographically and functionally, of the field of players in energy markets. A utility in New Jersey could now access generation in Pennsylvania using the same market structures through which it would receive power from a generator a town away. And now that generation in these territories is purchased in volatile wholesale markets, complex financial instruments have emerged to hedge risk and capitalize on arbitrage opportunities. Utilities' rate bases (the projects on which utilities can seek an ROE) have narrowed in these areas, but other actors have filled in the gaps, making the threat landscape regulators face more intricate.



RTO Map, Sustainable FERC Project

Enron's California trading activities in 2000-01 are the most famous example of a bad actor exploiting opportunities in restructured markets. In operations with names like Death Star, Fat Boy, and Get Shorty, Enron used its labyrinth of subsidiaries to collect congestion relief payments for power it did not actually supply; send California power out of state and then sell it back in state at higher, "imported" prices; and pledge supply and capacity in amounts that lowered energy prices and buy it back at lower prices without actually having any supply available for dispatch. Enron harnessed California's newly deregulated market structure and pitted it against neighboring, still-integrated states to create lucrative supply crunches. This caused major reliability issues and cost increases for customers.[40]

Another example of such abuses is the FirstEnergy scandal in Ohio in the mid-2010s and early 2020s. Ohio requires its investor-owned utilities to unbundle its generation holdings from its T&D holdings, with ROE allowed on the latter and simple cost passthrough on the former. FirstEnergy, which owned both generation and T&D, was forced to create separate corporate structures for competitive generation and regulated monopoly T&D; profits were not allowed to cross the firewall. The issue arose, then, when FirstEnergy sought to use its leverage with state utility regulators to win subsidies for its nuclear and coal plants, which were generally uncompetitive in

[40] "Addressing the 2000-2001 Western Energy Crisis," https://www.ferc.gov/industries-data/electric/general-information/addressing-2000-2001-western-energy-crisis.

wholesale markets. FirstEnergy paid $60 million in bribes to the Speaker of the Ohio House and four others, along with a separate $4.3-million bribe to the chair of Ohio's PUC, for favorable treatment in proceedings and the passage of a bill that provided financial support to FirstEnergy's plants. Consumers were forced to pay for this lifeline to FirstEnergy's plants through inflated energy prices along with opaque riders that added up to about $500 million in subsidies.[41]

A problem whose contours were at least fully visible in front of and adjustable by regulators has exploded in complexity and scope. Layered jurisdictions and market structures create blind spots, which can be, and have been, exploited by bad actors. The anticompetitive and consumer welfare dangers posed by private equity takeovers of investor-owned utilities in deregulated markets are merely a modern iteration of this tendency.

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[41] "House Bill 6 Scandal Timeline: Ohio's Largest Corruption Case," *Common Cause Ohio*, April 27, 2026, https://www.commoncause.org/ohio/resources/a-cycle-of-corruption-a-timeline-of-the-householder-hb6-scandal/.

Glossary

Advanced reconductoring: Replacing existing transmission wires with higher-capacity conductors to increase power flow on existing rights-of-way.

Capital expenditures (capex): Large infrastructure investments like transmission lines and distribution equipment. Utilities earn ROE on these.

Capacity market: A market run by RTOs in which generators are paid to be available to produce power during periods of high demand, based on load forecasts. Winning bids become passthrough costs for LSEs.

Compensable curtailment: A PPA provision triggering payment to the generator if the buyer refuses delivery because projected load didn't materialize.

Distributed energy resources (DERs): Small-scale power generation or storage located at or near the point of consumption, including rooftop solar and home batteries.

Gold plating: The practice of inflating capital investments beyond what is functionally necessary in order to grow the rate base and increase regulated returns.

Grid-enhancing technologies (GETs): Software and hardware solutions that increase the capacity and efficiency of existing transmission infrastructure without requiring new construction.

Inframarginal rents: The profits captured by lower-cost generators who are paid the market-clearing price even though their costs and bids are below it. The difference between their costs and the clearing price is pure profit.

Integrated resource plan (IRP): A utility's long-term plan for meeting customer demand through a mix of generation, transmission, and demand-side resources. Filed with and approved by the PUC.

Interconnection queue: The pipeline of generation projects awaiting approval to connect to the transmission grid. Currently severely backlogged across all major RTOs.

Load-serving entity (LSE): Any entity obligated to serve end-use electricity customers, including utilities, municipal electric companies, and retail electricity providers. Purchases power on behalf of customers in wholesale markets.

Marginal cost: The cost of producing one additional unit of electricity. Generators are meant to bid into wholesale markets at marginal cost.

Market-clearing price: The price paid to all dispatched generators in a given market interval, set by the most expensive generator called upon to meet demand.

Merit order: The ranking of available generators from lowest to highest marginal cost. RTOs dispatch generators in this order, calling on the cheapest resources first.

Operational expenditures (opex): Day-to-day operating costs like generation purchases (for utilities in RTOs), labor, and maintenance. Passed through to ratepayers at cost with no profit margin.

Power purchase agreement (PPA): A contract between a generator and an LSE for electricity delivery at a set price over a defined period.

Rate base: The total value of a utility's capital investments on which it is permitted to earn an ROE. Utilities have strong incentives to grow their rate base.

Return on equity (ROE): The profit margin regulators allow utilities to earn on capital investments. Applied to transmission and distribution assets, not generation in restructured markets.

Ring-fencing: Regulatory provisions that financially and operationally separate a regulated utility from its parent company and affiliates, preventing cross-subsidization.

Regional transmission organization (RTO)/independent system operator (ISO): A federally regulated, independent entity that operates the transmission grid and runs wholesale electricity markets across a multi-state region. RTOs and ISOs are functionally equivalent; the distinction is largely historical. Major examples include PJM Interconnection, the Midcontinent Independent System Operator (MISO), ISO New England, and the Electric Reliability Council of Texas (ERCOT).

Take-or-pay clause: A PPA provision requiring the buyer to pay a minimum amount regardless of whether it actually takes the contracted electricity.

Virtual power plant (VPP): An aggregation of distributed energy resources coordinated to act collectively as a single dispatchable generator in wholesale markets.