

DATA CENTER ENTRY AND U.S. ELECTRICITY PRICES: FROM THE WHOLESALE MARKET TO THE POWER BILL

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Executive Summary

Data centers are the fastest-growing source of new electricity demand in the United States. Reserve margins have declined and both wholesale and retail power prices have surged in recent years, (2025 NERC LTRA, published in 2026). These trends prompt an important question: What role have data centers played in driving power prices higher?

We address this question by tracing price effects across wholesale prices at individual grid-node wholesale prices, regional wholesale prices, and retail electricity rates. Although large data-center operators often use long-term contracts, electricity is still delivered through a shared grid, and prices respond to total system demand.

Using high-resolution wholesale pricing data from 2020–2025 and utility-level retail data from 2015–2025, we estimate these effects across three geographic scales.¹ At the wholesale node level, data-center entry is associated with higher nearby congestion costs of approximately \$1.45–\$2.30/MWh. At the wholesale zone level, entry is followed by an overall price increase of approximately \$3.44/MWh in the year after entry, driven by a \$5.43/MWh increase in the energy component. This is a pattern consistent with additional demand requiring higher-cost marginal generation to be dispatched.

At the retail level, growth in operating data-center capacity is associated with a small but measurable increase in residential electricity prices: A doubling of a utility's operating data-center capacity is associated with an approximately 0.65 percent increase in residential prices, with no statistically significant association for commercial or industrial rates. At a representative residential electricity price of \$0.16–\$0.17/kWh (U.S. Energy Information Administration, 2026), this translates to approximately \$1.00–\$1.06/MWh, or \$0.001–\$0.00106/kWh.²

However, the retail price impact is concentrated among electric cooperatives and municipal utilities. There is no significant effect of data center entry on investor-owned utilities' (IOUs) retail rates, which serve 68 percent of the U.S. population. Cooperative residential prices increase by approximately 0.42 percent when operating data-center capacity doubles, or roughly \$0.67–\$0.71/MWh, while municipal prices increase by 0.63 percent, or roughly \$1.01–\$1.07/MWh.

Limitations include focusing on empirical patterns from recent years, not on what will happen as the announced pipeline materializes. The estimates are best interpreted as recent entry effects in markets with varying degrees of prior data-center exposure.

These results provide context for current policy debates over data-center interconnection, rate design, and resource adequacy. The wholesale price pressure documented here is consistent with a tightening supply-demand balance in affected wholesale zones. Financial hedging instruments and grid-scale battery storage can help manage short-run exposure to price volatility, but they do not eliminate the underlying need for sufficient generation and transmission capacity to meet growing demand.

1. Introduction

The rapid expansion of data center infrastructure has become one of the most consequential developments in U.S. electricity markets. Data center facilities operated by major technology companies (e.g., Amazon, Microsoft, Google, and Meta), as well as colocation providers (e.g., Equinix, Digital Realty), now represent substantial and growing shares of electricity demand in several regional transmission organizations (RTOs). Looking forward, demand growth is projected to accelerate. For example, PJM projects that peak electricity demand will increase by more than 50 GW by the mid-2030s, driven primarily by data centers; MISO is expected to face approximately 18 GW of data center load by 2035, while thermal generation capacity has declined by 8.8 GW (NERC, 2026). At the same time, NERC also projects that anticipated reserve margins in several regions will fall below required levels, raising concerns about system reliability.

Such rapid growth in data center capacity raises policy concerns. If data center load raises electricity prices, communities hosting these facilities (and retail customers more broadly) may bear the cost of a private infrastructure buildout whose benefits accrue elsewhere. Understanding the magnitude and mechanism of this price effect is essential for regulators designing interconnection queues and capacity markets, utilities managing cost recovery, and policymakers weighing data center development incentives against ratepayer burdens.

A key institutional feature shapes how these effects operate. Large data-center operators often use long-term contracts, including physical or virtual power purchase agreements, to manage electricity costs and procure renewable energy.³ However, these contracts do not remove data centers from the physical power system. Electricity is generally delivered through the regional grid or local utility, so large data-center loads can still affect market prices and grid costs. In organized wholesale markets, locational marginal prices (LMPs) reflect the marginal cost of serving an additional unit of load at a specific location, including a system-wide energy component and location-specific congestion and loss components (ISO New England, n.d.). Because these components respond differently to changes in demand, data-center entry may affect prices across locations and over time through multiple channels. The extent to which wholesale price changes are reflected in retail rates depends on utility procurement practices, long-term contracts, hedging strategies, and rate regulation. Such factors can attenuate pass-through to end users.

Recent news articles have documented these effects at scale: Bloomberg Technology analysis of approximately 25,000 LMP nodes across seven RTOs found that, of nodes recording wholesale price increases between 2020 and 2025, more than 70 percent were located within 50 miles of significant data center activity (Saul et al., 2025). The New York Times documents the regulatory response, reporting that Ohio and Virginia have created data-center-specific rate classes requiring large data centers to pay for most of their contracted capacity (Penn & Weise, 2025).

Academic and technical work has begun to quantify these effects with causal designs. Mamkhezri et al. (2026) use propensity score matched difference-in-differences (a method that compares treated areas to similar untreated areas before and after data center entry) at the census-tract level within Virginia to show that data center entry raises the transmission-induced component of LMP by \$2.49 per MWh, approximately 70 percent above pre-treatment levels. Kay et al. (2026) use a dispatch model (i.e., a simulation of how grid operators choose which generators to run) to estimate that existing data centers have already raised wholesale prices by 3 to 5 percent nationally, with projected increases of 20 to 50 percent by 2028, depending on build-out and utilization assumptions.

While this evidence points to upward pressure in wholesale markets, the implications for retail electricity prices are more difficult to isolate. Retail rates reflect not only wholesale energy and capacity costs, but also transmission and distribution investment, fuel and purchased-power costs, operations and maintenance, wildfire-related costs, and state policy costs. Emerging evidence nevertheless suggests that data-center load can contribute to retail-price pressure in some settings, especially through wholesale-market pass-through, capacity-market costs, grid-upgrade costs, and localized utility cost allocation.⁴ Charles River Associates (DeCoursey & Saraswat, 2026) attributes most 2020–2024 retail rate increases in the Northeast to higher wholesale electricity market prices and rising purchased-power costs, and most of those in California to wildfire and wildfire-mitigation spending. The report notes that, with the exception of recent PJM capacity-market pass-through (where expected data-center demand was a contributing factor), data centers have not been a primary driver of observed retail rate increases.

Lawrence Berkeley National Laboratory's recent retail-price work provides a broader context for interpreting data-center-related effects. Forrester et al. (2024) identify fuel and purchased-power costs, operations and maintenance, and capital expenditures as major recent sources of utility cost growth, including rapid growth in distribution capital expenditures from 2019 to 2023. Wiser et al. (2025) provide a broader synthesis of recent retail-price drivers, including transmission and distribution investment, natural-gas price fluctuations, load growth, renewable portfolio standard (RPS) programs, rooftop solar,

and other state policies. They also discuss data centers as part of the broader load-growth and market-tightening channel, rather than estimating data-center-specific price effects.

Our three analyses follow the price-formation process from the most granular point of grid impact to the final residential retail electricity price (Figure 1). Wholesale prices are set first at transmission nodes, where local supply-demand balance determines congestion and energy components. These nodal prices aggregate to zone-clearing prices that load-serving entities pay. Retail rates are then determined by utility-specific cost recovery added to those wholesale prices. We estimate effects at each stage in turn.

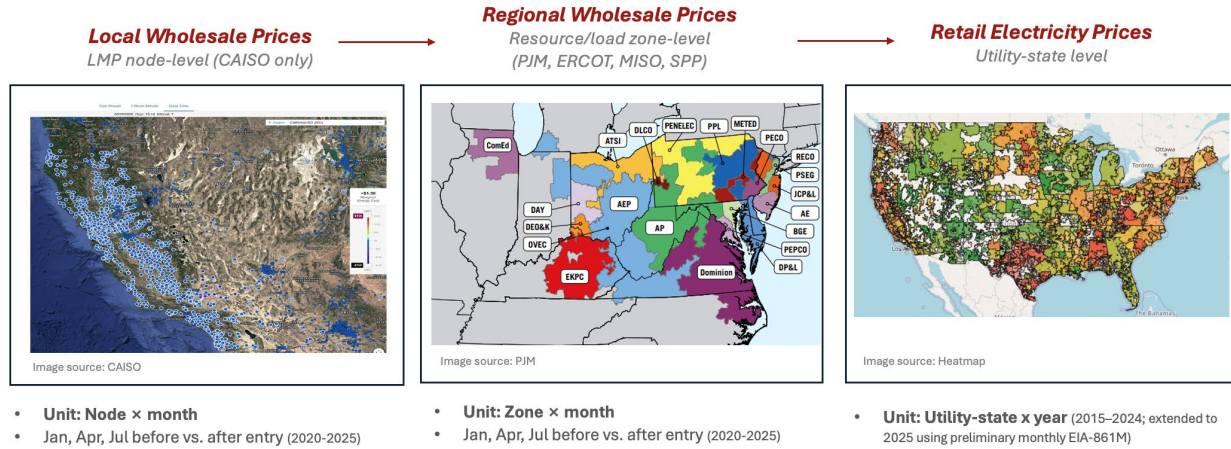


Figure 1. Three-stage price-formation framework. The brief estimates data center entry effects at three geographic scales: transmission nodes (CAISO, the California Independent System Operator), wholesale price zones (PJM, ERCOT, MISO, SPP), and utility service territories (national).

First, we document the **CAISO node-level congestion effect**. Each facility is matched to its nearest CAISO LMP nodes, and we estimate a stacked difference-in-differences design comparing prices near data-center entries to prices at not-yet-treated nodes within the same entry window. Data center entry is associated with a \$2.30/MWh increase in the congestion component of LMP, consistent with a local transmission-constraint channel and with evidence from Virginia under a different market structure (Mamkhezri et al., 2026).⁵ The energy component remains statistically unchanged at the node level, consistent with CAISO’s locational marginal pricing structure, in which the system marginal energy price is common across nodes while congestion and marginal-loss components vary spatially.

Second, we estimate **zone-level wholesale price effects across four major Non-CAISO RTOs** (PJM, ERCOT, MISO, and SPP) using an analogous binary first-within-panel-entry design, implemented as a stacked DiD across cohorts (each cohort is a zone-entry-year pair). Because every Non-CAISO RTO already hosted operational data centers before our 2020–2025 panel begins, some treated zone entries may be marginal additions to already-exposed areas rather than true first-ever zone entries. The design therefore identifies first-within-panel entry effects, holding pre-existing zone characteristics fixed through zone fixed effects.

Per-event price effects (i.e., the average zone-level price change in the year following a data center entry event, across 58 such events) are: Total LMP +\$3.44/MWh ($p < 0.01$), with the energy component carrying essentially the entire response (+\$5.43/MWh, $p < 0.001$) and congestion and loss components statistically indistinguishable from zero. The energy-component dominance reflects the dispatch-commitment mechanism described above: at a given fuel price, additional committed load forces dispatch of more expensive marginal generation, raising the zone-clearing price uniformly across the zone. Where the node-level result captures local transmission constraints, the zone-level result reveals a complementary channel operating through marginal generation cost.

Third, we examine **retail price associations across utility ownership types**. Using a utility-state-year panel from 2015 to 2024 with controls for fuel mix, coal and nuclear retirements, Renewable Portfolio Standard (RPS) compliance costs (i.e., state-level mandates that utilities source a minimum share of electricity from qualifying renewable sources), and reserve margins, we find that growth in operating data center load (“DC MW” henceforth) is associated with an increase in residential prices (approximately 0.65 percent increase as the operating data center capacity doubles or roughly \$1.04–\$1.10/MWh at a representative residential price of \$0.16–\$0.17/kWh) but has no detectable effect on commercial or industrial prices. The effect is concentrated among cooperative and municipal utilities rather than investor-owned utilities (IOUs), consistent with structural differences in size, market exposure, and procurement sophistication. The estimated retail association is strongest among smaller utilities, a pattern consistent with exposure to zone-clearing energy prices even where utilities are not the primary hosts of large data-center facilities. These patterns are similar when we extend the analysis to 2025 (\$1.00–\$1.06/MWh increase) using preliminary monthly data from EIA.

This report decomposes the price effect of data center entry across three geographic scales (i.e., grid node, wholesale zone, and utility service territory) and identifies which price component moves at each scale: congestion at the node, the system energy price at the zone, and a small but detectable residential pass-through concentrated among smaller utilities at the retail level. This decomposition traces the dispatch-commitment mechanism described above from the interconnection point to the household bill and reconciles findings in the existing literature that have measured pieces of this chain in isolation.

2. Data

2.1 Data Center Database

The primary source is the S&P Global 451 Research (reflects updates as of Q2 2025), which records facility-level utility power capacity (kW), operational status, build year, and coordinates for operational hyperscale and colocation facilities, excluding cryptocurrency miners, powered shells, and telecom facilities.

For the wholesale analysis, each facility is spatially matched using its latitude/longitude coordinates: to its five nearest CAISO transmission nodes (by geodesic distance) for the node-level analysis, or to non-CAISO RTO pricing zones using the published zone shapefiles from PJM, ERCOT, MISO, and SPP for the zone-level analysis.

For the retail analysis, facilities are spatially matched to utility service territories using the Homeland Infrastructure Foundation-Level Data (HIFLD) electric retail service territory shapefile.⁶ The full point-in-polygon match generates multiple candidate utilities for many facilities because HIFLD service-territory polygons overlap (investor-owned envelopes typically extend over rural areas that are actually served by cooperatives or municipals as carve-outs). In such cases, a facility was matched to the utility whose polygon strictly contains the facility's location, prioritizing retail providers over wholesale-only territories. The treatment variable is the sum of operating capacity (in MW) of all matched facilities in a utility's service territory in a given year.

2.2 Electricity Price Data

Wholesale Local Prices, CAISO. Five-minute LMPs and their components (energy, congestion, and losses) are obtained from GridStatus and aggregated to monthly medians. For CAISO, prices are measured at the node level, where each data center facility is matched to its five nearest transmission nodes using geodesic distance.⁷ The resulting panel covers January, April, and July for each year from 2020 through 2025 and includes 319 unique nodes, with 365 California data center facilities mapped to these nodes (77 of which are the closest match to at least one facility).

Wholesale Regional Prices, Non-CAISO. For PJM, ERCOT, MISO, and SPP, wholesale LMP data are obtained through GridStatus for the same three sample months and years as the CAISO panel. Five-minute prices are aggregated to monthly medians and then to the load-zone level using published node-to-zone or settlement-point-to-zone mappings. Data center facilities are assigned to zones using geographic shapefiles.⁸ The combined non-CAISO panel spans 55 load zones: 23 in PJM, 18 in SPP, 10 in MISO, and 4 in ERCOT.⁹

Retail Prices. EIA Form 861 annual utility revenue and sales, 2015-2024. Form 861 reports revenue and sales by customer class separately for each state of utility operation; we compute residential, commercial, industrial, and total prices as revenue divided by sales (cents per kWh) within each utility-state-year. We retain 1,798 utilities across 51 jurisdictions, restricting to bundled-service utilities reporting ownership-type data, and dropping utilities that appear in fewer than 3 years of the panel.¹⁰ The panel is unbalanced, with 16,163 utility-state-year observations across the ten-year window. Multi-state utilities (e.g., PacifiCorp, which operates in CA, ID, OR, UT, WA, and WY under a single utility ID) contribute one observation per state of operation, with state-specific prices and identical utility-level data center capacity.¹¹ We extend the panel through 2025 using Form EIA-861M, the Monthly Electric Power Industry Report, a preliminary monthly collection from a statistically chosen sample of EIA-861 respondents weighted toward larger utilities (see Appendix Section A4 for details).

We extend the panel by one year (through 2025) using Form EIA-861M, the Monthly Electric Power Industry Report (i.e., a preliminary monthly collection from a statistically chosen sample of utilities weighted toward larger utilities; see Appendix Section A4 for details).¹² The 2025 monthly observations are aggregated to annual utility-state-year cells (summed revenue and sales, recomputed price). After applying the same restrictions as for 2015–2024, the 2025 cross-section contains 309 unique retail utilities and 452 utility-state-year observations, adding 393 new observations to the panel.

2.3 Control Variables

Fuel mix. Utility-level gas, coal, nuclear, and renewable generation shares were obtained from EIA Form 923.¹³ Specifically, we aggregate net generation within each utility-year by reported fuel type, and compute shares as fuel-specific generation divided by total generation. For utilities that do not generate themselves (~75 percent of the sample, which are distribution-only), we fall back to state-year shares aggregated from the same sheet. The 2025 extension uses the monthly release and applies the same logic, cross-validated against state-level data from LBNL(Wiser et al., 2025).

Coal and nuclear retirements. Coal and nuclear retired capacity, measured in MW per utility-year, is sourced from EIA Form 860. We include coal and nuclear retirements because they proxy for the loss of large, dispatchable baseload resources that historically supplied substantial energy at relatively stable operating costs. Their retirement can tighten the supply-demand balance and require greater reliance on higher-cost marginal resources, creating upward pressure on wholesale prices that may pass through to retail rates. Gas retirements are excluded because retired gas capacity is more likely to include flexible mid-merit or peaking units, making it a less direct proxy for the loss of baseload supply.

RPS compliance controls. We use state-year renewable portfolio standard (RPS) measures from Wiser et al. (2025), matched to utilities by state and year. RPS programs require utilities or load-serving entities to procure a minimum amount or share of electricity from qualifying renewable resources. We include two related controls: incremental RPS generation, which captures the additional renewable generation associated with those requirements, and RPS compliance-cost intensity, which captures the estimated cost pressure of meeting them. States without an active RPS policy are coded as zero.

Reserve margin. Anticipated Reserve Margin (%) from NERC Summer Reliability Assessments (SRA), matched by assessment area and year.

Natural gas spot price. Monthly Henry Hub spot price (\$/MMBtu) from the U.S. Energy Information Administration, used as the marginal-fuel-cost control in the wholesale and retail specification.¹⁴ The series ranged from \$1.74/MMBtu in April 2020 to \$8.81/MMBtu in August 2022 across the panel window, reflecting the 2022 European gas-price crisis.

3. Methods

3.1 Wholesale Node-Level: CAISO Stacked DiD

Each facility is matched to its five nearest CAISO transmission nodes using geodesic distance. Treatment is the first month a facility becomes operational at that node. We estimate specifications with node-month and entry-year fixed effects, standard errors clustered at the node level.¹⁵

We construct a node-month panel covering CAISO transmission nodes from January 2020 through December 2025. Each data center facility is matched to its five nearest CAISO LMP nodes by geodesic distance, with the facility's MW capacity allocated across nodes using inverse-distance weights (normalized to sum to one within each facility). Treatment is defined at the node level: a node is "post-entry" in calendar year t if any matched facility is operational at that node by year t , and "pre-entry" otherwise. We restrict the sample to nodes that experience at least one entry event during the panel window, which allows a within-node pre/post comparison.

We estimate two specifications. The "all-entry" specification compares post-entry node-months to pre-entry node-months across the full panel of treated nodes, treating every facility-level entry event during the 2020–2025 panel as a treatment. The "first-entry" specification restricts the post-period to the year following each node's first within-panel entry event, isolating the marginal effect of the initial observed data center commitment at a node. As with the zone-level design (Section 3.2), "first-entry" here means the first entry observed in our 2020–2025 sample window, not necessarily the first-ever entry at that node; some CAISO nodes may have hosted facilities prior to 2020.

Entry events used in both specifications are restricted to those with both $E-1$ and $E+1$ observable within the panel window (i.e., entry years 2021–2024). Both specifications use the same fixed-effect structure: node $\times$ month-of-year fixed effects (which absorb time-invariant node characteristics and node-specific seasonal patterns) and entry-year fixed effects (which absorb CAISO-wide shocks common across cohorts within a given calendar year). Standard errors are clustered at the node level.

The estimating equation for component $c \in \{\text{LMP, congestion, energy, loss}\}$ is:

$$c_{n,t} = \beta \cdot \text{Post}_{n,t} + \alpha_{n,m(t)} + \tau_{e(n)} + \varepsilon_{n,t}$$

where c indexes the four LMP components (LMP, congestion, energy, loss), n indexes nodes, t indexes year-month, $m(t)$ is the calendar month of t , $e(n)$ is the entry year of node n , $\alpha_{n,m(t)}$ are node $\times$ month-of-year fixed effects, and $\tau_{e(n)}$ are entry-year fixed effects. The coefficient β is the average within-node difference in component c between post-entry and pre-entry months, after absorbing seasonal and entry-year patterns.¹⁶ $\varepsilon_{n,t}$ is the residual node-month error.

3.2 Wholesale Zone-Level: Stacked DiD

A cohort is a (zone, entry year) pair in which new data-center capacity enters a price zone within our 2020–2025 sample window. Entry is the first recorded entry in a zone-year. As with the CAISO node-level analysis, these are first-within-panel entries, not necessarily first-ever entries. Because every Non-CAISO RTO in the sample already hosted operational data centers before 2020, some treated zone entries may be marginal additions to already-exposed areas rather than true first-ever zone entries. The design therefore identifies first-within-panel entry effects, holding pre-existing zone characteristics fixed through zone fixed effects.¹⁷ For each cohort, we construct a 2×2 panel: the zone in the year before entry (relative year -1,

Post=0) and the year after (relative year +1, Post=1), stacked with the control group (i.e., zones that had not yet experienced any entry event as of the cohort's treatment year).

We specify treatment primarily as a *binary* indicator for the year after data-center entry, rather than scaling treatment continuously by MW. This choice reflects the institutional mechanism we seek to estimate: a new data-center commitment can enter ISO demand forecasts as a discrete addition to baseline load, requiring additional generation commitment even when the exact MW size varies across facilities. The binary coefficient should therefore be interpreted as the average per-entry-event price effect, not as a linear per-MW effect and not as a parameter that can be mechanically extrapolated to future GW additions. We nevertheless test the alternative continuous interpretation directly (Appendix Table A2).

Similar to the node level, we estimate the specification separately for each LMP component $c \in \{\text{LMP, congestion, energy, loss}\}$. The estimating equation for component c is:

$$c_{rtm} = \beta \cdot \text{Post}_{rt} + \text{HH}_t \gamma + \alpha_r + \delta_m + \mu_t + \varepsilon_{rtm}$$

Zone (α_r), month (δ_m), and entry-year (μ_t) fixed effects are included. The dependent variable c_{rtm} is the relevant LMP component (Total LMP, energy, congestion, or loss) for zone r in month m of year t ; HH_t is the monthly Henry Hub spot price, and γ is its coefficient. Standard errors are clustered at the cohort level (58 clusters in the primary specification). Time-varying supply-side controls (retirements, reserve margin) are not included in the baseline specification because they are observed at the RTO-year level, while the panel is at the zone-month level. ε_{rtm} is the residual zone-year-month error.

3.3 Retail Panel: Two-Way Fixed Effects

The retail specification is:

$$\ln(\text{Price}_{ut}) = \beta \cdot \ln(\text{DC_MW}_{ut} + 1) + X_{ut}\gamma + \alpha_u + \tau_t + \varepsilon_{ut}$$

where the coefficient β represents the within-utility change of price with respect to operating data center capacity (DC_MW_{ut}): a one percent increase in data center MW is associated with a β percent change in price.¹⁸ The by-ownership specification estimates separate β coefficients for the three largest ownership categories (i.e., cooperative, municipal, and investor-owned), which together serve approximately 96 percent of U.S. retail customers in our 2024 panel, according to the 2024 EIA Form 861. The remaining ~4 percent are served by political subdivisions, state, and federal utilities; these utilities enter the pooled regression but not the ownership-specific β estimates.

The vector $X_{ut}\gamma$ contains time-varying utility-, state-, and grid-level controls, such as the gas share and the renewable (wind and solar) share of generation, coal and nuclear retirement, RPS incremental generation, RPS cost intensity, and the anticipated reserve margin. The Henry Hub spot price is absorbed by the year fixed effect at the level and tested as a Henry Hub $\times$ state-mean-gas-share interaction in Appendix Table A3a; the DC coefficient is unchanged. α_u denotes utility fixed effects, and τ_t denotes year fixed effects.¹⁹ Standard errors are clustered at the state level. ε_{ut} is the residual utility-year error.

The unit of observation is the utility-state-year; multi-state utilities contribute one observation per state of operation following EIA Form 861's reporting structure, with state-specific retail prices but identical utility-level data center capacity. As Yue and Zeng (2026) emphasized in a county-level setting, retail price effects of data center entry can spill across boundaries that do not align with the treatment unit; for multi-state utilities in our panel, the within-utility-across-state observations are not strictly independent. Sensitivity analyses with utility $\times$ state fixed effects, with single-state utilities only, and with multi-state utilities can be found in the Appendix Table A3.

4. Results

4.1 Wholesale Node-Level Effects (CAISO)

At the CAISO node level, data center entry is associated with an increase in the congestion component of LMP: +\$1.45/MWh in the all-entry specification ($p < 0.001$) and +\$2.30/MWh in the first-entry specification ($p < 0.001$). Both estimates are highly statistically significant. The energy component is statistically null at the node level (point estimates of $-\$5.79$ and $-\$4.77$ /MWh, both indistinguishable from zero). This pattern is consistent with CAISO's uniform system energy price across nodes; node-level variation is confined to congestion and marginal losses.

The first-entry result (+\$2.30/MWh, $p < 0.01$) differs by pre-2020 matched data-center exposure. Among the 40 treated nodes in the first-entry sample, 27 had no matched pre-2020 data center, while 13 were already matched to at least one pre-2020 data center and received an additional entry during the sample period. The congestion response is smaller and statistically insignificant among nodes with no matched pre-2020 data center ($\beta = +\$0.97$ /MWh, $p = 0.20$), but larger among already-exposed nodes ($\beta = +\$5.07$ /MWh, $p < 0.01$). This pattern suggests that local congestion effects are strongest where additional data-center load is added to nodes that may already be closer to transmission constraints.

The Total LMP point estimates are negative but statistically indistinguishable from zero in both specifications, reflecting noise in the energy and loss components rather than evidence of a price decline. The consistent result is that the only LMP component that moves systematically after entry is localized congestion. The next section examines a complementary price channel at the zone level, where data-center entry is associated with changes in the energy component of LMP.

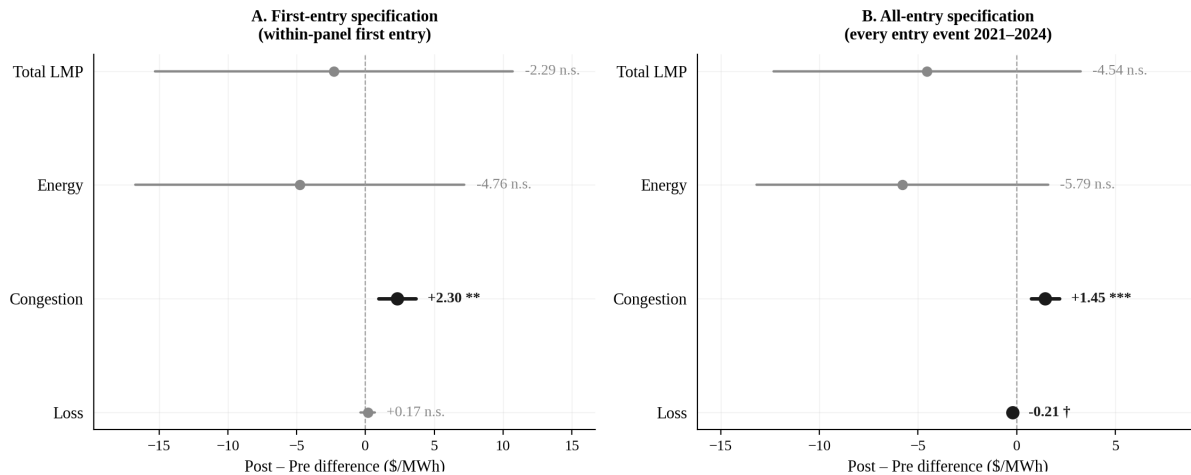


Figure 2. Stacked DiD on the CAISO node-month panel (2020–2025), shows that data center entry is associated with a \$2.30/MWh increase in the congestion component of LMP in the first-entry specification ($p < 0.01$) and a \$1.45/MWh increase in the all-entry specification ($p < 0.001$). The first-entry specification restricts the post period to the year following each node's first within-panel entry event; the all-entry specification treats node-level entry events (i.e., one or more data center entries) as a treatment.

As a complement to the binary first-entry design, we also estimate a per-MW slope on cumulative operating data-center MW in the same node-month panel (2020–2025, 96 treated nodes, $N = 1,695$). The continuous specification estimates a positive per-MW association between cumulative operating data-center capacity and the congestion component: $\beta = +\$0.0195$ /MWh per MW of cumulative operating DC capacity at the

node ($p < 0.001$). At the mean cumulative data-center load of 12.8 MW per treated node-month, the continuous specification implies a congestion effect of approximately \$0.25/MWh, far below the binary first-entry estimate of \$2.30/MWh. This suggests that the node-level congestion response is not well summarized by a simple linear per-MW relationship. LMP, energy, and loss components remain statistically null in the continuous specification, consistent with CAISO's uniform system-energy pricing across nodes.

4.2 Wholesale Zone-Level Effects (Non-CAISO)

The zone-level stacked DiD results are summarized in Figure 3 and reported in full in Appendix Tables A1 and A2.

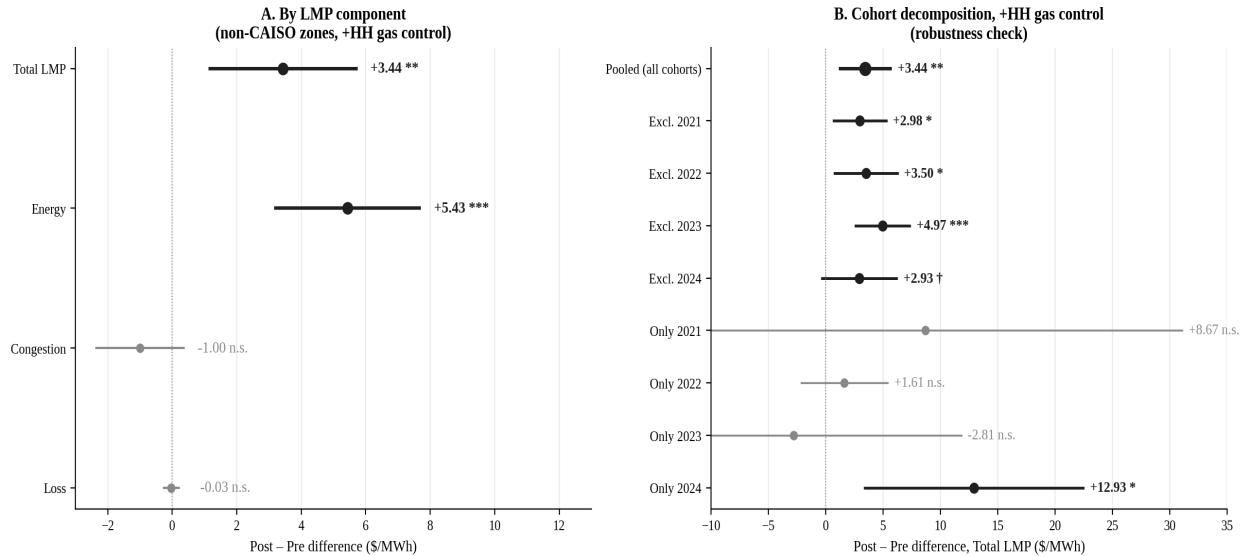


Figure 3. Stacked DiD on the year prior to and after entry. Zone, month, entry-year FEs (entry-year FE dropped in single-cohort specifications). Standard errors clustered at the cohort level. 95 percent CI shown. † $p < 0.10$ ** $p < 0.01$ *** $p < 0.001$. n.s. = not significant.

Our primary specification (Figure 3, Panel A) pools all entry cohorts and controls for monthly Henry Hub spot prices to absorb the substantial gas-price variation that coincided with the 2021–2024 entry window (Henry Hub ranged from \$1.74/MMBtu in April 2020 to \$8.81/MMBtu in August 2022).²⁰ Per-event price effects are: Total LMP +\$3.44/MWh ($p < 0.01$), energy component +\$5.43/MWh ($p < 0.001$), with congestion and losses statistically indistinguishable from zero. The Henry Hub coefficient itself is +\$8.39/MWh per \$1/MMBtu of gas, consistent with a typical gas-marginal heat rate of 7–8 MMBtu/MWh.

The result is robust to cohort exclusion (Figure 3, Panel B): leave-one-out estimates range from +\$2.93 to +\$4.97 for Total LMP and from +\$4.52 to +\$8.21 for the energy component (Appendix Table A2). It is also stable across entry size: smaller-than-median entries (<59 MW) and larger-than-median entries (≥59 MW) produce statistically indistinguishable per-event effects. We also estimate a continuous MW specification as a functional-form check. The continuous specification produces a much smaller implied effect at typical entry sizes than the binary entry estimate, suggesting that the wholesale price response is not well summarized by a simple linear per-MW relationship. Together, these results support interpreting the binary coefficient as an average per-entry-event effect rather than a scalable per-MW effect.

The mechanism is unchanged across specifications: the energy component is the channel through which entry moves wholesale prices, while congestion is null at the zone level both with and without the gas control. This pattern is consistent with data centers selecting into zones with low existing congestion and with the institutional mechanism described in Section 1: at a given fuel price, additional committed data-

center load can require dispatch of more expensive marginal generation, raising the zone-clearing energy price for all load-serving entities. Additional results, including the LMP-component decomposition, the cohort decomposition with and without gas control, the small/large entry-size split, and the continuous MW specification, are reported in Appendix Tables A1 and A2.

4.3 Retail Price Effects

The retail residential results show a small but consistent association between data-center growth and household electricity prices. In the primary 2015–2024 specification, operating data-center capacity is positively associated with residential prices ($\beta = 0.0094$, $p < 0.001$; Appendix Table A3), while accounting for utility and year fixed effects and controlling for generation mix, retired coal and nuclear capacity, RPS exposure, and anticipated reserve margins, with standard errors clustered by state. Because the treatment is measured as $\ln(\text{DC MW} + 1)$, where DC MW is cumulative operating data-center capacity in megawatts, the coefficient implies that the 100 percent increase in operating capacity is associated with about a 0.65 percent increase in residential prices, or roughly \$1.04–\$1.10/MWh at a representative residential price of \$0.16–\$0.17/kWh. The result is robust to alternative fixed-effect structures, single- and multi-state utility samples, and an additional Henry Hub gas price exposure control (see Appendix Section A3). Such a pattern is consistent in the preliminary 2015–2025 extension, where the pooled coefficient remains similar ($\beta = 0.0090$, $p < 0.01$), implying an increase of about 0.62 percent, or roughly \$1.00–\$1.06/MWh, when operating capacity doubles (Appendix Table A4a).

The ownership split shows that the retail association is concentrated outside the investor-owned utility sector in both estimation windows. In the primary 2015–2024 sample, an approximate doubling of operating data-center capacity is associated with about a \$0.74–\$0.79/MWh increase in cooperative residential prices ($\beta = 0.0067$) and a \$0.89–\$0.94/MWh increase in municipal residential prices ($\beta = 0.0080$), while the IOU estimate is small and statistically insignificant (\$0.07–\$0.08/MWh; $\beta = 0.0006$). The preliminary 2025 extension suggests a similar pattern: municipal utilities show the largest implied increase, about \$1.01–\$1.07/MWh ($\beta = 0.0091$), followed by cooperatives at about \$0.67–\$0.71/MWh ($\beta = 0.0060$), while the IOU estimate is nearly zero ($\beta = 0.0001$) (see Appendix Table A4b for both specifications).

This ownership pattern is economically important because IOUs serve roughly 68 percent of U.S. retail electricity customers, compared with about 16 percent for cooperatives and 11 percent for municipal utilities, based on 2024 EIA Form 861 data. But cooperatives and municipal utilities have a broader rural and small-city footprint; cooperatives alone cover roughly 56 percent of the U.S. land area (National Rural Electric Cooperative Association, 2025). This pattern is therefore consistent with partial pass-through of wholesale price pressure to residential customers in smaller utility systems, although the estimates remain conditional within-utility associations rather than definitive causal pass-through effects. Figure 4 plots the full set of coefficient estimates.

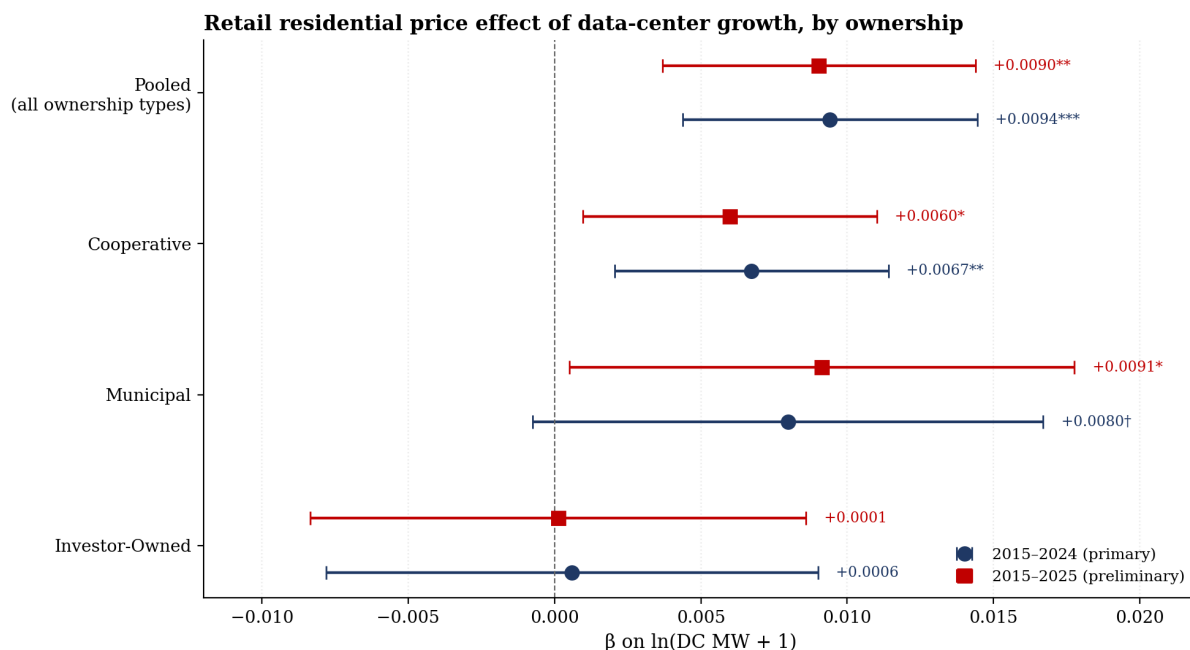


Figure 4. Two-way fixed effects estimates of the residential price effect on $\ln(\text{DC MW} + 1)$, full sample and by ownership type, plus total price across all customer classes. The dependent variable is the natural log of utility-state-year residential electricity price (cents per kWh) from EIA Form 861. Estimates are reported for the pooled sample and separately for the three ownership categories that enter the by-ownership regression: cooperative, municipal, and investor-owned. Two estimation windows are shown: the primary 2015–2024 specification (blue circles) and the preliminary 2015–2025 extension (red squares). Utility and year FEs; full controls listed in Appendix A3. Standard errors clustered at the state level. 95 percent CI shown. † $p < 0.10$ * $p < 0.05$ ** $p < 0.01$ *** $p < 0.001$.

To illustrate the household-level magnitude of the retail estimates, we translate each utility’s observed 2015–2025 data-center capacity growth into a model-implied historical monthly residential bill impact by utility service territory (Figure 5). This map is not a separate estimate or a forecast; it applies the ownership-specific regression coefficients to each utility’s observed data-center growth, 2024 residential rate, and typical monthly household consumption. The geography mirrors the ownership-split results. Model-implied increases are concentrated among cooperatives and municipal utilities, especially in rural Texas and the Tennessee Valley, including cooperative and municipal territories in Tennessee and Kentucky. Investor-owned utilities appear only faintly because the IOU coefficient is small and statistically insignificant, so those shaded areas should be interpreted only as an illustrative translation rather than evidence of a detectable IOU bill impact.

Investor-owned (IOU)

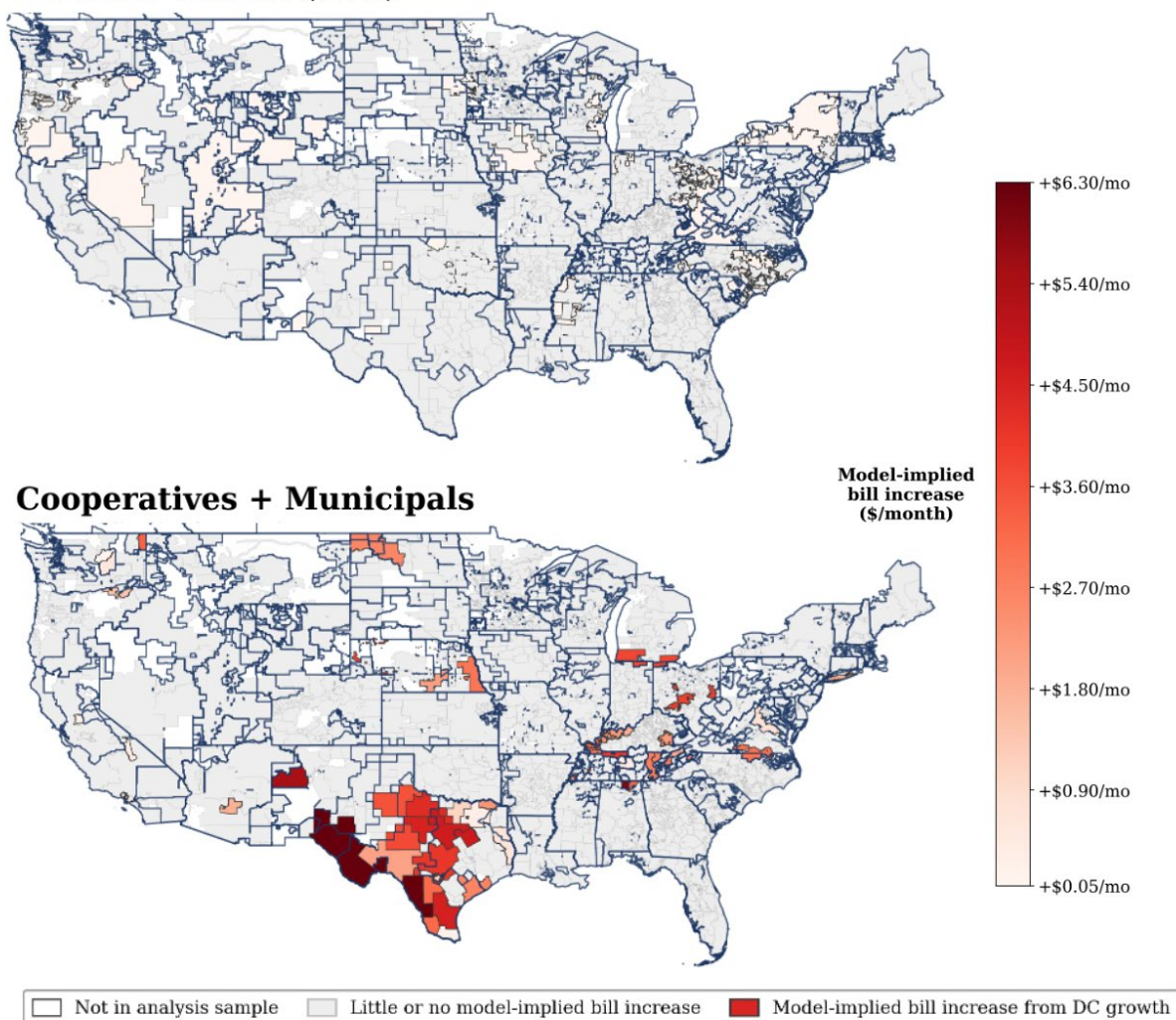


Figure 5. Model-implied historical monthly residential bill impact of observed 2015–2025 data-center growth, by utility ownership. Each polygon shows the implied increase on a typical monthly residential bill associated with each utility’s observed 2015–2025 growth in operating data-center capacity. The top panel shows investor-owned utilities, and the bottom panel shows cooperatives and municipals. The calculation applies the 2025 ownership-specific coefficient to the utility’s change in operating data-center capacity, 2024 residential rate, and typical monthly household consumption: $\beta \times \Delta \ln(\text{DC_MW} + 1) \times 2024 \text{ residential rate} \times 0.9 \text{ MWh/month}$. The 2024 residential rate is used because it is the most recent year with full annual EIA-861 coverage, and 0.9 MWh/month approximates typical household consumption (EIA, 2024).²¹ Ownership-specific coefficients are: cooperative +0.0060 ($p < 0.05$), municipal +0.0091 ($p < 0.05$), and investor-owned +0.0001 (not significant). The IOU coefficient is included only for visual consistency across ownership categories and should not be interpreted as evidence of a detectable impact on IOU bills. A \$0.05/month visibility threshold is applied so that the colored category corresponds to effects distinguishable from little or no implied bill increase. Because each panel is ownership-specific, gray areas include both out-of-panel ownership types and territories with little or no model-implied bill increase; white areas are outside the analysis sample (mostly small municipal and rural cooperative utilities with limited EIA reporting). The figure is intended as an illustrative translation of the regression estimates, not a complete accounting of all data-center-related bill impacts.

5. Forward-Looking Context

Two forces are converging on the same RTOs. NERC's 2025 Long-Term Reliability Assessment (2026, p.9) projects that aggregated assessment area summer peak demand will rise by over 224 GW over the next decade, with new data centers accounting for most of the projected increase across the bulk power system. The price effects we identify in Section 4 reflect data center entry under historically adequate reserve conditions; the forward outlook places further entry into a tightening supply environment.

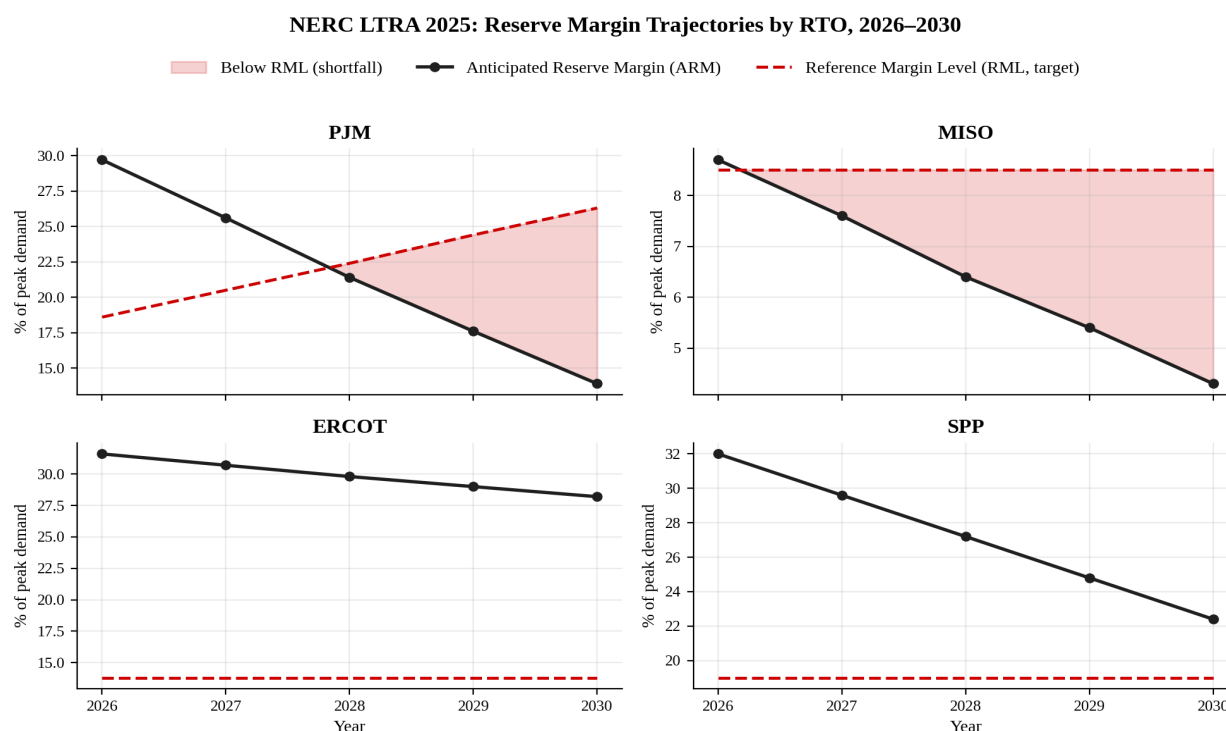


Figure 6. Reserve margin trajectories by RTO, 2026–2030, from Table 2 of NERC LTRA 2025 (p.14). Each panel plots the Anticipated Reserve Margin (ARM, solid black) against the Reference Margin Level (RML, dashed red); shaded regions indicate years of resource adequacy shortfall (ARM below RML), and the dotted vertical line marks the year ARM crosses below RML. PJM crosses below RML in 2028, reaching a -12.4 pp gap by 2030. MISO is at or below RML throughout the assessment window, reaching -4.2 pp by 2030. ERCOT and SPP remain above their RMLs throughout the period.

Table 2 of the 2025 NERC Long-Term Reliability Assessment Report (p. 14) projects substantial reserve margin deterioration in PJM and MISO. PJM's Anticipated Reserve Margin (ARM) falls from 29.7 percent (2026) to 13.9 percent (2030), while its Reference Margin Level (RML) rises from 18.6 percent to 26.3 percent, producing a -12.4 percentage-point deficit by 2030. MISO reaches a -4.2 pp deficit by 2030 (ARM 4.3 percent compared to RML 8.5 percent). ERCOT (ARM 28-32 percent compared to RML 13.8 percent) and SPP (ARM 22-32 percent compared to RML 19.0 percent) remain above their RMLs throughout the assessment period, though ERCOT's projected adequacy depends substantially on a demand-response expansion from 13.3 GW (summer 2026) to 53.1 GW (2030) tied to Texas Senate Bill 6's large-load curtailment authority. NERC nonetheless projects ERCOT as "high risk" from 2029, reflecting the qualitative concern that this adequacy outlook hinges on the new curtailment authority operating as planned, even as a more variable resource mix and unprecedented large-load growth tighten operating conditions.

The largest data center load forecasts and the steepest decline in reserve margin are concentrated in the same two RTOs: PJM and MISO. Our wholesale estimates identify a price response to data center entry under historical conditions in which reserve margins were generally adequate; under the projected shortfalls

that NERC anticipates, the systemwide energy demand effect documented in Section 4 would plausibly compound with any scarcity premium that emerges as reserves tighten. We do not estimate this compounding directly, and the magnitude depends on capacity-market design responses and supply-side adjustments not captured in our reduced-form estimates.

6. Discussion

A broader observation that emerges from our findings is that the wholesale price pressure we document is a symptom of physical undersupply: financial markets can reallocate that risk among participants but cannot create new generation. The long-run answer is more dispatchable generation built and connected to the grid at scale. The constraints on getting that done are concentrated in two places: permitting and generation financing, with hedging instruments and battery storage playing important but auxiliary roles in managing the gap until physical capacity catches up.

Permitting and generation financing. The first constraint is permitting: the set of approvals required to move new generation and transmission projects from announcement to operation, including RTO interconnection studies and state-level siting approvals. Evidence from NERC highlights the gap between announced and deliverable capacity. PJM, for example, illustrates the scale of the interconnection challenge: 811 new generation projects totaling 220 GW entered the first cycle of its reformed interconnection process in 2026, while PJM reports that, since 2020, more than 300 GW of projects have been processed but only 103 GW have signed interconnection agreements (PJM Interconnection, 2026). Local opposition further slows deployment, as solar, gas, transmission, and battery projects face siting challenges related to land use, safety, and community acceptance. The result is a timing mismatch: data center demand can be deployed within 18–24 months, while new generation and transmission require multi-year permitting timelines, contributing directly to the reserve-margin compression.

The second constraint is generation financing. Recent PJM capacity auctions show that the market is already signaling a need for more supply: prices reached the applicable cap, PJM fell short of its target reserve level, and very little new generation was added even as forecast demand rose sharply, largely because of data centers (Howland, 2025). In principle, high prices should encourage developers to build new power plants. Yet, in practice, that signal may not be enough on its own because new generation projects require long-term revenue certainty to secure financing, while capacity-market revenues can vary from year to year (Weiss & Sarro, 2013). Uncertainty about future market rules can further raise financing costs and delay investment. As a result, the price pressures identified in this brief may persist if demand grows faster than new supply can be financed, permitted, and built.

Hedging instruments and storage as auxiliary tools. Utilities can manage exposure to rising electricity prices, but these tools do not address the underlying supply constraint. Financial hedges, such as transmission rights, virtual power purchase agreements (VPPAs), and electricity futures, provide protection against price changes but do not supply physical electricity.²² Battery storage can help meet short-term demand peaks, particularly during evening hours, but remains limited in scale.²³ Even in California, which has the largest battery fleet in the United States, storage can meet only a small share of total daily electricity demand. As a result, both hedging and storage complement (without replacing) the need for new generation and transmission capacity to meet growing demand.

7. Conclusion

Across the three scales we examined, data center entry is associated with higher wholesale prices through congestion at the node level (+\$2.30/MWh in CAISO) and through the energy component at the zone level (+\$5.43/MWh). At the retail level, a 100 percent increase in a utility's operating data center capacity is associated with about a 0.65 percent increase in residential prices. Given a typical residential price of \$0.16–

\$0.17/kWh, a 0.65 percent increase implies \$1.04–\$1.10/MWh (0.62 percent or \$1.00–\$1.06/MWh increase under preliminary 2025 extension).

Our results identify two distinct price channels operating at different geographic scales. At the transmission node (CAISO), data-center entry is associated with higher local congestion costs, consistent with Mamkhezri et al. (2026)’s finding that spatial misalignment between load and generation drives transmission-induced price distortions. At the price zone level (Non-CAISO), the dominant effect is on the energy component of LMP, reflecting systemwide dispatch cost pressure.

The two designs identify complementary but distinct channels: the wholesale zone-level β captures the price response to first-within-panel data-center entry in zones with varying degrees of prior data-center exposure, while the retail panel uses a continuous treatment. Therefore, the β in the retail-level analysis identifies the elasticity of residential rates with respect to within-utility operating-capacity growth (a design that captures both first-ever entries and incremental growth at utilities already hosting). The two estimates are not directly comparable as point estimates, but together they trace the price-formation chain at the scale where each effect is identifiable.

The wholesale effect is larger because it falls on the zone-clearing energy price (which all load-serving entities in the zone pay through their wholesale procurement), whereas only a fraction passes through to retail customers in the host utility’s territory after PPAs, hedging, and regulated cost-recovery mechanisms attenuate the signal. The retail residential estimate captures only the share of any wholesale price increase that survives pass-through within a single year on a single utility’s residential customer class, and so likely understates the longer-run household-level price burden. Wholesale-to-retail pass-through dynamics over longer horizons, and the cross-utility distribution of the wholesale price increase, are open questions for future work.

Two non-exclusive mechanisms are consistent with this pattern. First, data centers may select zones with relatively unconstrained transmission, in which case post-entry congestion remains stable. Second, data center load may operate primarily through the system dispatch mechanism described in Section 1, in which the ISO’s commitment to a new baseline load block forces dispatch of more expensive marginal generation, raising the zone-clearing energy price uniformly. The entry-size split in Appendix Table A2 (where small and large entries produce statistically indistinguishable per-event effects on Total LMP, and where the linear per-MW slope of +\$0.0063/MWh implies an effect of only +\$1.21/MWh at the mean entry size, well below the binary +\$3.44/MWh estimate) is more consistent with the dispatch step-function mechanism than with a continuous demand-curve shift, but does not rule out a contributing role for selection. Both mechanisms imply that the increase in the energy component is the policy-relevant channel; they differ in whether congestion is muted because of data centers’ zone selection or because the relevant pressure is systemwide rather than local.²⁴

Our estimates have limitations. We focus on empirical patterns from recent years, not on what will happen as the announced pipeline materializes. The wholesale analyses identify first-within-panel entry effects, not always first-ever entry effects. At the CAISO node level, some first-within-panel entries may correspond to first-ever nearby data-center exposure, while others are marginal additions to nodes with pre-2020 exposure. At the Non-CAISO zone level, the estimates similarly capture entries observed during 2020–2025; because the sampled RTOs already hosted data centers before 2020, some treated zones may already have been exposed before the sample begins. The estimates are therefore best interpreted as recent entry effects in markets with varying degrees of prior data-center exposure.

Endnotes

¹ In the retail panel, 2015–2024 observations use annual Form EIA-861 data, while 2025 observations use preliminary monthly Form EIA-861M data. The 2025 data are sampled, weighted toward larger utilities, and subject to verification and revision. The 2015–2024 annual-data sample yields the same qualitative ownership pattern and is reported in Appendix Table A4a.

² We use \$0.16–0.17/kWh as an illustrative residential electricity price, corresponding closely to the U.S. average residential retail price in 2023–2025 (16 to 17.3 cents per kWh) reported by EIA Electric Power Monthly Table 5.3 (U.S. Energy Information Administration, 2026).

³ For the distinction between physical and financial PPAs, EPA (2025) 5/22/2026 2:36:00 PM explains that under a physical PPA the customer receives physical electricity delivery “through the grid,” while under a financial PPA the customer does not receive physical delivery and instead uses the contract as a hedge. EPA (2025) also describes financial PPAs as hedge arrangements that provide cost predictability. Norton Rose Fulbright notes that many data centers use corporate PPAs, often virtual PPAs, as financial instruments to manage electricity costs rather than direct purchases of physical electricity (Alcala & Rosenfeld, 2020). Therefore, a data center may be financially hedged against spot-market prices while still physically drawing power from the local utility or grid.

⁴ Yue and Zeng (2026) provide emerging causal evidence on retail electricity prices, estimating positive price effects in counties with lower utility-service spillover while cautioning that full-sample identification is complicated because utility service territories often span multiple counties.

⁵ Mamkhezri et al. (2026) 5/22/2026 2:36:00 PM report \$2.49/MWh as the combined component that sums congestion and marginal losses; our \$2.30/MWh isolates congestion alone.

⁶ <https://www.arcgis.com/home/item.html?id=597555ce8e4a4892a030784a7c657fdd>

⁷ CAISO LMP node coordinates were obtained from the open-source LMP Location Scraper (<https://github.com/emunsing/CAISO-Scrapers/tree/master/LMP%20Location%20Scraper>), which extracts node-level latitude/longitude from CAISO's public OASIS system. CAISO does not publish a clean coordinate file directly.

⁸ Zone boundary shapefiles for PJM, MISO, SPP, and ERCOT were obtained via publicly accessible ArcGIS Online endpoints. Cross-reference match rates are 94 percent in PJM, 88 percent in MISO, 86 percent in ERCOT, and 80 percent in SPP; facility-to-zone matching achieves full coverage by construction.

⁹ PJM, MISO, and SPP use real-time five-minute LMP series accessed through GridStatus. For MISO, 2020–2022 and January 2023 use the GridStatus series corresponding to MISO's “Real-Time 5-Min Ex Post Final” product, which reports finalized real-time prices rather than preliminary postings. ERCOT prices are measured at the settlement-point level.

¹⁰ A separate group of approximately 560 utilities (mostly small Coop and Municipal utilities) files the EIA-861 Short Form (861-S), which omits customer-class breakdowns; these utilities were excluded from the residential-rate regressions due to this limitation and are not included in the 1,798 retained above. These utilities have median total sales of ~3,500 MWh, representing roughly 360 customers each. Contributing approximately 0.05 percent of national electricity sales, they are unlikely to host large-scale data center loads, and their omission is not expected to materially bias our retail β estimates.

¹¹ 315 observations are dropped due to missing residential price (1.9 percent of the sample).

¹² Because EIA-861M is heavily weighted toward larger investor-owned utilities, every IOU in the 2015–2024 panel reports monthly, but only about one in six cooperatives and municipals do.

¹³ Raw utility-level shares occasionally exceed 1.0 or fall below 0.0 due to purchased power accounting. The final variables are capped at [0, 1].

¹⁴ <https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm>

¹⁵ The node $\times$ month-of-year and entry-year fixed effects absorb time-invariant node characteristics, node-specific seasonal patterns, and CAISO-wide shocks common across cohorts in a year. Node-specific time-varying shocks that affect some nodes more than others within a single year are not directly controlled.

The identifying assumption is that DC siting decisions are uncorrelated with these confounders, which we view as plausible, since DC location choices are driven by land, water, fiber, and interconnection availability rather than by exposure to retiring nuclear plants.

¹⁶ This specification is similar to the zone-level 2×2 stacked DiD in Section 3.2; both rely on a within-cohort post-pre comparison rather than an event study. The identifying assumption is that, in the absence of data center entry, the within-node post-pre price change would have looked like the corresponding change in not-yet-treated nodes. As in the zone-level design, this assumption is not directly testable through pre-trend leads (the pre-period for each node is collapsed into the pre-entry indicator), but is testable through cohort decomposition: if particular entry-year cohorts span calendar windows known to contain large idiosyncratic shocks (e.g., the 2022 European gas-price crisis), single-cohort estimates will reveal whether those shocks contaminate the pooled estimate. We report cohort decomposition results in Appendix A2.

¹⁷ The median entry event is 59 MW (range: 2 to 1,886 MW).

¹⁸ Because this specification uses within-utility variation in operating data-center capacity rather than a facility-siting event study, β should be interpreted as a conditional association. The specification absorbs time-invariant utility characteristics and common year shocks, but unobserved utility-specific trends correlated with data-center growth could still bias the estimate.

¹⁹ We note that this identification relies on within-utility variation in operating MW over time after absorbing utility fixed effects and common year trends. Unobserved utility-specific trends correlated with data center growth would bias β upward.

²⁰ <https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm>

²¹ U.S. Energy Information Administration (2024) 5/22/2026 2:36:00 PM reports that in 2022, the average annual electricity consumption for a U.S. residential utility customer was 10,791 kWh, equivalent to an average of approximately 899 kWh per month, or approximately 0.9 MWh per month.

²² <https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/ftf-fact-sheet.pdf>

²³ Battery energy storage systems (BESS) earn revenue through two primary channels: energy arbitrage in day-ahead and real-time markets, and ancillary services such as frequency regulation and spinning reserves. Arbitrage revenue is often summarized by the “Top-Bottom 4” (TB4) spread (i.e., the difference between the four highest-price and four lowest-price hours) reflecting the typical four-hour duration of most BESS facilities. In CAISO, day-ahead arbitrage accounted for approximately 70 percent of merchant BESS revenue as of 2025, with ancillary services and real-time energy making up the remainder (Hotz, 2025).

²⁴ A natural extension would apply the wholesale and retail specifications developed here out of sample to other electricity markets, including North American systems such as NYISO, IESO (Ontario), and AESO (Alberta), as well as selected international markets with comparable wholesale pricing frameworks (e.g., Chile, Mexico, and the Philippines). These markets differ along key institutional dimensions (e.g., including capacity market design, generator ownership, and retail regulation) while also experiencing varying degrees of large-load growth, including data center expansion. Replicating the stacked difference-in-differences designs in these settings would provide a test of the external validity of the price effects documented here, help discipline their magnitude under alternative market structures, and clarify which institutional features amplify or attenuate wholesale-to-retail pass-through.

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Appendix

A1. Wholesale Zone-Level Estimates: All Components

Table A1 compares three reference specifications of the wholesale zone-level stacked DiD across the four LMP components. Column (1) is the baseline specification: excluding the 2023 entry cohort and with no Henry Hub gas-price control (“HH”). Column (2) adds a Henry Hub control to the same sample, attenuating the effect substantially. Column (3) is our primary specification: pooling all 58 entry cohorts and including the Henry Hub control. The 2023 cohort is no longer excluded because the gas-price control absorbs the European gas-crisis variation that originally motivated the exclusion. The Henry Hub coefficient on Total LMP in the primary specification is +\$8.39/MWh per \$1/MMBtu of gas, consistent with a typical gas-marginal heat rate of 7–8 MMBtu/MWh. Treatment is the binary post-entry indicator.

<i>Coefficients</i>	(1) Baseline (excl. 2023, no HH)	(2) Excl. 2023, +HH	(3) <i>Primary:</i> All cohorts, +HH
Total LMP (\$/MWh)	+16.49*** (2.84)	+4.97*** (1.25)	+3.44** (1.18)
Energy (\$/MWh)	+20.30*** (2.88)	+8.21*** (0.93)	+5.43*** (1.16)
Congestion (\$/MWh)	-1.07 (0.85)	-0.96 (0.85)	-1.00 (0.71)
Loss (\$/MWh)	-0.17 (0.17)	-0.06 (0.14)	-0.03 (0.13)
Henry Hub control	No	Yes	Yes
2023 cohort	Excluded	Excluded	Included
Zone, month, entry-year FE	Yes	Yes	Yes
Cluster SE	Cohort	Cohort	Cohort
Observations (Total LMP)	266	266	344
Cohorts	45	45	58

Table A1. Wholesale zone-level stacked DiD by LMP component. Column (1) is the baseline specification (excl. 2023 cohort, no gas control). Column (2) adds a Henry Hub spot price control to the same sample. Column (3), our primary specification, includes 58 cohorts with the Henry Hub control. Henry Hub coefficient on Total LMP in column (3): +\$8.39/MWh per \$1/MMBtu. All columns: 2×2 stacked DiD on $rel_year \in \{-1, +1\}$; zone, month, entry-year FEs. Cohort-clustered SEs in parentheses. *** $p < 0.001$, ** $p < 0.01$, * $p < 0.05$, † $p < 0.10$.

A2. Wholesale Zone-Level Estimates: Robustness Check

Table A2 reports the wholesale zone-level cohort decomposition for the primary specification (all cohorts, with Henry Hub gas-price control). Panel A reports estimates for Total LMP and Panel B for the energy component, each shown side-by-side with and without the gas control. Panel C reports the entry-size split under the primary specification: smaller-than-median entries (<59 MW) and larger-than-median entries (≥59 MW) produce statistically indistinguishable per-event effects, evidence against linear per-MW scaling and consistent with the dispatch-commitment mechanism described in Section 1. Panel D reports a continuous-MW specification (post × entry MW) on the same panel.

Panel A: Total LMP	Baseline (no HH)	+ HH gas control (Primary)	Cohorts	N
Pooled (all cohorts); primary	+5.75 (3.56)	+3.44** (1.18)	58	344
Excl. 2021	-3.47 (3.06)	+2.98* (1.22)	46	272
Excl. 2022	+7.29 (4.48)	+3.50* (1.44)	46	274
Excl. 2023	+16.49*** (2.84)	+4.97*** (1.25)	45	266
Excl. 2024	+2.26 (5.49)	+2.93† (1.71)	37	220
Only 2021	+40.58*** (3.95)	+8.67 (11.48)	12	72
Only 2022	-0.01 (1.47)	+1.61 (1.96)	12	70
Only 2023	-30.86*** (2.59)	-2.81 (7.50)	13	78
Only 2024	+11.95*** (1.58)	+12.93* (4.91)	21	124
Panel B: Energy component	Baseline (no HH)	+ HH gas control	Cohorts	N
Pooled (all cohorts); primary	+8.58* (4.00)	+5.43*** (1.16)	58	284
Excl. 2021	-1.47 (3.60)	+5.08*** (1.13)	46	218
Excl. 2022	+9.67† (4.80)	+5.28*** (1.39)	46	238
Excl. 2023	+20.30*** (2.88)	+8.21*** (0.93)	45	218
Excl. 2024	+5.11 (6.35)	+4.52* (1.68)	37	178
Only 2021	+41.74*** (3.31)	+16.23* (6.56)	12	66
Only 2022	+3.59*** (0.25)	+6.12*** (0.21)	12	46
Only 2023	-30.11*** (2.79)	-7.41 (6.81)	13	66
Only 2024	+14.43*** (1.33)	+21.68*** (3.58)	21	106
Panel C: Entry-size split (primary)	Total LMP	Energy	Cohorts	N
Small entries (<59 MW)	+3.75** (1.29)	+4.42** (1.43)	29	173
Large entries (≥59 MW)	+2.91 (1.87)	+6.48** (1.86)	29	171
Panel D: Continuous-MW specification (per-MW slope on cohort entry MW, \$/MWh per MW)	Total LMP	Energy	Cohorts	N
Per-MW slope on entry MW	+0.0063* (0.0030)	+0.0064** (0.0023)	58	344

Table A2. Wholesale cohort decomposition under the primary specification, shown with and without the Henry Hub control. Panel A: Total LMP. Panel B: Energy component. Panel C: entry-size split at the median (59 MW). Panel D: continuous-MW specification (per-MW slope on cohort entry MW, \$/MWh per MW). Single-cohort specs drop the entry-year FE. Cohort-clustered SEs in parentheses. *** $p < 0.001$, ** $p < 0.01$, * $p < 0.05$, † $p < 0.10$.

A3. Retail Full Coefficient Vector and Sensitivity

Table A3 reports the residential price specification across five columns. Column (1) is the primary specification with utility and year fixed effects, used throughout the body of the brief. Column (2) replaces utility fixed effects with utility-state fixed effects to absorb cross-state heterogeneity within multi-state utilities. Column (3) restricts the sample to single-state utilities only; column (4) restricts to multi-state utilities only and uses utility-state fixed effects. Standard errors are clustered at the state level (51 clusters).

	(1) <i>Primary</i>	(2) <i>Util-state FE</i>	(3) <i>Single-state</i>	(4) <i>Multi-state</i>
Dependent variable: $\ln(\text{residential price})$				
$\ln(\text{DC MW} + 1)$	+0.0094*** (0.0026)	+0.0091*** (0.0024)	+0.0096** (0.0035)	+0.0076* (0.0033)
Gas share	-0.0338† (0.0199)	-0.0277 (0.0205)	-0.0310 (0.0211)	+0.0245 (0.0540)
Wind+solar share	-0.0496* (0.0208)	-0.0387† (0.0209)	-0.0631* (0.0236)	+0.0806† (0.0466)
$\ln(\text{Coal+nuclear ret. MW} + 1)$	-0.0006 (0.0005)	-0.0008 (0.0005)	-0.0007 (0.0005)	-0.0011 (0.0007)
RPS annual incremental gen.	+0.4698 (0.3911)	+0.4160 (0.3857)	+0.4396 (0.3678)	-0.0123 (1.1014)
RPS cost intensity (\$/MWh)	-0.0107 (0.0114)	-0.0089 (0.0111)	-0.0096 (0.0107)	+0.0107 (0.0379)
Anticipated reserve margin (%)	+0.0012* (0.0005)	+0.0014** (0.0005)	+0.0015** (0.0005)	+0.0008 (0.0007)
Utility FE	Yes	No	Yes	No
Utility-state FE	No	Yes	No	Yes
Year FE	Yes	Yes	Yes	Yes
Cluster SE	State	State	State	State
Observations	16,163	16,163	13,993	2,170
Utilities	1,798	1,798	1,688	110
Within R ²	0.013	0.016	0.018	0.017

Table A3. Retail residential price specifications. Dependent variable is the natural log of residential price (cents per kWh). The treatment variable is $\ln(\text{DC MW} + 1)$, where DC MW is the cumulative operating data center capacity in the utility's service territory in the given year. All columns include the full control vector. *** $p < 0.001$, ** $p < 0.01$, * $p < 0.05$, † $p < 0.10$. Standard errors in parentheses, clustered at state level.

A3a. Retail Robustness: Henry Hub Gas-Price Control

Table A3a tests whether the residential price effect of data center growth survives the addition of a Henry Hub natural gas spot price control. Because the retail TWFE specification already includes year fixed effects that absorb the level of Henry Hub common across utilities, we add an interaction of monthly Henry Hub spot price with the state-mean gas share of generation, which varies by state-year and is therefore not collinear with year FE.

Panel A reports all four customer classes (residential, commercial, industrial, total) under the baseline TWFE specification (column 1) and with the gas-control interaction added (column 2); the third column reports the coefficient on the interaction itself. Panel B reports the same comparison restricted to residential price, by ownership type.

Panel A: All customer classes	(1) Baseline	(2) + $HH \times state-gas-share$	$HH \times state-gas-share$ coefficient	<i>N</i>
Residential	+0.0094*** (0.0026)	+0.0095*** (0.0026)	+0.0171* (0.0075)	16,163
Commercial	+0.0043 (0.0060)	+0.0043 (0.0060)	+0.0113 (0.0097)	16,118
Industrial	+0.0017 (0.0084)	+0.0018 (0.0083)	+0.0260† (0.0131)	13,779
Total	+0.0020 (0.0045)	+0.0021 (0.0044)	+0.0178 (0.0107)	16,163
Panel B: Residential, by ownership	(1) Baseline	(2) + $HH \times state-gas-share$	$HH \times state-gas-share$ coefficient	<i>N</i>
Cooperative	+0.0067** (0.0024)	+0.0068** (0.0024)	+0.0194† (0.0112)	7,203
Municipal	+0.0080† (0.0044)	+0.0080† (0.0043)	+0.0088 (0.0103)	6,384
Investor-Owned	+0.0006 (0.0043)	+0.0007 (0.0042)	+0.0220 (0.0166)	1,858

Table A3a. Retail residential price effects: Henry Hub gas-control robustness. Coefficients on $\ln(DC\ MW + 1)$. Panel A: all customer classes. Panel B: residential by ownership type. *** $p < 0.001$, ** $p < 0.01$, * $p < 0.05$, † $p < 0.10$.

A4. Retail Extension to 2025 (Preliminary)

Table A4a extends the residential TWFE specification beyond the 2015–2024 window by appending preliminary 2025 rows aggregated from the EIA Form 861-M (formerly EIA-826). Monthly observations are summed within (utility, state, year) on revenue and sales, and price is recomputed as $100 \times \text{revenue/sales}$ (i.e., a sales-weighted annual average). 2025 covers the full calendar year.

Form 861-M coverage is a sample of large utilities, narrower than the annual Form 861 panel (the coop and municipal subsamples are thinned out by design). For the through-2025 specification, fuel-mix shares (gas, coal, nuclear, renewable) are recomputed from EIA-923 monthly 2025 (utility-level where reported, state-level fallback otherwise); coal retirements are from EIA-860M December 2025; and the anticipated reserve margin is from NERC (2026). Only the LBNL RPS compliance controls are carried forward from 2024 (Wiser et al., 2025).

Sample	Full controls β (SE)	No controls β (SE)	Percent per doubling (full ctrls)	N
A: Through 2024 (primary)	+0.0094*** (0.0026)	+0.0095*** (0.0026)	0.651%	16,163
B: Through 2025 (extended)	+0.0090** (0.0027)	+0.0092** (0.0028)	0.624%	16,556

Table A4a. Residential price TWFE. The dependent variable is the natural log of residential price (cents per kWh). Treatment is $\ln(\text{DC MW} + 1)$. Utility and year fixed effects, standard errors clustered by state. Row A presents the primary specification using finalized annual EIA data; Row B extends the sample through 2025 using EIA preliminary monthly data. In both the through-2024 and through-2025 specifications, comparable TWFE models for commercial, industrial, and total prices produce small, statistically insignificant coefficients.

Table A4b reports the same samples broken out by utility ownership type. The qualitative pattern from 2015–2024 is preserved through the 2025 extension: cooperative and municipal residential prices respond positively to data center growth, while the IOU residential coefficient is statistically nonsignificant in every sample.

Ownership	A: Through 2024 β (SE) [N]	B: Through 2025 β (SE) [N]
Cooperative	+0.0067** (0.0024) [7,203]	+0.0060* (0.0026) [7,320]
Municipal	+0.0080† (0.0044) [6,384]	+0.0091* (0.0044) [6,454]
Investor Owned	+0.0006 (0.0043) [1,858]	+0.0001 (0.0043) [2,036]

Table A4b. Residential price TWFE by utility ownership type, full controls. Coefficients on $\ln(\text{DC MW} + 1)$. Standard errors clustered by state. Significance: † $p < 0.10$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$.

This report was prepared by Shon R. Hiatt and Angela Ryu for the USC Marshall Zage Business of Energy Initiative. Energy briefs provide information and analyses that are intended to deepen students' comprehension of business of energy issues. They are not intended to serve as endorsements, sources of primary data, or illustrations of effective or ineffective management. Copyright ©2026, University of Southern California.

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