



# ERCOT 101

**A UNIQUE APPROACH TO POWER IN THE U.S.**

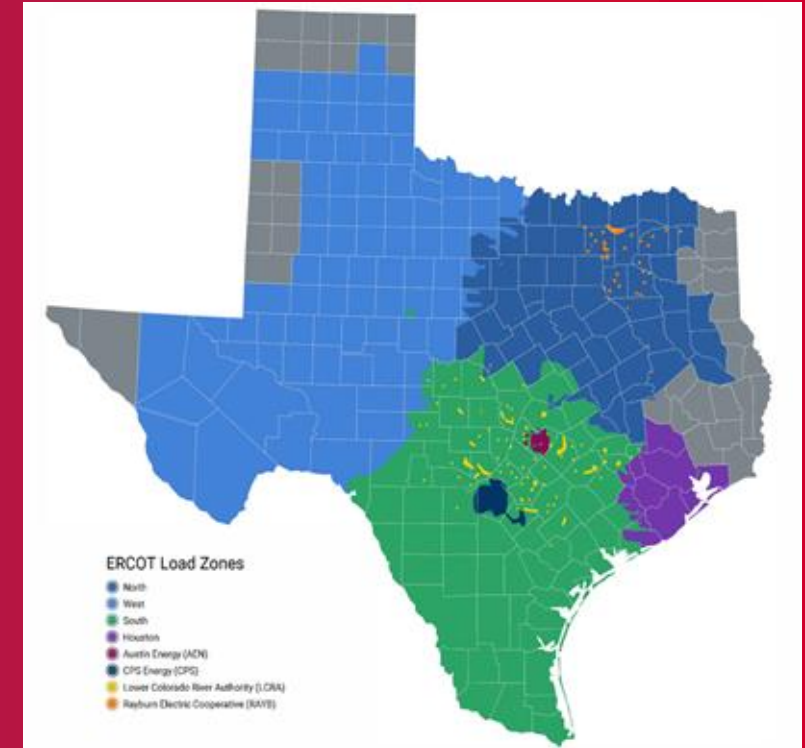


# WHAT IS ERCOT



## ERCOT: Electric Reliability Council of Texas

- Manages the flow of electric power to **27 million Texans** (~90% of state load)
- Covers ~75% of Texas land area
- Independent system operator (ISO)
- Oversees operation of the electric grid and wholesale electricity market



**Mission:** To ensure reliable operation of the electric grid and facilitate a competitive, efficient electricity market.

# HOW THE ERCOT MARKET WORKS



- **Energy-Only Market:** No payments to keep plants online in reserve
- **Real-Time Market:** Prices based on real-time supply and demand
- **Day-Ahead Market:** Bids submitted for expected demand 24 hours in advance
- **Ancillary Services:** Reserve capacity and grid support services



# DIFFERENT U.S. ELECTRICITY MARKET TYPES



Market Type	Who Uses It	Key Features
<b>Vertically Integrated</b>	Southeast, Northwest	Utilities own generation + delivery
<b>Energy + Capacity</b>	PJM, NYISO, ISO-NE	Payments for both energy and backup
<b>Energy-Only</b>	<b>ERCOT (only one)</b>	No capacity payments

# ENERGY ONLY MARKET - WHAT DOES THAT MEAN?

---



- Generators paid only for energy sold
- No long-term capacity payments
- Higher scarcity prices intended to encourage investment
- **Risk:** Fewer incentives for backup capacity
- **Unique in U.S.:** No other major U.S. market operates this way

# KEY PLAYERS IN THE ERCOT MARKET



- **Generators:** Power producers (e.g., gas, wind, solar, nuclear, coal)
  - Competitive market; plants bid into wholesale market
- **Retail Electric Providers (REPs):** Sell power to consumers
  - Competitive in deregulated areas; customers pick suppliers
- **Transmission and Distribution Utilities (TDUs):** Maintain poles and wires
  - Regulated utilities (e.g., Oncor, CenterPoint)
- **Consumers:** Residential, commercial, industrial users
- **ERCOT:** Coordinates and settles market transactions

# WHAT ABOUT MUNIS & CO-OPS?

---



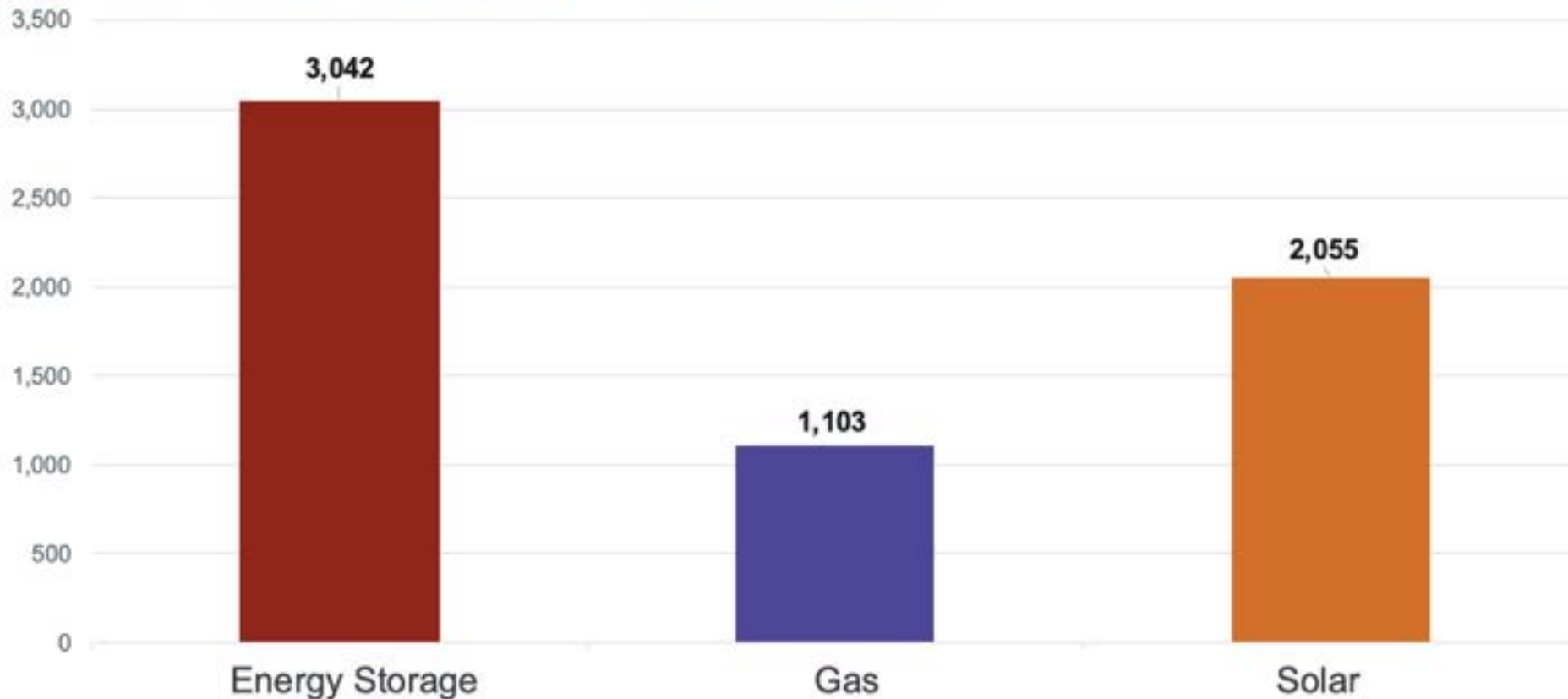
- **Municipal Utilities (Munis):** City-owned, vertically integrated (e.g., Austin Energy, CPS Energy)
- **Electric Cooperatives (Co-Ops):** Owned by members, often rural (e.g., Pedernales Electric)
- **Some are inside ERCOT, others outside**
- **Not required to participate in competitive retail market (Lubbock does)**
- **Buy (and some sell) power into the ERCOT Wholesale market**

## Latest Updates



Item 11

## Generation in the August QSA Being Evaluated to Synchronize January – March 2026

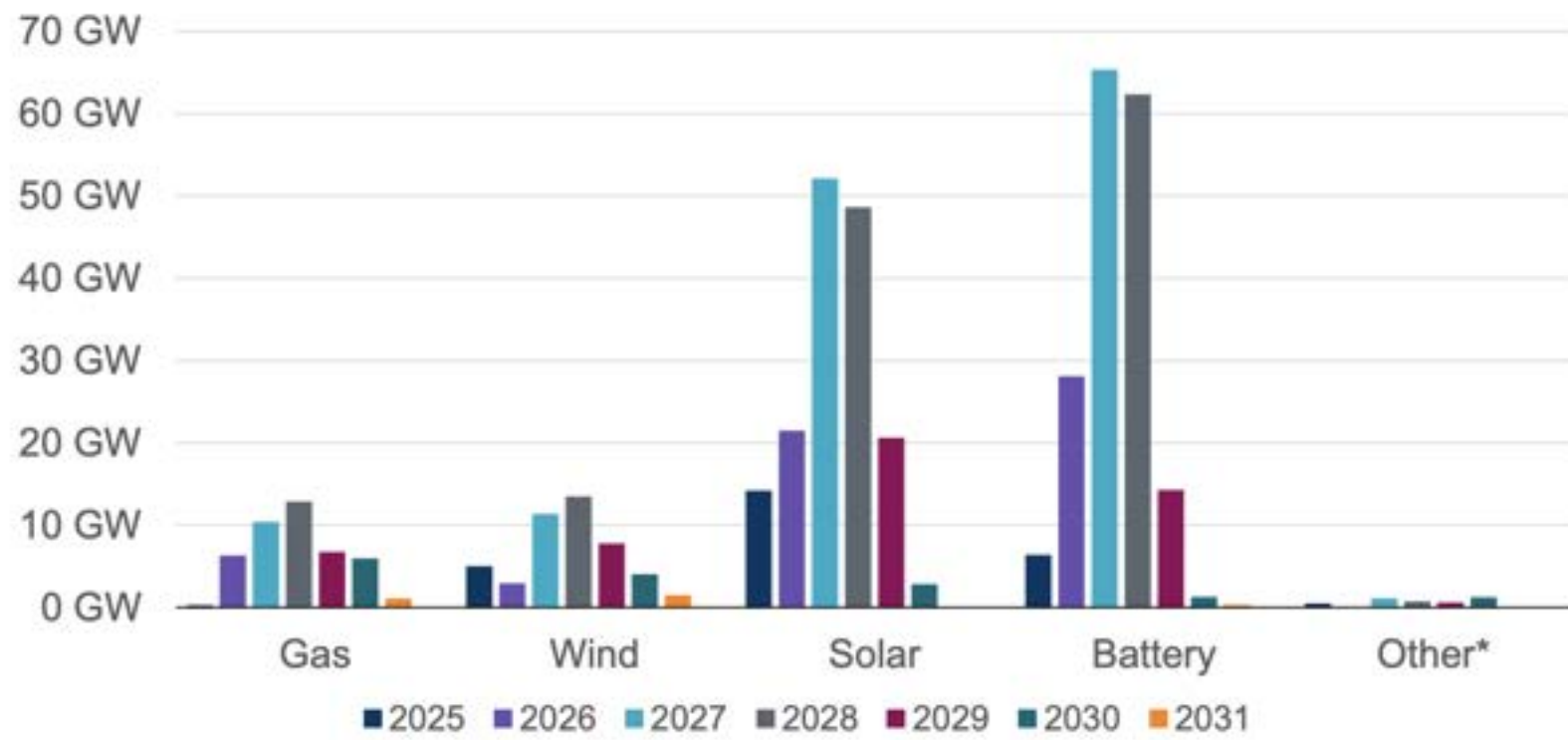


**Key Takeaway:** The August Quarterly Stability Assessment (QSA) is the largest one ERCOT has seen with over 6,000 MW of new generation. The first Texas Energy Fund Program projects are included in this QSA.



# Interconnection Queue Capacity by Fuel Type

Queue totals: Solar 160 GW (37%), Wind 46 GW (10.7%), Gas 44 GW (10.1%), Battery 178 GW (41.2%), Other 4 GW (1%)  
 (Excludes capacity associated with projects designated as Inactive per Planning Guide Section 5.2.5)

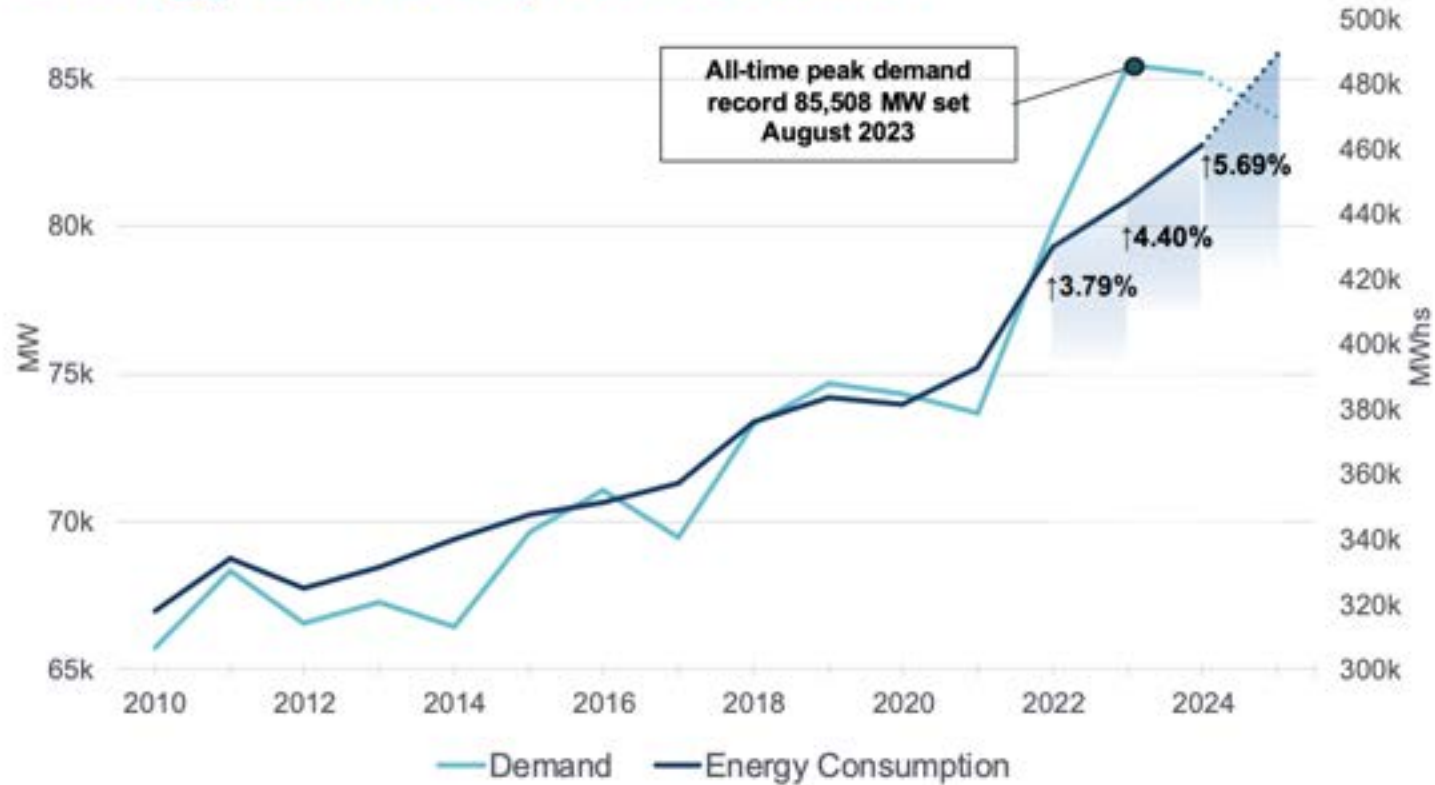


A break-out by zone can be found in the monthly Generator Interconnection Status (GIS) reports available on the ERCOT Resource Adequacy Page: <http://www.ercot.com/gridinfo/resource>

\* Other includes petroleum coke (pet coke), hydroelectric, fuel oil, Nuclear, geothermal energy, other miscellaneous fuels reported by developers, and fuel cells that use fuels other than natural gas.

Item 11

# Energy Consumption Growth



## Average Energy Growth

2010-2025	3.37%
2010-2020	2.53%
2021-2025	5.12%

*This is settled load data and does not include the ESR's.*

**Key Takeaway:** While ERCOT hasn't set a new all-time peak demand record since August 2023 (85,508 MW), energy consumption continues to increase year over year.



## Senate Bill (SB) 6 Implementation Roadmap



Net Metering Arrangements Involving a Large Load Co-Located with an Existing Generation Resource  
(PURA §39.169)

- PUCT Project No. 58479, **expected March 2026**
- Rulemaking will codify the process for the Commission's evaluation of a net metering arrangement involving a large load and co-located with an existing Generation Resource along with the criteria used to evaluate the arrangement.

Large Load Forecasting Criteria  
(PURA §37.0561)

- PUCT Project No. 58480, **expected March 2026**
- Rulemaking will establish criteria for including large loads in the forecasts that Transmission Service Providers (TSPs) submit to ERCOT for purposes of developing transmission planning and resource adequacy models and reports.
- Project will also establish criteria for Transmission Service Providers (TSPs) to reasonably determine existing and forecasted load (see *HB 5066 (88R)*).

Large Load Interconnection Standards (PURA §37.0561)

- PUCT Project No. 58481, **expected July 2026**
- Rulemaking will establish standards for the interconnection of large load customers in ERCOT that support business development while minimizing the potential for stranded infrastructure costs and maintaining system reliability.

Reliability Service to Competitively Procure Demand Reductions from Large Loads (PURA §39.170)

- PUCT Project No. 58482, **expected August 2026**
- Rulemaking will codify requirements for ERCOT to develop a new reliability service that competitively procures demand reductions from loads with a demand of  $\geq 75$  MWs to be deployed in the event of an anticipated emergency condition.

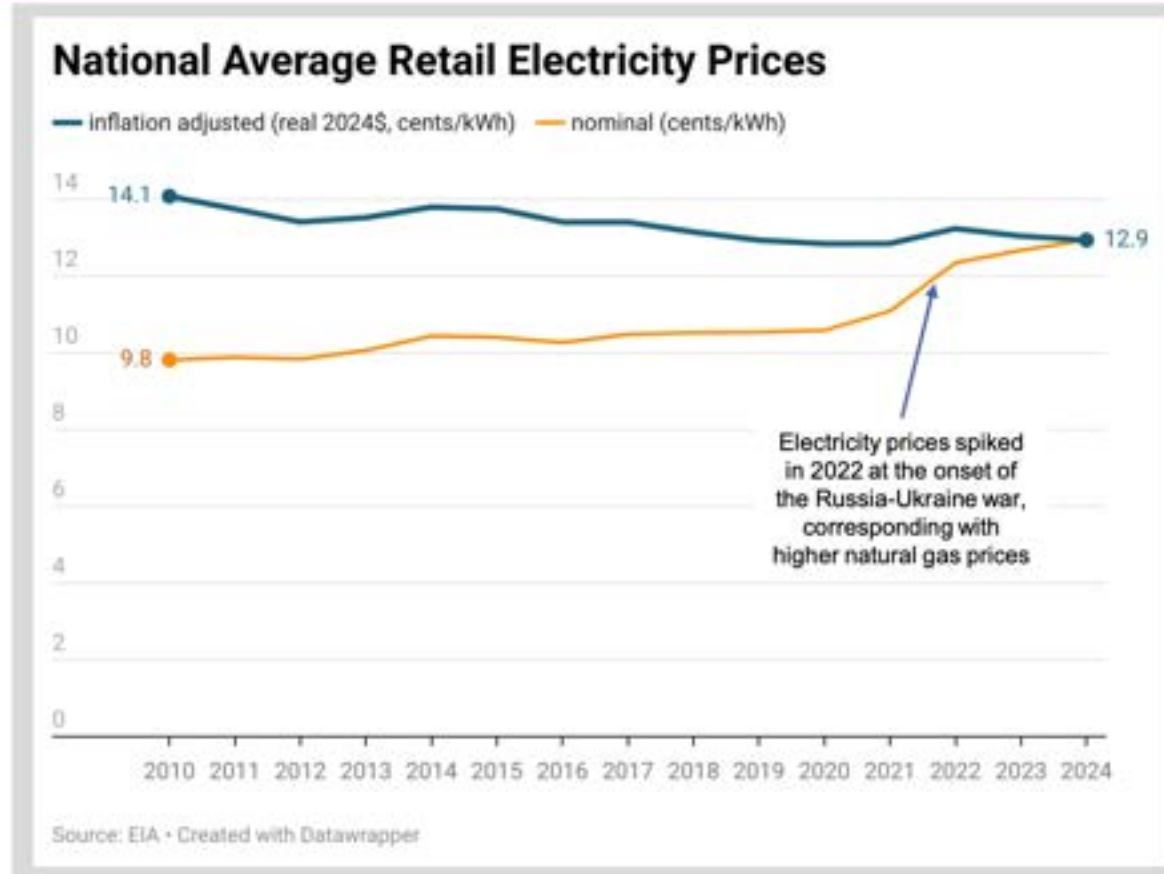
Evaluation of Transmission Cost Recovery (SB 6 Section 6 (a)-(c))

- PUCT Project No. 58484, **expected December 2026**
- Project will evaluate whether the existing 4CP methodology continues to appropriately assign costs for transmission investment or if an alternative methodology would more appropriately assign the costs of providing access and codify any recommendations in a subsequent rulemaking.



## While national-average nominal retail electricity prices have increased in recent years, the increases have largely tracked inflation

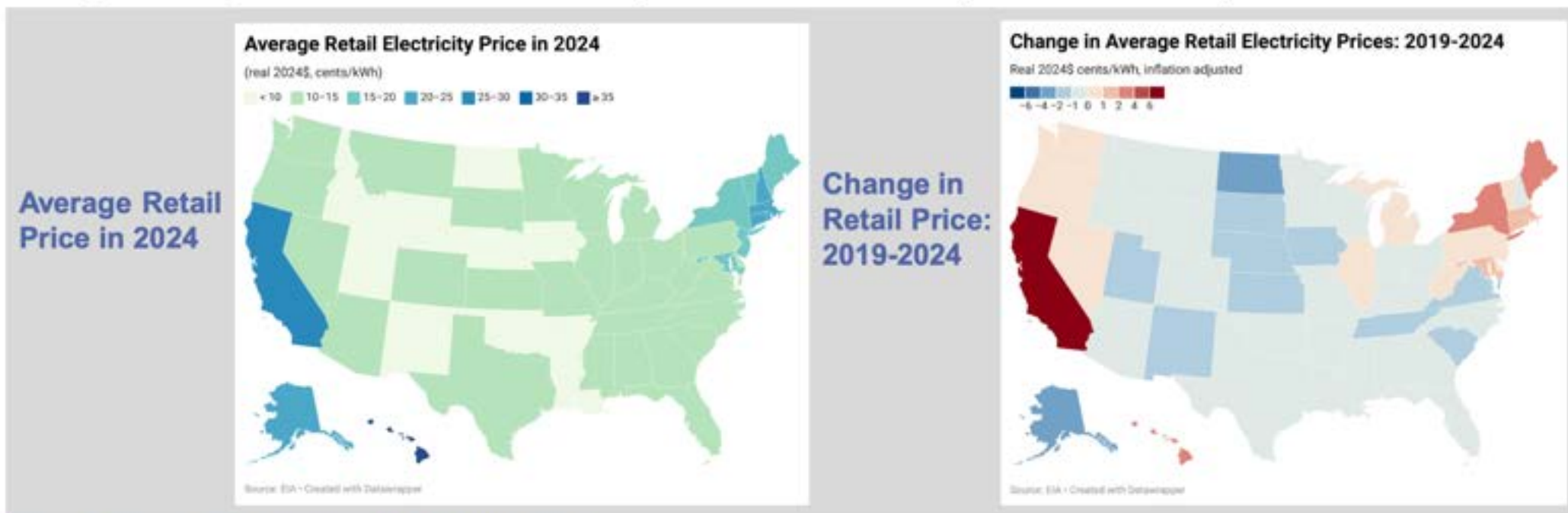
- ▣ In nominal terms (i.e., not inflation-adjusted), the average retail electricity price increased by 23% from 2019 to 2024, and 32% since 2010
- ▣ When adjusted for inflation, real prices in 2024 were the same as 2019, and 8% lower than 2010
  - This is generally consistent with the longer-term trends of declining real electricity prices and reflects the long-term decline in natural gas prices and other generation-related costs
- ▣ **Key takeaway:** Retail prices at a national level have largely tracked inflation in recent years



**Represents the "all-in" price, equivalent to total customer bills (including volumetric, demand, and fixed charges) divided by total retail electricity sales, and covers all costs associated with the provision of retail service (generation + transmission + distribution)**

## Recent national trends in retail electricity prices mask vastly varying trends in state-level average electricity prices

- Average retail electricity prices in 2024 vary widely across states; highest in HI, CA, the Northeast, AK (*left figure*)
- 90% of lower-48 landmass and 75% of U.S. population have all-sector average prices below 15 cents/kWh
- In nominal terms (i.e., not inflation-adjusted), almost all states experienced increases in retail prices between 2019-2024; however, in real terms (i.e., inflation-adjusted) most states experienced price decreases (*right figure*)
- California experienced the largest price increase in real terms, followed by HI and states in the NE, West, Great Lakes
- **Key takeaway:** A limited number of states experienced outsized retail price increases at a pace above inflation



## Distribution (and transmission) expenditures have contributed to retail price increases, whereas direct generation costs have declined nationally

- ▣ Over the last two decades, aggregate investor-owned utility (IOU) spending on distribution and transmission increased in real, inflation-adjusted terms, whereas expenditures on generation generally declined (*left figure*)<sup>1</sup>
- ▣ Focusing on aggregate national data from 2019 to 2024, inflation-adjusted distribution and transmission expenditures increased, whereas generation costs declined (*right figure*)<sup>1</sup>; distribution increase was widespread geographically
- ▣ Several factors drove distribution (and transmission) spending over this period:
  - **Ageing infrastructure:** Assets older than 50 years typically need to be replaced, costing over \$10 billion/year just for transmission<sup>2</sup>
  - **Equipment hardening:** Utilities are spending on adaptation and resilience measures, hardening their T&D systems<sup>3</sup>
  - **Supply-chain constraints:** Pandemic-era equipment shortages persist; T&D equipment costs have risen far above inflation<sup>4</sup>

